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May 9, 2022

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

2022 Long Term Gas Resource Plan (LTGRP)

On February 25, 2019, the British Columbia Utilities Commission (BCUC) issued its Decision and Order No. G-39-19 accepting FEI's 2017 LTGRP and directing FEI to file its next LTGRP on or before March 31, 2022, which was subsequently extended to May 9, 2022.[1]

In accordance with the BCUC's Resource Planning Guidelines and Section 44.1(2) of the *Utilities Commission Act* (UCA), FEI submits the attached 2022 LTGRP for the BCUC's review.

There are no approvals being sought by FEI as part of this LTGRP submission. The LTGRP presents a 20-year view of the demand-side and supply-side resources identified to meet expected future gas demand, reliability requirements and provincial greenhouse gas reduction requirements at the lowest reasonable cost to FEI's customers. The LTGRP includes an action plan that identifies the activities that FEI intends to pursue during the first four years of the 20-year planning horizon. FEI will file separate applications for Certificates of Public Convenience and Necessity, if and as necessary, for any of the identified activities in accordance with the BCUC's guidelines.

FEI respectfully seeks acceptance of its 2022 LTGRP in accordance with Section 44.1(2) of the UCA.

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[1] By letter dated March 18, 2022, the BCUC approved FEI's extension request to file its 2022 LTGRP by April 29, 2022 and by letter dated April 28, 2022, the BCUC approved FEI's further extension request to file by May 9, 2022.

If further information is required, please contact Ken Ross, Manager, Integrated Resource Planning and DSM Reporting at (604) 576-7343 or ken.ross@fortisbc.com.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): FEI's Resource Planning Advisory Group
FEI 2017 Long Term Resource Plan Registered Parties
FEI Annual Review for 2022 Rates Registered Parties

FORTISBC ENERGY INC.

2022 Long-Term Gas Resource Plan

May 2022

Territorial Acknowledgement

FortisBC acknowledges and respects Indigenous People in Canada, on whose traditional territories we all live and work. FortisBC is committed to Reconciliation with Indigenous Peoples and is guided by our Statement of Indigenous Principles.

https://www.fortisbc.com/in-your-community/indigenous-relationships-and-reconciliation/our-statement-of-indigenous-principles

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FortisBC Energy Inc.
2022 LTGRP

Executive Summary

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EXECUTIVE SUMMARY

1. INTRODUCTION

FortisBC Energy Inc. (FEI) files this 2022 Long-Term Gas Resource Plan (LTGRP) under section 44.1(2) of the *Utilities Commission Act* (UCA) and is respectfully seeking acceptance by the British Columbia Utilities Commission (BCUC) of the LTGRP as being in the public interest pursuant to section 44.1(6). Consistent with the UCA, the BCUC's Resource Planning Guidelines, and prior BCUC directives, the 2022 LTGRP presents FEI's long-term plan for meeting the forecast peak demand and energy requirements of customers with demand-side and supply-side resources over a 20-year planning horizon (2023 to 2042). FEI's 2022 LTGRP objectives are to:

- Ensure cost-effective, secure and reliable energy for customers;
- Provide cost-effective Demand-side Management (DSM) initiatives and lower-carbon solutions;
- Ensure consistency with provincial energy objectives; and
- Address prior BCUC directives.

The 2022 LTGRP serves as a foundation for further evaluation of gas supply and system infrastructure options for meeting forecast customer needs under different scenarios. The LTGRP is not a substitute for the analysis done to support specific supply or expansion projects, programs or rate design in the future, but rather helps to inform the process of other initiatives. FEI will further evaluate any specific resource projects that are identified within the LTGRP that require BCUC approval and file separate applications with the BCUC as needed in the future.

This 2022 LTGRP is profoundly shaped by the developments in climate change policy in recent years and, in particular, the Province's 2018 CleanBC plan and CleanBC Roadmap to 2030 (Roadmap) which set out ambitious targets for reducing greenhouse gas (GHG) emissions. In response to these policies and the need to reduce GHG emissions, this 2022 LTGRP provides FEI's plan to transition to a low-carbon energy future and transition toward distributing renewable and low-carbon gas. Future resource plans will build on this plan as innovation in low-carbon gas production, supply and use advances.

The foundation for the 2022 LTGRP and this transformational reduction in GHG emissions is FEI's existing infrastructure, service offerings, workforce and logistics, as well as the regional gas supply infrastructure that is vital to serving the energy needs of British Columbians. Table ES-1 provides a summary of FEI customer, demand and pipeline characteristics. Table ES-2 presents the renewable and low-carbon gas resources included in the 2022 LTGRP that, over the planning horizon, along with increased DSM and growth in fuel service for the low-carbon transportation (LCT) sector, are pivotal in reaching BC's GHG emission reduction goals.

Table ES-1: FEI Service Statistics

	2016	2021	Percentage Increase Since 2017 LTGRP
Number of Customers	994,004	1,064,800	7.1%
Annual Demand (PJ)[1]	197	228	15.7%
Peak Day Demand (TJ/day)[2]	1,334	1,399	4.9%
Length of Transmission Pipeline (km)	2,959	2,970	0.4%
Length of Distribution Pipeline* (km)	45,741	47,523	3.9%

** Includes both distribution and intermediate pressure pipelines.*

Table ES-2 Fuel Types and Decarbonization Technologies Used in the 2022 LTGRP

Fuel Type	Description[3]	Life cycle Emission Factor (tCO_2e/GJ)	End use cycle Emission Factor (tCO_2e/GJ)
Natural gas	Natural gas is a naturally occurring hydrocarbon. Hydrocarbons are a class of organic compounds consisting of carbon and hydrogen. Raw natural gas (before processing) is composed primarily of methane.[4]	0.0598	0.04987[5]
Renewable natural gas (RNG)	Upgraded biogas produced from farm or municipal organic biomass. Upgraded synthesis gas (syngas) produced from wood biomass at pulp mills and some municipal organic biomass.	0.0100	0.0003
Syngas	Produced from wood to displace natural gas used in lime kilns at pulp mills. Can also be upgraded to green hydrogen.	0.0100	0.0000
Lignin	Produced from black liquor to displace natural gas used in lime kilns at pulp mills.	0.0100	0.0000
Green Hydrogen	Produced via water electrolysis using renewable electricity feedstock.	0.0000	0.0000
Blue Hydrogen	Reformed from hydrocarbon feedstock with up to 90 percent carbon sequestered.	0.0200	0.0000[6]
Natural Gas with Associated Carbon Capture, Utilization and Storage (CCUS)	Applying the carbon reduction benefits of CCUS to the delivery of natural gas on FEI's gas network.[7]	0.0148	0.0148

1 1 PJ (petajoule) = 1,000,000 GJ.
2 1 TJ per day (terajoule/day) = 1,000 GJ per day.
3 All definitions for fuel types are sourced from FEI except where specified.
4 Online at: https://www.nrcan.gc.ca/energy/energy-sources-distribution/natural-gas/natural-gas-primer/5641.
5 GHG emission factor consistent with that used by the Province as discussed in Section 9.2.
6 Updated values for the carbon intensity of hydrogen production are currently under development and will be provided in the next LTGRP.
7 The International Energy Association describes CCUS as a suite of technologies that can play an important and diverse role in meeting global energy and climate goals. CCUS involves the capture of CO_2 from large point sources,

The resource planning process begins by closely examining the planning environment in which FEI operates and by identifying expectations for future customer and demand growth. The demand- and supply-side resource alternatives for meeting future demand are then assessed, and actions recommended to ensure that the proper resources are in place to deliver the preferred energy solutions to meet future customer needs. Finally, FEI presents a four-year Action Plan, which identifies the near-term activities needed to meet the long-term resource requirements identified in the LTGRP.

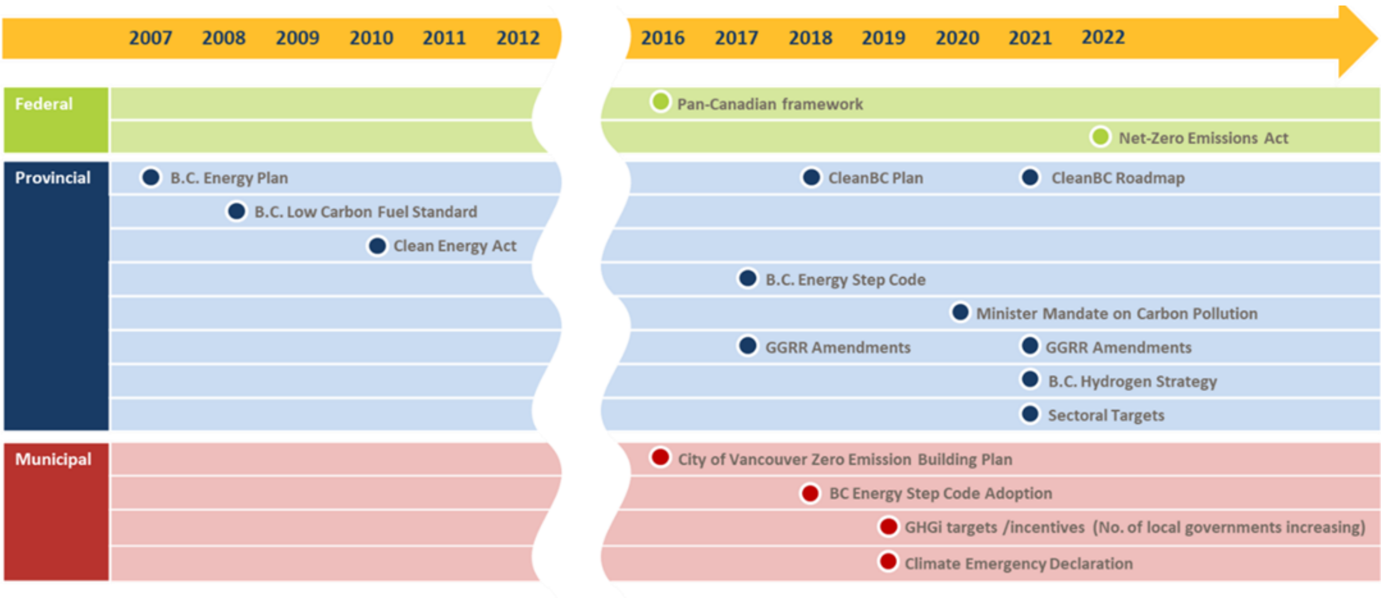
2. PLANNING ENVIRONMENT

This LTGRP involves forecasting and planning to 2042, during a time of rapid change and uncertainty in market forces, energy technologies and government policy, and at the early stages of FEI's journey to a low-carbon energy future. British Columbians, represented by all levels of government, Indigenous groups, and community representatives have been clear that a new path to a secure and low-carbon energy future must be developed. The 2022 LTGRP represents FEI's vision for how it will respond to this changing planning environment and participate in solutions to the imperatives placed on energy utilities like itself. This LTGRP represents FEI's long-term view of its transition to a low-carbon energy future, and is intended to be the catalyst for rapid progress in meeting the ambitious GHG reduction targets established by the provincial and federal governments.

Climate change is dramatically impacting the physical, political, social and economic environment in which FEI operates. Governments at all levels are enacting environmental policies and regulations aimed at reducing GHG emissions. These evolving energy and environmental policies are key factors in the LTGRP planning environment and help inform FEI regarding potential impacts on future customer demand and supply over the planning horizon. An overview of the major policies influencing FEI's planning environment and their evolution over time is illustrated in Figure ES-1.

including power generation or industrial facilities that use either fossil fuels or biomass for fuel. The CO_2 can also be captured directly from the atmosphere. If not being used on-site, the captured CO_2 is compressed and transported by pipeline, ship, rail or truck to be used in a range of applications, or injected into deep geological formations (including depleted oil and gas reservoirs or saline formations) which trap the CO_2 for permanent storage: CCUS Technology Report (2021), online at: https://www.iea.org/reports/about-ccus.

Figure ES- 1: Major Policies Adopted by All Levels of Government Demonstrate the Complexity of FEI's Planning Environment



There have also been significant legislative and policy developments with respect to the engagement with Indigenous groups since the 2017 LTGRP that have broad impacts on FEI's long-term planning. FEI recognizes and respects the constitutional rights of Indigenous peoples, and FEI's Statement of Indigenous Principles aims to ensure FEI's business operations are conducted with respect for Indigenous people's social, economic and cultural interests. Feedback and input from Indigenous groups during the development of this LTGRP emphasized the need for FEI to consider the key principles of the *United Nations Declaration on the Rights of Indigenous Peoples* and to ensure FEI considers Indigenous energy perspectives within its broader utility planning processes.

The competitive environment for FEI's products has grown more complex as a multitude of pricing and non-price considerations are influencing customer energy choices. Capital costs, installation requirements, operating and maintenance costs, government policies and public perception all play a role in this regard.

Gas markets continue to be volatile. With the anticipation of increased demand in the Pacific Northwest (PNW) and limited pipeline infrastructure becoming further constrained, regional price disconnects are expected to continue. Geo-political risk, and strained supply resources in the region during high demand periods, are creating upward price pressure and volatility risk. Infrastructure is needed to meet the pace of future demand growth, provide resiliency, and help support the clean energy transition in the PNW.

Decarbonizing FEI's gas supply in response to climate policy will put upward pressure on gas costs. This rising cost, regardless of specific cost recovery mechanisms or tariffs, will continue to be borne by FEI's customers, reducing FEI's price competitiveness when compared to other low-carbon fuel sources. Gas prices will continue to rise as renewable and low-carbon gas comprises a larger share of the fuel mix. In parallel, electricity rates associated with electrification may also rise due to the need for more transmission, distribution, and substation infrastructure required to meet increases in electricity peak demand. However, decarbonization is necessary to meet the GHG emission targets set out in the Roadmap and to respond with urgency to climate change. The 2022 LTGRP demonstrates how the Clean Growth Pathway has the advantage of leveraging the resilience and reliability of the provincial energy system as a whole, achieving GHG reductions aligned with the provincial government's objectives, and being a more affordable and practical pathway for BC than relying on electrification alone.

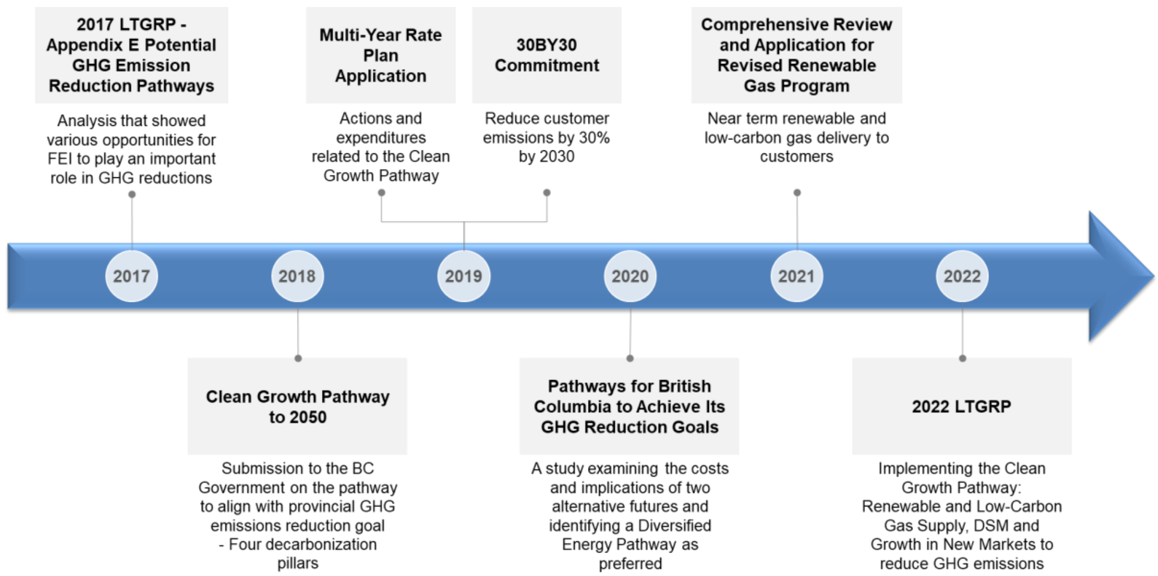
3. CLEAN GROWTH PATHWAY AND FOUR PILLARS TO A LOW-CARBON FUTURE

The 2022 LTGRP provides a comprehensive and long-term view of FEI's transition to a low-carbon future as it responds to a rapidly evolving energy landscape. FEI's Clean Growth Pathway lays the groundwork for this transition and represents FEI's 20-year vision. The Clean Growth Pathway is FEI's approach to supporting increasing government ambition and intervention to reduce GHG emissions and the adoption of policies to take greater climate action. The Clean Growth Pathway report (Appendix A-1) provides FEI's framework to transition to a low-carbon energy future and is supported by four key pillars, which figure prominently in the 2022 LTGRP:

- **Pillar 1:** Transitioning to renewable and low-carbon gases to decarbonize the gas supply;
- **Pillar 2:** Investing in DSM programs in support of energy efficiency and conservation measures to reduce energy use among residential, commercial and industrial customers;
- **Pillar 3:** Support for low-carbon transportation infrastructure to reduce emissions in this sector; and
- **Pillar 4:** Investing in LNG to lower GHG emissions in marine fueling and global markets.

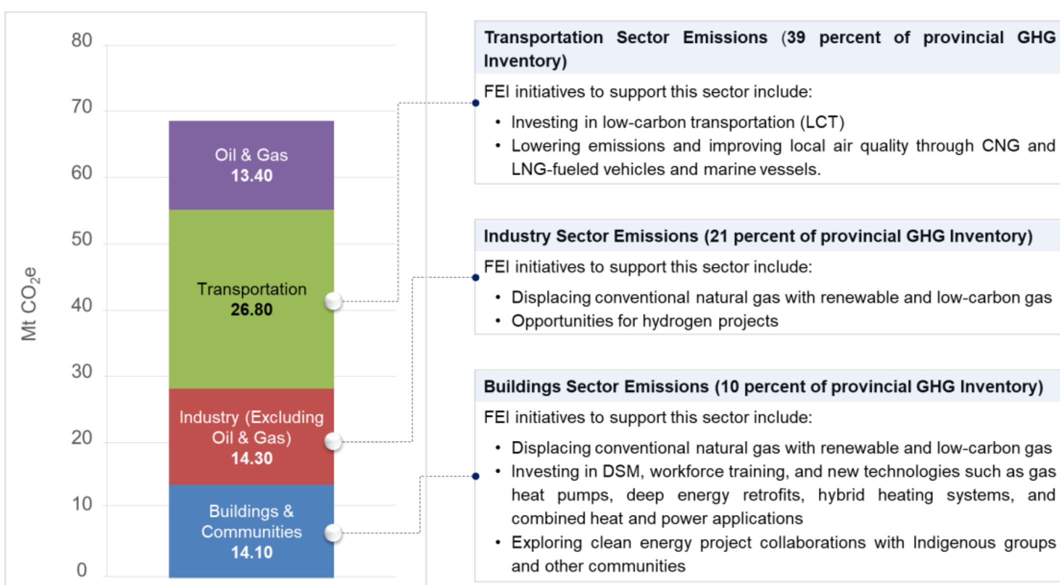
FEI's Clean Growth Pathway is a diversified pathway in that it relies on maintaining and growing both the existing gas and electricity infrastructure networks in BC to reach carbon reduction targets, catalyse energy innovation, and meet BC's growing need for energy over the long term. In addition to achieving GHG reductions aligned with the provincial government's objectives, other benefits include meeting peak demand on the coldest days of the year with the lowest risk, improving energy system resiliency, fostering emerging technologies and innovation, and economic development across the energy services supply chain. Figure ES-2 illustrates key milestones since the 2017 LTGRP that have set the stage for FEI's Clean Growth Pathway.

Figure ES-2. The Evolution of FEI's Clean Growth Pathway from 2017 LTGRP to 2022 LTGRP



The 2022 LTGRP plans for reducing BC's GHG emissions and contributing to global GHG emission reductions. Figure ES-3 illustrates BC's 2019 GHG emissions inventory by sector and describes FEI's initiatives to address these sectoral emissions.

Figure ES-3: 2019 GHG Emissions by Sector in BC[8] and FEI Initiatives to Support Decarbonization



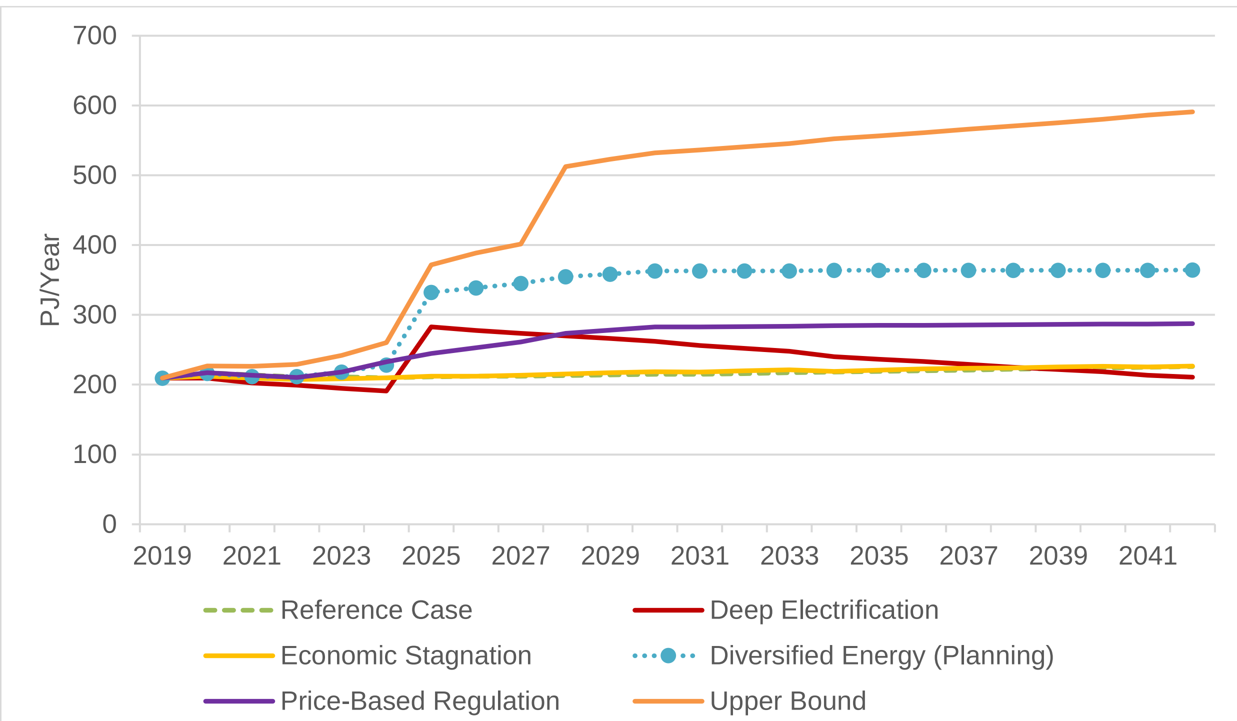
[8] BC's 2019 GHG emissions. Online at https://www2.gov.bc.ca/gov/content/environment/climate-change/planning-and-action/progress-targets#emissions.

4. ANNUAL ENERGY DEMAND FORECASTING

Forecasting customer energy demand is a key step in identifying the resources FEI needs to meet the future energy needs of customers. An annual demand forecast is the amount of gas that FEI expects its customers to use over the course of a year. This determines the amount of gas FEI needs to acquire and transport on behalf of its customers on an annual basis. The annual demand forecast also provides the basis for determining energy savings from DSM and for calculating GHG emissions and emission reductions. FEI's peak demand is discussed later in the LTGRP and is a basis for securing shorter duration peaking supply resources and planning to meet system capacity requirements.

For resource planning, FEI uses an End Use Annual Method of demand forecasting to examine different ways that end use trends could unfold over the planning horizon to impact demand for gas. FEI prepares a Reference Case forecast as well as a range of alternate future scenarios that enable FEI to examine how future demand might unfold. FEI has designated the Diversified Energy Scenario as its planning scenario, which enables FEI's Clean Growth Pathway. Figure ES-4 shows the total range of annual demand forecast including all customer categories for each of the Reference Case and alternate future scenarios examined.

Figure ES-4: Total Forecast Annual Demand– All Demand Categories, All Scenarios



FEI's expectation of future annual energy demand for planning purposes is represented by the outputs of the Diversified Energy (Planning) Scenario analysis as shown in Figure ES-4. Observed growth in annual demand in the first half of the planning horizon is driven by load growth in the transportation sector and global LNG market, primarily with the large load step increase for the addition of the Woodfibre LNG project, modelled to begin operation in 2027.

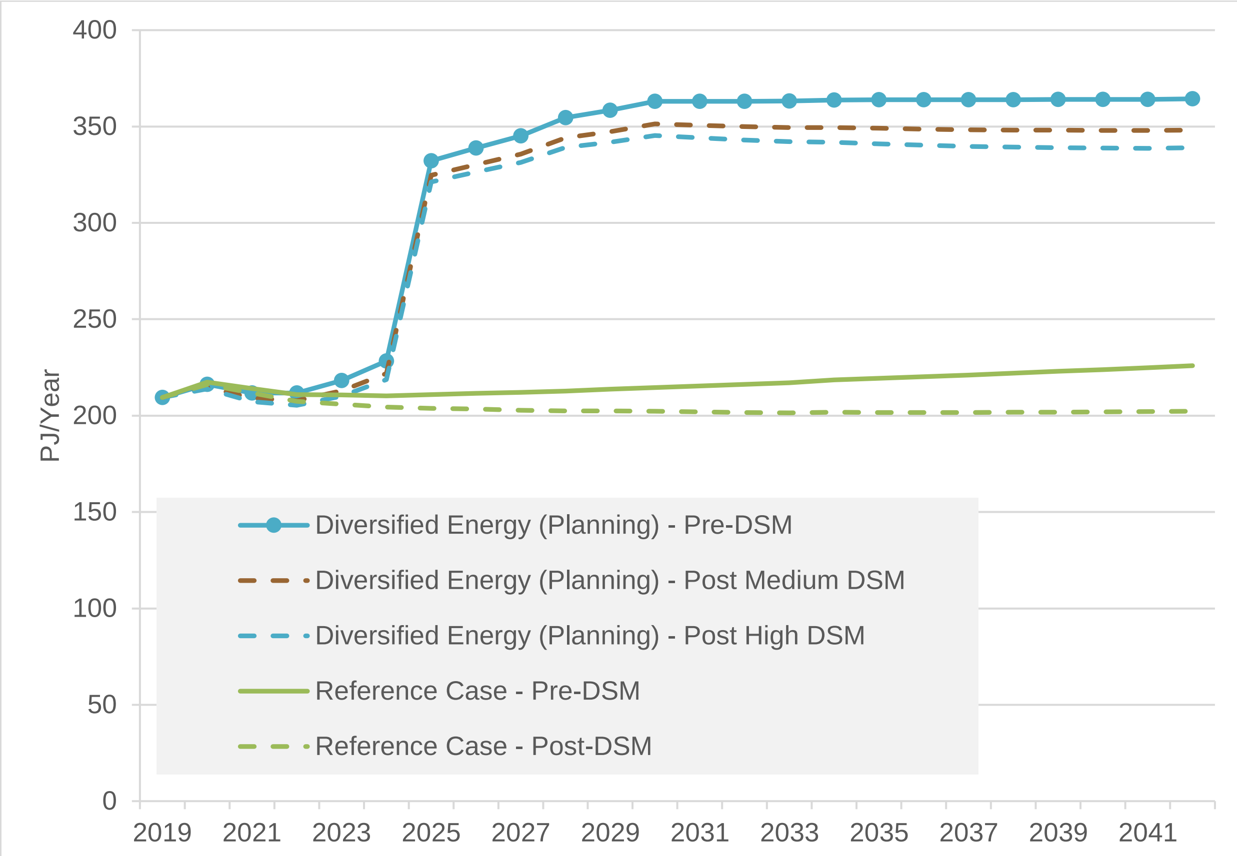
5. DEMAND-SIDE RESOURCES

FEI's adequate and cost-effective portfolio of DSM activities can result in significant energy and GHG emissions reductions over the planning horizon under the range of future scenarios examined for the LTGRP. As a pillar of FEI's Clean Growth Pathway, FEI anticipates expanding its existing DSM activities over the planning horizon to reduce GHG emissions to meet provincial GHG reduction targets. In particular, FEI's future DSM expenditure plans that will be filed with the BCUC for acceptance will be guided by the High DSM Setting analysed in this LTGRP. Under the Diversified Energy (Planning) Scenario with the High DSM Setting, FEI's savings from DSM activities are forecast to be significant, at approximately 25 PJ or 13 percent of annual load in 2042.

As directed in Order G-39-19, FEI's DSM funding scenarios reflect the results of the most recent Conservation Potential Review (CPR) (Appendix C-1), with incentive level, economic screen and budget settings applied to individual scenarios. The Diversified Energy (Planning) Scenario was used as the basis for a sensitivity analysis demonstrating the effects of the Low, Medium and High DSM settings on DSM expenditures, energy savings and cost effectiveness tests. These cost effectiveness tests include Total Resource Cost (TRC), Modified Total Resource Cost (MTRC) and Utility Cost Test (UCT) results expressed as a ratio and the Cost of Conserved Energy (CCE) expressed as $/GJ. FEI also provides a directional view of delivery rate and bill impacts for residential customers under the Low, Medium and High DSM Settings in the Diversified Energy (Planning) Scenario.

The final step in the DSM analysis is to develop total annual demand post-DSM to demonstrate the resulting energy savings effects of projected DSM activity. Figure ES-5 below illustrates the energy savings associated with DSM. In 2042, the Diversified Energy (Planning) Scenario – High Setting is 7 percent lower and the Medium Setting is 5 percent lower than the pre-DSM Annual Demand when taking into account the impact of both forecast LCT and also DSM activity. This results in 25 PJ of annual energy savings for the High DSM Setting and 16 PJ of annual energy savings for the Medium DSM Setting. In conclusion, this Diversified Energy (Planning) Scenario total annual demand after DSM (shown as Diversified Energy (Planning) – Post High DSM in the figure below) represents the annual demand that FEI is planning to in the 2022 LTGRP.

Figure ES-5: Total Annual Demand Before and After DSM for all Demand Categories



6. GAS SUPPLY PORTFOLIO

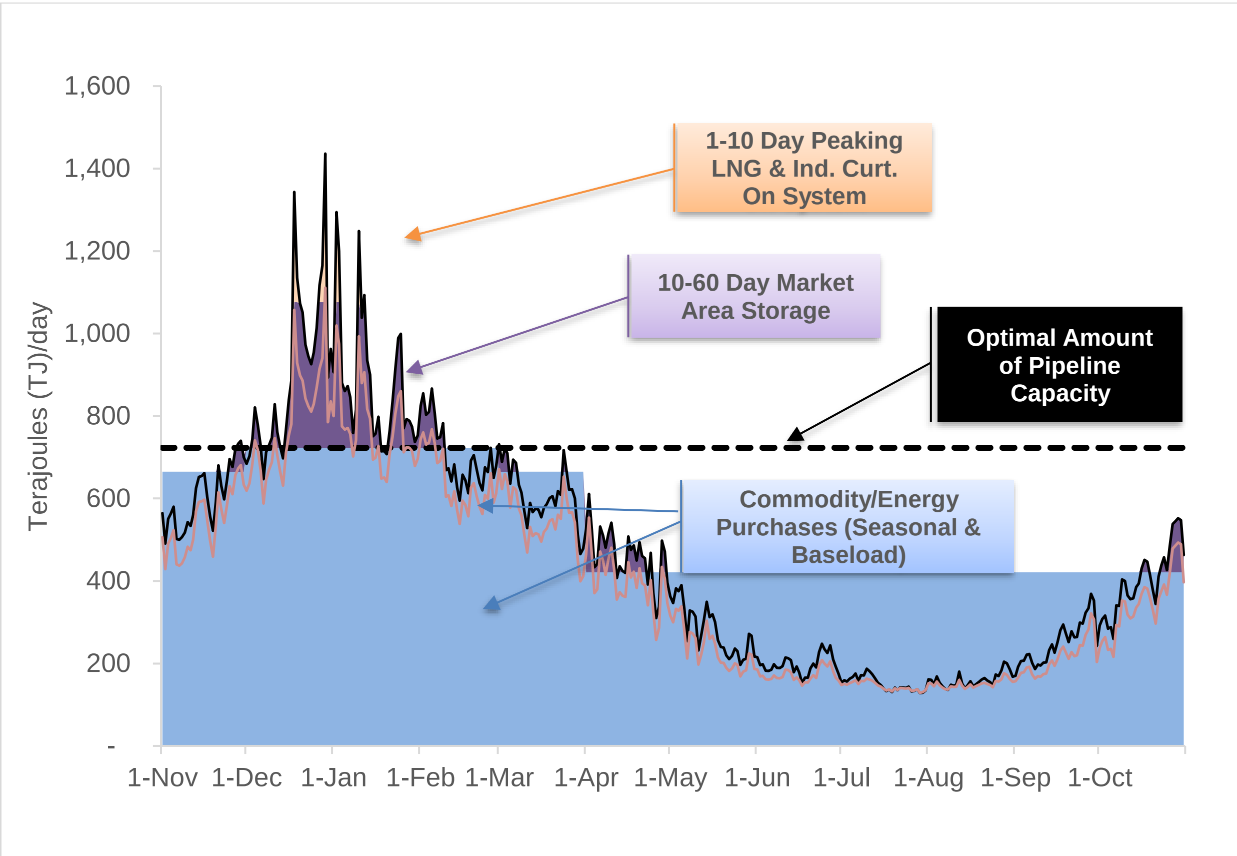
FEI's energy supply portfolio planning ensures that the forecast normal and peak day demand of core market (Core)[9] customers can be met. The planning process begins with considering the locations where FEI can purchase its gas supply resources and the physical gas storage and pipeline resources to which FEI has access. Other steps include planning for price risk management, pipeline and storage resources, potential changes in demand or market conditions, and the transition to renewable and low-carbon gas supplies through the Clean Growth Pathway.

The fundamental design principle of constructing an efficient gas supply portfolio of resources is to match the resource characteristics to the demand characteristics. Figure ES-6 provides an illustrative example of FEI's gas supply portfolio. Demand exhibits pronounced seasonality (i.e., high load in winter and low load in summer), and therefore a low annual load factor. This figure

[9] Core customers refer to Rate Schedules 1, 2, 3, 5, 6, 46 included; and Rate Schedule 4 (seasonal) excluded. FEI's gas supply portfolio includes the forecast normal, design, and peak day demand of these customers. Transportation Service customers arrange for their own supply that is then transported by FEI to their premises. System capacity planning (Section 7) needs to consider total system throughput to ensure that sufficient capacity exists on FEI's system to reliably deliver gas supply to meet the demand for both Core and Transportation service customers.

illustrates how the duration of supply resources fits the forecast annual normal and design load for Core customers.

Figure ES-6: 2021/2022 FEI Forecast Design and Normal Loads vs. Resources[10]



Constrained pipeline and storage resources in the PNW during the winter season continues to be a major concern, and market developments have caused significant supply and pricing risks in the region. Geo-political risks have added greater market uncertainty at this time. FEI has increased resiliency to a degree within the existing portfolio by holding contingency resources; however, resiliency needs to be further improved through new infrastructure projects. With the advancement of renewable and low-carbon gas supply resource in the region, FEI's future infrastructure is being planned to support the transition to a lower-carbon future by providing increased resiliency and supporting a broader range of supply resources.

Additional infrastructure and storage have been a major focus for FEI in light of recent supply disruptions, growing demand in the region, and the necessary requirements to transition to a renewable and low-carbon energy future. FEI has applied to the BCUC for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury LNG Storage Expansion (TLSE) project, which includes the construction of a new LNG storage tank and increased regasification capacity. The TLSE project would significantly increase the resiliency of FEI's gas system in the event of a

10 This forecast is for Core requirements and does not represent total system throughput.

critical disruption of regional pipeline supply by allowing FEI to continue to serve a much larger portion of the daily system in the event of a supply emergency and by providing sufficient storage to meet that load for a longer period of time. Similarly, FEI's Regional Gas Supply Diversity (RGSD) project would involve expanding the Southern Crossing Pipeline (SCP) to diversify FEI's gas supply on a separate pipeline path from those with constrained capacity.

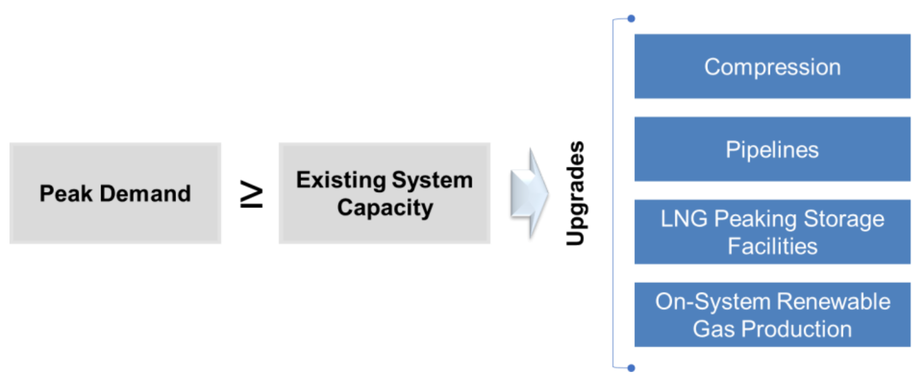
Implementing the RGSD project and expanding on-system storage resources (i.e., the TLSE project) are the most cost-effective ways to enhance resiliency, facilitate load growth opportunities, support the transition to renewable and low-carbon gas and also create diversity and flexibility within FEI's energy supply portfolio. Ultimately, the continued use of the gas infrastructure is a critical component of decarbonizing the province's energy system and, over the long term, will mitigate the cost of the low-carbon energy transition to British Columbians.

7. SYSTEM RESOURCE NEEDS AND ALTERNATIVES

A key aspect of ensuring safe, reliable, and secure delivery of gas to customers is identifying when and where any capacity constraints may appear and planning for the infrastructure and system resources that FEI requires to construct over the planning horizon. Growth in peak demand is among the most significant challenges for FEI's long-term planning. When the forecast for peak demand exceeds available capacity, a gas system expansion is required. The system resource needs discussed in the 2022 LTGRP also reflect the need to deliver renewable and low-carbon gases in increasingly larger volumes over the planning horizon and discusses the infrastructure changes required to accommodate this transition.

System planning includes system sustainment and renewal, integrity upgrades, and system expansion contributing to overall system resiliency. There are three primary resource options to evaluate when planning system expansions: pipelines, compression and storage as shown in Figure ES-7. Over time, FEI expects on-system renewable gas production to grow in importance as a fourth resource option. Often, some combination of the resource options leads to an optimal solution. Infrastructure projects on transmission systems to address system capacity constraints are often large and take many years to plan and execute, demonstrating the benefits of the long-term resource planning process.

Figure ES-7: Options for Gas System Reinforcements



To address specific local and regional demand, FEI considers the peak demand requirements for each of the three main transmission systems: Vancouver Island Transmission System (VITS); Coastal Transmission System (CTS); and Interior Transmission System (ITS). For each regional system, higher or lower than expected load growth could shift the timing of system expansion requirements either ahead or further out in time.

For the VITS, at this time, capacity upgrades are not required. Two pressure control station additions are currently proposed for installation in the next few years to serve the growing distribution systems of Greater Victoria and Nanaimo. The Woodfibre LNG project will require reinforcement of the existing VITS with pipeline looping and added compression near Squamish. This would match the capacity contracted by the project proponent under peak demand, while also preserving available capacity for existing customers and allowing large volumes of interruptible capacity to be available for much of the year.

For the CTS, the TLSE and RGSD projects would address demand and resiliency requirements. The Tilbury site in Delta, located on the CTS, is the location of the LNG liquefaction and storage facility used to serve demand for conventional gas from LCT initiatives, which is forecast to grow over the next 20 years. Based on FEI's demand forecasts for LNG, future phases of Tilbury LNG expansion beyond the current phase will need to be constructed. The RGSD project would expand the SCP from Oliver to the Lower Mainland to increase the CTS's supply diversity. The RGSD has also been developed in consideration of the Clean Growth Pathway and will have the capacity and capability to support FEI's plans to deliver hydrogen across the PNW, including BC.

For the ITS, capital expansion is required to meet forecast demand. FEI currently has a CPCN Application for the Okanagan Capacity Upgrades (OCU) Project in progress. The proposed OCU project would offer sufficient capacity to meet the future peak demand requirements. The preferred alternative is an approximately 30-kilometre NPS[11] 16 pipeline loop between Penticton and Kelowna, reinforcing the existing NPS 12 pipeline currently in service. Reinforcement alternatives have been identified to meet the demand forecast and would be required, in addition to completion of the OCU Project, by the winter of 2038 to 2039.

As FEI incorporates renewable gases into the gas distribution and transmission systems, the physical properties of these gases, such as density and energy content per standard volume, can have an impact on capacity. Gases with physical properties within the range of conventional gas, such as RNG, will have no net impact on delivery capacity. Delivering hydrogen or a blend of hydrogen and natural gas or hydrogen and RNG, where the gas density and energy content are different from traditional natural gas supply, will change the energy delivery capacity. Table ES-3 provides an overview of FEI's system planning considerations for integrating renewable and low-carbon gas into the individual regional transmission systems.

[11] Nominal pipe size, in inches.

Table ES-3: Overview of Considerations for Integrating Renewable and Low-Carbon Gas in FEI Systems

Fuel Type / Other Considerations	Regional Transmission and Distribution Line Considerations		
	VITS	**CTS**	**ITS**
RNG (on-system)	• Supply potential • No detrimental impact on transmission system capacity • Reliable supply from local on-system hubs will reduce upstream supply requirements and improve available capacity	• Supply potential • No detrimental impact on transmission system capacity • Reliable supply from local on-system hubs will reduce upstream supply requirements and improve available capacity	• Supply potential • No detrimental impact on transmission system capacity • Reliable supply from local on-system hubs will reduce upstream supply requirements and improve available capacity
Hydrogen	• Supply potential from blue or turquoise production potential may require system upgrades • Green hydrogen hub will reduce upstream supply requirements and improve available capacity, but reduce available capacity downstream	• By 2030, hydrogen production anticipated with hydrogen and RNG in similar proportions. • By 2042, hydrogen supplied from upstream of Huntington Control Station and comprises a much larger portion of the fuel mix • With upstream supply, hydrogen separation facility at Huntingdon anticipated • Dedicated hydrogen "backbone" pipeline likely	• Supply potential from blue or turquoise production potential may require system upgrades • Green hydrogen hubs will reduce upstream supply requirements and improve available capacity, but reduce available capacity downstream
Syngas and Lignin	• Supply potential	• No supply potential currently identified	• Supply potential
LNG and Industrial Project Impacts	• Woodfibre LNG project may preclude hydrogen blending upstream (at Eagle Mountain) • Management of hydrogen at FEI's Mount Hayes LNG facility would be required	• Flow of hydrogen likely to be separated from transmission system at Huntingdon control station due to large scale LNG production at Tilbury and Woodfibre LNG project	• Management of hydrogen at any future LNG facilities would be required

Fuel Type / Other Considerations	Regional Transmission and Distribution Line Considerations		
	VITS	CTS	ITS
System Upgrade Requirements	• Scope and location of system upgrades not yet feasible to determine as supply volumes and locations are currently in early stages of development	• Local supply hubs and small dedicated systems eventually connected to upstream by dedicated hydrogen "backbone" • Scope and location of system upgrades not yet feasible to determine as supply volumes and locations are currently in early stages of development	• Renewable and low-carbon projects could offset the need for upgrades • RGSD project under development could provide significant support for delivery of hydrogen and other renewable gas • Scope and location of system upgrades not yet feasible to determine as supply volumes and locations are currently in early stages of development

FEI's gas system must be expanded to meet future demand growth and optimize operation of the whole system. With annual increases in forecast peak demand, potential new sources of demand from LCT and industrial sources, and the introduction of renewable and low-carbon gases in significantly increasing quantities, the VITS, CTS and ITS transmission systems could all require capacity-enhancing projects to meet peak demand forecasts while enabling FEI's Clean Growth Pathway.

8. STAKEHOLDER INDIGENOUS AND COMMUNITY ENGAGEMENT

Connecting with customers, communities, Indigenous groups, and other stakeholders on long-range planning issues is of critical importance to FEI. FEI undertook a number of initiatives to offer interested participants the opportunity to contribute to the discussions that informed the 2022 LTGRP and FEI's Clean Growth Pathway initiatives. These activities continued into the first quarter of 2022 and included:

- Workshops with the dedicated Resource Planning Advisory Group (RPAG) engaged strategic representatives of municipalities, government, customers, associations, and organizations with interest, experience and/or significant industry knowledge in energy planning in the development of the LTGRP.
- Engagement workshops with First Nations community representatives provided feedback on how engagement can be strengthened for the ongoing LTGRP planning process, the development of clean energy projects, and other FEI initiatives.
- Community Engagement workshops recognizing the importance of considering diverse community perspectives and energy planning needs with respect to developing BC's energy future and FEI's role in the low-carbon transition across its service territory.

- FEI's other engagement activities that directly or indirectly inform the resource planning process, such as discussions with advisory groups, government, industry associations, customers and other stakeholders.

Through the RPAG workshop sessions, stakeholders have been able to provide FEI with input on many important factors, such as demand forecasting and scenario analysis methods, demand drivers and scenarios and feedback on FEI's Clean Growth Pathway. The workshops with Indigenous groups highlighted the need to further evolve engagement processes and in response FEI developed an Action Item accordingly. The Community Engagement workshops assisted FEI in identifying energy issues and planning opportunities in municipalities and communities throughout BC. The information gained through these activities informs FEI's market research and analysis, identifying long-term planning issues of concern to a number of stakeholder groups, feedback on FEI's transition to renewable and low-carbon gas, interest in local clean energy projects and identifying interested stakeholders who may become more engaged in the LTGRP process.

9. OUTCOMES OF THE CLEAN GROWTH PATHWAY

FEI's vision for the future of energy in BC is that of a diverse, integrated and resilient network of energy infrastructure and services, building on the strength and benefits of both the existing gas and electric energy delivery networks in the province. FEI's role in this future is to utilize, grow and strengthen its gas transmission and distribution systems for the continued delivery of safe, secure and reliable energy to customers, while reducing GHG emissions for customers through the four pillars of its Clean Growth Pathway. As FEI proceeds down this pathway, the continued commercialization of existing technologies, advancements in new technology and innovation will enable deeper carbon emission reductions, while putting BC at the forefront of emerging industries such as those that will drive BC's future hydrogen economy.

One of the key impacts of the Clean Growth Pathway is GHG emission reductions to meet the Roadmap's cap on emissions for natural gas utilities for residential, commercial and industrial customers, to be implemented as the Greenhouse Gas Reduction Standard (GHGRS). Through the Clean Growth Pathway, and based on end use demand in the Diversified Energy (Planning) Scenario, FEI's GHG emission reductions for the following categories are described below and illustrated in Figure ES-8:

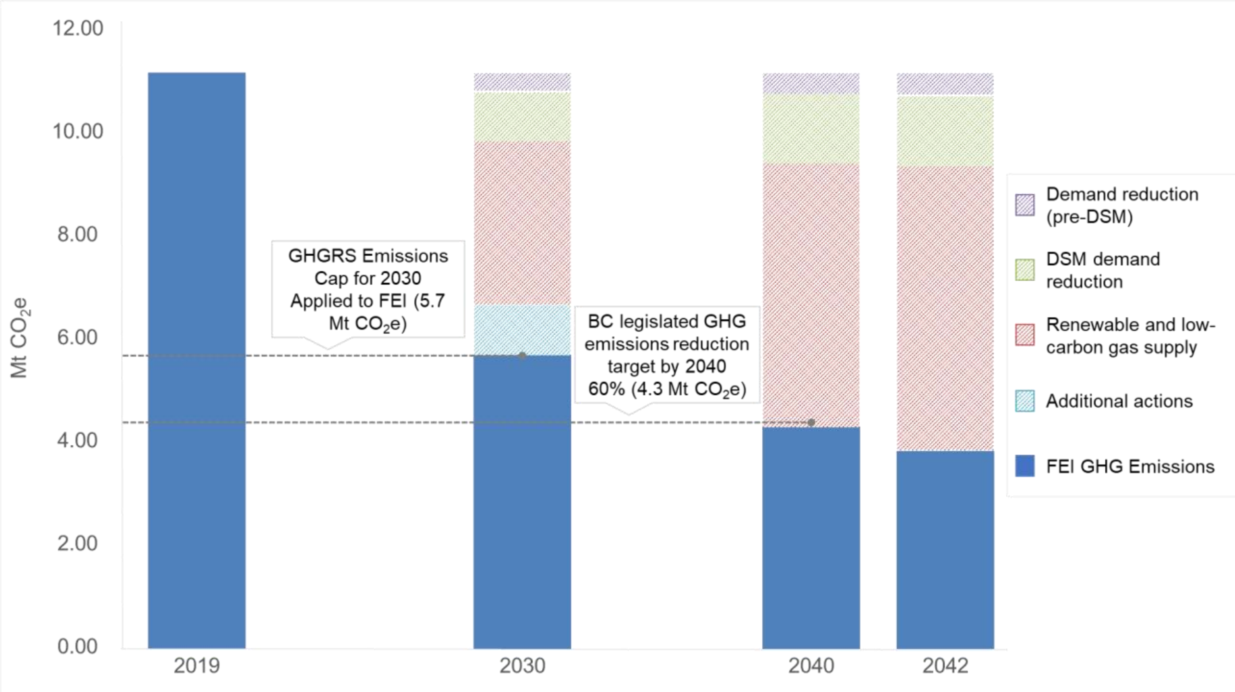
- **Changes in demand (pre-DSM)** describes the impact of natural efficiency[12] combined with a degree of electrification discussed in Section 4. This demand reduction corresponds to GHG emission reductions of 0.3 Mt CO_2e per year in 2030 and 0.4 Mt CO_2e per year in 2040;

[12] Efficiency improvements that occur through the natural replacement of older, less efficient equipment with newer, more efficient equipment as influenced by market transformation by DSM programs, regulations and other factors.

- **FEI's DSM programs** result in energy savings at the High DSM setting discussed in Section 5. This high level of energy savings results in 0.9 Mt CO_2e reductions in 2030 and 1.3 Mt CO_2e reductions in 2040;
- **The renewable and low-carbon gas supply transition** has the largest impact on GHG emission reductions as discussed in Sections 4, 6, and 7. Acquiring and allocating 60.2 PJ of renewable and low-carbon gas supply by 2030 to this group of customers' demand results in emission reductions of approximately 3.0 Mt CO_2e. In 2040, the allocation of 99 PJ of renewable and low-carbon gas to these customer groups result in 4.9 Mt CO_2e of GHG emission reductions; and
- **Additional GHG emissions reductions initiatives** were identified by FEI after completion of the demand and supply modelling for the 2022 LTGRP. Examples of these additional opportunities include further DSM opportunities and further renewable and low carbon gas reductions such as CCUS technology development. FEI expects these opportunities to result in a further 0.9 Mt CO_2e reductions or more by 2030. FEI is still considering how these additional opportunities feed into the emissions reductions later in the planning horizon and so has not included them in its assessment of 2040 emission reductions at this time. FEI will formally include these additional opportunities in its demand and GHG emission modelling for the next LTGRP.

FEI anticipates that as it proceeds along its Clean Growth Pathway, additional new opportunities and technology advancements will continue to arise for further potential GHG emission reductions for residential, commercial and industrial customers. The Roadmap states that the GHGRS emissions cap on gas utilities will be approximately 6 Mt CO_2e in 2030. Accounting for the fact that FEI is not the only gas utility in BC, the portion of the cap that applies to FEI is approximately 5.7 Mt CO_2e. Figure ES-8 shows the GHG emission reductions required to meet the GHGRS cap for gas utilities. FEI's modelling of GHG emissions reductions for the Diversified Energy (Planning) Scenario meets the Province's 2040 target emission reductions and puts net-zero GHG emissions by 2050 for these customer groups within reach. Over the long term, the Diversified Energy (Planning) Scenario has similar emission reductions to the Deep Electrification Scenario, with a somewhat deeper reduction driven by growth in the supply of renewable and low-carbon gases.

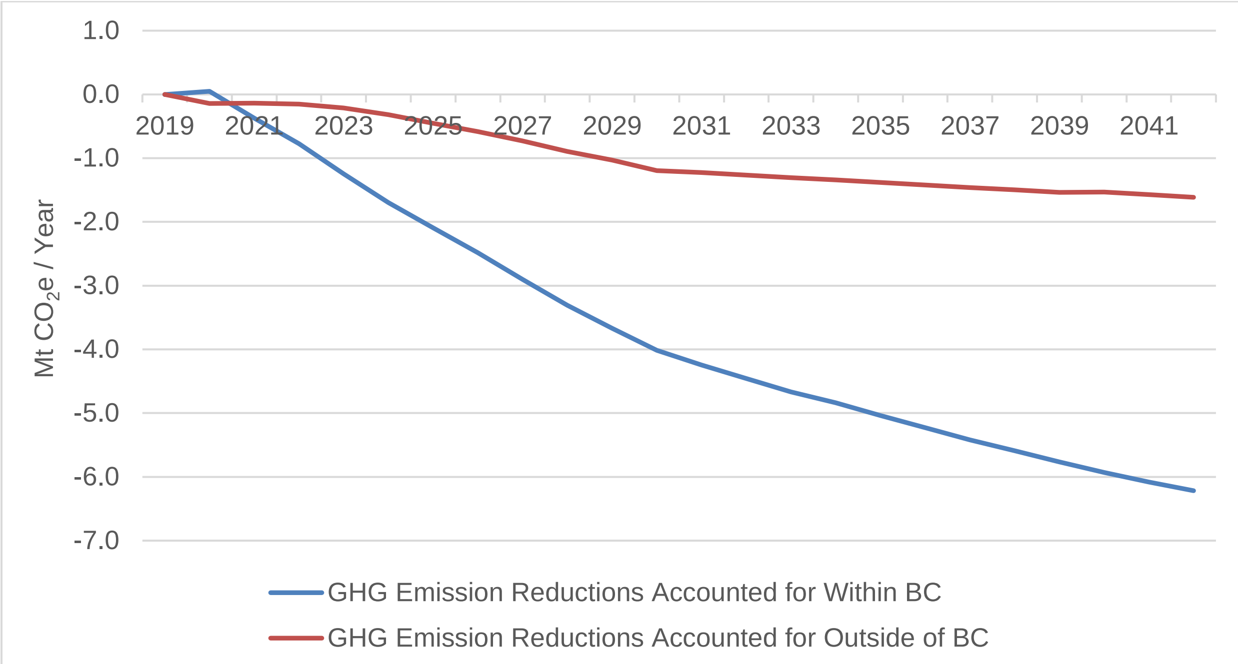
Figure ES-8. GHG Emission Reductions for Residential, Commercial and Industrial Customers Meets the GHGRS for the Diversified Energy (Planning) Scenario [13]



The total GHG emission reductions modelled in the Diversified Energy (Planning) Scenario represent the outcome of implementing initiatives outlined in the pillars of the Clean Growth Pathway. In order to provide a complete picture, GHG emission reductions from serving both the residential, commercial and industrial customer groups, and the low-carbon transportation and global LNG customers throughout the planning horizon are illustrated in Figure ES-9 (based on life-cycle emission factors). Figure ES-9 illustrates the total emissions resulting from Diversified Energy (Planning) Scenario broken out into reductions accounted for within BC and those that are accounted for outside of BC.

[13] GHG emissions reductions based on end-use emission factor in order to align with the GHGRS.

Figure ES-9: Total GHG Emission (Life Cycle) Reductions for the Diversified Energy (Planning) Scenario - BC and Outside of BC



To provide context for FEI's long-term volume forecasts and their influence on customer rates, FEI analysed the cost impacts of decarbonization initiatives and variations in demand over the planning period. Table ES-4 below summarizes the cumulative effective rate impact projections as well as the equivalent annual rate impact over the 20-year period for each select scenario.

Table ES-4: Summary and Comparison of Average Projected Delivery Rate Changes

		Effective Rate Change (2022 - 2042, %)							
	Average UPC (2022 - 2042)	**Reference**		**Upper Bound**		**Diversified Energy (Planning)**		**Deep Electrification**	
		Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual
Residential (RS 1)	60	73%	2.8%	77%	2.9%	118%	4.0%	235%	6.2%
Small Commercial (RS 2)	293	41%	1.7%	64%	2.5%	102%	3.6%	207%	5.8%
Large Commercial (RS 3)	3,253	40%	1.7%	69%	2.6%	107%	3.7%	206%	5.7%
General Firm Service (RS 5)	18,542	44%	1.9%	80%	3.0%	114%	3.9%	150%	4.7%

These cumulative effective rate impacts are made up of individual impacts in all components of FEI's rates, including delivery, cost of gas, storage & transport, and carbon tax. Using Residential (RS 1) as an example, the total residential bill is estimated to increase from approximately $1,029 in 2022 to $1,958 in 2031, and to approximately $2,215 in 2040 under the Diversified Energy (Planning) Scenario. The 118 percent cumulative effective rate impact by 2042 under the Diversified Energy (Planning) Scenario is made up of approximately 50 percent delivery rate impact, 41 percent commodity-related impact (cost of gas and storage & transport), and 9 percent carbon tax. More detailed discussion on rate impacts is presented in Section 9.4

10. ACTION PLAN

The Action Plan describes the activities that FEI intends to pursue over the next four years based on the discussion and conclusions provided in this LTGRP. The specific Action Items include the following:

1. Accelerate the development and acquisition of renewable and low-carbon gas supplies to meet customer energy needs and contribute to provincial emission reduction targets;
2. Pursue approval of DSM funding for the period beyond 2022 by submitting for BCUC approval a DSM expenditure plan in 2022;
3. Continue pursuing FEI's LCT and global LNG initiatives to address market opportunities for load growth in support of customer rates and reducing local and global GHG emissions;
4. Continually improve engagement processes and activities associated with FEI's long-term gas resource planning;
5. Seek BCUC approval for a deferral account to capture the costs of advancing the development of the RGSD project;
6. Continue to develop and implement FEI's Gas System Resiliency Plan;
7. Plan for and prepare CPCN applications for near-term system requirements identified in Section 7 to support safe, reliable and cost effective gas delivery to FEI's customers;
8. Continue monitoring, analysing, and contributing to the energy planning environment while working with government on policy framework for deep decarbonization;
9. Protect and promote the interests of FEI's customers by securing reliable, cost-effective, long-term gas supplies that include increasing proportions of renewable and low-carbon gas;
10. Continue monitoring for and evaluating system expansion needs across FEI's service regions; and
11. Prepare and submit FEI's next LTGRP.

In conclusion, FEI's Clean Growth Pathway will support BC's decarbonization initiatives by transforming and influencing energy supply service markets. Maintaining BC's gas and electric infrastructure will enable ongoing innovation and accelerate decarbonization such that provincial GHG emission reduction targets will be met at a more rapid pace. In this pathway, the gas infrastructure continues to grow and thrive by adding new customers, communities, and commercial and industrial processing. Sharing costs across a diverse set of customer segments ensures that individual customers can more readily absorb the additional costs incurred through the low-carbon transition.

FortisBC Energy Inc.
2022 LTGRP

Section 1:

INTRODUCTION

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1. INTRODUCTION

1.1 APPLICATION AND ORDER SOUGHT

FEI files this 2022 Long-Term Gas Resource Plan (LTGRP) under section 44.1(2) of the *Utilities Commission Act* (UCA). Consistent with the applicable requirements of the UCA, the BC Utilities Commission's (BCUC) Resource Planning Guidelines, and prior BCUC directives, the 2022 LTGRP presents FEI's long-term plan for meeting the forecast peak demand and energy requirements of customers with demand-side and supply-side resources over a 20-year planning horizon. FEI respectfully requests that the BCUC accept the 2022 LTGRP as being in the public interest pursuant to section 44.1(6) of the UCA.

This 2022 LTGRP is profoundly shaped by the developments in climate change policy in recent years and, in particular, the Province's 2018 CleanBC plan and CleanBC Roadmap to 2030 (Roadmap) which set out ambitious targets for reducing greenhouse gas (GHG) emissions. In response to these policies and the need to reduce GHG emissions, this 2022 LTGRP provides a preliminary overview of how FEI plans to transition to a low-carbon energy future and, in particular, how FEI will shift from distributing conventional gas to distributing renewable and low-carbon gas. FEI anticipates that future resource plans will provide increasingly more detail on the mechanics and progress of this transition.

FEI's planning scenario in this 2022 LTGRP is referred to as the Diversified Energy (Planning) Scenario, which is based on FEI's Clean Growth Pathway.[14] The Clean Growth Pathway is FEI's framework to transition to a low-carbon energy future and is supported by four key pillars, which figure prominently in the 2022 LTGRP:

- **Pillar 1:** Transitioning to renewable and low-carbon gases to decarbonize the gas supply;
- **Pillar 2:** Investing in Demand-side Management (DSM) programs in support of energy efficiency and conservation measures to reduce energy use among residential, commercial and industrial customers;
- **Pillar 3:** Investing in low- carbon transportation infrastructure to reduce emissions in this sector; and
- **Pillar 4:** Investing in liquefied natural gas (LNG) to lower GHG emissions in marine fueling and global markets.

As indicated by these four pillars, FEI plans to meet provincial emission reduction targets through accelerating its renewable and low-carbon gas supply, supporting the decarbonization of buildings through DSM activities, and growing customer demand in sectors that reduce GHG emissions. FEI's Clean Growth Pathway maintains a prominent role for FEI's infrastructure in achieving GHG reductions in alignment with the province's objectives. For this reason, the Clean Growth Pathway

[14] Appendix A-1: Clean Growth Pathway to 2050 (2018), online at: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/clean-growth-pathway-brochure.pdf.

is also a diversified pathway, which sustains the growth and viability of both gas and electricity infrastructure in the province to support BC's future energy needs in the most cost-effective manner. As described in Guidehouse's report titled Pathways for British Columbia to Achieve its GHG Reduction Goals (Pathways Report),[15] a diversified pathway is a more affordable, resilient and practical pathway for BC than other decarbonization alternatives.

Similar to past resource plans, the 2022 LTGRP forecasts annual energy and peak demand for a range of alternate future scenarios over the 20-year planning horizon. FEI evaluates the potential for demand reduction through FEI's DSM programs, and examines supply and demand-side alternatives for meeting the forecast peak demand and energy requirements. FEI will continue to focus on resource acquisition strategies, long-range infrastructure requirements for resiliency and meeting peak demand, all while ensuring FEI meets BC's energy and GHG emission-reduction objectives. FEI's objectives are to ensure cost-effective, secure and reliable energy for customers and provide cost-effective DSM and lower-carbon solutions, in a manner consistent with provincial energy objectives and prior BCUC directives.

The 2022 LTGRP serves as a foundation for further evaluation of gas supply and system infrastructure options for meeting forecast customer needs under different scenarios. The LTGRP is not a substitute for the analysis done to support specific supply or expansion projects, programs or rate design in the future, but rather helps to inform the process of other initiatives. FEI will further evaluate any specific resource projects that are identified within the LTGRP that require BCUC approval and file separate applications with the BCUC as needed in the future.

FEI submits that the 2022 LTGRP is in the public interest and that the BCUC should accept this 2022 LTGRP under section 44.1(6) of the UCA. A draft Order is attached as Appendix H-1.

1.2 OVERVIEW OF FEI AND THE RESOURCE PLANNING PROCESS

FEI is a Canadian-owned gas distribution utility that serves customers across its BC territory. It is a subsidiary of Fortis Inc., the largest investor-owned gas and electric distribution utility company by assets in Canada. FortisBC Inc. (FBC), which provides electric service in the BC Southern Interior, is a separate Fortis Inc. subsidiary and affiliate of FEI. The long-term planning considerations and business activities of FBC are not included in the 2022 LTGRP.

FEI provides energy distribution services to over one million residential, commercial, and industrial customers in more than 135 communities throughout BC. This ranks FEI among the largest gas utilities in Canada and the Pacific Northwest (PNW). Table 1-1 provides a summary of FEI customer counts, demand, and pipeline characteristics. Figure 1-1 illustrates the Company's service area locations.

[15] Appendix A-2: Pathways for British Columbia to Achieve its GHG Reduction Goals (2020), online at: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf.

Table 1-1: FEI Service Statistics

	2016	2021	Percentage Increase Since 2017 LTGRP
Number of Customers	994,004	1,064,800	7.1%
Annual Demand (PJ)[16]	197	228	15.7%
Peak Day Demand (TJ/day)[17]	1,334	1,399	4.9%
Length of Transmission Pipeline (km)	2,959	2,970	0.4%
Length of Distribution Pipeline* (km)	45,741	47,523	3.9%

** Includes both distribution and intermediate pressure pipelines.*

[16] 1 PJ (petajoule) = 1,000,000 GJ.
[17] 1 TJ per day (terajoule/day) = 1,000 GJ per day.

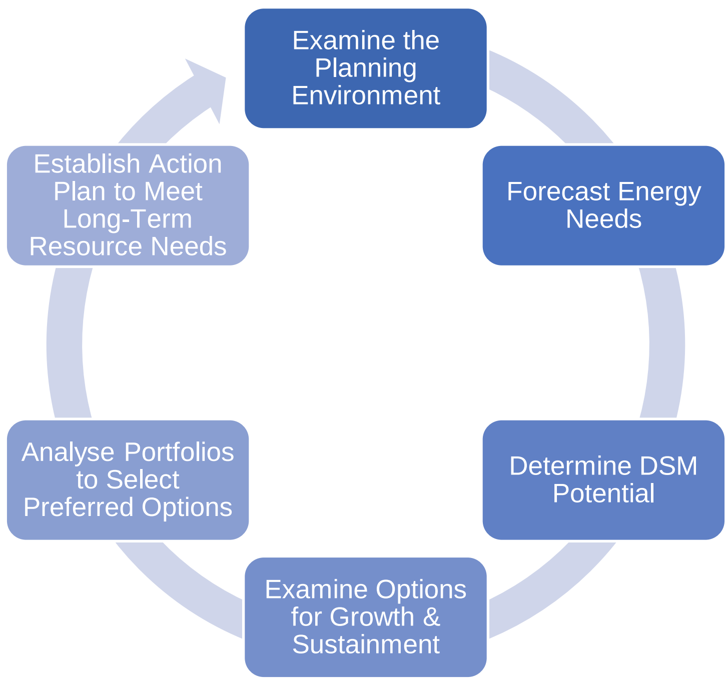
Figure 1-1: Map of FortisBC Service Areas (FEI Gas and Propane and FBC Electric)

FEI's long-term resource planning process involves several iterative steps in identifying resource options to meet expected demand. This process is one that is used by many utilities in resource planning and is consistent with the steps included in the BCUC's Resource Planning Guidelines.[18]

The resource planning process begins with examining the planning environment, which encompasses the external factors that influence future customer and demand growth. The demand- and supply-side resource alternatives for meeting future demand are then assessed, and actions are recommended to ensure that the proper resources are in place to deliver the preferred energy solutions to meet future customer needs. The final stage of the process is developing an action plan which identifies the near-term activities needed to meet the long-term resource requirements identified in the LTGRP, and to ensure continuing assessment of resource requirements and alternatives.

Figure 1-2 below summarises FEI's resource planning process:

Figure 1-2: FEI Long-Term Resource Planning Process



Consultation and engagement, which includes technical feedback from the Resource Planning Advisory Group (RPAG), engagement with Indigenous groups and community consultation, is an important element of FEI's long-term resource planning. The decisions made in long-term resource planning ultimately impact FEI's customers in terms of rates and fuel choices in the transition to low-carbon energy. In developing the LTGRP, the BCUC was updated throughout the process through their observer role on the RPAG. In addition to soliciting technical feedback

[18] BCUC, Resource Planning Guidelines (December 2003), online at: https://docs.bcuc.com/documents/Guidelines/RPGuidelines_12-2003.pdf.

from the RPAG, FEI held several community workshop sessions to advise participants about aspects of the LTGRP and gather their input and feedback to help inform the LTGRP. More details regarding FEI's consultation and engagement activities are provided in Section 8.

FEI shares common regional infrastructure with utilities in neighbouring jurisdictions, such as the PNW. This is why the competitive market environment, as well as the planning issues and resource requirements of other utilities, are important elements to consider in the planning process. It is especially critical to take into account information and developments regarding the transition to low-carbon energy. As such, FEI actively participates as a stakeholder in the resource planning efforts of other gas and electric utilities in the region, such as British Columbia Hydro and Power Authority (BC Hydro), FBC, Puget Sound Energy, Avista, and Northwest Natural Gas Company (NW Natural). To improve its understanding and response to regional resource issues, FEI also participates in planning, resource assessment activities and events conducted by regional organizations, including the Northwest Gas Association, the Northwest Power and Conservation Council, and the Pacific Northwest Economic Region. The regional outlooks provided by these utilities and organizations inform the analyses and recommendations in this LTGRP.

1.3 *FUEL TYPES AND DECARBONIZATION TECHNOLOGIES USED IN THE 2022 LTGRP*

As stated in Section 1.1, the 2022 LTGRP provides a preliminary overview of FEI's low-carbon transition from conventional gas to renewable and low-carbon sources. Table 1-2 presents a list of the different fuel types that were used in modelling the demand forecast scenarios in the resource plan. Throughout the 2022 LTGRP, FEI will generally refer to "natural gas, renewable and low-carbon gas" as a term that applies to the collective group of fuels outlined below. "Renewable and low-carbon gas" will be used to refer to renewable natural gas (RNG), syngas, lignin and (green and blue) hydrogen. FEI will use the term RNG when specifically referring to upgraded biogas. The chart also presents the emission factors that were used for each fuel source in modelling GHG emission forecasts.

Table 1-2: Fuel Types and Decarbonization Technologies Used in the 2022 LTGRP

Fuel Type	Description[19]	Life cycle Emission Factor (tCO_2e/GJ)	End use cycle Emission Factor (tCO_2e/GJ)
Natural gas	Natural gas is a naturally occurring hydrocarbon. Hydrocarbons are a class of organic compounds consisting of carbon and hydrogen. Raw natural gas (before processing) is composed primarily of methane.[20]	0.0598	0.04987[21]

[19] All definitions for fuel types are sourced from FEI except where specified.

[20] Online at: https://www.nrcan.gc.ca/energy/energy-sources-distribution/natural-gas/natural-gas-primer/5641

[21] GHG emission factor consistent with that used by the province as discussed in Section 9.2.

Fuel Type	Description[19]	Life cycle Emission Factor (tCO_2e/GJ)	End use cycle Emission Factor (tCO_2e/GJ)
Renewable natural gas (RNG)	Upgraded biogas produced from farm or municipal organic biomass. Upgraded synthesis gas (syngas) produced from wood biomass at pulp mills and some municipal organic biomass.	0.0100	0.0003
Syngas	Produced from wood to displace natural gas used in lime kilns at pulp mills. Can also be upgraded to green hydrogen.	0.0100	0.0000
Lignin	Produced from black liquor to displace natural gas used in lime kilns at pulp mills.	0.0100	0.0000
Green Hydrogen	Produced via water electrolysis using renewable electricity feedstock.	0.0000	0.0000
Blue Hydrogen	Reformed from hydrocarbon feedstock with up to 90 percent carbon sequestered.	0.0200	0.0000[22]
Natural Gas with Associated Carbon Capture, Utilization and Storage (CCUS)	Applying the carbon reduction benefits of CCUS to the delivery of natural gas on FEI's gas network.[23]	0.0148	0.0148

1.4 FEI'S FOUR LONG-TERM RESOURCE PLANNING OBJECTIVES

FEI's resource planning objectives form the basis for identifying and evaluating potential resources in the LTGRP, including major infrastructure projects, gas supply alternatives including renewable and low-carbon gas, and DSM. These objectives reflect FEI's commitment to providing customers with cost-effective, secure and reliable energy services, while playing a key role in BC's low-carbon future. FEI's four resource planning objectives are discussed below and are consistent with the objectives outlined in FEI's 2017 Long-Term Gas Resource Plan (2017 LTGRP), unless otherwise noted.

1.4.1 Ensure Cost-Effective, Secure and Reliable Energy for Customers

The most desirable resource options for meeting future customer needs will provide cost-effective service solutions and help to manage rate volatility, both in the near term, and into the future. Cost comparisons in this resource plan require more analysis than the traditional costs of natural

22 Updated values for the carbon intensity of hydrogen production are currently under development and will be provided in the next LTGRP.

23 The International Energy Association describes CCUS as a suite of technologies that can play an important and diverse role in meeting global energy and climate goals. CCUS involves the capture of CO_2 from large point sources, including power generation or industrial facilities that use either fossil fuels or biomass for fuel. The CO_2 can also be captured directly from the atmosphere. If not being used on-site, the captured CO_2 is compressed and transported by pipeline, ship, rail or truck to be used in a range of applications, or injected into deep geological formations (including depleted oil and gas reservoirs or saline formations) which trap the CO_2 for permanent storage: CCUS Technology Report (2021), online at: https://www.iea.org/reports/about-ccus.

gas. Carbon tax implications and the costs associated with decarbonization initiatives over the long term must be considered. From a broader perspective, energy affordability must be taken into consideration for all alternatives under consideration in planning BC's energy future.

A secure and reliable energy supply is essential for all FEI customers. Ensuring a sufficient supply of gas and the capacity to deliver gas to customers during anticipated peak demand periods is an ongoing objective for FEI. Acquiring resources that improve the reliability, system resiliency and security of supply will also help to reduce rate volatility and protect customers from potential outages.

1.4.2 Provide Cost-Effective DSM and Lower Carbon Solutions

Providing cost-effective DSM and other solutions to address carbon emissions have long been objectives of FEI's LTGRP. FEI used the term "cleaner customer solutions" early in the resource planning process to define FEI's decarbonization objectives. Late in the process of preparing the 2022 LTGRP, FEI adjusted this objective to read 'lower carbon solutions' in order to better align with the BC government's recent carbon reduction policy statements and to emphasize FEI's role in helping to reach provincial carbon reduction goals. Providing lower-carbon solutions reflects FEI's transition to a low-carbon energy system through the implementation of the Clean Growth Pathway.

Cost-effective DSM strategies offer value to customers by increasing energy efficiency and delivering gas more effectively. FEI's DSM programs are governed in part by the UCA and the *Demand-side Measures Regulation* (DSM Regulation).[24] In addition to FEI's DSM programs, FEI also delivers innovative energy solutions through initiatives for the transportation and marine sectors and through the development, sourcing and delivery of renewable and low-carbon gas supplies.

1.4.3 Ensure Consistency with Provincial Energy Objectives

The Province of BC's energy objectives are numerous and evolving. They include those objectives set out in the *Clean Energy Act* (CEA)[25] and are embodied in other provincial energy policies, strategies and regulations, such as *Greenhouse Gas Reduction (Clean Energy) Regulation* (GGRR) and the recent BC Hydrogen Strategy. FEI serves more than 1 million customers across BC in 135 communities. This wide reach enables FEI to play an important role in providing services to customers that help BC meet these objectives. Section 1.5.3 shows the applicable British Columbia's energy objectives and how they are supported by the LTGRP. Section 2.2.2 provides a discussion of other relevant BC energy and climate policies. In its 2022 LTGRP and the Clean Growth Pathway discussed throughout, FEI has endeavoured to maintain consistency with and support these provincial energy objectives.

[24] B.C. Reg. 236/2008, online at:: https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/10_326_2008.
[25] S.B.C. 2010, c. 22, online at: https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/10022_01.

1.4.4 Address Prior BCUC Directives

The BCUC set out a number of directives that apply to FEI's 2022 LTGRP. This objective has been added to the 2022 LTGRP to ensure that prior directives are highlighted and addressed as part of the resource planning process. The BCUC directives provided in the 2017 LTGRP Decision and from other proceedings that impact resource planning activities are outlined in Section 1.5.5.

1.5 THE 2022 LTGRP ALIGNS WITH THE LEGAL AND REGULATORY FRAMEWORK

It is good utility practice to conduct long-term resource planning and FEI has a regulatory obligation to file long-term resource plans under section 44.1(2) of the UCA. The UCA outlines the requirements for resource plans and the BCUC's Resource Planning Guidelines (Guidelines) provide general guidance as to the BCUC's expectations for the development of resource plans. FEI must also adhere to any directives from the BCUC related to FEI's previously filed long-term resource plans. Resource planning must also be conducted in accordance with the principles of the United Nations Declaration on the Rights of Indigenous Peoples (the UN Declaration). These requirements and guidelines are discussed in the following sections:

- United Nations Declaration on the Rights of Indigenous Peoples;
- UCA requisite contents and considerations;
- CEA objectives;
- BCUC Resource Planning Guidelines; and
- BCUC directives.

1.5.1 United Nations Declaration on the Rights of Indigenous Peoples (UN Declaration)

Sections 2.3 and 8.3 of this LTGRP discuss FEI's Statement of Indigenous Principles and support for the overarching principles outlined in the UN Declaration.[26] FEI acknowledges that the principles of the UN Declaration will play a significant role in energy policy and the regulatory environment over the twenty-year planning horizon of this LTGRP. FEI is committed to aligning its resource plans with provincial policy, and will continue to review its engagement process to ensure that FEI is engaging in meaningful dialogue with Indigenous groups regarding its resource plans. As the UN Declaration continues to be implemented across government through the

[26] Appendix F-1: United Nations Declaration of the Rights of Indigenous Peoples (2007), online at: https://www.un.org/development/desa/indigenouspeoples/wp-content/uploads/sites/19/2018/11/UNDRIP_E_web.pdf.

development of action plans, FEI will continue to evolve its planning and business practises in alignment with this implementation.

1.5.2 *Utilities Commission Act*

Section 44.1(2) of the UCA sets out the required content for a public utility's long-term resource plan. Table 1-3 outlines the specific elements that are to be included in resource plans and indicates the corresponding sections of this LTGRP in which these requirements have been met.

Table 1-3: Requisite Contents for a Long-Term Resource Plan

Section of the UCA	Requirement Defined in the UCA	Section of LTGRP Addressing Requirement
44.1(2)(a)	An estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan	Demand Forecast scenarios are outlined in Sections 4.6, 4.7 and 4.8.
44.1(2)(b)	A plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures	Demand-side measures are discussed in Section 5 and demand reduction in Section 5.4.2.
44.1(2)(c)	An estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures	Energy demand after DSM is discussed in Section 5.4.3.
44.1(2)(d)	A description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c)	FEI's System Resource Needs and Alternatives are discussed in Section 7.
44.1(2)(e)	Information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c)	FEI's Gas Supply Portfolio and Price Risk Management are discussed in Section 6.
44.1(2)(f)	An explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures	FEI's System Resource Needs after DSM are discussed specifically in Sections 7.2.3.1 and 7.3
44.1(2)(g)	Any other information required by the Commission	

In determining whether to accept a long-term resource plan, section 44.1(8) of the UCA requires the BCUC to consider several items. These are listed in Table 1-4 along with the applicable sections of the LTGRP where they have been addressed.

Table 1-4: BCUC Considerations for Accepting a Long-Term Resource Plan

Section of the UCA	Considerations for Acceptance	Section of LTGRP Addressing Requirement
44.1(8)(a)	The applicable of British Columbia's energy objectives	Section 1.5.3 below discusses the BC energy objectives applicable to the LTGRP and further information is provided in Sections 2 and 9.
44.1(8)(b)	The extent to which the plan is consistent with the applicable requirements of Sections 6 and 19 of the CEA	Section 1.5.3 below describes LTGRP's consistency with the CEA.
44.1(8)(c)	Whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures	Sections 3, 5 and 9 discuss demand-side measures and FEI's GHG emission reduction initiatives.
44.1(8)(d)	The interests of persons in British Columbia who receive or may receive service from the public utility	Portfolio analysis results include DSM and supply-side resource options that are cost effective, environmentally sound and provide socio-economic benefits to the province and FEI's customers. This is discussed in Section 9 and throughout the LTGRP.

1.5.3 *Clean Energy Act*

Section 44.1(8) of the UCA requires the BCUC to consider certain factors when accepting a utility's long-term resource plan, including:

- The applicable of British Columbia's energy objectives as defined in the CEA; and
- The extent to which the long-term resource plan is consistent with the applicable requirements under sections 6 and 19 of the CEA.

The CEA contains a set of sixteen specific energy objectives for the Province of BC. It provides a guide to help the Province meet its self-sufficiency goals and to reduce GHG emissions. The CEA includes several social and economic goals for the province, including a greater focus on encouraging economic development, creating and retaining jobs, and encouraging economic development for Indigenous and rural communities through the development of clean or renewable power.

The following table lists the CEA objectives applicable to FEI and how these are supported by the LTGRP. It is important to note that these are provincial objectives and some of the objectives are specific to BC Hydro, as referenced in the CEA by the term 'the authority'.

1 **Table 1-5: Applicable CEA Objectives Directly Relevant to the LTGRP**

CEA Section	CEA Objective	Supported in the 2022 LTGRP
2(b)	To take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%.	The 66 percent target is specific to BC Hydro and does not extend beyond 2020. FEI has assessed several DSM scenarios as discussed in Section 5.
2(d)	To use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources.	Sections 3, 5, and 9 address FEI's actions to support innovative and clean or renewable energy technologies in addition to portfolio analysis throughout the LTGRP. Section 5 addresses FEI's DSM analysis that provides support for energy conservation and efficiency including the use and development of innovative technologies.
2(g)	To reduce BC GHG emissions: (i) by 2012 and for each subsequent year to at least 6% less than the level of those emissions in 2007, (ii) by 2016 and each subsequent calendar year to at least 18% less than the level of those emissions in 2007, (iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007, (iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and (v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*.	The LTGRP demonstrates that FEI's Clean Growth Pathway is key to helping the province meet BC's GHG emission targets. FEI recommendations include transitioning the gas supply to renewable and low-carbon sources, DSM programs, zero and low-carbon transportation and LNG marine bunkering. The LTGRP focuses on FEI's transition to low-carbon energy and Section 9 addresses GHG emissions and emission reductions from FEI's forecast energy demand and initiatives.
2(h)	To encourage the switching from one kind of energy source to another that decreases greenhouse gases in British Columbia.	Sections 3, 4, 5 and 9 address FEI's fuel switching initiatives such as using compressed natural gas (CNG) and LNG as a transportation fuel to displace higher carbon fuels such as diesel and marine bunker fuel. The potential for fuel switching from gas to electricity has been considered in the development of the plan.

CEA Section	CEA Objective	Supported in the 2022 LTGRP
2(i)	To encourage communities to reduce greenhouse gas emissions and use energy efficiently.	Section 3 presents FEI's Clean Growth Pathway. Section 5 discusses energy conservation through FEI's DSM activities and the associated GHG emission reductions. Section 8 addresses FEI's community outreach. Section 9 addresses GHG emissions and emissions reductions from FEI's forecast energy demand and renewable and low-carbon supply initiatives.
2(j)	To reduce waste by encouraging the use of waste heat, biogas and biomass	Sections 2, 3, 5, 6, 7 and 9 discuss FEI's RNG and other bioenergy resources including syngas and lignin opportunities, DSM programs including waste heat recovery and portfolio analysis related to decarbonization throughout the LTGRP.
2(k)	To encourage economic development and the creation and retention of jobs	FEI's Clean Growth Pathway, discussed in Section 3, highlights opportunities for economic development and job creation. Section 9 summarizes FEI's 2022 LTGRP analysis results in light of BC's energy objectives. The LTGRP encourages the development of renewable and low-carbon gas projects, DSM activities and low-carbon transportation that will contribute to BC's economic development and job creation.
2(l)	To foster the development of First Nation and rural communities through the use and development of clean or renewable resources.	FEI will consider opportunities with Indigenous groups and local communities in the development of clean energy projects (see Sections 3, 5, 8 and 9)
2(m)	To maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia.	LTGRP provides a framework for partnerships and strategies that maximize value as FEI transitions to a low-carbon energy future (see Sections 3, 5, 6, 7 and 9).

1.5.4 BCUC Resource Planning Guidelines

In 2003, the BCUC issued Resource Planning Guidelines, which outline a process to assist in the development of resource plans to be filed with the BCUC. According to the Guidelines, "resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run." The Guidelines do not distinguish between utilities that provide generation, transmission or distribution services; therefore, some items (such as supply-side portfolio analysis[27]) are more relevant to integrated

[27] Supply-side portfolio analyses are conducted outside of FEI's LTGRP planning process and are submitted for approval to the BCUC through the Annual Contracting Plan (ACP) and Price Risk Management Plan (PRMP).

electric utilities. The BCUC reviews resource plans in the context of the unique circumstances of the utility in question. FEI adheres to the BCUC's Resource Planning Guidelines where relevant and applicable to FEI's operating context. Table 1-6 below outlines the key elements of the Resource Planning Guidelines and the sections of the 2022 LTGRP in which they are addressed.

Table 1-6: BCUC Resource Planning Guidelines

Resource Planning Guideline	Section of LTGRP Addressing Guideline
1. Identification of the planning context and the objectives of a resource plan	Objectives and context are discussed in Section 1.4, and Planning Environment Section 2.
2. Development of a range of gross (pre-DSM) demand forecasts	Demand forecasts (pre-DSM) are discussed in Section 4.
3. Identification of supply and demand resources	Supply and demand resources are discussed in this LTGRP as follows: • The Planning Environment, Section 2, provides context for existing resources and dynamics concerning new resources; • The Annual Demand Forecasting, Section 4, presents the future load that FEI is planning for in this LTGRP; • The amount of future demand that can be met through DSM is considered in Demand-Side Resources Section 5; and • Sections 6 and 7 discuss the need for new gas supply and system infrastructure resources respectively.
4. Measurement of supply and demand resources	Measurement of supply and demand are outlined in Sections 4, 5 and 6.
5. Development of multiple resource portfolios	FEI is not a vertically integrated utility, and does not develop and compare multiple integrated resource portfolios. Rather, in the 2022 LTGRP, FEI plans to the Diversified Energy (Planning) Scenario. However, in the future, this may change as FEI transitions to renewable, low-carbon gas and community solutions, which may require future resource plans to examine alternative supply resource portfolios. Background for this discussion is found in Demand-Side Resources Section 5, Gas Supply Portfolio Planning Section 6 and System Resource Needs and Alternatives Section 7.
6. Evaluation and selection of resource portfolios	FEI plans to the Diversified Energy (Planning) Scenario that represents the Clean Growth Pathway. As FEI transitions to renewable and/or low-carbon gas and community solutions, it may be positioned as a vertically integrated utility. In this case, future resource plans may examine alternative supply resource portfolios. Background for this discussion is found in Demand Side Resources Section 5, Gas Supply Portfolio Planning Section 6 and System Resource Needs and Alternatives Section 7.
7. Development of an action plan, including contingency plans	The 2022 LTGRP Action Plan is provided in Section 10.
8. Solicit stakeholder input during the planning process	The 2022 LTGRP stakeholder, Indigenous groups, and community engagement initiatives are described in Section 8.

Resource Planning Guideline	Section of LTGRP Addressing Guideline
9. Seek regulatory input from Commission staff	FEI has received and considered input from the BCUC and BCUC staff through: • regulatory proceedings on various FEI filings that have implications for long range planning; • periodic discussions with staff concerning various regulatory filings and proceedings; and • the BCUC request for Integrated Resource Plan modelling of common future scenarios for FEI and BC Hydro. In addition, BCUC staff participated as observers in FEI's external RPAG.
10. Consideration of government policy	The 2022 LTGRP provides an overview of policy considerations in the Planning Environment in Section 2.2 and Section 9.
11. Regulatory review once a resource plan is filed	The regulatory review process will be determined by the BCUC in consideration of FEI's recommendations provided in Section 1.7.

1.5.5 BCUC Directives from the 2017 LTGRP Decision and Other Applications

In Decision and Order G-39-19 accepting the 2017 LTGRP[28] and its decisions in other proceedings, the BCUC provided a number of directives and suggestions for FEI to integrate in future resource plans. The recent and historical directives that remain applicable to the 2022 LTGRP are outlined in Table 1-7, along with a description of where in the LTGRP they are addressed.

Table 1-7: List of BCUC Directives and FEI Actions Pursuant to Order G-39-19

Directive #	BCUC Directive	Section of LTGRP Addressing Directive
1.	In the next LTGRP filing, FEI is directed to: • Update the information filed in this proceeding to respond to the BCUC's directive in the 2014 LTRP Decision to provide an analysis of FEI's End Use Method as compared to other end use methods, including an assessment of the of FEI's method compared to other models that incorporate some form of end use modelling combined with econometric modelling; • Provide a detailed explanation of any changes to its demand forecast methodology as it evolves between now and the next LTGRP filing; and • Include high level assessment of the effectiveness of the Traditional and End Use Models compared to actual results.	Directives relating to the Traditional Annual Method versus the End Use Annual Method, including an update to the industry review of forecast methods, an explanation of changes to the End Use Method and a high-level assessment of the effectiveness of the two methods are discussed in Section 4 and Appendix B-1 and B-6.

[28] Decision and Order G-39-19, February 25, 2019, online at: https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/item/363860/index.do?q=G-39-19.

Directive #	BCUC Directive	Section of LTGRP Addressing Directive
2.	FEI is directed to continue use of its Traditional Method as a comparison to test its End Use Method until such time as the BCUC approves a new demand forecast methodology.	The results of the Traditional Method as in this reference are included in Section 4 as the End Use Method. The name has been changed from Traditional to Business as Usual (BAU) forecast to better represent the nature of the forecast as discussed in Section 4.
3.	The Panel directs FEI to continue to provide the following information, in the next LTGRP: • DSM funding scenarios, reflecting the results of the most recent Conservation Potential Review, that include a "reference" DSM funding scenario with "high DSM" and "low DSM" scenarios that are relative to the reference scenario; • An analysis of each DSM scenario, at a portfolio level and for each DSM category (residential, low-income[29],[30],[31], commercial etc.), including: o Total Resource Cost/modified Total Resource Cost test results; o Utility Cost Test result, expressed as a ratio and $/GJ;	An overview of FEI's approach to the LTGRP DSM analysis, DSM funding scenarios ranging from high to low budgets, and energy savings estimates and cost-effectiveness test results are provided in Section 5. Appendix C-2 provides further detail on cost-effectiveness for DSM categories comprising sectors (residential, commercial and industrial).
	o Delivery rate impact; o Estimated total bill impact (including delivery and commodity), expenditures ($'s) and percentages (%'s), with residential split between high and low use gas customers;	Details regarding delivery rate impacts and total bill impacts are provided in Sections 5 and 9.
	o Estimated gas (GJ) and GHG emission reductions.	Details regarding gas and GHG emission reductions estimates resulting from DSM (Section 5) and other GHG reduction initiatives over the planning horizon are provided in Section 9.
4.	The Panel directs FEI to provide an update of its analysis of opportunities for DSM to be used to cost-effectively replace or defer infrastructure investments in its next LTGRP.	An update on FEI's efforts to explore the potential for DSM programs to replace or defer infrastructure investments is presented in Section 5. Appendix C-3 provides the study that examines the state of the gas utility industry in considering and implementing non-pipe solutions to provide peak energy savings and other customer benefits.

[29] In LTGRP scenarios, low income customers are modelled within the residential sector, as these customers are not differentiated in FEI's customer database. FEI estimates that about 20 percent of its residential customers would be eligible for Low Income programs. According to Statistics Canada's 2016 Census data (Appendix F-15), 14-15% of British Columbians are considered low income, based on low-income cut-offs (LICO) before tax. The DSM Regulation uses LICO multiplied by a factor of 1.3 to determine low-income thresholds. This suggests that, under the definition set out in the DSM Regulation, FEI's 20 percent estimate is reasonable.

[30] Appendix F-2: Low-Income Status Data tables (2016 Census), online at: Low-income Indicators (4), Individual Low-income Status (6), Age (8) and Sex (3) for the Population in Private Households of Canada, Provinces and Territories, Census Divisions and Census Subdivisions, 2016 Census - 100% Data (statcan.gc.ca).

[31] LICOs can be found online at: https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1110024101.

Directive #	BCUC Directive	Section of LTGRP Addressing Directive
5.	In the next LTGRP, the Panel directs FEI to address the implications for FEI's long-term resource and conservation planning of the 2018 CleanBC plan released by the Government of BC on December 6, 2018 and to provide an update on its analysis of GHG targets. In particular, the Panel expects that FEI should address the long-term impacts to FEI of the following points:	• FEI has incorporated the resource planning and GHG reduction implications of the 2018 CleanBC plan; and • Where possible, FEI has also incorporated the implications of the 2021 release of the Roadmap. However, details are not yet fully known about how that update will be enacted through regulation.
	• Initiatives targeting more energy efficient buildings, in terms of gas demand and FEI's DSM activities	Initiatives targeting opportunities to decarbonize buildings are provided in Sections 3, 5 and 8.
	• Requirements for 15 percent of natural gas consumption to be from renewable gas	Initiatives related to the acceleration of renewable and low-carbon gas supply are provided in Sections 3, 6, 7 and 9. FEI has also addressed the increased renewable and low-carbon gas consumption targets outlined in the Roadmap.
	• Industrial electrification, with respect to demand for natural gas	Considerations related to industrial electrification are provided in Sections 4, 5, and 9. FEI has incorporated different assumptions about electrification percentages for all sectors into each of the future scenarios examined in the LTGRP.
	• How 2018 CleanBC's plans for clean transportation affect FEI's forecast for its low-carbon transportation (LCT) programs	Considerations related to FEI's LCT forecasts are provided in Sections 2.2.2.3.2 where the Low Fuel Standard and Greenhouse Gas Reduction Regulation for Transportation are discussed. Demand forecasts for LCT are discussed further in Sections 4 and 9.
	• Other initiatives to be developed by the Government of BC over the next 18 to 24 months	FEI has incorporated the implications of the Roadmap and other recent initiatives including the Greenhouse Gas Reduction Regulation (GGRR), emissions cap for natural gas utilities (GHGRS), provincial and federal hydrogen strategies, BC Carbon Tax and electrification strategy and other policy impacts in Section 2. The implications of government initiatives on FEI's long-term plan are discussed throughout the LTGRP.
6.	The Panel directs FEI to address security of supply concerns in its next LTGRP.	Security of supply and resiliency considerations are provided in Sections 2, 3, 6, 7, and 9. Refer to Appendix E for FEI's Gas System Resiliency Plan.
7.	The Panel directs FEI to file its next LTGRP on or before March 31, 2022. By letter dated April 28, 2022 the BCUC granted an extension to file on May 9, 2022.	2022 LTGRP filed on May 9, 2022.

The BCUC has also provided directives and suggestions for FEI related to the 2022 LTGRP in the following:

- Decision and Order C-2-21 granting a CPCN for the Pattullo Gas Line Replacement Project; and

- Decision and Order G-366-21 approving FEI's Annual Review for 2022 Delivery Rates.

These directives or suggestions and the related LTGRP section where they are addressed are outlined in Table 1-8 below.

Table 1-8: List of BCUC Directives and Suggestions from Additional Applications and FEI Actions Taken in 2022 LTGRP

Directive #	BCUC Directive	Section of LTGRP Addressing Directive / Suggestion
Order C-2-21	The Panel directs FEI to address resiliency in a comprehensive manner in its 2022 Long-Term Gas Resource Plan.	FEI's resiliency considerations are provided throughout the LTGRP and addressed specifically in Sections 3, 6, 7, 9. Appendix E provides FEI's Gas System Resiliency Plan as a consolidated and comprehensive overview.
Order C-2-21	The Panel suggests FEI may address pathways to zero GHG emissions by 2050 in its upcoming LTGRP.	FEI's Diversified Energy (Planning) Scenario provides FEI's decarbonization transition plan to 2042, which may be extrapolated to 2050. However, both FEI and BC Hydro have suggested that they would not extend resource plan scenarios to 2050 based on the uncertainties that lie beyond a twenty-year horizon.
Order G-366-21	Provide context around the Regional Gas Supply Diversity (RGSD) project and whether it is in the public interest to explore or pursue this project. This would allow the BCUC a more holistic view of how the project aligns with BC's energy objectives as set out in Section 2 of the *Clean Energy Act*, and how in combination with other infrastructure and energy purchase plans the RGSD would meet future load forecasts.	The RGSD project is explored in many aspects in the LTGRP, including sections 3.3.3 (Clean Growth Pathway), 6.3.3 (Gas Supply Portfolio Planning), 7.5.1.1 (System Resource Needs and Alternatives), 10 (Action Plan) and Appendix E (Gas System Resiliency Plan).

1.6 STATUS OF THE 2017 LTGRP ACTION PLAN

In each successive resource plan, FEI presents a list of actions that can be taken to implement the recommendations outlined throughout the plan. Table 1-9 below provides an update of the items identified in the four-year Action Plan of the 2017 LTGRP.

Table 1-9: 2017 LTGRP Action Items

Action Item	Status
1. Continue to monitor and analyse the energy planning environment.	FEI has continued monitoring and analysing the planning environment, which is becoming increasingly complex. To support its analysis of the policy planning environment, FEI, since the 2017 LTGRP, has dedicated resources specifically to public policy analysis. Section 2 presents an overview of FEI's current analysis of the planning environment.
2. Continue exploring the application of projected changes across end use patterns to peak demand forecasting.	FEI conducted extensive analysis of peak demand forecasting across end use patterns as outlined in Section 7.
3. Protect and promote the interests of FEI's customers by securing a reliable, cost-effective long-term gas supply.	The 2022 LTGRP remains committed to FEI's customers in securing a reliable, cost-effective and long-term gas supply, through the low-carbon transition over the planning horizon as outlined in Section 6. FEI develops an efficient supply portfolio on an annual basis that consists of an appropriate balance of commodity, pipeline, and storage resources to meet the forecast demand from all of FEI's gas service areas. The constrained pipeline and storage resource environment in the region during the winter season continues to be a major concern. FEI continues to manage this risk with the following contracting strategies: • Contract for firm resources directly with pipeline or storage facilities for the majority of its gas supply requirements. In FEI's view, this is a prudent strategy that protects customers from large prices spikes and limited availability of gas at Huntingdon; • Until new infrastructure is added to the region, FEI will continue to hold contingency resources within its portfolio. Contingency resources are resources (supply, LNG, and/or pipeline infrastructure) above the current load forecasts for its customers. FEI will determine the optimal amount on an annual basis based on market conditions discussed in Section 6. Over the long term, FEI's supply portfolio can also benefit from a mix of new infrastructure, specifically expansions to on-system storage (Tilbury LNG Storage Expansion (TLSE)) and a new pipeline (RGSD project). These projects will enhance gas supply resiliency in the portfolio, facilitate load growth opportunities, and help with the transition to cleaner energy.
4. Continue monitoring and evaluating system expansion needs in the Okanagan and Vancouver Island areas to maintain reliable and cost-effective gas delivery to FEI's customers.	FEI submitted a CPCN application for the Okanagan Capacity Upgrade in January 2021. FEI continues to monitor and evaluate the Interior Transmission system and expects a system capacity constraint to occur in 2023, with contingency planning for 2021 and 2027. Section 7.3.3 discusses this analysis and the project is listed in Section 7.5.1. Further capacity constraints on the Vancouver Island Transmission System (VITS) are not expected within the forecast period. It is expected that the system will meet the Traditional Peak Method forecast.

Action Item	Status
5. Plan for and prepare CPCN applications for near-term system requirements identified in Section 6 to support safe, reliable and cost-effective gas delivery to FEI's customers. The 2017 LTGRP listed the following priority project on the CTS and regional infrastructure as upcoming CPCN applications: • Upgrades to lateral pipeline segments in the interior region to enable and implement inline inspection (ILI) programs (referenced in Section 6.4 as Transmission System Laterals ILI Capability); • The Southern Crossing Pipeline Class Location Project; • The Pattullo Bridge Crossing Replacement; • The evaluation of major bridge crossings on the CTS to determine if upgrades should be considered to improve the resiliency of piping during a seismic event (referenced in Section 6.4 as Bridge Crossing Seismic Upgrade Assessment – Lower Mainland); • Implementation of advanced technology inline inspection programs (e.g. EMAT) for the transmission pipelines that are already inspected using current technology; and • A potential reliability upgrade to the Langley compressor facility.	An update on the high priority projects listed in the 2017 LTGRP consists of the following: • The BCUC granted a CPCN and FEI has commenced construction of the Inland Gas Upgrades Project to upgrade lateral pipeline segments in the Interior region to enable and implement inline inspection (ILI) programs as discussed in Section 7.6.2; • The Southern Crossing Pipeline Class Location Project, discussed in Section 7.6.3, addresses pipeline safety factors. This could be a potential future CPCN; • The BCUC granted a CPCN by Order C2-21 and FEI has commenced construction of the Pattullo Gasline Replacement Project; • FEI continues the evaluation of major bridge crossings on the Coastal Transmission System to determine if upgrades should be considered to improve the resiliency of piping during a seismic event (referenced in 2017 LTGRP as Bridge Crossing Seismic Upgrade Assessment – Lower Mainland). Major DP, IP and TP Lateral Pipeline Crossings are discussed in Section 7.5.2.1; • FEI is awaiting a BCUC decision on the CTS Transmission Integrity Management Capabilities Project for the implementation of EMAT ILI programs for the CTS. In 2022, FEI will be filing a similar application for the implementation of EMAT ILI for the Interior Transmission System as discussed in Section 7.6.4; and • Some reliability upgrades to the Langley compressor facility are occurring as discussed in Section 7.6.5. As FEI's planning efforts were and continue to be undertaken to ensure that planned improvements optimize operation of the system as a whole, these system upgrade requirements were integrated with reinforcement options that were considered to meet FEI's capacity needs.

Action Item	Status
6. Continue to implement the Company's Low-Carbon Transportation (LCT) initiatives to meet market needs while capturing an important opportunity for load growth and GHG emissions reductions.	FEI has been successful in promoting the use of both CNG and LNG vehicles in the transportation sector via its LCT initiatives. To date, FEI has provided incentive funding for approximately 850 CNG vehicles, 148 LNG vehicles, and 10 marine vessels. In addition to incentive funding for vehicles, FEI has provided funding towards the construction of 19 CNG and LNG fueling stations that are currently operating. FEI will continue to explore opportunities to construct CNG and LNG fueling stations along strategic corridors to support the continued adoption of natural gas vehicles. FEI has been focusing on the adoption of LNG in the marine market segment, particularly in the short sea marine segment in BC. This segment includes marine vessels that transit intra-provincial waterways to move goods and passengers. To date, FEI has provided vessel capital incentives to ten LNG-powered marine vessels. (Data above accurate as of March 31, 2022)
7. Pursue approval of Conservation and Energy Management (C&EM) funding for the period beyond 2018 by submitting for BCUC approval a C&EM expenditure schedule in 2018.	The BCUC approved FEI's 2019-2022 DSM Expenditures Plan. FEI is implementing this portfolio and delivers annual performance reports to the BCUC. From 2019 - 2022, FEI forecast an investment of $353 million in DSM programs. 2021 expenditures were three times greater than the 2018 investment. Over this timeframe, the programs are forecast to generate 4 Million GJ in annual savings and 40 Million GJ over the life of the installed measures. This translates to 2.4 Mt CO_2e of GHG emission reductions.
8. Pursue approvals as necessary of a funding envelope dedicated to enabling FEI to further monitor and, where applicable, support innovative conventional, renewable and low-carbon gas technologies, which may help FEI, meet market preferences while also supporting solutions for BC's emissions policy objectives.	FEI's Clean Growth Innovation Fund is committed to innovation through investments in cleantech and emissions-reducing projects that provide solutions for current and emerging energy challenges in BC. The fund provides funding to support innovative energy projects, in partnership with government, industry, communities and Indigenous groups.

The actionable items that FEI intends to pursue over the next four years are provided in Section 10 of this 2022 LTGRP.

1.7 *PROPOSED REGULATORY PROCESS*

FEI submits that, consistent with past resource plans and due to the technical nature of the material, a written hearing is appropriate for the review of the 2022 LTGRP. FEI proposes the following regulatory timetable, which includes two rounds of information requests and an opportunity for intervener evidence, followed by submissions on further process or a procedural conference. FEI also notes that it expects to file on August 12, 2022 supporting commentary regarding the energy scenarios as directed by the BCUC in the BCUC's Energy Scenarios proceeding[32] as an update to the evidentiary record in this Application. The proposed regulatory

[32] Online at: Energy Scenarios for BC Hydro and FEI (For Information Only) - BCUC.

timetable below takes into account this update as well as deadlines already established in other ongoing regulatory proceedings before the BCUC.

Table 1-10: Proposed Regulatory Timetable

ACTION	DATE (2022)
BCUC Issues Procedural Order by	Thursday, June 9
FEI Publishes Notice of Filing by	Friday, July 8
Registration of Interveners and Interested Parties	Thursday, July 21
FEI Submits Energy Scenarios Evidentiary Update	Friday, August 12
BCUC Information Request No. 1	Tuesday, August 30
Intervener Information Request No. 1	Thursday, September 8
FEI Responses to Information Requests No. 1	Thursday, October 27
BCUC and Intervener Information Request No. 2	Thursday, November 24
	DATE (2023)
FEI Responses to Information Requests No. 2	Thursday, January 26
Notification by Interveners of Intent to file Evidence	Thursday, February 9
Submissions on Further Process or Procedural Conference	To be determined

A draft Procedural Order is attached as Appendix H-2.

FortisBC Energy Inc.
2022 LTGRP

Section 2:

PLANNING ENVIRONMENT

Table of Contents

2. PLANNING ENVIRONMENT

2.1 INTRODUCTION

FEI is submitting this 2022 LTGRP during a time of rapid change in government policy, emerging technologies, and global economic factors, while the effects of climate change are being experienced first-hand in BC. A wide range of factors influences FEI's long-term analysis and planning decisions especially during this pivotal time for FEI's transition to a low-carbon future. This section discusses the factors that are the most important.

Understanding the planning environment is the first step in FEI's resource planning process. The planning environment is set in the context of the evolution of FEI's Clean Growth Pathway and the many factors influencing FEI's long-term energy decisions, including the need to decarbonize in a way that maintains cost-effective, reliable and resilient service to customers. The planning environment includes relevant external factors that could impact FEI's demand-side and supply-side resource options and prices for future market purchases, influenced by an accelerated path to decarbonization.

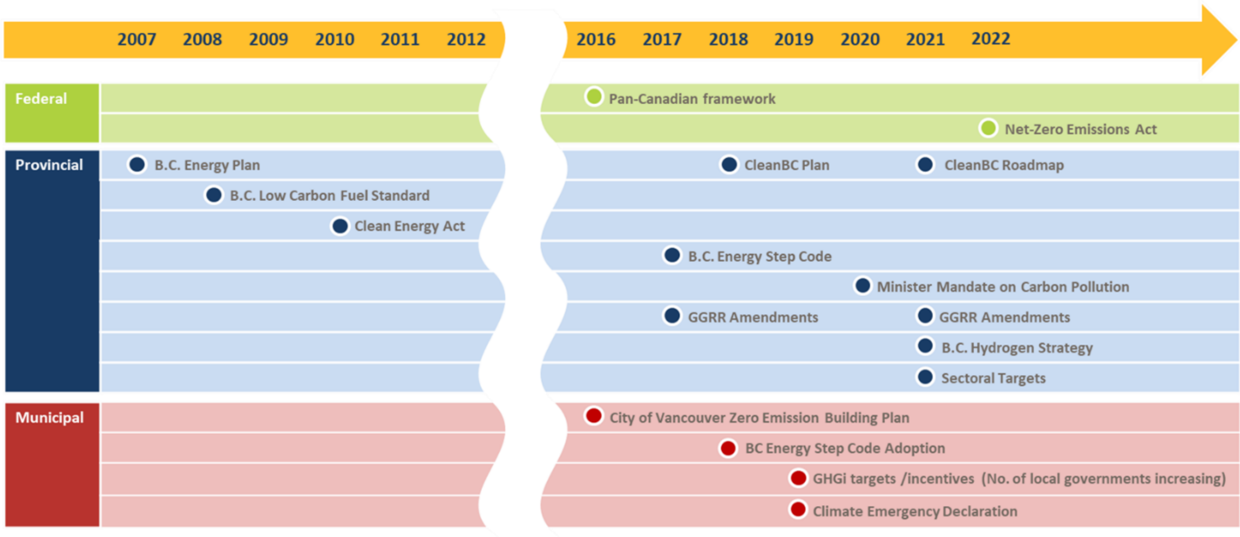
This section provides important context for the analysis, results and recommendations that are provided throughout the LTGRP by discussing the policies, legislation and competitive environment that are impacting energy planning at the time this LTGRP is being prepared. This section is organized as follows:

- Section 2.2 provides an overview of the relevant policy and regulatory context facing FEI that impact future resource options, market prices, and influence customers' behaviour regarding energy use in the future.
- Section 2.3 provides the background for FEI's engagement with Indigenous groups for long-term resource planning.
- Section 2.4 discusses the increasingly complex competitive environment for gaseous energy. Competition is influenced not only by regional energy markets and commodity pricing, but also by supply infrastructure capacity, end use equipment installation and competition.
- Section 2.5 discusses the need for resiliency in BC's energy system.
- Section 2.6 provides a summary and conclusions about FEI's planning environment and the many forces affecting the evolution of FEI's climate plan.

2.2 ENERGY AND CLIMATE POLICY DEVELOPMENTS

The urgency for climate action has resulted in environmental regulation, plans and policies from all three levels of government to promote decarbonization. Figure 2-1 provides an overview of key policy initiatives that impact FEI's business and long-range planning. As the figure shows, the majority of policies have been implemented from 2016 onwards and represent a considerable amount of change since the submission of the 2017 LTGRP.

Figure 2-1: Major Policies Adopted by All Levels of Government Demonstrate the Complexity of FEI's Planning Environment



In the sections below, FEI describes these federal, provincial and local government policies in greater detail, including those policies that have yet to be implemented.

- Section 2.2.1 outlines Canadian federal policies and initiatives.
- Section 2.2.2 outlines provincial government policies.
- Section 2.2.3 outlines local government and municipal policies.

2.2.1 Canadian Federal Energy and Climate Policies

There have been a number of Canadian federal policies and initiatives aimed at addressing climate change, reducing GHG emissions, and developing cleaner energy sources. The federal Liberal party committed to greater effort to meet and exceed the Paris targets, including a pledge to reach net-zero by 2050. In the fall of 2020, the Liberal government announced a new climate plan to exceed its 2030 targets, signaling carbon tax increases, deep energy and climate policy reform, and significant public investment into energy transition efforts. Of significance, within the plan is a proposed carbon tax escalation of $15 per tonne per year after 2022, reaching $170 per tonne by 2030. Most recently, at the COP26 conference in November 2021, the federal government announced a cap on oil and gas sector emissions[33] to reach net-zero by 2050.

The federal climate policy framework is focused on achieving Canada's 2030 GHG reduction goals with wide-ranging measures targeting all key emitting sectors (buildings, transportation and

[33] Appendix F-3: Cap and Cut Emissions from Oil and Gas (2020), online at: https://liberal.ca/our-platform/cap-and-cut-emissions-from-oil-and-gas/.

industry). However, while natural gas is one of the most widely used fuels in Canada, there is no specific federal climate policy direction on the future of the gas delivery system.

The policies, targets and initiatives discussed below illustrate that the conversation around the role of the gas system in decarbonizing Canada's GHG emissions is undefined. While public opinion and governmental objectives have become more stringent regarding climate change, there remains a lack of clarity regarding the specific actions expected of energy utilities such as FEI.

2.2.1.1 *Pan-Canadian Framework*

The *Pan-Canadian Framework on Clean Growth and Climate Change*[34] (PCF) was Canada's first national climate plan and was released in December 2016. The PCF marked a shift towards increased federal involvement in climate policy. The PCF has four main pillars:

- pricing carbon pollution;
- complementary measures to reduce emissions;
- climate change adaptation; and
- actions to accelerate innovation.

Most notably, the PCF contains measures to significantly reduce emissions in the buildings sector by making new buildings net-zero, retrofitting existing buildings, fuel switching, improving energy efficiency for appliances and equipment and supporting building codes and energy-efficient housing. In 2017, the PCF set an aspirational goal that by 2035 all space heating technologies sold will have a performance of greater than 100 percent efficiency. This would effectively ensure that only electric or gas heat pumps would be available for use by this time. The PCF signalled further electrification measures for the buildings sector and fuel switching from natural gas.

2.2.1.2 *Net-Zero Emissions Accountability Act and Emissions Reduction Plan*

The *Canadian Net-Zero Emissions Accountability Act* (CNZEAA) was passed in 2021[35] and as part of this Act, the first Emissions Reduction Plan[36] (ERP) was recently published in March, 2022.[37] The ERP outlines over $9 billion in additional funding along with policies, actions and strategies that will lead Canada to the newly updated target of a 40-45 percent GHG emissions reduction by 2030. Some of the key features of the ERP include:

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[34] Appendix F-4: Pan-Canadian Framework on Clean Growth and Climate Change (2017), online at: https://publications.gc.ca/collections/collection_2017/eccc/En4-294-2016-eng.pdf.

[35] S.C. 2021, c. 22, online at: https://laws-lois.justice.gc.ca/eng/acts/c-19.3/FullText.html.

[36] Online at: https://www.canada.ca/en/environment-climate-change/news/2022/03/2030-emissions-reduction-plan--canadas-next-steps-for-clean-air-and-a-strong-economy.html

[37] Environment and Climate Change Canada, 2030 Emissions Reduction Plan (2022), online at: https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf.

- A cap on emissions from the upstream oil and gas sector set at 42 percent below 2019 levels and a 75 percent reduction in methane emission by 2030;
- Programs and incentives to reduce the use of fossil fuels in buildings and funding for a national green buildings strategy;
- Medium and heavy duty sales mandate to achieve 100 percent zero emissions vehicle mandate by 2040;
- A bioenergy strategy to optimize use of Canadian bioenergy resources;
- Advancement of the federal Hydrogen strategy to increase the use of hydrogen in transportation, industrial and hard to decarbonize sectors;
- A national carbon capture, utilization and storage strategy and tax credit to encourage the adoption of such technologies (potentially including hydrogen made from natural gas feedstock); and
- Funding for nature-based carbon sequestration activities.

This is the first time the federal government has published a comprehensive plan for reducing emissions that is legally binding based on the CNZEAA. The ERP is subject to change and adaptation as it has not been fully designed. The CNZEAA establishes a legally-binding process to set five-year national emissions reduction targets as well as develop a credible science-based emissions reduction plan to achieve each target. It also establishes a requirement to set national emissions reduction targets for 2035, 2040 and 2045, with plans to achieve it. Under CNZAA, the federal government formed the Net-Zero Advisory Body to provide independent advice to the Minister of Environment and Climate Change on achieving net-zero emissions by 2050. This includes recommendations on GHG emissions reduction targets for 2030, 2035, 2040 and 2045, as well as GHG emissions reduction plans by the Government of Canada, including measures and sectoral strategies the government should implement to meet GHG targets. The Net-Zero Advisory Body has the influence to direct policy at the highest level in Canada and does not include any representatives from the gas industry.

2.2.1.3 *Clean Fuels Regulations*

Under the *Canadian Environmental Protection Act, 1999*, the federal government published a draft of its *Clean Fuel Regulations*[38] at the end of 2020, which is central to the federal government's mandate to reduce GHG emissions 30 percent by 2030. The 2020 draft does not include gaseous and solids streams, and only targets liquid fuels, mainly used in the transportation sector. This means that there is currently no federal mandate for gas utilities to decarbonize their fuel and signals that there is no longer-term vision for the low-carbon solutions delivered by the gas system as part of the federal government's overall approach to climate action, despite the merits of this approach to decarbonization.

[38] Appendix F-5: Clean Fuel Regulations (2020), online at: https://gazette.gc.ca/rp-pr/p1/2020/2020-12-19/html/reg2-eng.html.

2.2.1.4 *New Federal Climate Plan: Healthy Environment and a Healthy Economy*

In December 2020, the federal government released a plan titled *A Healthy Environment and a Healthy Economy*[39] (HEHE) that builds on the PCF. The current HEHE plan includes a number of measures that promote the electrification of key emitting sectors in Canada.

A significant focus of federal energy intervention has been on improving building energy efficiency for new and existing buildings. The HEHE contains measures to improve energy efficiency in buildings and work on building codes with provincial and municipal governments. This includes an investment of up to $1.5 billion over three years in energy efficient buildings. It also includes an investment of $2.6 billion over seven years to help homeowners retrofit their existing homes, create a low-emission buildings material supply chain, design a new retrofit code for existing buildings to be put into place by 2025, and initiate Canada's first national infrastructure assessment that would undertake long-term planning towards a net-zero future.

The HEHE does not outline a specific role for the gas system to achieve the net-zero by 2050 target except for expanded program spending for clean fuels, which includes renewable natural gas.

2.2.1.4.1 CANADA GREENER HOMES GRANT

The Canada Greener Homes Grant[40] is a federal government initiative launched in 2021, under its policy umbrella of energy efficiency for homes. The aim of this grant is to help Canadians make their homes more energy efficient, create jobs across Canada for energy advisors and help homeowners make retrofits.

While FEI supports the federal government's funding for energy efficiency initiatives, the Canada Greener Homes Grant, as it currently stands, primarily uses taxpayer dollars to help citizens invest in electric technologies. In doing so, the program misses the opportunity to support high-efficiency gas appliance upgrades, which can be fuelled seamlessly by renewable and low-carbon gas over the planning horizon.

2.2.1.4.2 FEDERAL CARBON PRICE

A key aspect of the federal government's emissions reduction strategy as outlined in the HEHE is an updated approach to carbon pricing. In December 2016, the federal government announced that it planned to require the provinces to impose a price of at least $10 per tonne of carbon dioxide equivalent emissions starting in 2018. The price would rise by $10 per tonne a year for the next four years, reaching $50 per tonne by 2022.

As part of the HEHE plan, the federal government announced that it plans to increase the price on carbon as part of a push to meet and surpass Canada's goal of reducing GHG emissions by

[39] Appendix F-6: A Healthy Environment and a Healthy Economy (2020), online at: https://www.canada.ca/en/environment-climate-change/news/2020/12/a-healthy-environment-and-a-healthy-economy.html.

[40] Appendix F-7: Canada Greener Homes Grant (2020), online at: https://www.nrcan.gc.ca/energy-efficiency/homes/canada-greener-homes-grant/23441.

30 per cent below 2005 levels by 2030. The carbon price would rise by $15 per tonne a year for the next eight years beginning in 2023, to reach $170 per tonne in 2030. There are still some key unknowns on the future of carbon pricing in Canada.

2.2.1.4.3 LOW-CARBON INDUSTRY

For industrial emitters, the federal government is launching a "Net-Zero" challenge for large emitters to implement plans to transition their facilities to net-zero. To support industry's efforts in this area, the Federal government has committed to investing $3 billion over five years in the Strategic Innovation Fund's Net-Zero Accelerator. This fund will expedite decarbonization projects and scale-up new technology. The federal government is also investing $1.5 billion in a low-carbon and zero-emission fuels fund to increase the use of low-carbon fuels which include hydrogen, renewable natural gas and diesel. This plan also introduces Canada's Hydrogen Strategy,[41] which FEI discusses in Section 2.2.2.4., along with the BC Hydrogen Strategy.[42]

2.2.1.4.4 IMPACT ASSESSMENT ACT NOW REQUIRES PROJECTS TO ACHIEVE NET-ZERO BY 2050

The *Strategic Assessment of Climate Change*[43] (SACC) was released in 2019 and is conducted under the *Impact Assessment Act*[44] (IAA). It applies to designated projects as defined under the IAA and each assessment must consider the extent to which the project will hinder or contribute to Canada's ability to meet its climate change commitments and the project's potential impact on the environment. The SACC is meant to provide guidance to stakeholders and decision-makers on how climate change policies and commitments should be considered in impact assessments.[45] Included in the SACC, is the requirement for projects with a lifetime beyond the year 2050 to provide a credible plan that describes how the project will achieve net-zero emissions by 2050.

Federal guidance on evaluating net-zero projects will be needed to outline the potential mechanisms to achieve net-zero along with an appropriate designation of net-zero accounting. It is anticipated that this requirement is likely to continue to evolve as climate impacts, technologies, political and policy contexts change. Projects under development by FEI are being evaluated and designed to meet climate objectives, and FEI will continue to undertake further analysis as additional investments are made over the planning horizon.

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[41] Appendix A-3: Hydrogen Strategy for Canada (2020), online at: https://www.nrcan.gc.ca/sites/nrcan/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf.

[42] Appendix A-4: B.C. Hydrogen Strategy (2019), online at: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bc_hydrogen_strategy_final.pdf.

[43] Appendix F-8: Strategic Assessment of Climate Change (2020), online at: https://www.canada.ca/en/services/environment/conservation/assessments/strategic-assessments/climate-change.html#toc0.

[44] S.C. 2019, c. 28, online at: https://laws-lois.justice.gc.ca/eng/acts/I-2.75/.

[45] Appendix F-9: Terms of Reference for Conducting a Strategic Assessment of Climate Change (2019), online at:https://www.strategicassessmentclimatechange.ca/strategic-assessment-of-climate-change-terms-of-reference.

2.2.2 Provincial Energy and Climate Policies

Similar to the federal government policies outlined in Section 2.2.1, the provincial government has intensified its efforts to address climate change through a variety of policies, measures and proposals discussed below, which suggest that both electrification and the decarbonization of the gas system are key strategies to meet the provincial government's climate goals. The depth and intensity of measures reflects that, while BC has made progress to reduce the carbon intensity of its economy, it is not on pace to achieve its 2030 target of a 40 percent reduction from 2007 levels. Therefore, further initiatives are underway to accelerate climate action, which create new opportunities and challenges for FEI and its customers.

2.2.2.1 *Climate Change Accountability Act*

In 2017, the provincial government enacted the *Climate Change Accountability Act*[46] (CCAA) which included targets for reducing GHG emissions in BC. The CCAA identified GHG reduction targets below 2007 levels as follows:

- 16 percent by 2025;
- 40 percent by 2030;
- 60 percent by 2040; and
- 80 percent by 2050.[47]

The CCAA includes a climate change accountability framework, which involves an independent advisory committee and detailed annual reporting on actions taken to reduce emissions and manage climate change risks.

The CCAA required the Minister of Environment and Climate Change to establish sector-specific targets for GHG reductions by March 31, 2021, and to then review these targets by the end of 2025 (and at least once every five years thereafter). In March 2021, sectoral targets for 2030 were established as follows, expressed as a percentage reduction from 2007 sector emissions:

- Transportation – 27 to 32 percent;
- Industry – 38 to 43 percent;
- Oil and Gas – 33 to 38 percent; and
- Buildings and Communities – 59 to 64 percent.[48]

These targets will apply a more focused and directed approach to reducing emissions in these sectors. Notably, FEI delivers the majority of its energy to the industry and buildings and

[46] S.B.C. 2007, c. 42, online at: https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/07042_01.
[47] Government of British Columbia, "Climate Action Legislation" (2021) online at: https://www2.gov.bc.ca/gov/content/environment/climate-change/planning-and-action/legislation.
[48] Online at: https://www2.gov.bc.ca/gov/content/environment/climate-change/planning-and-action/sectoral-targets.

communities sectors, which are the sectors with the most ambitious targets. This places significant pressure on FEI to source affordable, reliable and low-carbon energy. While oil and gas are considered in the sectoral targets, the CCAA provides little detail on how various sectors are to achieve the targets and how these targets will be incorporated into future climate plans and reporting.

2.2.2.2 *CleanBC Roadmap to 2030 (Roadmap)*

On October 25, 2021, the provincial government released the CleanBC Roadmap to 2030 (Roadmap)[49] as an update to the 2018 CleanBC plan and part of its commitment to achieve BC's legislated GHG reduction target of 40 per cent below 2007 levels by 2030. The Roadmap articulates a plan to fully achieve this target and sets the course to reach net-zero by 2050. The Roadmap, includes ambitious measures that place FEI at the forefront of the global energy transition. It is also anticipated to have a significant impact on FEI's customer rates, competitiveness and throughput.

Key measures in the Roadmap that directly impact FEI include:

- An increased carbon tax which will rise to $170 per tonne by 2030;
- A GHG cap for natural gas utilities;
- A zero-carbon requirement for new buildings and highest efficiency standards for space and water heating equipment by 2030;[50]
- Amendments to the *Greenhouse Gas Reduction (Renewable & Low-carbon Fuel Requirements) Act* and the *Renewable & Low-carbon Fuel Requirements Regulation*, known collectively as British Columbia's Low-carbon Fuel Standard (BC-LCFS),[51] to decrease the carbon intensity benchmark while including marine and aviation fuels in the amendment; and
- A 75 percent reduction in oil and gas methane emissions by 2030.

The Roadmap identifies key priorities for decarbonizing the buildings and communities, transportation, and industry sectors; however, its measures rely heavily on electrification to reduce GHG emissions. This policy preference is demonstrated in the release of the BC Hydro Electrification Plan[52] which aims to increase electrification of gas end uses, including transportation, and in measures such as zero carbon new construction and energy efficiency

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[49] Appendix A-5: CleanBC Roadmap to 2030.

[50] This includes a requirement that all space and hot water heating equipment must meet or exceed 100 percent efficiency after 2030 which cannot be met with conventional natural gas equipment.

[51] BC-LCFS, online at: https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/renewable-low-carbon-fuels.

[52] BC Hydro Electrification Plan, online at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/electrification/Electrification-Plan.pdf.

standards where gas solutions are not yet established. Several aspects of the Roadmap are explored further below.

2.2.2.2.1 BC CARBON TAX

Among the measures announced in the Roadmap, the carbon price of $50 will either match or exceed the federal carbon price, which is expected to rise to $170 per tonne by 2030, with annual increases of $15 starting in 2023. This would have the effect of increasing the carbon price on natural gas to approximately $8.40 per GJ by 2030. In BC, the provincial government has recognized the emission reduction benefits of RNG through a credit providing a benefit to purchasers of RNG. The credit is equal to the carbon tax payable on the specified volume or percentage of biomethane,[53] thereby incenting customers to transition to a lower-carbon fuel.

The cap on emissions for natural gas utilities as proposed in the Roadmap, to be implemented as the Greenhouse Gas Reduction Standard (GHGRS), would put an implicit price on carbon by limiting the supply of GHG emissions that would be allowed. The GHGRS is discussed further in Section 2.2.2.2.2 below.

2.2.2.2.2 GREENHOUSE GAS REDUCTION STANDARD (GHGRS): EMISSIONS CAP FOR NATURAL GAS UTILITIES

Before the Roadmap, the 2018 CleanBC plan outlined a target for natural gas delivered to industrial and residential consumers to contain at least 15 percent renewable content by 2030. Displacing 15 per cent of the natural gas supply with renewable gas would increase the annual renewable gas supply to approximately 30 PJ and reduce emissions by approximately 1.5 million tonnes. The renewable gas target was thus a substantial part of the buildings emissions reduction strategy.

The Province’s approach was updated in the Roadmap with a cap on GHG emissions for natural gas utilities called the GHGRS. The GHGRS will establish an obligation for natural gas utilities to reduce GHG emissions from energy use in the buildings and industrial sectors. FEI expects compliance with the cap to be overseen by the BCUC and that enabling legislation will be developed that will further define how this policy will be implemented for gas utilities.

The move from a voluntary renewable gas target to a mandated GHG emissions cap is a substantial change in direction for provincial policy. While details on the GHGRS remain under development, FEI expects that it will place a stringent emissions reduction obligation on gas utilities. Compliance pathways to achieve the cap have not yet been developed; however, these pathways will be highly consequential for the overall role of gas utilities and for customers that rely on the energy that natural gas utilities deliver.

The GHGRS is the first of its kind in Canada, and will mandate FEI to invest in carbon saving technologies and solutions to displace natural gas consumption by 2030. As described in the report, “the cap will be set at approximately 6 Mt of CO_2e per year for 2030, which is approximately

[53] Part 4.1, *Carbon Tax Regulation*, B.C. Reg. 65/2021, online at: https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/125_2008.

47 percent lower than 2007 levels."[54] The GHGRS would require a GHG reduction of approximately 5.5 Mt of CO_2e, which is equivalent to displacing approximately half of the natural gas delivered by FEI.

Additionally, the GHGRS imposes a target of a 61 percent emissions reduction in the buildings sector by 2030. This is an aggressive goal that disproportionately impacts FEI, and is more representative of a 2040 target, thereby requiring a more rapid transition in the buildings sector at greater cost and risk.

It is anticipated that the GHGRS policy framework will enable FEI to invest in a broad set of GHG-saving actions such as increasing renewable and low-carbon gases and incenting higher levels of energy efficiency and other measures. Although many uncertainties remain for FEI, the 2022 LTGRP provides context around FEI's approach to addressing the Roadmap. FEI will continue to work with the Province and other stakeholders to further clarify issues and implications for FEI and its customers.

2.2.2.2.3 BUILDINGS SECTOR

In the Roadmap, new carbon pollution standards are set for the BC Building Code, which envision a transition to zero-carbon new buildings by 2030. The standards are anticipated to be performance-based with flexible options, such as the use of renewable and low-carbon fuels like RNG. For renewable and low-carbon fuels to have a meaningful role in the buildings sector decarbonization policies, issues such as GHG reduction permanency[55] will need to be resolved. This makes new approaches such as FEI's proposed revised Renewable Gas Comprehensive Review, submitted to the BCUC in December 2021,[56] essential to aligning with the provincial government's GHG reduction objectives.

In addition to requiring low-carbon energy for new buildings, the Roadmap requires all new space and water heating equipment sold and installed in BC to be at least 100 percent efficient by 2030. Electric and high-efficiency gas heat pumps, hybrid systems, and deep energy retrofits will be used to reach this goal while incentives for conventional natural gas-fired equipment will be phased out. This suggests that the provincial government sees a declining role for conventional home heating and water heating appliances in favour of gas and electric heat pump solutions. However, gas heat pumps are not yet commercially available for residential customers, leading to uncertainty regarding gas heat pump adoption timelines in reference to the 100 percent efficiency standard in 2030.

In the 2022 provincial budget announcement, there were additional measures to support electrification. These factors included increased carbon tax on natural gas bills, elimination of

[54] Representing the average sectoral reduction required for the buildings and communities and industry sectors.

[55] Permanency of GHG emissions reductions is an important issue for municipal policymakers and refers to the extent to which FEI's measures, such as supplying RG, are voluntary in nature, allowing customers to opt out of an offering over time, thereby eroding their permanence.

[56] Exhibit B-11, FEI Comprehensive Review and Application for Approval of a Revised Renewable Gas Program (December 17, 2021), online at: https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf.

provincial sales tax (PST) for heat pumps and increased PST on all gas combustion appliances such as furnaces, water heaters and fireplaces.[57] Each of these factors contribute to reducing FEI's price competitiveness and influence customer energy choices.

2.2.2.2.4 TRANSPORTATION SECTOR: THE BC LOW-CARBON FUEL STANDARD

The BC-LCFS focuses on reducing environmental impacts of transportation fuels by requiring decreases to the average carbon intensity of transportation fuels. In the 2018 CleanBC plan, the stringency of the BC-LCFS was doubled and the carbon intensity reduction target for gasoline and diesel rose from 10 percent to 20 percent by 2030.

Under the BC-LCFS, organizations can generate credits by using fuels with a carbon intensity below the targets and receive debits for fuels with a carbon intensity above the targets. Each credit represents 1 tonne of CO_2e that was either removed from the atmosphere or not released into the atmosphere as the result of direct, beyond business-as-usual action by a project proponent. These credits can be traded between companies or banked for future use.

Conventional natural gas is below the current carbon intensity threshold in the BC-LCFS. As such, FEI's Compressed Natural Gas (CNG) and LNG transport customers can earn credits under the BC-LCFS and sell them to other organizations, reducing the cost of adopting a low-carbon transportation solution. As an even lower carbon fuel, RNG and hydrogen present an opportunity for FEI's customers in the transport sector to further exceed the carbon intensity threshold in the BC-LCFS, earn more credits, and sell the credits to offset the costs of the supply.

The Roadmap states that the provincial government will increase the stringency of the BC LCFS. New targets will be developed for medium- and heavy-duty vehicles, as the costs and difficulty to electrify these vehicles remain high. The provincial government also intends to modernize the legislation governing the BC-LCFS, including expanding it to cover marine and aviation fuels beginning in 2023. The increased stringency of the BC-LCFS results in uncertainties for FEI's CNG and LNG vehicle programs as the volume of credits they generate may be significantly reduced or eliminated. While RNG will be able to generate more credits as a result of the BC-LCFS change, there will be pressures on RNG supply to meet FEI's other GHG reduction obligations under the GHGRS. In the Roadmap, the CI target will be raised beyond 20 percent to 30 percent.

The BC-LCFS will also be expanded to include marine and aviation fuels, which is advantageous for FEI because the inclusion of marine fuels improves the competitiveness of BC LNG. However, there is currently no detail on the timing or nature of this policy development.

2.2.2.2.5 INDUSTRIAL SECTOR

The Roadmap sets out that all new large industrial facilities need to have a plan to achieve net-zero emissions by 2030 and demonstrate alignment with BC's interim 2030 and 2040 targets. Moreover, emitters of methane will be required to reduce their emissions by 75 percent by 2030 and have emissions close to zero by 2035. FEI will explore opportunities for renewable and low-

[57] The PST on electricity consumption was eliminated in 2019.

carbon gas to serve these sectors as they seek low-carbon alternatives. It is unclear at this point how these industrial requirements overlap with the emissions cap for utilities.

2.2.2.2.6 OIL AND GAS SECTOR

The Roadmap aims to reduce methane emissions from upstream oil and gas, reduce oil and gas emissions in line with sectoral targets, advance CCUS, and engage industrial customers in GHG reduction planning. While there are few details on the cap for oil and gas emissions, the benefits of reduced emissions reduction in upstream gas production will reduce the carbon intensity of natural gas that FEI distributes and provincial emissions. However, these initiatives could potentially increase the commodity cost of gas in the province, impacting FEI customer rates.

2.2.2.3 *Support for Renewable and Low-Carbon Gases and Low-Carbon Transportation: The Clean Energy Act (CEA) and Greenhouse Gas Reduction Regulation (GGRR)*

2.2.2.3.1 RENEWABLE AND LOW-CARBON GASES

The CEA has been the key piece of legislation enabling an increase in the supply of RNG. When FEI applied for approval of what was then called the Biomethane Program in 2010, the energy objectives in the CEA, including the objectives to reduce GHG emissions and waste by encouraging the use of waste heat, biogas and biomass,[58] supported FEI's development of the program. Since that time, the Lieutenant Governor in Council has amended the GGRR to prescribe undertaking to encourage public utilities to acquire renewable and low-carbon fuels to reduce GHG emissions. These undertakings are described below.

On March 21, 2017, the Lieutenant Governor in Council issued Order in Council 161/2017 approving an amendment to the GGRR related to the acquisition of RNG as follows:

> (3.7) A public utility's undertaking that is in the class defined in subsection (3.8) is a prescribed undertaking for the purposes of section 18 of the Act.
>
> (3.8) The public utility acquires renewable natural gas
>
> > (a) for which the public utility pays no more than $30 per GJ, and
> >
> > (b) that, subject to subsection (3.9), in a calendar year, does not exceed 5percent of the total volume of natural gas provided by the public utility to its non-bypass customers in 2015.

This GGRR amendment has facilitated the growth in RNG supply projects over the last four years by allowing FEI to acquire RNG up to a maximum price (supply volumes and projects are further described in Section 6).

[58] Section 2, CFA, online at: https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/10022_01#section2.

More recently, in 2021, the provincial government amended the GGRR to broaden its scope and further increase the production and use of renewable and low-carbon gases, including renewable energy from green and waste hydrogen in BC, to reduce GHG emissions. The changes to the GGRR supporting growth in renewable and low-carbon supply include:

- Enabling utilities to acquire green and waste hydrogen, synthesis gas[59] and lignin, in addition to RNG;
- Increasing the amount of RNG, green and waste hydrogen, lignin, and syngas that utilities can acquire from five percent to fifteen percent of the total annual supply of natural gas;
- Specifying the methods by which utilities can acquire renewable and low-carbon gases, including producing it or upgrading it themselves for injection into the pipeline, paying a third party to produce it or upgrade it for pipeline injection, or purchasing hydrogen, syngas or lignin to displace the use of natural gas at customer facilities; and
- Increasing the price cap utilities can pay to acquire renewable and low-carbon gases from $30 to $31 per GJ for contracts for purchase signed after March 31, 2021[60] and increasing the price cap annually by inflation.

The GGRR enables FEI to be more flexible, stimulates investment in renewable energy and accelerates growth of renewable and low-carbon gas supply in the gas system and acquire renewable and low-carbon gases from $30 to $31 per GJ for contracts. The changes to the GGRR enable FEI to help to achieve the CleanBC Plan objectives, which call for a 15 percent renewable and low-carbon gas content in the natural gas system by 2030. Further, with the recent introduction of the Roadmap in October 2021, FEI expects supply volumes to exceed 15 percent.

BC is the first province in Canada to pass legislation to encourage the production of renewable and low-carbon gases, including hydrogen. The GGRR supports the provincial government's hydrogen strategy, as described below, which includes goals to increase the production and use of renewable and low-carbon hydrogen to help achieve climate targets under the Roadmap.

2.2.2.3.2 LOW-CARBON TRANSPORTATION (LCT)

The GGRR also authorizes a utility to invest up to $331.5 million in low-carbon transportation (LCT) programs, with commitments for funding to be made by March 31, 2022. The Province's plans to continue to support LCT through the GGRR are not yet known. To date, funding was included for the following:

- Capital incentives to transportation fleets that use natural gas as a fuel in place of diesel (or other higher carbon emitting fuels). These fleets include marine vessels, heavy duty

[59] The CleanBC Roadmap inadvertently referred to this as synthetic gas, when it should be synthesis gas. Synthesis gas (or syngas) and lignin can be produced from biomass and used to displace the use of natural gas for industrial heat applications. Please refer to Section 2.3.1.2 for further description.

[60] Or, where the utility is producing the Renewable Gas, where the decision to construct the production facilities is made after March 31, 2021.

trucks, locomotives, mine haul trucks, and busses. Funding also includes natural gas used to produce power for remote industrial applications.

- Capital incentives to CNG and LNG transportation fleets that consume gas supply that is derived entirely from biogas or biomass;
- Developing LNG bunkering infrastructure such as shoreside fueling assets to the marine market;
- Building, owning and operating CNG and LNG fueling stations; and
- Grants to meet safety guidelines for operating and maintaining natural gas vehicles.

These prescribed undertakings in the GGRR are designed to facilitate adoption of natural gas as a transportation (or power generation) fuel to displace higher carbon emitting fuels such as diesel and heavy marine oil. For LCT customers, there are immediate benefits from adopting natural gas into their fleets, such as lower fuel and operating costs, improved air quality due to reduced emissions, and reduced environmental hazards associated with diesel and oil storage tanks.

FEI's LCT efforts will assist BC in achieving its GHG reduction goals by converting the province's transportation fleets from more carbon intensive fuels, such as diesel and gasoline, to relatively cleaner-burning natural gas. Further, the broader adoption of natural gas fuel in the transportation sector will reduce air contaminants such as particulate matter (PM), sulfur oxides (SOx) and nitrous oxides (NOx).

For FEI's customers, CNG and LNG demand also adds value by increasing the year-round load on the gas distribution system (and hence FEI's delivery revenues), thereby reducing upward pressure on delivery rates for all gas customers.

2.2.2.4 *Hydrogen Policies*

Hydrogen technology continues to evolve and is becoming an increasingly viable option for decarbonizing the gaseous fuel stream. While the potential for hydrogen has been around for many decades, the price advantage and robust natural gas supply chain has made it difficult for hydrogen to make inroads in the utility energy supply market. However, with increasing GHG reduction mandates, hydrogen is now seen as a viable option for decarbonizing the gas system, as recognized in the amendments to the GGRR permitting the acquisition of hydrogen. Both the federal and provincial governments have a hydrogen strategy each of which is outlined in this section.

2.2.2.4.1 CANADIAN HYDROGEN STRATEGY

The Hydrogen Strategy for Canada lays out a plan to position Canada as a global leader in clean renewable fuels. The strategy shows that, with the use of clean hydrogen, Canada can achieve net-zero goals by innovating and embracing new technologies. Canada is currently one of the top ten producers of hydrogen in the world and is well positioned to decarbonize many sectors of the economy. The Hydrogen Strategy aims to position Canada as a world-leading producer, user, and exporter of clean hydrogen and associated technologies. Areas of focus include:

- **Production**: Canada is rich in feedstocks such as water, electricity, fossil fuels and biomass and hence is well positioned to become a top global producer of clean hydrogen.
- **Distribution and storage**: leveraging Canada's extensive natural gas pipeline network, along with new storage and distribution assets, allows hydrogen to be transported from production to end use locations.
- **Heat and power**: developing a suite of tools and resources to blend low-carbon intensity hydrogen into Canada's natural gas networks, for use in both industry and the built environment.
- **Feedstocks for industry**: developing policies that will ensure long-term certainty to encourage private sector investment and innovation for hydrogen as an energy source and feedstock in industrial processes.

2.2.2.4.2 BC HYDROGEN STRATEGY

For BC to meet its climate targets, hydrogen will play a critical role. The BC Hydrogen Strategy lays out the actions that the provincial government will take to grow the hydrogen economy. Recognizing the potential for hydrogen in the province, industry and researchers will work together to carry out the provincial government's plan to accelerate the production and use of hydrogen and be a leader in the growing hydrogen economy. These government supply strategies provide the backdrop for growing FEI's renewable and low-carbon gas supply portfolio.

The provincial government's hydrogen strategy includes 63 actions the province intends to pursue over the short, medium and long-term. The BC Hydrogen Strategy includes:

- **2020 to 2025**: Support for blending hydrogen with natural gas.
    - Establish a regulatory framework for injecting hydrogen into the natural gas and propane distribution systems.
    - Include hydrogen as a prescribed undertaking under the GGRR.
    - Partner with a utility to review the infrastructure requirements to accommodate up to 100 percent hydrogen in the distribution system.[61]
- **2025 to 2030:** Support hydrogen injection trials into natural gas and propane distribution systems.
    - Mandate that new or modified natural gas or propane pipelines be hydrogen compatible.
    - Support the introduction of hydrogen-tolerant equipment.

[61] Some of these activities are already underway.

  - Explore the role of hydrogen in meeting the CleanBC 15 percent renewable gas target.

- **2030 and beyond**: Support large-scale hydrogen injection into the natural gas and propane distribution systems.

In 2019, FEI, BC Bioenergy Network, and the Province commissioned the BC Hydrogen Study[62] which identified the significant role that hydrogen could play in achieving provincial deep decarbonization goals. Securing additional supply from a diversified group of providers will provide greater reliability to FEI's renewable and low-carbon gas supply. The study also identifies how the gas infrastructure is a strategic asset both for the transportation and storage of hydrogen and identifies the potential for blending hydrogen into the gas system.

2.2.3 Municipal Actions Addressing Energy and Climate Policy

Evolving municipal and local government policies to address climate change at the local level are primarily focused on further electrification. Many municipalities in FEI's service area are developing updated versions of their climate action plans, with a major focus on reducing GHG emissions while setting ambitious targets out to 2050. Most of the targets address emissions in the transportation and building sectors, with the use of alternative energy sources and energy efficiency helping to reduce the reliance on fossil fuels. Before the provincial government released the Roadmap in October 2021, climate and energy policy at the local government level was evolving at a much faster pace than both provincial and federal policy.

The majority of local governments in BC have signed the BC Climate Action Charter, a voluntary agreement between the provincial government and the Union of BC Municipalities under which each local government signatory commits to take action on climate change. In doing so, municipalities and local governments began undertaking their own initiatives, in addition to provincial efforts, to reduce emissions. In recent years, 30 municipalities in BC have also declared climate emergencies, including the Cities of Surrey, North and West Vancouver, Vancouver, Burnaby, Richmond, New Westminster, and Port Moody.

Along with these commitments, a growing number of local governments are implementing changes to their building codes[63], planning guidelines, and zoning bylaws in order to reduce GHG emissions in new building construction projects and in some cases with existing building retrofits and improvements. This is being achieved by:

- establishing GHG target limits for new construction, necessitating the use of low- carbon or renewable energies; and

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[62] Appendix A-6: British Columbia Hydrogen Study (2019), online at: https://bcbioenergy.ca/resources/bcbn-publications/british-columbia-hydrogen-study/.

[63] Specifically, the City of Vancouver is enabled under the Vancouver Charter to adopt by-laws to regulate the design and construction of buildings. Other municipalities must follow the provincial building code but can provide zoning by-laws that can be enforced.

- incenting developers to use electricity as a low-carbon solution (or in some cases to not connect to a "fossil fuel supply grid" system).

2.2.4 Energy and Climate Policy in Relevant US States

US energy policy influences markets and energy distribution throughout BC's broader energy trading region and is therefore a consideration in FEI's long-term resource planning environment. Electricity, natural gas, and RNG are supplied and distributed throughout networks across North America. It is therefore important to consider the North American perspective in energy planning and GHG reduction strategies. Overall, the US policy context impacts BC's natural gas use environment in the following ways:

- Upstream natural gas resources in northeast BC and Alberta serve large portions of Western US demand for natural gas and natural gas used for electricity generation.
- US policy may influence Canadian policy due to potential impacts on the relative economic competitiveness of each jurisdiction. Various legislative and policy developments of the federal and state governments in the US may affect demand for natural gas from natural gas utilities and electricity generation facilities, and therefore impact the interconnected wholesale electricity market and subsequently natural gas and renewable gas markets in the western US.
- Initial efforts had been placed on decarbonizing the electricity sector (primarily by retiring coal-fired generation), and more recently, promoting electrification as the subsequent initiative for GHG emission reduction. Across the North American grid, there remains a high proportion of higher carbon electricity that needs to be considered. In a comprehensive review of energy planning, it is becoming clear that electricity will not be able to service all the needs for energy across residential, commercial and industrial sectors and that a diversified approach is critical to meet a growing population and economy.[64]

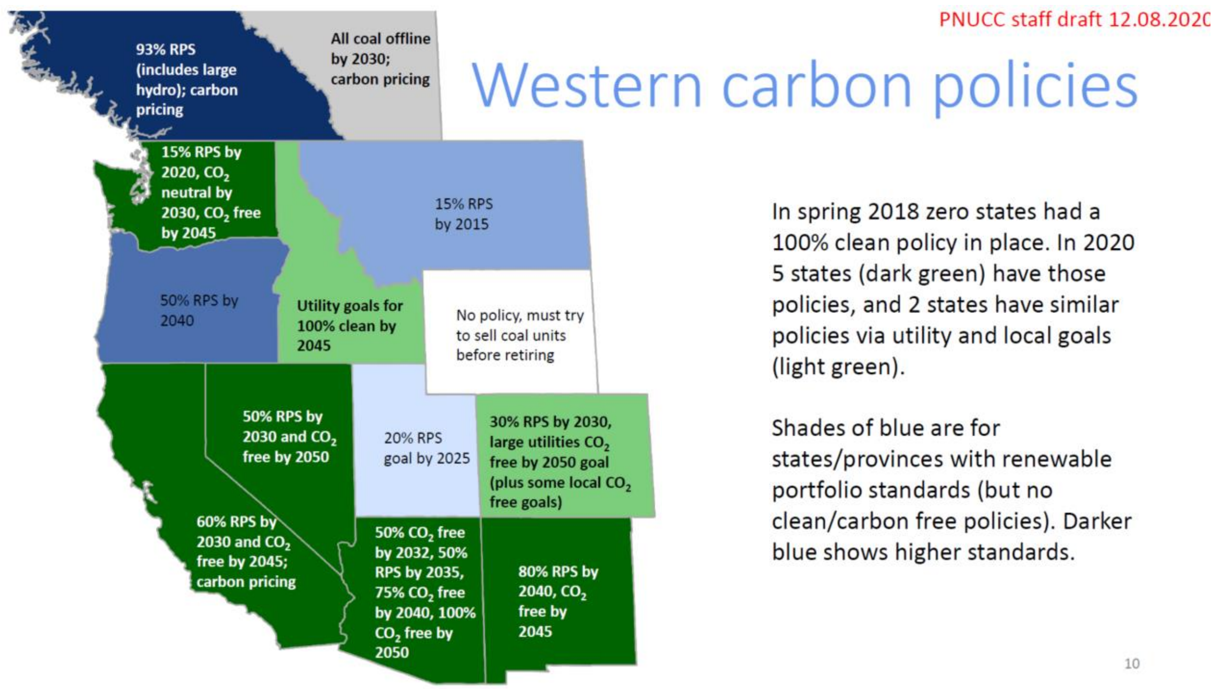
Renewable Portfolio Standards (RPS) are policies designed to increase generation of electricity from renewable sources. These policies require or encourage electricity producers within a given jurisdiction to generate and supply a minimum share of their electricity from designated renewable resources such as wind, solar, biomass, some forms of hydro-electricity and other alternatives to fossil fuel and nuclear electricity generation. The adoption of these standards demonstrates the speed of change and innovation in the energy sector.

The 2017 LTGRP highlighted the increase in the introduction of RPS. Since 2017, these policies have been rapidly accelerated to address the effects of climate change. US policy objectives include decarbonizing the power sector towards net-zero emissions by 2035, and for the US as a whole to achieve net-zero emissions by 2050. Figure 2-2 illustrates the speed of change of

[64] Appendix A-7: Guidehouse (for the American Gas Foundation), Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience (2021), online at: https://gasfoundation.org/wp-content/uploads/2021/01/Building-a-Resilient-Energy-Future-Full-Report_FINAL_1.13.21.pdf.

western US states with regards to the adoption of RPS or voluntary targets, versus those without any standard or target. The following two sections detail recent policy action affecting natural gas utilities in two relevant PNW states, Washington and Oregon, as these policies may impact BC's energy market.

Figure 2-2: Western Carbon Policies[65]



2.2.4.1 *Washington Policy Actions*

In March 2020, Washington released its climate targets to reduce GHG emissions by 45 per cent below 1990 levels by 2030 and 95 per cent below 1990 levels by 2050.[66] This was put into legislation in April 2021, when Washington obtained senate approval of its *Climate Commitment Act* (CCA).[67] One of the key components of the CCA includes a program with a declining cap on carbon emissions. The CCA targets the largest emitters in the state to help ensure that Washington can meet its climate targets. The CCA was passed in 2021, with the program beginning January 1, 2023.

Additionally, as part of the *Clean Energy Transformation Act* [68] passed in 2019, Washington state enacted legislation that requires total natural gas costs to include the social cost of GHGs and related upstream carbon emissions, which is expected to increase total natural gas costs.

[65] Northwest Power System Trends 2021, slide 10, as presented in Pacific Northwest Utilities Conference Committee System Planning Committee meeting December 16, 2020.

[66] Governor Jay Inslee's Medium Page, "Inslee announces bold climate legislation as part of supplemental budget rollout" (December 19, 2019).

[67] Online at: https://app.leg.wa.gov/RCW/default.aspx?cite=70A.65.

[68] Online at: https://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/Session%20Laws/Senate/5116-S2.SL.pdf.

A potential piece of legislation, Washington HB 1084,[69] the *Healthy Homes and Clean Buildings Act*, could substantially reduce, and potentially eliminate, natural gas utilities' role in delivering energy to many state ratepayers. This bill would require all new buildings in Washington to be zero-carbon by 2030 and seek to eliminate fossil fuel consumption in existing buildings by 2050, through providing a roadmap to phasing out gas utility service in Washington. However, this could potentially increase the replacement of conventional natural gas with RNG and other low-carbon gas, as a new policy in Washington State provides utilities the flexibility to develop RNG programs.[70] This legislation, if enacted, would put Washington on pace to become the first US state to implement statewide restrictions on natural gas infrastructure in new construction, while simultaneously tackling retrofits in existing buildings.

2.2.4.2 *Oregon Policy Actions*

Oregon has a Climate Action Plan (OCAP) that was issued in March 2020, when an executive Order 20-04 was released that stated that Oregon needs to reduce its GHG emissions by at least 45 per cent below 1990 levels by 2035, and 80 per cent below 1990 levels by 2050.[71] Further specifics on this executive order will be outlined in the upcoming years on carbon costs and programs such as a cap and reduce program to buy or sell offsets. In terms of energy, the plan targets the transportation, buildings, innovation, and clean energy sectors. In the buildings sector, OCAP set new energy efficiency goals for residential and commercial construction, representing at least a 60 percent reduction in new building energy consumption from 2006 levels. The new energy efficiency standards for appliances will also be consistent with tougher standards set by more stringent jurisdictions, specifically California. In the clean energy section of OCAP, the state utility commission will prioritize proceedings that advance decarbonization and make reductions to GHG emissions in the utility sector.

As a result of the OCAP, in December 2021, Oregon enacted a Climate Protection Program which will set enforceable limits on GHG emissions from fossil fuel use[72]. Beginning in 2022, Oregon has set an emissions cap for fossil fuel providers, which includes natural gas utilities, and the cap will tighten each year through 2050. However, the Climate Protection Program provides several compliance pathways for fossil fuel providers, which includes companies incorporating renewable fuels into their supply mix or contributing to projects that support communities' transition from fossil fuels. Lastly, Oregon governor signed Senate Bill 98 in 2019, setting voluntary RNG goals

[69] S&P Global, "Washington State proposes legislation to phase out natural gas utility service" (January 6, 2021), online at: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/washington-state-proposes-legislation-to-phase-out-natural-gas-utility-service-61819435.

[70] Washington Utilities and Transportation Commission, DOCKET U-190818, "Report and Policy statement on investigation of Renewable Natural Gas programmatic design and pipeline safety standards" (December 16, 2020).

[71] Executive Order No. 20-04, "Directing State Agencies to Take Actions to Reduce and Regulate Greenhouse Gas Emissions" (March 10, 2020).

[72] Oregon Public Broacasting, "State approves new 'more aggressive' Climate Protection Program (December 16, 2021), online at: https://www.opb.org/article/2021/12/16/state-approves-new-more-aggressive-climate-protection-program/.

for gas utilities in the state. This means that as much as 30 percent of RNG could be added into the system by 2050.[73]

2.2.5 Energy and Climate Policies Influence FEI's Long-Term Planning

The evolving federal, provincial and regional energy and environmental policies are key factors in the LTGRP planning environment and help inform FEI regarding potential impacts on future customer demand and supply over the planning horizon. Section 2.2.1 discussed how the federal climate policy framework is focused on achieving Canada's 2030 GHG reduction goals with wide-ranging measures targeting all key emitting sectors (buildings, transportation and industry). However, while natural gas is one of the most widely used fuels in Canada, there is no specific direction on the future of the gas delivery system. Furthermore, its role in decarbonizing Canada's GHG emissions remains undefined. Sections 2.2.2 and 2.2.3 discussed how the provincial and municipal policy frameworks are in alignment with the climate policy objectives. Section 2.2.4 discussed how US energy policy influences markets and energy distribution throughout BC's broader energy trading region and outlined the current policy environment in Washington and Oregon.

Overall, the policy preference at all three levels of government for the use of electricity across many end uses puts downward pressure on FEI's demand and upward pressure on FEI's rates. Demand is reduced though the focus on energy efficiency of buildings and appliances, and policies which limit FEI's ability to attach new customers. Rates are increased by the need to invest in higher cost gaseous energy in response to emission reduction pressures and these costs are borne across the energy value chain. Taxes add additional upward rate pressure. Downward pressure on FEI's ability to add customer attachments could eventually result in a smaller customer base resulting in higher costs per customer to support decarbonization initiatives.

From a broader perspective, these initiatives change the economics of customer and builder energy-use decisions and underpin the weakness of electrification-centric plans that overlook the opportunity for the gas system to contribute to decarbonization. As economic signals, they also confound the ability for customers to choose the right energy for the right use at the right time, and may result in unintended consequences, such as high energy rates, supply and capacity issues and destabilization of the province's energy system.

Currently, there is a lack of broader understanding associated with the long-term costs and infrastructure requirements needed to completely re-engineer BC's energy system and the implications of electrification policies on the western regional energy system as whole. Absent from energy planning are insights related to the long-term requirements for peak electricity demand, how customers' energy needs will be met in extreme and cold weather events, and the associated costs of ensuring the system meets demand and capacity for a deep electrification scenario. It has yet to be seen if clean electricity could provide more effective decarbonization

[73] Bill 98, ORS 757.390 – 757.398, online at: https://oregon.public.law/statutes/ors_757.390.

and further reduce GHG emissions if a broader perspective is employed for its use in the PNW rather than focusing on energy plans at the local level.

These evolving energy and environmental policies are key factors in the LTGRP planning environment and help inform FEI regarding potential impacts on future customer demand and supply over the planning horizon. Market forces create a measure of uncertainty in the market and thus FEI must be prepared for a range of possible outcomes as presented in the LTGRP planning scenarios. FEI's customer demand is discussed in Section 4 and energy supply is discussed in Section 6.

2.3 *INDIGENOUS GROUPS - LEGISLATIVE AND POLICY DEVELOPMENTS*

There have been significant legislative and policy developments with respect to the engagement with Indigenous groups since the 2017 LTGRP that have broad impacts on FEI's long-term planning. FEI recognizes and respects the constitutional rights of Indigenous Peoples, and FEI's Statement of Indigenous Principles[74] aims to ensure FEI's business operations are conducted with respect for Indigenous people's social, economic and cultural interests. The development of infrastructure has become more complex and may take longer due to increased engagement, consensus seeking, consideration of cumulative effects, and regulatory decision making processes. This section highlights a number of developments that will need to be taken into consideration over the planning horizon.

2.3.1 BC Has Passed Legislation to Give Effect to the UN Declaration of the Rights of Indigenous Peoples

In November of 2019, the BC Legislature passed the *Declaration on the Rights of Indigenous Peoples Act* (Declaration Act)[75] into law and in June 2021, the federal *United Nations Declaration on the Rights of Indigenous Peoples Act* (UNDRIP Act)[76] became law. The Declaration Act and the UNDRIP Act provide for BC and Canada's laws, respectively, to be brought into alignment with the UN Declaration and the development of action plans to meet the objectives of the UN Declaration.[77]

BC released the final version of its Action Plan in March 2022.[78] The BC Action Plan articulates the actions that the Province will take in consultation and cooperation with Indigenous peoples from 2022-2027, including modernizing and reforming legislation to be aligned with the UN Declaration; implementing joint decision-making and consent agreements; co-developing

[74] Appendix A-8: FEI's Statement of Indigenous Principles, online at: https://www.fortisbc.com/in-your-community/indigenous-relationships-and-reconciliation/our-statement-of-indigenous-principles.

[75] S.B.C. 2019, c. 44, online at: https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/19044.

[76] S.C. 2021, c. 14, online at: https://laws-lois.justice.gc.ca/eng/acts/U-2.2/page-1.html.

[77] Declaration Act, ss. 3 and 4.

[78] Appendix F-10: Declaration on the Rights of Indigenous Peoples Action Plan (2022), online at: https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/ministries/indigenous-relations-reconciliation/declaration_act_action_plan.pdf.

environment, land and resources policies; and identifying and supporting First Nations-led clean energy opportunities.

At this point, the federal action plan has not been developed and the priorities for that plan are unknown. However, the legislative review and action plans of both governments may result in amendments to provincial and federal legislation or policy which may impact FEI's operations. Currently, the BC Action Plan contemplates the reform of provincial forestry legislation and the *Mineral Tenure Act*, and the establishment of a Secretariat that would be tasked with ensuring legislation is consistent with the UN Declaration.

The Declaration Act empowers the provincial government to enter into decision-making agreements with Indigenous groups. Such agreements could require the exercise of statutory decision-making powers jointly by an Indigenous governing body and the BC government, or the consent of an Indigenous governing body before the exercise of a statutory power.[79] The BC Action Plan identifies entering into such decision-making agreements and seeking all necessary legislative amendments to enable the implementation of such agreements to be one of the focuses for the years 2022-2027.

Both the Declaration Act and the UNDRIP Act have raised questions and differing perspectives as to the meaning of "free, prior and informed consent" (FPIC) in the UN Declaration and what obligations may exist with respect to seeking consent from Indigenous groups. At this point, neither the Declaration Act nor the UNDRIP Act include a definition of consent or FPIC. Many Indigenous groups assert that FPIC requires that consent be obtained from Indigenous groups for a project to proceed. The conflicting perspectives on FPIC's meaning have created new risks for FEI, including cost escalation, project delays, uncertain timelines and risks that authorizations may be challenged where decisions are made without the consent of Indigenous groups.

Further, BC's "Draft Principles that Guide the Province of British Columbia's Relationship with Indigenous Peoples" include the principle that meaningful engagement aims to secure FPIC when BC proposes to take actions which impact Indigenous peoples and their rights, and identifies that BC will look for opportunities to build processes and approaches aimed at securing consent and mechanisms to build deeper collaboration and consensus.[80] The BC Action Plan includes the finalization of the Draft Principles as an Action Item for 2022-2027.[81] The development of such processes and mechanisms may impact the method and timing for obtaining FEI project approvals.

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79 Declaration Act, s. 6.

80 Government of British Columbia, Draft Principles that Guide the Province of British Columbia's Relationship with Indigenous Peoples, online at: https://www2.gov.bc.ca/assets/gov/careers/about-the-bc-public-service/diversity-inclusion-respect/draft_principles.pdf.

81 Declaration_Act_-_Draft_Action_Plan_for_consultation.pdf (gov.bc.ca), Action 2.2.

2.3.2 Legislation Relevant to FEI's Planning Is Being Amended to Align with the UN Declaration

In BC, legislation related to project permitting is being adopted to align with the UN Declaration. For example, the new *Environmental Assessment Act* (EAA),[82] which was brought into force in December 2019, introduces changes to the environmental assessment process in BC to incorporate the concept of FPIC. Under the new EAA, Indigenous groups can self-select which project assessments they wish to participate in as a "Participating Indigenous Nation". The Environmental Assessment Office must then seek to achieve consensus with the Participating Indigenous Nations at various stages of the environmental assessment process.[83] Although not all FEI's projects or operations require an environmental assessment, the EAA provides an opportunity for a person (including an Indigenous group) to apply to have a project that is not otherwise reviewable designated as a reviewable project.[84] These changes could significantly increase FEI's engagement and consultation obligations with Indigenous groups in environmental assessments. In the context of resource planning, FEI must therefore take into account longer lead times for project development and the potential to enter into agreements with Indigenous groups with respect to projects.

2.3.3 Summary of Legislative and Policy Developments for Indigenous Groups

The evolving legislative and policy developments and FEI's commitment to engagement with Indigenous groups will have impacts that will be taken into consideration in FEI's long-term planning. In Section 5.2.1.2, FEI discusses opportunities to collaborate on DSM activities. In Section 8.3, FEI summarizes its consultation with Indigenous groups on this LTGRP and the opportunity to improve ongoing activities for resource planning and implementation of the low-carbon transition. In Section 10, FEI acknowledges the need to continually evolve its engagement process to ensure the outcomes of this LTGRP and future resource planning processes meaningfully integrate the input from Indigenous groups. In summary, feedback and input from Indigenous groups throughout the development of this LTGRP emphasized the need for FEI to consider the key principles of the UN Declaration and to ensure FEI considers Indigenous energy perspectives within its broader utility planning processes.

2.4 COMPETITIVE ENVIRONMENT FOR THE TRANSITION FROM NATURAL GAS TO INCREASED RENEWABLE AND LOW-CARBON GAS

The competitive environment for FEI's products has grown more complex as a multitude of pricing and non-price considerations are influencing customer energy choices. In terms of pricing, forecasting energy prices into the future is a complex and challenging task with significant uncertainty. FEI recognizes that the natural-gas-focused approach in the 2017 LTGRP is no

[82] S.B.C. 2018, c. 51, online at: https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/18051.
[83] EAA, see for example ss. 16, 19, 27, 28, 29, 31 and 32.
[84] EAA, s. 11.

longer the environment in which FEI will be operating. Therefore, this section addresses both natural gas pricing and the influence of adding renewable and low-carbon gas to customer rates.

Non-price considerations include of a number of factors influencing FEI's competitive position. For example, consumer, builder and developer, commercial and industrial end user preferences influence the use of gas versus electricity, choice among alternative energy solutions and potential use of other sources of energy. Factors influencing non-price considerations may include the following:

- GHG emission concerns;
- Type of housing mix, the size of new dwellings, and commercial building requirements;
- Builder and developer preferences;
- Capital costs, installation requirements, operating and maintenance costs over the lifetime of the equipment;
- Customer perceptions;
- Availability of new technologies;
- Availability of utility and government incentives and rebates for new construction, retrofits, commercial buildings and industrial facilities;
- Commercial and industrial end user requirements; and
- Government policies (such as local governments' support for non-fossil fuel alternatives through updates to building codes and bylaws, which is discussed in Section 2.2.3).

FEI discusses the competitive forces influencing customers' energy choices in the following sections:

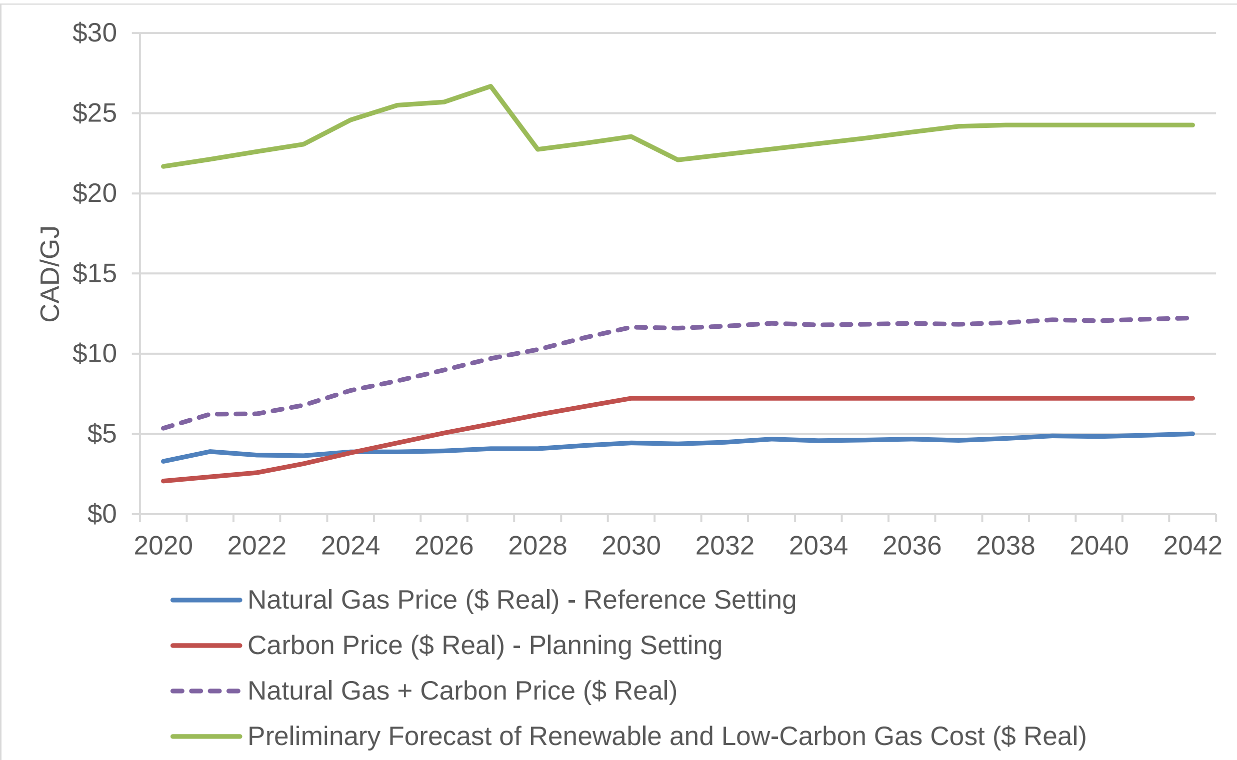
- Section 2.4.1 provides an overview of pricing considerations for renewable, low-carbon and natural gas supply and commodity pricing. Further information about natural gas supply and a market overview is provided in Section 6 and Appendix D-1;
- Section 2.4.2 provides an overview of energy choices facing FEI's customers. Residential rate comparisons are provided based on current natural gas and electricity rates, and estimated annual fuel costs for space heating in the Lower Mainland. The section then discusses relative upfront capital and installation costs of gas appliances compared to electric appliances on customer rates; and
- Section 2.4.3 provides a summary of FEI's increasingly complex competitive environment over the planning horizon.

2.4.1 Energy Pricing Considerations

Figure 2-3 below illustrates the energy prices that were used to generate outcomes for the scenario analyses undertaken in Sections 4, 5, and 6, and the Rate Impact Analysis provided in

Sections 5.4.2 and 9.4. The renewable and low-carbon gas price reflects the mix of fuels developed for use in the demand forecasting analysis presented in Section 4. These forecasts are based on FEI's current understanding of what the long-term pricing could be for natural gas, renewable and low-carbon gas, electricity, and carbon taxes. However, market uncertainties, such as socio-political and environmental risks, will influence North American and world energy prices. The costs for renewable and low-carbon gas are expected to go down over time and will be influenced by technological improvements that will positively impact production volumes and associated benefits resulting from economies of scale. GHG emission reduction policy and many other factors will influence energy prices over the planning horizon. Figure 2-3 helps set the stage for reviewing FEI's competitive pricing landscape over the planning horizon as discussed further in this section in greater detail.

Figure 2-3: Outlook of Energy Costs for Fuel Types Used in the Development of the LTGRP[85,86]



2.4.1.1 *Renewable and Low-Carbon Gas Price Considerations*

FEI recognizes that it is difficult to predict long-term prices for renewable and low-carbon fuel types; however, by developing and considering a range of price forecasts for analysis within different future scenarios, the resource planning process provides a number of different outcomes that are considered within the 2022 LTGRP demand forecasting analysis (Section 4). Section 6

85 Critical Uncertainty Input Settings for Each Future Scenario described in Section 4.5.3.
86 Fuel costs include inflation assumption of 2.0 percent.

further discusses how FEI plans to meet demand in the long-term through its energy supply arrangements. Section 9 discusses the resulting projected rate impacts of decarbonization.

Renewable and low-carbon gas will play an integral role in allowing FEI to meet its GHG reduction targets. The blend of fuel types is currently expected to be more expensive than natural gas plus carbon tax and, as more is incorporated into FEI's energy portfolio, fuel costs and rates will face upward pressure.

In summary, decarbonizing FEI's gas supply in response to climate policy will cause the average cost of gas to increase. This rising cost, regardless of specific cost recovery mechanisms or tariffs, will continue to be borne by FEI's customers, reducing FEI's price competitiveness when compared to other energy alternatives. However, this action is necessary to meet the GHG emission targets set out in the Roadmap and to respond with urgency to address climate change, just as electrification will also result in increased costs for ratepayers and taxpayers.

2.4.1.2 *Conventional Natural Gas Commodity Price Considerations*

This section provides a high-level overview of natural gas prices and volatility and how they affect FEI's competitive position. More details on the North American and regional natural gas marketplace are provided in Appendix D-1, Natural Gas Market Overview. Section 6 also addresses how FEI plans to meet demand in the long-term through its energy supply arrangements.

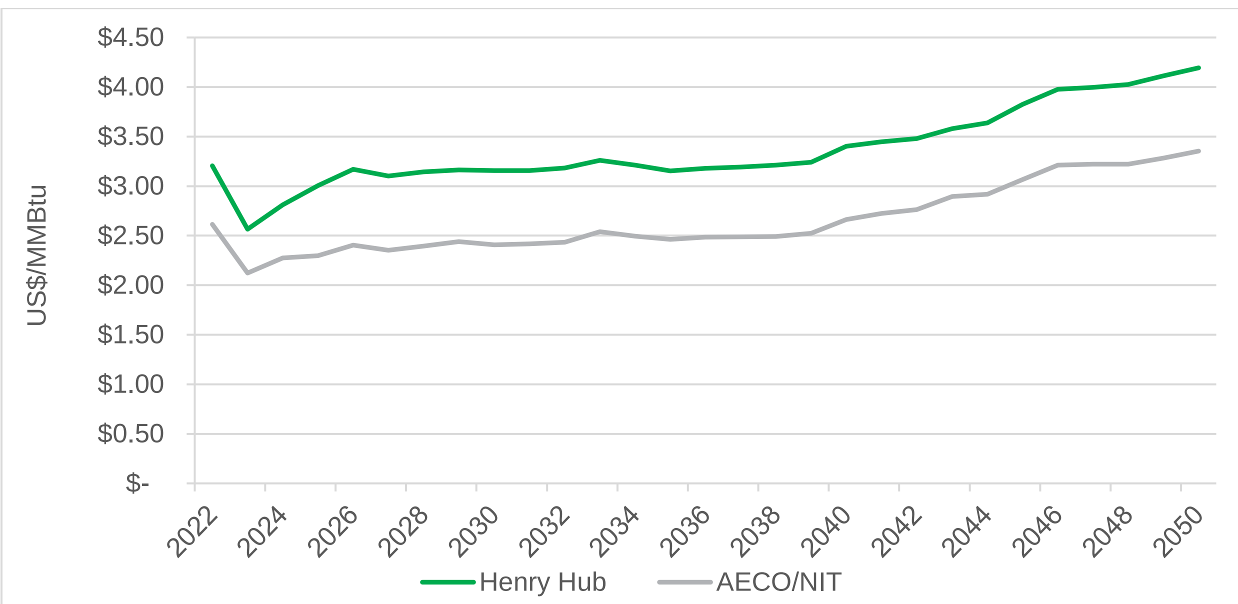
In general, commodity rates in the natural gas utility sector reflect the utility's cost of purchasing gas on behalf of its customers, without mark-up. Natural gas prices are set in an open and competitive market and are influenced by many variables throughout North America, as well as each utility's operating region. Commodity rates will therefore fluctuate in response to changes in supply and demand conditions for natural gas.

The shale gas potential in North America and the technological efficiencies in extracting it have had a major impact on actual natural gas commodity prices and long-term forecasts. Gas market analysts currently predict that North America could produce over 100 years of economically-recoverable supply, based on current consumption levels. The significant shale gas potential in North America and the improvements in drilling technologies have provided North America with an abundance of low-cost natural gas supply. The majority of Canada's supply originates within the Montney formation, located in the northwest of the Western Canadian Sedimentary Basin. As in the 2017 LTGRP, the abundance of natural gas supply in North America and comparatively low price levels have supported the commodity's competitiveness with other sources of energy. This has improved the price competitiveness of using natural gas on an operating cost basis, even though natural gas direct-use applications (such as space and water heating) typically require higher capital, installation and maintenance costs than electric appliances, as outlined in Section 2.4.2.

With an abundance of supply, North American natural gas became more economically attractive relative to other fuel sources as it was significantly disconnected from other competing fuels, such as heating and fuel oil. Figure 2-4 shows IHS Markit's (S&P Global) long-term price forecast for natural gas based on the Henry Hub and AECO/NIT markets in real 2021 dollars. The forecasts do not include temporary price spikes or dips that can occur due to extreme weather events or other supply/demand imbalance events, as evident due to the current supply/demand imbalances and geopolitical events in Europe. The figure illustrates natural gas price forecasts for the following:

- **Henry Hub** is the official pricing point for natural gas futures on the New York Mercantile Exchange (NYMEX) and is used as the benchmark for the North American natural gas market. The notable growth of shale gas supply in recent years has resulted in a significant drop in natural gas prices.
- **AECO/NIT** and **Station 2** are the supply hubs from which FEI procures most of its supply. These hubs are forecast to trade at a significant discount to the Henry Hub price. After the TC Energy North Montney Mainline was placed into service in January 2020, Station 2 prices have strengthened relative to AECO/NIT and now typically trade at parity to AECO/NIT, and therefore only AECO/NIT is shown.

Figure 2-4: Natural Gas Price Forecast (2021 Real Dollars) [87]



The natural gas market continues to be volatile[88] and this volatility has increased since the development of the 2017 LTGRP. Natural gas prices remained relatively low after 2016, however became more volatile after oil prices dropped significantly in March 2020 due to decreasing demand and rising supply corresponding to the trajectory of the recovery from the COVID-19 pandemic. Following the collapse of world energy prices in 2020, prices began rising once again

[87] Source: © 2022 S&P Global. All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by S&P Global.

[88] This forecast was completed prior to the Russian invasion of Ukraine and thus does not include the impact of the current geopolitical climate and does not illustrate the volatility of prices or the current futures price market.

due to the rebalancing of the global supply and demand. The combination of increasing demand, producers cutting production and a global energy shortage caused natural gas prices in Europe and world LNG prices to surge above $30 USD per MMBtu. This combination also caused North American prices to rise significantly, with current prices being above $5 USD per MMBtu. Current political and social unrest demonstrates the volatility exhibited in the energy market for many commodities, and is illustrated further in Appendix D-1.

With the anticipation of increased demand in the PNW and already limited pipeline infrastructure becoming more constrained, regional price disconnects are expected to continue. This will continue to strain resources in the region during high demand periods, and creates upward price pressure and volatility risk at the Sumas price hub for the Huntingdon marketplace in BC. This gas price volatility is one reason why FEI has identified the need for system upgrades and expansion (such as the TLSE and RGSD projects) as part of FEI's resiliency plans.

Future demand growth in North America has been driven by relatively low natural gas prices, and the majority of anticipated growth will be through the LNG export market. In terms of the regional market, in recent years, natural gas usage for power generation has increased in the PNW, due to the retirement of coal plants. As power generation from coal is replaced with renewable electricity resources in the region, it is uncertain what the future usage will be, as these resources are not sufficiently available at this time, and will be intermittent (i.e., dependent on weather conditions). Therefore, natural gas demand and power prices in the PNW will continue to become more interconnected, consequently increasing price volatility.

This regional market price volatility is expected to continue in the future. While regional infrastructure additions can help mitigate some of the regional price disconnection risk, these additions require a long time to plan, secure shipper commitments, receive regulatory approval, and construct. The Southern Crossing Pipeline, Westcoast T-South, Mist, and Jackson Prairie storage facilities expansions are examples of regional infrastructure projects that were approved and subsequently constructed to meet growing regional demand and helped to reduce some regional constraints. However, further infrastructure is needed to meet the pace of future demand growth, provide resiliency, and help support the clean energy transition in the PNW.

In summary, the significant shale gas potential in North America and the improvements in drilling technologies have provided North America with an abundance of low cost supply of natural gas. This ability to maintain production even with a relatively low commodity price has resulted in supply outpacing demand. FEI will continue to accelerate the procurement of renewable and low-carbon gas over the planning horizon; however, natural gas is likely to have a long-term role to play in storage and other specialized needs that are still under development as FEI transitions to a low-carbon future.

2.4.2 Competitive Environment in BC for Energy End Uses: Gas Versus Electricity

A potential natural gas customer often compares the cost of gas space heating and water heating equipment with the alternative electric options before making a purchase decision. As such, price competitiveness of natural gas versus electricity is an important factor that needs to be considered in the LTGRP as customer energy choices impact the number of customer additions and retention over the twenty-year planning horizon.

In the following sections, the price competitiveness of natural gas is compared with electricity from both the energy cost and total cost (energy cost plus capital and maintenance costs) perspectives. In comparison to electricity in BC, natural gas prices are more volatile, primarily because natural gas costs are market based, whereas electricity supply is primarily cost based. Furthermore, electricity prices are heavily influenced by BC Hydro's low embedded costs and provincial government policies. Natural gas competitiveness in BC and in other provinces in Canada is further challenged by the implementation of the carbon tax as well as other non-price factors. In Section 2.4.2.1 FEI compares its energy rates (excluding upfront capital and installation costs) against BC's electricity rates. Section 2.4.2.2, illustrates the current cost comparisons influencing residential customer energy choices for new construction, based on the upfront capital and installation cost differences between gas and electricity end use applications (space and water heating) including the adoption of new technologies which support the use of electricity.

2.4.2.1 *Natural Gas and Electricity Rates for Residential Sector*

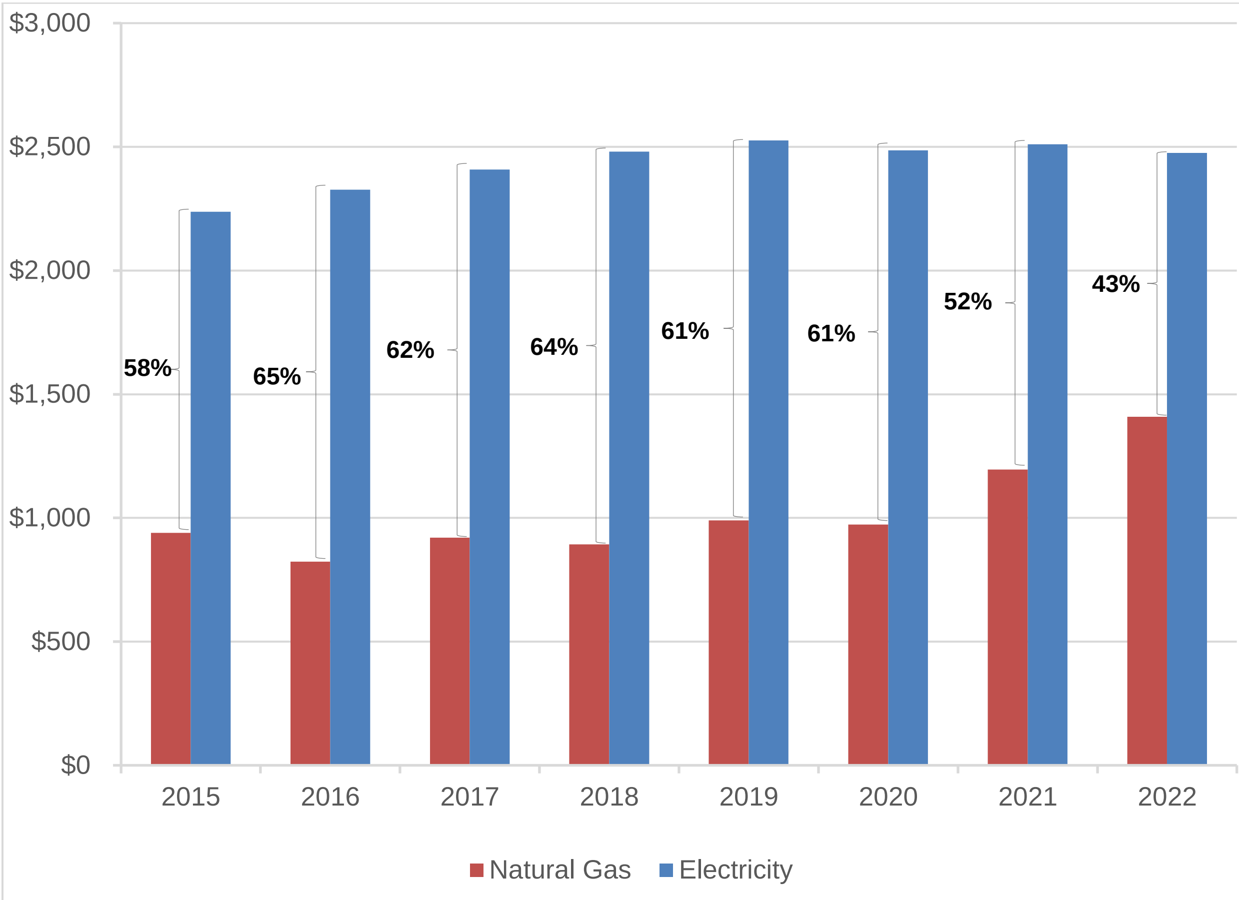
In this section, FEI compares its energy rates (excluding upfront capital and installation costs) against BC Hydro's electricity rates. A review of the trend in the energy cost differential between natural gas and electricity indicates that over time natural gas's cost advantage has declined. Figure 2-5 below shows the trend in annual bill amounts based on FEI's burner tip[89] rates versus BC Hydro's electric equivalent rates, with the favourable energy cost advantage held by gas decreasing from 58 and 65 percent (2015 and 2016) to 43 percent (2022). Further detail on FEI's total effective rate for a typical residential customer is illustrated in Figure 2-6. The share of carbon tax as a proportion of the total effective rate has increased from 13 percent in 2015 to 16 percent in 2022. Once the announced carbon tax increase to $170 per tonne is in place in 2030, the carbon tax rate will have increased by more than 5.5 times, to $8.40 per GJ.

The decrease in energy cost differential between natural gas and electricity in the 2021-2022 period can be attributed to higher natural gas commodity cost as well as delivery rate and carbon tax increases. All else equal, and considering the projected increases to provincial carbon tax, as well as BC Hydro's proposed rate changes in its recently-filed 2023-2025 Revenue Requirements Application,[90] FEI expects the decline in price differential to continue in the coming years. Gas prices will continue to rise as renewable and low-carbon gas comprises a larger share of the fuel mix. However, electricity rates associated with electrification may also rise due to the need for more transmission, distribution, and substation infrastructure to meet increases in electricity peak demand.

89 FEI's burner tip rate includes the commodity charge, storage and transport charge, fixed basic, and delivery charges, and the carbon tax to provide a comparison against the electric equivalent (based on an average annual use rate of 90 GJ per year).

90 BC Hydro Fiscal 2023 to 2025 Revenue Requirement (August 31, 2021), Online at: https://www.bcuc.com/OurWork/ViewProceeding?ApplicationId=921.

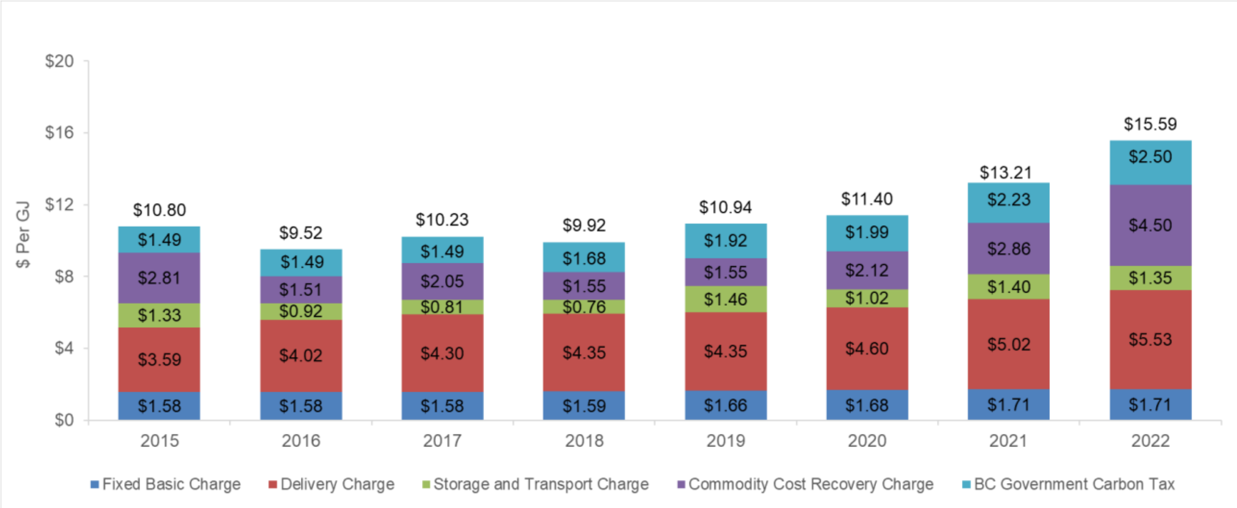
Figure 2-5: Residential Annual Bill Amount Trend in BC



Assumptions:

- Estimated residential bills are based on prevailing rates on April 1 of each specified year. BC Hydro bill estimates exclude the basic charge since a household already pays the basic electric charge for non-heating use.
- The average efficiency of gas equipment is assumed to be 92 percent relative to 100 percent for electricity to determine equivalent electric rates.
- Estimated bills are calculated based on annual use rate of 90 GJ.
- FEI bills are inclusive of the BC carbon tax and exclude other applicable taxes.

Figure 2-6: Breakdown of FEI's Historical Total Effective Rate for Residential Customers



Assumptions:

- Natural gas use of 90 GJ per year assumed for Fixed Basic Charge.
- FEI rates and the BC carbon tax are weighted averages (where applicable), to reflect rate changes which occur throughout the year.
- All delivery and commodity rates are inclusive of applicable rate riders.

While today's low natural gas rates contribute to a natural gas operating cost advantage relative to electricity, commodity price is only one factor that impacts the price competitiveness of natural gas in BC relative to electricity. Other factors include natural gas price volatility (discussed in the Natural Gas Market Overview, Appendix D-1) and the upfront capital and installation cost of natural gas appliances relative to electric appliances as discussed in the following section. Non-price considerations are also a factor in a customer's energy use choices as discussed earlier in the section.

2.4.2.2 *Installation and Operation Comparisons Provide Total Cost Perspective (New Construction)*

Section 2.4.2.1 provided an overview of natural gas price competitiveness on the basis of average annual bill amounts. In this section, price competitiveness will be analysed by also considering the upfront capital cost differences between gas and electricity end use applications (space and water heating) for new construction, including the adoption of new technologies which support the use of electricity. In addition to capital costs, efficiency rates and maintenance costs affect the total cost of the appliance over its measure life. Today's gas appliances have typically higher capital and maintenance costs and lower efficiency rates than electric alternatives, which tend to decrease the total price competitiveness of gas versus electric alternatives.

Table 2-1 below provides the upfront capital costs and efficiency estimates for new construction that are used in FEI's total cost comparison analysis. For space heating, a gas furnace is compared with electric baseboard heating, as well as an electric heat pump. The electric heat pump is a relatively new space heating option (which also provides an attractive cooling option) that is being increasingly promoted by policymakers and gaining market share,[91] and therefore has been added to the space heating analysis.

As shown below, a gas furnace is considerably more costly than an electric baseboard heater yet less expensive than an electric heat pump.[92] For the purpose of this analysis, a new gas furnace is assumed to be 96 percent efficient, an electric baseboard heater is assumed to be 100 percent efficient, and an electric heat pump is assumed to be 200 percent efficient.[93]

For water heating, a gas hot water tank is compared with an electric water heater. Gas water heaters continue to be more costly than the electric alternative. The efficiency of a gas water heater is assumed to be 67 percent while the electric water heater tank is assumed to be 100 percent efficient.

Table 2-1: Upfront Costs and Efficiency Estimates for Space and Water Heating[94]

	Space Heating Options			Water Heating Options	
Equipment	**Gas Furnace**	**Electric Baseboard**	**Electric Heat Pump**	**Gas Water Heater Tank**	**Electric Water Heater Tank**
Capital Cost[95]	$18,000	$9,200	$21,000	$2,800	$1,550
Efficiency Rate	96%	100%	200%	67%	100%

To compute the total cost differential between gas and electric options, the upfront and installation cost differential is first converted into an annualized format using the builder's assumed interest rate and measure life of the equipment. In the next step, the sum of the annualized upfront capital cost and annual maintenance cost[96] differentials are divided by the assumed space heating and water heating consumption levels for new construction to calculate the capital and maintenance cost difference per GJ.

As demonstrated in Table 2-2, the cost difference per GJ between a gas furnace and an electric heat pump is negative, reflecting the fact that, all else equal, a gas furnace has a lower capital cost than a heat pump, but is not able to provide the cooling benefits of a heat pump. As gas heat

91 According to FEI's 2017 Residential End Use Study, 14 percent of new Single Family Dwellings (constructed in 2016 or after) use an air source heat pump as their main space heating equipment.

92 The provincial and municipal governments provide various rebates for electric heat pumps to decrease the upfront costs and make them price competitive with gas furnaces.

93 Electric heat pumps are often advertised to have 200 percent or even higher efficiency. However, the actual efficiency of heat pumps may be lower than the nameplate efficiency depending on outside temperature and other factors.

94 Cost estimates were provided to FEI by an independent consultant (Ecolighten Energy Solutions Ltd.).

95 Both gas furnace and central heat pump cost estimates include the cost of ductwork that is usually contracted out to the sheet-metal contractor who does all the ducting and exhaust fans in a new home. Per the BC Building Code, the electric baseboard cost estimate includes the cost of a mechanical ventilation system that would be needed in a house with no forced-air space heating system.

96 Manufacturers may recommend a certain maintenance schedule, however homeowners may not always follow these recommendations. As such, annual maintenance cost is situational and can change from one household to the other. These numbers are FEI's best estimates.

pump technology for the residential sector is still in the pre-commercialization phase, installed costs are still under investigation, but may be considered in the next LTGRP.

Table 2-2: Difference in Costs for Space and Water Heating over Measure Life[97]

	Space Heating (Gas Furnace)		Water Heating (Gas vs Electric)
	vs Heat Pump	vs Baseboard	
Difference in capital costs	**($3,000)**	**$8,800**	**$1,250**
Annual payments for recovery of capital costs	($257)	$753	$137
Difference in maintenance costs per year	$0	$100	$0
Total costs per year to pay off difference in capital cost	**($257)**	**$853**	**$137**
Energy consumption (GJ)/year	38	38	22
Difference in capital and maintenance costs between gas and electric equipment ($/GJ)	**($6.8)**	**$22.4**	**$6.2**

Finally, the annualized capital and maintenance cost differentials are compared to the difference between FEI's burner tip rate and efficiency adjusted electric rates.[98] If the operating cost advantage of natural gas (calculated as the difference between FEI's burner tip rate and efficiency adjusted electric rates) is greater than the difference in capital and maintenance costs between gas and electric options, then the natural gas equipment is assumed to be the more economic option for the consumer. However, if the natural gas operating cost advantage is smaller than the upfront capital and maintenance cost differential, then the electric option will be more economical. The results of this analysis are shown in the table below.

[97] Assumptions based on the new construction of a home in the Lower Mainland (Medium Size Dwelling), interest rate of 5 percent and the measure life of 18 years for a natural gas space heating furnace and 13 years for hot water tank. The annual payments to recover the difference in upfront capital costs are calculated based on the present value of an annuity formula where PV of an annuity = annuity * [(1-(1+r)^-n)/r] (r is interest rate and n is the measure life of the equipment).

[98] To calculate the electric equivalent rate, the electric to gas efficiency ratio is applied to the Step 1 and Step 2 BC Hydro RIB rate. For example, to compare a gas furnace with an electric heat pump, the assumed 96 percent efficiency of a new gas furnace is divided by the heat pump's assumed efficiency of 200 percent and multiplied with Step 1 and Step 2 rates.

Table 2-3: Operating Cost Advantage vs Capital Cost Differential between Gas and Electric Equipment[99]

	Space Heating (Gas Furnace)		Water Heating (Gas vs Electric)
	vs Heat Pump	vs Baseboard	
BCH Step 1 Rate Adjusted for Efficiency	$12.3	$24.7	$17.2
BCH Step 2 Rate Adjusted for Efficiency	$18.5	$37.0	$25.9
FEI's Burner Tip Rate	$15.6	$15.6	$15.6
FEI's Operating Cost Advantage vs BCH Step 1 Adjusted Rate	**($3.3)**	**$9.0**	**$1.6**
FEI's Operating Cost Advantage vs BCH Step 2 Adjusted Rate	**$2.9**	**$21.4**	**$10.2**
Difference in capital and maintenance costs between gas and electric equipment ($/GJ)	**($6.8)**	**$22.4**	**$6.2**

The results can be summarized as follows for each of the three columns shown in Table 2-3.

Gas Furnace as Compared to Electric Heat Pump

The analysis above shows that a gas furnace is less costly than a heat pump, with the difference estimated at $6.80 per GJ over the measure life. BC Hydro's efficiency adjusted Step 2 rate is $2.90 per GJ higher than FEI's burner tip rate and its Step 1 rate is $3.30 per GJ lower; therefore, without a means of reducing the heat pump's high capital costs, the gas furnace option will be more economic. Currently, both provincial and local governments as well as BC Hydro provide generous rebates to households who install heat pumps or convert their fossil fuel heating systems to central heat pumps. As such, when the heat pump's higher rebates are considered, the gas furnace's cost advantage can be reduced or eliminated in favour of the electric heat pump, depending on the rebate amount available at the time of installation.

Gas Furnace as Compared to Electric Baseboard

The table above shows that a gas furnace is significantly more costly than electric baseboard heating, with the difference estimated at $22.40 per GJ over the measure life. The upfront capital costs associated with the installation of a gas furnace eliminates FEI's competitive position against both Step 1 and Step 2 efficiency-adjusted electric rates, as FEI's operating cost advantage over both Step 1 and Step 2 efficiency-adjusted rates is less than $22.40 per GJ. This price advantage in favour of electricity is even more persuasive when considering smaller multi-family dwellings, such as townhouses and apartment units, are more likely to have electric baseboards as their main space heating. For these units, lower consumption means lower savings in annual energy costs to offset the higher capital cost of a gas furnace.

[99] Based on FEI's Approved Rates for 2022 and BC Hydro's proposed rates in its 2023-2025 RRA.

Gas as Compared to Electric Water Heating

The table above shows that gas water heating is somewhat more costly than electric water heating, with the difference estimated at $6.20 per GJ over the measure life. The upfront capital costs associated with the installation of a gas water heater eliminates FEI's competitive position against the Step 1 efficiency adjusted rate and greatly reduces its competitiveness with efficiency-adjusted Step 2 rate.

Over time, the price competitiveness of natural gas versus electricity has reduced, from both the energy price and total price perspectives. The capital cost differentials have increased, decreasing FEI's total price competitiveness. Electric heat pumps have higher upfront capital costs but the current government rebates (ultimately funded by taxpayers) effectively change the price advantage in favour of heat pumps. Further, ongoing increases in carbon taxes, as well as increases in natural gas and renewable gas costs, will further reduce FEI's price competitiveness in the coming years.

2.4.3 Summary of FEI's Competitive Environment

This section addresses the competitive environment influencing customers' energy choices and demonstrates how the environment has grown more complex since the 2017 LTGRP. The section provided background on fuel pricing for all fuel types and the cost impacts of transitioning to renewable and low-carbon gas supply as it takes on an increasing portion of the energy mix over the planning environment. The section also discussed natural gas pricing considerations, as although it is declining, it will continue to be part of the energy mix for FEI over the planning environment. Finally, the section provided a summary of comparisons between natural gas and electricity rates. Comparisons of current residential rates for electricity, and natural gas demonstrate the factors customers are facing in home energy choices and the rapidly changing competitive environment for FEI.

The competitive environment for FEI's products has grown more complex as a multitude of non-price considerations are influencing customer energy choices. Consumer, builder and developer, commercial and industrial end user preferences influence the use of gas versus electricity, renewables and other sources of energy. FEI will continue to monitor the complex competitive environment influencing customer energy choices over the planning horizon.

2.5 RESILIENT ENERGY INFRASTRUCTURE CONTINUES TO BE A CRITICAL CONSIDERATION

The planning environment needs to consider BC's energy system resiliency as a whole, taking into consideration the need to optimize both the gas and electric systems. Policymakers and regulators need to recognize that resilience is best achieved through a diversified approach to long-term resource planning in the interest of providing safe, reliable and affordable energy. Reliable and resilient energy delivery is especially critical on the coldest days of the year when British Columbians are most reliant on a secure energy supply to heat their homes and businesses. This was dramatically illustrated by the loss of life from hypothermia due to the gas and electric outages in the state of Texas during the February 2021 winter storm.[100] Climate change, in terms of extreme weather events, highlights the need for increased system resiliency to be incorporated in all system planning discussions regarding BC's energy future.

BC's current energy system relies on the gas system's ability to withstand extreme weather events and meet peak and seasonal demand provided through storage resources inherent in the gas system. The value of resilience should not be overlooked or jeopardized in an electrification-centric policy environment in which a single-minded pursuit of decarbonization goals could face unintended consequences such as system outages and other disadvantages. Technological advances in renewable and low-carbon gas will make decarbonization a reality, and long-term planning can recognize the importance of resilient gas infrastructure as a critical component in providing a strong future energy system for British Columbia. Section 3.2.2.3 further discusses resiliency as a benefit in the Clean Growth Pathway and introduces FEI's Gas System Resiliency Plan (Appendix E).

2.6 *SUMMARY OF FEI'S PLANNING ENVIRONMENT*

The planning environment outlined above provides the backdrop to the factors setting the stage for decarbonization in FEI's Clean Growth Pathway to 2050. There is an overwhelming trend in the increasing stringency of energy and environmental policy in Canada, the US, and internationally as federal, provincial, state, and municipal governments implement initiatives to reduce GHG emissions and transition to low-carbon sources. These initiatives are key factors in the LTGRP planning environment and help inform FEI regarding potential impacts on future customer demand and supply over the planning horizon.

Federal government policies and initiatives outlined in Section 2.2.1 are aimed at addressing climate change, reducing GHG emissions, and developing cleaner energy sources. The federal climate policy framework is focused on achieving Canada's 2030 GHG reduction goals with wide-ranging measures targeting all key emitting sectors (buildings, transportation and industry). However, while natural gas is one of the most widely used fuels in Canada, there is no specific federal climate policy direction on the future of the gas delivery system and its role in decarbonizing Canada's GHG emissions is undefined.

Provincial government energy and environmental policies and initiatives outlined in Section 2.2.2, demonstrate that both electrification and the decarbonization of the gas system are key strategies to meet the provincial government's climate goals. While BC has made progress to reduce the carbon intensity of its economy, it is not on pace to achieve its 2030 target of a 40 percent reduction from 2007 levels. Therefore, the provincial climate policy framework is focused on achieving the CleanBC Roadmap's GHG reduction goals with wide-ranging measures targeting all key emitting sectors (buildings, transportation and industry). Local government policy is also rapidly evolving in support of similar goals for GHG emission reduction.

[100] Online at: https://www.dallasnews.com/news/weather/2021/04/30/number-of-texas-deaths-linked-to-winter-storm-grows-to-151-including-23-in-dallas-fort-worth-area/.

Section 2.3 addressed FEI's commitment to engagement with Indigenous groups as another key consideration in FEI's long-term planning. FEI recognizes and respects the constitutional rights of Indigenous Peoples, and FEI's Statement of Indigenous Principles aims to ensure the Company's business operations are conducted with respect for Indigenous people's social, economic and cultural interests. As FEI considers working with Indigenous groups on clean energy projects, FEI will be taking all reasonable steps to ensure these developments are given consideration over the planning horizon.

Section 2.4 addressed the increasingly complex competitive environment influencing customers' energy choices. The section provided background on energy pricing and transitioning to renewable and low-carbon gas supply. Pricing considerations for natural gas, although declining in use, will continue to be part of the energy mix for FEI over the planning horizon. Finally, the section discussed end use comparisons of current residential rates for electricity, natural gas, and renewable and low-carbon natural gas to demonstrate the factors customers are facing in home energy choices.

Finally, Section 2.5 discusses the need for the planning environment to consider resiliency of BC's energy system as a whole, taking into consideration the need to optimize both the gas and electric systems. System resilience is best achieved through a diversified approach to long-term resource planning in the interest of providing safe, reliable and affordable energy to British Columbians even on the coldest days of the year and during extreme weather events that are occurring more frequently due to the effects of climate change.

The planning environment sets the stage for the discussion of the four pillars of FEI's Clean Growth Pathway in Section 3. Scaling the supply of renewable and low-carbon gas and expanding DSM investment for decarbonizing the built environment are fundamental objectives in FEI's low-carbon transition. FEI's low-carbon transportation, marine bunkering, LNG initiatives and support of emerging technologies, will further reduce BC's GHG emissions and positively impact global emissions.

FortisBC Energy Inc.
2022 LTGRP

Section 3:

CLEAN GROWTH PATHWAY – FOUR PILLARS TO A LOW-CARBON FUTURE

Table of Contents

3. CLEAN GROWTH PATHWAY – FOUR PILLARS TO A LOW-CARBON FUTURE

3.1 *INTRODUCTION*

The Clean Growth Pathway is FEI's response to the rapid changes in policy described in Section 2 and provides the framework and FEI's 20-year vision[101] for a low-carbon energy future. The Clean Growth Pathway is described in FEI's Clean Growth Pathway to 2050 report attached as Appendix A-1. Through the Clean Growth Pathway, FEI will support increasing government ambition and intervention to reduce GHG emissions and take greater climate action.

The Clean Growth Pathway is a "Diversified Pathway", as it includes a mix of expanded electrification and renewable and low-carbon gas, with a prominent role for FEI's infrastructure to achieve decarbonization objectives. As concluded in the Guidehouse Pathways Report in Appendix A-2, a Diversified Pathway has the advantage of leveraging FEI's extensive existing infrastructure and the resilience and reliability of the provincial energy system as a whole. The Diversified Pathway achieves GHG reductions aligned with the provincial government's objectives, and is a more affordable, resilient and practical long-term pathway for BC. A number of other studies included in Appendix 9 outline the benefits of comprehensive energy system planning akin to that achieved by the Diversified Pathway, while highlighting that there are unintended consequences and risks of pursuing an electrification-centric approach to energy planning in BC.

FEI's Clean Growth Pathway is supported by four key pillars:

- **Pillar 1:** Transitioning to renewable and low-carbon gases to decarbonize the gas supply;
- **Pillar 2:** Investing in DSM programs in support of energy efficiency and conservation measures to reduce energy use among residential, commercial and industrial customers;
- **Pillar 3:** Investing in low-carbon transportation infrastructure to reduce emissions in this sector; and
- **Pillar 4:** Investing in LNG to lower GHG emissions in marine fueling and global markets.

Each of these pillars are essential elements to achieving a low-carbon future, and are described in detail in this section and throughout the 2022 LTGRP.

The remainder of this section is organized as follows:

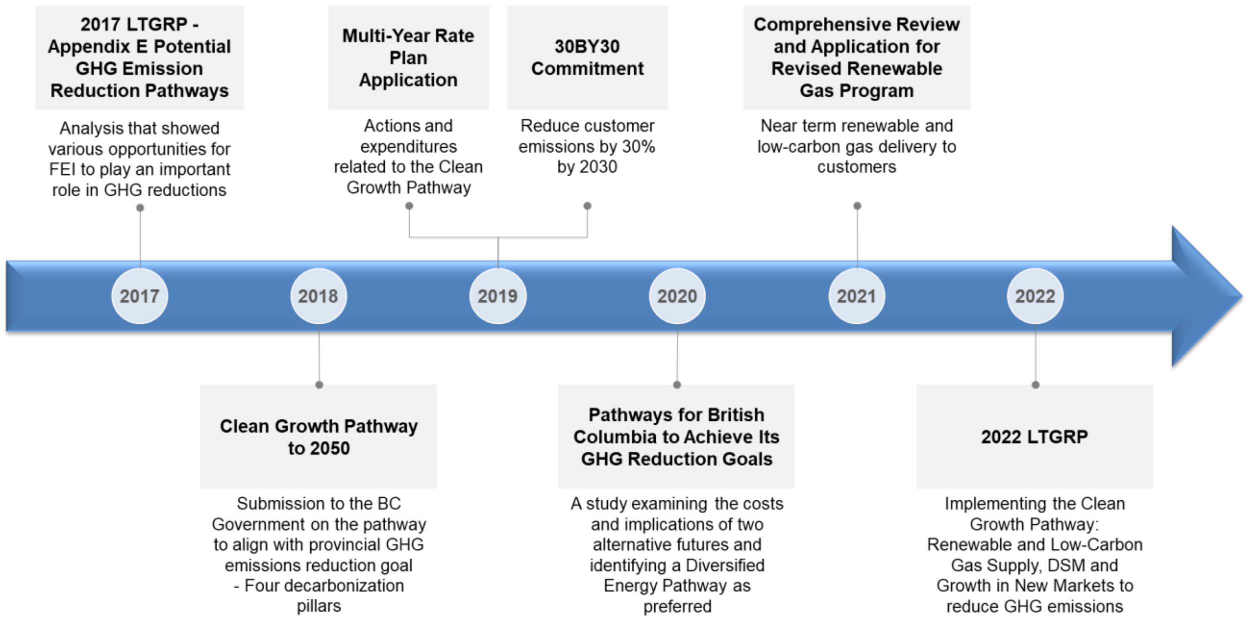
[101] FEI has provided a 20-year vision in its resource plans since the directive from the BCUC in its Decision on the 2010 LTGRP to include a 20-year vision in the 2014 LTRP: "This vision could describe what [the FEU] may look like in the future: its business lines, its customers, the expectations for supply and demand and the major issues it will deal with over the 20 year resource plan timeframe."

- Section 3.2 discusses the benefits of the Clean Growth Pathway to British Columbians in terms of GHG reductions, affordability, peak demand, resiliency, innovation, and economic development;
- Section 3.3 describes the first pillar of the Clean Growth Pathway: transitioning to renewable and low-carbon gases to decarbonize the gas supply;
- Section 3.4 describes the second pillar of the Clean Growth Pathway: investing in DSM programs in support of energy efficiency and conservation measures to reduce energy use among residential, commercial and industrial customers;
- Section 3.5 describes the third pillar of the Clean Growth Pathway: investing in low- carbon transportation infrastructure to reduce emissions in this sector;
- Section 3.6 describes the fourth pillar of the Clean Growth Pathway: investing in LNG to lower GHG emissions in marine fueling and global markets;
- Section 3.7 describes research studies that support a complementary and diversified approach to energy system planning; and
- Section 3.8 presents a summary and conclusion of the background and benefits of the Clean Growth Pathway.

3.2 THE CLEAN GROWTH PATHWAY WILL REDUCE GHG EMISSIONS AND PROVIDE OTHER SIGNIFICANT BENEFITS

FEI initiated the Clean Growth Pathway to address BC's GHG emissions and realize additional non-GHG-related benefits. The Clean Growth Pathway will leverage the decarbonization potential of both the gas and electric energy systems in supporting provincial GHG emission reductions, as well as the affordability, reliability, resiliency, and economic development advantages in pursuing a diversified approach to decarbonization. Figure 3-1 below describes the evolution of FEI's Clean Growth Pathway, which began in 2017 when FEI provided analysis demonstrating its important role in decarbonizing BC's energy system in the 2017 LTGRP.

Figure 3-1: The Evolution of FEI's Clean Growth Pathway from 2017 LTGRP to 2022 LTGRP



The figure demonstrates the climate action milestones FEI has achieved since the 2017 LTGRP to set the stage for the diversified decarbonization pathway that FEI is taking over the 20-year planning horizon. In particular, in 2020, FEI commissioned the Pathways Report, which defines and compares two pathways to achieve BC's GHG emissions targets as follows:

- The "Diversified Pathway" which includes a mix of expanded electrification and low-carbon gas, with a prominent role for FEI's infrastructure to achieve the deep decarbonization objectives of FEI's Clean Growth Pathway; and
- The "Electrification Pathway", which is primarily focused on deep electrification of BC's energy system.

The Pathways Report concludes that "the Diversified Pathway can achieve the same level of provincial GHG emissions reductions as the Electrified Pathway at a significantly lower cost to British Columbians. Although initiatives are used to different extents, both pathways defined in this study would require transformative changes in every sector of BC's economy. By 2050, the societal value of achieving the Diversified Pathway is expected to be in excess of $100 billion higher than the Electrification Pathway."

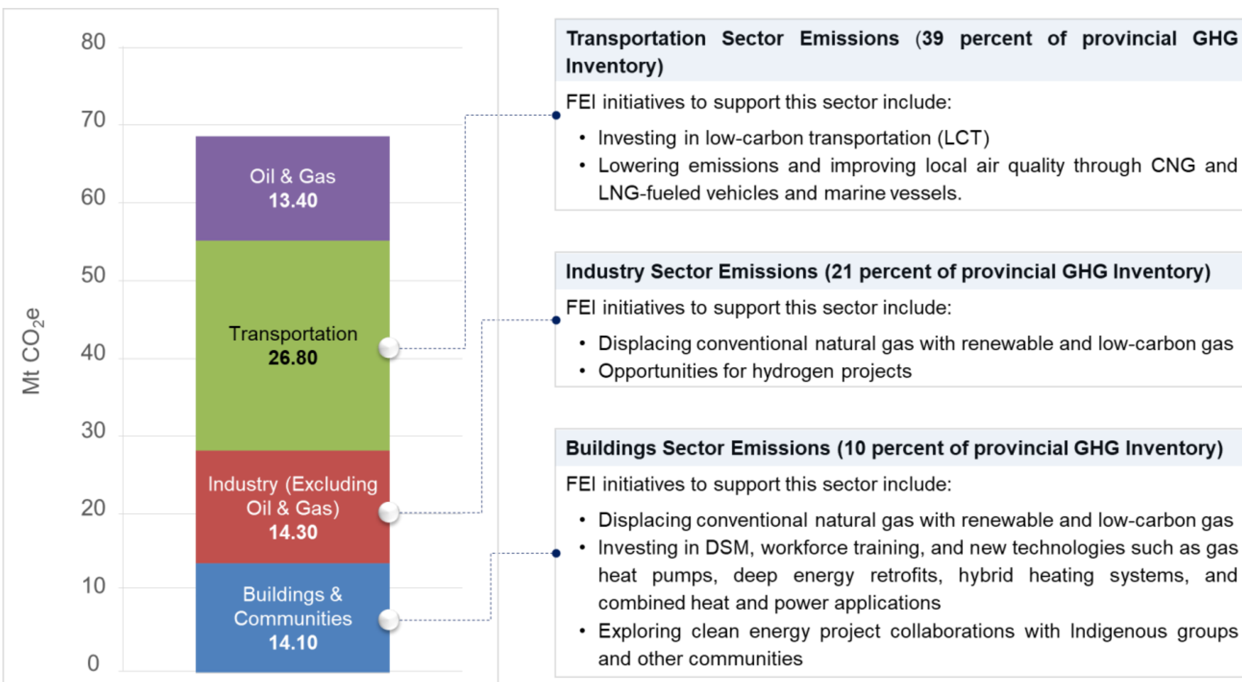
These and other benefits of the Clean Growth Pathway are explored below.

3.2.1 The Clean Growth Pathway Addresses BC's GHG Sectoral Emissions

As part of the consultation process for the BC government's CleanBC plan in 2018, FortisBC released its Clean Growth Pathway report (see Figure 3-1). This report outlines FortisBC's actions to align with the provincial government's GHG emission reduction goals. Building upon the Clean Growth Pathway, FortisBC established its first emissions reduction target in 2019, "30BY30", setting an initial and voluntary target of reducing the GHG emissions associated with FortisBC's customers' energy use by 30 percent by the year 2030[102]. In October 2021, the Province announced the Clean BC Roadmap to 2030, with even more aggressive policy measures, including the introduction of a cap on gas utility emissions in BC of approximately 6 Mt of CO_2e annually (as discussed in Section 2.2.4.2). Although the elements of the plan have not yet been enacted into law, FEI has considered these additional targets within this 2022 LTGRP where possible and will continue to build on its previously developed GHG emission reduction initiatives. These initiatives are leading the way to a lower carbon economy through active partnerships with customers, communities, industry, and government. Ultimately, FEI's decarbonization targets demonstrate FEI's understanding of the importance of a low-carbon future and serve as a way to measure progress on the actions outlined in the Clean Growth Pathway.

FEI's Clean Growth Pathway will substantially reduce BC's GHG emissions and contribute to global GHG emission reductions. Figure 3-2 illustrates BC's 2019 GHG emissions inventory by sector and describes FEI's initiatives to address these sectoral emissions. This emissions inventory is used to compare FEI's customers' GHG emissions in the comparative analysis provided in Section 9.2.

Figure 3-2: 2019 GHG Emissions by Sector in BC[103] and FEI Initiatives to Support Decarbonization



[102] From a 2007 baseline year, which is used in BC's provincially legislated emission targets.
[103] BC's 2019 GHG emissions. Online at https://www2.gov.bc.ca/gov/content/environment/climate-change/planning-and-action/progress-targets#emissions.

3.2.2 Benefits of the Clean Growth Pathway Beyond GHG Emission Reduction

The Clean Growth Pathway is a holistic approach to energy system planning. It provides not only for GHG reductions that align with government objectives, but also other whole-system benefits. Decarbonization is achieved under the Clean Growth Pathway without detracting from traditional planning considerations such as cost to the customer and ability to meet peak demand.

In addition to GHG reductions, the key benefits of the Clean Growth Pathway over deep electrification are greater affordability, the ability to meet peak demand on the coldest days of the year, energy system resiliency, integrated community energy systems, and economic development and job creation for the clean energy sector. A Diversified Pathway realizes the GHG abatement potential of a complementary approach that ensures both the gas and electric system contribute to BC's low-carbon energy future. This approach is optimal for decarbonizing BC's economy as it makes use of existing and largely paid-for energy delivery infrastructure to reduce emissions while supporting BC's economy in retaining and creating jobs in the clean energy sector of the economy.

3.2.2.1 *The Clean Growth Pathway Optimizes Energy Affordability*

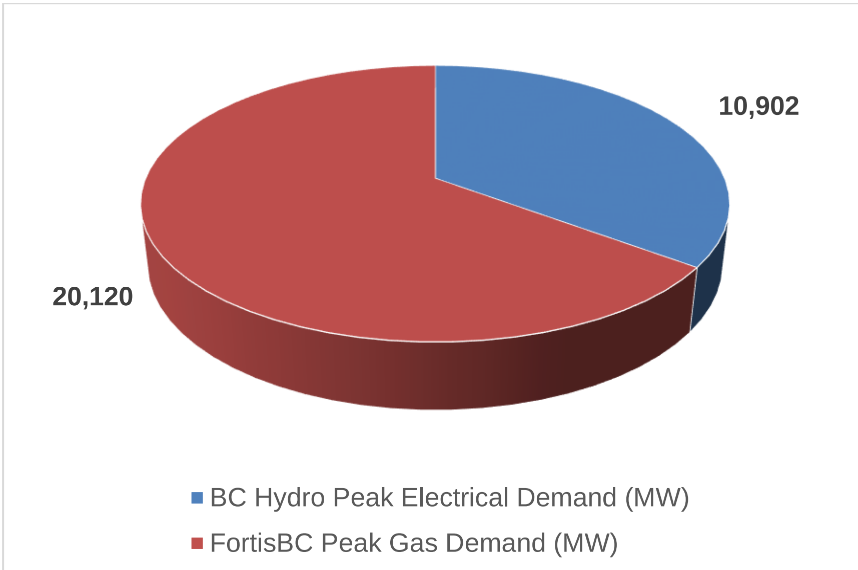
One key benefit to the Clean Growth Pathway is its potential contribution to energy affordability for British Columbians. The Diversified Pathway is a lower-cost approach than a deep electrification pathway primarily because it optimizes the gas and electric systems by fully utilizing the 50,000 km of energy delivery infrastructure of FEI's gas system, avoiding the need for extensive build-out of the electricity system. The cost savings are significantly more pronounced after 2030 when new electric infrastructure would be required and load on the gas system would otherwise decline markedly. This emphasizes the importance of having a longer-term view beyond 2030 for decarbonization strategies employed today. According to the Pathways Report, pursuing the Diversified Pathway is approximately $100 billion dollars less costly by 2050 than a deep-electrification pathway. Even though renewable and low-carbon gases are expensive compared to conventional natural gas, maintaining a role for the gas distribution system is less costly than sole reliance on firm electric power capacity. Both pathways will require significant levels of investment and collaboration across all stakeholders will be required to make decarbonization a reality.

3.2.2.2 *The Clean Growth Pathway Provides Lowest Risk to Meeting Peak Demand*

The Clean Growth Pathway provides the lowest risk to British Columbians as it relies on multiple systems to deliver energy, including for peak day demand on the coldest days of the year when British Columbians need energy the most. Relying on multiple systems enhances the resilience of the overall provincial energy system and helps ensure the overall operational and financial health of utilities in BC.

BC's exceptionally cold weather on December 27, 2021, provides an excellent illustration of the necessity of ensuring factors such as peak demand and resiliency are considered when creating policy direction. On that day, BC's two main energy delivery systems were operating near capacity. Throughput on FEI's gas system nearly reached its peak design capacity while BC Hydro reached a record level of peak demand.[104] Figure 3-3 illustrates the distribution of energy supply between gas and electricity on this historic day.

Figure 3-3: FEI[105] and BC Hydro Peak Hour Energy Demand – December 27, 2021



The fact that the provincial energy system successfully met this landmark demand reflects the critical role for both gas and electric infrastructure in meeting BC's energy needs during the coldest days of the year. Moreover, this event, when the gas system delivered approximately double the electric peak energy needs of British Columbians, demonstrates the significant and important delivery capacity of the gas system and the need to ensure BC continues to benefit from a robust gas delivery system that is operationally and financially healthy.[106]

3.2.2.3 *The Clean Growth Pathway Offers Energy System Resilience*

BC's energy system resilience is best achieved through keeping both gas and electric energy systems thriving to ensure British Columbians are not relying on a single energy system. A diversified approach is of even greater importance with the advent of extreme weather events caused by climate change, which can catalyse unanticipated system outages. Where one system is experiencing a supply disruption, other systems can supplement energy to meet customer demand in the interim. The deep electrification pathway requires reliance on only one source of supply, whereas the Clean Growth Pathway leverages the supply potential of both gas and

[104] BC Hydro Operational Update December 28, 2021, described that between 5 and 6 PM on December 27, 2021, demand for electricity hit an all-time high of 10,902 megawatts.

[105] Peak gas demand in equivalent MW using standard unit conversion of 1 MW = 3.6 GJ/hour.

[106] The gas system is also superior at meeting prolonged or multiple peaks due to its energy density and storage capacity. In contrast, the emergence of summer and winter peak events on BC's electric systems represents a growing challenge given the seasonal replenishment of storage reservoirs.

electricity infrastructure to protect British Columbians from the consequences of supply disruptions.

FEI has provided safe and reliable gas service in the province for many years and as part of the Clean Growth Pathway it will continue to provide this service for many years, even if the fuel composition changes. To provide reliable service, FEI has maintained the integrity of its assets, and ensured the adequacy and security of gas supply. FEI has completed a number of projects that have significantly enhanced the resiliency of its system, such as the Southern Crossing Pipeline (SCP) and Mt. Hayes LNG facility. While FEI has long regarded resiliency as an important system attribute, the T-South pipeline rupture that occurred on October 9, 2018, and the capacity restrictions imposed thereafter on the Westcoast Energy Inc. (Westcoast) T-South system[107] (T-South incident) underscored the pressing need for FEI to make new investments in its system to enhance overall resiliency. In 2021, the T-South system experienced another concerning event during the flooding in the Coquihalla region, leading to a washout of its NPS 30 pipeline.

FEI is dependent on the T-South system for approximately 85 percent of the gas entering its system, leaving FEI and its customers at risk of experiencing significant consequences resulting from a supply disruption. The T-South incident underscored the value that additional resiliency in FEI's system would provide, given that the T-South incident resulted in a complete loss of gas supply from the two T-South pipelines. FEI's system was at risk of pressure collapse for a period of approximately 48 hours, and that outcome was narrowly avoided as a result of FEI's efforts and due to mild weather that had reduced heating load in the broader PNW, thereby allowing some gas to physically flow northwards across the border.

FEI's system resilience is a key consideration in all of FEI's initiatives and major projects. Sections 6 and 7 provide more information on FEI's approach to resiliency and Appendix E provides FEI's Gas System Resiliency Plan.

3.2.2.4 *The Clean Growth Pathway Supports Emerging Technologies and Innovation in BC*

Developing integrated and innovative energy solutions to support a low-carbon energy system is multi-faceted. In Section 3.3 below, FEI discusses its approach to decarbonizing the gas supply through renewable and low-carbon gas production, CCUS and other technologies that generate low-carbon gas. In parallel, there will be continued innovation to the electric system bringing on renewables, and upgrades to transmission and distribution networks. Innovative energy solutions can span the spectrum from individual projects at single building end uses such as gas adsorption heat pumps, to a dedicated pipeline for delivering hydrogen into a community or industrial project. Some specific examples of FEI's role in advancing emerging technologies and innovation in BC are outlined below and discussed throughout the section.

[107] The T-South system is owned and operated by Westcoast Energy Inc. which is a wholly owned subsidiary of Enbridge Inc.

3.2.2.4.1 FEI SUPPORTS INNOVATIVE TECHNOLOGIES IN THE BUILT ENVIRONMENT

FEI is contributing to various projects that support commercializing innovative gas utilization technologies that will help FEI meet its customers' needs while also addressing societal plans for reducing GHG emissions. Such technologies achieve this goal by raising the efficiency of gas end uses and also reducing the GHG emissions intensity of both the gas stream as well as individual end uses. The initiatives include:

- Working with the Canadian Gas Association and its member companies to explore injection of hydrogen into the natural gas pipeline system;
- Researching the commercialization of gas-driven heat pumps to provide gas equipment which exceed 100 percent end use efficiency;
- Evaluating the potential for dual-fuel (hybrid) heating systems with smart controls, replacing a conventional air-conditioner with a higher efficiency air-source heat pump, and pairing it with a gas furnace and smart controls;
- Support for small-scale residential and commercial carbon capture projects to capture carbon emissions from end use appliances and make them commercially usable, including from appliances such as commercial furnaces;
- Research into micro combined heat and power appliances that increase the aggregate energy use efficiency of gas end use appliances by generating heat and power from the gas stream;
- Support for commercializing small-scale residential natural gas end use appliances that are designed to meet the reduced heating requirements of more energy efficient newly constructed buildings; and
- Exploratory research and pilot programs to support deep energy retrofits for residential and commercial buildings.

There are many new end use technologies that will increase the system performance of heat and water heating equipment. Gas heat pumps are a gas-consuming technology that represent an opportunity for research and development and innovation. Gas heat pumps are more efficient than conventional natural gas space heating systems, but they have not yet reached their full market potential in Canada due to cost, availability, and other factors. However, gas heat pumps are expected to be instrumental in helping Canada meet its 2030 and 2050 emissions reductions targets.

3.2.2.4.2 FEI'S CLEAN GROWTH INNOVATION FUND SUPPORTS THE IMPLEMENTATION OF THE CLEAN GROWTH PATHWAY

FEI's Clean Growth Innovation Fund helps advance the adoption of clean technologies by providing grant funding for pre-commercial technologies that can lower emissions or reduction the cost of low-carbon solutions for customers. The fund collects approximately $5 million per year from customers to the end of 2024 that is available to support innovative energy projects, in partnership with government, industry, and communities. Organizations can apply for project funding, and an external advisory council comprised of representatives from customer groups, academia, government and industry provide feedback to FEI in selecting projects that support GHG emission reductions while providing value to FEI customers. Some examples of projects funded to date include:

- A project with the University of British Columbia (UBC) School of Engineering and another partner, with the goal to develop a novel scalable and automated hydrogen-enriched natural gas laboratory. The laboratory will be setup for conducting an integrated experimental study on the performance and feasibility of hydrogen-enriched natural gas with respect to injection, mixing quality, material exposure, separation, combustion and emissions;
- A feasibility and pilot study of a coupled anaerobic digester and pyrolyzer for co-processing organic waste to RNG and biochar (a charcoal-like carbon-rich solid);
- Several proposals that would create blue or green hydrogen: a catalytic converter to turn bioethanol into green hydrogen; a proton exchange membrane electrolyser; a process using electrochemistry to split mineral salt and water to generate hydrogen and hydroxide; a continuous reactor to convert waste polyethylene to hydrogen and carbon black using sulphur; and two pyrolysis-based initiatives that would generate hydrogen and carbon black from methane;
- A proposal for developing a combination forced air furnace and water heating unit capable of running on 100 percent hydrogen;
- A proposal for developing and piloting a molten alloy reactor for methane pyrolysis to produce hydrogen and solid carbon;
- Several initiatives related to carbon capture, including a tandem carbon recycling system for carbon capture and utilization from exhaust flue gas stream, a modular decarbonization system using membrane contractors, and a system that uses flue gas to cultivate microalgae in photobioreactors for capture and utilization; and
- Proposals that would create syngas from woody biomass, displacing the use of natural gas at lime kilns.

The CGIF will continue to be an important catalyst for the transition to a lower-carbon energy future in British Columbia.

3.2.2.4.3 EXPLORING ADVANCED METERING AND ENERGY UTILIZATION SOLUTIONS

FEI is exploring a number of innovative solutions to modernize the gas infrastructure through the automation of load management, energy management systems that enable customers to review and manage their energy consumption, and programs that support customers in reducing their energy use. These new technologies and innovations ultimately offer customers greater autonomy over their energy use than the traditional utility model. The Advanced Metering Infrastructure (AMI) Project and Demand Response programs are examples of these innovative energy utilization solutions; however, more energy utilization solutions will undoubtedly be available over the planning horizon for end users to use energy as efficiently as possible and provide the ability to regulate peak demand more effectively.

In May 2021, FEI filed its AMI project CPCN application with the BCUC. AMI represents a significant opportunity for modernizing the gas infrastructure and adding additional components to support system resiliency. The AMI solution will be capable of collecting gas consumption and other information from all customer meters and will add capacity for the collection of information on infrastructure and pipeline assets through use of communicating sensors. System resiliency will be enhanced by providing FEI with the ability to strategically manage system load and prevent system pressure collapse during an extended loss of supply.

The AMI system will also allow customers to access their hourly consumption information through a secure online customer information portal. The ability to access hourly consumption data will result in more opportunities for DSM program support and evaluation, consumption pattern awareness, and ultimately behaviour modification programs and energy savings for both residential and commercial customers. As such, AMI is a foundational step in energy management systems, upon which more innovative technologies will be built in time.

Some gas utilities are starting to explore the deployment of novel Demand Response programs. Broadly, these refer to curtailment of gas demand over a specific set of hours during peak demand periods through an automated system or a planned schedule. Interruptible Rates are the traditional gas utility resource analogous to Demand Response. A broader variety of technologies and price-based solutions are becoming available such as advanced thermostats, behavioural programs, and direct load control (i.e., remotely controlled curtailment). These approaches might help shift natural gas demand that has traditionally been served with firm service away from natural gas during peak periods. Though still being explored, Demand Response may prove useful at reducing peak demand in cases where gas utilities can remotely dispatch during peak events. Demand Response may be able to alleviate day-long constraints at city gates or hourly constraints on the distribution system.

FEI will continue to explore energy utilization technologies to assist customers in using energy more efficiently and regulating periods of peak demand over the planning horizon. The exploration of innovative technologies as a DSM activity is discussed in Section 5.2.1.5.

3.2.2.5 *The Clean Growth Pathway Supports Economic Development in BC*

The Clean Growth Pathway will provide a wide range of economic benefits to the province from offering customer benefits achieved from lower energy costs and economic development through FEI's investment in its four pillars. Clean energy projects to develop renewable and low-carbon gas, increased DSM investment in buildings and industry, investment in low-carbon and marine transportation, and global LNG export will result in higher gross domestic product, tax revenue and jobs in British Columbia. FEI's investments will support communities, including Indigenous groups, across BC in the low-carbon transition.

3.3 *PILLAR ONE: TRANSITIONING TO RENEWABLE AND LOW-CARBON GASES TO DECARBONIZE THE GAS SUPPLY*

The first pillar of the Clean Growth Pathway is the transition to renewable and low-carbon fuels to decarbonize the gas supply. FEI's gas distribution infrastructure has a critical role in providing low-carbon and renewable energy, which has enormous potential to reduce BC's GHG emissions by 2030 and throughout the 20-year planning horizon of the LTGRP. As FEI continues to increase RNG supply for its customers, it is also looking at adding clean-burning hydrogen, syngas and lignin to its renewable and low-carbon gas supply portfolio. Hydrogen has a number of benefits, including its versatility as an energy carrier that is carbon-free at the point of use. It can also be made from a range of feedstocks that are abundant in BC. As such, hydrogen is poised to play a key role in decarbonizing the gas network and FEI is working to find the most cost effective ways to integrate and scale up all renewable and low-carbon gas.

3.3.1 Overview of FEI's Renewable and Low-Carbon Gas Program

Transitioning to renewable and low-carbon gas is central to meeting the challenge of reducing emissions in BC by 40 percent by 2030. Since 2010, FEI has recognized the significant role a renewable and low-carbon gas supply will play as a fundamental pillar in providing low-carbon energy to its customers. Residential and commercial customers, public sector building owners, municipalities, and public transportation entities continue to express interest in purchasing significant volumes of renewable and low-carbon gas over the planning horizon. This interest was evident in the community engagement session discussions outlined in Section 8.4. Through its Renewable Gas Program and other efforts, FEI has been a leader in decarbonizing to meet policy objectives and customer demand.

FEI has offered a Renewable Gas Program since 2010, with cost recovery of the acquired renewable gas volume from voluntary program participants through the Biomethane Energy Recovery Charge (BERC) which was set to match projected supply costs. In February 2020, the BCUC accepted FEI's first acquisition of renewable gas outside of BC as a prescribed undertaking under the GGRR. In May 2021, the provincial government amended the GGRR, increasing the acquisition cost cap and volumes and expanding acquisition opportunities for FEI as discussed previously in Section 2.2.2.3.

In December 2021, FEI filed its Comprehensive Review and Application for a Revised Renewable Gas Program (RG Program Application), which, along with other revisions, seeks to blend renewable gas volumes with natural gas to be sold to all sales customers as part of their gas service. As renewable gas supply increases to meet government emission reduction targets, FEI intends to distribute that supply to all sales customers.[108] As shown in Figure 3-4 below, the program has changed over the years with respect to the maximum volumes, supply projects, service offerings and pricing.

[108] FEI's sales customers include those in RS 1, 2, 3, 4, 5, 6 and 7.

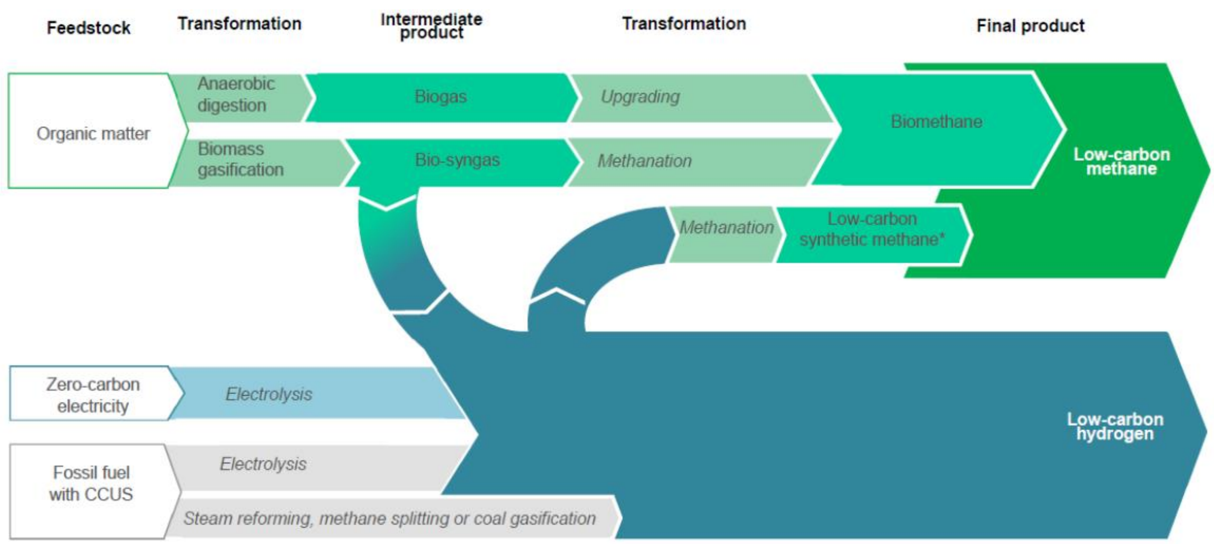
Figure 3-4: Overview of key milestones in the development of FEI's Renewable Gas Program

Characteristic	Phase 1 Pilot Program 2010-2013	Phase 2 Permanent Program 2014-2016	Phase 3 New Renewable Gas Rate (BERC) 2016-2017	Phase 4 GGRR amended to include RG 2017-2021	Phase 5 GGRR amended to further support RG; RG Application 2021 and future years
Volumes and Acquisition Cost Cap	0.25 PJ/Yr @ $15.28/GJ	1.5 PJ/Yr @ $15.28/GJ	1.5 PJ/Yr @$15.28/GJ	8.9 PJ/Yr @$30/GJ	>31 PJ/Yr @ $31/GJ
Supply Projects	First two projects	Added projects	Continued to add projects	Out-of-province projects added	Acquisition opportunities expanded
Offerings	Customer program initiated	Expanded customer offering	Long-term contracts available	No Change	RG Application Section 7.4
Price Mechanism	BERC = Program Costs	BERC = Program Costs	BERC = Market Price	No Change	RG Application Section 8

3.3.2 Renewable and Low-Carbon Gas Supply Technology Will Facilitate the Clean Growth Pathway

The GGRR now prescribes undertakings for the acquisition of hydrogen, lignin, and syngas, in addition to RNG. Other low-carbon gas resources can also be brought to bear on the transition to low-carbon energy using FEI's infrastructure, such as by combining CCUS with gas production. This section describes these new types of renewable and low-carbon gas that are now becoming commercially viable solutions to reducing GHG emissions from gas combustion. Figure 3-5 below demonstrates a number of production pathways for renewable and low-carbon gases that will facilitate FEI's Clean Growth Pathway, not all of which are currently authorized by the GGRR.

Figure 3-5: Production Pathways for Renewable and Low-Carbon Gas for FEI's Low-Carbon Transition[109]



FEI has been working with suppliers of RNG, hydrogen, syngas and lignin in BC and other jurisdictions to expand its portfolio of renewable and low-carbon gases. CCUS[110] provides a suite of emerging technologies that FEI can explore for furthering its decarbonization objectives. Taking advantage of new technologies, will not only reduce GHG emissions, but also diversify FEI's energy system and supply. The benefits of such diversity extend to the provincial and the PNW energy systems as a whole.

3.3.3 FEI's Clean Growth Pathway Supports BC's Hydrogen Economy

FEI's vision for a hydrogen economy is built around evolving policy and technology developments in BC,[111] Canada[112] and internationally. Hydrogen is a versatile energy source and carbon-free at the point of use. It broadens opportunities for renewable and low-carbon fuels, as it can be used as an energy carrier, energy storage medium, gaseous fuel alternative to natural gas, and as a chemical feedstock to address difficult-to-decarbonize end use applications such as high temperature industrial processes, space heating, and long-haul transportation. As the BC Hydrogen Study indicates, it has the potential to be produced at scale in BC using commercially available technology. Developing and delivering hydrogen through or enabled by existing gas infrastructure would give FEI the opportunity to create new partnerships, expand business

[109] International Energy Agency (IEA), The Oil and Gas Industry in Energy Transitions (2020) p. 144, online at: https://www.iea.org/reports/the-oil-and-gas-industry-in-energy-transitions.
[110] CCUS Technology Report (2021), online at: https://www.iea.org/reports/about-ccus.
[111] Appendix A-6: BC Bioenergy Network, British Columbia Hydrogen Study, online at: https://bcbioenergy.ca/resources/bcbn-publications/british-columbia-hydrogen-study/.
[112] Appendix A-3: Natural Resources Canada, Hydrogen Study for Canada, online at: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf.

operations and contribute to significant GHG emission reductions. BC's economy will benefit from hydrogen resource development projects, dedicated hydrogen infrastructure, domestic hydrogen market growth and hydrogen for export, given that the global hydrogen demand is projected to increase across multiple sectors. FEI intends to be a key player in establishing the foundation for a hydrogen economy in BC.

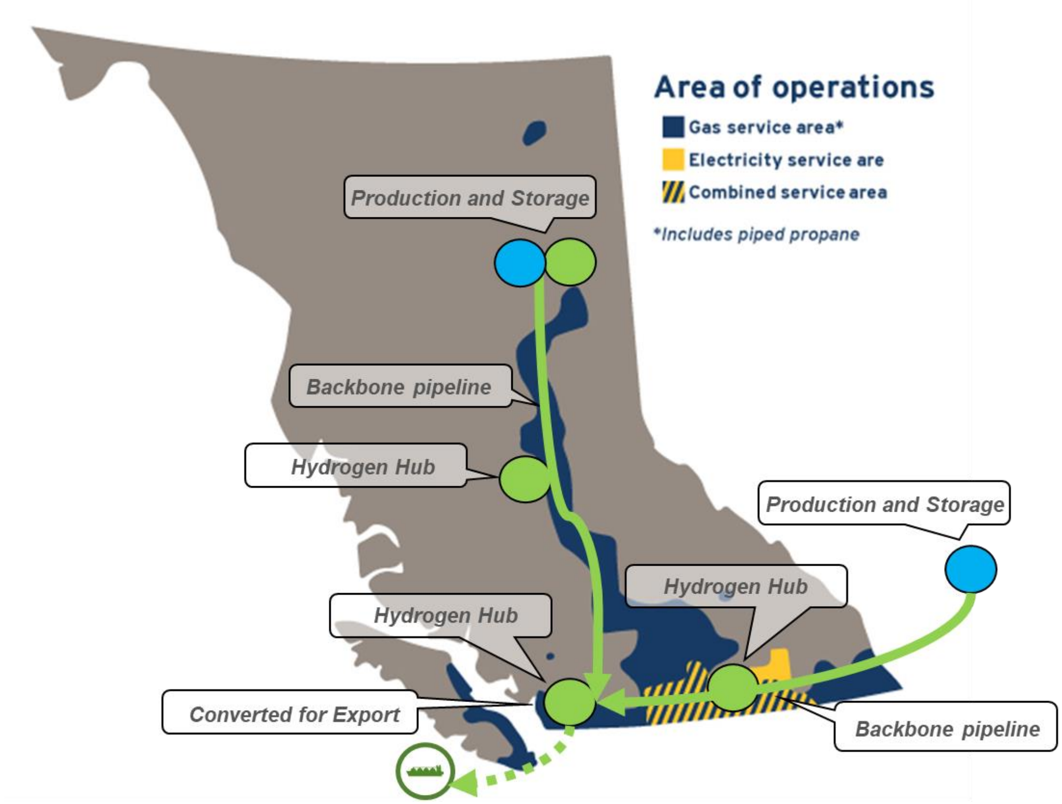
There are a number of pathways FEI can undertake for hydrogen distribution, including:

- Supplying the existing gas grid at low concentrations or blends;
- Directly supplying to customers that are hydrogen ready (initially, large commercial and industrial end users);
- Delivering supply to end users through purpose-built pipeline systems;
- Combusting directly or converting to electricity using fuel cells;
- Utilizing power-to-gas technologies that could strategically couple the gas and electric grids to convert electrical energy to chemical energy in the form of hydrogen or methanized hydrogen for storage and delivery; and
- Supplying for transportation applications.

Hydrogen is a clean-burning molecule that can be used to displace natural gas and liquid fossil fuels to decarbonize a range of end use applications. Hydrogen demand will need to grow in BC and there is the opportunity to develop initial market nodes or "hydrogen hubs" in the Lower Mainland, Interior, and Northern regions of BC. Over time, as demand grows, existing pipeline corridors will be expanded, retrofitted and upgraded to transport hydrogen. A low-carbon "backbone system" would provide the necessary capacity to link hydrogen hubs,[113] producers, and consumers over longer distances and enable a regional market. Pipeline capacity at scale would also support development of the supply chain for marine fuel and offshore demand. Figure 3-6 illustrates some of the ways that FEI's infrastructure can facilitate the incorporation of hydrogen production, transmission and use.

[113] A hydrogen hub integrates a number of hydrogen-based energy services through centralized infrastructure and supporting technology. Online at: hydrogenhub.org.

Figure 3-6: Illustrative Example of FEI's Transition to a Hydrogen-Enabled System



Over the next five years, FEI will be considering a number of approaches to locally displace conventional natural gas in the gas system and opportunities to distribute hydrogen directly to gas customers. This analysis is necessary to establish hydrogen demand in BC and inform new market segments of the versatility and safety of hydrogen as a mass market consumer fuel. To support this goal, FEI is enabled under the GGRR to acquire hydrogen to meet near-term objectives including:

- Blending hydrogen in the gas distribution system to displace conventional natural gas (similar to RNG) including either hydrogen produced by FEI or through a third party; and
- Purchasing hydrogen that could be distributed through dedicated infrastructure (new or repurposed) to gas customers to displace conventional natural gas usage.

In the medium term (projected to be by 2030), FEI envisions that blending of hydrogen would expand across the low-pressure gas distribution system, with the potential for segments within the system to expand to include hydrogen hubs which can distribute 100 percent hydrogen.

Over the longer term (between 2030 and 2050), and as demand for hydrogen grows, the existing gas system's high pressure transmission pipeline corridors will be retrofitted, upgraded, and expanded to transport an increasing share of hydrogen and RNG in a progressively decarbonized gas system. Similarly, and with this goal in mind, FEI's RGSD project, discussed in sections 6.3.3 and 7.5.1.1, will be developed to be hydrogen-enabled.

Gas system planning will play a pivotal role in the transition to hydrogen as outlined in Section 7.4. Safety, reliability and resiliency of the energy delivery system will continue to be key priorities for FEI. Due to its different properties from biomethane, hydrogen will require particular attention to be successfully integrated into FEI's and BC's existing gaseous energy supply chain. The unique physical, chemical, interchangeability, and utilization characteristics when compared to conventional natural gas may limit hydrogen gas as a drop-in replacement fuel, beyond a percentage blend expected to be in the concentration range of 2 to 20 percent by volume. As hydrogen is less dense, it will require somewhat larger pipes and more compression to deliver similar amounts of energy. Introducing hydrogen into the existing gas network, the potential impacts on end users, and supporting the development of codes, standards, and regulations are all areas FEI is evaluating. Hydrogen pilots are currently anticipated to become operational in the 2023 to 2024 timeframe as demonstrations for proof of concept. FEI's first hydrogen supply project is anticipated as early as 2025. All of the necessary system planning considerations will be developed and implemented over the planning horizon.

3.3.4 Potential for Hydrogen to Decarbonize the Industrial Sector

Decarbonization of the industrial sector represents a large opportunity to reduce provincial GHG emissions. In 2019, GHG emissions in BC surpassed 68 Mt CO_2e as illustrated in Figure 3-2. At that time, BC's industry sector emissions represented 21 percent of BC emissions. A large portion of these emissions are a result of industrial heat and unavoidable process emissions. Industrial heat requirements are difficult to decarbonize by electrification, due to the nature of the established processes and equipment involved such as kilns and furnaces. Industries such as pulp mills and cement manufacturing are among the largest industrial contributors to GHG emissions in BC and good candidates as hydrogen projects.

FEI envisions low-carbon hydrogen playing a critical role in decarbonizing BC's industrial sector, which is expected to be most difficult to decarbonize to reach the Province's 2030 and 2050 climate goals. Transitioning BC's industry to hydrogen as a heating solution supports the concept of a BC hydrogen backbone system that will involve repurposing and upgrading sections of the existing gas grid to reliably supply clean, low-carbon hydrogen to industrial end users.

Currently, there is an opportunity to start transitioning pulp mills and cement manufacturing facilities to using low-carbon hydrogen. This transition can be initiated with minimal upgrades and process impacts by blending low-carbon hydrogen into the end user's existing natural gas supply, starting at as low as 2 percent by volume. An industrial hydrogen blending test program will be conducted, administering appropriate safety and impact assessments in order to allow for safe incremental increases of hydrogen blending, by up to 20 percent.

During the blending period, existing technology for 100 percent hydrogen burners is to be investigated and piloted for use in cement kilns. Once commercialized, hydrogen burner technology can be tested and rolled out at industrial facilities, with the goal of converting pulp mills and cement manufacturing facilities to 100 percent low-carbon hydrogen, which would help to achieve net-zero carbon for BC by 2050.

FEI is working with industry and government to identify opportunities to begin the industrial transition to low-carbon hydrogen. In these difficult-to-decarbonize sectors, FEI believes innovation in hydrogen technology will best serve the needs of British Columbians by preserving clean electricity for other uses and regions where electrification may present greater opportunities for GHG reductions.

3.3.5 Renewable and Low-Carbon Gas Production Potential in BC and North America

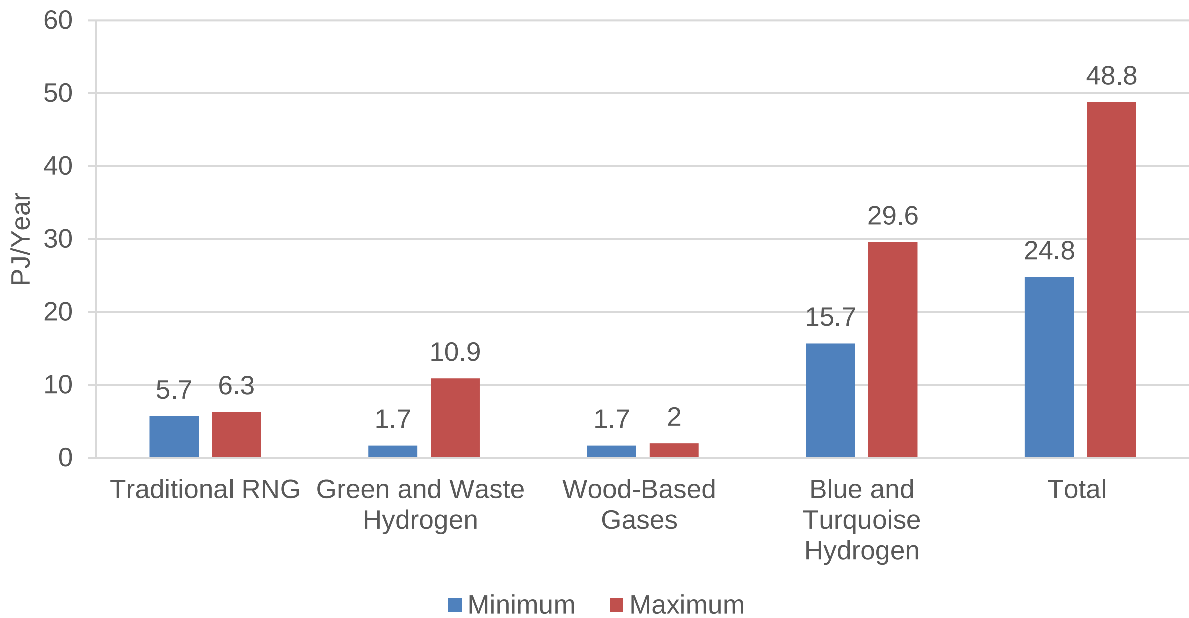
As described in Section 2.2.2.2, the Roadmap includes plans to establish a GHG emissions cap for natural gas utilities. This would require natural gas utilities in BC to reduce the carbon emissions related to their gas sales to the Buildings and Industrial Sectors to approximately 6 Mt of CO_2e per year by 2030, which is approximately 47 percent lower than 2007 levels. It is anticipated that this cap will, in part, drive the production and acquisition of renewable and low-carbon gas as a key measure to displace conventional natural gas.

In response to the need for renewable and low-carbon gas production, FEI, the BC Bioenergy Network, and the Province of British Columbia commissioned a report to conduct a detailed assessment of the supply potential and production costs of renewable and low-carbon gas in BC through 2050 (see Appendix D-2). The report, titled B.C. Renewable and Low-Carbon Gas Supply Potential Study, describes the potential for renewable and low-carbon gas[114]. The report includes hydrogen derived from renewable electricity, woody biomass and natural gas feedstocks[115] as well as RNG, syngas and lignin derived from woody biomass feedstocks. The study developed a “Minimum Scenario” based on pessimistic assumptions with respect to the availability and cost of supply by 2030 and 2050 in BC. In this scenario, 25 PJ of renewable and low-carbon gas supply is projected to be available by 2030 and over 100 PJ by 2050. In the Maximum Scenario based on optimistic assumptions on the availability of and costs of feedstocks and technology development and lower costs 49 PJ of renewable and low-carbon gases is projected to be available in BC by 2030 and 444 PJ by 2050. Figures 3-7 and 3-8 describe the potential by gas and feedstock in more detail.

[114] The study did not consider alternative options, such as switching natural gas heating to wood pellets, heat pumps, or increased energy efficiency.

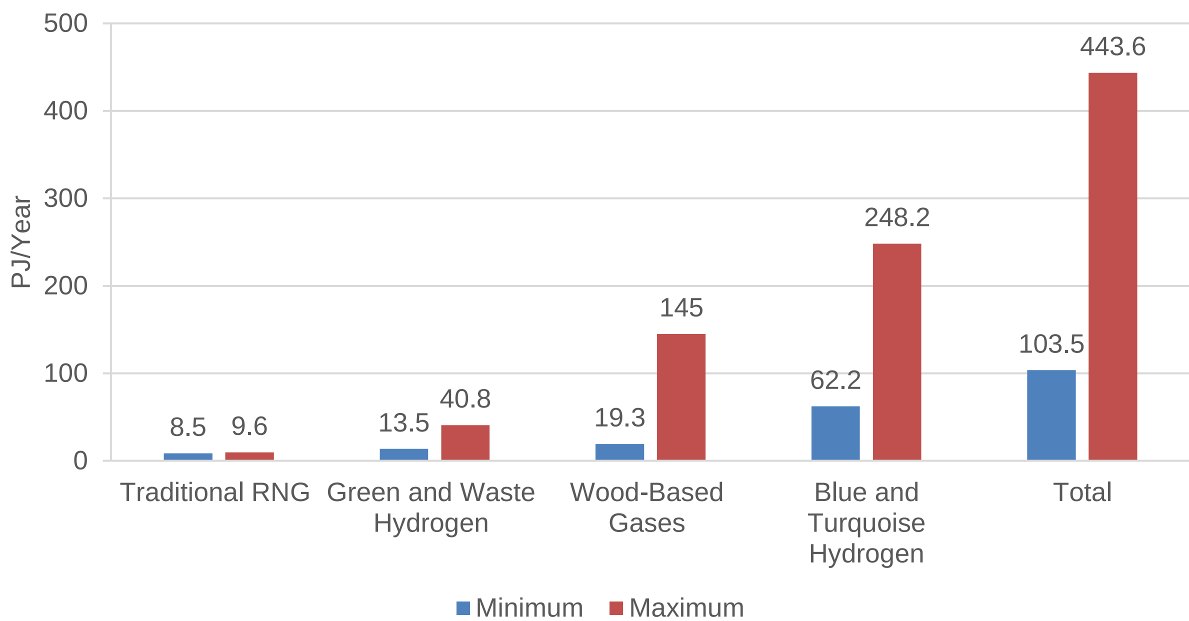
[115] Natural gas feedstocks in this analysis require carbon capture and sequestration or other technologies that ensure that the hydrogen is low-carbon.

1 **Figure 3-7: 2030 Renewable and Low-Carbon Gas Supply Potentials by Scenario**



2

3 **Figure 3-8: 2050 Renewable and Low-Carbon Gas Supply Potentials by Scenario**



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5 Competition for both the supply and use of renewable and low-carbon gas will be growing
6 nationally and in the US as evidenced by the increasing requirements and compliance monitoring
7 of California's Low-carbon Fuel Standard, which has set a minimum price threshold per unit of
8 renewable energy in order to increase the range of low-carbon and renewable fuel alternatives
9 available to the transportation sector.

Collaborative partnerships and a favourable regulatory environment are crucial for the development of a BC-based industry. All levels of government, communities and Indigenous groups, utilities, and other industry players must work together on innovative research, policy development and joint ventures to fund and support development and production of these projects.

The transition to low-carbon energy is discussed throughout this LTGRP and discussed specifically in the following sections:

- For forecasts on costs, refer to Section 2.4;
- For forecasts on rate impacts, refer to Sections 5.4.2 and 9.4;
- For incorporation in demand forecasts, refer to Section 4;
- For incorporation in supply portfolio planning, refer to Section 6;
- For incorporation in system resource needs, refer to Section 7;
- For the Outcomes of FEI's Clean Growth Pathway, refer to Section 9 and;
- For related Action Items, refer to Section 10.

3.4 *PILLAR TWO: INVESTING IN DSM PROGRAMS TO REDUCE ENERGY AMONGST RESIDENTIAL, COMMERCIAL AND INDUSTRIAL CUSTOMERS*

The second pillar of the Clean Growth Pathway is the continued and expanded investment in energy efficiency and conservation measures across FEI's residential, commercial and industrial customer uses. As discussed in Section 3.2, these activities focus on initiatives to further reduce the 21 percent of provincial GHG emissions attributed to buildings and communities through high performance buildings initiatives such as energy efficiency and energy management.

FEI has long invested in energy efficiency to ensure that customers have options to moderate their energy use and improve affordability. To make further progress on improving energy efficiency in residential, commercial and industrial sectors, since 2017, FEI has tripled its annual DSM investment to reach $107 million in 2021. In addition, FEI is piloting next generation equipment, innovative technologies and new approaches to efficiency in the buildings sector such as deep energy retrofits, gas heat pumps, dual-fuel heating systems and buildings controls to leverage new emissions reduction energy technologies.

In the residential and commercial buildings sector, FEI is incorporating a broader, high performance, whole-buildings approach that will likely involve activities beyond traditional equipment-focused DSM activities for both retrofit and new construction. These activities broadly include:

- An envelope-first approach to deep energy retrofits;

- Customized programs to support income-qualified customer segments and Indigenous communities;
- Activities to accelerate market transformation to gas heat pump technology, dual-fuel hybrid heating systems, and other innovative technologies that will reduce GHG emissions while enhancing resiliency to utilize the strengths of both the gas and electric systems during periods of peak demand;
- Support for economic development and job growth through the expansion of trades and industry support to increase contractor capacity and training across all sectors to support quality best practices in existing buildings and new construction;
- Advancing digital platforms for virtual home energy audits, energy literacy, demand response, behaviour modification, commissioning or maintenance programs, and energy management systems to optimize building performance. FEI's current AMI application may enhance the capability to provide these services;
- Working with local governments, Indigenous communities, associations and buildings science professionals to accelerate the adoption of high performance buildings in retrofit and new construction; and
- Continuing to work with BC Hydro and the Ministry of Energy, Mines and Low Carbon Innovation to advance building decarbonization activities across the province.

Expanding FEI's low- and zero-carbon solutions in buildings will be a key component of this pillar in the Clean Growth Pathway. FEI's Conservation and Energy Management group and supporting teams throughout the organization are focused on this key objective. Transitioning the buildings sector to low-carbon energy is discussed throughout this LTGRP and discussed specifically in the following sections:

- For the incorporation of DSM initiatives in demand forecasts, refer to Section 5.4;
- For the Outcomes of FEI's Clean Growth Pathway, refer to Section 9 and;
- For related Action Items, refer to Section 10.

3.5 PILLAR THREE: INVESTING IN LOW-CARBON TRANSPORTATION INFRASTRUCTURE TO REDUCE EMISSIONS IN THIS SECTOR

The third pillar of the Clean Growth Pathway is investing in low-carbon transportation (LCT) infrastructure[116]. GHG emissions from transportation make up the largest share of overall provincial emissions at 39 percent and freight transportation is one of the most challenging sectors to decarbonize. FEI is working to convert medium-duty and heavy-duty fleet vehicles and marine

[116] FBC is also investing in EV infrastructure and provides customers with clean electricity to support the transition to zero and low-carbon transportation in the passenger vehicle market. However, this activity will not be discussed in the 2022 LTGRP.

vessels to lower carbon alternative fuels like CNG and LNG. In addition to a significant GHG reduction benefit, using CNG and LNG in vehicles and marine vessels can dramatically improve air quality by reducing particulate matter as well as sulfur and nitrogen oxides released into the environment.

Supplying fuel for LCT and remote power generation for non-grid connected communities and industrial sites currently using higher carbon fuels are key opportunities for FEI to serve the energy needs of customers and help reach the ambitious GHG reduction targets legislated by the province. In the LCT and remote power generation sectors, FEI is looking to displace petroleum fuels such as diesel with cleaner-burning natural gas and RNG. Natural gas is a lower-carbon alternative to conventional transportation and remote power generation fuels and can play a significant role in reducing emissions and reducing reliance on petroleum-based fuels. Where opportunities exist, substituting conventional natural gas with RNG can increase emission reductions further. RNG is a direct substitute for conventional natural gas in vehicles, and requires no incremental capital investment to the vehicles or infrastructure that are already capable of operating on natural gas.

To capture the LCT benefit, customers must make investments in vehicles, equipment and marine vessels designed to use natural gas or RNG. Given the investment dollars at stake for early adopters of natural gas as a transportation fuel, customers view FEI as a partner that can be depended upon to deliver the energy they need to facilitate the shift from conventional petroleum fuel to cleaner sources of energy.

The GGRR is one mechanism that utilities in the province have used to begin the market transformation process of converting applicable transportation and power generation applications to natural gas and RNG as a feedstock fuel. However, the prescribed undertaking period for investment in LCT infrastructure under the GGRR ended on March 31, 2022. At the time of writing, the Province's plans to continue to support LCT through the GGRR are not yet known.

LCT is discussed throughout this LTGRP and discussed specifically in the following sections:

- For the incorporation of LCT initiatives in demand forecasts, refer to Section 4.6.2;
- For the Outcomes for LCT in the Clean Growth Pathway, refer to Section 9 and;
- For related Action Items, see Section 10.

3.6 *PILLAR FOUR: INVESTING IN LNG TO LOWER GHG EMISSIONS IN MARINE FUELING AND GLOBAL MARKETS*

The fourth pillar of the Clean Growth Pathway is investing in LNG to lower GHG emissions in marine fueling and global markets. Natural gas is increasingly becoming a viable fuel for the global marine vessel market. Global environmental regulations have been implemented which will likely continue to drive out the use of higher carbon fuels that have traditionally been consumed by the global marine market. Due to these tighter restrictions on marine vessel emissions, natural gas in the form of LNG is an attractive alternative fuel for vessel operators to comply with these tighter restrictions. It is expected that more and more end users will transition to natural gas to meet the restrictions.

The Province of BC and FEI are strategically positioned to be leaders in this transition and help reduce global GHG emissions. BC has significant natural gas resources, with remaining raw reserves of approximately 1.165 trillion cubic metres. Over 60 billion cubic metres of natural gas were produced in 2018.[117] However, domestic use of conventional natural gas may possibly decrease over time to reach CleanBC's 2050 domestic target. In that scenario, BC's natural gas could then be exported as LNG to Asia to displace higher carbon and higher polluting fuels such as coal and oil, which could result in a net reduction of global GHG emissions.

BC's LNG can also power large ocean vessels, which would displace higher-emissions fuels like diesel and heavy oil. An analysis conducted by Thinkstep concluded that LNG from BC used in marine shipping could reduce GHG emissions by up to 27 percent compared to the global average for LNG supply.[118] As the policies in CleanBC are implemented (e.g., electrifying upstream gas production and implementing regulations to reduce methane emissions), the carbon intensity of the LNG supply chain in BC could be half that of the current global average by 2030.[119] To support provincial and federal objectives to become a world leader in LNG bunkering,[120] FEI is promoting use of LNG for marine use to replace the world's most carbon intensive fuels.

3.6.1 GHG Emissions Opportunities from LNG Exports

There have been discussions over the past number of years with several overseas customers who have expressed interest in exporting LNG from Tilbury to destinations in Asia. Exporting LNG can help countries overseas reduce their reliance on higher carbon fuels, such as coal, and make immediate emissions reductions more affordably. As an added benefit, LNG from Tilbury has a production carbon intensity up to 30 percent lower than global average LNG carbon intensities.

By replacing conventional coal with LNG, approximately 40 to 45 percent and 26 to 32 percent emissions reductions can be obtained for Chinese textile and chemical industries, respectively. The highest emissions reduction of approximately 60 percent is observed when coal is replaced with natural gas from LNG for district heating.[121] The Liquefaction Facility component of Tilbury

117 Pathways Report, p. 29.
118 Pathways Report, p. 20.
119 Pathways Report, p. 20.
120 The Province's CleanBC Roadmap aims to "make our ports attractive to global shipping fleets transitioning to LNG as a lower cost, lower GHG transition fuel": Roadmap, p. 61. Further, in a news release issued in October 2019, the Province of BC announced its plan to partner with the Vancouver Fraser Port Authority and FortisBC to establish the first ship-to-ship LNG marine bunkering service on the west coast of North America, which "will allow B.C. to have a direct impact on global emissions by reducing the amount of greenhouse gas emissions from visiting vessels": Government of British Columbia, "Province supports proposal for LNG ship-refueling facility" (October 23, 2019), online at: https://news.gov.bc.ca/20855. The federal government also supports LNG marine bunkering goals, as the Prime Minister of Canada has directed the Minister of Transport to work with partners to support efforts to convert marine vessels and infrastructure toward "more environmentally friendly fuels, like liquefied natural gas": Office of the Prime Minister, Ministry of Transport Mandate Letter (December 13, 2019), archived online at: https://pm.gc.ca/en/mandate-letters/2019/12/13/archived-minister-transport-mandate-letter .
121 Kotagodahetti, Ravihari et.al, Liquefied natural gas exports from Canada to China: An analysis of internationally transferred mitigation outcomes (ITMO) (2022). Online at:

Phase 2 LNG Expansion Project is being developed by a non-regulated FortisBC entity for bulk export, and is currently undergoing an environmental assessment under the direction of the BC Environmental Assessment Office.

3.6.2 Marine Fueling Opportunities in BC Will Reduce GHG Emissions

Bunkering is the act of supplying a marine vessel with fuel, and can include truck-to-ship or ship -to-ship fueling. Various incumbent fuels are used in marine transportation, including marine gas oil, marine diesel oil, intermediate fuel oil and heavy fuel oil.[122] Currently, heavy fuel oil accounts for the majority of the fuel used for tankers, bulk carriers and container ships globally; as such, it presents an immense opportunity for growth. LNG is a relatively new fuel in the marine bunkering market. Its adoption is being driven by operating cost advantages, sulphur emission limits and the opportunity to replace some of the world's highest carbon intensity fuels with clean LNG sourced from BC.

The LNG marine bunkering opportunity is a key part of FEI's strategy to reduce GHG emissions and will positively impact FEI's customer rates. The opportunity leverages pre-existing FEI-owned assets and operational expertise to drive growth in new markets and contribute to BC's economy. Although the original Tilbury LNG facility serves as a winter peaking facility, over time, the expansions to the facility have evolved and expanded to produce LNG to serve a variety of new LNG markets.

In general, a ship requiring bunkering is either loading or unloading at the cargo berth, or anchored at the port. LNG marine bunkering is most frequently performed via an LNG bunkering vessel that pulls up alongside the vessel requiring fuel, and the fuel is transferred from the bunkering vessel to the receiving vessel.

FEI has had initial success advancing the LNG marine bunkering market in BC, as evidenced in the following milestones:

- In late 2016, FEI bunkered a Seaspan Ferries Corp. ferry using an LNG tanker truck to transfer the LNG directly into the ship, eliminating any stationary LNG fueling infrastructure (truck to ship bunkering). This innovative method of bunkering had never previously been performed in the marine sector. The success of the innovative process was a product of over two years of collaboration with Seaspan, BC Ferries, Class Societies and Transport Canada, among others. The success of the first truck to ship bunkering led to increased adoption of LNG vessels. From 2017 to 2019, Seaspan's LNG vessel fleet grew to three and BC Ferries added five LNG vessels.
- FEI celebrated its 1000th bunker event in 2018 and expects to reach its 5000th bunker event in late 2022. This annual growth is illustrated in Figure 3-9.

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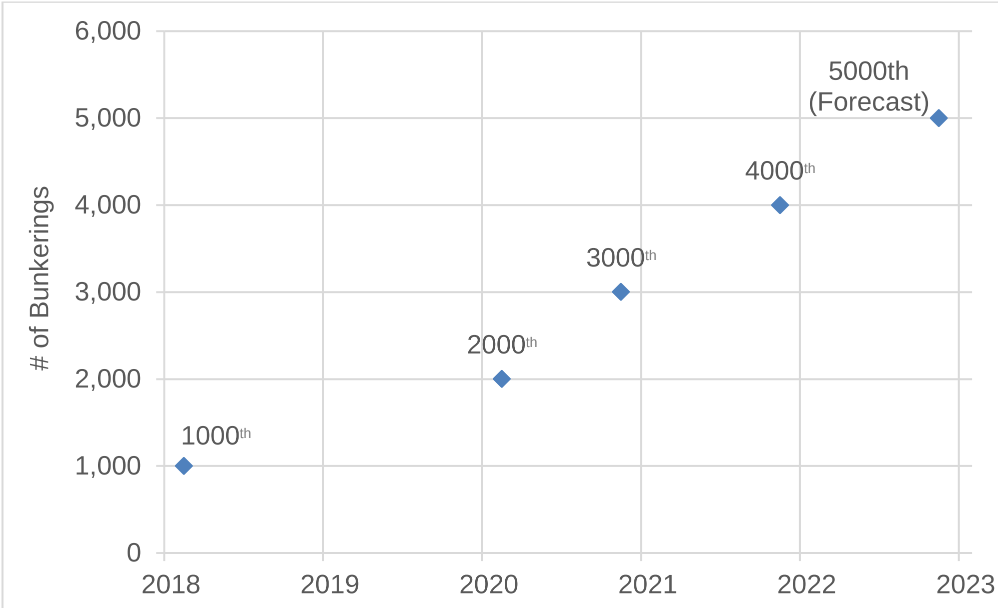
https://www.sciencedirect.com/science/article/abs/pii/S0959652622009210

[122] These four marine fuels are ordered from lightest to heaviest in terms of density and weight (i.e., least emitting to highest emitting).

Figure 3-9: Timeline of FEI's Annual Bunkering Milestones (2018-2023)



- In 2022, FEI increased its LNG delivery frequency with the addition of two Seaspan LNG vessels and one LNG vessel from BC Ferries.

Leveraging FEI's success in marine bunkering, an FEI Affiliate is exploring a potential marine jetty next to the Tilbury LNG storage facility that would allow for ship-to-ship LNG bunkering using LNG from FEI's Tilbury LNG facility for Trans-Pacific customers and for bulk delivery to overseas markets. It is important to note that the jetty will be owned by a non-regulated entity with services provided to it by FEI. This is not part of FEI's initiatives included in the LTGRP, however this initiative needs to be considered in terms of gas supply and any system contracting requirements, as it is expected the marine jetty will enable significant sales under Rate Schedule 46. The marine jetty is currently completing an environmental assessment under the direction of the BC Environmental Assessment Office. The environmental assessment is expected to conclude in 2022. If approved, the jetty could provide service for LNG marine fueling by 2024 or 2025.
FEI will continue to advance its interests in the LNG marine bunkering market as an LNG fuel. FEI's early progress in this market, coupled with recent supportive market conditions, creates a favourable opportunity for further helping to reduce customer rate pressures and reducing GHG emissions.

The LCT opportunities are further discussed generally throughout this LTGRP, and discussed specifically in the following sections:

- For the incorporation of LNG initiatives in demand forecasts, refer to Section 4.6.2;
- For the Outcomes in the Clean Growth Pathway, refer to Section 9 and;
- For related Action Items, refer to Section 10.

3.7 STUDIES SUPPORTING THE DIVERSIFIED PATHWAY APPROACH

Appendix A-9 provides a number of studies outlining the benefits of comprehensive energy system planning akin to that achieved by the Diversified Pathway, while highlighting that there are unintended consequences and risks of pursuing an electrification-centric approach to energy planning in BC. These studies are described below.

3.7.1 Studies on Diversified Energy Approaches in Other Jurisdictions

3.7.1.1 *Canadian Gas Association*

The Canadian Gas Association study from 2019[123] highlights the implications for moving away from an integrated multi-fuel, multi-grid energy system towards a fully electrified system. The study presents the significant and costly expansion of Canada's electrical system required to replace refined petroleum products and natural gas in homes, businesses, industry, and vehicles with electricity. Further, the incremental costs associated with meeting increased peak load for extreme cold events will require additional investments. Diversified energy approaches can be optimized to provide a reliable, more affordable, low emissions energy system by allowing for system integration and the leverage of natural gas for peak loads on very cold days.

3.7.1.2 *American Gas Association*

The American Gas Association study[124] emphasized how energy system resiliency is increasingly essential to all sectors of the US economy and communities served and the ways in which the gas system contributes to the overall resilience of the US energy system as a whole. Service disruptions create economic and social hardships, including lost productivity, safety and health risks - and has even led to the loss of life. Future energy infrastructure design must incorporate resilience at a system-wide level. The energy sector is transforming at a rapid pace, and the study concludes with the importance of understanding "the increasing interdependence of gas and electric systems and their role in creating a more resilient future".[125]

3.7.1.3 *Ontario Energy Association*

The Ontario Energy Association released a comprehensive energy-use plan[126] with the key objectives of finding the most affordable, reliable, and sustainable pathway to fulfill energy requirements and emission reductions objectives. The plan outlines the need for all levels of government, utilities, and other stakeholders to work together on a costed and complementary emissions reduction strategy, optimizing the use of existing infrastructure, while investing in new

[123] Appendix A-9.1: ICF, Implications of Policy-Driven Electrification in Canada: A Canadian Gas Association Study (October, 2019), online at: https://www.cga.ca/wp-content/uploads/2019/10/Implications-of-Policy-Driven-Electrification-in-Canada-Final-Report-October-2019.pdf.

[124] Appendix A-7.

[125] Appendix A-7. Page 1.

[126] Appendix A-9.2: Ontario Energy Association, Energy Platform (2022), online at: https://energyontario.ca//Files/PDF%20files%20to%20share/OEA_Energy_Platform_2022_FinalWEB.pdf.

infrastructure, technology, energy efficiency and behaviour change in developing a coordinated response to energy planning for Ontario.

3.7.1.4 *The European Union*

The European Union is envisioning an integrated energy system across Europe as the best path to decarbonization. Their plan[127] proposes "coordinated planning and operation of the energy system 'as a whole', across multiple energy carriers, infrastructures, and consumption sectors – as the pathway towards an effective, affordable and deep decarbonisation of the European economy in line with the Paris Agreement and the UN's 2030 Agenda for Sustainable Development". The report summarizes the complementary energy system approach as follows:

> Energy system integration will translate into more physical links between energy carriers. This calls for a new, holistic approach for both large-scale and local infrastructure planning, including the protection and resilience of critical infrastructures. The objective should be to make the most of the existing infrastructure while avoiding both lock-in effects and stranded assets. Infrastructure planning should facilitate the integration of various energy carriers and arbitrate between the development of new infrastructure or re-purposing of existing ones. It should consider alternatives to network based options, especially demand-side solutions and storage.[128]

3.7.1.5 *Energy and Utilities Alliance – United Kingdom*

A 2021 UK study sponsored by Energy and Utilities Alliance in partnership with Leeds Beckett University[129] reviewed opportunities to decarbonize residential buildings. They concluded that net-zero carbon missions could only be achieved through complementary energy systems including repurposing gas networks for hydrogen. The study highlighted some of the constraints in electrifying home heating and the benefits of gas-based technologies and a decarbonized gas network.

3.7.2 Independent Academic Studies on Energy Capacity in BC

In the following section, FEI highlights key messages from two independent academic studies examining decarbonization approaches for BC's energy systems. These studies highlight the importance of taking a diversified, complementary systems approach to energy system planning in BC, one in which peak demand and resiliency are incorporated into critical decision-making to serve the energy needs of residential, commercial and industrial energy needs in BC.

[127] Appendix A-9.3: European Commission, Powering a climate-neutral economy: An EU Strategy for Energy System Integration (July 2020) p.2

[128] Appendix A-9.3: European Commission, Powering a climate-neutral economy: An EU Strategy for Energy System Integration (July 2020) p.17

[129] Appendix A-9.4: Energy and Utilities Alliance (EUA) in partnership with Leeds Beckett University and UK gas distribution networks Cadent, Northern Gas Networks, SGN and Wales & West Utilities, "Decarbonising heat in buildings: putting consumers first" (April, 2021).

3.7.2.1 *University of Victoria's Institute for Integrated Energy Systems*

The University of Victoria's Institute for Integrated Energy Systems studied[130] the decarbonization of the building heating systems in Metro Vancouver by comparing two transition pathways: one that substitutes natural gas with electricity (electrification pathway), and the other that substitutes natural gas with biogas and electrolytic hydrogen (renewable gas pathway). Preliminary results indicated that exclusive electrification could increase peak electricity demand beyond available hydropower requiring significant electricity storage that comes at a high cost. Replacing natural gas with renewable and low-carbon gas can avoid increasing the peak electricity demand and use surplus electricity during off-peak times to produce hydrogen. At low heat demand, the existing hydroelectric capacity is almost sufficient to serve the additional electric power demand, making electrification the lowest cost option. If variable wind and solar power are not available during very cold periods, then the renewable gas pathway is lower cost because this pathway avoids the high cot of electricity storage. Overall, under certain circumstances either pathway can be lower cost, but the electrification pathway has greater cost uncertainty.

3.7.2.2 *The University of British Columbia's Clean Energy Research Centre (CERC)*

The University of British Columbia's Clean Energy Research Centre reviewed[131] the use of clean energy in achieving the GHG emission reductions outlined in the Roadmap to 2030 and to 2050. Economic and population growth will result in increased demand for heating, transportation and industrial production. Energy efficiency and demand reduction to meaningful levels (i.e. 25 percent) will require transformative change. The study found that neither hydroelectric electricity nor bioenergy alone are sufficient to meet demand. The CERC developed a number or models to examine some alternatives, stated in their report as follows:

> Although electrification is seen as a core strategy for GHG mitigation in BC, electricity supply is insufficient to meet the growth in demand inherent in the electrification-centered strategy. Even with Site C and radical demand reduction, about 60 PJ of additional supply will be needed to meet the 2030 target, and 160 PJ for carbon neutrality in 2050. New electricity generation will be needed by 2030 and beyond, comparable in magnitude to the projected output of the current Site C project. This implies installing hundreds of wind turbines and millions of solar panels. The bioenergy-centered strategy is an alternative to a strategy dominated by electrification; it would dramatically increase demand for bioenergy. As the first step, it must fully exploit existing waste biomass, predominantly woody waste. Even then, roughly 250 and 450 PJ of additional primary bioenergy supply will be needed for 2030 and 2050, respectively. This is well beyond any foreseeable waste supply within BC.

[130] Appendix A-9.5: Palmer-Wilson, Rowe, Wild, "Decarbonization of the building heating system in Metro Vancouver: comparison of two transition pathways" (May, 2021).
[131] Appendix A-9.6: Wang, Clift, and Bi, "Clean Energy Pathways to Meet British Columbia's Decarbonization Targets" (January, 2022), Part I and Part II, 35p.

> **Hence, strategies that rely solely on either electricity or bioenergy will raise demand beyond sustainable and manageable supplies.** There is no single 'silver bullet' renewable energy source to meet BC's GHG mitigation targets: it is essential to utilize all the available bioenergy and renewable electricity resources and promote a balanced renewable energy portfolio. The limited time frame to 2030 emphasizes the difficulty of securing the renewable energy needed and the urgency of action to reduce demand. For the long-term target of carbon neutrality, the supply problems emphasize the need for a balanced renewable energy strategy.
>
> [Emphasis added.]

3.8 *CLEAN GROWTH PATHWAY - CONCLUSION AND RECOMMENDED ACTIONS*

In response to the planning environment described in Section 2, FEI has developed its Clean Growth Pathway that leverages the decarbonization potential of both the gas and electric energy systems in supporting provincial GHG emission reductions. In addition to GHG emission reductions, in pursuing a diversified approach to decarbonization, the Clean Growth Pathway offers many benefits to British Columbians. These benefits include energy affordability, lowest risk to meeting peak demand on the coldest days of the year, energy system resiliency, fostering emerging technologies and innovation and economic development across the energy services supply chain. The section also provides research and reports in support of a diversified and complementary energy systems approach.

The Clean Growth Pathway provides FEI's framework to transition to a low-carbon energy future through four key pillars:

- **Pillar 1:** Transitioning to renewable and low-carbon gases to decarbonize the gas supply;
- **Pillar 2:** Investing in DSM programs in support of energy efficiency and conservation measures to reduce energy use among residential, commercial and industrial customers;
- **Pillar 3:** Investing in low-carbon transportation infrastructure to reduce emissions in this sector; and
- **Pillar 4:** Investing in LNG to lower GHG emissions in marine fueling and global markets.

Through the low-carbon energy transition, FEI's focus on resilience will be key for both the gas and electric energy systems in providing the energy requirements of British Columbians, especially on the coldest days of the year when provincial energy demand is highest. FEI's Resiliency Plan, which includes reducing the reliance of FEI's Lower Mainland customers on the Westcoast T-South transmission system, is even more critical in ensuring energy is available to meet peak day demand now and into the future. New infrastructure will be built to accommodate the low-carbon transition including hydrogen-enabled pipelines and transmission systems.

In the sections of the LTGRP below, FEI's Clean Growth Pathway is reflected in FEI's Diversified Energy (Planning) Scenario. This scenario and alternate future scenarios are examined in the LTGRP with respect to their impacts on annual and peak demand, DSM activities, conventional, renewable and low-carbon gas supply portfolio planning and system resource needs over the planning horizon.

FortisBC Energy Inc.
2022 LTGRP

Section 4:

ANNUAL ENERGY DEMAND FORECASTING

Table of Contents

4. ANNUAL ENERGY DEMAND FORECASTING

4.1 *INTRODUCTION AND BACKGROUND*

Two key elements that underpin FEI's resource planning activities are the 20-year forecasts of annual demand and peak demand for gas. FEI's demand forecasts are used to ensure adequate system capacity, plan gas supply resources, and provide a baseline against which to analyse the impact of proposed or potential future initiatives such as expanded energy efficiency and conservation activities or growth in conventional natural gas sales for fueling transportation.

The annual demand forecast discussed in this section represents annual consumption by region and customer class before consideration of energy savings from incremental new DSM activities,[132] and allows FEI to determine directional rate impacts and annual gas supply needs in long-term planning. The peak demand forecast provides an estimate of the maximum daily gas demand that would be expected under extreme weather conditions. Gas supply planning uses system-wide daily peak demand (discussed in Section 6) and relies on the annual shape of the load curve to model prolonged periods of high demand to plan the supply resources FEI requires throughout the year. In contrast, system capacity planning relies on regional peak day and, in certain cases, peak hour demand (each discussed in Section 7) to design FEI's regional system infrastructure to meet that peak day or peak hour demand.

The current planning environment is undergoing rapid change and therefore subject to more uncertainty than seen in resource planning processes over the past two decades or more. FEI recognizes that its customers are using gas in different ways and amounts than they did in the past and that reducing global carbon emissions is a key priority. Heating equipment installed in new buildings and in retrofit situations is more efficient and, in some cases, results in a different demand profile than the older equipment it replaces. Potential new demand from the transportation and industrial sectors may also impact FEI's overall demand profile. While recent demand history is appropriate for short-term demand forecasting, a method which relies on modelling long-range changes in energy end uses is more appropriate for longer forecast horizons.

The discussion of forecast future demand in this section is organized into the following three demand categories:

- **Residential, Commercial and Industrial**: This is FEI's traditional base of residential, commercial and industrial customers;
- **Low-Carbon Transportation and Global LNG**: These are FEI's CNG and LNG customers, representing an important opportunity for FEI to build system load while reducing GHG emissions; and

[132] Gas savings from incremental new DSM activities are discussed in Section 5, Demand-side Resources.

- **Potential New Large Industrial Load:** This represents the potential for substantial load requirements from single, atypical industrial customers that could cause a large step change in the annual demand forecast from one year to the next, such as Woodfibre LNG project.

The modelling of forecast annual gas demand for each of these three categories is discussed separately, as are the resulting demand forecasts. These forecasts are then summed to present a view of total annual gas demand.

This section is organized as follows:

- Section 4.2 presents FEI's customer counts and demand as of 2019 forms the base year for the 2022 LTGRP's annual demand forecast;
- Section 4.3 explains and presents the forecasting of customers for each of the demand categories over the forecast period of 20 years;
- Section 4.4 describes the methods used to forecast future demand for the 2022 LTGRP. This section contains information about the Traditional Annual Demand Method, which is used for short-term planning for the Residential, Commercial and Industrial Demand Category, and the End Use Annual Method, which is FEI's long-term planning forecast method for the 2022 LTGRP, for each of the demand categories described above;
- Section 4.5 explains the process of developing alternate future scenarios for FEI's forecasting analysis. This section identifies the planning scenario for the 2022 LTGRP as the Diversified Energy (Planning) Scenario and explains why the Reference Case is not an appropriate planning forecast for the 2022 LTGRP. This section also explains the critical uncertainties and modelling input settings used to model future demand for each of the future scenarios, with additional explanation provided in Appendix B-3;
- Section 4.6 presents the demand forecast results for each of the demand categories described above. This section also explains that the amount of electrification that has been modelled in the Deep Electrification and Lower Bound scenarios is determined to be not plausible and presents the context for limiting their further consideration within the 2022 LTGRP; and
- Section 4.7 presents the total annual demand for the Diversified Energy (Planning) Scenario. Section 4.8 presents the demand results for all scenarios and Section 4.9 provides a summary and conclusion for Section 4.

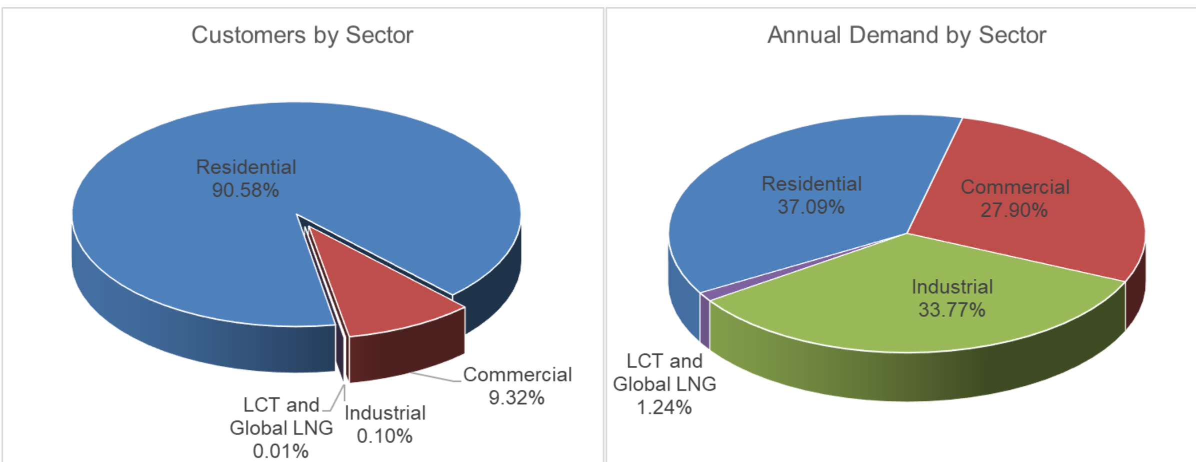
4.2 *2019 BASE YEAR DEMAND*

The base year for FEI's demand forecasts and alternate future scenarios in the 2022 LTGRP is 2019. To meet an early 2022 filing date, FEI commenced the analysis phase of the 2022 LTGRP in early 2020. During this phase, FEI needed to complete the Reference Case demand forecast to inform the 2021 Conservation Potential Review. At that time, 2019 actual data was the most current data available. The following sections discuss the 2019 base year demand for the Residential, Commercial and Industrial, LCT and Global LNG, and potential new large industrial demand categories.

4.2.1 Residential, Commercial and Industrial, and LCT and Global LNG Customers

At the end of 2019, FEI's customer base included more than one million customers. While residential customers account for approximately 91 percent of the number of customers as shown in Figure 4-1 below, there is a more even split among the residential, commercial and industrial groups on an annual demand basis. The makeup of FEI's customer base and their demand patterns has implications for infrastructure requirements and conservation goals as discussed throughout this LTGRP.

Figure 4-1: FEI 2019 Customer Base and Demand Overview[133]



4.2.2 New Large Industrial Demand

The purpose of examining alternative forecasts of large industrial customer additions is to make sure that FEI understands what the impact of a very large demand customer on its system would be and is prepared for such an event. An example of this potential step change in demand is the expected addition of demand from the Woodfibre LNG project. By its nature, therefore, the current annual demand for this category is zero and there are no current customers as of 2019. All existing industrial demand is captured in Figure 4-1 as "Industrial".

[133] Due to the weather sensitive nature of residential and commercial demand, the base year demand for these customers has been weather normalized.

4.3 *LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS*

4.3.1 Residential, Commercial and Industrial Customers

As an input into the annual demand forecast for Residential, Commercial and Industrial demand FEI establishes a base customer forecast for these customer segments. FEI uses a well-established method that remains consistent with previous LTGRP filings. The forecast of residential customers is based on the Conference Board of Canada housing starts forecast for BC, while commercial customers are forecast based on recent trends in growth for the commercial customer group. The forecast of industrial customers includes existing customers at the end of the base year (2019 year-end) along with any known commitments from customers to either join or leave the system. Explanation of the customer forecast method is provided in Appendix B-1.

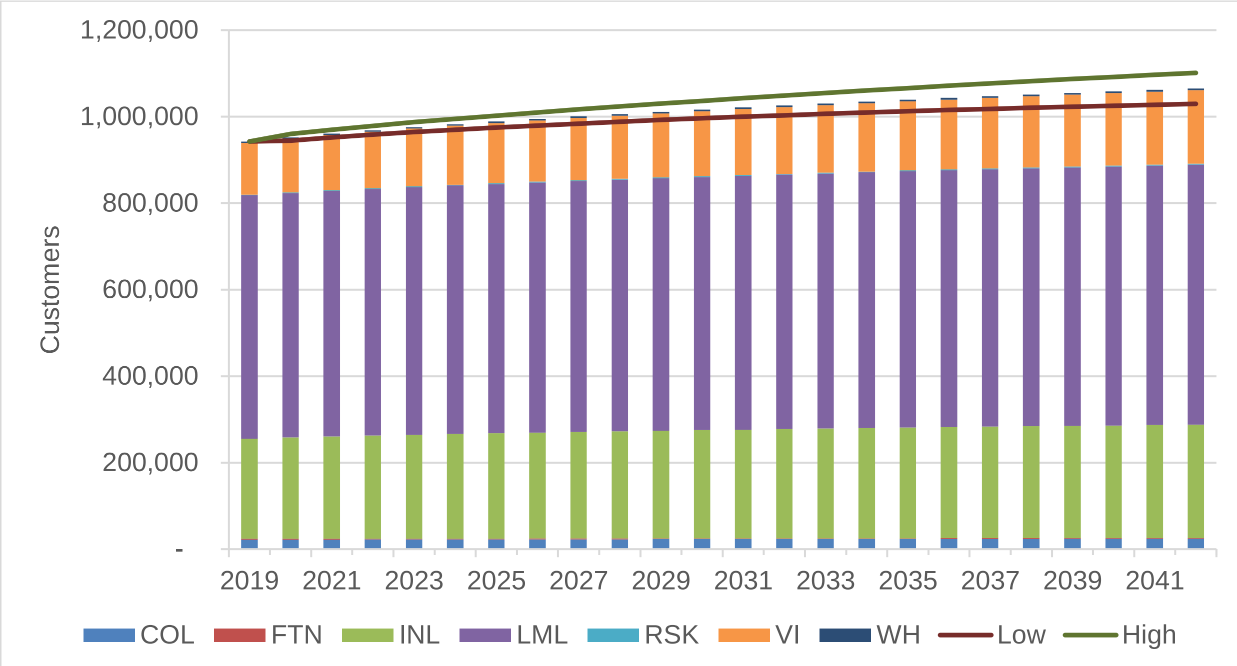
The 2022 LTGRP uses statistical 95 percent confidence intervals of historical customer additions for each customer segment to augment the base customer forecasts with high and low uncertainty bands. The high and low uncertainty bands act as alternative high and low customer additions sensitivities to provide an understanding of what range of potential high and low customer forecast trajectories could unfold over the planning horizon.

The base customer forecast is used in both the Traditional Annual Method and the End Use Annual Method of demand forecasting. Section 4.5.3 explains how the LTGRP uses the different customer forecast trajectories as one of the critical uncertainties for its scenario analysis in the End Use Annual Method. It should be noted that considerations for future uncertainties around end use energy, such as potential for new large industrial demand, or potential for electrification, are addressed as part of the demand forecast and not as part of the customer forecast.

4.3.1.1 *Residential Customer Forecast*

Figure 4-2 shows the residential customer forecast by region in the bar chart along with the high and low confidence intervals shown as the dark green and red lines. The FEI aggregate forecast predicts a compound annual growth rate of 0.48 percent across the 20-year planning period, with the regional distribution remaining relatively unchanged.

Figure 4-2: Long-Term Residential Customer Forecast by Region[134]



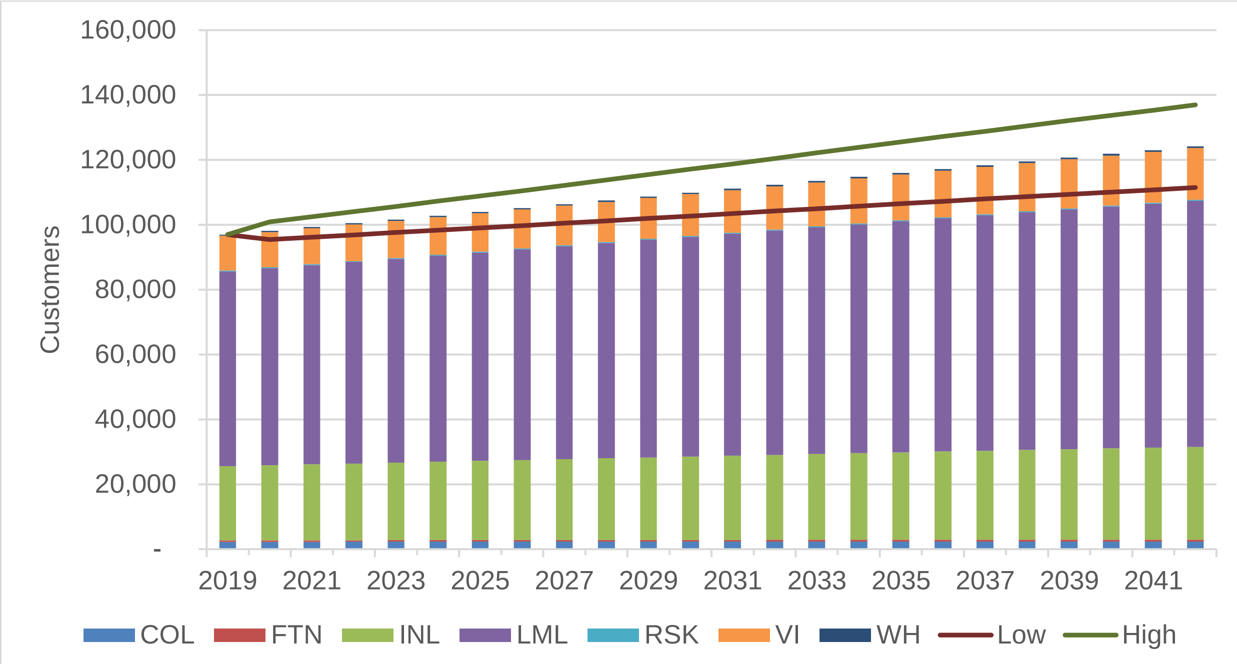
COL: Columbia	**INL:** Inland	**RSK:** Revelstoke	**WH:** Whistler
FTN: Fort Nelson	**LML:** Lower Mainland	**VI:** Vancouver Island	

4.3.1.2 *Commercial Customer Forecast*

Figure 4-3 shows the commercial customer forecast, excluding LCT customers, by region in the bar chart along with the high and low confidence intervals shown as the dark green and red lines. The FEI aggregate forecast predicts a compound annual growth rate of 1.06 percent across the planning horizon with the regional distribution remaining relatively unchanged.

[134] In the 2022 LTGRP analysis, customer counts represent the number of FEI accounts. All 2022 LTGRP annual demand, customer, GHG, and rate impact graphs, tables, and results exclude data for the Vancouver Island Gas Joint Venture (VIGJV), BC Hydro Island Generation, and Company Use.

Figure 4-3: Long-Term Commercial Customer Forecast by Region (Excluding LCT)



COL: Columbia	**INL:** Inland	**RSK:** Revelstoke	**WH:** Whistler
FTN: Fort Nelson	**LML:** Lower Mainland	**VI:** Vancouver Island	

4.3.1.3 *Industrial Customer Forecast*

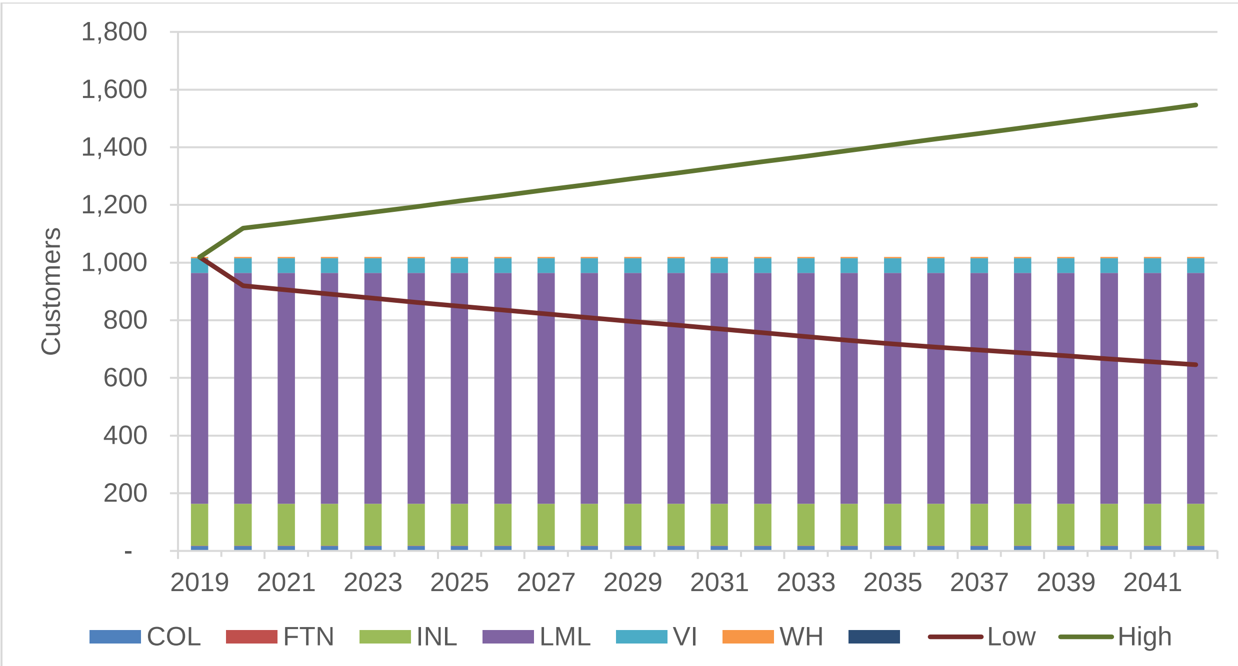
The Company had 1,019 industrial customers at the end of 2019. At the time the long-term forecast was prepared, there were no firm commitments for new industrial customers to take conventional natural gas service or for existing customers to close their accounts. Hence, there is no forecast growth or decline in the industrial customer forecast.

FEI notes the inclusion of a simple cycle gas turbine fueled by RNG in the preferred portfolio of FBC's 2021 Long Term Electric Resource Plan[135] beginning in 2031. At the time of preparing the 2022 LTGRP, no firm request has been made by FBC for gas service from FEI, therefore this addition has not been included in FEI's industrial customer (or demand) forecast at this time. Further, FEI notes that since this facility would provide a peaking resource to FBC, its operation would be for short durations only and as such the annual demand implications for FEI are relatively small compared to the total industrial load over the forecast period. The implications of such a customer addition for peak demand is discussed in Section 7.3.3.5.

[135] FortisBC Inc. 2021 Long-Term Electric Resource Plan. Section 11.3.9, page 195, online at: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/electric-utility/210804-fbc-2021-lterp-lt-dsm-plan.pdf?sfvrsn=9d1e2f27_0#page=225&zoom=100,92,114.

Figure 4-4 below shows the long-term industrial forecast by region, excluding LCT customers, along with the high and low confidence intervals shown as the dark green and red lines.

Figure 4-4: Long-Term Industrial Customer Forecast by Region (Excluding LCT)



COL: Columbia	**INL:** Inland	**RSK:** Revelstoke	**WH:** Whistler
FTN: Fort Nelson	**LML:** Lower Mainland	**VI:** Vancouver Island	

4.3.2 Low-Carbon Transportation and Global LNG Customer Forecast

For the LCT and Global LNG category, FEI does not create a base forecast of customer additions over the planning horizon in the same way that it does for the Residential, Commercial and Industrial Demand Category. This difference is because, for LCT, each customer represents a fleet of vehicles that can vary widely in size from one customer to another. Growth in demand is therefore caused by both the addition of new customers and the expansion of fleets belonging to single customers. FEI discusses the demand forecast settings for the LCT and Global LNG demand category in Sections 4.4.2 and 4.6.2.

4.3.3 New Large Industrial Customer Forecast

FEI's consideration of new large industrial customers is limited to two customers, each with similar, very large annual demand. The first of these is Woodfibre LNG project, for which expected demand and operational timing have been announced publicly. The second customer is a generic industrial customer with a similar annual demand expectation to that of Woodfibre LNG project. Such a customer has not currently been identified by FEI and is modelled generically to ensure that FEI is assessing what system impacts might be required if such a customer were to come forward during the planning horizon. FEI incorporates either zero, one or two large industrial customers in the future scenarios, as discussed in Section 4.5.3 and Appendix B-3.

4.4 LONG-TERM ANNUAL GAS DEMAND FORECAST METHODS

This section discusses the methods that FEI used to forecast energy demand for the three categories of demand: the residential, commercial and industrial customers, LCT and Global LNG customers, and potential new large industrial customers, over the next 20 years. The amount of gas that FEI expects its customers to use over the course of a year determines both the amount of gas that FEI needs to acquire and transport on behalf of its customers on an annual basis, and the number of units of energy per year over which FEI is able to recover its cost of service. Hence, the forecast of annual demand is a key step in identifying the resources FEI needs to meet the future energy needs of customers.

4.4.1 Residential, Commercial and Industrial Demand

FEI employs an End Use Annual Method to forecast long-term annual demand for energy on its system. For this demand, FEI also uses a more traditional time series approach (the Traditional Annual Method) to estimating future demand with which to compare the results of its End Use Method. Since application of the Traditional Annual Method is limited to the residential, commercial and industrial demand[136] and only used as a comparator to the End Use Annual Method results, this section first explains the Traditional Annual Method, then discusses the End Use Annual Method and finally presents the results of a jurisdictional review of demand forecasting methods.

4.4.1.1 *Traditional Annual Method of Demand Forecasting for the Residential, Commercial and Industrial Demand Category*

For the purpose of rate setting, FEI use its Traditional Annual Method to produce short-term demand forecasts based on historical data and the short-term Forecast Information System (FIS), which has been in use since 2002. Using historical data to prepare short-term time series forecasts of future consumption is a common and accepted industry practice. This method provides a high level of confidence for near-term business and operational decision making. The Traditional Annual Method is described in detail in Appendix B-1.

By extending the short-term time series forecast, FEI uses the Traditional Annual Method to produce a single BAU forecast. Extending the Traditional Annual Method over the longer-term planning horizon for the LTGRP in this manner provides a reference point against which to compare the outcomes of FEI's End Use Annual Method under various future scenarios. As it is based on historical data, however, the Traditional Annual Method is limited in its ability to

[136] The traditional time series forecast method cannot be applied to the LCT and New Large Industrial demand categories since there is little historical information for these two categories on which to conduct such an analysis.

incorporate rapid change in the planning environment and uncertainty in how the longer-term future could unfold.

4.4.1.2 *End Use Annual Method of Demand Forecasting for the Residential, Commercial and Industrial Demand*

For resource planning purposes, FEI uses the "End Use Annual Method" of demand forecasting. As described in Section 2.4, end use energy solutions and the way in which customers are using energy is changing and historical trends are not robust enough to provide the best basis on which to forecast the long-term potential range of FEI's future demand. For this reason, FEI uses the End Use Annual Method to demand forecasting which involves examining different ways that end use trends in energy utilization could potentially impact future demand for gas. This method produces a Reference Case annual demand forecast and enables FEI to examine how future demand might unfold under alternate future scenarios.

In its Decision on the 2017 LTGRP, the BCUC directed FEI to update its detailed analysis of the relative benefits and shortcomings of its particular end use method as compared to other end use methods. The original analysis for the 2014 LTRP was completed by Boreas Consulting Ltd. (Boreas). In that study, Boreas concluded that almost half of the 30 surveyed North American entities use end use models for all or part of their long-term forecasts and that FEI's end use model compares well with other North American end use methods. The update to the Boreas study for the 2017 LTGRP was conducted by Energitix Consulting.[137] Energitix confirmed that using an end use demand forecasting method remains a common practice among gas and electric utilities, particularly those that are of a similar size and facing similar challenges to FEI. Further, while such utilities do tailor the end use modelling to address the specific challenges they are facing over the planning horizon, the FEI modelling includes the key components that are common to all of the end use modelling practices examined as part of the study. The Energitix study report is included in Appendix B-2.

FEI has improved on its End Use Annual Method for the 2022 LTGRP to enhance FEI's ability to examine the Reference Case annual demand forecast and analyse how annual demand behaves across alternate future scenarios. Improvements[138] include:

- addition of new critical uncertainties;
- updated end use studies that provide key inputs to the base year data;
- a closer tie between the Conservation Potential Review (CPR) analyses and the end use demand forecasting analyses;
- bringing new market intelligence in the transportation fuels industry to bear on the forecast of CNG and LNG demand; and

[137] While different consulting firms completed the respective demand forecasting reviews, the key individual leading the study was the same, providing consistency between the studies.

[138] In its Decision on the 2017 LTGRP, BCUC directed FEI to provide a detailed explanation of any changes to its demand forecast methodology as it evolves between now and the next LTGRP filing.

- the addition of PowerBI data analytics interface to improve the ability to display and assess forecasting results.

FEI engaged Posterity Group (Posterity) to support FEI in preparing the End Use Annual Method forecast for the 2022 LTGRP. Posterity was instrumental in preparing FEI's 2021 CPR and 2017 LTGRP end use demand forecast. Posterity prepared an updated end use forecast model for FEI based on learnings from the 2017 LTGRP.

The End Use Annual Method forecast process starts with developing a Reference Case forecast. The Reference Case is based on end use patterns observed, as well as any new changes in law or policy that will affect future demand and have been, or are quite certain of becoming, enshrined in legislation, codes, standards or bylaws in and as of the base year. The Reference Case keeps these patterns constant throughout the planning period. FEI and Posterity used the following data sources to calibrate[139] the forecast model to FEI's 2019 base year actuals and to identify Reference Case end use changes across the forecast horizon:

- FEI's 2021 Conservation Potential Review (2021 CPR);
- FEI's 2017 Residential End use Survey (REUS) which represents FEI's most recent REUS at the time the forecast modelling was undertaken;
- FEI's 2019 Commercial End use Survey (CEUS) which represents FEI's most recent study of its commercial customers; and
- Research and data analysis from the 2017 LTGRP which FEI included to utilize and build upon work that had already been completed for the 2017 LTGRP.

The impact of DSM programs up to and including 2019 are implicitly included in the end use characteristics identified for the base year, but the existing program activity is assumed not to have any incremental impact through the planning period for the purpose of demand forecasting. Section 5 separately discusses the impact of FEI's forecast future DSM programs.

4.4.1.3 *Developing a Reference Case for Annual Demand for Residential, Commercial and Industrial Demand*

The Reference Case began with the development of a base year, in this case 2019. The base year was built from customer account and weather-normalized consumption data, categorized by region, rate schedule, and, for industrial and commercial customers, industry. Gas consumption was further subcategorized by end use based on the detailed customer information in the 2021

[139] The calibration process ensures that the sum total annual gas demand of all base year end uses in the End Use Annual Method demand forecast model matches FEI's base year actuals.

CPR and 2017 LTGRP, including end use consumption, market saturation[140] and gas share.[141] As described in Section 4.4.1 above, some of this information has been derived from end use surveys commissioned by the Company, while other aspects emerged from detailed building modelling.

The resulting model, calibrated to match FEI's actual normalized sales of gas, is subdivided as follows:

- By region: Lower Mainland, Vancouver Island, Whistler, Southern Interior, Northern BC[142];
- By sector: Residential, Commercial and Industrial;
- By segment (i.e., sub-sector):
    - In residential—three dwelling types by detachment type, dominant heating fuel, and vintage;
    - In commercial—seventeen building types, by predominant use and building size (office, retail, school, hospital, etc.);
    - In industrial—thirteen plant types (mining, wood products, non-metallic minerals, etc.);
- By rate schedule: one rate schedule in residential, six rate schedules in commercial, and nine rate schedules in industrial; and
- By end use: ten residential, five commercial and seventeen industrial gas end uses.

Beginning with the calibrated base year, the Reference Case forecast was built using FEI's 20-year customer forecast (discussed in Section 4.3), with new residential dwellings and commercial floor area based on the account growth rates as identified in Section 4.3. Anticipated efficiency improvements from minimum energy performance standards that are not associated with DSM activities, such as the natural replacement of furnaces,[143] were incorporated in both existing buildings and new construction. Anticipated changes in the saturation and gas shares for specific end uses were also included. The End Use Annual Method forecast model provides the forecast consumption values for each forecast year at the same level of granularity as the base year.

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[140] Market saturation is a percentage indicating what portion of the population of buildings has a given end use. For end uses such as space heating and water heating, this is assumed to be 100 percent of dwellings. For an end use such as clothes drying, where the logical unit of analysis is the appliance, the percentage is the number of clothes dryers divided by the number of dwellings. Market saturation in the commercial sector is based on the percentage of building floor space with a given end use, instead of percentage of dwellings. Market saturation is not employed in the industrial model, saturation is taken into account in the overall end use consumption for a given plant type.

[141] Gas share is the percentage of the energy end use that is supplied by gas. For clothes dryers, for example, this translates into the percentage of dryers that are gas-fired. Note that that gas share is based on the percentage of useful energy supplied to accomplish the end use (i.e., the tertiary load); actual energy consumption equals tertiary load divided by the efficiency of the appliance that meets this load.

[142] The region names specified in FEI's End Use Annual Method demand forecast method are independent from FEI's internal service areas that may appear in other regulatory submissions or short-term forecasts.

[143] Anticipated efficiency improvements from minimum energy performance standards are incorporated in existing buildings when old equipment is replaced and new construction when new equipment is installed.

Figures 4-5 and 4-6 below display Reference Case results using the End Use Annual Method demand forecast of annual demand by sector and by region. Overall, the Reference Case annual demand forecast shows slight growth, driven by growth in the commercial and residential sectors as shown in Figure 4-5 below.

Figure 4-5: Reference Case Annual Demand Forecast for Residential, Commercial and Industrial by Rate Schedule

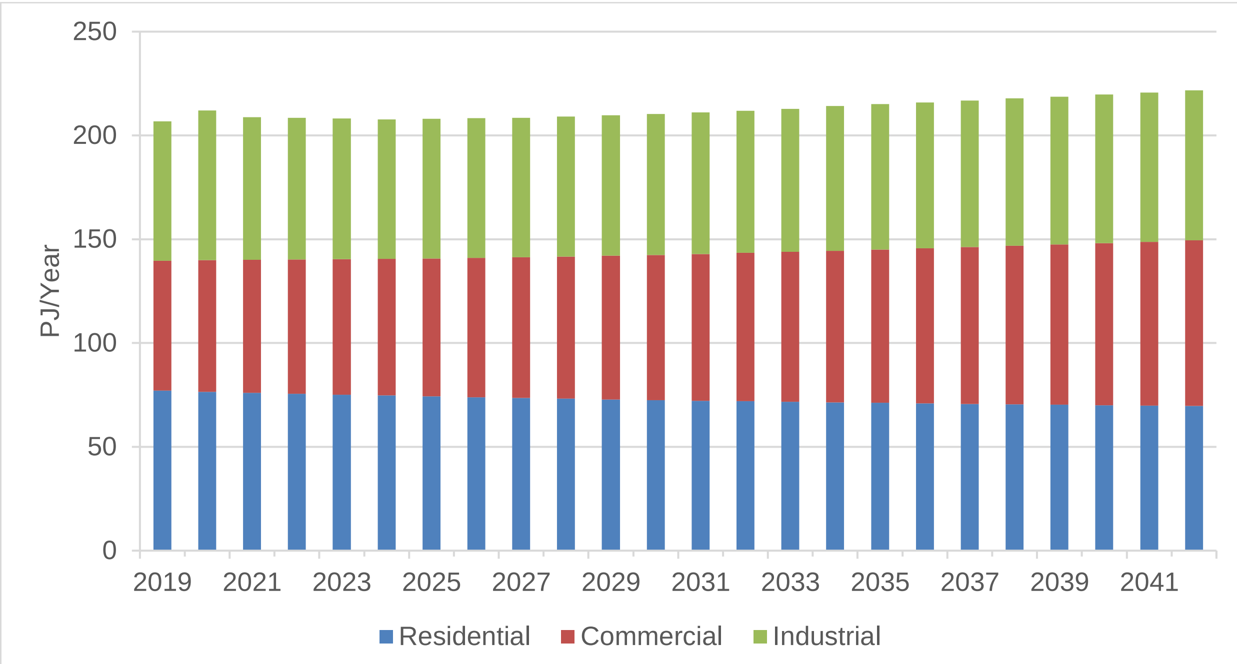
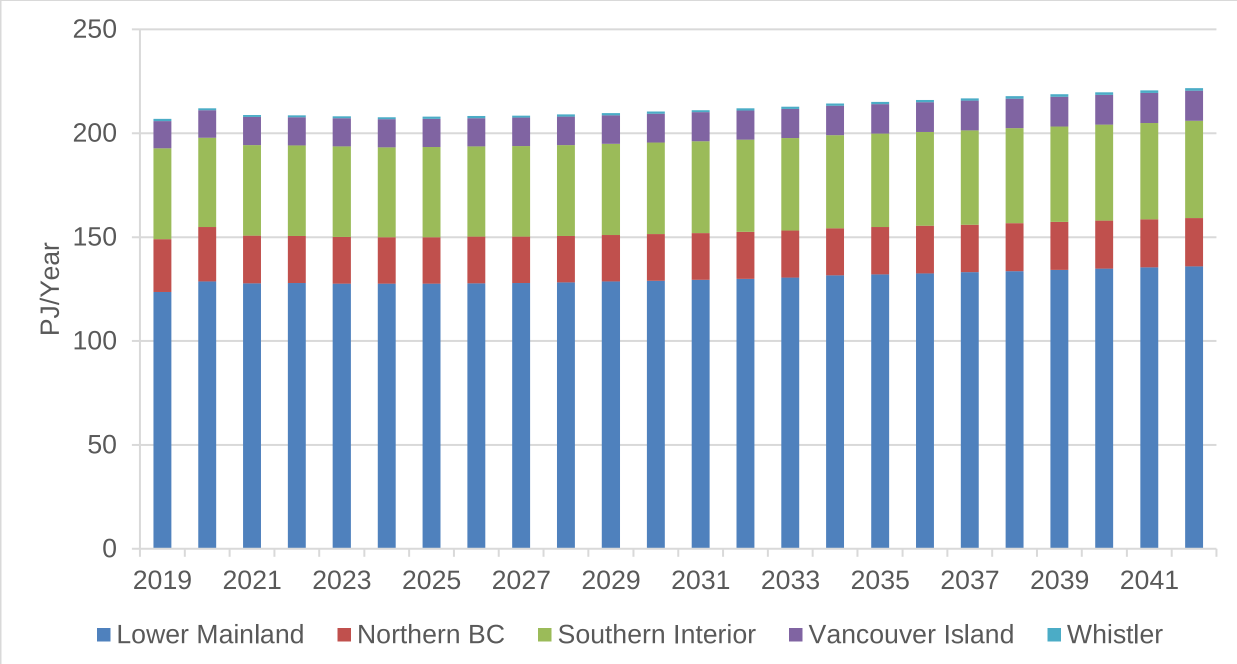


Figure 4-6: Reference Case Annual Demand Forecast for Residential, Commercial and Industrial by Region



4.4.1.4 *Comparing the Traditional Annual and End Use Annual Methods for Forecasting Residential, Commercial and Industrial Annual Demand*[144]

As discussed above, FEI's End Use Annual Method, which is used to create the Reference Case, differs in a number of ways from the Traditional Annual Method, which is used to create the BAU forecast. Comparing the Reference Case forecast with the BAU forecast shows that the results of the End Use Annual Method and the Traditional Annual Method are reasonably aligned for a future that remains relatively unchanged from conditions present as of the base year. This comparison thus provides additional confidence that FEI's End Use Annual Method provides a sound approach for examining alternate future scenarios.

Figure 4-7 below compares the BAU forecast annual demand with the Reference Case forecast. By the end of the planning period, the two forecast methods differ by only five percent. This variance is due to the various differences between the two methods. One of these differences is that the BAU forecast is based on intrinsic historical end use trends, whereas the Reference Case limits itself to fully known, legally enshrined, and mandatory or highly-assured future changes[145] in trends. For example, the BAU forecast is influenced by historical trends due to changes in energy performance codes and standards, while the end use method Reference Case only accounts for such changes that are already legally enshrined and are or will be mandatory during

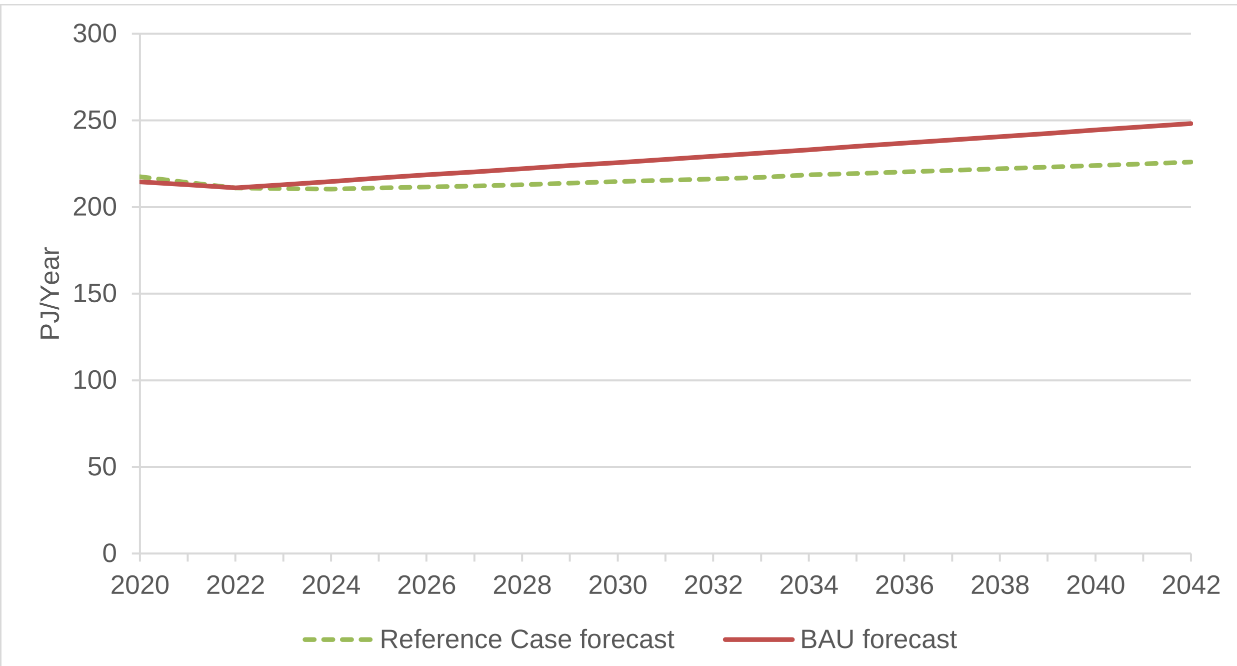
[144] BCUC Directive No.2 from the 2017 LTGRP decision directs FEI to "continue use of its Traditional Annual Method as a comparison to test its End Use Method until such time as the BCUC approves a new demand forecast methodology."

[145] By their nature, such assured future changes are limited to the near future, since the farther into the future changes are estimated to occur, the more uncertain they become.

the forecast horizon, such as a building code amendment that has been announced but not yet implemented. By the same token, the BAU forecast includes historical DSM program participation trends, whereas the End Use Annual Method Reference Case relies on specific assumptions regarding future changes in equipment characteristics and adoption but not DSM programs.

Across the LTGRP planning horizon, FEI uses the End Use Annual Method Reference Case to plan for its forecast long-term annual demand. Please refer to Appendix B-1 for more detailed results from the BAU forecast.

Figure 4-7: Comparing the End Use Reference Case and Traditional BAU Annual Demand Method Forecast Results



4.4.2 End Use Annual Method of Demand Forecasting for the Low-Carbon Transportation and Global LNG Category

This section describes FEI's forecast of annual demand for conventional natural gas as a LCT fuel, which has emerged as a growing market in BC, both for CNG and LNG customers. An important benefit of using CNG and LNG as a transportation fuel is the carbon emission reductions that result from displacing higher carbon fuels such as diesel and bunker oil. The GHG emission reductions resulting from FEI's forecast of CNG and LNG demand are discussed in Section 9.2.

4.4.2.1 *CNG Transportation Demand Forecast Method*

To derive the CNG demand forecasts, FEI formulated the CNG demand forecast settings (Reference, Planning, High, Low) by accounting for commitments that have been made by customers to take CNG supply and by forecasting the impacts of a variety of factors. These factors include inflation, discussions on new station builds, vehicle incentive applications, regulatory changes that are expected to drive conventional natural gas adoption and assumptions regarding adoption rates based on past experience. Section 1.2.1 of Appendix B-3 provides a more detailed explanation of the CNG demand settings.

To determine the percentage of BC's CNG market that will be captured in the forecasts, FEI determined the eligible market size by first quantifying the size of the diesel fuel and conventional natural gas market for transportation in BC. This data was obtained from Natural Resource Canada's (NRCan) Transportation Sector – British Columbia and Territories database, which displays the 2018 fuel consumption for the transportation sector by fuel type.[146] This fuel consumption database provided the basis for the 2018 market size, which was then escalated by a forecast growth rate fuel consumption calculated from the Canadian Energy Report Update.[147] This report is a forecast of Canada's energy supply and demand projections to 2050. The sectors included in the market size assessment were freight trucks, medium duty trucks, heavy duty trucks, school buses and urban transit and inter-city buses.

4.4.2.2 *LNG Transportation and Global LNG Demand Forecast Method*

The forecast settings developed for LNG transportation customers are the same as those for CNG transportation customers (Reference, Planning, High, Low). The forecast settings for global LNG demand are similar except that since the Reference setting assumes no global LNG demand beyond the first two years of the forecast period, there is no Low setting. Appendix B-3, Section 1.2.1 provides additional explanation of the LNG transportation and global LNG demand forecast settings.

FEI supplies LNG to customers from the Tilbury LNG facility in the Lower Mainland and the Mt. Hayes LNG facility on Vancouver Island. FEI formulated the LNG demand forecast by accounting for commitments that have been made by customers to take LNG supply, and by forecasting the impacts of a variety of factors. These factors include the availability of Original Equipment Manufacturer (OEM) technology capable of adopting conventional natural gas, regulatory changes (see Section 2.2.2.3) that are expected to drive conventional natural gas adoption and assumptions regarding adoption rates based on past experience for some of the market segments. A description of the key factors affecting the LNG market is provided below. While the key early adopters of LNG in BC were on-road heavy-duty trucking customers, conventional natural gas engines that are able to haul in excess of 80,000 pounds have recently been discontinued. On-road heavy duty trucking customers are now unable to replace or add additional 15L vehicles to their fleets, resulting in lower demand and decelerating LNG adoption for on-road trucking. LNG for the mining sector has also developed slower than expected for mine haul trucks and remote power generation. The key market that has emerged over the past years, however, is high horsepower applications for marine vessels.

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[146] Appendix F-11: NRCan, Transportation Sector – British Columbia and Territories (2018), online at: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_tran_bct.cfm.

[147] Appendix F-12: Canada Energy Regulator, "Canada's Energy Future 2021: Update – Energy Supply and Demand Projections to 2050 - Figure Data" (2021), online at: https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2021/index.html.

The two key marine segments that FEI has targeted are the short sea segment[148] and the trans-Pacific segment. FEI currently offers truck-to-ship fueling for regional ferry and small vessel operators. FEI is focused on supporting the ship-to-ship LNG fueling for trans-Pacific vessels requiring larger LNG transfer volumes. FEI expects to be able to supply ship-to-ship LNG fueling through a marine bunkering jetty connected to the Tilbury LNG facility. The jetty project is currently under development by an FEI affiliate. Final approvals for the marine jetty project are expected in 2023 with the marine jetty to be in service by the middle of 2024. FEI is also actively pursuing the LNG market for trans-Pacific exports by an International Organization for Standardization (ISO) container, using the truck loading bays at Tilbury. FEI has had some success in this market prior to the recent pandemic-related issues with international shipping and expects the market to continue to grow going forward.

4.4.3 End Use Annual Method of Demand Forecasting for the New Large Industrial Demand Category

FEI's forecast for new large industrial customer demand has evolved as a result of interest from industry that would use substantial amounts of conventional natural gas as a feedstock to locate in BC. FEI is currently developing the Eagle Mountain Woodfibre Gas Pipeline (EGP) Project that would expand the existing gas pipeline that runs between Coquitlam and a site near Squamish to provide pipeline service to Woodfibre LNG project, a new LNG processing and export facility, which has announced its intention to proceed to construction. The addition of the anticipated Woodfibre LNG project load would add significant demand, modelled for the LTGRP at 95 PJ of conventional natural gas annually.

The interest by this large industrial user of conventional natural gas in locating in BC has caused FEI to consider what impacts the potential for a second large industrial customer locating in BC's Lower Mainland could have on the conventional natural gas system in the region. While there is no firm proposal for such service, FEI believes it is important to consider this possibility in its long-term planning. FEI has based the annual demand for this second facility on that of the Woodfibre LNG project (95 PJ annually)

The forecast considerations for new large industrial customer load are limited to either zero, one or two such large industrial facilities. FEI expects the Woodfibre LNG project demand to materialize. Due to the length of time for decision making, locating and constructing such a large project, FEI does not see a need at this time to consider more than two such facilities materializing over the next 20 years.

4.5 *ALTERNATE FUTURE SCENARIOS AND CRITICAL UNCERTAINTY SETTINGS*

In order to examine different ways that the future could potentially unfold to impact the amount of demand, FEI has developed, in consultation with stakeholders, a range of six alternate future

[148] Short Sea is considered by FEI to be the segment that includes marine vessels that transit intra-provincial waterways to move goods and passengers.

scenarios (in addition to the Reference Case) within which changes in demand can be modelled using the End Use Annual Method discussed above.

This section explains the alternate future scenarios and describes how the settings for each of the Critical Uncertainties – those factors that could substantially impact future demand and which remain relatively uncertain – have been determined for each scenario and applied to the forecast modelling. Consistent with the Reference Case, 2019 formed the base year data for all six alternate future scenarios.

Section 3 of this LTGRP provides a detailed discussion of FEI's Clean Growth Pathway. FEI believes that a diversified pathway in which both the existing gas and electricity systems within BC have an important role to play in decarbonizing energy use in the province, is critical to a successful, reliable, resilient and cost-effective energy future, and that the Clean Growth Pathway plays a critical role. As such, FEI is designating the Diversified Energy (Planning) Scenario as its planning scenario for the 2022 LTGRP.

The following sections first describe the Diversified Energy (Planning) Scenario as FEI's planning scenario, followed by a discussion of how the critical uncertainties were determined and used to identify the alternate future scenarios. FEI also explains the settings for each of the critical uncertainties that apply to the three demand categories (Residential, Commercial and Industrial, LCT and Global LNG, and new large industrial demand) and cause future demand forecasts to unfold in different ways in each of the future scenarios.

4.5.1 Identifying FEI's Planning Scenario – The Diversified Energy (Planning) Scenario

The Diversified Energy (Planning) Scenario sets the planning context for FEI's 2022 LTGRP and the actions FEI will take over the next four years to ensure it can meet customers' energy needs over the planning horizon and beyond. For the residential, commercial and industrial demand category, the Diversified Energy (Planning) Scenario meets the BC GHGRS cap on carbon emissions for gas utilities. Section 9.2 presents the GHG reductions that result from the residential, commercial and industrial demand category as it relates to the GHGRS emissions cap for gas utilities.

In the Diversified Energy (Planning) Scenario, FEI models future changes needed to pursue its Clean Growth Pathway and meet decarbonization targets. The Diversified Energy (Planning) Scenario includes essential elements of the Clean Growth Pathway, such as accelerated acquisition of renewable gas supply, growth in the use of low-carbon gas as a transportation fuel, and electrification[149] initiatives in BC that impact gas demand. As these elements were not established within the trends present in 2019, they are not reflected in the Reference Case demand forecast.

[149] The Diversified Energy (Planning) Scenario is modelled with the assumption that 25% of residential and commercial gas demand, and 10% of industrial gas demand is electrified by 2050, with a straight line interpolation for each year of the forecast period.

In analysing the energy planning environment in BC, it was clear to FEI that a Diversified Energy (Planning) Scenario must be the solution to meeting the growing energy needs of British Columbians and reducing carbon emissions over the next 20 years and beyond. The Diversified Energy (Planning) Scenario depends on the utilization and improvement of both the gas and electric systems, maximizing all available energy resources. It represents a future in which the need for robust, reliable and resilient gas and electric infrastructure is embraced and promoted by government and municipal policy actions, and where customers' energy use decisions are influenced by near term signals that minimize the longer term costs of decarbonization and energy capacity challenges in BC. The integrated nature of these energy systems establishes a higher level of resiliency than relying on one system over the other and allows a multi-pronged approach to energy solutions that reduces carbon emissions in BC and globally. Working together, these systems enable the integration of a broader range of local, innovative energy solutions to meet community and customer needs and support a broader range of industry and economic development in BC.

Customer growth for both electric and gas utilities is part of the Diversified Energy (Planning) Scenario. In this scenario, FEI undertakes high levels of DSM over the planning horizon, and an aggressive transition to renewable and low-carbon gas takes place early in the planning horizon and continues. Growth in the use of gas as a transportation fuel to reduce carbon emissions in the transportation sector takes place and is larger in the Lower Mainland than in other regions of the province, particularly in the marine transportation sector.

In the following sections, FEI examines its Diversified Energy (Planning) Scenario against a number of other annual demand scenarios that represent possible other futures that could unfold. These alternate future scenarios are informed by FEI's examination of the BC energy planning environment as well as feedback from stakeholders, interveners and the BCUC as part of this and prior LTGRP processes.

4.5.2 Identifying and Developing Alternate Future Scenarios for End Use Analysis

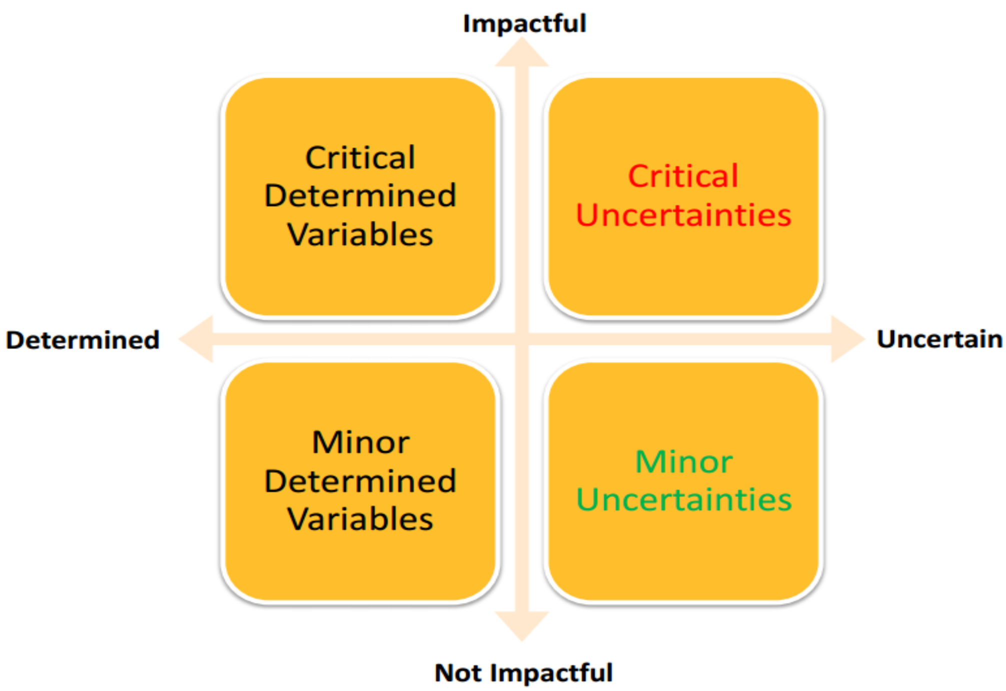
For the 2022 LTGRP, FEI developed six alternate future scenarios, including the Diversified Energy (Planning) Scenario described above, to provide insight into the impact on demand of a broader range of potential future conditions than has been examined in previous LTGRPs. FEI developed these scenarios based on critical uncertainties for annual demand, which represent future conditions that could have the biggest impact on FEI's business. FEI identified these critical uncertainties with input from the scenario analysis work for the 2017 LTGRP, and both internal FEI stakeholders and members of the external RPAG, as well as from themes that emerged from the 2022 LTGRP's community engagement workshops. The Reference Case provides a baseline against which the forecast demand under the six alternate future scenarios can be examined.

Following a standard scenario planning approach, FEI's scenario analysis proceeded in four steps:

1. Evaluating planning environment variables and identifying critical uncertainties;
2. Determining the number of outcomes (called settings) and their broad qualitative boundaries for each selected critical uncertainty;
3. Determining plausible combinations of outcomes for each critical uncertainty and creating reasonable scenario plotlines for annual demand; and
4. Populating quantitative data into the outcomes for each critical uncertainty and iterating with internal and external stakeholder feedback.

The first step in the above list intends to focus the scenario analysis by determining which of the many variables in the planning environment should be used to alter the Reference Case into alternate future scenarios. This involves selecting the most impactful and most uncertain variables. Figure 4-8 below illustrates how FEI classified planning environment variables for this first step.

Figure 4-8: Classification of Planning Environment Variables



FEI intentionally held each step separate from the other steps. Selecting critical uncertainties first, and then determining their qualitative boundaries before generating the plotlines and populating quantitative data, guards against inadvertently favoring certain visions of the future over others by presupposing scenario results rather than focusing on inputs.

FEI has grouped the critical uncertainties under demand (residential, commercial and industrial), supply (renewable and low-carbon gas supplies) and transportation (new demand for gas as a transportation fuel) uncertainties. The 2022 LTGRP's critical uncertainties break down as described below.

- Residential, Commercial and Industrial Demand:
  - Economic growth, represented by account growth values and increases in commercial and industrial floor area in the forecast model;
  - Conventional natural gas commodity price, based on a multitude of third-party forecasts (this accounts for price changes motivated by various factors, such as demand-supply balance or upstream regulatory changes);
  - Carbon price, which accounts for provincial and federal carbon pricing actions and is agnostic to the specific pricing mechanism (the forecast model simply assumes a stream of price values without identifying, for example, whether these are the result of a carbon tax or a cap and trade system);
  - Non-price policy levers, which account for changes in the building code, energy performance standards, and any requirements for switching from one fuel type to another (e.g., district energy systems[150]).
- LCT and Global LNG Demand:
  - Demand for CNG and LNG in the conventional natural gas for transportation sector and for global LNG demand. Demand for these fuels impacts FEI's system and reduces GHG emissions as CNG and LNG displace fuels that emit more GHGs.
- New Large Industrial Customer Demand
  - The potential for one or two new large industrial facilities to require substantial annual amounts of gas. As discussed in Section 1.3 of Appendix B-3, the two potential large demand industrial facilities considered within the scenarios are each either added to the system, or they are not. These demand additions each cause step change increases in demand in the year in which they are assumed to become operational within the scenarios.
- Supply and GHG emissions:
  - Renewable and low-carbon gas supply options (CCUS associated with gas use, hydrogen, RNG, syngas and lignin). While not demand uncertainties, renewable and low-carbon supply options are modelled along with demand uncertainties across the scenarios to understand how gas demand can be met while reducing GHG emissions relative to historical emissions at a point in time (i.e., 2007) or relative to a scenario where load is primarily met with conventional natural gas (i.e., the Reference Case).

[150] As noted in Section 2.3.4, some BC municipalities are pursuing goals to supply 100 percent of their energy needs via renewable and low-carbon sources by 2050. Some of these municipalities are encouraging deployment of district energy systems. In the near term, such district energy systems may rely on gas but municipalities may intend to shift these to other fuel sources in the long term.

4.5.3 Critical Uncertainty Input Settings for Each Future Scenario

Table 4-1 below summarizes the six alternate future scenarios that FEI has modelled, including the Diversified Energy (Planning) Scenario described in Section 4.5.1 as FEI's planning scenario. Scenario descriptions, input settings for each critical uncertainty, and a brief discussion of each scenario's specific attributes is included. This table does not include the Reference Case because the Reference Case sets the baseline for the scenario analysis by using the Reference setting for all critical uncertainties. The Reference setting for each of the critical uncertainties is based on the expectation of what would happen if the conditions for that uncertainty remained as they were known to be as of the base year. As such, using the Reference setting for all of the critical uncertainties results in the Reference Case forecast. Based on the Reference Case, the scenario analysis alters the outcomes of each critical uncertainty to be higher or lower, or accelerated or delayed, compared to the Reference setting. In some cases (electrification in the Diversified Energy (Planning) Scenario, for example), settings may be assumed to change moderately from the Reference setting over the panning horizon, but not to the extent the change would be considered high or low. A setting of 'Planning' indicates that the input value for that critical uncertainty is what FEI expects it to be in the Diversified Energy (Planning) Scenario. Appendix B-3 provides further explanation of the scenario analysis method and the critical uncertainty settings for each of the demand categories.

Table 4-1: Alternate Future Scenario Summary

Scenario	Description	Input Settings		Discussion
Upper Bound	The BC economy experiences higher-than-average growth. Infrastructure development in other regions, coupled with extraction infrastructure development in BC, keep regional gas supply abundant. Continued electoral strength within the right political spectrum causes governments to focus on issues other than climate policy. The BC government keeps supporting LNG exports and LCT as cost-effective existing carbon solutions.	**Residential, Commercial and Industrial Demand Category**		In general, the outcomes of the multiple critical uncertainties can offset each other's impact on annual demand but this scenario combines all outcomes that would increase annual demand. As such, this scenario represents one of two boundary scenarios that frame the scenario analysis. The Upper Bound scenario informs those conditions that FEI can monitor to understand in advance if demand is trending higher than expected, but is not the basis on which FEI plans.
		Appliance Standards	Reference	
		Carbon Price	Low	
		Customer Forecast	High	
		Fuel Switching	Reference	
		New Construction Code	Delayed	
		Retrofit Code	Reference	
		Natural Gas Price	Low	
		Low-Carbon Transportation and Global LNG Demand Category		
		LCT Demand	High	
		Global LNG Demand	High	
		New Large Industrial Demand Category		
		Industrial Demand Growth	High	

Scenario	Description	Input Settings		Discussion
Diversified Energy (Planning)	The Diversified Energy (Planning) Scenario's key planning assumptions build upon a diversified approach to energy delivery and emissions reductions to British Columbians. Under this scenario, customer growth occurs for both electric and gas utilities and the existing gas infrastructure is used to deliver low-carbon energy solutions to customers. FEI uses the Diversified Energy (Planning) Scenario as its planning scenario.	**Residential, Commercial and Industrial Demand Category**		The explanation of the Diversified Energy (Planning) Scenario and its selection as FEI's planning scenario is provided in Section 4.5.1.
		Appliance Standards	Reference	
		Carbon Price	Reference	
		Customer Forecast	Reference	
		Fuel Switching	Moderate electrification	
		Natural Gas Price	Reference	
		New Construction Code	Reference	
		Retrofit Code	Reference	
		Low-Carbon Transportation and Global LNG Demand Category		
		LCT Demand	Planning	
		Global LNG Demand	Planning	
		New Large Industrial Demand Category		
		Industrial Demand Growth	Planning	

Scenario	Description	Input Settings		Discussion
Price-Based Regulation	The BC government concludes that price signals and more ambitious upstream emissions reductions provide the best solution for carbon abatement and refrains from other forms of regulation. The price signals boost development of renewable gases, CCUS, and LCT. Upstream methane emissions regulations increase regional gas commodity costs. The policy environment has limited impacts on economic growth and LNG Exports.	**Residential, Commercial and Industrial Demand Category**		Use of price signals instead of carbon regulation within the planning environment as described in this scenario also creates favourable conditions for FEI to implement its Clean Growth Pathway. Exclusion of future demand from the Woodfibre LNG project in this scenario allows FEI to examine the unexpected, but still plausible situation in which that facility does not proceed.
		Appliance Standards	Reference	
		Carbon Price	High	
		Customer Growth	Reference	
		Fuel Switching	Reference	
		Natural Gas Price	High	
		New Construction Code	Reference	
		Retrofit Code	Reference	
		Low-Carbon Transportation and Global LNG Demand Category		
		LCT Demand	High	
		Global LNG Demand	Reference	
		New Large Industrial Demand Category		
		Industrial Demand Growth	Reference	

<table>
<tr><th>Scenario</th><th>Description</th><th colspan="2">Input Settings</th><th>Discussion</th></tr>
<tr><td rowspan="14">Economic Stagnation</td><td rowspan="14">In this scenario the BC economy tightens, influenced by other North American and global trends, leaving fewer dollars available to the government and utility customers in BC to aggressively pursue decarbonization initiatives. Regional growth in conventional natural gas demand slows, keeping BC's gas demand/supply balance abundant. Global economic performance reinforces trends towards the right political spectrum and causes governments to focus on areas other than climate policy. The economic environment has some negative impact on LNG exports and significant negative impact on conventional natural gas as a transportation fuel. This scenario is not intended to model a 20-year recession, but rather a general trend over the planning horizon in which spending is reigned in.</td><td colspan="2">Residential, Commercial and Industrial Demand Category</td><td rowspan="14">While FEI does not apply sophisticated econometric modelling to its demand forecasting analysis, this scenario allows examination of a future in which poorer economics prevail and impact energy trends and related policy to a greater extent.</td></tr>
<tr><td>Appliance Standards</td><td>Reference</td></tr>
<tr><td>Carbon Price</td><td>Low</td></tr>
<tr><td>Customer Growth</td><td>Low</td></tr>
<tr><td>Fuel Switching</td><td>Reference</td></tr>
<tr><td>Natural Gas Price</td><td>Low</td></tr>
<tr><td>New Construction Code</td><td>Delayed</td></tr>
<tr><td>Retrofit Code</td><td>Reference</td></tr>
<tr><td colspan="2">Low-Carbon Transportation and Global LNG Demand Category</td></tr>
<tr><td>LCT Demand</td><td>Low</td></tr>
<tr><td>Global LNG Demand</td><td>Reference</td></tr>
<tr><td colspan="2">New Large Industrial Demand Category</td></tr>
<tr><td>Industrial Demand Growth</td><td>Reference</td></tr>
<tr><td colspan="2"></td></tr>
</table>

Scenario	Description	Input Settings		Discussion
Deep Electrification	The BC government does not increase carbon taxes to avoid electoral backlash but uses all other policy levers to electrify the economy in order to achieve domestic carbon abatement. Government also promotes CCUS for non-electrified sectors. Such policies create constraints for the BC economy and reduce the uptake of LCT solutions and renewable gases. To support economic growth, the BC government supports LNG exports to other jurisdictions. Despite these exports, the domestic shift towards electricity causes a regional conventional natural gas supply glut, leading to low regional gas prices.	**Residential, Commercial and Industrial Demand Category**		In this scenario, electrification is the primary avenue utilized by the BC Government to decarbonize the BC economy. This in turn causes a decrease in annual gas demand. Coinciding with this decrease in annual gas demand are corresponding increases in electricity annual and peak demand that are not fully modelled in FEI's annual gas demand analysis, and which are anticipated to make a deep electrification not plausible as described in Section 4.6.1.1
		Appliance Standards	Accelerated	
		Carbon Price	Reference	
		Customer Growth	Low	
		Fuel Switching	Accelerated electrification	
		Natural Gas Price	Low	
		New Construction Code	Accelerated	
		Retrofit Code	Accelerated	
		Low-Carbon Transportation and Global LNG Demand Category		
		LCT Demand	Low	
		Global LNG Demand	Planning	
		New Large Industrial Demand Category		
		Industrial Demand Growth	Reference	

Scenario	Description	Input Settings		Discussion
Lower Bound	The BC economy experiences lower-than-average growth as part of global economic stagnation. This reduces investment in regional gas supply so much that BC's demand balance becomes constricted. Global economic performance reinforces trends towards the right of the political spectrum in other jurisdictions but causes a counter-movement to the left in BC. This causes the BC government to focus on climate policy and electrification without support for renewable gases, CCUS, LNG exports, or LCT.	**Residential, Commercial and Industrial Demand Category**		This represents the second of the two boundary scenarios. This scenario is designed to represent the most extreme, low-gas-demand scenario from an annual demand perspective. In addition to deep electrification policies, all other critical uncertainties that could act to reduce gas demand do so. However, in this scenario, like the deep electrification scenario, the requirement for corresponding increases in electricity energy and peak demand requirements that are not fully modelled in FEI's annual gas demand analysis are anticipated to make the lower bound annual demand scenario not plausible as described in Section 4.6.1.1
		Appliance Standards	Accelerated	
		Carbon Price	High	
		Customer Growth	Low	
		Fuel Switching	Extensive electrification	
		Natural Gas Price	High	
		New Construction Code	Accelerated	
		Retrofit Code	Accelerated	
		Low-Carbon Transportation and Global LNG Demand Category		
		LCT Demand	Low	
		LNG Export Demand	Reference	
		New Large Industrial Demand Category		
		Industrial Demand Growth	Reference	

The modelling process involved turning each of these assumptions into concrete changes to the input values for buildings in the three sectors. For example:

- In response to higher or lower gas prices, adjustments were made to the number of new buildings using gas for specific end uses, or to the number of existing buildings whose owners might opt to change fuels when equipment needs replacement.
- The policy environment affects assumptions about the number of customers who would opt to install energy-efficient equipment naturally, without influence from utility programs.
- Assumptions for developing district energy systems resulted in adjustments to the fuel shares for those options: increases in those fuel shares would generally displace the demand for gas.
- Renewable energy systems include systems such as geo-exchange, waste heat recovery, and solar thermal energy and can be stand alone or part of a district energy system. This

has the effect of displacing gas consumption, particularly for space and water heating in commercial buildings and apartments. With limited but growing market penetration of low-carbon thermal energy systems, FEI must continue to monitor this growth to gauge its impact over time on its gas infrastructure, annual and peak day demand, system capacity needs and rate design.

The model results for the six scenarios have the same level of granularity as the Reference Case. FEI does not assign probabilities to the scenarios. Rather, the six scenarios (considered together) provide a range of future demand that FEI will need to consider over the next 20 years. Please refer to Appendix B-3 for a detailed explanation of the end use demand forecast scenario parameters.

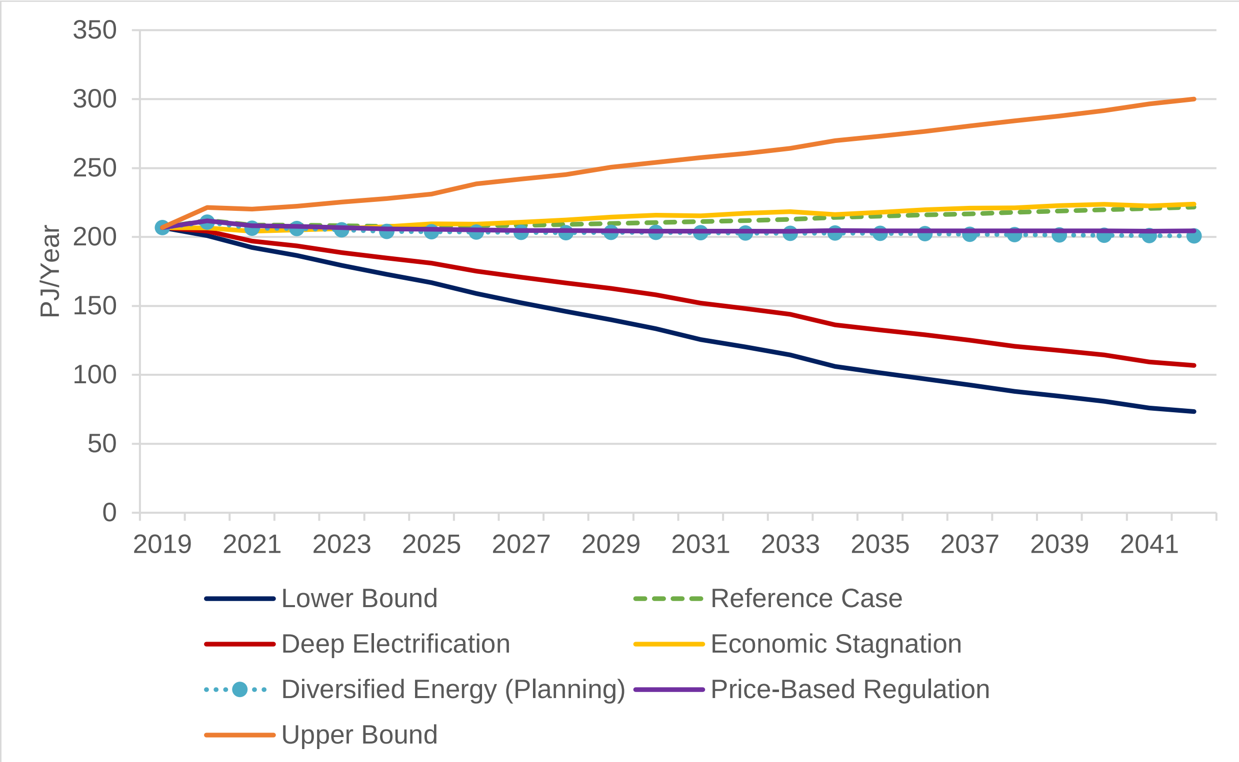
4.6 *END USE ANNUAL METHOD DEMAND FORECAST RESULTS BY SCENARIO*

This section presents the demand forecast results for each of the Residential, Commercial and Industrial, the Low-Carbon Transportation and Global LNG and the New Large Industrial Customer demand categories for all of the planning scenarios.

4.6.1 Residential, Commercial and Industrial Customer Demand Category

Figure 4-9 below displays the End Use Annual Method demand Reference Case and scenario results for the residential, commercial and industrial demand category across all regions for each of the scenarios described in Table 4-1. This figure shows that the range of annual demand forecast scenarios is sufficiently broad to ensure that FEI has examined the potential for quite different futures to unfold over the planning horizon.

Figure 4-9: Annual Demand Scenarios – Residential, Commercial and Industrial Sectors



4.6.1.1 *Lower Bound and Deep Electrification Scenarios for Residential, Commercial and Industrial Demand not Plausible*

While the Lower Bound and Deep Electrification scenarios are useful for examining a full range of possible future actions and testing the boundaries of the critical uncertainties that can change the way energy is used in the future, there are significant implications for electricity demand, particularly with regard to peak capacity requirements, system resiliency and economic implications, that cannot be reconciled for these scenarios. Both of these scenarios assume that 100 percent of residential and commercial demand for gas is switched to electricity by 2050, and that 30 percent of industrial demand is switched to electricity in the Lower Bound scenario and 20 percent in the Deep Electrification scenario over that time period.

A number of studies have shown that an electrification pathway to decarbonization is more costly and riskier than a diversified pathway, in which the existing gas infrastructure is optimized and utilized to deliver low-carbon energy to customers in combination with a strong and resilient electricity system. In Section 3.7 and Appendix A-9, FEI has presented a number of these reports, including:

- The UBC CERC report, “Clean Energy Pathways to Meet British Columbia’s Decarbonization Targets”;

- The University of Victoria's "Decarbonization of the building heating system in Metro Vancouver: comparison of two transition pathways";
- The Canadian Gas Association Report, "Implications of Policy Driven Electrification in Canada";
- The American Gas Association report, "Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience by Guidehouse";
- FortisBC's own report, "Pathways for British Columbia to Achieve its GHG Reduction Goals", also completed by Guidehouse; and
- A number of other studies from other jurisdictions in Canada and Europe.

These studies consider growth in energy demand and the challenges of meeting peak energy requirements under increasingly volatile weather extremes and recognize the benefits that both systems have for a more diverse, reliable and resilient overall energy system for the province. No credible alternative study has been brought forward for BC's energy system that fully examines the long-term implications and costs of full electrification of the province's entire energy infrastructure.

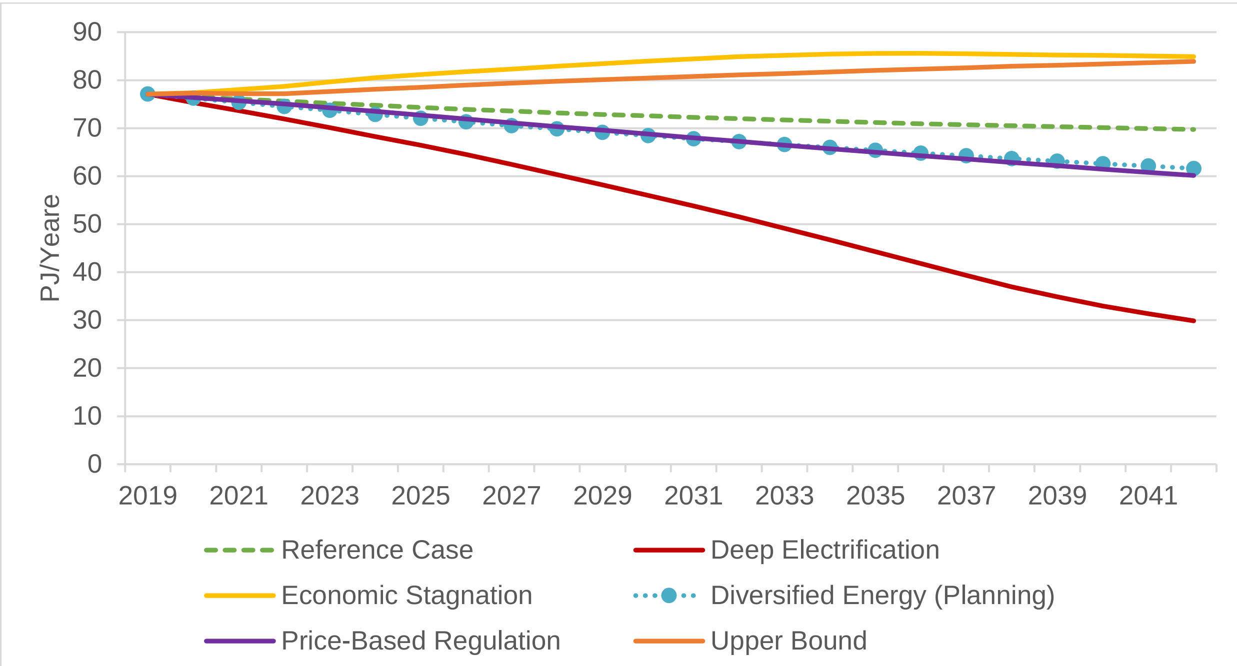
Both the Lower Bound and the Deep Electrification scenarios create technical and logistical requirements for alternative energy systems to be able to manage the scale of shifting energy resources that are not plausible, particularly to support peak energy, reliability and resiliency requirements. Since the Lower Bound scenario is a mechanical scenario that does not have a logical explanatory narrative, but simply examines what demand would look like if all settings were set to minimize demand as much as possible, it is considered untenable, and no further examination of this scenario is conducted in the 2022 LTGRP. As such, it is excluded from the remainder of this section. While the Deep Electrification scenario is also considered by FEI to be not plausible, some useful insights can be gained by examining its impact on the gas and electricity systems in BC. As such, the Deep Electrification scenario is examined through the remainder of this LTGRP to facilitate the reader's consideration of the extent of the challenge that deep electrification implies for BC's energy systems.

The majority of scenarios, including the Diversified Energy (Planning) Scenario, cluster within a narrower annual demand range since outcomes across critical uncertainties offset each other's impact on annual demand. In the Diversified Energy (Planning) Scenario, overall demand in the residential, commercial and industrial sectors declines very slightly as DSM activities and a moderate amount of electrification are largely, though not entirely, offset by new customer additions.

4.6.1.2 *End Use Annual Method Demand Forecast Results for Residential, Commercial and Industrial Customers – By Sector*

Figure 4-10 below displays the annual demand scenarios for the residential sector.

Figure 4-10: Annual Demand Scenarios – Residential Sector



Some key observations from Figure 4-10 are as follows:

- The Upper Bound and Economic Stagnation scenarios differ in their customer growth assumption only. Since new residential customers are using less gas and the difference between the high and low customer growth is modest, the difference in demand for these scenarios is not large.
- The deep electrification scenario shows a steep decline in demand for gas. As discussed in Section 4.6.1.1, the deep electrification scenario has implications for electricity supply in BC that makes such a scenario unrealistic, but is important for a full understanding of the long term implications of near term decisions on electrification.
- The remaining three scenarios are also closely aligned. The difference between the Reference Scenario and the Diversified Energy (Planning) Scenario includes a degree of electrification occurring over the planning horizon.[151]

[151] The Diversified Energy (Planning) Scenario assumes that by 2050, 25 percent of commercial and residential gas demand will be electrified.

To provide further insight into the Diversified Energy (Planning) Scenario, Figure 4-11 shows the annual demand forecast for the top three end uses in the residential sector under the Diversified Energy (Planning) Scenario.

Figure 4-11: Diversified Energy (Planning) Annual Demand – Residential Sector Top End Uses

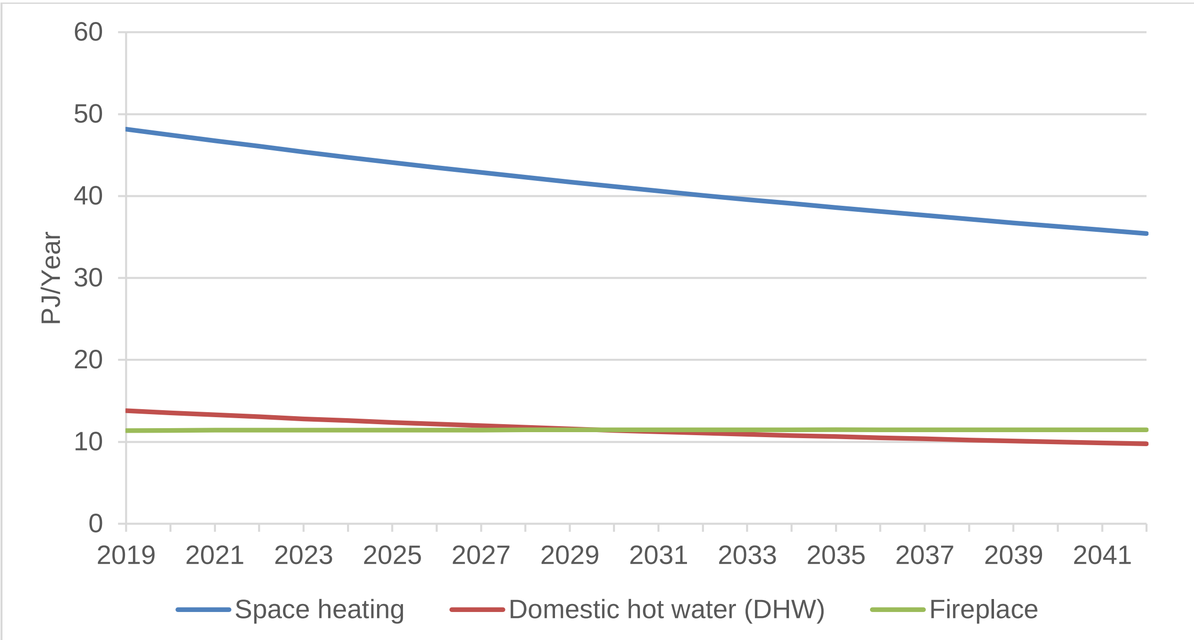
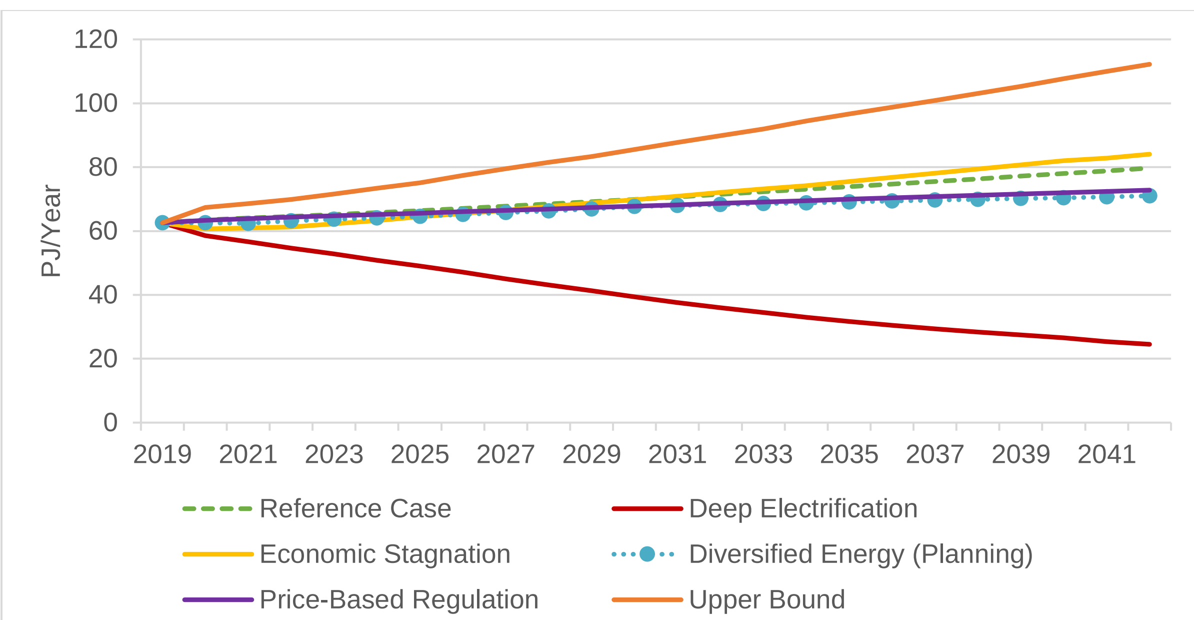


Figure 4-12 below displays the annual demand information for the commercial sector in all regions for each scenario.

Figure 4-12: Annual Demand Scenarios – Commercial Sector

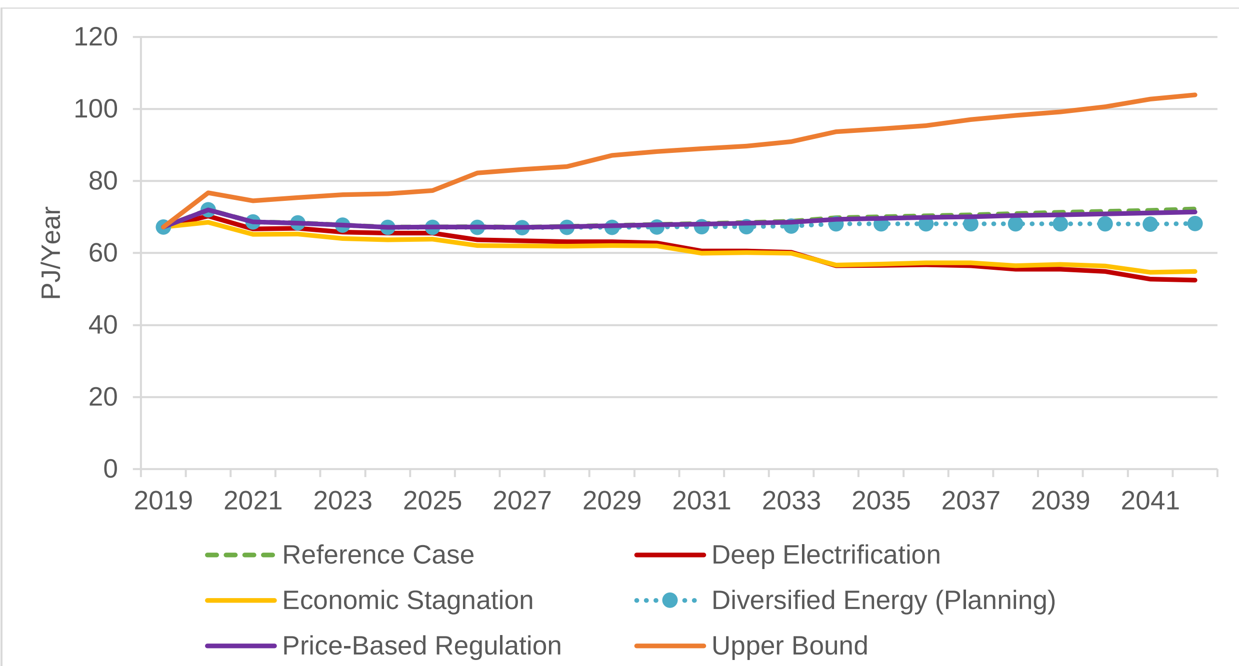


Some key observations from Figure 4-12 are as follows:

- The difference between the Upper Bound and the Economic Stagnation scenario results illustrates the impact of the differing customer growth settings on the commercial sector annual demand.
- As with residential demand, the deep electrification scenario shows a steep decline in gas demand in the commercial sector due to electrification.[152] As discussed in Section 4.6.1.1, the lack of a viable alternate energy source to take on this much demand over that time frame makes this scenario unreasonable, but important for considering near-term decision making regarding electrification to avoid future unintended consequences.
- The remaining demand scenarios are fairly narrowly clustered, with the difference between the Reference Case and Diversified Energy (Planning) Scenario again being primarily the consideration of some electrification in the Diversified Energy (Planning) Scenario and not in the Reference Case over the planning horizon[153]

Figure 4-13 below displays the annual demand scenarios for the industrial sector in all regions.

Figure 4-13: Annual Demand Scenarios – Industrial Sector



Some key observations from Figure 4-13 are as follows:

[152] Deep Electrification Scenario assumes 100 percent of gas load in the commercial sector will be electrified by 2050.
[153] In the Diversified Energy (Planning) Scenario, 25 percent of commercial load is assumed to be electrified by 2050.

- The annual demand trajectories are jagged because the customer growth critical uncertainty causes additions/removals of individual customers, and industrial customers have comparatively high annual demand.
- The Upper Bound Scenario examines the impact of high industrial customer growth and other conditions that put upward pressure on demand.
- The Deep Electrification Scenario models similar demand reductions in the industrial sector as does the Economic Stagnation Scenario. In this scenario, electrification of the industrial sector over the planning horizon is modelled to be less than that of the residential and commercial sectors as it is assumed that some industrial end uses will be too difficult to electrify in that time frame.
- The remaining scenarios are tightly clustered showing steady industrial demand throughout the planning period. The Reference Case and the Diversified Energy (Planning) Scenario are much closer than for the residential and commercial sectors since less electrification is assumed for the industrial sector in the Diversified Energy (Planning) Scenario than for residential and commercial customers due to the assumed difficulty of electrifying some industrial end uses.

4.6.2 Low-Carbon Transportation and Global LNG Demand Category

This section presents the annual demand forecasting results for CNG and LNG demand settings. In Sections 4.7 and 4.8 below, these demand setting results are mapped to the demand scenarios to arrive at the forecast of total demand for each scenario as shown in the tables below.

Table 4-2: Mapping CNG/LNG Demand Forecast Settings to the 2022 LTGRP Annual Demand Scenarios – Transportation Fuel

CNG / LNG Demand Forecast Setting	2022 LTGRP Annual Demand Scenario
Reference	Reference Case
Low	Lower Bound, Deep Electrification, Economic Stagnation
Planning	Diversified Energy (Planning)
High	Upper Bound, Priced-Base Regulation

Table 4-3: Mapping Global LNG Demand Forecast Settings to the 2022 LTGRP Annual Demand Scenarios

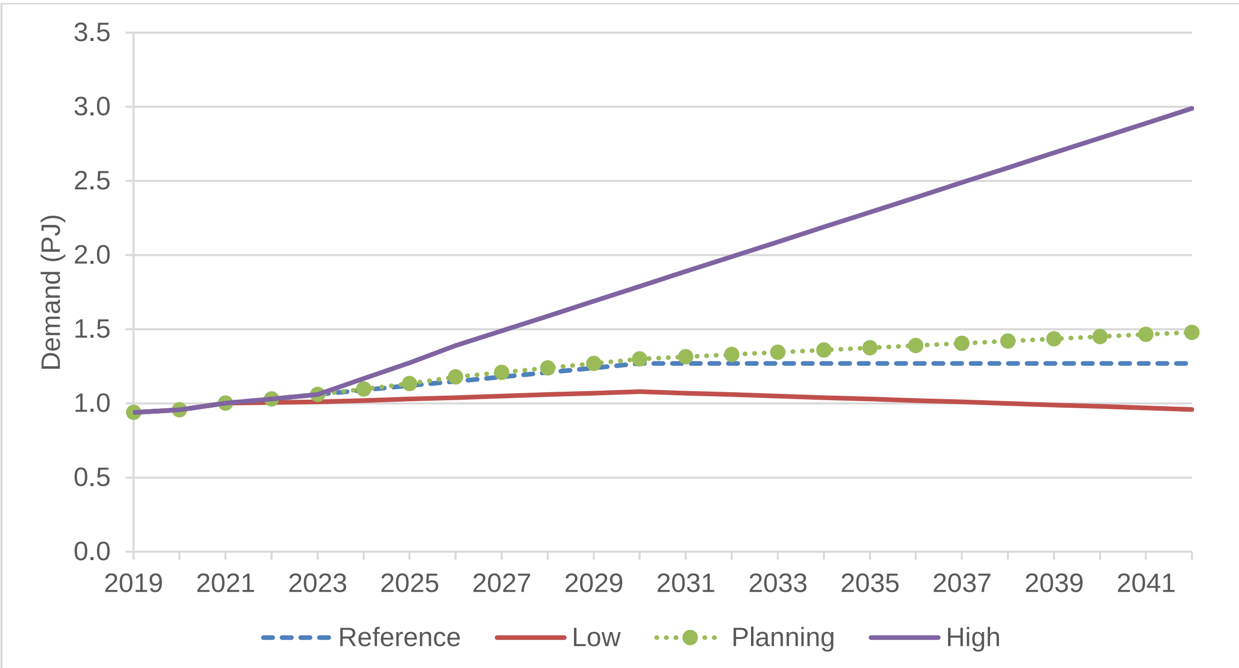
Global LNG Demand Forecast Setting	LTGRP Annual Demand Scenario
Reference	Reference Case, Price-Based Regulation, Economic Stagnation, Lower Bound
Planning	Diversified Energy (Planning), Deep Electrification
High	Upper Bound

Note: Because in the Reference Setting Global LNG Demand drops to zero, there is no "Low" setting.

4.6.2.1 *CNG Annual Demand Forecast Results*

Figure 4-14 displays a forecast of CNG demand on FEI's system over the planning period (2020 to 2042) for the four CNG demand settings.

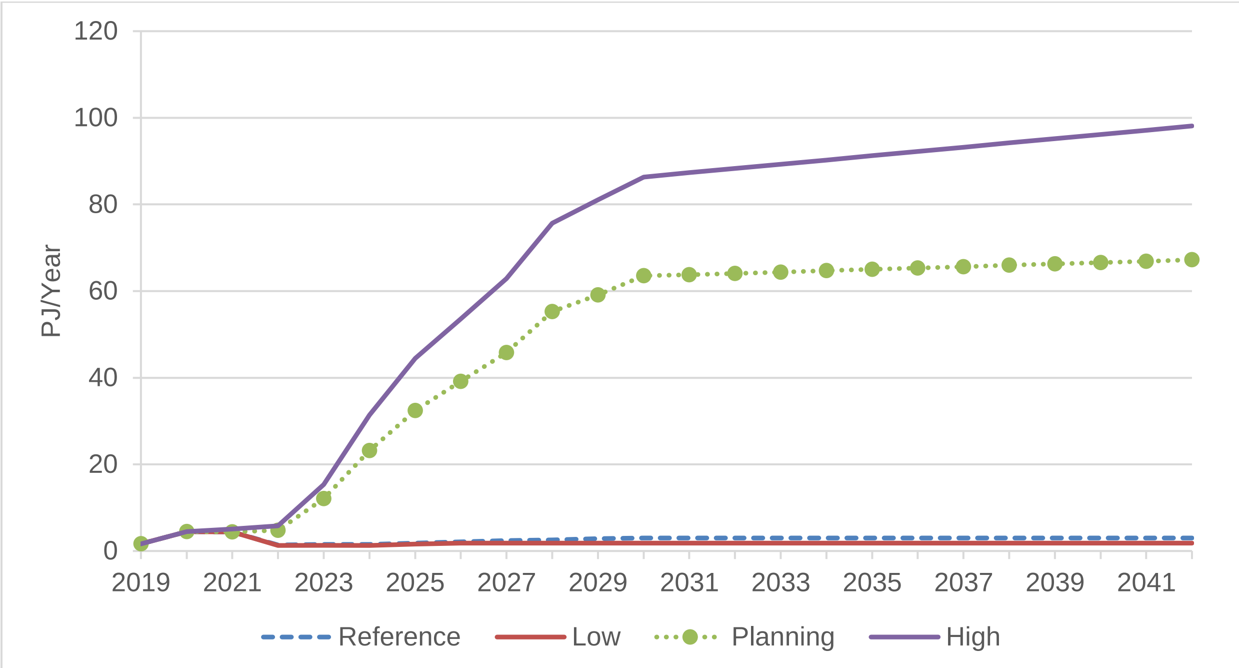
Figure 4-14: Annual Demand Forecast for the CNG Demand Settings (2020-2042)



4.6.2.2 *LNG Annual Demand Forecast Results*

Figure 4-15 below provides an illustration of the four LNG annual demand settings over the forecast period.

Figure 4-15: Annual Demand Forecast for LNG Demand Settings (2020-2042)



4.6.2.3 *Combined CNG and LNG Demand Forecast*

Figure 4-16 below illustrates the combined conventional natural gas demand forecasts by setting for both CNG and LNG, as described in the sections above. FEI combines forecast annual demand from CNG and LNG since FEI considers cumulative annual demand of FEI's customers and initiatives in its long term planning. While each fuel type has its own merit in the local and international markets, LNG accounts for a larger portion of forecast LCT annual demand than CNG and thus shapes the appearance of the combined annual demand graph.

Figure 4-16: Annual Demand Forecast for the Low-Carbon Transportation and Global LNG Demand Categories in Total (2020-2042)

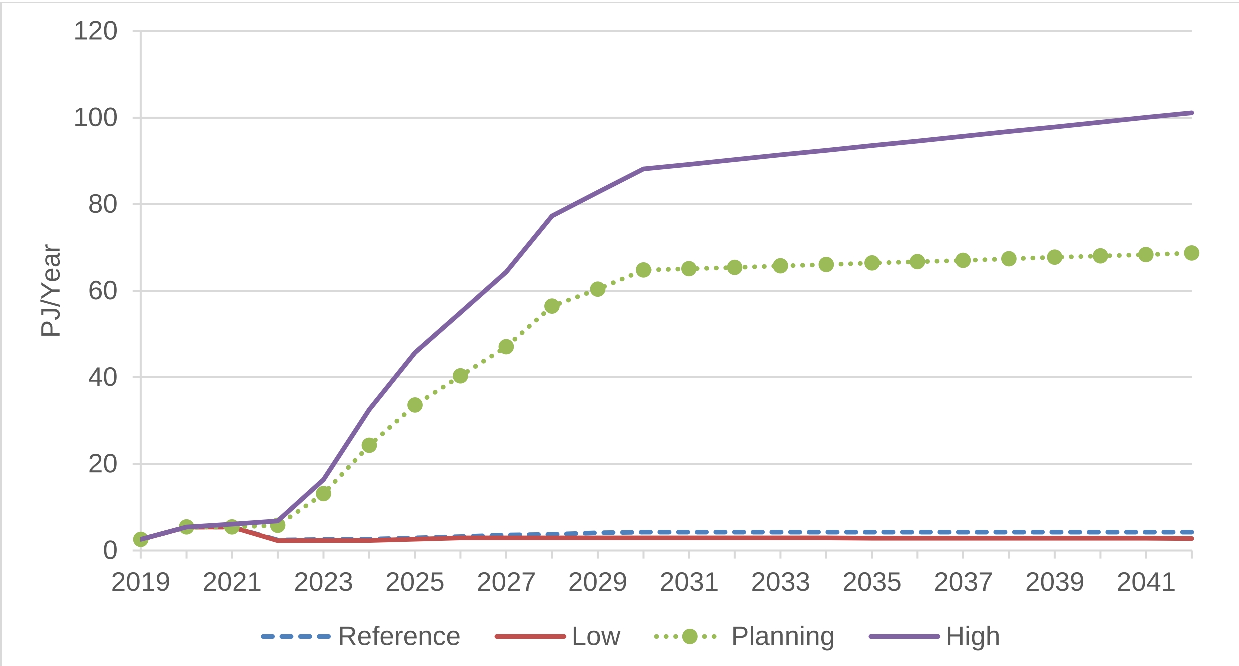
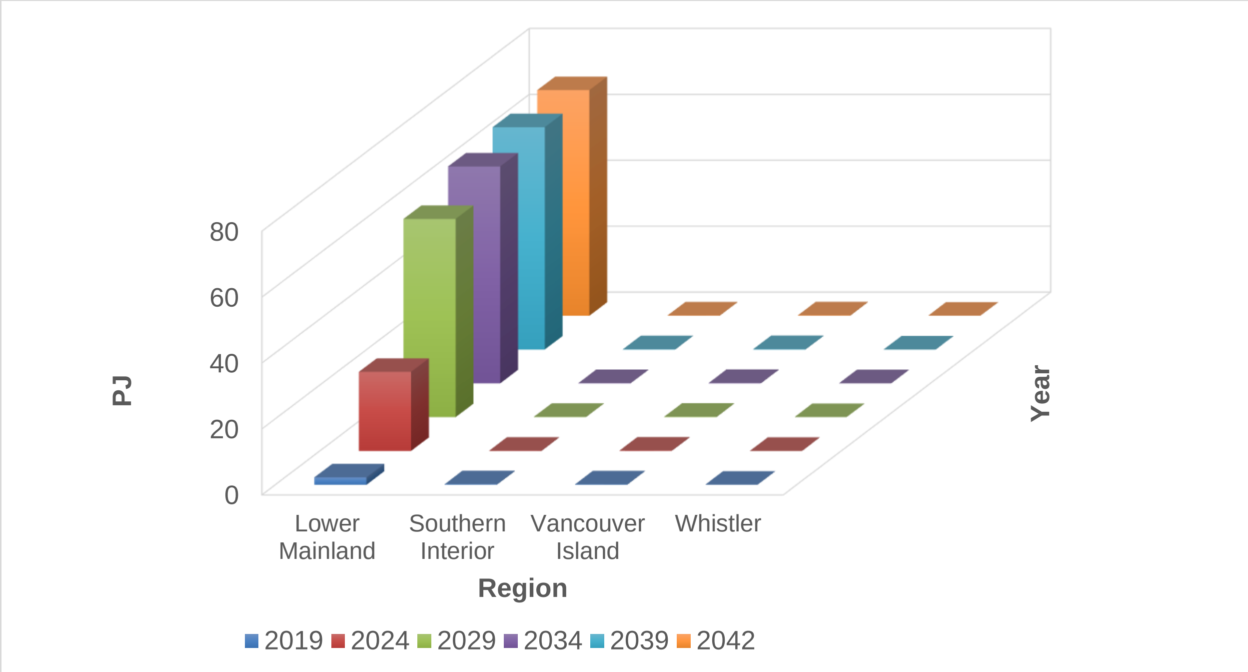


Figure 4-17 below provides a regional look at the Low-Carbon Transportation and Global LNG Demand Category for the Planning setting, which is applied to the Diversified Energy (Planning) Scenario. This graph depicts the effect of adding LCT load to the distribution system and illustrates how the majority of LCT load is expected to come onto the system in the Lower Mainland since this is where the LNG is produced and since the largest portion of LNG demand is for the marine sector. Though not shown, this locational effect is seen across the scenarios that include substantial demand growth in this category.

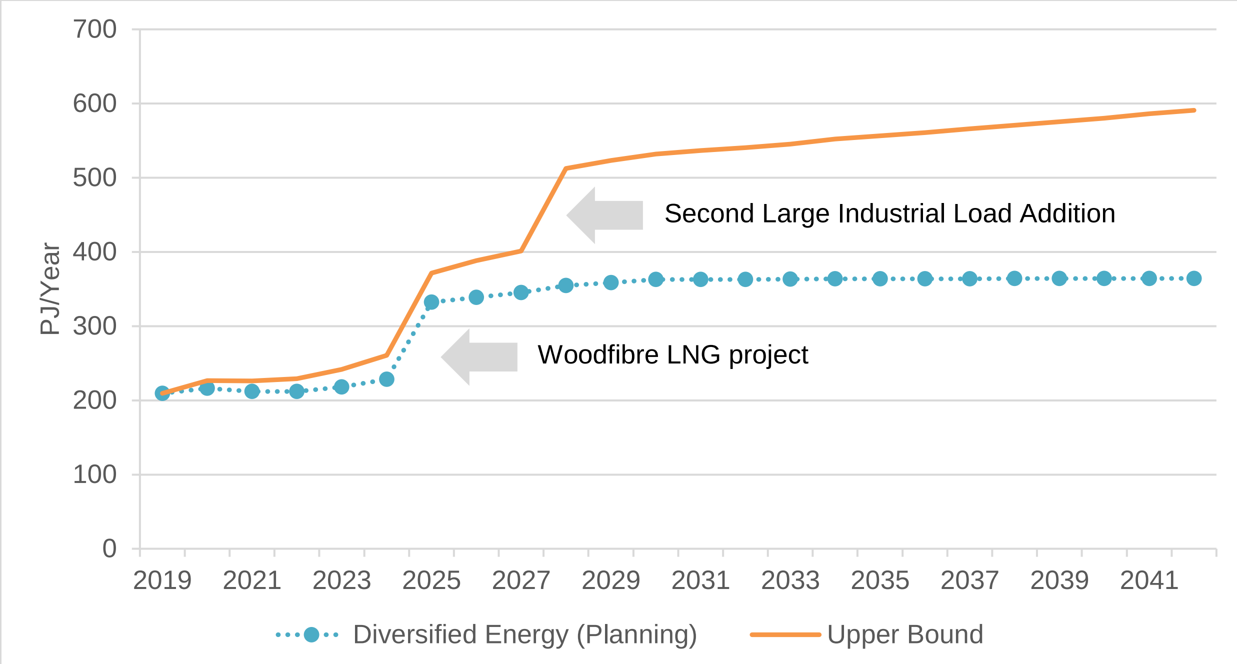
Figure 4-17: LCT and Global LNG Annual Demand Forecast for CNG and LNG Planning Setting– by Region in Select Milestone Years



4.6.3 New Large Industrial Demand Category

As discussed in Section 4.3.3, the addition of each of the two new large industrial loads would cause a large step change in demand in the scenarios in which they are applied. This effect is illustrated in Figure 4-18 which shows the total annual demand results for the Diversified Energy (Planning) and the Upper Bound Scenarios. FEI included only the Woodfibre LNG project in the Diversified Energy (Planning) Scenario, whereas FEI included both the Woodfibre LNG project and the second new large industrial facility (somewhat later) in the Upper Bound scenario. The total demand for all scenarios is presented in Section 4.8.

Figure 4-18: Total Annual Demand for the Diversified Energy (Planning) and Upper Bound Scenarios illustrating the inclusion of the New Large Industrial demand

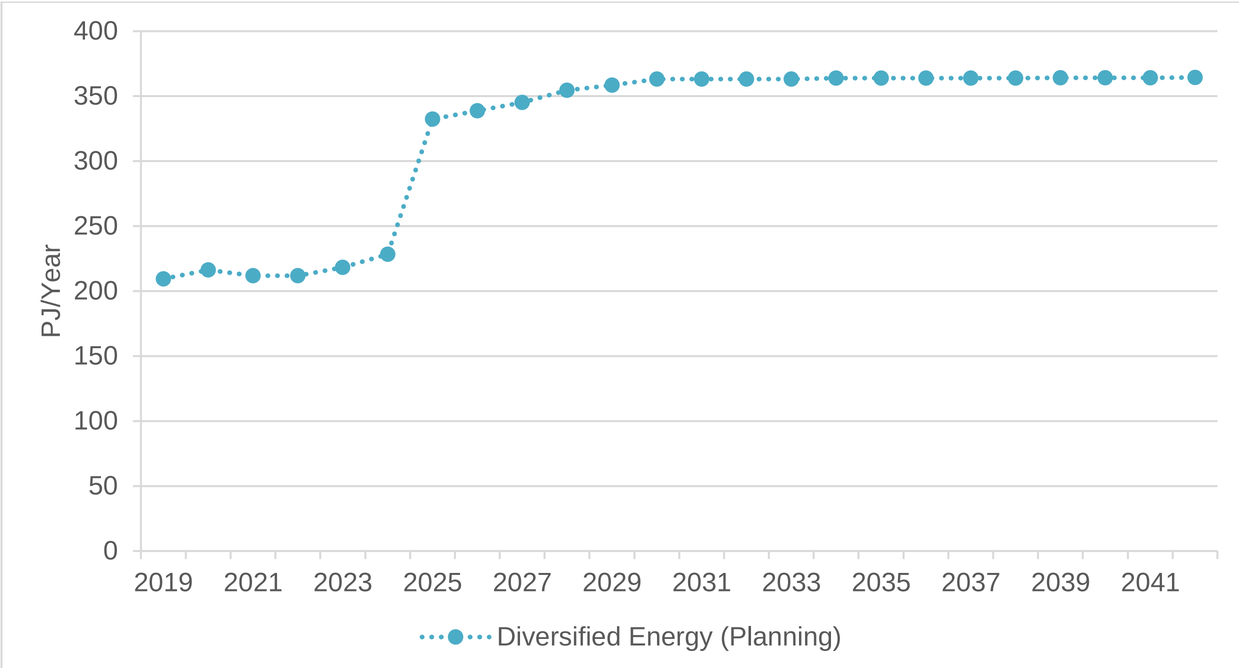


4.7 TOTAL ANNUAL DEMAND – DIVERSIFIED ENERGY (PLANNING) SCENARIO

FEI's expectation of future annual energy demand for planning purposes is represented by the outputs of the Diversified Energy (Planning) Scenario analysis illustrated in Figure 4-19 below. This planning scenario includes some electrification of gas demand captured historically by FEI in the residential, commercial and industrial sectors, though FEI continues to add customers in these sectors through the planning horizon. Observed growth in annual demand in the first half of the planning horizon is driven by load growth in the transportation sector and LNG export market, primarily with the large load step increase when the Woodfibre LNG project is modelled to begin operation in 2025[154]. Emission reductions in this scenario will result to some extent from DSM activity which is discussed in Section 5, from displacing higher carbon fuels for transportation discussed earlier in Section 4 and from FEI's transition to renewable and low-carbon gas supplies as discussed in Section 6, all of which are a part of FortisBC's Clean Growth Pathway.

[154] After the demand forecast modelling was completed, Woodfibre LNG issued a notice to proceed. Based on that notice, FEI now expects demand from Woodfibre LNG project to begin in 2027.

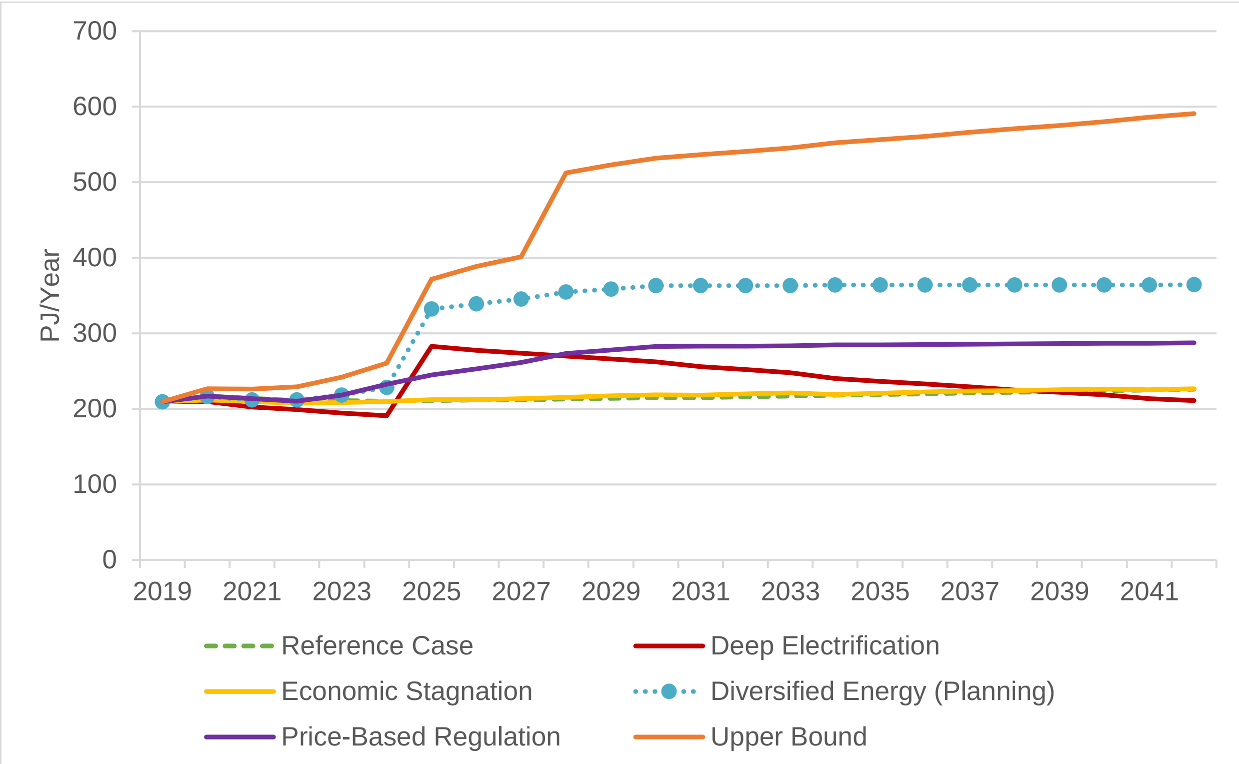
Figure 4-19: Total Annual Demand Including LCT – Diversified Energy (Planning) Scenario



4.8 *TOTAL ANNUAL DEMAND – ALL SCENARIOS*

FEI serves a growing demand for energy from residential, commercial, industrial, CNG and LNG customers. This includes demand growth in a relatively new sector to FEI, the marine transport sector, where fuel switching from higher carbon fuels to LNG will reduce global GHG emissions. FEI's demand scenarios have considered the potential for LNG export to serve carbon reduction efforts in other parts of the globe and have also considered the potential for adding new large industrial loads that can result in substantial step change increases in annual demand. The full range of demand forecast scenarios examined in developing this LTGRP is presented in Figure 4-20. Appendices B-4 and B-5, respectively, present summary tables and a working MS Excel data file of the End Use Annual Method annual demand results.

Figure 4-20: Total Annual Demand Including LCT – All Categories, All Scenarios



Consideration for electrification in the residential, commercial and industrial sectors has been considered in both the Diversified Energy (Planning) Scenario, which models the demand trajectory that reaches 25 percent electrification of residential and commercial demand and 10 percent of industrial demand by 2050, and the Deep Electrification scenario, which models the demand trajectory that reaches 100 percent electrification of the commercial and residential sectors and 20 percent of industrial demand by 2050. The Lower Bound and Deep Electrification scenarios are found to have electrification assumptions that are not plausible in that no credible fuel switching alternative has been presented that can address the peak demand requirements of this much energy demand. Both of these scenarios are shown in Figure 4-20 for completeness. However, the Lower Bound scenario is not explored further in this LTGRP and the Deep Electrification scenario is presented to facilitate the reader's consideration of the extent of the challenge that deep electrification implies for BC's energy systems.

FEI's Upper Bound scenario models all critical uncertainties set to increasing gas demand, including the highest setting for potential CNG and LNG demand growth as well as both the Woodfibre LNG project and a second generic industrial facility of similar annual demand to that of Woodfibre LNG project. These two industrial load additions cause the large step-change demand increases that can be seen in Figures 4-18 and 4-20. FEI has not assumed that it would need to acquire gas supplies to serve these industries, but uses the results of Upper Bound scenario to understand the implications of these types of demand increases and thus to monitor for indications that these types of demand increases might be unfolding. In this way, the Upper Bound scenario provides important information for consideration in planning FEI's infrastructure.

The Reference Case demand forecast models only those trends and known changes in conditions in the near term for all sectors that were in place at the time the scenario modelling began. Since it does not consider the future changes that are required to transition to lower carbon gas supplies and meet GHG reduction targets, it is no longer considered FEI's planning scenario. It is useful, however, in providing a reference point in considering a different future outcome in terms of energy demand and emissions reductions.

The broad range of demand between the alternate scenarios is dramatic, and representative of substantial change and uncertainty in the energy planning environment as discussed in Section 2. Even the range between the more moderate scenarios, Diversified Energy (Planning), Priced-Based Regulation and Economic Stagnation, is quite large at approximately 140 PJ in 2042.

The Diversified Energy (Planning) Scenario represents FEI's expectation of the way in which future demand will unfold, before DSM activities, when considering the actions that FEI is planning to take to transition to a deep decarbonization of the gas it delivers to customers. This scenario includes increased demand from sectors where conventional natural, renewable and low-carbon gases will reduce GHG emissions within BC and globally, as well as expected demand from the Woodfibre LNG project. The remainder of the 2022 LTGRP focuses on the Diversified Energy (Planning) Scenario as FEI's planning scenario.

4.9 *CONCLUSION*

FEI has provided an estimate of the annual demand for gas that it expects to serve over the 20-year planning horizon before considering the impact of new, incremental DSM activities, as required under Section 44.1(2)(a) of the UCA. This estimate is presented in Figures 4-19 and in 4-20 as a potential range of future demand that can reasonably be expected to occur under differing potential future conditions impacting residential, commercial and industrial customers, as well as customers using conventional natural gas as a transportation fuel and gas delivered on FEI's system for export to other global markets.

Since the likelihood of accurately predicting actual future conditions is low, probabilities are not assigned to the different scenario outcomes. Rather, FEI identifies and implements a set of cost-effective resources to meet the planning scenario and establishes contingency plans for meeting the scenario range of potential future annual demand.

Sections 6 and 7 of this LTGRP discuss the gas supply and physical infrastructure resources FEI requires to meet this range of demand (after DSM), including the timing of peak capacity requirements under higher or lower demand growth. These sections also discuss the implications of FEI's transition to renewable and low-carbon gas for FEI's gas supply and infrastructure planning. FEI discusses the influence of the 2022 LTGRP annual demand and supply scenarios on customer rates in Section 9.4.

FortisBC Energy Inc.
2022 LTGRP

Section 5:

DEMAND-SIDE RESOURCES

Table of Contents

5. DEMAND-SIDE RESOURCES

5.1 *INTRODUCTION*

This section describes how FEI's adequate and cost-effective portfolio of DSM activities can result in significant energy and GHG emissions reductions over the planning horizon under the range of future scenarios examined for the LTGRP. As a pillar of FEI's Clean Growth Pathway, FEI anticipates expanding its existing DSM activities over the planning horizon to reduce GHG emissions to meet provincial GHG reduction targets. In particular, FEI's future DSM expenditure plans that will be filed with the BCUC for acceptance will be guided by the High DSM Setting analysed in this LTGRP. Under the Diversified Energy (Planning) Scenario with the High DSM Setting, FEI's savings from DSM activities are forecast to be significant, at approximately 25 PJ or 13 percent of annual load in 2042.

As directed in Order G-39-19, FEI's DSM funding scenarios reflect the results of the most recent CPR (Appendix C-1), with incentive level, economic screen and budget settings applied to individual scenarios as described in Table 5-3. The Diversified Energy (Planning) Scenario (DEP) is now the equivalent to the "reference" scenario referred to in the directive, and was used as the basis for a sensitivity analysis demonstrating the effects of the Low, Medium and High DSM settings on DSM expenditures, energy savings and cost-effectiveness tests. These cost-effectiveness tests include Total Resource Cost (TRC), Modified Total Resource Cost (MTRC) and Utility Cost Test (UCT) results expressed as a ratio and the Cost of Conserved Energy (CCE) expressed as $/GJ. FEI also provides a directional view of delivery rate and bill impacts for residential customers under the Low, Medium and High DSM Settings on the Diversified Energy (Planning) Scenario.

In order to more clearly demonstrate the impacts of DSM energy savings on total demand, FEI has selected the Diversified Energy (Planning) Scenario and the Reference Case for comparative purposes throughout this section. The impact of the DSM analysis on all scenarios is presented in Appendix C-2.

Table 5-1: Overview of Reference Case and Alternate Future Scenarios in DSM Analysis and Where Addressed in the LTGRP

Scenario	DSM Setting	Section Where Addressed
Reference Case	Medium	Section 5.4 and Appendix C-2
Diversified Energy (Planning)	High (sensitivity analysis conducted with Low and Medium settings)	Section 5.4 and Appendix C-2
Deep Electrification	Taper Off	Appendix C-2
Price-Based Regulation	Medium UCT	Appendix C-2
Economic Stagnation	Medium	Appendix C-2
Upper Bound	N/A – no DSM	Appendix C-2

As FEI does not construct its own energy generation resources, FEI's DSM analysis does not weigh the cost of DSM against the need for procuring or constructing upstream energy generation resources to meet demand growth. Instead, FEI's DSM analysis primarily seeks to establish an adequate and cost-effective level of DSM activity and explore the extent to which the peak demand implications of such DSM activity may defer FEI's requirements for downstream infrastructure. To the extent that decarbonization initiatives lead FEI to produce renewable and low-carbon gas, such as for RNG and hydrogen, the benefits of DSM activities in reducing the need for additional upstream energy generation may be considered in upcoming LTGRP filings.

In prior LTGRP submissions and in more traditional DSM modelling approaches, the savings of each additional unit of energy saved would be treated equally. However, in this LTGRP, where FEI is transitioning to renewable and low-carbon gas, the software model was designed to prioritize reducing conventional natural gas. Although the ability to apply DSM savings equally to all fuel types is discussed in the 2022 LTGRP, the analysis could not be completed in time for the 2022 LTGRP submission date since such analysis will require reconfiguring the software. The decision was made early in the LTGRP planning process, that the priority for DSM in this model was to focus on energy savings to reduce GHG emissions. As an artifact of the logic in these models, the analysis may show curtailed DSM expenditures after 2030 as the proportion of renewable and low-carbon gas increases and natural gas declines. This is not demonstrated in the Reference Case due to the higher proportion of natural gas. FEI will assess updating the model for the next LTGRP, which will result in DSM savings being applied proportionally to all fuel types including renewable and low-carbon gas, so that savings will not be curtailed as the conventional gas share decreases.[155]

Section 5 is organized as follows:

- Section 5.2 describes how FEI has a cost-effective, adequate DSM portfolio.
- Section 5.3 describes the DSM analysis methodology used to develop DSM savings potential for the scenarios presented in Section 4.
- Section 5.4 provides the results of the DSM analysis for select scenarios, including:
    - a sensitivity analysis of the effects of the Low, Medium and High DSM Settings on the Diversified Energy (Planning) Scenario in terms of energy savings, expenditures, and CCE (5.4.1).
    - a directional view of delivery rate and bill impacts for residential customers under the Low, Medium and High DSM Settings on the Diversified Energy (Planning) Scenario (5.4.2).
    - the forecast long term demand after DSM savings for all sectors combined with comparisons for the Diversified Energy (Planning) Scenario – High and Medium DSM Settings, Reference Case, and Upper Bound excluding LCT (5.4.3).

[155] RPAG members were in general agreement that DSM savings could be applied proportionally to all fuel types in a future model, recognizing the value in saving an additional unit of energy whether it be natural, renewable or low-carbon gas.

  - the forecast total annual demand and the effects of projected DSM activity in reducing demand for all sectors combined (5.4.4).
  - forecast DSM expenditures for all sectors combined for the Diversified Energy (Planning) Scenario – High and Medium DSM Settings, Reference Case and Upper Bound (5.4.5).
  - cost-effectiveness test results for all sectors combined for the Diversified Energy (Planning) Scenario – High and Medium DSM Settings, Reference Case and Upper Bound for all sectors combined (5.4.6).
  - the energy savings market potential to 2030 for the top ten measures and the extent to which these measures contribute to a large proportion of total energy savings for the Diversified Energy (Planning) Scenario – High DSM Setting in comparison with the Reference Case (5.4.7).
- Section 5.5 discusses the approach FEI has taken to better understand the long-term implications of FEI's projected DSM activities on peak demand.
- Section 5.6 provides the long-term plan for implementing DSM programs.
- Section 5.7 provides the conclusion and recommended actions for the section.

5.2 FEI PLANS TO CONTINUE WITH AN ADEQUATE, COST-EFFECTIVE DSM PORTFOLIO

FEI's DSM activities consist of a portfolio of efficiency and conservation programs and activities and represents an important pillar in the Clean Growth Pathway. While supporting government energy and emissions reduction objectives, DSM activities also drive market transformation to a higher efficiency and decarbonized built environment through equipment advances, deep retrofits and innovative technologies such as gas heat pumps. Energy efficiency programs also support decarbonization in the commercial and industrial sectors by focusing on facility and process improvements. FEI's DSM activities have other customer and societal benefits, such as reducing water consumption, enhancing human health and comfort, creating jobs, and encouraging a culture of conservation throughout BC.

Over the 2022 LTGRP planning horizon, FEI's specific program offers will likely evolve to suit the evolving marketplace, legislative provisions outlined in the Roadmap, other future policy and legislative updates and FEI customer needs. In accordance with the UCA, FEI will continue to bring forward adequate, cost-effective DSM portfolios for acceptance by the BCUC.

In the subsection below, FEI provides an overview of the Program Areas that comprise its DSM portfolio and how it meets the adequacy requirements of the DSM Regulation.

5.2.1 FEI's DSM Portfolio Investment is a Key Pillar in the Clean Growth Pathway

The BCUC accepted FEI's existing DSM portfolio[156] in its decision on FEI's 2019-2022 DSM Expenditures Plan, finding that the DSM portfolio was cost-effective and in the public interest.[157] FEI's DSM portfolio assists customers in using FEI's products as efficiently as possible, contributing both to affordability and emissions reduction. The DSM current program offerings address all customer segments as outlined below.

5.2.1.1 *Residential Program Area*

Residential programs are available to over 954,000[158] customers in the FEI service territories. For DSM purposes, these customers predominantly include those living in single-family homes, row houses, townhomes or mobile homes.[159] Some in-suite measures in multi-unit residential buildings are also included in this program area. Residential programs encompass retrofit and new home applications, enabling FEI customers to reduce their energy consumption and support the building industry in improving overall home performance. The combination of rebates, policy support, customer and trades engagement offered through FEI programs is instrumental in driving a culture of conservation and fostering market transformation in the residential sector.

5.2.1.2 *Low Income Program Area*

FEI's Low Income Program Area serves individual Low Income[160] customers, Indigenous housing, co-operative housing, non-profit housing, and charities that aid Low Income customers. Low Income programs will continue to be a critical part of FEI's portfolio as these customers are anticipated to be the hardest hit by rate impacts of the clean energy transition for both gas and electrically heated homes. Affordability is a key issue that needs to be addressed for all communities in BC.

In the LTGRP scenarios, Low Income customers are modelled within the residential category, as these customers are not differentiated in FEI's customer database. FEI estimates that about 20 percent of its residential customers would be eligible for Low Income programs. According to Statistics Canada's 2016 Census data,[161] 14 to 15 percent of British Columbians are considered low income, based on Low Income cut-offs (LICO) before tax. The DSM Regulation uses LICO

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156 BCUC Proceeding, FEI 2019-2022 Demand-side Management Expenditures Plan~ Project No.1598964, online at: https://www.bcuc.com/OurWork/ViewProceeding?applicationid=635.

157 BCUC Decision and Order Number G-10-19, Application for Acceptance of 2019-2022 Demand-side Management Expenditures Plan (January 17, 2019), online at: https://docs.bcuc.com/Documents/Proceedings/2019/DOC_53240_G-10-19-FEI-2019-2022-DSM-Plan-Reasons.pdf.

158 BCUC Decision and Order G-319-20, FEI Annual Review for 2020 and 2021 Delivery Rates (December 8, 2020), online at: https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/489787/1/document.do.

159 Programs for Multifamily Dwellings served under Rate Schedule 2 or 3 are included in the commercial DSM program area.

160 As defined in DSM Regulation.

161 Appendix F-2: Low-Income Status Data tables (2016 Census), online at: statcan.gc.ca.

multiplied by a factor of 1.3 to determine low income thresholds. This suggests that, under the definition set out in the DSM Regulation, FEI's 20 percent estimate is reasonable.

5.2.1.3 *Commercial Program Area*

FEI's Commercial Program Area encourages commercial customers to reduce their overall consumption of natural gas and associated energy costs. These programs enable commercial and institutional customers to conduct both simple and comprehensive energy efficiency upgrades at their buildings. The combination of financial incentives, consultant and contractor outreach, and effective marketing in these programs is instrumental to the ongoing success of these programs in generating natural gas savings and fostering market transformation in the commercial sector.

5.2.1.4 *Industrial Program Area*

FEI's Industrial Program Area offers a number of industrial programs that encourage industrial customers to reduce their overall consumption of natural gas and associated energy costs. Industrial initiatives can be large projects with significant energy savings that span multiple years. These programs have been successful in the manufacturing, agricultural, mining and other sectors, which use large amounts of natural gas and therefore provide substantial energy savings opportunities.

5.2.1.5 *Innovative Technologies Program Area*

FEI's Innovative Technologies Program Area identifies pre-commercial and market-ready technologies that are not yet widely adopted in BC, and which are suitable for development or inclusion in the portfolio of ongoing DSM programs in other program areas. This is accomplished through pilot and demonstration projects, pre-feasibility studies and the use of industry standard evaluation, measurement and verification protocols to validate manufacturers' claims related to equipment and system performance. A number of key areas of growth for FEI's DSM portfolio have been under development in this program area. These include:

- Advancing the commercialization of gas heat pumps whereby the technologies can achieve system efficiencies of greater than 100 percent. FEI was recognized for its leadership in the evaluation and advancement of gas heat pumps across the Pacific Northwest and was the recipient of the Northwest Energy Efficiency Alliance's 2021 Leadership in Energy Efficiency Award for Innovation.
- Investigating energy consumption and technological considerations for dual fuel heating systems (hybrids) in which the gas system provides back-up to an electric system.
- Advancing FEI's understanding and implementation of Deep Energy Retrofits as the key growth area of the DSM portfolio for both Part 3 Commercial and Part 9 residential buildings.

5.2.1.6 *Conservation Education and Outreach and Enabling Activities*

FEI's conservation education and outreach initiatives continue to support DSM portfolio goals by fostering energy literacy and a culture of conservation among FEI's residential, low income, Indigenous, new Canadian, and commercial customers and educational institutions. Initiatives include programs to support behaviour change, including the My Energy Use portal through customers' online service accounts and home energy reports. FEI also continues to support training seminars and educational workshops in collaboration with such organizations as the Greater Vancouver Home Builders Association and other industry associations.

DSM-enabling activities focus on trade alliances for program support and quality installation, trades and builders' associations, building science research, advancing building codes and appliance standards, maintaining FEI's DSM tracking system, and funding to support post-secondary energy management programs.

FEI continues to focus on education, energy literacy, behavioural change and industry training to foster a culture of conservation in BC while driving program awareness and participation. These enabling and portfolio-level activities are not listed in Section 5.4.5 DSM incentives program expenditures schedules as they only report on programs with energy savings. In the past, these expenditures represented a range of about 18 to 30 percent of annual DSM portfolio expenditures.

5.2.2 DSM Portfolio Meets Adequacy Requirement of DSM Regulation

In BC, the implementation of demand-side measures is governed by the UCA, the DSM Regulation, and by the definition of "demand-side measure" found in section 1(1) of the CEA, which is as follows:

> A rate, measure, action or program undertaken (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand . . . but does not include (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or (e) any rate, measure, action or program prescribed.

All of FEI's DSM activities meet the definition of "demand-side measures" in the CEA and help customers reduce their natural gas consumption, thereby reducing GHG emissions.

The DSM Regulation defines what demand-side measures must be included in a public utility's plan portfolio to be "adequate" within the meaning of section 44.1(8)(c) of the UCA. The table below lists the adequacy requirements of section 3(1) of the DSM Regulation and how FEI's DSM portfolio meets those requirements.

Table 5-2: Adequacy Requirements of the DSM Regulation

Section of the DSM Regulation	Adequacy Requirement	How FEI's DSM portfolio addresses adequacy
3 (a)	A demand-side measure intended specifically (i) to assist residents of low income households to reduce their energy consumption, or (ii) to reduce energy consumption in housing owned or operated by (A) a housing provider that is a local government, a society as defined in section 1 of the *Societies Act*, other than a member-funded society as defined in section 190 of that Act, or an association as defined in section 1 (1) of the *Cooperative Association Act*, or (B) the governing body of a first nation, if the benefits of the reduction primarily accrue to (C) the low income households occupying the housing, (D) a housing provider referred to in clause (A), or (E) a governing body referred to in clause (B) if the households in the governing body's housing are primarily low income households;	Low Income Program Area: serves individual Low Income customers, Indigenous housing, co-operative housing, non-profit housing, and charities that aid Low Income customers.
3(b)	If the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;	Rental Apartment Efficiency Program: incentives and energy saving support for rental apartment buildings targeted for landlords, property managers, and in-suite upgrades for tenants in participating buildings.
3(c)	An education program for students enrolled in schools in the public utility's service area;	FEI's Conservation, Education and Outreach Program Area: FEI's School Education Program supports school initiatives across FEI's service area.
3(d)	If the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area;	FEI's Conservation, Education and Outreach Program Area: FEI's School Education Program supports initiatives for post-secondary institutions across FEI's service area.

Section of the DSM Regulation	Adequacy Requirement	How FEI's DSM portfolio addresses adequacy
3(e)	One or more demand-side measures to provide resources as set out in paragraph (e) of the definition of "specified demand-side measure", representing no less than (i) An average of 1% of the public utility's plan portfolio's expenditures per year over the portfolio's period of expenditures, or (ii) An average of $2 million per year over the portfolio's period of expenditures;	FEI's Enabling Activities Program Area: provides funding and support for developing codes and performance standards at the municipal, provincial and national level for energy efficient products and codes. FEI provides resources for and collaborates with other partners and municipalities on implementation and adoption of codes and standards and adoption of the BC Energy Step Code.[162]
3(f)	One or more demand-side measures intended to result in the adoption by local governments and first nations of a step code or more stringent requirements within a step code.	FEI's New Home and Commercial New Construction Program: provides tiered incentives for BC Energy Step Code including a customized offer for Indigenous groups.

5.2.3 Summary

FEI's DSM activities are a key pillar of FEI's Clean Growth Pathway. As described in Section 3.4 FEI, through increased investments in DSM, will be expanding the Company's low- and zero-carbon solutions in buildings and commercial and industrial processes. FEI is focused on this key objective through activities managed by FEI's Conservation and Energy Management group and supporting teams throughout the organization. Over the planning horizon, FEI will maintain an adequate, cost-effective portfolio of DSM activities that will continue to contribute to energy savings, GHG emission reductions and a culture of conservation in British Columbia.

5.3 DSM POTENTIAL SAVINGS ARE ESTIMATED FOR EACH ALTERNATE FUTURE SCENARIO

5.3.1 Introduction

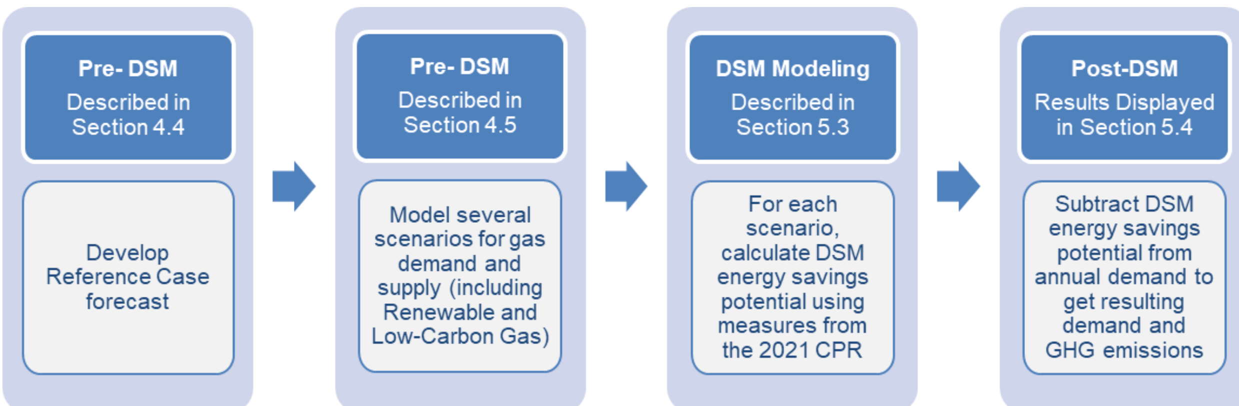
This section describes the 2022 LTGRP's DSM analysis used to develop energy savings forecasts from DSM activity for the scenarios set out in Table 5-1 above. As discussed in Section 4, the Reference Case forecast assumes that conditions that are present and legally enshrined in the planning environment when the demand forecasting exercise was undertaken prevail throughout the planning horizon. The Diversified Energy (Planning) Scenario represents FEI's planning scenario. The other scenarios (Deep Electrification, Price-Based Regulation, Economic Stagnation and Upper Bound) present a wide range of alternate futures for consideration in the

[162] BC Energy Step Code is an optional compliance path in the BC Building Code that local governments may use to incentivize or require a level of energy efficiency in new construction that goes beyond the BC Building Code requirements.

resource planning process. The impact of the DSM analysis on all scenarios is presented in Appendix C-2.

- Figure 5-1 illustrates how the modelling process used to develop DSM potential savings for each of the scenarios follows after the development of the demand forecast described in Section 4, and results in a post-DSM forecast of annual demand. DSM energy savings potential is estimated only for the built environment (residential, commercial and industrial sectors), as DSM programs do not apply to the LCT and Global LNG or New Large Industrial demand categories.

Figure 5-1: Overview of LTGRP DSM Modelling Process Conducted for Each Scenario



The modelling of the DSM impact for the Reference Case and each of the five scenarios was carried out in three key steps:

- The 2021 CPR was conducted to determine the technical, economic, and market potential for gas savings from 2020 to 2040.
- Five DSM Settings, from “Taper Off” to “High”, were developed based on incentive level, economic screen, and budget to estimate the total energy savings that could be achieved in the Reference Case and alternate future scenarios.
- The DSM potential for the Reference Case and each alternate future scenario was calculated based on the 2021 CPR, DSM Settings and the policy and economic conditions assumed in the Reference Case and each scenario.

Each of these steps is described below.

5.3.2 2021 Conservation Potential Review (CPR)

The 2021 CPR is the basis for long term DSM program analysis and reviews the energy efficiency opportunities available to FEI’s residential, commercial and industrial sectors. Using 2019 as the base year, the 2021 CPR determined the technical, economic, and market potential for gas savings from 2020 to 2040. The purpose of the 2021 CPR is not to recommend specific programs or targets to be implemented, but to examine available energy efficiency technologies, understand the inventory of energy equipment in a utility's service area, and determine the conservation potential that exists. Please refer to the 2021 CPR report included as Appendix C-1 of the Application for a description of the study approach and methods, including a summary of the study results.

The range of potential DSM measures based on the 2021 CPR results informs the 2022 LTGRP DSM analysis presented in Figure 5-1, including energy savings and expenditure estimates and projected cost-effectiveness test results. FEI's 2023 and future DSM expenditure plan applications will be informed by both the 2021 CPR and the 2022 LTGRP's DSM analysis.

The 2021 CPR and the 2022 LTGRP represent long term forecasts and do not include a request for acceptance from the BCUC for specific DSM expenditures.

5.3.3 DSM Settings Used in the Scenarios

Five DSM Settings were developed ranging from "Taper Off" to "High", to estimate the total energy savings that could be achieved in the Reference Case and alternate future scenarios. The DSM Settings are based on the following three variables:

- Incentive Level: The measure incentive levels (50 percent or 100 percent) of each measure's incremental cost. In general, higher incentives drive higher participation in DSM.
- Economic Screen: The economic screens (TRC, MTRC, or UCT) that determine which measures are included in the analysis.
- Budget Setting: Overall budget limitations, including both incentive spending and non-incentive program spending.

Table 5-3 below describes each of the five DSM Settings and the incentive level, economic screen and budget setting applied to each.

Table 5-3: DSM Settings

	Taper Off	Low	Medium UCT	Medium	High
Description	Assumes DSM spending tapers off as the province electrifies	Constrained to include only the most cost-effective measures. Only 50% incentive level is used, and measures must pass TRC > 1 (no MTRC).	Any incentive level is permitted, but measures must pass UCT > 2 and MTRC or TRC >1. This represents more efficient budget spending.	Similar to the 2021 CPR's medium market potential scenario where adoption of measures is based on incentives covering 50% of a measure's incremental cost	Similar to the 2021 CPR's high market potential scenario where adoption of measures is based on incentives covering 100% of a measure's incremental cost
Incentive Level	Any incentive level is permitted	50% of measure incremental cost	Any incentive level is permitted	50% of measure incremental cost	100% of measure incremental cost
Economic Screen	Passes either TRC>1 or MTRC>1	Passes TRC>1	Passes TRC>1 or MTRC>1 and UCT>2	Passes TRC>1 or MTRC>1	Passes TRC>1 or MTRC>1
Budget Setting	Budget limited to 50% of 2022 spending in 2023, declining to 25% of 2022 spending by 2042	No budget limit applied	No budget limit applied	No budget limit applied	No budget limit applied

Table 5-1 shows which DSM setting was applied to each scenario based on how it aligned with the scenario narrative in Section 4. FEI selected the High DSM Setting for the Diversified Energy (Planning) Scenario. Consistent with the Clean Growth Pathway, the High DSM Setting maximizes energy savings potential and therefore the potential to reduce GHG emissions by accelerating building retrofits, high performance new construction and energy efficiency in commercial and industrial processes. The choice of the High DSM Setting is also consistent with the positive support from the RPAG, Energy Efficiency Advisory Committee (EECAG) and community engagement sessions for FEI to undertake high levels of DSM.

5.3.4 Estimation of the DSM Potential for Each Scenario

The next step in the DSM analysis is to determine the potential for energy savings for each of the scenarios. As discussed in Section 4 and Appendix B-3, different combinations of settings for Critical Uncertainties were used to reflect various economic and policy conditions when developing the scenarios.

The following steps were taken to estimate the DSM savings for each scenario:

1. ***Create a DSM baseline for each scenario*** based on the scenario input assumptions, including customer account growth, the level of fuel switching (price- and policy-driven),

the stringency of codes and standards and other factors. These input assumptions affect measure potential in the following ways:

- The number of building units to which a measure is applicable varies from one scenario to another. For example, differences in the number of new building units being constructed impacts potential for measures applicable to new buildings. Differences in the fuel share of existing building units and end uses to which the measure applies impacts potential as, for example, decreased gas fuel share for an end use means less potential for applicable measures.
- The savings potential for a measure may change because the unit energy consumption (pre-DSM) may be different from one scenario to another. For example, more aggressive improvements in insulation or furnace efficiency as part of an advanced carbon policy scenario will mean less energy savings potential for advanced thermostats in the DSM estimate.

2. ***Apply DSM measures*** by incorporating the CPR's measure assumptions.
3. ***Calculate technical potential*** using applicability and Reference Case adoption rates adjusted for the avoided cost of energy in each scenario. In scenarios where more advanced codes and standards are assumed, certain measures require further adjustments to applicability and reference case adoption rates to reflect those assumptions.
4. ***Calculate economic potential*** based on the economic screen specified in the DSM Setting for the scenario and the avoided costs. These inputs affect measure potential in the following ways:
   - For scenarios in which MTRC is the economic screen, more measures will pass than for those in which TRC is the screen. Where the Medium UCT is the economic screen, measures must also pass a UCT screen.
   - The avoided cost of conventional natural gas varies from one scenario to another. Higher avoided costs for natural gas, due to commodity cost increases or higher carbon price, results in more measures passing the TRC and UCT tests. Note that this mechanism does not affect the MTRC results, as MTRC uses the Zero-Emission Energy Supply Alternative avoided cost, rather than the natural gas avoided cost.
5. ***Calculate market potential*** based on the participation rates (measure uptake) for the scenario. Measure participation rates for each incentive level are adjusted in each scenario based on the avoided costs and retail rates; avoided cost tends to drive retail rates in the long run. Therefore, in the scenarios where avoided costs change, the retail rates are assumed to change in proportion. Higher retail rates make measures more attractive to the end user, because the simple payback after incentive will be shorter. This is assumed to increase program uptake.
6. ***Incorporate program costs*** using the assumptions specified in the DSM Setting for the scenario. In the CPR, there were three incentive levels (25 percent, 50 percent, and 100

percent of measure incremental costs) and non-incentive program costs were assumed to be 15 percent of the corresponding incentive costs. The DSM Setting specifies which incentive level(s) and associated participation rates to use for the scenario.

- ***For the Deep Electrification Scenario Only: Iterate to find the optimal solutions of measures that meet the program budget.*** The process involves multiple iterations to solve for an economic screening threshold in each year that allows just enough measures to pass the screen so that the program spending is below a specified limit for that year. This capability was used for the "Taper Off" Setting which was applied only to the Deep Electrification Scenario. All other scenarios use the spending value that is calculated from implementing all the measures that pass the screening with no budget limit imposed.

7. ***Apply the energy savings potential to annual demand.*** The energy savings are subtracted from the DSM baseline to calculate the resulting annual demand for the scenario. Similarly, the GHG reductions associated with the measure savings are subtracted from the emissions baseline to calculate the resulting GHG emissions post-DSM for the scenario.

5.3.5 Summary

In short, the DSM analysis estimates the potential impact of DSM programs by tailoring the results of the 2021 CPR to the economic and policy considerations reflected in each scenario. This enables FEI to calculate post-DSM annual demand forecasts for each scenario. The results presented in Section 5.4 focus on the Diversified Energy (Planning) Scenario in comparison to the Reference Case. A chart illustrating results for all scenarios is presented in Appendix C-2.

5.4 *RESULTS OF LONG-TERM DSM ANALYSIS*

This section provides estimated DSM savings, expenditures and cost-effectiveness test results for a number of illustrative comparisons of the DSM analysis and its impact on annual demand for gas for the Diversified Energy (Planning) Scenario and Reference Case.[163] In most cases, the analysis is presented for all sectors combined, followed by the individual residential, commercial and industrial sectors.

The LTGRP DSM analysis provides the outcome of pursuing all cost-effective energy savings potential based on the economic screen used for each scenario. It is important to recognize that the CPR and the 2022 LTGRP DSM analysis display only a theoretical estimate of DSM uptake in relation to the ratio between incentive levels and measure incremental costs. These estimates take into account program experience and technology diffusion for a long-term forecast of estimated DSM potential and activity. In contrast, FEI's DSM expenditures plan takes into account

[163] A chart illustrating the results for all scenarios is presented in Appendix C-2, Figure C2-1 and C2-2.

operational program delivery factors, such as staffing levels or specific program eligibility rules, when developing a DSM expenditure plan application.

5.4.1 The Effects of the Low, Medium and High DSM Settings in the Diversified Energy (Planning) Scenario

In recognition of the key role for DSM in decarbonization and as a key pillar in the Clean Growth Pathway, and in response to positive support in RPAG, EECAG and community engagement sessions for FEI to undertake high levels of DSM, FEI selected the High DSM Setting for the Diversified Energy (Planning) Scenario. This setting maximizes GHG reduction potential and contributes to BC's objectives for accelerating building retrofits, high performance new construction and energy efficiency in commercial and industrial processes.

In its acceptance of the 2017 LTGRP (Order G-39-19) and prior resource plan submissions, the

BCUC provided a number of directives and suggestions for FEI to integrate in future resource plans. This section fulfills Directive 3 requesting that FEI provides the following information, in the next LTGRP:

- DSM funding scenarios, reflecting the results of the most recent CPR, that include a "reference" DSM funding scenario with "high DSM" and "low DSM" scenarios that are relative to the reference scenario.
- An analysis of each DSM scenario, at a portfolio level and for each DSM category (residential, low income[164], commercial etc.), including:
    - TRC and MTRC cost test results; and
    - UCT expressed as a ratio and CCE expressed as $/GJ.
- The delivery rate impact and estimated total bill impact (in dollar and percentage) demonstrated for high and low gas usage residential customers.

As directed, FEI conducted additional analysis to understand a broad range of outcomes for DSM potential under the Diversified Energy (Planning) Scenario (DEP), which is now the equivalent to the "reference" scenario referred to in the directive. The additional analysis involved applying the Low and Medium DSM Settings to vary the incentive level for measures and develop a range of outcomes in the modelling process. The Reference Case is provided for comparison. The results of this analysis are shown in Figure 5-2, Figure 5-3, and Figure 5-4 below.

[164] Refer to Section 5.2.3.2 for description of low-income program area.

Figure 5-2: Diversified Energy (Planning) or DEP Scenario DSM Savings Potential – 3 DSM Settings

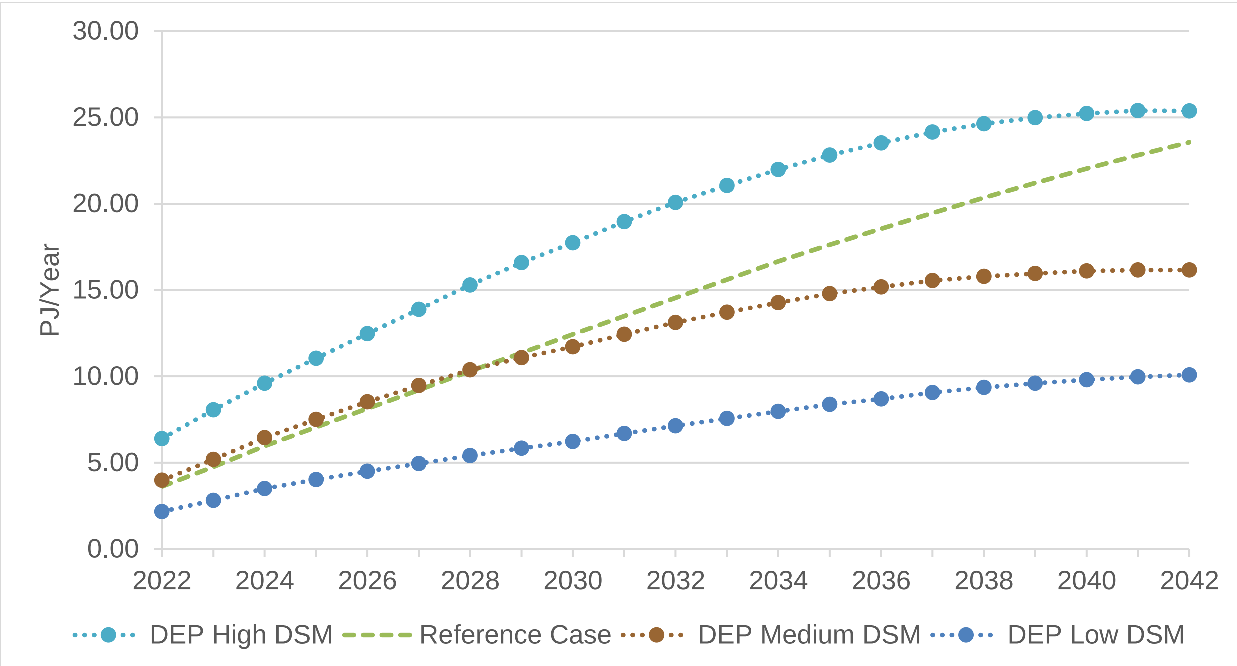
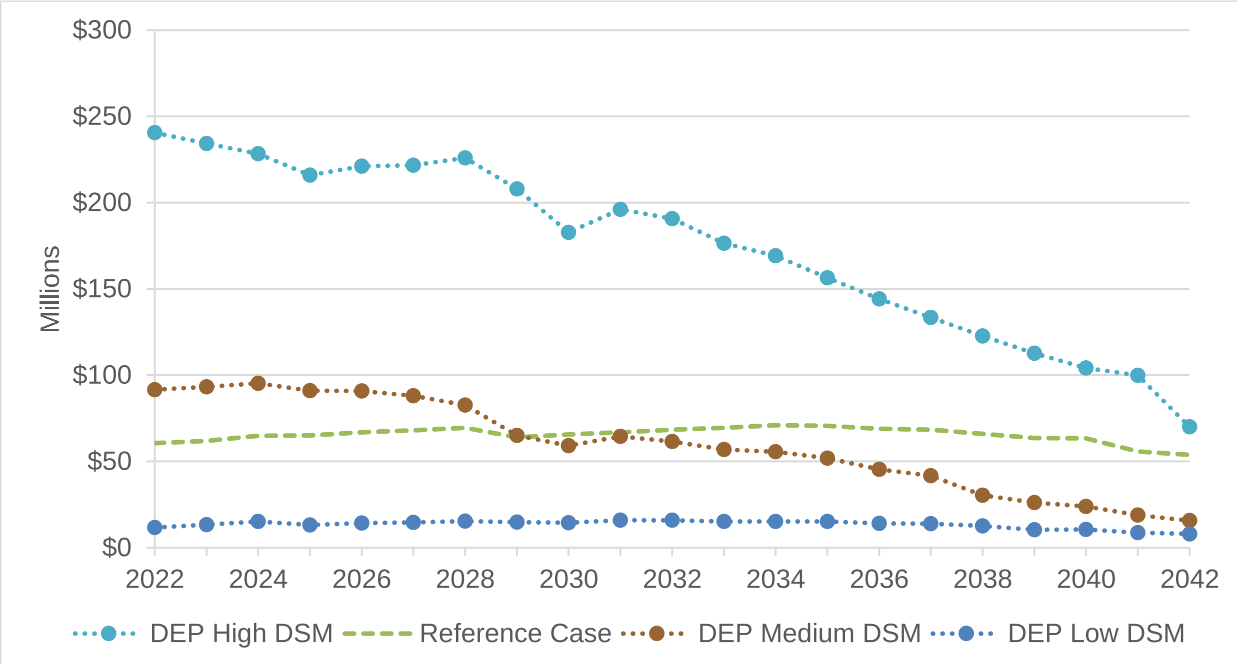


Figure 5-2 illustrates the energy savings potential of DSM activities over the long term. The PJ per year savings reflect savings from all measures providing savings in that year, including those measures where incentives were paid in prior years but the installed measure or upgrade are still operational. As shown in Figure 5-2, in 2042, DSM savings potential would be forecast as:

- 25 PJ for the DEP High Scenario;
- 16 PJ for the DEP Medium Scenario; and
- 10 PJ for the DEP Low Scenario.

Energy savings from the Reference Case (Medium DSM Setting) is 24 PJ which is almost equivalent to the DEP High Scenario. This is due to the high proportion of conventional natural gas and very limited electrification in this scenario and therefore there is a relatively higher potential for DSM savings.

Figure 5-3: Diversified Energy (Planning) or DEP Scenario DSM Expenditures – 3 DSM Settings

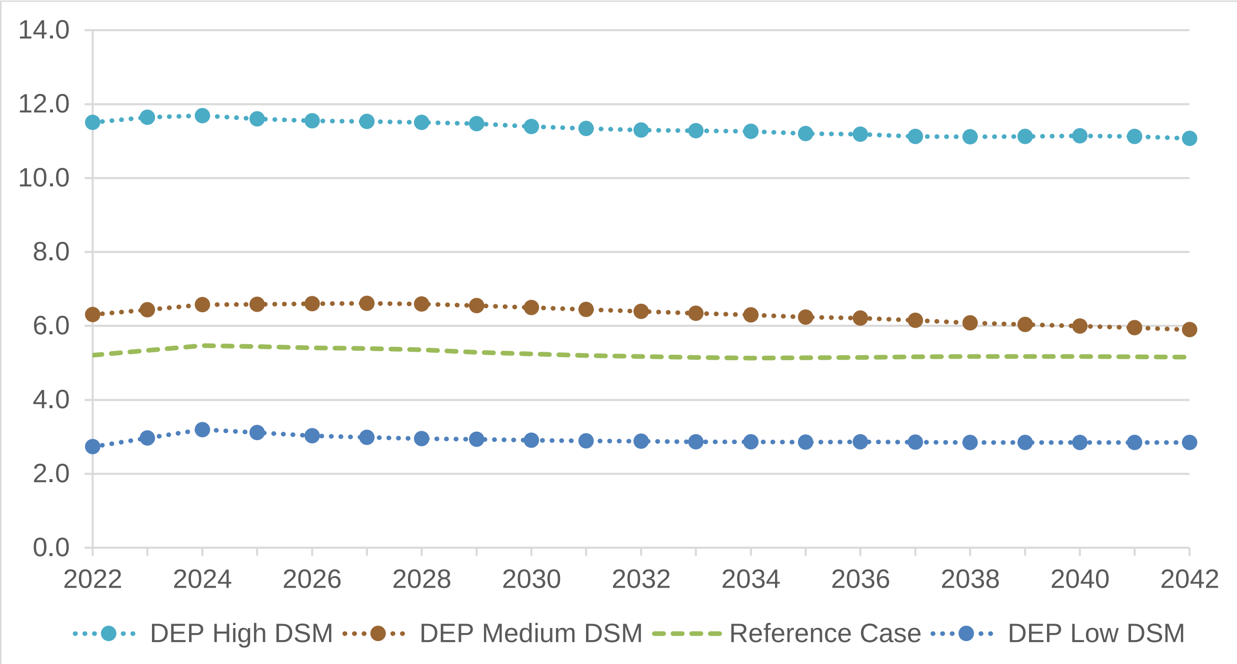


As shown in Figure 5-3, in 2042 annual DSM potential expenditures would be forecast as:

- $70 Million for the DEP High Scenario;
- $16 Million for the DEP Medium Scenario;
- $8 Million for the DEP Low Scenario; and
- $54 Million for the Reference Case.

The decline in DSM investment over the planning horizon is an artifact of the model in that DSM is allocated to conventional gas. For this reason, activity wanes by 2042 when renewable and low-carbon gas makes up a large proportion of the fuel mix. FEI will assess updating the model in the next LTGRP to include all fuel types and FEI is committed to maintaining a high level of DSM investment over the planning horizon as a key pillar in the Clean Growth Pathway.

Figure 5-4: Diversified Energy (Planning) or DEP Scenario CCE ($'s/GJ) – 3 DSM Settings



In Figure 5-4, the Cost per unit of Conserved Energy (CCE $'s/GJ) is provided and demonstrates the effect of the DSM Settings over the planning horizon. In 2042, the CCE would be forecast as:

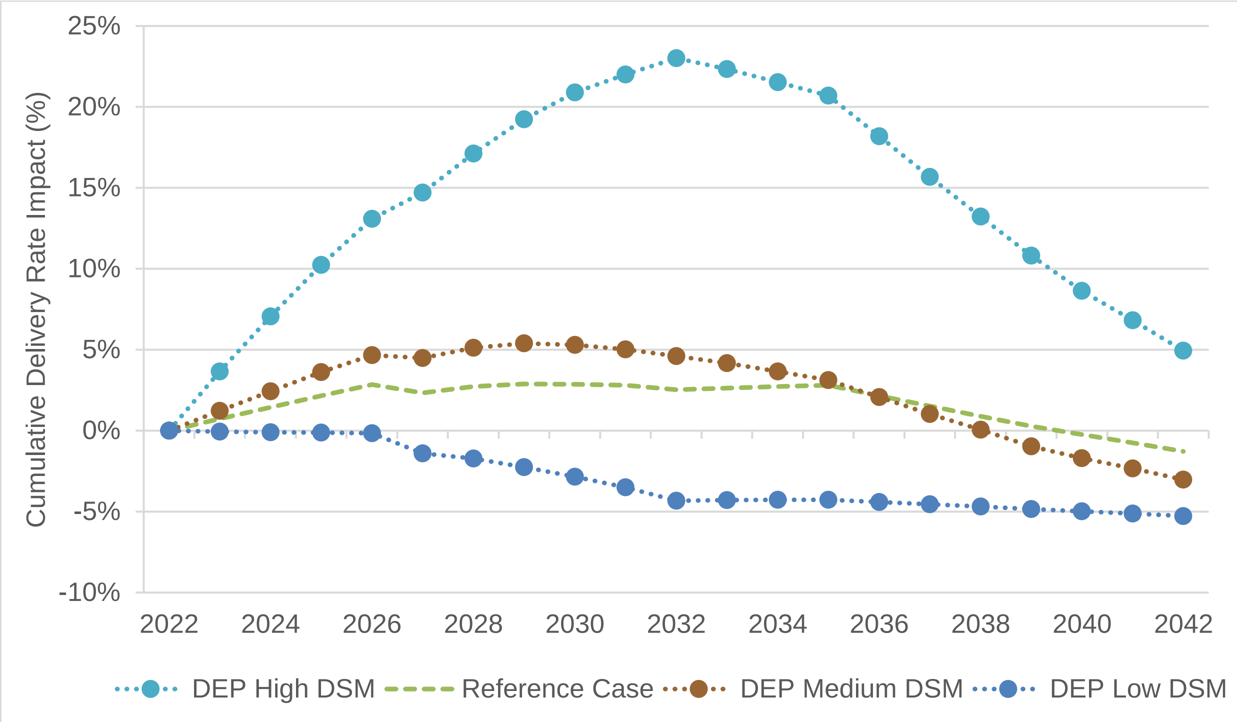
- $11.1 per GJ for the DEP High Scenario;
- $5.9 per GJ for the DEP Medium Scenario;
- $2.8 per GJ for the DEP Low Scenario; and
- $5.2 per GJ for the Reference Case

In Section 2.4, Figure 2-3, FEI forecasts that in 2042 natural gas plus carbon tax would be over $12 per GJ and renewable and low-carbon gas would be over $24 per GJ. Therefore, the CCE value of $11.1 per GJ for the DEP High Scenario will be cost effective. The CCE illustrates that DSM activities are valuable tools in GHG emission reductions, as saving one additional unit of energy (renewable, low-carbon or conventional natural gas) will be beneficial to customers over the planning horizon.

5.4.2 Delivery Rate and Bill Impact of Low, Medium and High DSM Settings

To provide further context on residential customer impact, Figure 5-5 below provides a directional look at the potential delivery rate impact (compared to the approved 2022 delivery rates) of the different DSM Settings (Low, Medium, and High) under the DEP scenarios. The delivery rate impact for the Reference Case is also included for comparison. Presenting this analysis addresses part of BCUC Directive No 3 from the 2017 LTGRP decision (see Table 1-7).

Figure 5-5: Estimated Delivery Rate Impact due to Low, Medium and High DSM Settings



Figures 5-6 to 5-8 below also provide the equivalent annual total bill impact (including commodity, delivery, carbon tax, and GST) in percentage term due to Low, Medium, and High settings of DSM under the DEP scenario from 2022 to 2042, respectively for residential customers with consumption level range from 5 to 250 GJ annually. It can be seen that the average annual bill impact due to DSM under the DEP scenario ranges in this analysis from 0.18 percent to 0.31 percent across all residential customers, depending on the DSM Settings. Furthermore, it can be seen that for residential customers that have an annual consumption of approximately 75 GJ, which is the majority of FEI's residential customers, the cumulative bill impact in 2042 due to DSM programs under the DEP scenario ranges from $8 to $15 per month average depending on the DSM Settings. FEI notes the figures do not consider future rate design changes and are not indicative of a detailed bill forecast. They simply provide a directional view of the estimated 2042 bill impact due to DSM when compared to currently approved rates in 2022[165].

[165] The analysis indicates estimated bill impacts from the perspective of a customer that does not participate in DSM programs. DSM program participants are likely to experience cost savings on their bills.

Figure 5-6: Estimated Cumulative Bill Impact for Residential Customers (5 GJ to 250 GJ) due to DSM under the Diversified Energy (Planning) Scenario – Low DSM Setting

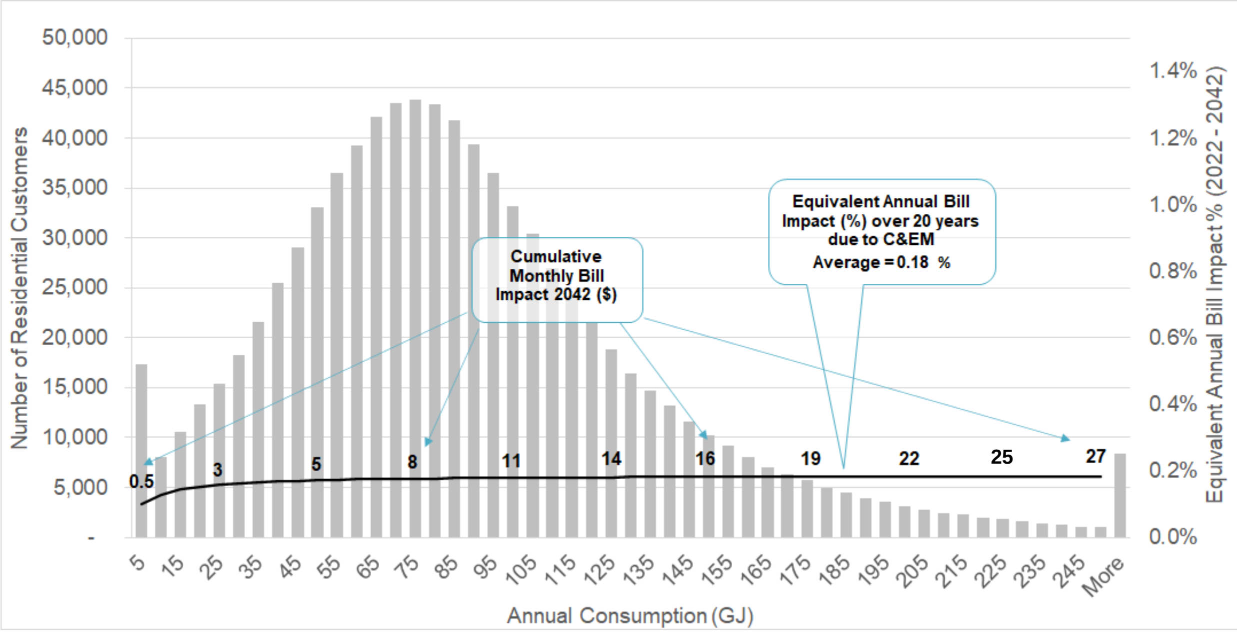


Figure 5-7: Estimated Cumulative Bill Impact for Residential Customers (5 GJ to 250 GJ) due to DSM under the Diversified Energy (Planning) Scenario – Medium DSM Setting

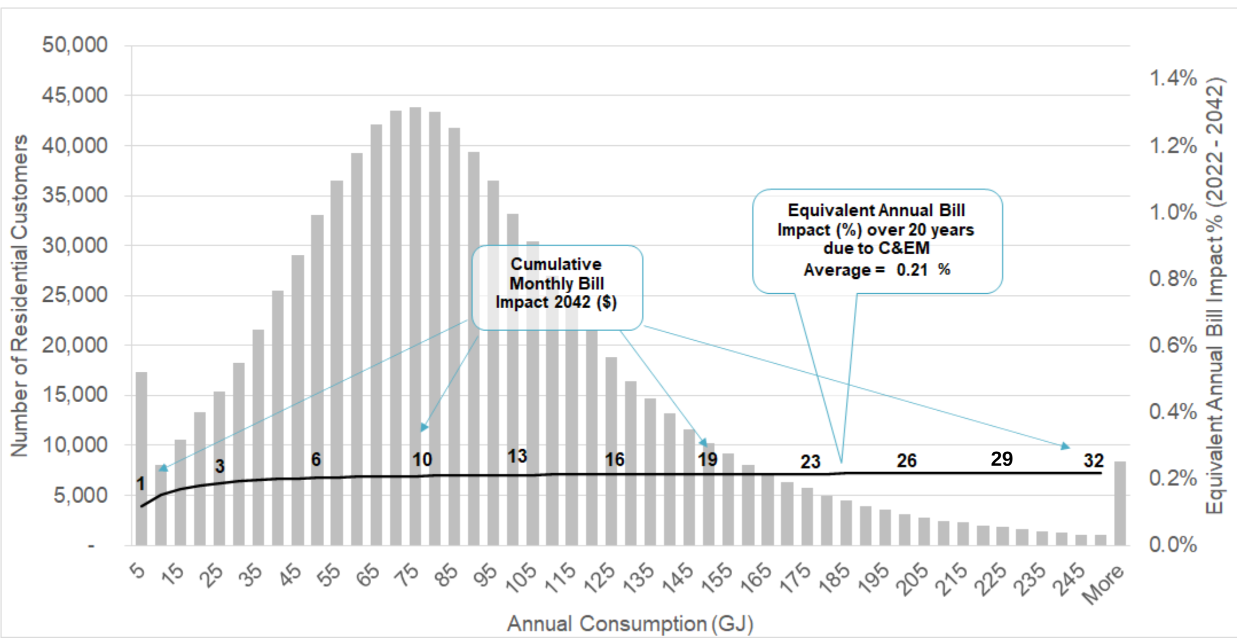
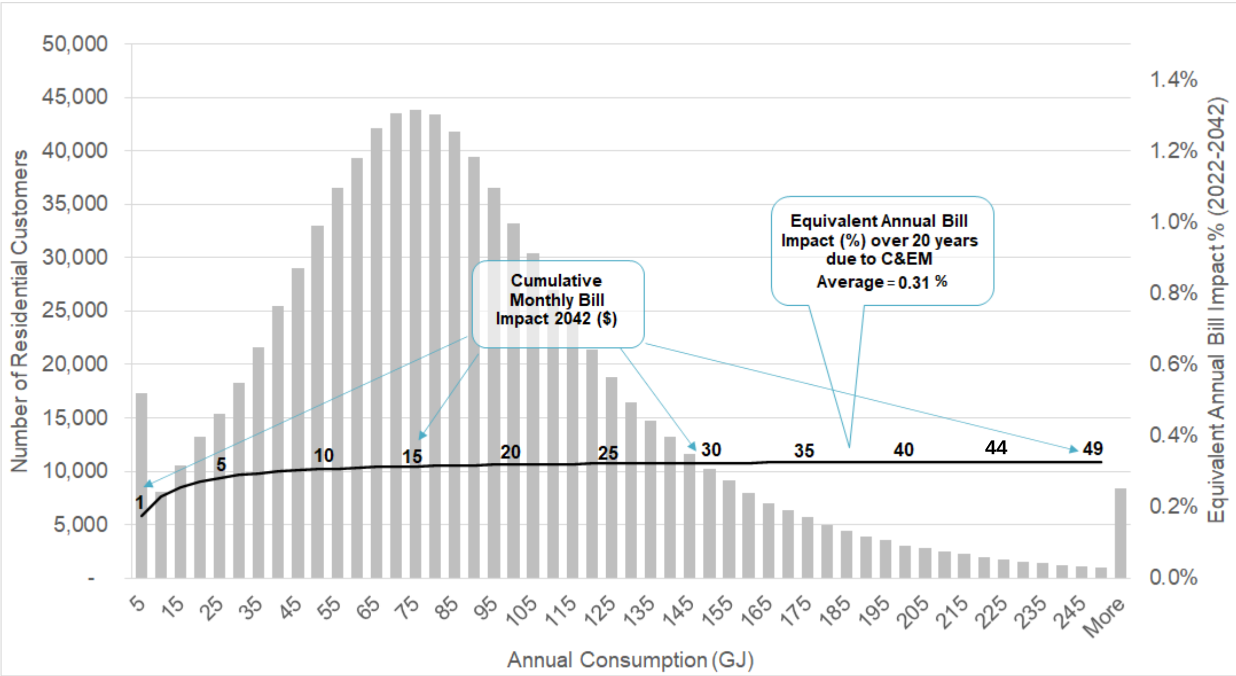


Figure 5-8: Estimated Cumulative Bill Impact for Residential Customers (5 GJ to 250 GJ) due to DSM under the Diversified Energy (Planning) Scenario – High DSM Setting



5.4.3 Total Annual Demand after DSM Savings – Excluding LCT

Figure 5-9 below illustrates annual energy demand, excluding LCT, before and after estimated DSM energy savings for all sectors combined, illustrated for the DEP and Reference Case scenarios. In terms of cumulative energy savings across the planning horizon, by 2042:

- Cumulative DEP High energy savings exceed the DEP Medium savings by 54 percent;
- Cumulative DEP High energy savings exceed the Reference Case energy savings by 31 percent;
- DEP High annual energy savings are forecast to account for a 13 percent reduction in demand in 2042 while DEP Medium are forecast to account for an 8 percent reduction; and
- Reference Case annual energy savings are forecast to account for a 11 percent reduction in Reference Case projected demand in 2042.

Figure 5-9: Annual Demand Before and After Estimated DSM Savings (Excluding LCT) – All Sectors Combined

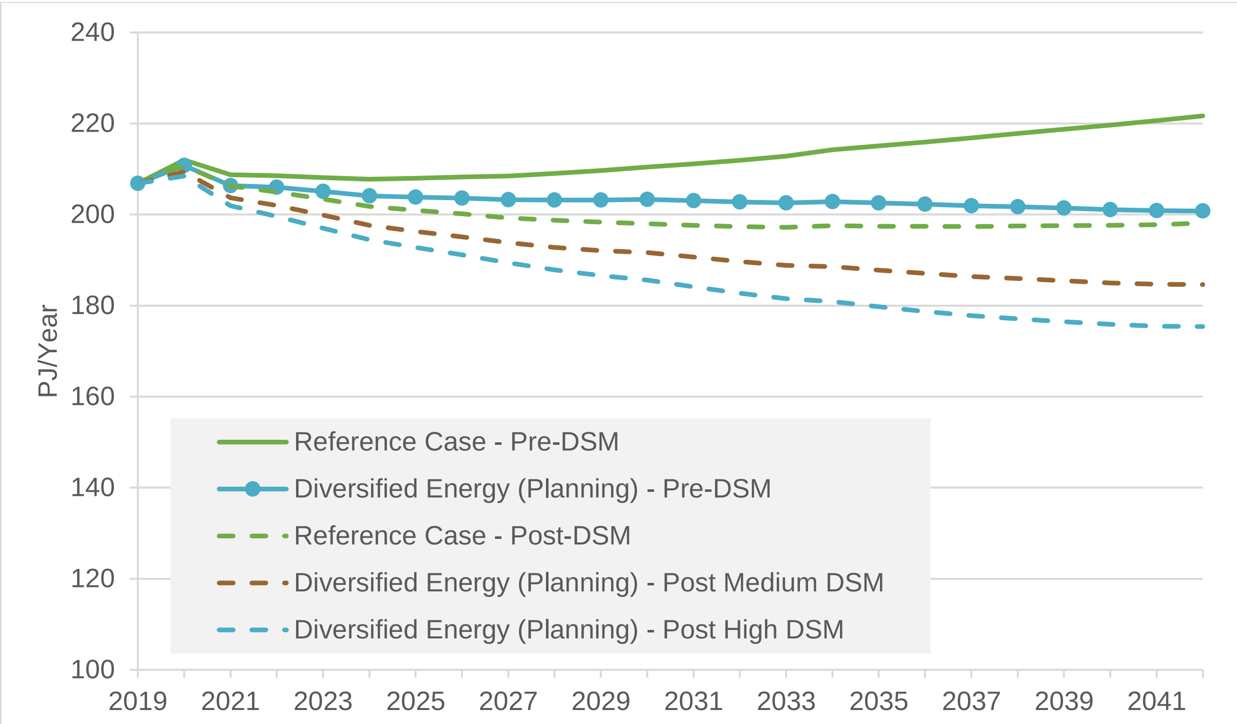


Figure 5-10 below illustrates annual energy demand, excluding LCT, before and after estimated DSM energy savings for the **residential sector**. In terms of cumulative energy savings across the planning horizon, by 2042:

- Cumulative DEP High energy savings exceed the DEP-Medium savings by 7 percent;
- Cumulative DEP High energy savings exceed the Reference Case energy savings by 5 percent;
- DEP High annual energy savings are forecast to account for a 14 percent reduction in and DEP Medium a 13 percent reduction in residential demand in 2042; and
- Reference Case annual energy savings are forecast to account for a 15 percent reduction in residential Reference Case demand in 2042.

Figure 5-10: Annual Demand Before and After Estimated DSM Savings (Excluding LCT) – Residential Sector

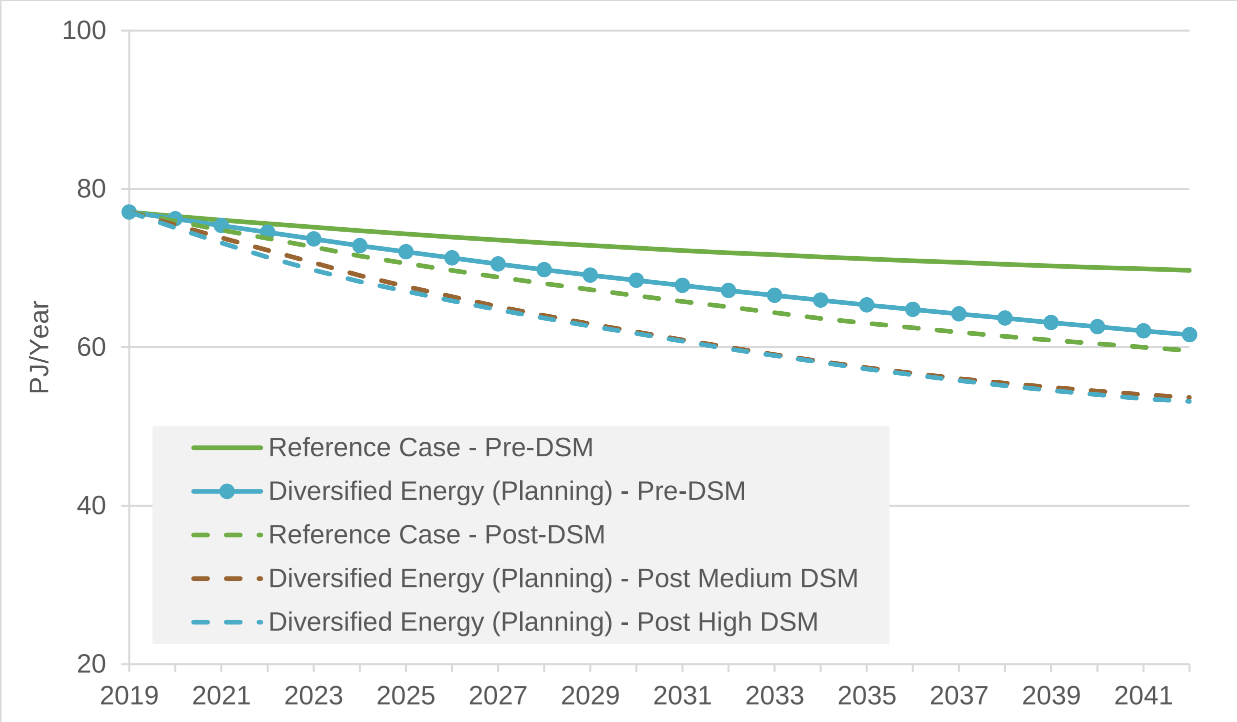


Figure 5-11 below illustrates annual energy demand, excluding LCT, before and after estimated DSM energy savings for the **commercial sector**. In terms of cumulative energy savings across the planning horizon, by 2042:

- Cumulative DEP High energy savings exceed the DEP-Medium savings by 168 percent;
- Cumulative DEP High energy savings exceed the Reference Case energy savings by 113 percent;
- DEP High annual energy savings are forecast to account for a 16 percent reduction and DEP Medium a 6 percent reduction in commercial projected demand in 2042; and
- Reference Case cumulative energy savings are forecast to account for an 8 percent reduction in commercial projected demand for the Reference Case in 2042.

Figure 5-11: Annual Demand Before and After Estimated DSM Savings (Excluding LCT) – Commercial Sector

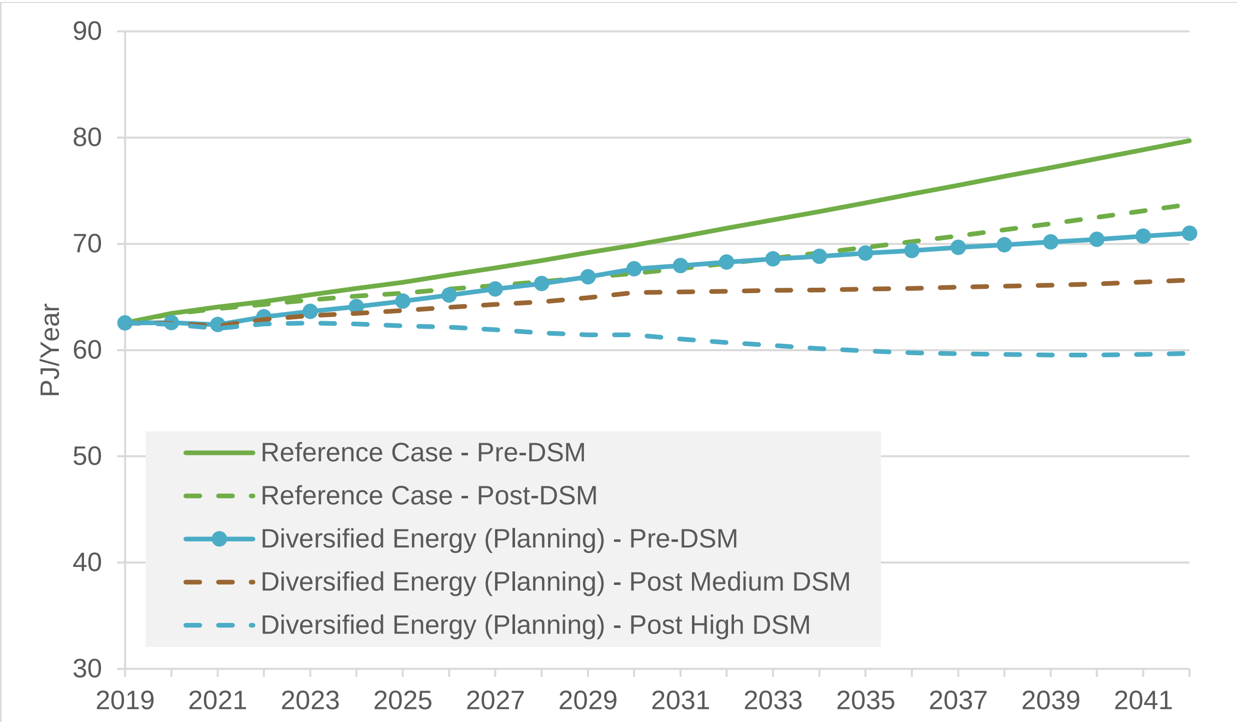
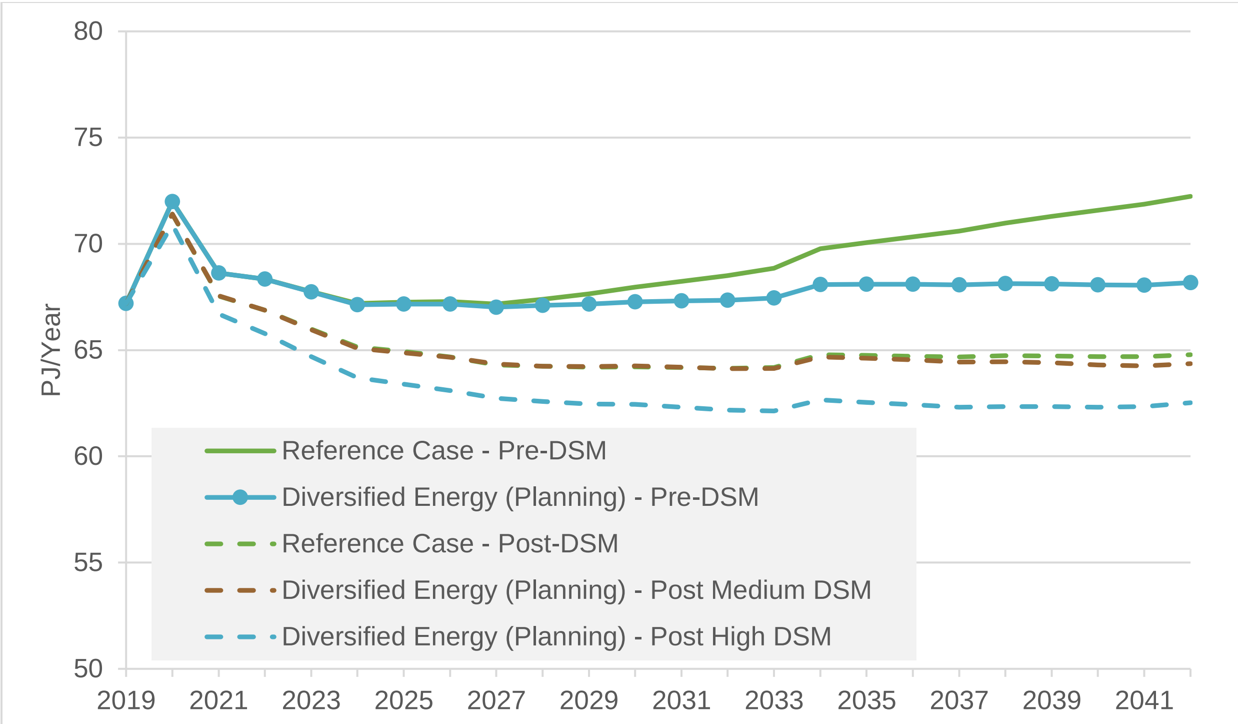


Figure 5-12 below illustrates annual energy demand, excluding LCT, before and after estimated DSM energy savings for the **industrial sector**. In terms of cumulative energy savings across the planning horizon, by 2042:

- Cumulative DEP High energy savings exceed the DEP-Medium savings by 59 percent;
- Cumulative DEP High energy savings exceed the Reference Case energy savings by 11 percent;
- DEP High annual energy savings are forecast to account for an 8 percent reduction and DEP Medium a 6 percent reduction in industrial projected demand in 2042; and
- Reference Case annual energy savings are forecast to account for a 10 percent reduction of industrial projected demand for the Reference Case in 2042.

Figure 5-12: Annual Demand Before and After Estimated DSM Savings (Excluding LCT) – Industrial Sector



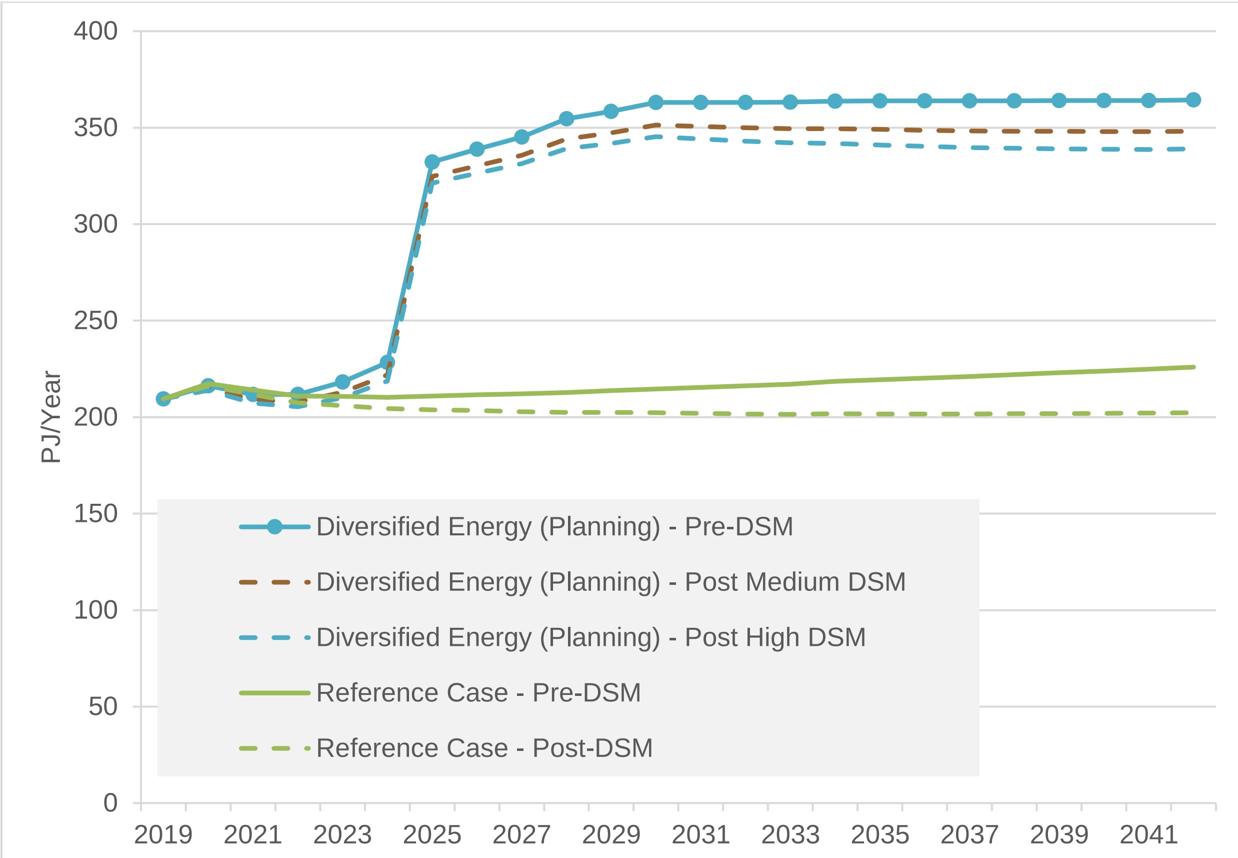
5.4.4 Total Annual Demand after DSM – Including LCT

The final step in the DSM analysis is to develop total annual demand post-DSM to demonstrate the resulting energy savings effects of projected DSM activity. Figure 5-13 below illustrates the following comparisons:

- The figure compares the Diversified Energy (Planning) Scenario pre-DSM analysis and post-DSM analysis for the High and Medium DSM Settings. A further comparison is made with the Reference Case pre-DSM analysis and post-DSM analysis (Medium DSM Setting). The demonstrated energy savings from DSM only include residential, commercial and industrial sectors. LCT demand is also included in the total annual demand forecast.
- In 2042, the DEP High is 7 percent lower, and the DEP Medium is 5 percent lower than the DEP pre-DSM Annual Demand when taking into account the impact of both forecast LCT and also DSM activity. This results in 25 PJ of annual energy savings for the High DSM Setting and 16 PJ of annual energy savings for the Medium DSM Setting.
- In 2042, the Reference case post-DSM is 12 percent lower resulting in 24 PJ of annual energy savings.

In conclusion, this Diversified Energy (Planning) Scenario total annual demand after DSM (shown as Diversified Energy (Planning) – Post High DSM in the figure below) represents the annual demand that FEI is planning to in the 2022 LTGRP.

Figure 5-13: Total Annual Demand After DSM - Including LCT



5.4.5 Long-Term DSM Expenditure Estimates

This section provides estimated DSM expenditures for a number of illustrative comparisons. First FEI presents a table of annual DSM expenditures for the DEP High DSM Setting. Then FEI presents a chart with an illustrative comparison of DEP High, DEP Medium, Reference Case and Upper Bound scenarios. These tables and charts are presented for all sectors combined, followed by the individual residential, commercial and industrial sectors.

The results presented in this section are long term expenditure estimates only and are informed by the results of the CPR and program experience.[166] The DSM expenditures and cost-effectiveness results discussed in the following sections are based on current regulation. Any future regulatory amendments that are in effect before the next LTGRP will be captured at that time.

These results do not take into account the following factors which flow into DSM expenditure plans and DSM annual reports to the BCUC:

[166] For this reason, individual DSM expenditure plans may contain higher or lower energy savings and expenditures in the short and medium term than indicated in the long term DSM analysis in the LTGRP.

- Non-incentive expenditures that support or enable DSM programs at the portfolio level, such as Enabling Activities and Conservation Education Outreach expenditures;[167]
- Operational program delivery considerations, such as changes in required DSM staffing levels or program eligibility requirements;
- Unanticipated market uptake of current technologies, emergence of new technologies more than five years into the future, or technologies which are currently unknown that may increase aggregate energy savings opportunities and thus enable greater actual DSM program expenditures and potentially savings across the planning period[168]; and
- Future DSM Regulation changes, and their impact on FEI's DSM portfolio, which could enable more DSM or result in fewer DSM program offerings.

The results shown in Table 5-4 represent the Diversified Energy (Planning) Scenario - High DSM Setting, for all sectors combined, as FEI recognizes the key role of DSM programs in the Clean Growth Pathway. There are a number of points for consideration in comparing the forecast annual expenditures for the 2022 DEP High DSM Setting ($241 million) and 2021 actual DSM portfolio level results ($107 million)[169], as follows:

- Estimated expenditures are more than double 2021 levels as a result of using the DEP High DSM Setting which may cover up to 100 percent of incentive levels to accelerate the adoption of energy efficient measures and building upgrades. In the current DSM environment, incentive levels are on average set at about 50 percent of incremental costs for the upgrade. These ratios vary per measure, per program and per program area.
- The LTGRP DSM analysis, like the CPR, also includes numerous energy efficiency measures which are not included, or have yet to be scaled, in FEI's current DSM program portfolio. For example, Deep Energy Retrofits represent significant energy savings potential. However, it will take time to establish the program and ensure a qualified workforce is available to support scaling these programs in residential, commercial and low income sectors.
- In this analysis, expenditures are estimated to be around $200 million until around 2030, when a decline in expenditures is demonstrated. This decline represents a greater proportion of renewable and low-carbon energy in the supply. As mentioned in Section 5.1, this software model was built on energy savings allocated to conventional gas taking priority as GHG reductions were emphasized at the time the model was built. The next LTGRP software modelling tool is anticipated to include DSM savings potential across all fuels.

[167] FEI expects these expenditures to continue but FEI's future DSM expenditure plans will determine to what extent.

[168] FEI does not project the actual expenditure impact of unforeseen future technologies as these depend on both their per-measure DSM expenditure and also their total DSM participation rate.

[169] 2019 was the base year for the CPR. DSM Annual Expenditures totaled $64.5 Million across the portfolio. 2021 DSM Annual Expenditures represents the most recent DSM Annual Report in which expenditures totaled approximately $107 Million.

Table 5-4: Estimated Diversified Energy (Planning) - High DSM Setting Expenditures – All Sectors Combined

	Diversified Energy (Planning) Scenario (Millions)		
Year	**Incentive Estimate**	**Non-Incentive Estimate**	**Total Estimate**
2022	$209	$31	$241
2023	$204	$31	$234
2024	$199	$30	$228
2025	$188	$28	$216
2026	$192	$29	$221
2027	$193	$29	$222
2028	$196	$29	$226
2029	$181	$27	$208
2030	$159	$24	$183
2031	$170	$26	$196
2032	$166	$25	$191
2033	$154	$23	$177
2034	$147	$22	$169
2035	$136	$20	$156
2036	$125	$19	$144
2037	$116	$17	$133
2038	$107	$16	$123
2039	$98	$15	$113
2040	$91	$14	$104
2041	$87	$13	$100
2042	$61	$9	$70

Figure 5-14 below provides comparisons of the estimated annual DSM expenditures for the DEP High, DEP Medium, and Reference Case. The DEP High DSM Setting provides the highest DSM investments, whereas the DEP Medium and Reference Case are both Medium DSM Settings and represent closely aligned expenditures. Cumulatively across the planning horizon, DEP High estimated expenditures exceed the DEP Medium estimated expenditures by 192 percent and exceed the Reference Case estimated expenditures by 166 percent. Refer to previous Section 5.4.1 to review a sensitivity analysis of the DSM Settings within the DEP (Planning) Scenario.

Figure 5-14: Estimated Annual Expenditures by Scenario – All Sectors Combined

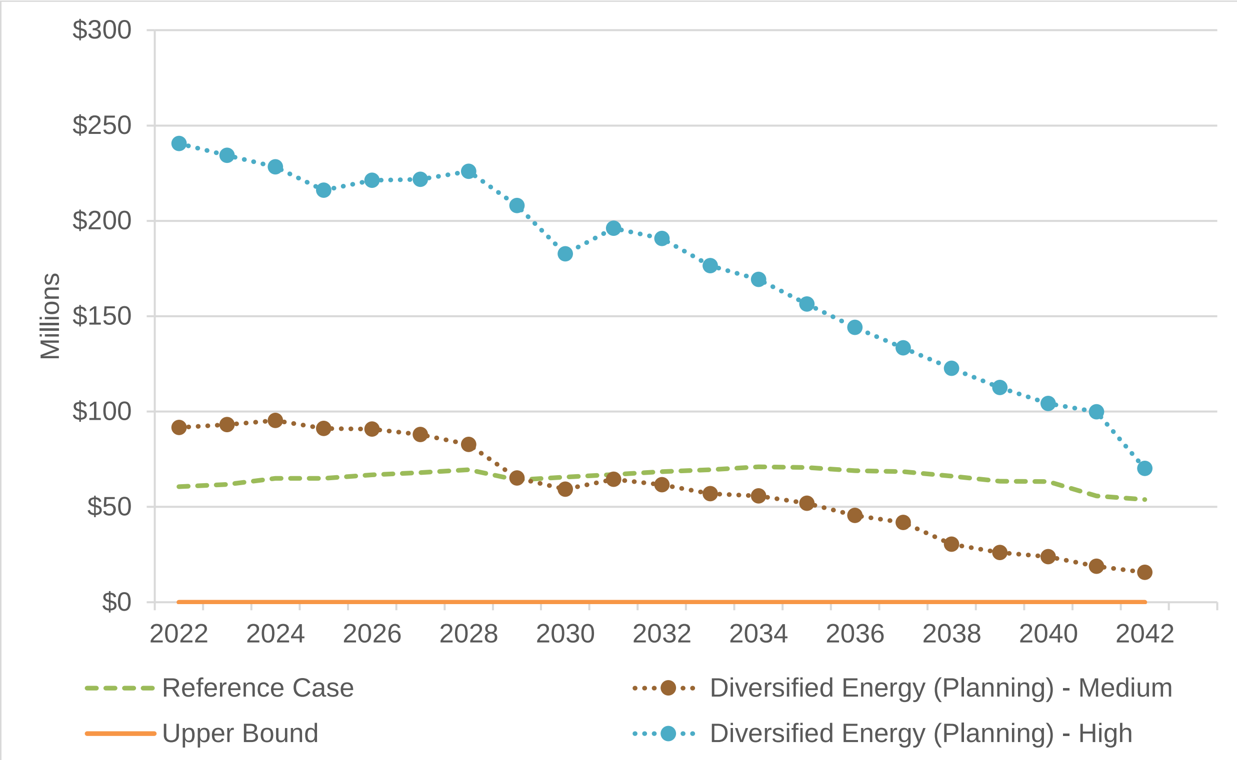


Table 5-5 below displays estimated annual DSM expenditures for the **residential sector**. Estimated expenditures are expected to decline over the years as available energy savings opportunities decline, for example through the introduction of new Minimum Efficiency Performance Standards and other codes. However, the decline in energy savings is partially an artifact of the current model where savings are based on reducing conventional natural gas, whereas after 2030 the proportion of renewable and low-carbon gas in the fuel mix grows significantly. In addition, in future DSM plans for the residential sector, technologies such as gas heat pumps, hybrid heating systems and deep energy retrofits may provide a higher energy savings opportunity than was foreseen when the CPR was being developed in 2019.

Table 5-5: Estimated Diversified Energy (Planning) Scenario - High DSM Setting Expenditures – Residential Sector

	Diversified Energy (Planning) Scenario (Millions)		
Year	Incentive Estimate	Non-Incentive Estimate	Total Estimate
2022	$156	$23	$180
2023	$142	$21	$164
2024	$125	$19	$144
2025	$103	$15	$118
2026	$96	$14	$110

	Diversified Energy (Planning) Scenario (Millions)		
Year	**Incentive Estimate**	**Non-Incentive Estimate**	**Total Estimate**
2027	$90	$14	$104
2028	$88	$13	$101
2029	$74	$11	$85
2030	$65	$10	$75
2031	$74	$11	$85
2032	$71	$11	$82
2033	$67	$10	$77
2034	$65	$10	$74
2035	$61	$9	$70
2036	$55	$8	$63
2037	$52	$8	$59
2038	$49	$7	$57
2039	$46	$7	$53
2040	$42	$6	$48
2041	$44	$7	$50
2042	$21	$3	$25

Figure 5-15 below further illustrates estimated annual DSM expenditures across the DEP High, DEP Medium and Reference Case scenarios for the **residential sector**. Cumulatively across the planning horizon, DEP High estimated expenditures exceed the DEP Medium estimated expenditures by 91 percent and exceed the Reference Case estimated expenditures by 90 percent.

Figure 5-15: Estimated Annual Expenditures by Scenario – Residential Sector

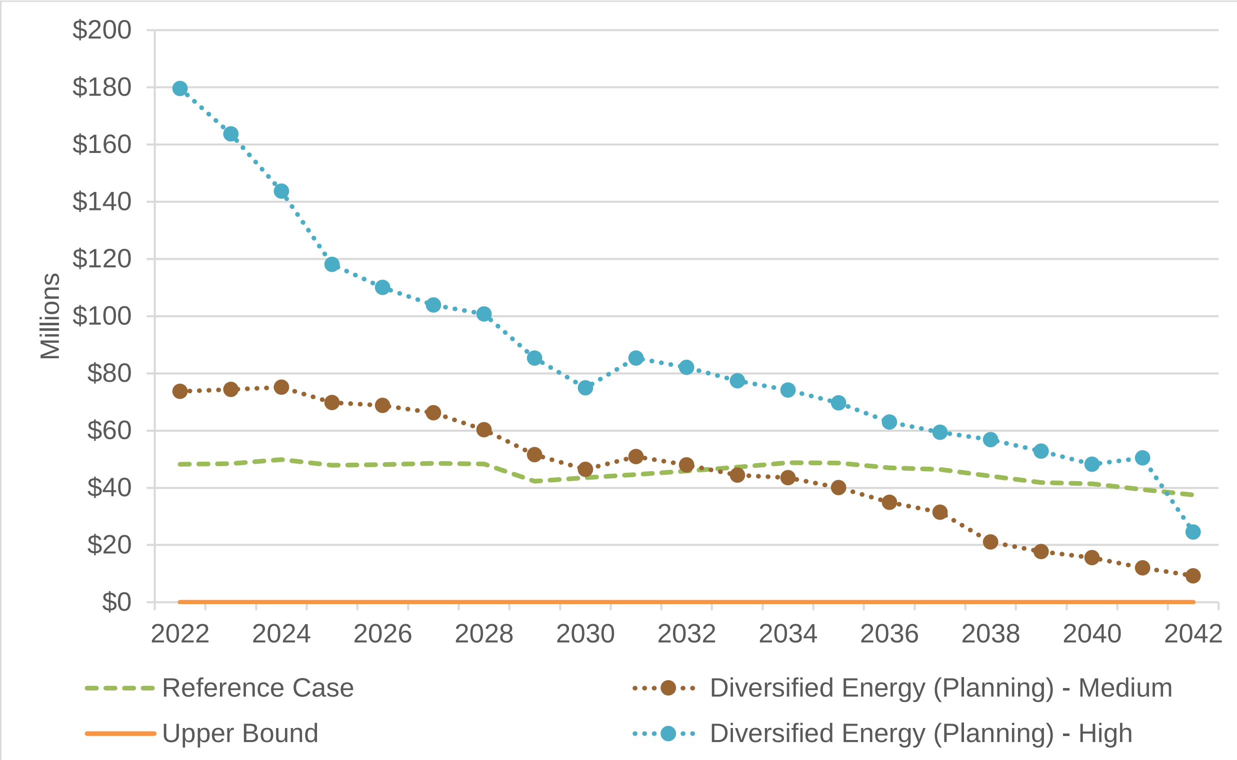


Table 5-6 below illustrates that estimated annual DSM expenditures for the **commercial sector** are expected to increase until 2031, and then decline after this year towards the end of the planning horizon. However, as discussed for the residential sector, the decline in energy savings is partially an artifact of the current model where savings are based on reducing conventional natural gas. In addition, in future DSM plans for the commercial sector, technologies such as gas heat pumps, hybrid heating systems and deep energy retrofits may provide a higher energy savings opportunity than was foreseen when the CPR was being developed in 2019.

Table 5-6: Estimated Diversified Energy (Planning) Scenario – High DSM Setting Expenditures Commercial Sector

	Diversified Energy (Planning) Scenario (Millions)		
Year	Incentive Estimate	Non-Incentive Estimate	Total Estimate
2022	$27	$4	$31
2023	$39	$6	$44
2024	$53	$8	$61
2025	$66	$10	$76
2026	$79	$12	$91
2027	$87	$13	$100
2028	$93	$14	$107

	Diversified Energy (Planning) Scenario (Millions)		
Year	Incentive Estimate	Non-Incentive Estimate	Total Estimate
2029	$93	$14	$107
2030	$89	$13	$103
2031	$91	$14	$105
2032	$89	$13	$103
2033	$82	$12	$94
2034	$78	$12	$90
2035	$71	$11	$81
2036	$66	$10	$76
2037	$60	$9	$69
2038	$54	$8	$62
2039	$50	$7	$57
2040	$46	$7	$53
2041	$41	$6	$47
2042	$38	$6	$43

Figure 5-16 below illustrates estimated annual DSM expenditures across the DEP High and DEP Medium and Reference Case scenarios for the **commercial program sector.** Cumulatively across the planning horizon, DEP High estimated expenditures exceed the DEP Medium by 753 percent and exceed the Reference Case by 559 percent.

Figure 5-16: Estimated Annual Expenditures by Scenario – Commercial Sector

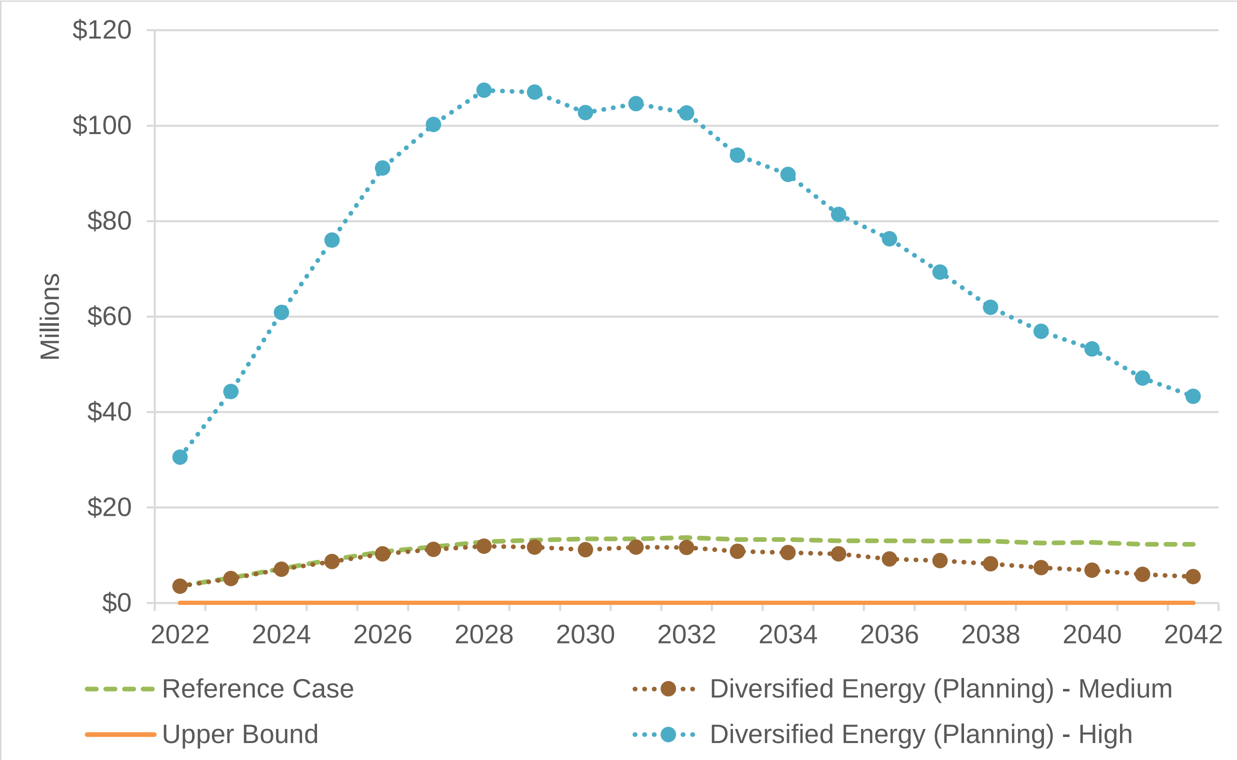


Table 5-7 below displays estimated annual DSM expenditures for the **industrial sector.** Estimated expenditures are expected to decline after 2022 towards the end of the planning horizon as available energy savings opportunities decline. However, as discussed for the residential and commercial program areas, the decline in energy savings is partially an artifact of the current model. The industrial sector can be difficult to decarbonize and poses many possibilities for direct-to-customer clean energy projects in the Clean Growth Pathway. These decarbonization priorities may not be categorized as traditional DSM energy savings opportunities but may provide significant opportunities for GHG emission reductions.

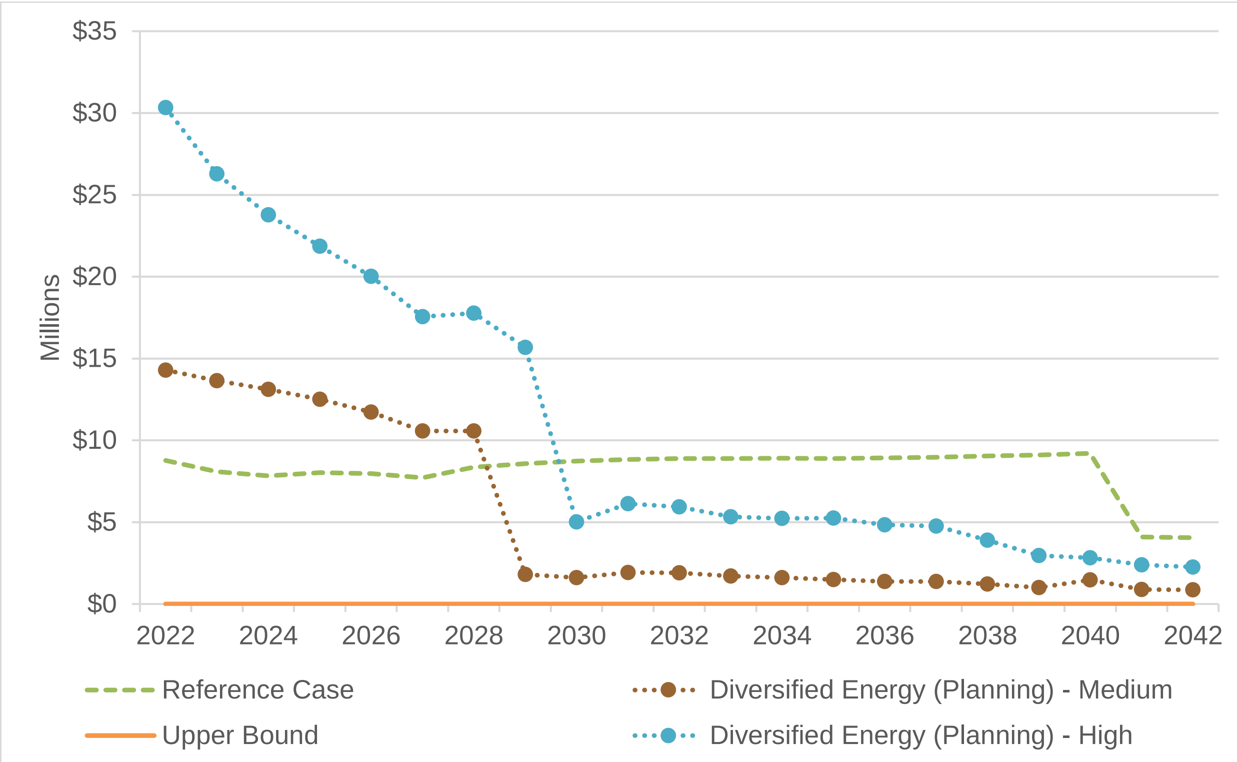
Table 5-7: Estimated Diversified Energy (Planning) Scenario – High DSM Setting Expenditures – Industrial Sector

	Diversified Energy (Planning) Scenario (Millions)		
Year	Incentive Estimate	Non-Incentive Estimate	Total Estimate
2022	$26	$4	$30
2023	$23	$3	$26
2024	$21	$3	$24
2025	$19	$3	$22
2026	$17	$3	$20
2027	$15	$2	$18

	Diversified Energy (Planning) Scenario (Millions)		
Year	Incentive Estimate	Non-Incentive Estimate	Total Estimate
2028	$15	$2	$18
2029	$14	$2	$16
2030	$4	$1	$5
2031	$5	$1	$6
2032	$5	$1	$6
2033	$5	$1	$5
2034	$5	$1	$5
2035	$5	$1	$5
2036	$4	$1	$5
2037	$4	$1	$5
2038	$3	$1	$4
2039	$3	$0	$3
2040	$2	$0	$3
2041	$2	$0	$2
2042	$2	$0	$2

Figure 5-17 below illustrates estimated annual DSM expenditures across the DEP High, DEP Medium and Reference Case scenarios for the **industrial sector**. Cumulatively across the planning horizon, DEP High estimated expenditures exceed the DEP Medium by 116 percent and exceed the Reference Case by 34 percent.

Figure 5-17: Estimated Annual Expenditures by Scenario – Industrial Sector



5.4.6 Long-Term Cost-Effectiveness Estimates for all Sectors Combined

Section 5.4.6 provides cost-effectiveness estimates for a number of illustrative comparisons. First Table 5-8 summarizes cost-effectiveness results (TRC, MTRC, UCT, and CCE) for the DEP High scenario, all sectors combined, for each year across the 20 year planning horizon. Then, Figures 5-18 to 5-21 illustrate how cost-effectiveness test results vary across DEP High and Reference Case scenarios for all sectors combined.

DSM cost-effectiveness test results presented in this section are long term estimates only and are informed by the results of the 2021 CPR and program experience.[170] The cost-effectiveness results are based on current DSM regulation. Any future regulatory amendments that are in effect before the next LTGRP will be captured at that time.

In general, cost-effectiveness test ratios decrease over time as the more easily-realized energy savings opportunities (i.e., the low-hanging fruit) are actualized. The 2022 LTGRP DSM cost-effectiveness test results also display the CCE in dollars per GJ. The CCE is an industry standard method for expressing the TRC results in dollars per GJ. Electric utilities use the CCE to express the net cost of saving one unit of utility-supplied energy. The CCE can be used to express UCT

[170] For this reason, individual DSM expenditure plans may contain higher or lower energy savings and expenditures in the short and medium term than indicated in the long term DSM analysis in the LTGRP.

1 results in dollars per GJ by applying the UCT benefit and cost inputs.[171] The aggregate portfolio
2 CCE across the planning horizon is $11.3 $/GJ as illustrated below.

3 **Table 5-8: Estimated Diversified Energy (Planning) Cost-Effectiveness Test Results – All Sectors**
4 **Combined**

Year	TRC	MTRC	UCT	CCE ($/GJ)
Aggregate	**4.1**	**14.2**	**4.0**	**11.3**
2022	6.8	25.2	6.7	11.5
2023	6.1	22.3	6.0	11.6
2024	5.5	20.1	5.4	11.7
2025	5.1	18.6	5.0	11.6
2026	4.8	17.3	4.7	11.5
2027	4.5	16.2	4.4	11.5
2028	4.3	15.3	4.2	11.5
2029	4.1	14.6	4.1	11.5
2030	4.0	14.1	4.0	11.4
2031	4.0	13.8	3.9	11.3
2032	3.9	13.6	3.9	11.3
2033	3.9	13.4	3.8	11.3
2034	3.9	13.2	3.8	11.3
2035	3.9	13.1	3.8	11.2
2036	3.8	13.0	3.8	11.2
2037	3.8	12.9	3.8	11.1
2038	3.8	12.8	3.8	11.1
2039	3.8	12.7	3.7	11.1
2040	3.8	12.6	3.7	11.1
2041	3.8	12.6	3.7	11.1
2042	3.8	12.6	3.7	11.1

5

[171] In this case, the CCE represents the annualized and, where applicable, discounted UCT net costs (i.e. sum of UCT costs minus sum of UCT benefits, excluding cost savings for utility fuel sales) divided by annual energy savings. This information fulfills BCUC Directive from the 2017 LTGRP.

Figure 5-18: Estimated TRC Results by Scenario – All Sectors Combined

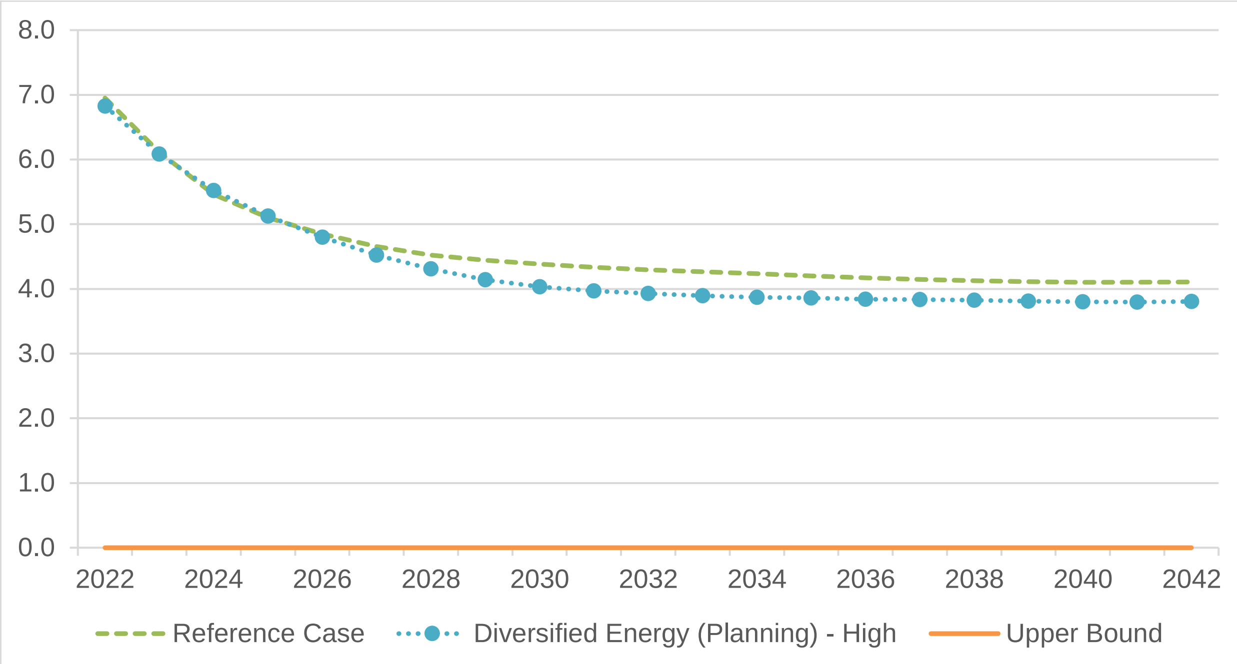


Figure 5-19: Estimated MTRC Results by Scenario – All Sectors Combined

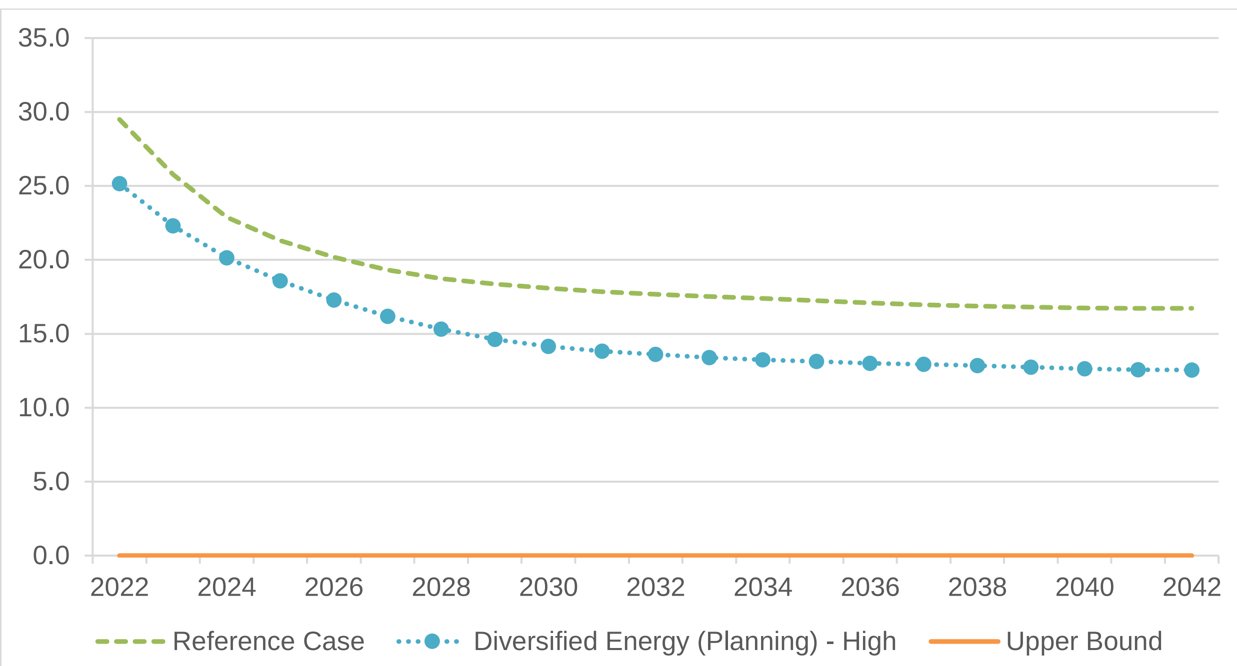


Figure 5-20: Estimated UCT Results by Scenario – All Sectors Combined

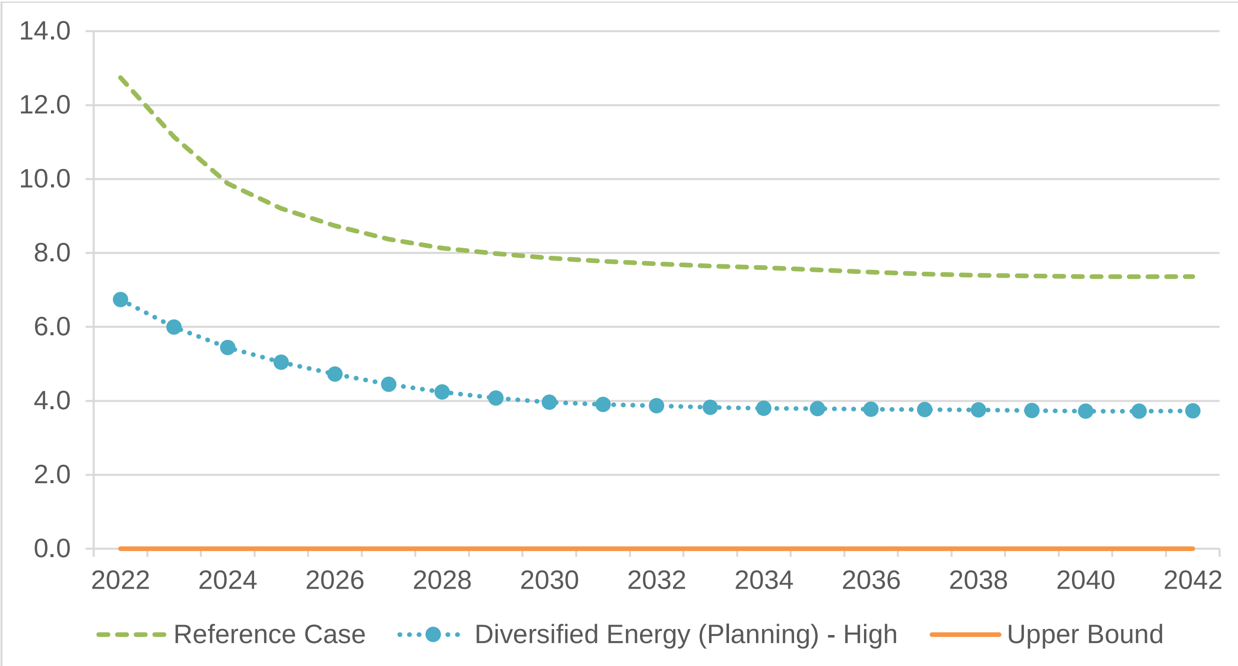
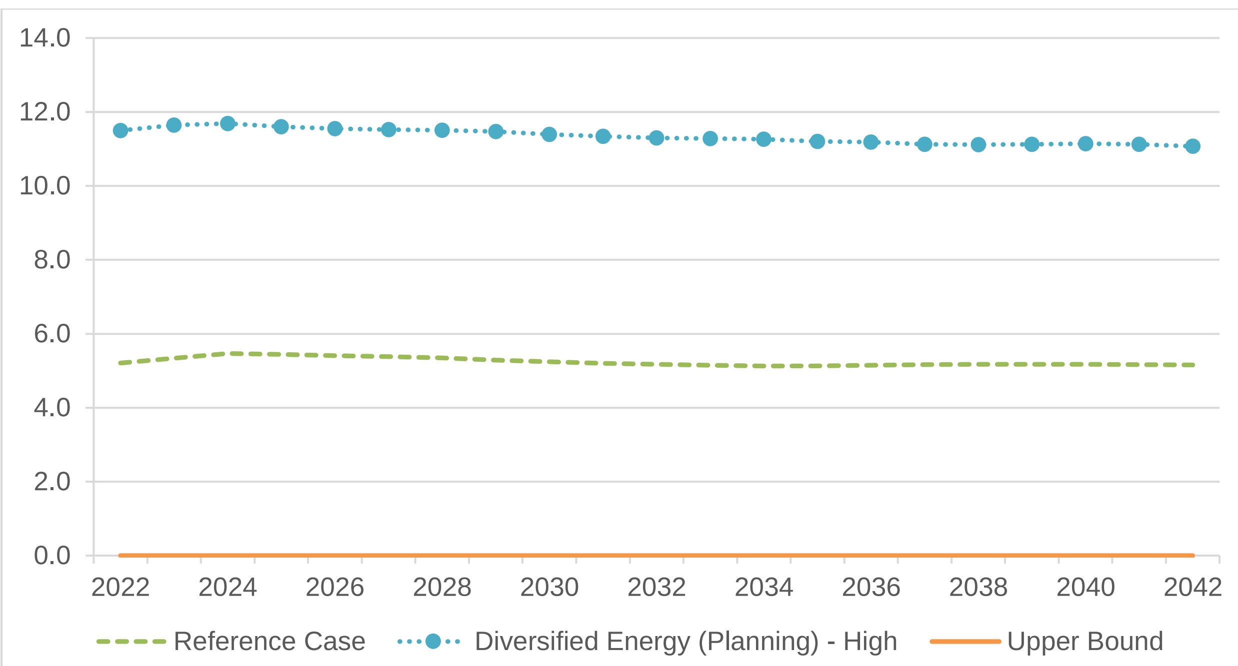


Figure 5-21: Estimated CCE Results by Scenario ($/GJ) – All Sectors Combined



Refer to Appendix C-2 for the comparison of cost-effectiveness test results for the Diversified Energy (Planning) - High and Reference Case for individual sectors within the 2022 LTGRP DSM analysis.

5.4.7 Energy Savings Market Potential to 2030 from Top Ten Measures

Tables 5-9 to 5-12 below outline projected cumulative market potential energy savings to 2030 for the top ten measures in the DEP High DSM Scenario and illustrate how these cumulative energy savings change based on individual scenarios.

The cumulative market potential energy savings to 2030 for the top ten measures represent a significant share of total portfolio savings:

- The combined program area top ten measures account for **42** percent of DEP High DSM combined program area savings.
- The residential program area top ten measures account for **69** percent of DEP High DSM residential program area energy savings.
- The commercial program area top ten measures account for **62** percent of DEP High DSM commercial program area energy savings.
- The industrial program area top ten measures account for **73** percent of DEP High DSM industrial program area energy savings.

FEI's future DSM expenditure plans will be informed by the measure data from the 2021 CPR and 2022 LTGRP's DSM analysis and will represent program design and delivery decisions that are in accordance with changing customer needs, regulatory requirements, and technology evolution.

Table 5-9: Estimated 2030 Cumulative Savings from Top 10 Measures by Diversified Energy (Planning) – All Sectors Combined

	Diversified Energy (Planning)	Reference Case	
Measures	**Savings (GJ)**	**Savings (GJ)**	**% Change from Diversified Energy (Planning)**
Drain Water Heat Recovery (Residential)	799,597	490,145	-39%
High-Efficiency (ENERGY STAR) Condensing Gas Tankless Water Heater - Mature Market Costs (Residential)	775,356	497,415	-36%
Steam to Hot Water Conversion (District Energy) (Industrial)	748,368	446,594	-40%
Low Flow Showerhead (Residential and Commercial)	420,358	825,919	96%
HVAC Zoning (HVAC Zone Control) (Residential)	410,425	359,840	-12%
Home Energy Report (Residential)	408,430	518,459	27%
Attic Insulation (R-20 Baseline) (Residential)	405,840	170,460	-58%
High Quality Furnace Installation - ENERGY STAR Verified (Residential)	384,626	179,463	-53%
High-Efficiency Heat Recovery Ventilator (Residential)	349,440	449,954	29%
Energy Management (Industrial)	344,725	443,074	29%

Table 5-10: Estimated 2030 Cumulative Savings from Top 10 Measures by Diversified Energy (Planning) – Residential Sector

	Diversified Energy (Planning)	Reference Case	
Measures	Savings (GJ)	Savings (GJ)	% Change from Diversified Energy (Planning)
Drain Water Heat Recovery	799,597	490,145	-39%
High-Efficiency (ENERGY STAR) Condensing Gas Tankless Water Heater - Mature Market Costs	775,356	497,415	-36%
HVAC Zoning (HVAC Zone Control)	410,425	359,840	-12%
Home Energy Report	408,430	518,459	27%
Attic Insulation (R-20 Baseline)	405,840	170,460	-58%
High Quality Furnace Installation - ENERGY STAR Verified	384,626	179,463	-53%
Low Flow Showerhead	368,647	767,866	108%
High-Efficiency Heat Recovery Ventilator	349,440	449,954	29%
Communicating Thermostat	335,561	462,314	38%
High-Efficiency Storage Gas Water Heater	212,999	162,788	-24%

Table 5-11: Estimated 2030 Cumulative Savings from Top 10 Measures by Diversified Energy (Planning) – Commercial Sector

	Diversified Energy (Planning)	Reference Case	
Measures	Savings (GJ)	Savings (GJ)	% Change from Diversified Energy (Planning)
Heat Transfer Tech	240,167	271,621	13%
Advanced Thermostat	231,643	327,166	41%
Occupant Behaviour	222,854	247,912	11%
Boiler/Furnace Tune-Up	130,531	148,226	14%
Building Energy Report	125,512	140,282	12%
Boiler Cycling Controls	113,905	158,135	39%
Efficient Cook Equipment	92,212	117,810	28%
Energy Recovery Ventilators	79,461	101,139	27%
Comprehensive Recommissioning (RCx)	78,542	90,620	15%
Reverse Flow Energy Recovery Ventilator	77,462	67,587	-13%

Table 5-12: Estimated 2030 Cumulative Savings from Top 10 Measures by Diversified Energy (Planning) – Industrial Sector

Measures	Diversified Energy (Planning) Savings (GJ)	Reference Case Savings (GJ)	Reference Case % Change from Diversified Energy (Planning)
Steam to Hot Water Conversion (District Energy)	748,368	446,594	-40%
Energy Management	344,725	443,074	29%
Heat Recovery Systems	340,118	499,910	47%
Process Boiler Load Control	222,014	281,033	27%
Process Control	188,033	303,503	61%
Replace Steam Traps	169,795	216,969	28%
High Efficiency Dryers	159,366	247,029	55%
Boiler Tune-Up	147,753	194,060	31%
Integrated Greenhouse Environmental Controls	101,816	113,438	11%
Furnace Efficiency Retrofit	80,226	114,959	43%

5.5 ESTIMATED LONG-TERM DSM IMPACTS ON PEAK DEMAND

In its Decision on the 2014 LTRP, the BCUC requested FEI to make stronger linkages between the peak demand and the annual demand forecasts, to understand how ". . . new insights on evolving customer consumption patterns might affect time-of-day demand as well as annual demand . . . and how changes in base load annual demand under different scenarios translate into changes in base load peak demand under the same scenario assumptions."[172]

FEI commissioned Posterity to develop an exploratory process linking peak demand forecasts to the end use scenarios used in the annual demand forecasts. Section 7.2.3 further discusses this process. Overall, Posterity's approach suggests that the 2022 LTGRP's DSM forecast decreases peak demand. Section 7.3 discusses how this may impact infrastructure expansion requirements for each of FEI's regional transmission systems. FEI emphasizes that Posterity's approach currently is theoretical in nature and unsupported by direct measurement. Thus, FEI's infrastructure planning continues to rely on FEI's traditional peak demand forecast method (Traditional Peak Method).

Furthermore, in its Decision on the 2017 LTGRP, the BCUC requested that FEI "provide an update of its analysis of opportunities for DSM to be used to cost-effectively replace or defer infrastructure

[172] BCUC Decision and Order G-189-14, FortisBC Energy Utilities 2014 Long Term Resource Plan (December 3, 2014), p. 22, online at: https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/111658/1/document.do.

investments in its next LTGRP."[173] To help meet this directive, FEI commissioned ICF to update its review of the state of the North American gas utility industry in exploring opportunities and implementing DSM programs that could potentially replace or defer infrastructure. ICF's report, titled Non-Pipe Solutions Status Update, is found in Appendix C-3. Non-pipe solutions are non-traditional and/or demand-side solutions that may be used to defer investment in the gas distribution system infrastructure. These non-traditional investments may include approaches such as energy efficiency, natural gas demand response, decarbonization approaches[174] and others. The report focused on demand-side non-pipe solutions, through a review of jurisdictions with relevant non-pipe solutions activity. The report highlights that there is only modest experience to date with implementing non-pipe solutions projects to address peak demand constraints, but interest is starting to grow, especially in response to decarbonization activities. FEI's AMI project, under BCUC review at this time, may provide FEI and customers the ability to more actively manage peak demand. However, the extent to which AMI can be used for Demand Response as a DSM activity, and with respect to deferred infrastructure investments, is still being explored. Further, AMI is not necessarily a requirement for undertaking non-pipe solutions and opportunities exist for FEI to further explore and perhaps pilot some non-pipe solutions initiatives.

Although not a "demand-side measure" as defined in the CEA, in Section 7.3.5.4, FEI provides an example of its first operational non-pipe solutions installed within a distribution system. In the Gibsons Distribution System, the capacity of the IP pipeline is insufficient to meet current peak demand without temporary mitigation measures. The preferred and lowest cost alternative was determined to be a local CNG peak shaving facility. This provides some insight into the use of non-pipe solutions as an alternative to address system capacity.

5.6 *LONG-TERM PLAN FOR IMPLEMENTING DSM ACTIVITIES*

In the long term, based on the 2022 LTGRP DSM analysis, FEI intends that it will design its DSM expenditures plans with the High DSM Setting in mind as DSM represents a key pillar in the Clean Growth Pathway. FEI will continue to offer residential, commercial, industrial, low income, innovative technologies, conservation education and outreach as well as DSM-enabling activities. The measures analysed in the CPR and the LTGRP DSM analysis will inform FEI's future DSM expenditure plans that will be filed with the BCUC for acceptance. In addition, FEI will continue monitoring the cost-effectiveness of its DSM activities and identifying any new measures that can be included in its activities. Over the 2022 LTGRP planning horizon, FEI will operationalize these activities through successive DSM expenditure plans. In these future expenditure plans, FEI's specific program offers will likely change to suit the evolving marketplace, legislative provisions (including future adequacy requirements), end use technologies, and FEI customer needs. FEI will continue to update its long term DSM analysis through successive future LTGRPs over the planning horizon and will continue to explore non-pipe solutions opportunities.

[173] BCUC Decision and Order G-39-19, FEI 2017 Long Term Gas Resource Plan (February 25, 2019), pp. 14-17, online at: https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/363860/1/document.do.
[174] Note that impacts to the electric system were not examined in this study.

5.7 CONCLUSIONS AND RECOMMENDED ACTIONS

Expanding investment in DSM programs is a pillar of the Clean Growth Pathway and a critical contribution to FEI's efforts to meet the GHG emissions cap in the Roadmap. FEI's DSM analysis shows that significant energy and GHG emissions reduction can be achieved over the planning horizon under the range of alternate future scenarios examined for the LTGRP. Under the Diversified Energy (Planning) Scenario with the High DSM Setting, savings from DSM activities are forecast to be about 25 PJ or 13 percent of annual demand in 2042. It is important to note that the DSM measures implemented over the planning horizon will shift depending on how the future actually unfolds.

FEI will continue to examine opportunities to develop other DSM activities that offer similar benefits or to expand existing offerings and, where appropriate, seek approval for expenditures related to those offerings. Recommended actions to acquire and implement demand-side resources over the planning horizon are to:

- Develop DSM expenditure plans for the next funding period(s) reflecting an adequate and cost-effective portfolio of DSM activities guided by the High DSM Setting, and apply to the BCUC for acceptance of those expenditures.
- Assess the implications of increasing amounts of renewable and low-carbon gas over the planning horizon on FEI's DSM activities, program modelling and reporting tools. For example, FEI will assess the impact of these supplies on cost-effectiveness models to understand how these fuels impact program offerings in alignment with the Roadmap.
- Continue to examine the potential for DSM activities to reduce peak demand on FEI's transmission and distribution systems, and thus delay or avoid infrastructure investments. FEI will continue to monitor studies and advancements across the gas utility industry on DSM related non-pipe solutions as well as evaluations of the effectiveness of such initiatives. FEI will consider opportunities for studies or pilot programs for such activity on its own system.

Continue to work with federal, provincial and municipal governments and other potential partners to explore and identify ways in which FEI's DSM activities can continue to help meet government objectives while ensuring benefits for FEI and its customers. This activity will include examining and understanding the impact of any new changes to the DSM Regulation on FEI's DSM programming if and when such changes are enacted.

FortisBC Energy Inc.
2022 LTGRP

Section 6:

GAS SUPPLY PORTFOLIO PLANNING

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6. GAS SUPPLY PORTFOLIO PLANNING

In this section, FEI describes its long-term gas supply portfolio plan to meet the total forecast annual demand described in Section 4, with consideration of the transition to renewable and low-carbon gas and associated reductions to carbon emissions as FEI pursues its Clean Growth Pathway. Planning for gas supply involves accounting for FEI's DSM activities (described in Section 5), resources available to contract for gas supply, and the resources required to deliver gas to customers. This section also analyses the requirements to manage security of supply risks to FEI's gas supply portfolio and options for meeting these requirements over the planning horizon.

FEI's gas supply portfolio planning considers a subset of the total system throughput that FEI uses for system capacity planning described in Section 7. FEI's gas supply portfolio planning is responsible for appropriately planning for the forecast normal, design, and peak day demand of core market (Core) customers.[175] The gas supply requirements for the remaining portion of the total system throughput are the responsibility of customers who have elected to take service under FEI's Transportation Service model (Transportation Service customers). These Transportation Service customers arrange for their own supply that is then transported by FEI to their premises. Therefore, system capacity planning needs to consider total system throughput to ensure that sufficient capacity exists on FEI's system to reliably deliver gas supply to meet the demand of all customers.

Table 6-1 below illustrates the differences between FEI's customer service types for gas supply portfolio and system capacity planning in the LTGRP.

Table 6-1: Summary of LTGRP Customer Service Types

LTGRP Customer Service Type	Rate Schedules	FEI Gas Supply Portfolio Planning	FEI System Capacity Planning
Core	1, 2, 3, 4, 5, 6, 46	Included	Rate Schedules 1, 2, 3, 5, 6, 46 included; and Rate Schedule 4 (seasonal) excluded.
Firm Transportation	The contracted firm delivery component of 22 (including 22A and 22B), 23, 25, the transportation component of 46, and other special Rate Schedules[176]	Excluded (these customers secure their commodity supply on their own or through a shipper agent)	Included

[175] As outlined in Table 6-1, this also applies throughout Section 6 to any applicable delivery component of Interruptible customers.

[176] The special Rate Schedules are Byron Creek, BC Hydro Island Generation, and Vancouver Island Gas Joint Venture (VIGJV). These special Rate Schedules are applicable for both Firm Transportation and Interruptible customers, as they have all contracted firm delivery and interruptible components.

LTGRP Customer Service Type	Rate Schedules	FEI Gas Supply Portfolio Planning	FEI System Capacity Planning
Interruptible	7, 27, the Interruptible component of 22 (including 22A and 22B) and other special Rate Schedules	For Rate Schedule 7 and any non-transportation component of special Rate Schedules: • Included: contracted firm delivery component; • Excluded: interruptible delivery component. All other Interruptible service customers are excluded.	Interruptible components excluded (FEI can reduce gas flow to these customers during peak conditions to any firm contract amount)

FEI's gas supply portfolio planning relies on the Traditional Annual Method for deriving system-wide demand forecasts for Core customers each day through the entire year, as well as the peak design day, which is the coldest day of the design year estimated via extreme value analysis to have a return period of 20 years. In contrast, system resource planning (to be discussed in Section 7) relies on location-specific (not system-wide) peak demand. Section 7 outlines FEI's traditional peak method for deriving peak demand and also discusses FEI's exploration of an end use peak demand forecast method that may in the future provide additional insights about the impact of emerging gas use trends on peak demand.

FEI's transition to renewable and low-carbon gas supplies will continue to accelerate in order to reach carbon emissions reduction targets. While this transition is happening both within and outside of BC, it remains in early stages. In each of Sections 6.1, 6.2 and 6.3, FEI discusses the current outlook for these gas supplies and how they will impact FEI's gas supply planning moving forward. At this early stage, market information and future forecasting on renewable and low-carbon gas supplies is, as expected, less available than for conventional natural gas, and yet is developing quickly. In this LTGRP, FEI provides the information it has available about these supplies, and anticipates that evolving market intelligence for these gases will inform future LTGRPs and gas supply planning.

The remainder of this section is organized as follows:

- Section 6.1 provides background information and sets out the regulatory requirements for FEI's gas supply portfolio planning.
- Section 6.2 discusses existing gas supply portfolio planning strategies, which include managing demand uncertainty and security of supply concerns in the short-term.
- Section 6.3 describes how future supply projects will help manage security of supply concerns and enhance supply resiliency over the medium- to long-term planning horizon.

6.1 PORTFOLIO PLANNING REGULATORY REQUIREMENTS AND FILINGS

6.1.1 Regulatory Requirements for Gas Supply Planning

Section 44.1(2) of the UCA outlines the requirements for long-term resource plans. In relation to gas supply, the UCA requires long-term resource plans to provide:

> Information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c); and

> An explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures.[177]

This section meets the above UCA requirements by outlining the long-term considerations that apply to FEI's energy purchases and the impact of demand drivers, such as DSM, on such considerations. FEI's Annual Contracting Plan (ACP) operationalizes these considerations in the short and medium term, and takes into consideration the specific purchase requirements and demand driver impacts that affect FEI.[178]

As discussed in Section 1.5.5, Tables 1-7 and 1-8, the BCUC has set out two directives and one suggestion for FEI's 2022 LTGRP,[179] which are addressed in this Section:

- The Panel directs FEI to address security of supply concerns;
- The Panel directs FEI to address resiliency in a comprehensive manner; and
- The Panel suggests FEI may address pathways to zero GHG emissions by 2050.

Both the security of supply and supply resiliency items are discussed in the short, medium and long term within Sections 6.1.2, 6.2 and 6.3 below, with a discussion of the alternative supply resources available to FEI and conclusions about FEI's future supply planning. Also integrated into these sections is a discussion of how renewable and low-carbon gas resources are being integrated into FEI's gas supply portfolio considerations. To date, the majority of renewable and low-carbon gas has been acquired by FEI through direct contract negotiations and agreements with suppliers, and makes up a small, though growing, portion of the resources available to FEI to contract. Over time, as the renewable and low-carbon gas supplies in North America and the PNW grow, FEI anticipates that market participation by more players will increase and market dynamics will evolve. FEI will continue to monitor and take advantage of these developments as the market for renewable and low-carbon gas continues to develop.

[177] UCA s. 44.1.

[178] The impact of demand-side measures to date is inherently considered in the ACP since the short-term demand forecast, on which the ACP is based, captures these recent efficiency trends. Future ACPs will likewise consider future demand-side measures.

[179] BCUC Order No G-39-19 and C-2-21.

6.1.2 Relationship between FEI's Gas Supply Plans

FEI uses three different plans for its gas supply and price risk management activities: the LTGRP, ACPs, and Price Risk Management Plans (PRMP). The LTGRP, ACP and PRMP differ in the type of demand forecast on which the plans are prepared. The LTGRP is based on a broad range of long-term demand forecast scenarios and on the total system throughput of all customers. In contrast, the ACP and PRMP are based on short- and medium-term forecasts derived from trends observed in recent years (or on customer reported expectations in the case of industrial customers) and only consider the demand of Core customers, a subset of total system throughput.

The LTGRP establishes long-term planning principles, objectives, and a framework that is used to help ensure the long-term provision of safe, reliable, and cost effective service to all customers. In doing so, the LTGRP also sets out gas supply contracting and price risk management principles within the context of a 20-year outlook. The ACP and the PRMP each describe more detailed strategies and tactics for managing either the physical availability of gas supply or the impact of gas costs on rates.

The ACP is based on short- and medium-term load forecasts derived from trends observed in recent years (or on customer-reported expectations in the case of industrial customers), and also takes into account regional[180] market developments. Therefore, the ACP sets strategies and tactics for managing the availability of third-party transmission capacity, securing the physical supply of natural gas, and managing the impact of costs on customers' rates. The ACP more closely considers diversity and purchasing term supply from different supply hubs, purchasing term supply on a daily and monthly indexed basis, and using storage resources to meet peaking and seasonal demand requirements while balancing FEI's pipeline system on a daily basis.

The PRMP provides strategies and tools to enhance existing price risk management in managing the impacts of market price volatility on commodity rates and in capturing market price opportunities to help provide customers with affordable rates. The PRMP is, to a large degree, informed by the ACP since the ACP determines the physical resources required and degree of portfolio exposure to market prices.

FEI is not seeking approval of any of its gas supply portfolio or price risk management activities as part of the LTGRP, as these approvals are sought through separate applications to the BCUC. Discussion of FEI's ACPs and PRMPs is included in the LTGRP only to provide context for resource planning considerations.

6.2 *GAS SUPPLY PORTFOLIO PLANNING*

FEI's gas supply portfolio consists of natural gas commodity contracts, third-party pipeline capacity and storage resources. This section discusses the key factors that FEI considers when developing its gas supply portfolio, including marketplace developments that will affect traditional regional gas flows, and supply and demand in the region. FEI is continuing to assess the regional

[180] In this section, the term "region" broadly refers to the Pacific Northwest (PNW), which includes BC.

market for renewable and low-carbon gas volumes, and is managing the security of its supply and enhancing resiliency of its portfolio taking into account long-term supply risks, as well as managing pricing risks.

6.2.1 Overview of the Gas Supply Planning Process

FEI files an ACP with the BCUC in the spring of each year. In those plans, FEI assesses the overall North American natural gas market and evaluates the regional market with respect to supply and infrastructure. Key objectives of the ACP are:

1. To contract for resources that appropriately balance cost minimization, security, diversity and reliability of gas supply in order to meet the Core customer forecast design peak day and annual requirements; and
2. To develop a gas supply portfolio mix, which incorporates flexibility in the contracting of resources based on short- and long-term planning and evolving market dynamics.

Since the T-South incident (discussed in Appendix E), FEI has placed more emphasis on enhancing supply resiliency within its portfolio, which may increase the cost of the portfolio. Enhancing resiliency within the portfolio through the existing assets in the region is discussed in Section 6.2.4, while potential infrastructure additions to further enhance resiliency are discussed in Section 6.3.

FEI conducts portfolio planning to provide secure and reliable supply to Core customers so that system-wide forecast normal, design, and peak design day demands are met. FEI contracts the majority of its gas supply resources over the short- to medium-term,[181] and the resource cost and availability of the supply is primarily determined in the gas marketplace where FEI competes with other parties.

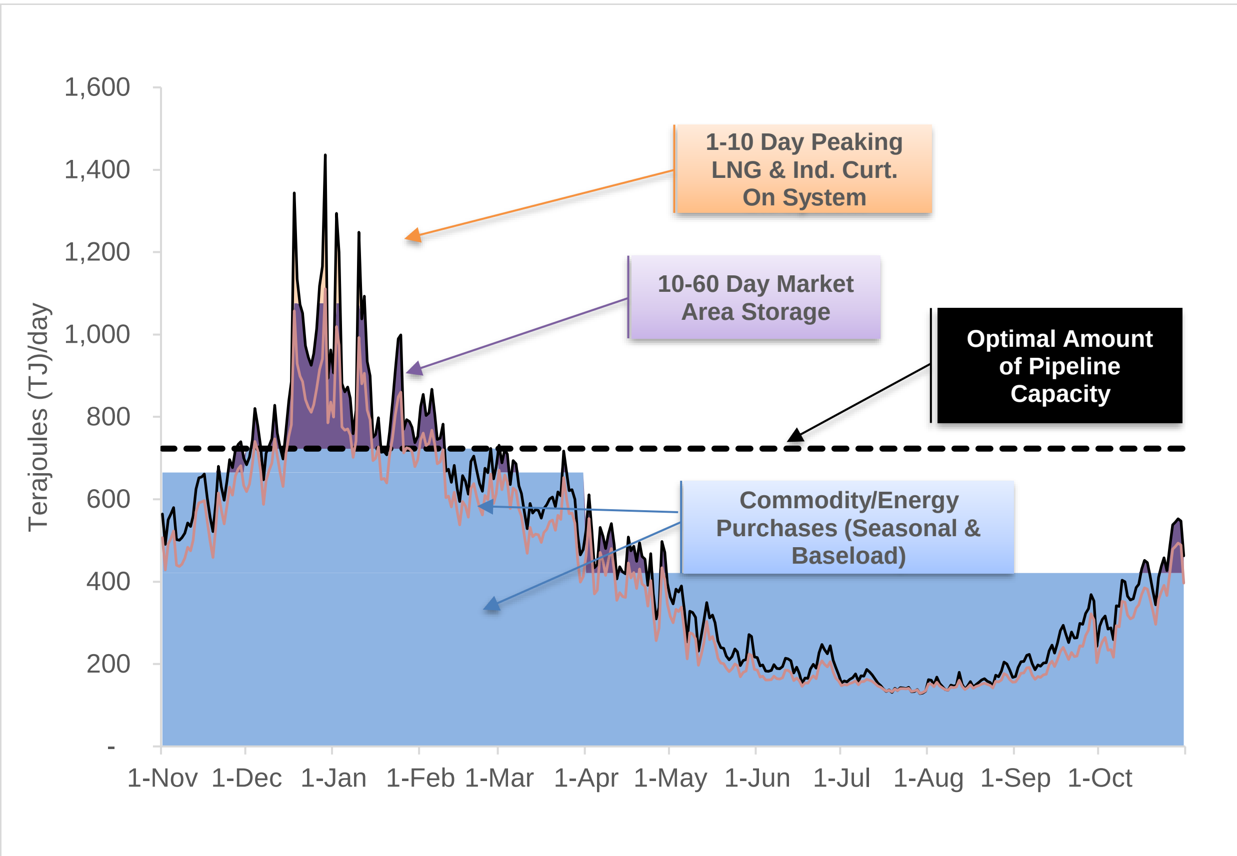
The fundamental design principle of constructing an efficient gas supply portfolio of resources, which FEI has used for many years in the ACP, is to match the resource characteristics to the demand characteristics. In broad terms, that efficient supply portfolio consists of:

- Purchasing firm natural gas commodity volumes and contracting third-party pipeline capacity to address seasonal and base load requirements (i.e., consistent demand for the 151-day winter season and annual demand);
- Shorter duration market area storage to provide short- to medium-duration seasonal supply; and
- On-system storage resources for short-duration supply to cover events such as winter demand peaks.

[181] It is not FEI's intention to specifically delineate what time periods the phrases short- and medium- term encompass for the purpose of gas supply planning throughout this section. Rather, these are general timing considerations that for short-term is approximately zero to three years and for medium-term is approximately three to seven years.

The resulting gas supply portfolio for a system such as FEI's that has pronounced demand seasonality (i.e., high load in winter and low load in summer), and therefore a low annual load factor, is illustrated in Figure 6-1 below. This figure illustrates the ACP resources that were planned to be used in the 2021/2022 gas contract year (November 1, 2021 to October 31, 2022), and how their duration fits the forecast annual normal and design load for Core customers.

Figure 6-1: 2021/2022 FEI Forecast Design and Normal Loads vs. Resources[182]



Notably, Figure 6-1 shows that the majority of this mix of resources will be used in a typical winter, when total loads can easily reach or exceed 1,000 TJ on a cold winter day. In a winter that involves several cold spells, or where these cold spells span several days, a larger portion of resources like market area storage and LNG storage will be used. This figure also illustrates that colder weather in the winter period is highly variable and can occur within any period between November 1 through March 31. Therefore, FEI must ensure that it has sufficient resources in place during the entire 151-day winter period. This weather variability also requires resources that are flexible so that they can be deployed on relatively short notice to meet changes in load requirements.

[182] This forecast is for Core requirements and does not represent total system throughput.

6.2.2 Sources of Regional Gas Supply Resources

The locations where FEI can purchase its gas supply resources and the physical gas storage and pipeline resources that FEI has access to are the foundation of FEI's gas supply planning activities. While there are various contracting and trading instruments that FEI can utilize to acquire gas supplies throughout the year, the physical resources needed to store and transport these supplies onto FEI's system for distribution to customers when needed are the bases for FEI's market planning and actions. These resources are also critical for FEI's use of displacement mechanisms that allow FEI to purchase natural, renewable and low-carbon gas supplies elsewhere in North America while ensuring the physical delivery of energy to customers in BC. As FEI moves forward on its Clean Growth Pathway, access to renewable and low-carbon gas supplies will leverage these physical resources within the PNW for the delivery of the energy customers require. Sections 6.2.2.1 and 6.2.2.2 provide an overview of the gas supply resources that FEI relies on for acquiring and delivering energy to its customers.

6.2.2.1 *Sources of Natural Gas Supply Resources*

For orientation, Figure 6-2 below provides an overview of FEI's operating region, the gas supply basins that service markets in the PNW, the transportation pipelines and storage facilities required by these markets, and the location of the trading hubs where commodity purchases are transacted.

Figure 6-2: Regional Supply Resources – Pipelines, Storage and Trading Hubs

The majority of FEI's natural gas supply is contracted at the supply hubs of Station 2 in Northeast BC, and AECO/NIT (NOVA Inventory Transfer) in Alberta. Alternative considerations when purchasing supply would be at delivered market hubs that are on the international border at Huntingdon/Sumas and Kingsgate. Purchasing supply at these market hubs allows parties to avoid contracting for pipeline resources, although at the disadvantage of increased supply and pricing risks under certain market conditions, which will be discussed next in Section 6.2.4.

Seasonal gas storage is an integral part of FEI's gas supply portfolio as it provides flexibility to meet load variations during the winter and summer months. FEI contracts the majority of seasonal storage with Aitken Creek in NEBC and a currently small portion with Rockpoint Gas Storage in

Alberta. These seasonal storage assets are available to be utilized throughout the winter season as needed. FEI also contracts for shorter duration market area storage resources, which are needed when colder-than-normal winter loads are greater than the supply available from termed gas supply and seasonal storage. FEI contracts these shorter duration assets at Jackson Prairie Storage (JPS) in Washington and Mist Storage in Oregon.

In order to facilitate the purchase of gas supply from various sources and to manage withdrawals and injections from storage facilities for delivery to FEI's transmission system, FEI contracts with third parties for transportation services (Westcoast, TC Energy's NGTL and FoothillsBC, and Williams' Northwest Pipeline (NWP)). Contracting for transportation capacity on Westcoast's T-North and T-South system provides FEI with the principal access to gas supply from NEBC, which is mainly purchased at the Station 2 market hub, and supply that is withdrawn from Aitken Creek. Contracting for capacity on TC Energy's NGTL and Foothills BC systems and utilizing FEI's own SCP allows FEI to access gas supply from the AECO/NIT and Kingsgate markets and Alberta-located storage facilities. Finally, transportation capacity on NWP provides access to redeliveries from storage facilities south of the international border in Washington and Oregon states.

FEI utilizes its own on-system LNG storage facilities at Tilbury and Mt. Hayes to provide high volume gas supply during periods of cold winter weather or during emergency situations. These are the only on-system physical storage resources that FEI has the control over to protect its system, as they are not impacted by third-party transportation or storage capacity disruptions. This is critical during an emergency situation, as on-system storage provides additional response time until the flow of gas from upstream pipelines can be partially or fully restored, or a new supply-demand balance can be achieved by shedding load.

Table 6-2 below provides a high-level summary of FEI's resource portfolio mix that was required to meet the Core customer's load forecast for the 2021/2022 gas year.

Table 6-2: FEI's 2021/2022 Planned Core Peak Day Portfolio[183]

Peak Day Portfolio	2021/2022 Portfolio-Planned (TJ/day)
Fort Nelson Supply	**5**
Alberta Baseload Supply	103
Station 2 Baseload Supply	308
Total Commodity Supply	**411**
Seasonal Supply	135
Seasonal Storage	201
Market Area Storage	211
Spot Supply	120
Mt. Hayes LNG	163
Tilbury LNG	163
Industrial Curtailment	26
Total Midstream Supply	**1020**
Total Resources	**1,436**
Peak Day Demand	**1,436**

6.2.2.2 *Sources of Renewable and Low-Carbon Gas Supply Resources*

Development of the market for producing, transporting, and trading renewable and low-carbon gas resources is relatively new but is growing quickly. At this time, the key resources that FEI anticipates acquiring over the next 20 years and beyond to increasingly displace conventional natural gas supplies are RNG, hydrogen, syngas and lignin, as discussed in Section 3. All of these supply sources will allow FEI to leverage its existing and future infrastructure to deliver low-carbon energy to customers. RNG is interchangeable with conventional sources of natural gas. Hydrogen delivery can be integrated with the existing gas infrastructure in different ways, as discussed more fully in Section 7. Syngas and lignin would utilize existing biomass waste or by-product to deliver energy to nearby industry currently served by natural gas.

By leveraging the energy trading capabilities made possible by the existing gas transportation network, discussed in Section 6.2.2.1 above, renewable and low-carbon gases can be purchased from producers across Canada and the US, with the carbon reduction benefits of that production being delivered to FEI's customers in BC. FEI expects this source of supply to be an important part of its transition to renewable and low-carbon gas supplies, particularly in the early years of the transition. Over the planning horizon, however, FEI expects to purchase or produce increasing amounts of its supplies of renewable and low-carbon gas within BC.

[183] The table is broken into two supply components: Commodity and Midstream. The Commodity supply represents the daily baseload gas required to meet the forecast annual normal load for FEI's Core customers. FEI's Midstream supply manages the variability in customer demand, including the peak day demand. It does this by providing seasonal and peaking commodity, storage services, and pipeline capacity necessary to manage swings in demand.

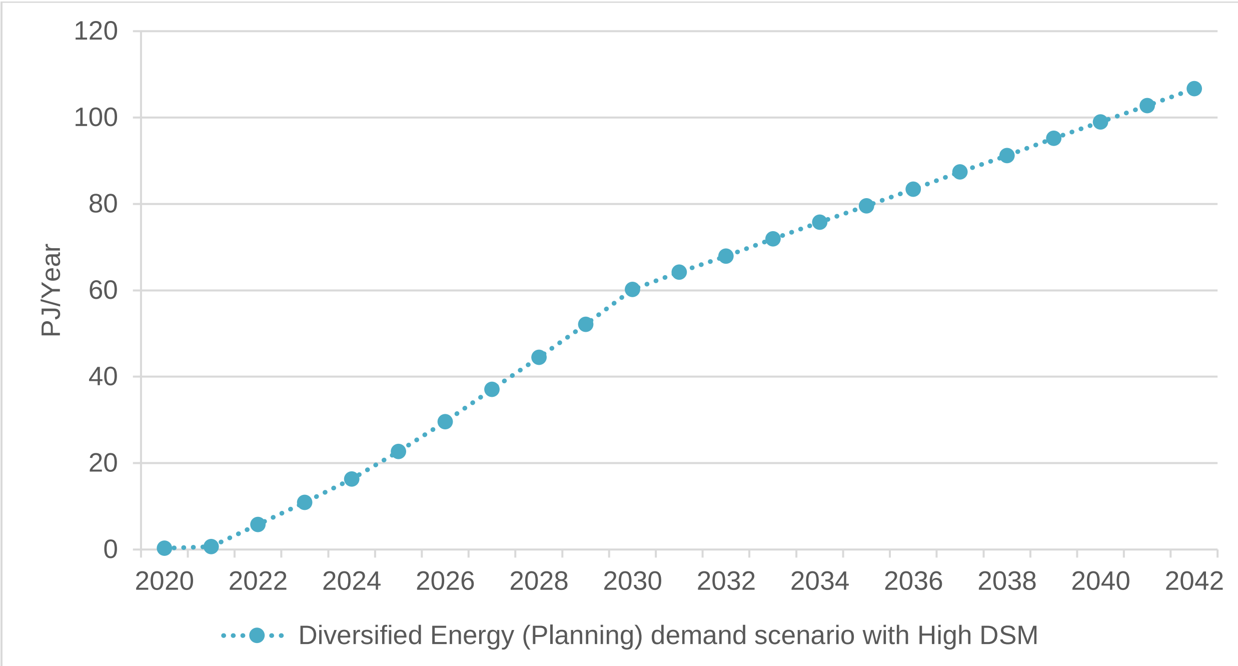
The locations within BC where new supplies will be produced are still being developed. The identified supply volumes are very large and the potential production locations are numerous as identified by the study "Renewable and Low-Carbon Gas Potential in BC and North America", commissioned in partnership with the BC Bioenergy Network and the Province of British Columbia and included in Appendix D-2. The study has assessed the costs of these resources based on information available today, and estimates that a potential of up to 444 PJ per year could be supplied within BC by 2050. This equates to approximately twice FEI's current annual energy throughput.

FEI expects the understanding of the production, supply resources, and market dynamics for these renewable and low-carbon gas supplies to evolve quickly over the coming months and years and will continue to update this information in subsequent LTGRPs. Some concern has been expressed by stakeholders about the competition for these supplies; however, increasing demand for these resources will be a catalyst for accelerating their development and decreasing costs through technology advancement and economies of scale.

6.2.3 Portfolio Integration of Renewable and Low-Carbon Gas Supply

FEI has targeted its long-term acquisition of renewable and low-carbon gas supply to meet BC provincial targets for carbon emission reductions in 2030 and 2050. Figure 6-3 below shows the forecast increase in supplies of renewable and low-carbon gas that FEI expects to acquire annually over the planning horizon. The majority of these supplies will be made up of RNG and hydrogen, with smaller amounts of syngas and lignin, and potentially conventional natural gas or RNG combined with CCUS later in the planning horizon. The amount of each of these types of renewable and low-carbon gas supplies is more difficult to forecast, although FEI expects its forecasts to evolve and be refined in future LTGRPs. Additional discussion of the renewable and low-carbon gas supply mix is provided in Section 7.4, along with a discussion of the implications for FEI's infrastructure needs.

Figure 6-3: Forecast Renewable and Low-Carbon Gas Supply



FEI's modelling of supply resources over the next 20 years has identified the following gas supply resource mix observations for annual demand for the Diversified Energy (Planning) Scenario over the planning horizon and beyond:

To 2030:

- RNG and hydrogen from off-sysem supply sources will be relied on more heavily in the early stages of FEI's carbon reduction transition. Conventional natural gas and RNG will continue to make up the majority of physical deliveries to customers during this period and will be delivered to FEI by displacement as with conventional natural gas purchases[184]. Physical flows of hydrogen on FEI's gas infrastructure are expected to rise but be limited to smaller amounts and portions of FEI's system until around 2030 as the technologies and infrastructure needed to manage larger volumes are refined and implemented.
- One or more syngas and lignin projects will displace some industrial load, though natural gas may continue to provide firm back-up service for periods when syngas or lignin production is unavailable.
- CCUS is expected to still be in development stages, perhaps available in small amounts through pilot projects, in 2030.

From 2030 to 2042:

[184] Off-system supply includes purchases that are injected into another gas system, typically out-of-province, displacing an equal unit of gas, delivered to FEI at a physical delivery point, such as Huntingdon, AECO/NIT, or Station 2.

- This is the latter part of the planning horizon for the 2022 LTGRP and as such is subject to greater uncertainty. The proportion of FEI customers using conventional methane for space and water heating as opposed to other renewable and low-carbon gas supplies will have decreased, but will still make up a majority of customers. While the development of on-system resources will have grown in the intervening years, FEI anticipates there will still be reliance on off-system supplies.

Beyond 2042:

- The steps taken earlier in the planning horizon will set FEI on a pathway to deep decarbonization by 2050 and well on its way to achieving carbon neutrality on an annual basis. RNG and hydrogen will both be an important part of FEI's resource mix.

FEI expects the mix of supply resources described above to apply to a moderate range of possible higher or lower demand forecasts based on a Diversified Energy (Planning) Scenario, in which both the electric and gas infrastructure systems are relied on to decarbonize BC's energy infrastructure.

As the supply of renewable and low-carbon gas grows, FEI will monitor whether the supply is directly connected to FEI's system (on-system) or delivered to FEI's system through displacement (off-system). FEI will also assess the firm amount of supply delivered on FEI's system, or at the Huntington/Sumas, AECO/NIT, or Station 2 market hubs. RNG purchases have different contractual obligations than FEI's conventional natural gas purchases. This is because contracted RNG projects can have either an annual or monthly supply requirement to FEI, or a minimum daily firm amount. Therefore, the volumes delivered to FEI can fluctuate during the month, based on whether the RNG plant is running and other market conditions. This will require FEI to maintain a portion of conventional natural gas within the portfolio to manage the risk of any supply variability.

Over the past several years, FEI has incorporated RNG supply into the gas supply portfolio, and expects the amount of supply will continue to grow. FEI anticipates that the majority of this supply will be secured outside of FEI's service areas (i.e., off-system supply). These supply arrangements will be delivered primarily at the AECO/NIT or Station 2 hubs by way of displacement. Therefore, FEI will still require contracts with third parties for transportation services to deliver gas (whether conventional or RNG) to FEI's customers. The impact to FEI's portfolio for this off-system RNG supply will be a reduction of conventional natural gas commodity purchases at those supply hubs. Section 6.2.4.3 discusses how FEI's contracting strategy will be flexible enough to handle these types of annual adjustments.

As RNG volumes continue to increase each year, FEI will monitor and make any adjustments that are required to the remainder of the gas supply portfolio through each ACP. Additionally, as FEI begins to integrate other low-carbon gas supply such as hydrogen, syngas or lignin, as discussed in Sections 3.3 and 6.2.2.2, FEI will annually assess the impact to the portfolio in each ACP. Although there is still uncertainty as to what the impact will be to each of FEI's service regions, many of these projects will continue to utilize the existing regional natural gas infrastructure (pipelines and storage) in a significant way.

6.2.4 Managing Long-Term Supply Risks within the Gas Supply Portfolio

Consistent with FEI's past LTGRPs, constrained pipeline and storage resources during the winter season continue to be a major concern. Over the past several years, market conditions have caused increased supply and pricing risks in the region. The following three subsections describe the major supply and demand issues that can affect the planning portfolio and how FEI will mitigate these risks with its existing portfolio of resources.

6.2.4.1 *Gas Supply Resiliency Risks*

FEI has provided safe and reliable natural gas service in the province for many years. To provide reliable service, FEI has maintained the integrity of its assets, and ensured the adequacy and security of its supply. FEI has also completed projects over the years that have enhanced resiliency, such as the SCP and the Mt. Hayes LNG facility.

While FEI has long regarded resiliency as an important system attribute, the T-South incident (discussed in Section 3.2.2.3) brought into focus the risk of supply interruption for FEI's customers. FEI obtains most of its natural gas via the Westcoast T-South system, making a disruption on the T-South system the greatest supply risk facing FEI at present. A sudden, prolonged, and wide-scale gas supply interruption could directly or indirectly affect the livelihood, health, and safety of virtually every resident of the Lower Mainland, regardless of whether they are a customer of FEI or not.

Over the past few years, FEI has, to some degree, increased resiliency within the portfolio by holding contingency resources on T-South and by taking back capacity on the SCP.[185] However, FEI has few options to further increase resiliency in the short-term given that resources in the region are fully contracted as shown in Table 6-3 below, and can be constrained during the winter.

[185] A portion of pipeline capacity on SCP was historically contracted out to regional parties. However, FEI took back this capacity effective November 1, 2020, as it was the only opportunity in the marketplace for FEI to diversify its supply portfolio.

Table 6-3: Existing Pipeline and Storage Resources in the Region

Pipeline	Daily Deliverability[1] (MMcf/day)	Total Winter Supply (Bcf)	Contract Status
Westcoast T-South (Huntingdon Deliveries)	1800	272	Fully Contracted
Westcoast T-South (Interior Division)	224	34	Fully Contracted
FortisBC SCP (Oliver North)	140	21	Fully Contracted
FortisBC SCP (Kingsvale)[2]	105	16	Fully Contracted
TC Energy (FoothillsBC)	2930	442	Fully Contracted
NWP Gorge	534	81	Fully Contracted
Market Area Storage	**Daily Deliverability (MMcf/day)**	**Storage Capacity (Bcf)**	
Jackson Prairie Storage (JPS)	1161	25	Fully Contracted
Mist	637	19	Fully Contracted
On System Storage	**Daily Deliverability (MMcf/day)**	**Storage Capacity (Bcf)**	
Mt. Hayes LNG	150	1.5	Fully Utilized on Peak Day
Tilbury LNG	150	1.6	Fully Utilized on Peak Day

Notes:

[1] Daily deliverability is the maximum amount of gas that can flow on the pipeline or the maximum amount of gas that can be withdrawn out of storage. It is important to note that the daily deliverability out of the market area storage is assuming storage inventories are full. The withdrawal rates of these resources decline as working gas volumes decline.

[2] The 105 MMcf/day is included in the 1,800 MMcf/day Huntingdon Deliveries (i.e., Kingsvale to Huntingdon).

In the past, FEI contracted pipeline capacity on third-party pipelines based on the winter design load requirements of its Core customers. Since 2019, FEI has maintained contingency resources within the ACP portfolio and FEI plans to continue this practice for the foreseeable future. Contingency resources are resources (e.g., supply, LNG, and pipeline infrastructure) above the current load forecast for Core customers that can be called on if planned resources are unexpectedly not available or insufficient to meet demand. Each year, FEI will determine a planning margin for contingency resources based on market conditions (e.g., supply risks, and fully or de-contracted regional resources).

FEI will continue to evaluate contingency resources through existing regional assets, and the resiliency of its supply portfolio, until new pipeline and storage resources are developed. Section 6.3 details the pipeline and storage projects that FEI has evaluated for its supply portfolio, and how these developments would fit into future ACPs.

6.2.4.2 *Regional Transportation and Storage Constraints*

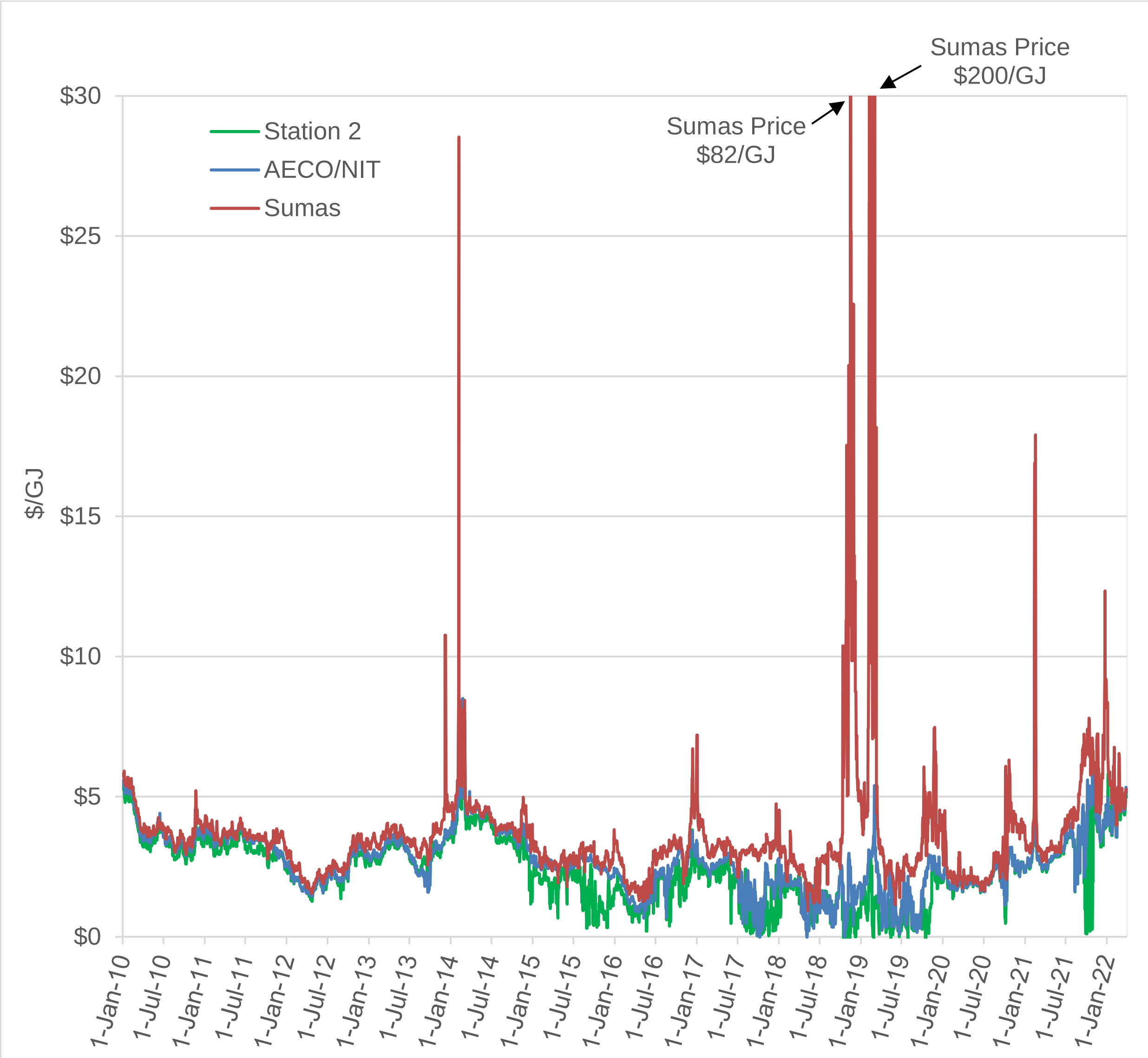
Despite the abundance of gas supply produced in the western Canadian shale gas basins (as discussed in Appendix D-1) and delivered to the AECO/NIT and Station 2 market hubs, constrained pipeline infrastructure to the Huntingdon/Sumas market results in price volatility and Sumas price spikes.

Periods of volatile pricing typically occur when increased demand in the PNW exceeds the delivery capacity of pipelines into the region, which then causes Sumas prices to rise significantly above other market hubs. This typically caused commercial and industrial users to use alternative fuel(s) if possible. Any service disruption on regional infrastructure, as occurred during the T-South incident, can also cause price spikes and sustained elevated prices.

Over the past few years there has been another growing risk to the Huntingdon/Sumas market that results from an increased reliance on natural gas-fired power generation in both the I-5 Corridor and the broader Western markets. As discussed in more detail in Appendix D-1, increased gas demand for electricity generation in the region is due in large part to recent coal-fired generation retirements across western North America that has been replaced by gas-fired generation, strengthening the relationship between gas and electricity markets in the PNW and Western markets.

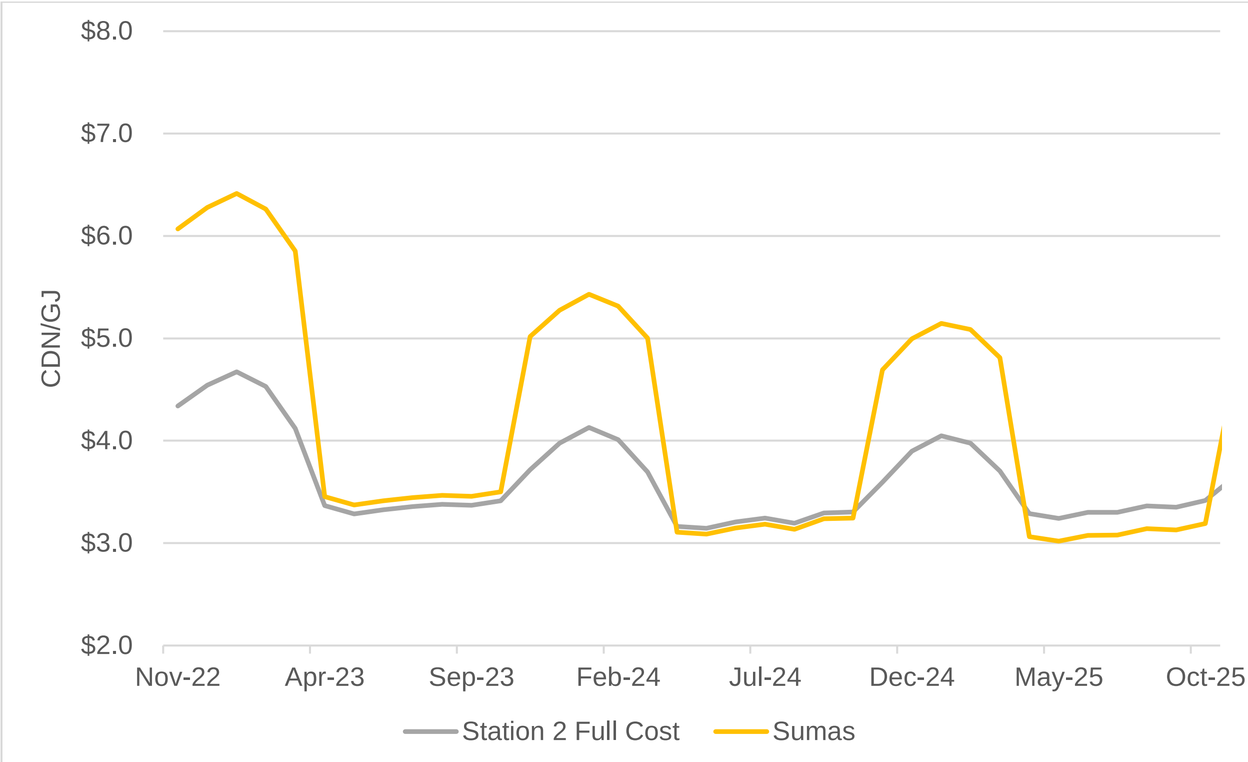
Figure 6-4 below illustrates this volatility, which includes periods of supply disruption. The figure shows historical AECO/NIT, Sumas, and Station 2 daily spot prices over the last twelve years.

Figure 6-4: Historical Daily Market Spot Prices



FEI expects that the Huntingdon/Sumas market will continue to have significant supply risks and pricing volatility going forward until pipeline resources are added to the region. The planned addition of Woodfibre LNG project demand will provide additional supply and pricing risks, as Woodfibre LNG project has already secured firm transportation capacity on the T-South system for a significant portion of their demand requirements. This continued price risk, and constrained resource environment during the winter period is demonstrated through forward prices at the Huntingdon/Sumas market hub, which are shown in Figure 6-5 below.

Figure 6-5: Station 2 Full Cost and Sumas Forward Price Comparison [186]



The forward price curve reflects the market view that there is value for regional parties to hold firm supply resources (pipeline or off-system storage) to manage their winter load requirements, instead of purchasing at the Huntingdon/Sumas market.

FEI's gas contracting strategy for its Core customers in today's marketplace has limited supply exposure to the Huntingdon/Sumas market. This is because FEI's strategy, as accepted by the BCUC in past ACPs, has been to hold firm pipeline capacity and mitigate fixed costs for holding such capacity whenever possible. FEI began to implement this strategy as far back as 2014, given the unfolding market conditions in the region. In FEI's view, this was a less risky and more prudent strategy that provided protection to customers from large price spikes, higher overall gas costs and limited availability of gas at the Huntingdon/Sumas market. However, this strategy does not insulate FEI's Core customers from cost increases, as the tolls on the T-South system have increased over the past few years, due to the restoration of the pipeline after the T-South incident, and the incremental expansion of the T-South system in 2021. These tolling costs will likely continue to increase in the future, given the greater need for maintenance and reliability on aging infrastructure in the region.

Although FEI's Core customers do not currently rely on the Huntingdon/Sumas market, many Lower Mainland customers in the Transportation Service model do, given that they do not have the credit or financial capabilities to secure long-term pipeline capacity on third-party pipelines.

[186] Graph is based off indicative forward pricing provided by Amerex on January 24, 2022. Station 2 Full Cost includes Station 2 forward monthly price, T-South fuel, Westcoast 2021 Final Tolls, Motor Fuel and Carbon Tax.

Currently, these Transportation Service customers have been able to serve their demand requirements by accessing some transportation capacity in the secondary market[187] and by purchasing gas supply at the Huntingdon/Sumas market. In the long-term, however, as new regional demand materializes, specifically from Woodfibre LNG project, much of this capacity is expected to be taken back to serve this new demand, particularly given that the Woodfibre LNG project has already secured its transportation as described above.

FEI first became concerned with these regional transportation and storage resources constraints in 2014 and secured additional T-South capacity to allow for the potential of Transportation Service customers returning to bundled service[188], as well as for future load growth.[189] This proved to be a prudent decision because the T-South to Huntingdon capacity has been fully contracted since that time. FEI began to experience an increase in Transportation Service customers moving back to the bundled service in 2017, but the most significant movement occurred after the T-South incident, when 42 percent (over 900 transportation service customers) provided notice to FEI of their intention[190] to return to bundled service as of November 1, 2019. Given FEI's proactive decision to secure additional T-South capacity for this potential development, the customer movement after the T-South incident did not have a material impact on the portfolio.

Transportation Service customer movement does pose risks to FEI's gas supply portfolio, such as not being able to secure enough incremental resources in the region to serve more Transportation Service customers moving to FEI's bundled service. As previously discussed, FEI has mitigated this risk in the past by securing contingency resources above what Core customers require within its portfolio and will continue to annually assess the planning margin for contingency resources. If additional Transportation Service customers elect to return to bundled service, the existing contingency resources could mitigate a portion, if not all, of this increased Core customer demand within FEI's supply portfolio. However, this will come at the expense of a potentially lower than recent contingency margin.

There is also a risk of having underutilized resources if customers later choose to return to Transportation Service. Despite the future risks of relying on that marketplace, this development could occur if there is a prolonged duration in which the Sumas price is lower than FEI's rate. This potential large customer movement between FEI's bundled service and the Transportation Service model creates planning uncertainty for the supply portfolio, and therefore FEI pre-emptively monitors customer movement between bundled service and transportation service.

[187] Shippers on the T-South system can temporarily release pipeline capacity on an annual or seasonal basis that is not required for their own use.

[188] Bundled service means that a customer purchases both the gas supply and delivery service from FEI. FEI's Core customers take bundled service.

[189] Approved by the BCUC on December 3, 2015 via Letter L-43-15.

[190] This was due to the volatility at the Huntingdon/Sumas market when the average Sumas daily price for the entire 2018/19 winter was approximately $15 CDN per GJ, which was approximately $12 CDN per GJ higher than FEI's cost of gas.

6.2.4.3 *Demand Uncertainties*

As discussed in Section 4, critical uncertainties could result in either increased or decreased annual demand for FEI, and this introduces planning uncertainty over the long term. While FEI's long-term supply outlook has been developed for the Diversified Energy (Planning) Scenario, FEI has also considered the potential for higher or lower demand outcomes as modelled in Section 4. Figure 4-20 shows the range of total scenario demand outcomes that have been modelled in the 2022 LTGRP. Based on this range of demand outcomes and considering the energy savings from DSM activities discussed in Section 5.4.3 and 5.4.4, the following discussion explains that FEI is prepared for managing demand outcomes either higher or lower than the Diversified Energy (Planning) Scenario demand should they arise.

As discussed in Section 2.2.2, several policies such as the Province's plan to cap carbon emissions from gas utility customers, or to transition new buildings to zero-carbon by 2030, may result in less use of conventional natural gas in the residential, commercial, and industrial sectors. There is uncertainty tied to the Diversified Energy (Planning) Scenario and FEI expects the continued development and expansion of renewable and low-carbon gas supply to address these policies. FEI expects increased gas use in the LCT sector. Reducing conventional natural gas supply, however, will not create a major risk to FEI's medium- to long-term supply portfolio planning strategy due to the contracting flexibility of FEI's portfolio:

1. Commodity Purchases – Although FEI has entered into some long-term supply commitments with counterparties, a majority of the gas supply purchased for the Core customers is negotiated on an annual basis and priced off a market index. Therefore, FEI could easily reduce or resell the amount of commodity purchases if Core demand declines or is displaced with low-carbon supply.
2. Transportation Capacity – FEI's transportation portfolio has been designed so that portions of capacity on third-party pipelines are up for renewal each year. This would allow FEI to de-contract a significant amount of its transportation capacity over a five-year period if it encounters a future with lower demand than expected in its planning scenario - the Diversified Energy (Planning) Scenario.
3. Storage Portfolio – FEI's approach to storage contracts is similar to the transportation portfolio; however, the contract terms may not necessarily expire on an annual basis but on a two or three-year period. Storage contracts are more difficult to manage because there are no renewal rights embedded in the contract terms, so FEI must balance term length versus the risk of losing access to storage supply. In any case, if the load duration curve changes over time such that less storage supply is needed, FEI will still have the ability to determine, as a long-term solution, an approach to de-contracting storage resources.

As Figure 4-20 also illustrates, the Diversified Energy (Planning) and Upper Bound demand scenarios show a large step change increase in demand in 2024. This is due to a large-scale industrial project, Woodfibre LNG project, which is discussed further in Appendix D-1. The Woodfibre LNG project would increase the region and FEI's overall load, but not FEI's gas supply portfolio as was shown in Table 6-2, since Woodfibre LNG Limited will be securing its own gas supply. However, if Woodfibre LNG project comes into service, which is likely not until 2027[191] at the earliest, the regional gas flow and prices for all customers may be impacted, and this could also elevate the supply and pricing risks at the Huntingdon/Sumas market.

As such, the risk to FEI's customers (in terms of access to sufficient and cost-effective gas supply) of demand outperforming the Diversified Energy (Planning) Scenario expectations is higher than the risk of demand underperforming the Reference Case expectations. This is due to the limited transportation and storage resources currently available in the region, and competition from other PNW utilities, such as those in Washington and Oregon, for these resources. FEI has already mitigated a portion of this risk through holding contingency resources above the Core customers' portfolio, as previously discussed, and will continue with this strategy to manage increased load until new infrastructure (pipeline and storage) is added to the gas system.

This demand uncertainty over the coming decades highlights the importance of continually assessing the demand, supply, and market conditions each year through the ACP process, and any infrastructure projects needed as part of FEI's supply portfolio.

6.2.5 Managing Pricing Risks within the Gas Supply Portfolio

FEI's gas supply portfolio includes diversified commodity, storage and transportation resources to maintain supply reliability and reduce commodity price uncertainty. While the ACPs include the portfolio of resources for each upcoming gas year, they also include resources and contracts that extend for five years and longer. This is because the natural gas marketplace is competitive and many resources cannot be acquired, or contracted for, just prior to each gas contract year but instead must be planned for and arranged ahead of time.

Volatility in natural gas prices is partially managed by maintaining access to supply hubs, utilizing a variety of storage and transportation resources, and using different pricing structures and contract terms. FEI manages price risk by accessing appropriate natural gas infrastructure, minimizing reliance on any supply that is delivered on an interruptible basis, and diversifying the gas supply portfolio, including by considering the measures discussed in Table 6-4.

Table 6-4: Price Risk Managing Mechanisms and Benefits

Measure	Benefit
Purchasing physical supply at daily and monthly index prices.	Provides pricing stability in the portfolio, as periods of high winter demand can cause daily priced supply to trade at levels much higher than monthly priced supply, and vice versa

[191] FEI notes the inclusion of a step change demand increase caused by Woodfibre LNG project in 2025, rather than 2027, within demand charts elsewhere in this LTGRP. This difference is due to the announcement of the updated in-service date coming after much of the demand modelling for the LTGRP was already complete.

Measure	Benefit
Ongoing evaluation of purchasing supply based on different pricing arrangements. This could include gas supply arrangements based on a fixed pricing structure.	Fixed-price physical purchases provide long-term security of supply as well as provide mitigation against market price volatility.
Contracting for term purchases outside the gas year (not exceeding three years) if the Station 2 monthly discount to AECO/NIT is wider than a target level laid out in the ACP.	Has allowed FEI to layer in term supply by reducing the buying exposure at Station 2 during a given contract year.
Extending the Negotiation Period[192] for when FEI purchases winter term supply at Station 2.	Provides additional pricing diversification within the portfolio, as term purchases would be layered in over a longer period of time
Procuring seasonal and market area storage capacity and deliverability from third parties.	Storage diversifies FEI's overall portfolio by not having to buy all of its winter gas requirements during the winter time. This also provides a natural physical winter hedge by locking in the value between summer and winter gas prices for gas that will be used during the heating season.
Diversifying storage resources by utilizing different storage facilities and staggered contract expiry dates.	FEI contracts for storage capacity at Aitken Creek Storage in BC, Rockpoint Gas Storage in Alberta, and JPS and Mist in the US. Storage contract terms and expiry dates are staggered to provide optionality for portfolio shaping, reduction in negotiation failure risks, and to alleviate the need to contract for large volumes of storage capacity, particularly during periods of high storage prices.
Utilizing the Tilbury and Mt. Hayes LNG facilities to balance the load in cold or extreme weather conditions, or to provide gas supply during emergency conditions.	The deliverability from these facilities helps to manage price volatility at the Huntingdon/Sumas market, while providing a secure source of on-system gas supply.

Financial hedging strategies, which are assessed through PRMPs, are another way of managing price volatility and the natural gas commodity costs. Hedging involves the use of financial derivative instruments wherein the market index-based price for gas supply purchases is converted to a fixed price or capped price (i.e., financial swap) via a transaction with a counterparty, such as a bank. The benefits of this approach include greater gas supply cost certainty and protection against rising market prices. It is important to note that hedging directly impacts the cost of gas supply for the medium or longer term while other rate smoothing mechanisms, such as the use of deferral accounts, do not directly affect gas costs but rather defer costs or surpluses over the shorter term.

[192] Term supply transactions are typically completed between one and six months prior to the gas delivery date (Negotiation Period). Since 2021, FEI has extended the Negotiation Period to ten months for winter term supply.

The last PRMP application filed to hedge prices at AECO/NIT was FEI's 2018 PRMP. This application included requests for approval of a medium-term hedging strategy at AECO/NIT, which recommended locking in up to fifty percent of the commodity supply portfolio with fixed price hedges if predefined price targets were reached, and implementing long-term hedging with terms up to five years. The 2018 PRMP was denied approval by the BCUC.[193] While the goal of FEI's price risk management is not to "beat the market", it is to capture opportunities to lock in prices and reduce rate volatility. FEI considers the development of its price risk management strategies an iterative process and continues to monitor market conditions at AECO/NIT and Station 2, and may look to bring forward another request to the BCUC for approval in the future depending on market conditions. Currently, FEI's PRMP has focused on mitigating any Sumas pricing exposure that the Core customers may have at the Huntingdon/Sumas market. Over the long term, this exposure will depend on load growth and market conditions in the region. The strategy to mitigate the Sumas pricing risk has been generally approved in the past by the BCUC. Going forward, FEI's price risk management strategies will continue to be assessed in consideration of market conditions and any underlying exposure to customers.

The price risk management tools discussed in this section have not yet been widely applied to renewable and low-carbon gases. However, with rapid industry growth and increasing supply availability expected over the planning horizon, FEI may seek to apply these tools and tactics to these renewable and low-carbon gas supplies as well. As renewable and low-carbon gas supply increases in its portfolio, FEI may look to use price risk management tools to help manage the costs for these supplies as well.

6.2.6 Short-Term Actions

FEI will continue to develop a portfolio that provides its customers secure and reliable supply for the short to medium term. FEI's efficient supply portfolio consists of natural gas commodity contracts, third-party pipeline capacity and storage resources, and FEI will continue to assess the regional market for renewable and low-carbon gas volumes and adjust the portfolio annually as needed through the ACP. Near term efforts in acquiring renewable and low-carbon gases are aimed at accelerating the transition to a low-carbon energy future to meet 2030 provincial emission reduction targets.

Until new infrastructure is added in the region, FEI's contracting strategy will continue to hold more resources than the Core customers require within its portfolio of resources. Maintaining contingency resources mitigates the risk of supply disruptions, but also benefits FEI for the next few years in ensuring sufficient resources for the expectation of continued small amounts of growth in the short-term. Further, FEI resells excess resources on the day or month if they are not required, which helps to mitigate the costs of the total portfolio. The alternative is to attempt to contract for additional resources in the future when they are forecast to be needed. However, given the current demand for these resources and their value, it would be difficult or even impossible to re-contract the resources back in the future.

[193] BCUC Decision and Order G-108-19 (May 22, 2019).

6.3 *INFRASTRUCTURE CONSIDERATIONS TO FURTHER OPTIMIZE FEI'S SUPPLY PORTFOLIO (MEDIUM TO LONG-TERM ACTIONS)*

The following subsections outline medium to long-term considerations that could further optimize FEI's gas supply portfolio planning and help mitigate the planning uncertainties discussed above. Additional infrastructure in the PNW has been a major focus for FEI, especially in light of the T-South incident, growing demand in the region, and the necessary requirements to transition to a renewable and low-carbon energy future.

6.3.1 Mist Storage Facility Capacity and Contracting Potential

The Mist storage facility is located in Oregon and owned and operated by NW Natural. FEI currently has a variety of market area storage contracts at Mist, each with different capacities, expiry dates, and injection and withdrawal capabilities. FEI's market area storage contracts at Mist are recallable, which means once these contracts expire, NW Natural may take back all or a portion of the storage capacity for their customer load requirements. This has not been an issue for FEI in the past because recalls have impacted other Mist customer contracts. NW Natural has also added less-than-firm resources in their supply portfolio which have provided additional supply resources in the near term, but are expected to be discontinued once Woodfibre LNG project is in service, since the amount of demand from Woodfibre LNG project could affect regional gas flows. If this change occurs in NW Natural's resources, it will cause a recall and could cut into the Mist capacity FEI has historically held.

The market area storage resources are essential to FEI's gas supply portfolio especially when colder than normal winter loads are greater than the supply available from seasonal storage and termed gas supply (Figure 6-1). Alternative resources in the region are evaluated by FEI on an annual basis, however, they are limited given that resources in the region are fully contracted and can be constrained during the winter, as discussed in Section 6.2.4. Further, alternative resources in the region do not have the same benefits that Mist provides in terms of helping FEI balance and meet load requirements on an intra-day basis. Given that the T-South pipeline is fully contracted and the value of holding the T-South capacity is strong, the pipeline has run at or near its maximum capacity available each winter season over the past several years. Therefore, when demand increases over the course of the day, FEI has to rely on its market area storage resources to meet the changing load requirement.

In the long-term, FEI will proactively assess the need for market area storage, as impacted by future peak demand, its winter load profile, and the daily balancing requirements of the system in normal operations. FEI has had some preliminary discussions with NW Natural regarding the potential to contract for long-term non-recallable capacity. In order for this to occur, NW Natural would have to further expand its Mist storage facility.

6.3.2 Tilbury LNG Storage Expansion (TLSE) Project

The Tilbury Base Plant[194] was built and sized to ensure that adequate natural gas supply was available to provide service to FEI's customers on the coldest days, managing the very short durations when demand during cold weather events exceeded contracted supply. Given that Tilbury is located on-system, it also provides benefits related to security of supply, reliability and flexibility to serve loads within FEI's system.

The experience of the T-South incident signalled that enhancements to gas supply resiliency are required, especially the ability of the system to withstand and recover from a no-flow[195] event. The T-South incident resulted in a two-day no-flow period, whereby commercial arrangements within FEI's gas supply portfolio were suspended. Under these types of emergency events, the physical resources that FEI has under direct control are critical. Although the Tilbury Base Plant helped during the T-South incident, ultimately its regasification capacity and storage are insufficient to support the daily load in the Lower Mainland on most days of the year, with the greatest shortfall occurring during the winter months.

Therefore, FEI applied to the BCUC for a CPCN for the TLSE project[196] on December 29, 2020, which entails constructing a new 3 Bcf LNG storage tank and 800 MMcf per day of regasification capacity. The TLSE project will significantly increase the resiliency of FEI's gas system in the event of a critical disruption of regional pipeline supply by:

- Allowing FEI to continue to serve a much larger portion of the daily system in the event of a supply emergency, including during winter periods; and
- Providing sufficient storage to meet that larger portion of the daily system load for a longer period of time (i.e., at least three days), having regard to a reasonable estimate of the time during which supply to FEI's system could be disrupted. This would allow additional time for FEI to make any necessary operational decisions so that, if needed, FEI could execute a controlled shutdown.

The LNG storage volume and regasification capacity are intended for resiliency purposes. From a planning perspective, FEI will reserve 2 Bcf in the tank at all times to meet FEI's Minimum Resiliency Planning Objective (MRPO),[197] and the incremental 1 Bcf will provide flexibility for gas supply, operational purposes, and future load growth. Further, the TLSE project will also replace the Tilbury Base Plant, which is currently part of FEI's gas supply portfolio, as shown in Table 6-2. This is important because absent the Tilbury Base Plant, FEI would have to find a replacement

[194] The Tilbury Base Plant refers to the original production and storage facility in operation since 1971.

[195] A no-flow event refers to an incident affecting regional pipeline infrastructure that results in the total interruption of gas flows on the pipeline.

[196] FortisBC, Application for a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion project (Application) (December 29, 2020), online at: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/201229-fei-tlse-cpcn-application-redacted-ff.pdf?sfvrsn=8aed3564_2.

[197] FEI developed a MRPO for the TLSE CPCN as a way to conceptualize or articulate the identified risk that FEI's Lower Mainland system faces from a disruption on the T-South system based on FEI's actual experience. The MRPO was defined as having the ability to withstand and recover from, a three-day no-flow event on the T-South system without having to shut down portions of FEI's distribution system or otherwise lose significant firm load.

for this storage in the open market. Contracting for the existing 150 MMcf per day peaking asset in the open market would be both challenging and costly, given that the resources in the region are fully contracted (as shown in Figure 6-4 above).

The TLSE project will also continue to be a vital resiliency resource within FEI's Clean Growth Pathway, as the transition to renewable and low-carbon gas takes place. The shorter duration peaking supply service provided by the TLSE project will continue to be utilized beyond the 20-year planning horizon of the 2022 LTGRP. RNG, which will form a large portion of the renewable and low-carbon gas supplies over the planning horizon, is methane and therefore interchangeable from a system infrastructure perspective with FEI's current natural gas supplies. Hydrogen, the other major component of the renewable and low-carbon supplies over the planning horizon, is not as interchangeable with natural gas as is RNG, but its use by FEI's customers can still benefit from the resiliency benefits of the TLSE project over time.

This project is currently before the BCUC and if approved, FEI plans to initiate the execution phase for the project in 2023, which would result in the project completion occurring in 2026.

Following an emergency, it is typical for the outage to be followed by a ramp-up to normal supply conditions. For example, after the two-day "no flow" period during the T-South incident, supply to FEI's system remained constrained for approximately 14 months. Although the TLSE project is intended to address relatively short-duration supply disruptions in the Lower Mainland, the period of time that the TLSE project will help following a ramp-up back to normal supply conditions is limited by the storage tank size. The next section discusses how additional pipeline infrastructure, such as the RGSD project, would provide further resiliency by ensuring that alternate pipeline supply is available during a T-South event that involves a sustained loss of pipeline capacity.

6.3.3 Regional Gas Supply Diversity (RGSD) Project

The need for new regional pipeline infrastructure (such as the RGSD project) is predominantly driven by the following three market conditions which are outside of FEI's control:

1. **Constrained Capacity on the T-South System:** FEI, and the PNW as a whole, rely on the T-South system for the majority of their daily gas supply. Despite nominal increases in capacity as recently as November 2021, the T-South system remains fully subscribed due to high demand in the region. As discussed in Section 6.2.4.2 above, the region has been facing several periods of market price volatility at the Huntingdon/Sumas market during the winter seasons. This pricing volatility is a reflection that the regional infrastructure is becoming more constrained. Also, as discussed above, the T-South incident highlighted the serious supply shortfall the region faces in a circumstance where pipeline capacity is either restricted or entirely interrupted for a period of time. From a resiliency perspective, the continued reliance on a single pipeline system to provide the majority of gas supply to the region is a serious risk that needs to be addressed.
2. **Forthcoming Increases in Regional Demand:** Constrained pipeline capacity and supply disruption risks will be exacerbated by both the addition of load associated with the Woodfibre LNG project and load growth in the region over time. Woodfibre LNG project

going into service will leave an immediate, significant capacity shortfall. Moreover, the demand for gas-fired electricity in the US PNW is expected to continue growing with the retirement of coal-fired generation. These developments, among others, will drive new regional pipeline infrastructure.

3. **Expansion of Renewable and Low-Carbon Gas Supply Due to Government Policy:** Government policies aimed at decarbonization drive a need for RNG and hydrogen from new supply sources, with hydrogen blending into the gas system requiring capacity increases due to its lower energy density.[198] As hydrogen emerges in the market, it will be blended into existing gas transmission and distribution systems. Additional pipeline capacity will be required to support this transition, as more volume of hydrogen will be required to deliver the same amount of energy as conventional natural gas.

To protect the interests of FEI and its customers, FEI needs to influence which regional pipeline infrastructure gets built, thereby maximizing the value obtained from it. The RGSD project would involve an expansion of SCP through construction of additional compressor stations and a new pipeline connecting SCP near Oliver, BC to the Huntingdon/Sumas market. This project will increase the capacity to the Huntingdon/Sumas market by approximately 500 TJ/day[199], and is FEI's preferred choice given that it would open valuable access to an entirely different path from the T-South system. This would provide FEI with greater access to one of the largest natural gas trading hubs in North America (AECO/NIT), and allow FEI to split its gas supply portfolio between Station 2 and AECO/NIT more evenly via the new pipeline, thereby diversifying its supply resources, improving its long-term supply security, increasing supply resiliency and further optimizing its supply portfolio.

Therefore, FEI will file an application for approval of a deferral account for the development of the RGSD project in Q2 2022.[200] This application will more fully describe how the RGSD project aligns with Section 2 of the *Clean Energy Act* and how the RGSD is needed along with other infrastructure to meet resiliency requirements, future demand forecasts in light of regional supply constraints and the transition to renewable and low-carbon gas.

Employing a mix of pipeline diversity (i.e., the RGSD project) and expanding storage resources (i.e., the TLSE project) is the most cost effective way to enhance resiliency, facilitate load growth opportunities, support the transition to renewable and low-carbon gas, while also creating flexibility within FEI's gas supply portfolio. Stated another way, it would not be efficient, or in the interest of customers, to build resiliency by holding year-round diverse pipeline resources in quantities that would only be required if a no-flow event occurred during a short duration peaking period. Conversely, it is unlikely to be feasible or economic to attempt to manage long-duration

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[198] Hydrogen blending requires more pipeline capacity to move the same energy; compared to natural gas hydrogen has a much lower energy content partially offset by higher velocity capability.

[199] The pipeline capacity could be expanded to more than 500 TJ/day, depending on potential interest from third-party shippers. It is expected that FEI and other parties would contribute to the cost of the project.

[200] FEI anticipates filing the RGSD development cost deferral account application in Q2 2022.

supply events or exposures only with on-system LNG storage, since the amount of storage required would be too large.

6.4 CONCLUSIONS AND RECOMMENDED ACTIONS

Effective gas supply portfolio planning and price risk management on the short-, medium- and long-term basis enables FEI to secure cost effective and reliable supply and mitigate market price volatility for customers. Given the regional marketplace developments in terms of gas supply and infrastructure, FEI must continue to monitor changes and be proactive in assessing challenges and identifying opportunities in order to meet the LTGRP objectives, and may look to bring forward another price risk management application for approval in the future.

The constrained pipeline and storage resources in the region during the winter season continues to be a major concern, and market developments have caused significant supply and pricing risks. FEI has increased resiliency within the existing portfolio by holding contingency resources; however, resiliency needs to be further improved through new infrastructure projects. With the advancement and growth of renewable and low-carbon gas supplies in the region, FEI's future infrastructure is being planned to support the transition to a lower carbon future by providing increased resiliency and supporting a broader range of supply resources.

As resources in the region are limited, by monitoring potential changes in demand or market conditions, FEI maintains an evolving strategy to assess its supply portfolio annually through the ACP. FEI's portfolio does maintain contracting flexibility to mitigate security of supply risk, and is in adequate position for the short-term, but ultimately meeting increased demand over the long term will require increased storage and pipeline infrastructure.

Recommended actions that FEI will take to manage FEI's gas supply portfolio include:

- Manage supply risk and price volatility in the region by maintaining access to supply hubs (Station and AECO/NIT), hedging any supply exposure to the Huntingdon/Sumas market with financial hedges, utilizing a variety of storage and transportation resources, and using different pricing structures and contract terms;
- Continue using financial hedging strategies as approved by the BCUC in FEI's PRMPs and, where applicable, request BCUC approval for an expansion of financial hedging strategies via future PRMPs;
- Continue to support the regulatory process for the TLSE project which will significantly increase the resiliency of FEI's natural gas system in the event of a critical disruption of regional pipeline supply;
- Evaluate opportunities within FEI's own operating region to improve infrastructure resiliency and supply diversity such as the RGSD project, which will support diversity, reliability, and decarbonization over the long term;

- Evaluate opportunities to contract for long-term non-recallable capacity at Mist, which will help manage security of supply concerns in the gas supply portfolio.
- Continue to accelerate the acquisition of renewable and low-carbon gas supplies for inclusion in FEI's gas supply portfolio as part of FEI's Clean Growth Pathway; and
- Assess the firmness of renewable and low-carbon gas supplies for year-round delivery to customers and assess the evolving marketplace for opportunities to apply traditional portfolio risk mitigation mechanisms to these renewable and low-carbon supplies.

FortisBC Energy Inc.
2022 LTGRP

Section 7:

SYSTEM RESOURCE NEEDS AND ALTERNATIVES

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7. SYSTEM RESOURCE NEEDS AND ALTERNATIVES

7.1 *INTRODUCTION*

This section discusses FEI's gas delivery infrastructure and identifies any system resource needs in consideration of regional peak capacity and the energy demand of its customers, addressing the requirements of subsections 44.1(2)(d) and (f) of the UCA. While Section 6 described FEI's energy supply portfolio for deriving system-wide demand for Core customers each day through the entire year, as well as the peak design day, this Section 7 describes system resource planning for deriving location-specific (not system-wide) peak demand. Key aspects of providing a safe, reliable, and secure supply of gas to customers are identifying when and where any capacity constraints may appear, and planning for the infrastructure and system resources that FEI requires to construct over the planning horizon. When forecast peak demand exceeds available system capacity, a gas system expansion is required. FEI recognizes the rapidly emerging need for delivering renewable and low-carbon gases in increasingly larger volumes and has incorporated these discussions in relation to system planning within this section.

Planning for system resource needs includes system sustainment and renewal, integrity upgrades, and system expansion projects that together contribute to overall system resiliency. FEI's system sustainment planning process identifies important near-term and long-term system renewal requirements and projects to improve system integrity. There are traditionally three resource options to evaluate when planning system expansions: pipelines, compression and storage. As FEI continues to develop renewable and low-carbon resources, reliable on-system production will soon become a fourth alternative for consideration. To solve capacity constraints, each alternative is analysed with respect to Indigenous and public impacts, overall cost, difficulty of implementation, operational flexibility, implementation time, and other factors within the overall philosophy of system sustainment and reliability. Often, some combination of the three resource options leads to an optimal solution. Transmission infrastructure projects to address system capacity constraints are often large and take many years to plan and execute, underscoring the need for a long-term resource planning process.

Annual increases in forecast peak demand are influenced by a number of factors. The industrial sector relies on gas for existing, new, or expanded applications, as favourable pricing and a preference for lower carbon natural gas over more traditional fossil fuels such as propane, diesel or coal continues to drive demand. In addition, the LCT sector and opportunities for the LNG market continue to drive growth in demand. The location of customer demand on the system is a significant factor in determining the ability (capacity) of the system to deliver gas.

To address the specific local and regional requirements, FEI builds regional peak demand forecasts from the bottom up, assembling the peak demand from the recent consumption and regional weather history of each customer within the system. FEI conducts this analysis for each of its three main transmission systems: Vancouver Island Transmission System (VITS); Coastal Transmission System (CTS); and Interior Transmission System (ITS).

In the 2022 LTGRP, FEI's traditional peak demand forecasting method (Traditional Peak Method) is compared with a new exploratory method which links peak demand forecasts to the end use scenarios used in the annual demand forecasts. Currently, the exploratory end use method remains theoretical in nature and is unsupported by direct measurement. Until such time as more granular data from advanced metering infrastructure becomes available, FEI will continue to rely on the Traditional Peak Method for infrastructure planning which is predominantly based on current monthly consumption of FEI customers. The exploratory end use method does, however, provide a means of assessing a range of peak demand forecast possibilities and the impacts on the scope and timing of upgrade projects required for each.

FEI takes a broad outlook on system resource needs that considers long-term system capacity and sustainment plans and expansion requirements. This outlook enables an integrated approach to determining the most effective system improvements. This discussion on resource needs is organized as follows:

- Section 7.2 discusses FEI's approach to system capacity planning and describes the method for determining peak demand forecasts and infrastructure project alternatives to address forecast capacity constraints;
- Section 7.3 discusses the capacity of FEI's gas transmission infrastructure to meet current and forecast peak demand for each of FEI's major transmission service regions: VITS, CTS, and ITS. For each of the service regions, the following information and considerations are discussed:
    - Forecasts resulting from FEI's Traditional Peak Method and unique regional peak demand forecasts for LTGRP scenarios and sectors (residential, commercial and industrial and others) before and after DSM energy savings are applied;
    - Potential increases in industrial load, increasing LNG demand, and their impacts on the Traditional Peak Method forecast and system upgrade requirements where these loads are anticipated; and
    - The section further discusses forecast capacity constraints and significant projects impacting FEI's transmission laterals and distribution system networks as described in Sections 7.3.4 and 7.3.5, respectively;
- Section 7.4 introduces the considerations necessary to assess infrastructure upgrades as FEI integrates renewable and low-carbon gases into FEI systems and provides illustrative examples of the capability of FEI systems for their delivery. Further it discusses the system specific implications of renewable and low-carbon gas integration with emphasis on the unique requirements for hydrogen based on its molecular properties in relation to methane;
- Section 7.5 discusses the requirements to continue to improve FEI's systems to be more resilient in the event of supply disruptions that may occur within the regional gas infrastructure or within FEI's own systems; and

- Section 7.6 provides a description of other major system projects that are not driven by system capacity considerations and that FEI anticipates may result in CPCN applications in the next several years.

7.2 SYSTEM CAPACITY PLANNING

This section discusses FEI's approach to system capacity planning and describes the method for determining peak demand forecasts and infrastructure project alternatives to address forecast capacity constraints. Peak demand forecasts for system capacity (infrastructure) planning include considerations of demand at the local and regional level. This is a bottom-up and more granular approach than the approach used when considering system-wide peak demand use for gas supply planning (as discussed in Section 6).

Ensuring adequate capacity within the transmission and distribution systems to meet existing and forecast load is critical to the safety and reliability of gas delivery. After identifying the forecast growth in gas demand and the expected impact of DSM across FEI's service areas, FEI examines the capacity of the gas transmission systems to meet anticipated demand. When forecast demand exceeds available capacity, a gas system expansion is required. Different system expansion alternatives are then identified to determine the most effective means to address specific capacity constraints.

Gas supply resources must be designed to meet peak demand requirements of Core customers[201] (customers for whom FEI purchases gas). Further, when assessing supply resources, gas supply forecasting considers the system-wide peak. This is, in part, because on a system-wide basis, an increase in peak demand in one location can be offset by a decrease in demand in other regions and still meet the supply requirements of the whole system. As system demand changes year-over-year, supply resources can generally be adjusted in a timely and responsive manner to meet the overall peak requirement (refer to Section 6).

In contrast, infrastructure projects to address system capacity constraints on transmission systems are often large and take many years to plan and execute. As a result, securing infrastructure resources is not as expeditious as securing gas supply resources. In addition, the location of customer load within the system is a significant factor in determining the ability of the system to meet customer demand. Increasing peak demand in one region cannot necessarily be offset by a system expansion or decrease in peak demand in another region. To address the specific local and regional requirements, regional peak demand forecasts are built from the bottom up, aggregating the peak demand from the recent consumption and regional weather history of each customer within the system. For commercial or industrial loads that consume gas for process purposes and hence are not primarily driven by heating demand, either their contract demand (if they have one) or their maximum billed demand are used.

[201] Table 6-1 provides a summary of FEI customer service types for the LTGRP, and the considerations required in discussing Section 6 (Gas Supply Portfolio) and Section 7 (System Resource Needs and Alternatives).

Transmission system expansion planning is based on this regional peak forecast of demand for Core customers and also includes Firm Transportation customers not included in gas supply resource planning (as described in Table 6-1). Firm Transportation customers are those that secure their gas supply from a source other than FEI but rely on FEI's pipeline systems to transport gas to their premises for consumption. Some Transportation customers with an interruptible contract, under which FEI can curtail when necessary to control peak demand, also have a portion of their demand designated as firm which must be considered in system expansion planning.

Gas system infrastructure planning must ensure that gas system assets have sufficient capacity (in terms of size, compression requirements, and volume, for example) to meet the demand on a given system. To ensure constraints are identified and considered with sufficient lead time to plan and construct the necessary infrastructure, peak demand forecasts over a 20-year planning horizon are used.

In general, system demand growth is determined by region and applied to hydraulic models which determine resulting pressures at critical locations throughout the system. In the context of growing demand, demand will eventually exceed capacity, which typically manifests by the pressure at critical locations falling below minimum values, and a system expansion is required.

FEI's continuously monitors these factors that can impact capacity requirements to determine if there is a need to advance or delay proposed capacity expansions. Section 7.3 discusses factors that might increase peak demand and thus advance capacity requirements, as well as alternatives for addressing system constraints. Potential for lower than expected peak demand delaying the timing of system constraints is also discussed. As such, contingency planning for system capacity requirements is inherently included in FEI's regional system capacity plans.

In addition to load growth, other factors can also affect system capacity. For example, increased urban density close to existing pipeline assets can lead to a class location designation change and may result in a subsequent reduction in allowable operating pressure for that pipeline. Class location designations are defined in the Canadian Standards Association (CSA) Z662:19 *Oil and Gas Pipeline Systems* standard and used as a protective measure in pipeline design to address population density and other criteria in the vicinity of a pipeline. A reduction in operating pressure to address a class location change due to population growth in the vicinity of the pipeline will lead to a decrease in available pipeline capacity. As FEI incorporates renewable and low-carbon gases into the gas distribution and transmission systems, the physical properties of these gases, such as density and energy content per standard volume, and the ability to generate supply located on-system can have an impact on capacity. These changes in physical properties and supply options must be considered. Section 7.4 discusses the potential impacts of renewable and low-carbon gases on FEI transmission system capacity at a high level.

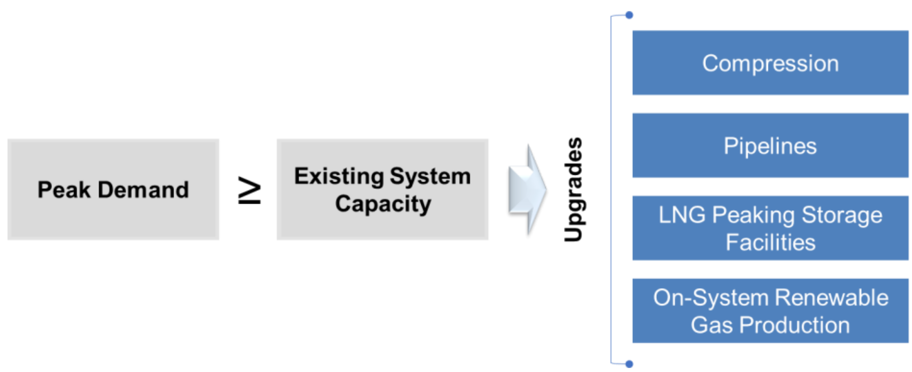
7.2.1 System Reinforcement Considerations

Pipeline capacity is determined by the quantity of gas that can be transported from a supply point at a given supply pressure to delivery points at or above required minimum delivery pressures.

The key objective of any new capacity expansion is to maintain, under peak conditions, pressures at all delivery points sufficient for the system to deliver to the consumer the contracted quantities of gas. Physically, pipeline capacity depends on the diameter and length of the pipeline, internal roughness of the pipeline, maximum operating pressure (MOP), required minimum delivery pressures and the distribution of customer demand along the system. Pipeline pressures are constrained by the MOP. The MOP is established in accordance with provincial regulations and good engineering practices in consideration of original construction specifications. To overcome friction and allow gas to flow through the pipeline, a pressure differential between the supply and delivery points is required. Compressors are used to increase this pressure differential and move large volumes of natural gas at high pressures through the transmission pipelines to major delivery points. The end pressures, which vary inversely with flow, are then controlled by pressure-regulating stations before gas enters the intermediate or distribution pressure systems for delivery to customers.

Traditionally three resource options are evaluated when planning system expansions: pipelines, compression, and storage. Each is described below. In the future a fourth, on-system renewable gas production, will become available. This fourth option is discussed in more detail in Section 7.4.

Figure 7-1: Options for Gas System Reinforcements



- **Pipelines:** To increase throughput capacity, an existing pipeline can be replaced by a larger diameter pipeline (increasing the flow area and decreasing the gas velocity) or it can be "looped" with a parallel pipeline.
- **Compression:** Adding compression helps to increase the average pipeline pressure, thereby providing a higher supply (or driving) pressure to move the gas. This higher pressure also increases the gas density leading to a reduction in gas pipeline velocity and correspondingly lower rate of pressure drop along the pipeline. Compressors can be added to existing compressor sites to provide additional station throughput capacity or new compressors can be added at intermediate locations on the pipeline.
- **On-System Storage:** Storage facilities located within a service region are considered "on-system" supply-side resources. FEI considers LNG storage to be an on-system storage facility. During low demand periods, gas is liquefied and pumped into the storage facility. Conversely, during high demand periods, stored gas is vapourized and compressed back

into the pipeline system to maintain pipeline operating pressure and increase system capacity without having to install throughput capacity from pipelines or compressors. Since FEI can call upon these resources when necessary, system security and reliability increase using these on-system storage facilities. Another benefit of FEI's LNG facilities is the ability to provide customers with the potential to buy LNG for use as a fuel in land or marine transport or for shipping internationally.

To solve capacity constraints, each resource option is analysed with respect to overall cost, difficulty of implementation, operational flexibility, implementation time, and other factors to meet system sustainment and reliability objectives. Either a single resource or some combination of the three resource options will be the optimal solution.

7.2.2 System Capacity Planning Considerations

Options to improve gas system capacity are identified through hydraulic analysis using computer models of the pipeline systems. Computer simulations allow various "what if" scenarios to be evaluated and compared against one another. In determining the need for transmission system expansions, FEI considers the following:

- Optimizing resource capacity additions to meet demand requirements over a 20-year planning period;
- Correlating actual billed consumption information against temperature to determine the expected demand under design temperature conditions;
- Planning capacity additions to meet the total Core customer and Firm Transportation customer peak demand. Interruptible demand is not considered when identifying system improvements to sustain this peak demand. System capacity upgrades identified for supporting firm peak demand provide new opportunities for interruptible customers during off-peak conditions;
- Designing transmission systems to meet peak demand. FEI's Core customer demand varies on an hourly basis and typically exhibits a morning peaking period between six and ten a.m. and an evening period between five and nine p.m. The peak hour demand for these customers can be more than 40 percent above the hourly average (daily demand/24 hours). Transmission systems are designed to meet this peak demand condition;
- The amount of line pack[202] within a transmission system, as this determines whether it should be designed to meet peak day or peak hour conditions. A pipeline system with a large relative line pack can temporarily support increased demand out of the system (to customers) that exceeds the supply into the system by drawing on some of the gas "inventory" contained in the pipeline system. As demand exceeds supply, the amount of gas "packed" in the pipeline (i.e., line pack) is reduced and pressure in the pipeline is drawn down, until such time that the demand drops below the supply into the system, at which point pressure (and line pack) can recover. Pipeline length and operating pressure

[202] Line pack is the "storage" of pressurized gas in the pipeline that can be drawn on to support short-term peaks in demand that may briefly exceed the supply into the pipeline.

determine the amount of line pack available in the system. Typically, longer, larger diameter systems operating at higher pressures with high line pack are designed to peak day conditions; conversely, systems with lower amounts of line pack (due to factors such as lower pressures and smaller volumes) are designed to meet peak hour loads; and

- Long lead times are needed for large infrastructure projects. This is due to regulatory reviews, Indigenous engagement, public consultation, conceptual design, detailed engineering, procurement, construction, and commissioning schedules.

7.2.3 Regional Peak Demand Forecasting

Traditionally, FEI has built regional peak demand forecasts based on the current peak hour use per customer (UPC_{peak}) that is held constant over the planning horizon. Since the 2017 LTGRP, FEI has worked with a consultant, Posterity, in studying a potential means of applying knowledge gained from the end use method of forecasting annual demand to forecast how UPC_{peak} might vary for each end use future scenario presented in Section 4 as well as how DSM programs may affect peak demand.

7.2.3.1 *Traditional Peak Method*

FEI has long-established methods for creating regional peak demand forecasts that have worked well in identifying system constraints and developing projects to address constraints in a timely fashion. FEI's Traditional Peak Method forecast is built from a "load gather" process that determines unique daily and hourly UPC_{peak} values for each customer. Values for most customers are based on a regression analysis of average consumption against local temperature using the most recent 24 months of consumption information extracted from monthly meter read data. Measured values are then extrapolated to the regional design temperature where the customer is located. The regional design temperature represents a one in 20-year value determined for each region. For customers where hourly consumption data is available (typically large commercial and industrial customers), UPC_{peak} is determined directly from that data. The unique hourly UPC_{peak} values for each customer are then grouped by rate and region to determine average hourly UPC_{peak} for each region and rate schedule that can then be applied to an account forecast to determine a peak demand forecast. A unique UPC_{peak} for residential, small commercial and large commercial rate schedules in 66 separate regions across the province is developed in FEI's Traditional Peak Demand Method.

For large industrial demand, the Traditional Peak Method forecast does not apply any forecast growth or decline in the demand associated with these customers. This is because the ability to forecast both the future load and location of these customers is subject to a great deal of uncertainty. UPC_{peak} for large industrial customers varies widely and can significantly impact local system capacity. Speculating on infrastructure requirements for loads of unknown magnitude and location has little value in long-term planning of facilities whose design can be greatly influenced by their location within the transmission or distribution system. However, to explore impacts to peak demand because of potential changes in industrial account forecasts, FEI has produced both high and low account forecasts that show increasing or decreasing numbers of accounts, respectively. These forecasts have been applied to the end use regional peak demand forecasts using the average peak demand for existing industrial customers in that region as an estimate of the peak demand for any new account additions or subtractions. As the location of new industrial demand is not specifically known, this increase or decrease in industrial peak demand was applied proportionally across the relevant transmission system.

UPC_{peak} values used in the Traditional Peak Method forecast are determined based on current measured consumption for customers. When applied to the 20-year account forecast to determine the peak demand forecast, these values are assumed to remain unchanged over the planning horizon. As such, there is no explicit allowance for evolving customer utilization in this approach. The estimates of UPC_{peak} and the peak demand forecasts are "point in time" forecasts, however, and are refreshed annually. Therefore, assessments of future capacity constraints and timing upgrade projects are regularly refreshed with current customer consumption patterns and end uses that reflect the presently measured impacts of energy economics, housing renewal, and DSM programs.[203]

The Traditional Peak Method forecast currently remains FEI's base forecast for determining infrastructure requirements and timing for addressing capacity constraints.

7.2.3.2 *Deriving Regional Peak Demand Forecasts from End Use Scenarios*

In its decision regarding the 2014 LTRP, the BCUC identified opportunities to make stronger linkages between the peak demand and the annual demand forecasts, to understand how "[...] new insights on evolving customer consumption patterns might affect time-of-day demand as well as annual demand [...] and how changes in base load annual demand under different scenarios translate into changes in base load peak demand under the same scenario assumptions."[204]

For this LTGRP, FEI commissioned Posterity to develop an exploratory process linking peak demand forecasts to the end use scenarios used in the annual demand forecasts. Currently the process remains theoretical in nature and unsupported by direct measurement. Until such time as data from advanced metering becomes available, FEI's infrastructure planning continues to rely on the Traditional Peak Method which is predominantly based on current monthly consumption of FEI customers. The exploratory end use method does, however, provide a means of assessing a range of peak demand forecast possibilities and the impacts on the scope and timing of upgrade projects required for each.

Posterity's approach relies on applying a series of appliance load shape profiles, developed from industry studies on appliance use, to sequentially break down annual consumption into peak monthly consumption, monthly to peak daily consumption and finally daily to peak hourly consumption. Using the base year LTGRP inputs developed for the annual demand forecast, Posterity derived a base year hourly UPC_{peak} for each rate schedule and region. The results were

[203] In the Section 6 analyses, the term DSM refers to FEI's forecast DSM activity discussed in Section 5.
[204] 2014 FEI Long-term Resource Plan (LTRP) Decision and Order G-189-14, p. 22.

corrected to peak design temperatures for each region. Posterity then determined calibration factors to match the derived UPC_{peak} values for the base year to FEI's current values of UPC_{peak} (determined from FEI's established load gather process and used in FEI's Traditional Peak Method regional peak demand forecasts). The process, using the derived calibration factors, can then be applied similarly to any year in any scenario to derive UPC_{peak} forecasts and subsequently peak demand forecasts in a format that can be easily applied to FEI's established capacity modelling methods.

The results provide a means for relating annual demand more directly to peak demand. Future effects of DSM programs and the potential impact on peak demand and infrastructure requirements can be reviewed using this approach. This exercise also provides some indication of how various end use scenarios might influence the peak hour factor (PHF), which is the ratio of peak hour consumption to peak day consumption. The results of this exploratory, end use approach are represented below in the sections discussing each regional transmission system.

Since the exploratory end use method is not based on metered FEI customer data, and the effectiveness of DSM programs on peak demand cannot be directly measured until hourly metering is deployed, the Traditional Peak Method forecast, which intrinsically reflects the current effects of DSM programs, remains FEI's base forecast for determining infrastructure requirements and timing for addressing capacity constraints. However, FEI's current application before the BCUC for its AMI project will support FEI's ability to field-validate the projections of the exploratory end use peak demand forecast method and will enable FEI to improve this method in future LTGRPs.

7.3 *REGIONAL TRANSMISSION SYSTEM CAPACITY PLANS*

For capacity planning purposes, FEI is split into three main transmission systems and several smaller transmission laterals. The three main transmission systems are described below:

- The VITS encompasses customers served on Vancouver Island, the Sunshine Coast, Squamish and Whistler;
- The CTS encompasses the Fraser Valley and surrounding cities, and Metro Vancouver; and
- The ITS encompasses the Southern Interior communities in the Kootenays, the Okanagan Valley, and the South Thompson Valley.

Each of the three main transmission systems is discussed in further detail below. For each system, FEI will discuss:

- Existing major system infrastructure;
- Demand and capacity balance, which determines approximately when demand in the region will reach the capacity of the system to deliver natural gas during peak conditions, thus identifying when system constraints will occur;

- Peak demand forecast sensitivity using the range of peak demand forecasts before and after DSM energy savings are applied;
- System expansion alternatives. These are the infrastructure options that exist for solving identified system constraints. The options for constraints that occur in the near term are more developed and are presented in more detail than those that are further out in the planning period;
- Potential increases in industrial load, increasing LNG demand, and their impacts on the Traditional Peak Method forecast and system upgrade requirements where these loads are anticipated; and
- The impact of delivering renewable gases and hydrogen on the system.

FEI examines these factors to identify the expected timing of system constraints and the action plan needed to develop formal solutions that may require further expenditure applications to the BCUC. Year after year, changes in the planning environment and new information may emerge that could impact the timing of the constraints, or the alternative solutions being considered. Such changes will be presented in future LTGRPs or in any required applications to the BCUC.

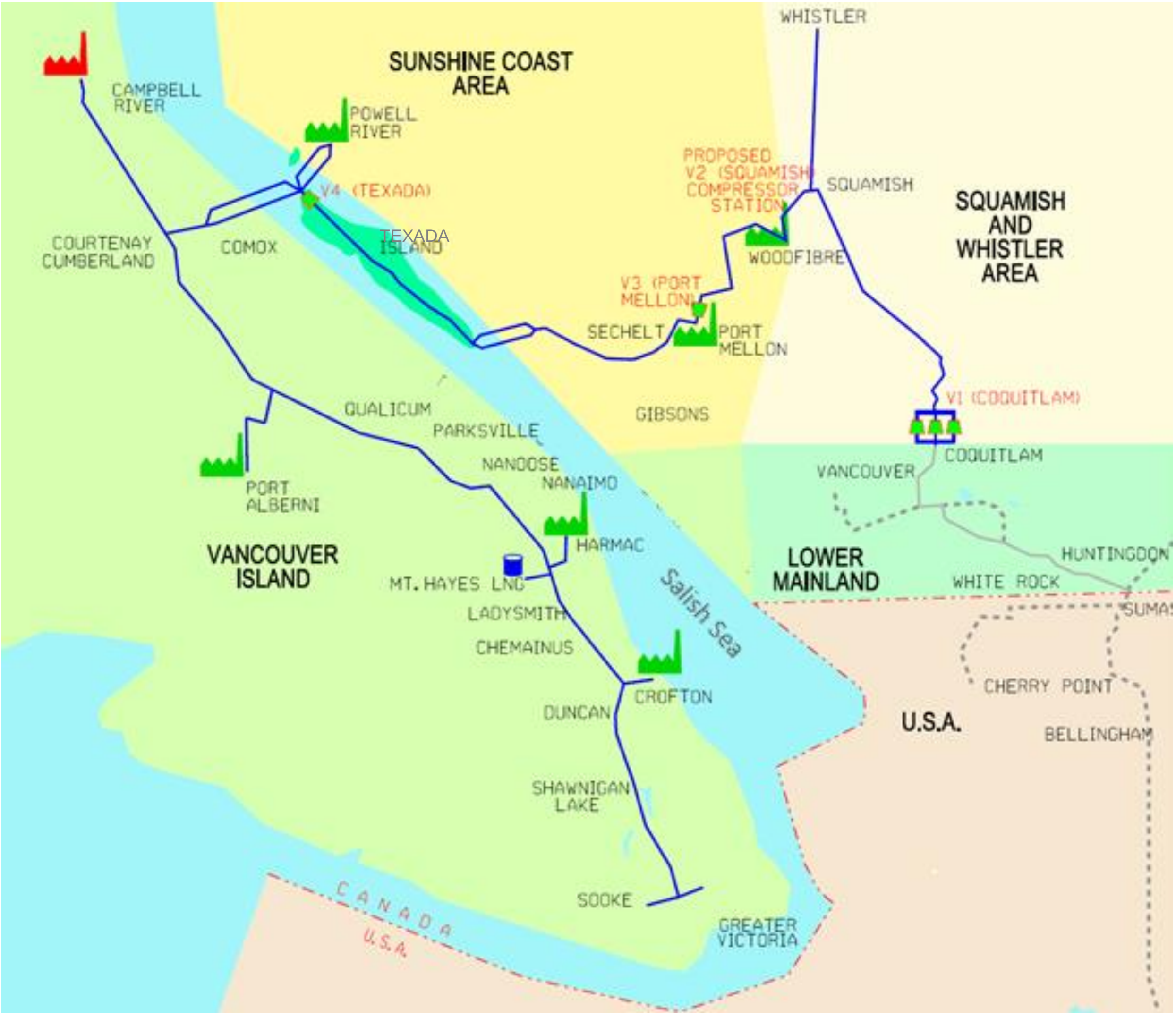
While not discussed in detail in the following sections, for peak demand associated with future CNG, FEI projected that incremental annual CNG demand of 15,000 GJ per year would result in a new fueling station constructed somewhere in the regions served by the three main transmission systems. A typical fueling station designed to deliver up to 15,000 GJ per year is estimated to exert a peak hour demand of 750 standard cubic meters per hour. These peak demands are based on fast-fill stations currently installed or being designed throughout the FEI system. The peak demand impact of CNG in all systems does not produce a significant change in peak demand or adjust the timing of any identified capacity upgrades and is not explicitly shown in the forecasts that follow.

7.3.1 Vancouver Island Transmission System

The VITS serves Vancouver Island, the Sunshine Coast and feeds the communities of Squamish and Whistler. It consists of 626 kilometres of high-pressure pipelines, including three twinned marine crossings of the Salish Sea, three compressor stations, and the Mt. Hayes LNG storage facility near Ladysmith. The system serves approximately 140,000 residential, commercial and industrial customers. Natural gas for VITS customers is delivered from upstream sources on the West Coast pipeline system to the Huntingdon-Sumas trading point. From Huntingdon, the VITS demand transits through the CTS to the start of the VITS at Eagle Mountain in Coquitlam. The Mt. Hayes LNG storage facility has improved system reliability and enabled significant operational flexibility of the combined CTS and VITS.

Figure 7-2 shows the layout of the VITS including the location of the Mt. Hayes LNG storage facility, compressor stations shown as V1 (Coquitlam), V3 (Port Mellon), V4 (Texada) and a potential future site V2 (Squamish), major industrial customers and major communities served by distribution networks.

Figure 7-2: Layout of the VITS



7.3.1.1 *VITS Configuration and Capacity*

The VITS needs to serve the natural gas capacity requirements for the following customers:

- Core residential and small commercial customers located on Vancouver Island and the Sunshine Coast, and in Squamish and Whistler;
- Pulp and paper mills represented by the Vancouver Island Gas Joint Venture (shown as the green factory symbol at various communities in Figure 7-2);
- BC Hydro for its Island Generation Plant (shown as the red factory symbol at Campbell River in Figure 7-2); and
- The proposed Woodfibre LNG project (The green factory symbol at Woodfibre in Figure 7-2).

The Peak Demand of the VITS Core and Firm Transportation customers is discussed in the following paragraphs.

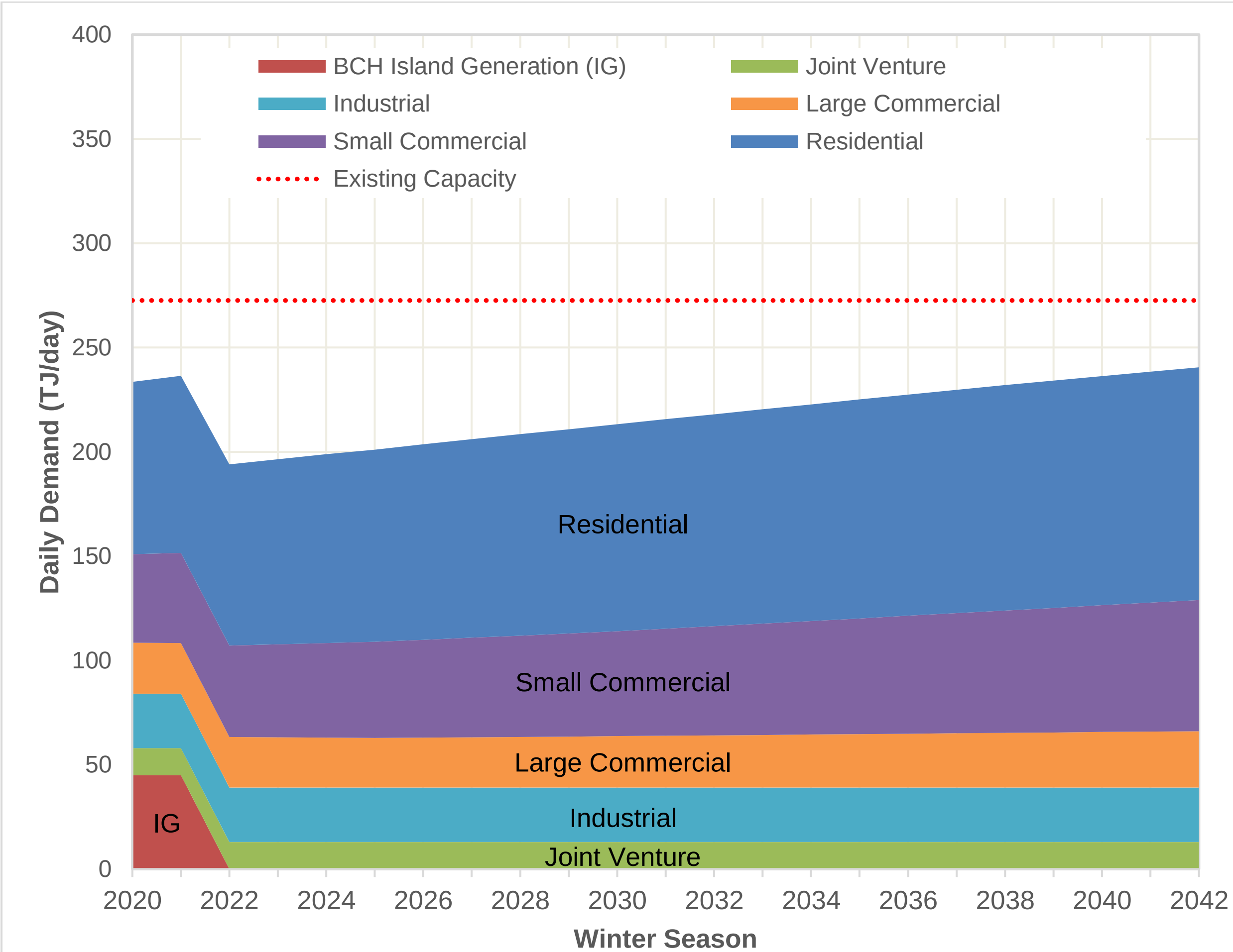
As of November 2020, the current contract demand requirement for BC Hydro Island Generation was 45 TJ per day. The agreement with BC Hydro for the Island Generation facility, the FEI-BC Hydro Transportation Service Agreement (TSA), expired in April 2022. In the next few years, there may be some seasonal demand from the facility, but no firm peak demand for winter operations at the facility has been negotiated. The forecasts shown for the VITS that follow represent the current agreement expiring in 2022 by removing 45 TJ per day from the peak demand forecasts from the winter season of 2022/2023 forward.

The Vancouver Island Gas Joint Venture currently has a firm contract demand of 13 TJ per day, which was in place beginning in the 2015/16 winter season. For demand and capacity modelling, it is assumed that the Vancouver Island Gas Joint Venture demand is fixed at 13 TJ per day throughout the forecast.

Prior to existence of the Mt. Hayes LNG storage facility, the VITS demand exceeded the pipeline capacity and the VITS relied upon a right to call back capacity from BC Hydro Island Generation during design weather events in order to serve its Core and Firm Transportation market design day (i.e., peak demand) requirements. Construction of the Mt. Hayes LNG storage facility was completed in 2011 and the facility entered service for the 2011-12 winter season. The Mt. Hayes facility has a storage capacity of 1.5 Bcf (approximately 1,614 TJ), a liquefaction capacity of 7.5 million standard cubic feet per day (MMscf/day), and a send-out deliverability of 150 MMscf/day (161 TJ per day). This on-system storage facility optimizes the existing system infrastructure by providing significant operational flexibility, regional storage resource benefits for FEI's customers, winter peak shaving capacity benefits and improved system reliability.

Further capacity constraints on the VITS are not expected within the forecast period. It is expected that the system will meet the Traditional Peak Demand forecast. Figure 7-3 shows the peak demand for the VITS with the 2020 Traditional Peak Demand forecast, and with the various customer types represented, and daily transportation requirements for Vancouver Island Gas Joint Venture mills (13 TJ per day) and BC Hydro Island Generation (45 TJ per day, until 2022).

Figure 7-3: VITS Traditional Peak Demand Forecast

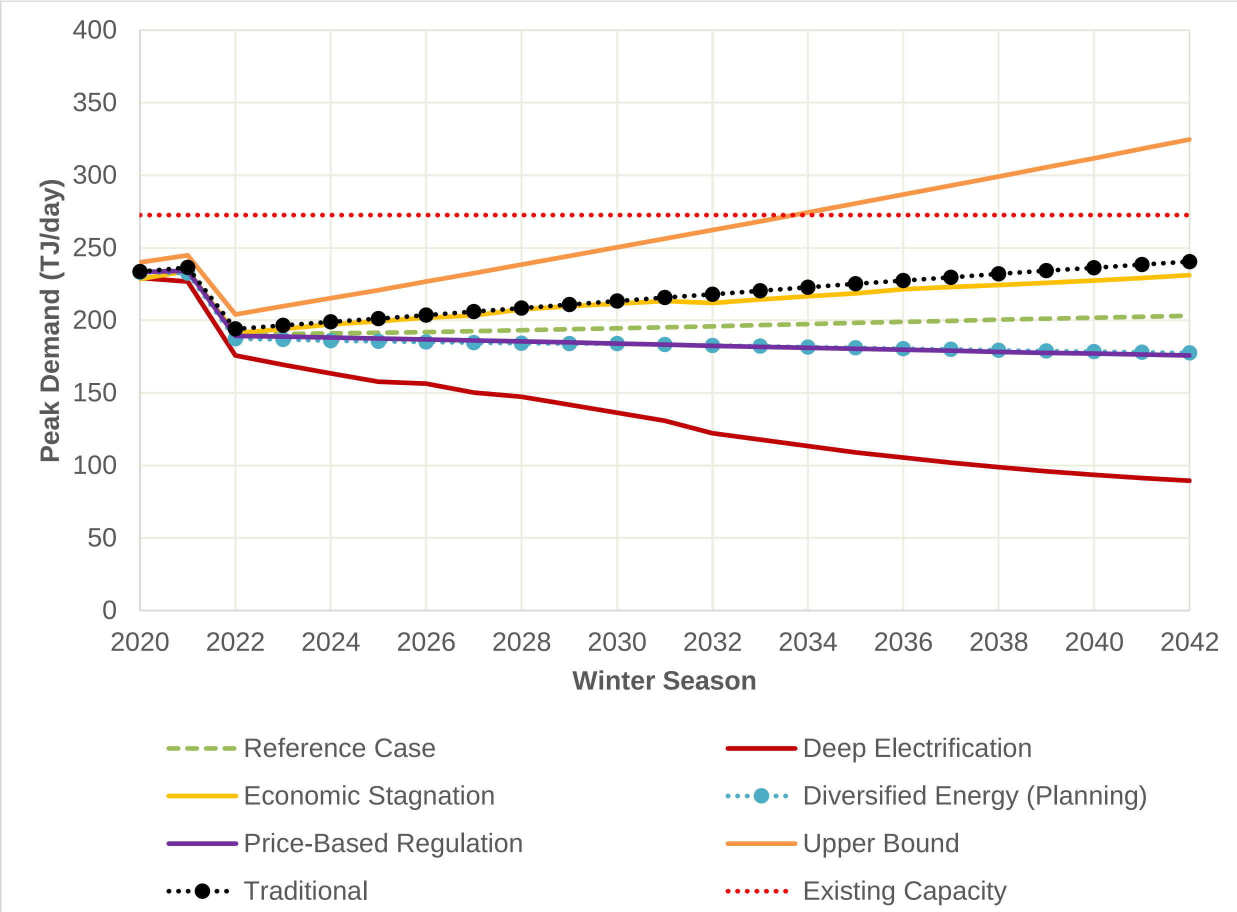


7.3.1.2 *VITS Traditional Peak Demand Forecast and End Use Peak Demand Scenarios*

The VITS regional peak demand forecast shown in Figure 7-4 below was analysed against end use peak demand scenarios. The VITS currently has sufficient facilities with the existing installed pipelines, compressors and the Mt. Hayes LNG vapourizers to meet Traditional Peak Demand excluding any proposed large industrial demand to the end of the planning horizon in 2042.

The end use method provides a wide variation in peak demand forecasts with some forecasts showing increasing and some showing decreasing system demand over time. Figure 7-4 shows: the forecasts are bounded on the high end by the Upper Bound Scenario; the Traditional Peak Demand forecast, Economic Stagnation and the Reference Case scenarios follow with lower but positive growth; the Diversified Energy (Planning) and Price-Based Regulation scenarios show very slight declining demand; and the Deep Electrification Scenario trails on the lower end with more significantly declining demand. Only the Upper Bound forecast would require facility upgrades to the VITS to increase system capacity, possibly by the winter of 2033-2034. The current capacity supports all other peak demand forecasts through the forecast period.

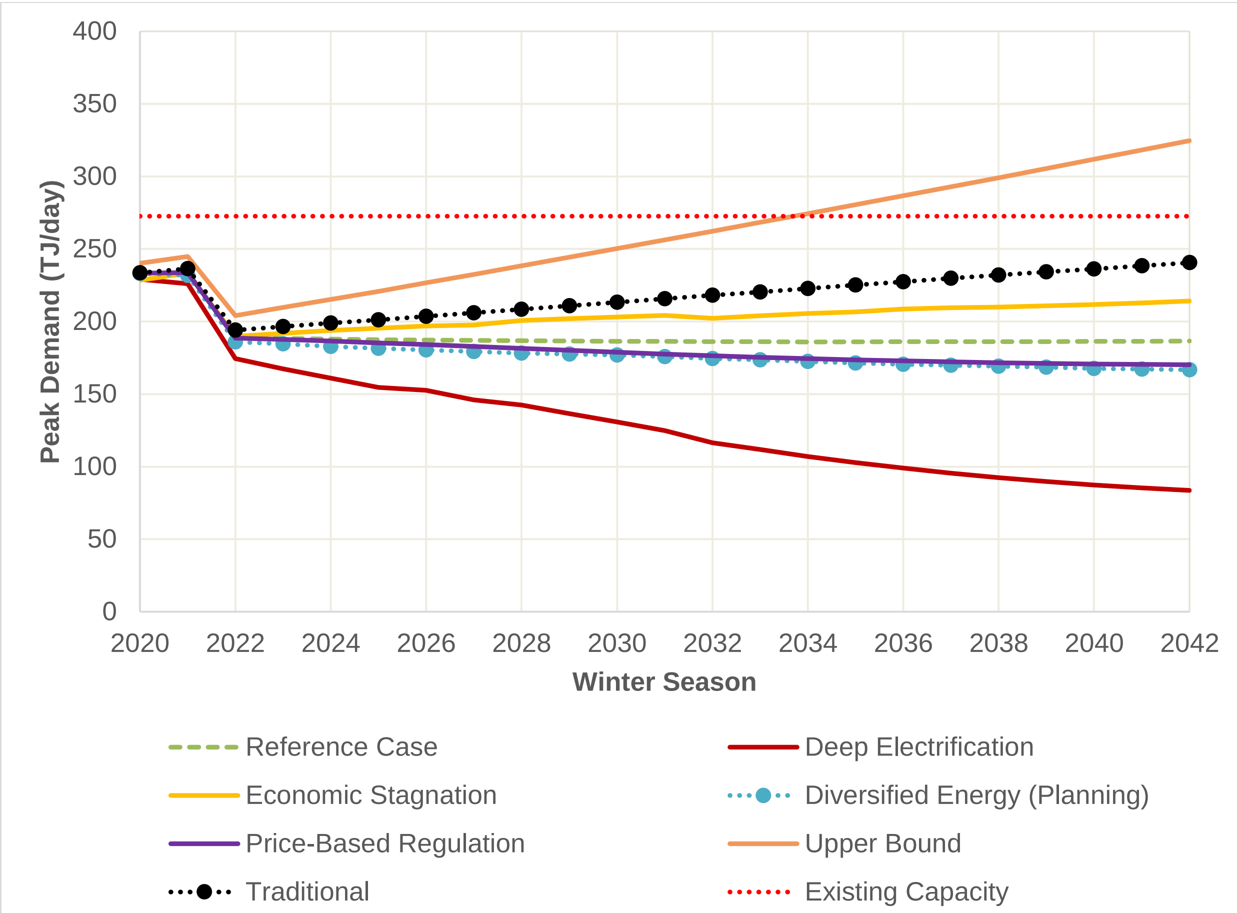
Figure 7-4: VITS Demand-Capacity Balance Using Traditional and End Use Forecasts



7.3.1.3 *VITS Peak Demand Forecast and End Use Peak Demand Scenarios with DSM*

Figure 7-5 illustrates a comparison of the traditional and end use peak demand forecasts including the impacts of DSM applied to each scenario on the same basis as it was applied to each annual demand scenario as shown in Table 5-3. Including DSM impacts causes the end use peak demand scenario forecasts to move downward, except for the traditional and Upper Bound forecasts where DSM is not applied. The Upper Bound Peak Demand Scenario continues to show a potential capacity constraint by 2033-2034. All other forecast scenarios show a decline in peak demand over time with no capacity constraint projected within the planning horizon.

Figure 7-5: VITS Demand-Capacity Balance Using Traditional and End Use Peak Demand Scenarios with DSM



7.3.1.4 *VITS System Expansion Requirements*

With the expiry of the current FEI-BC Hydro TSA for service to BC Hydro's Island Generation facility, FEI's Traditional Peak Demand forecast shows there is no need for capacity expansion on the VITS in the forecast period. Only the Upper Bound Forecast shows enough peak demand to require some system expansion.

Since the forecasts were prepared, recent customer growth on the Vancouver Island system shows that growth is currently trending well below the Upper Bound; however, if the forecast were to begin to trend towards the Upper Bound forecast, the capacity upgrade could be addressed in the future by expanding compressor horsepower (HP) on the VITS and by looping the VITS between Mt. Hayes and Duncan with a second NPS 12 or larger pipeline to support growth in the Greater Victoria area.

Although the Traditional Peak Demand forecast establishes there is no need for capacity expansion on the VITS in the forecast period, there are two pressure control station additions in the VITS that are currently proposed for installation in the next few years to serve the growing distribution systems of Greater Victoria (in the Colwood area) and Nanaimo (in the Lantzville area).

7.3.1.5 *Expanding the System for Potential New Large Industrial Demand*

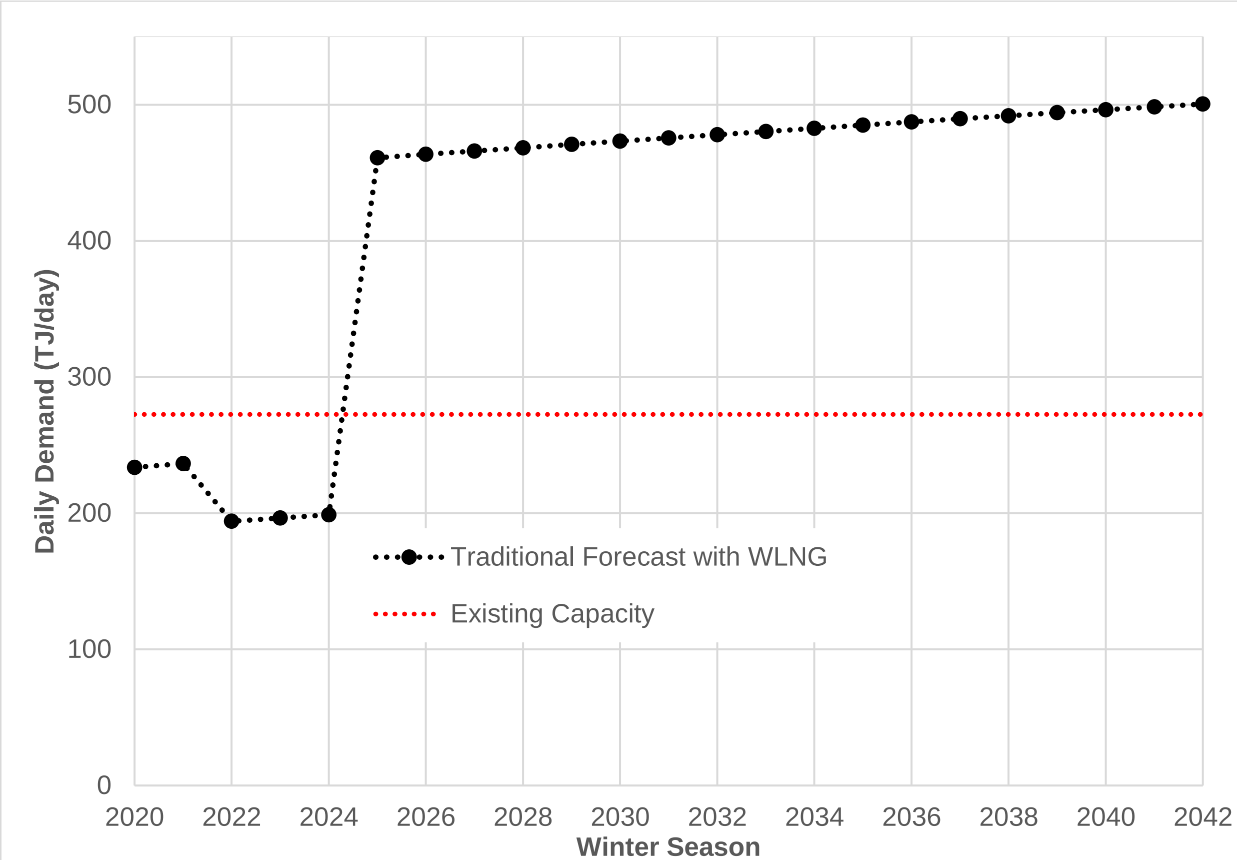
Low natural gas prices and other market dynamics in BC have spurred interest from a range of industries in locating or expanding facilities that would use large volumes of natural gas within the province. Any required major reinforcements to serve potential new industrial loads would be evaluated as part of a formal submission to the BCUC once firm agreements regarding natural gas services have been made.

One such example on the VITS is the Woodfibre LNG project, which is a small-scale LNG export and processing facility located on the VITS at the former Woodfibre pulp mill site near Squamish. Woodfibre LNG Limited, a subsidiary of Pacific Oil & Gas, and FEI entered into a Development Agreement. For several years, FEI has been carrying out development work for the Woodfibre LNG project, including a feasibility study, consultation and stakeholder engagement, engineering, and exploring the regulatory and other approvals required to expand the VITS to provide a firm natural gas transportation service to the project. Woodfibre LNG Limited has presently indicated that it expects to require Firm Transportation service from FEI of up to 237 MMscf/day on the VITS.[205] Once a final investment decision is made, the estimated in-service date of this facility is currently projected no earlier than 2025, and more likely by 2027. This project is discussed further in Section 1.4.2 of Appendix D-1.

Figure 7-6 shows the impact of the proposed Woodfibre LNG project's firm 237 MMscf/day delivery against the VITS Traditional peak demand forecast, showing that the demand exceeds the current capacity of the VITS.

[205] As a transportation service customer, the Woodfibre LNG project would not impact FEI's Vancouver Island gas supply planning as the customer would independently acquire its gas supply.

Figure 7-6: VITS Demand Using Traditional Peak Demand Forecast with Woodfibre LNG project



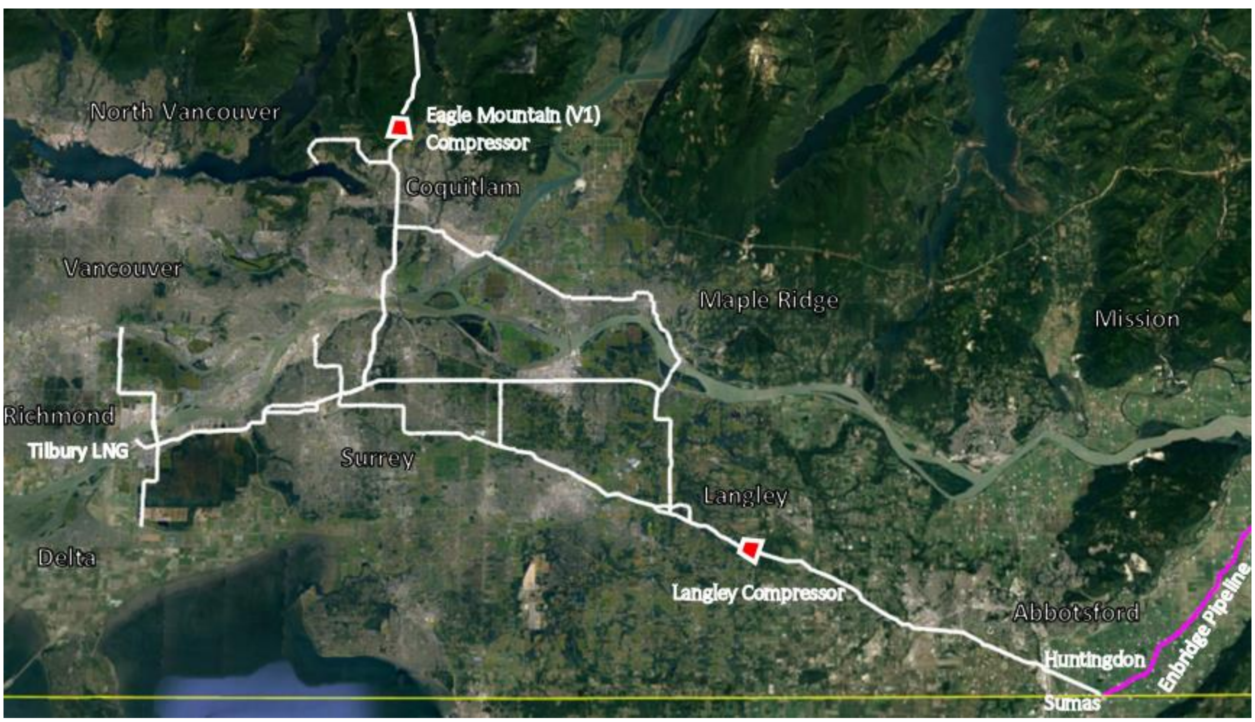
To accommodate this load addition, there is a need to reinforce the existing VITS with pipeline looping and added compression near Squamish. This infrastructure expansion would match the Firm Transportation capacity contracted by Woodfibre LNG Limited under peak demand, preserving available capacity for existing customers, but would allow large volumes of interruptible capacity to be available for much of the year. The Woodfibre LNG project will help reduce costs for firm service on FEI systems providing benefits to FEI's existing customers. Woodfibre LNG project's toll will recover the cost of the Woodfibre LNG project and provide an additional contribution to FEI's other customers over time.

The Woodfibre LNG project, while a relatively small LNG project, is an example of the impact of a large industrial load (relative to the existing system demand) on an FEI system and the challenges of forecasting and planning around such a load addition. These projects take many years of advance planning and design, and are significant in scope and impact on the pre-existing system. The projects are managed and designed to preserve existing capacity and service to customers and need to be constructed to meet FEI system requirements and the specific process and economic needs of the industrial customer. As discussed previously in Section 7.2, the upgrade requirements to support large increases in demand are very specific to the magnitude of the demand and the location of demand on the system, because of the effects of the customers' demand on flow and pressure loss across the system. As a result, the upgrades necessary to provide adequate pressure to all points in the system following a load addition cannot be forecast in advance without knowing both location and demand requirements. The solution for the Woodfibre LNG project and required system changes would look significantly different if the location of the project were at a different point on the FEI system. However, the process of managing the timing of large load additions and associated system expansion requirements without eroding service reliability to existing customers would not change.

7.3.2 FEI Coastal Transmission System

The CTS consists of a 276 km network of pipelines providing gas transportation from the Huntingdon-Sumas trading point to various metering and regulating stations in the Fraser Valley, Metro Vancouver, and Coquitlam areas. There are approximately 585,000 customers served directly by this transmission system not including the customers in the VITS who receive their gas through the CTS. There are two primary capacity-related facilities on the CTS: the Langley Compressor Station, which is used to boost pressures on the CTS during periods of high demand, and the Tilbury LNG storage facility, which is used to provide peaking gas supply during colder weather. The CTS delivers gas to the distribution networks in the Lower Mainland and to the VITS at Eagle Mountain in Coquitlam. Figure 7-7 shows the general layout of the CTS.

Figure 7-7: Layout of the Coastal Transmission System Including the Langley Compressor Station and Tilbury LNG Storage Facility



7.3.2.1 *CTS Configuration and Capacity*

Recent changes to the CTS that impact its capacity include the construction of three transmission pipeline loops that entered service in late 2017:

- A 1.5 km NPS 42 pipeline loop of an existing NPS 24 pipeline between Nichol and Roebuck Valve Stations in Surrey;
- A 4.9 km NPS 36 pipeline loop of an existing NPS 24 pipeline between Nichol and Port Mann Valve Stations in Surrey; and
- A 4.5 km NPS 36 pipeline loop of an existing NPS 20 pipeline between Cape Horn Valve Station and Coquitlam Gate Station in Coquitlam.

Approval for the construction of these loops, collectively identified as the "CTS project", was granted through BC Government Direction No. 5 under OIC 557 in 2013. The CTS project loops existing pipelines that were single points of failure on the CTS and additionally addressed the existing capacity constraints on the CTS that were identified in Section 5 of the 2014 LTRP.

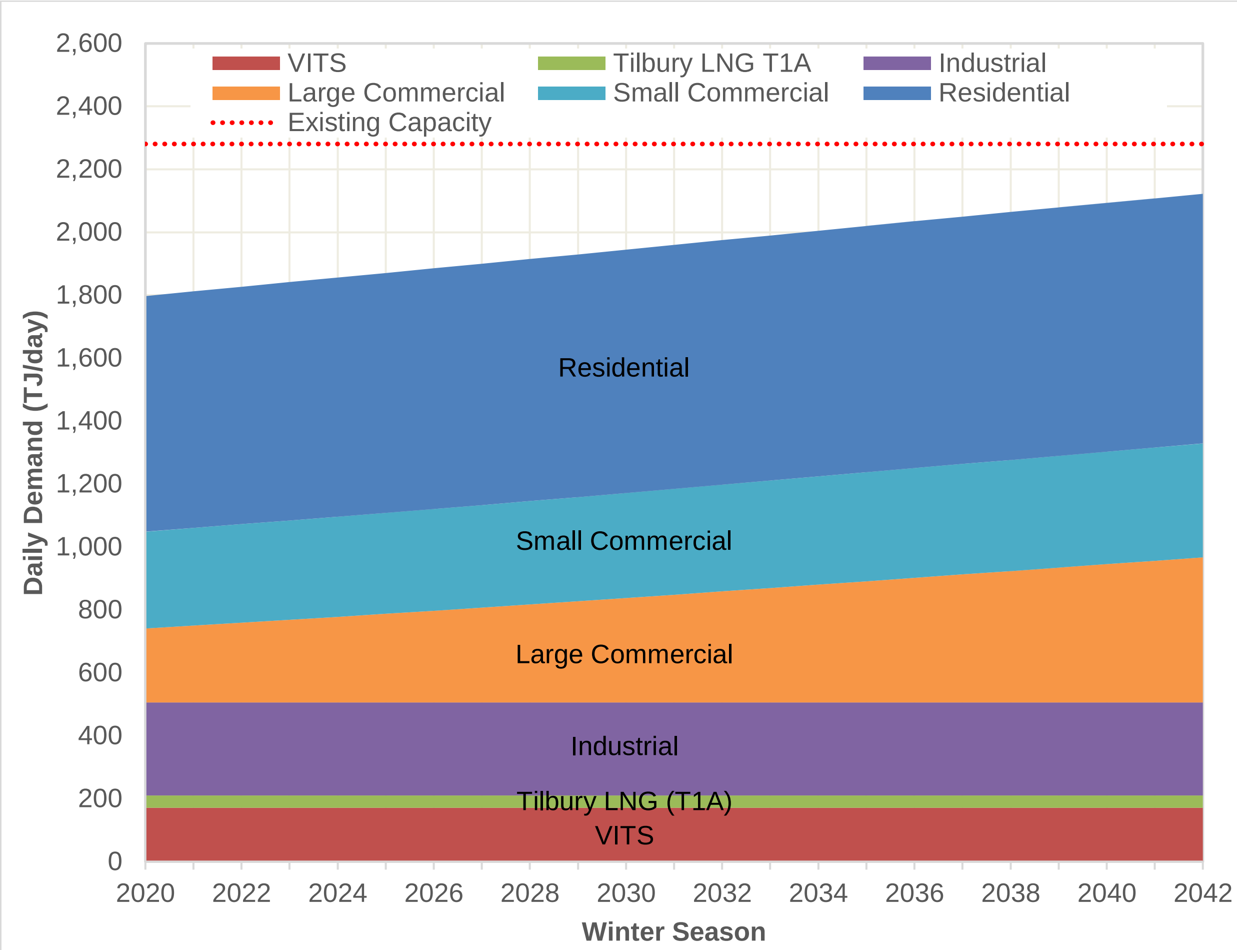
In addition to the CTS project, the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) projects (Coquitlam Gate IP project and Fraser Gate project) were complete and in service as of the fall of 2021. The Coquitlam Gate IP project replaced an existing NPS 20 pipeline nearing the end of its service life, between Coquitlam Gate Station and 2nd Avenue and Woodland Drive Station in Vancouver with a new high-capacity NPS 30 pipeline. The Fraser Gate project replaced approximately 300 metres of NPS 30 pipe with new NPS 30 pipe to upgrade the Fraser Gate IP Pipeline to current seismic design standards. The LMIPSU projects influence the CTS capacity balance through their ability to shift peak load within the transmission system from Fraser Gate to Coquitlam Gate, thereby enabling a significantly more resilient supply to the Metro Vancouver area distribution system.

In June 2021, the BCUC issued Order C-2-21 granting a CPCN for the Pattullo Gasline Replacement (PGR) project. This project will replace the supply to the Metro Vancouver area distribution system currently provided by FEI's pipeline on the Pattullo Bridge (Pattullo Gasline). The PGR project will replace the Pattullo Gasline with a new overland pipeline connecting the Coquitlam IP System to the existing system in east Burnaby currently fed by the Pattullo Gasline. The PGR project, when in service, will influence the CTS capacity by increasing the demand requirement flowing to Coquitlam to supply the PGR pipeline once the Pattullo Gasline is removed.

Since December 2018, the Tilbury 1A LNG expansion, the first of several projected increases in LNG production, has been in service at the Tilbury LNG site in Delta. This facility increases the peak demand of the CTS by 35 MMscf/day.

Figure 7-8 below shows the Traditional Peak Demand forecast for the CTS with the various customer types represented.

Figure 7-8: CTS Traditional Peak Demand Forecast



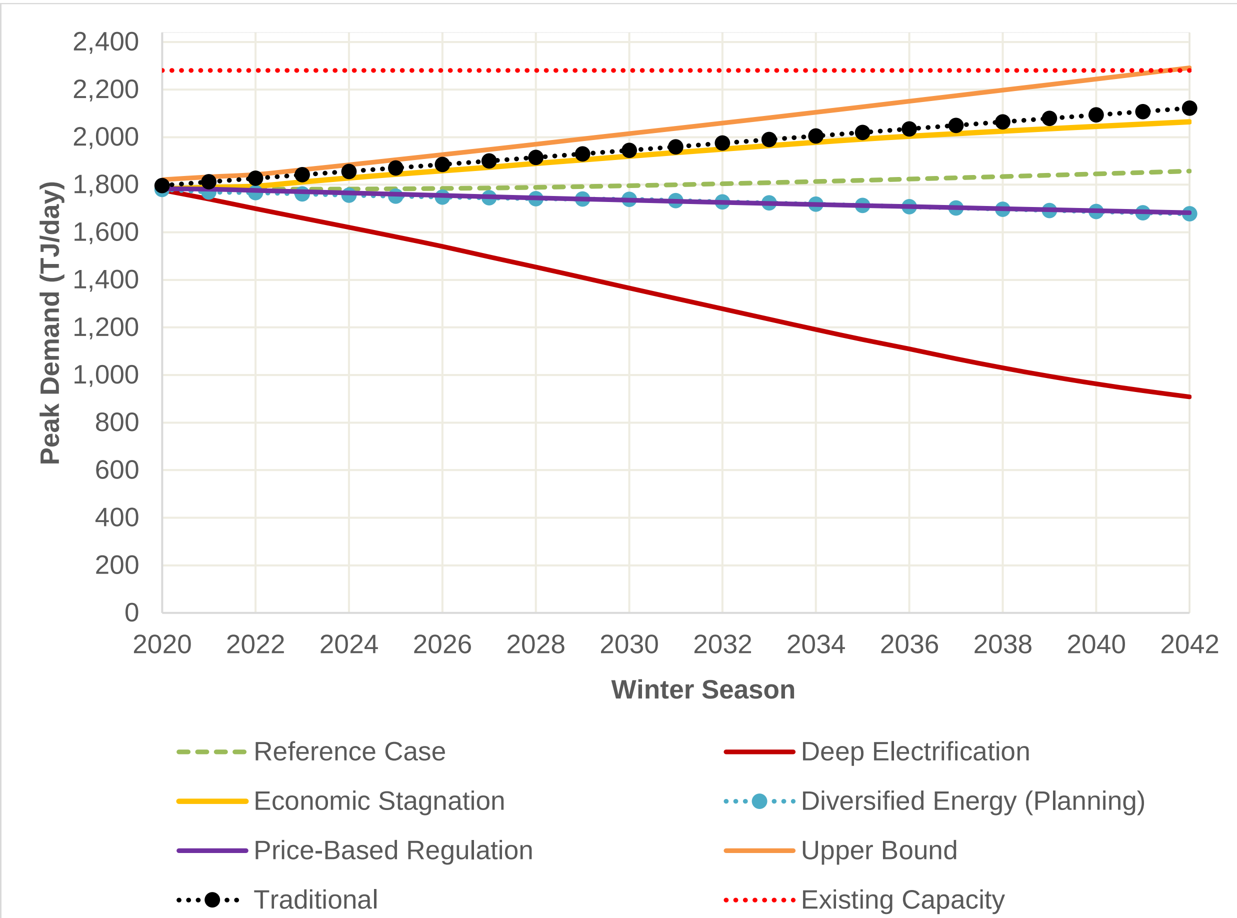
7.3.2.2 *CTS Traditional Peak Demand Forecast and End Use Peak Demand Scenarios*

The CTS currently has sufficient capacity to support peak demand throughout the 20-year planning horizon with additional capacity to support some LNG liquefaction expansion at locations like Tilbury LNG in Delta and the Woodfibre LNG project in Howe Sound. For the foreseeable future, additional expansion requirements for the CTS will be driven by LNG additions or other large industrial demand in the Lower Mainland or VITS, rather than by Core customer growth.

The regional Traditional Peak Demand forecast and end use scenarios are shown in Figure 7-9, which compares the forecast peak demand to system capacity to illustrate when system constraints may occur. FEI does not expect any capacity constraints to occur within the 2022 LTGRP planning horizon under the Traditional Peak Demand forecast.

The forecasts in Figure 7-9 show a wide range of peak demand, with the Upper Bound Scenario showing greater growth in the forecast period than the Traditional forecast and the Economic Stagnation Scenario showing slightly lower growth. The Reference Case Scenario shows a very slight increase in peak demand over the planning horizon, while the remaining scenarios show modest to more significant peak demand decline with the Deep Electrification Scenario showing the greatest peak demand decline. In the absence of large industrial loads that will be discussed later the CTS currently has capacity to meet the peak demand to the end of the planning horizon.

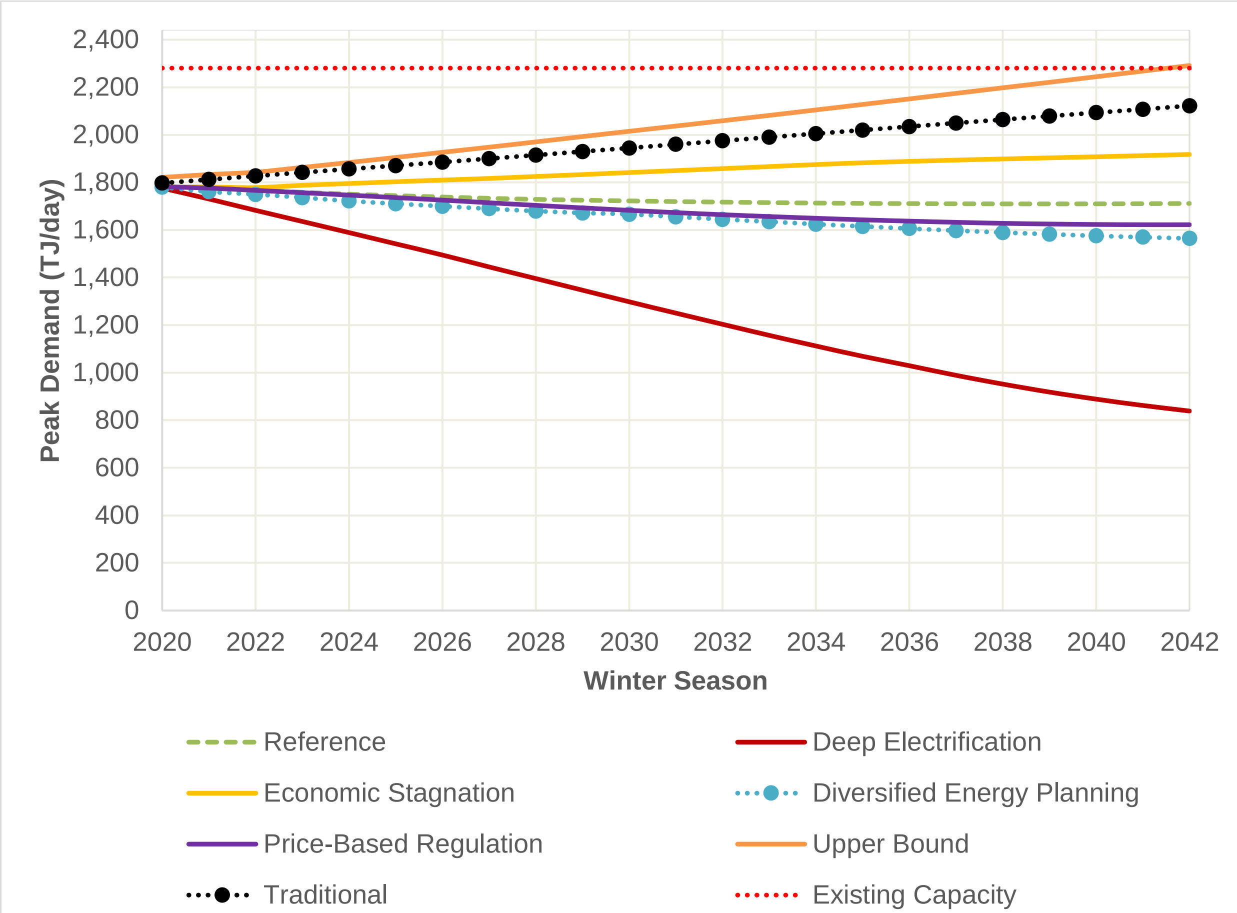
Figure 7-9: CTS Demand-Capacity Balance Using Traditional and End Use Forecasts



7.3.2.3 *CTS Peak Demand Forecast and End Use Peak Demand Scenarios with DSM*

Figure 7-10 shows the end use scenarios with DSM program impacts added (as described in Table 5-3). Applying the impacts of DSM using the end use peak demand method moves almost all end use scenario forecasts lower, apart from the Upper Bound and Traditional forecast where no DSM is applied. The Upper Bound continues to show the highest growth followed by the Traditional forecast. The Economic Stagnation Scenario shows very moderate growth through the forecast. The Reference Case Scenario shows a very slight decline in peak demand through the forecast horizon. The remaining scenarios show moderate to more significant decline in peak demand through the forecast. No forecast scenarios exceed the current capacity of the CTS.

Figure 7-10: CTS Demand-Capacity Balance Using End Use Peak Demand Forecasts with DSM



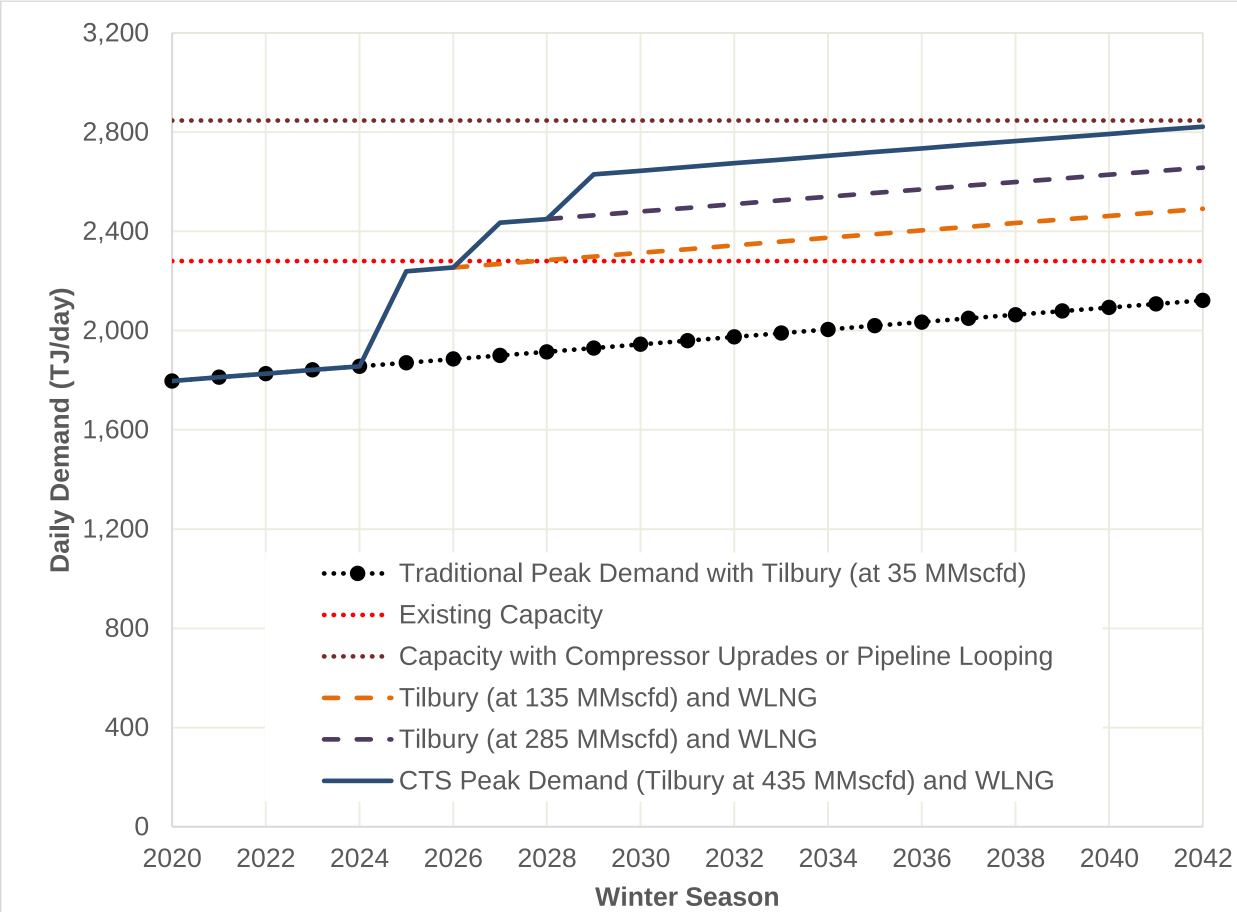
7.3.2.4 *Impact of Potential New Large Industrial Loads (Future Demand for LCT and LNG Exports)*

The demand for conventional gas from transportation sector fuel customers is forecast to continue growing over the next 20 years (as discussed in Section 4.6), and increased use of LNG as a lower intensity fuel for road and marine transport in the Lower Mainland area will likely drive LNG demand growth. The potential demand and the point-source nature of additional LNG liquefaction production in peak conditions at Tilbury may create system impacts and could trigger the need for system reinforcements of the CTS.

FEI expects demand by LNG customers across the FEI service territories to be primarily served by FEI's Tilbury LNG facilities. Based on FEI's natural gas demand forecasts for LNG, future phases of Tilbury LNG expansion beyond the current Phase 1A will need to be constructed. FEI's long-term outlook considers the system requirements for such an expansion.

Figure 7-11 shows the impact of LNG demand on the CTS Traditional Peak Demand forecast over the next 20 years.

Figure 7-11: Impact of LNG on CTS Peak Demand



The peak demand forecasts shown have a different profile from the annual demand with LNG forecasts shown in Figure 4-18. The production of LNG is consistent throughout any day of the year when the liquefying facilities are operating and has no seasonal or daily peak. In practice, the actual peak demand that may occur on the CTS in any given period would be dependent on the liquefaction capacity installed at the LNG plant to meet the forecast. LNG liquefaction trains generally operate at a fixed production rate and, for reasons of efficiency, do not vary production rates substantially when in operation. The peak demand profile on the CTS would therefore occur in a more defined stepwise fashion than is represented in an annual demand forecast, with each step corresponding to a phase of expansion in liquefying capability at the LNG facility.

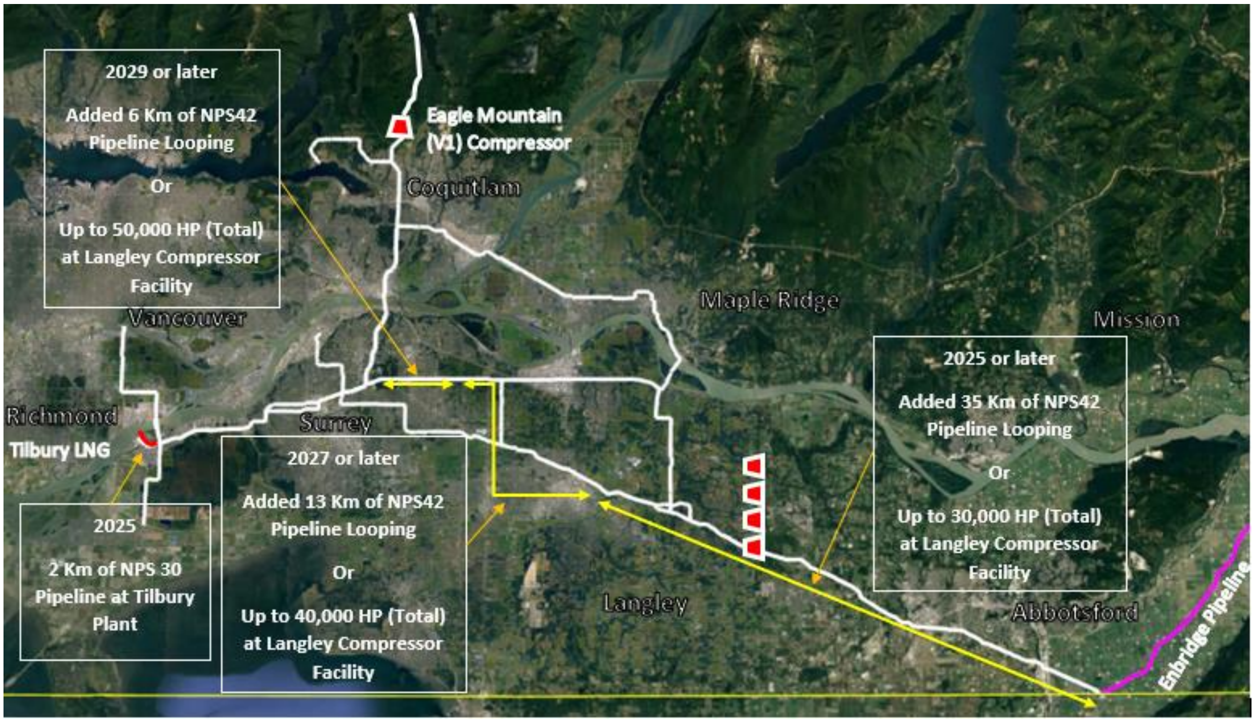
To illustrate the potential impact of LNG expansion on the CTS, some potential CTS expansion phases are described in Table 7-1, with the corresponding capacity for liquefaction that could be delivered to the Tilbury area. The next future expansion of LNG liquefaction at Tilbury will require a two kilometre NPS 30 pipeline. That pipeline will replace an NPS 6 pipeline from the plant to the CTS transmission pipelines east of the plant site. At a diameter of NPS 30, this pipeline is sufficient to accommodate any additional future anticipated LNG expansion without needing to be replaced with a larger diameter. Apart from this initial two kilometre pipeline, LNG expansion can be accommodated in the CTS though an expansion of compressor facilities in the system at the existing Langley Compressor site, or through incremental pipeline looping of the exiting NPS 42 and NPS 30 CTS pipelines between FEI's Huntingdon Control Station in Abbotsford and Nichol Valve Station. An alternative expansion scenario could also be a combination of some pipeline looping and some compression addition to meet the growth in LNG demand. The combination of upgrades selected and how they are phased to be most efficient and cost effective will be determined once the LNG demand and production requirements to meet the demand become more defined.

Table 7-1: CTS Expansion Scenarios for LNG

CTS Upgrades	LNG Expansion	Timeframe
2 km NPS 30 from Tilbury Plant and up to 15,000 HP Added (up to 30,000 HP total) or 35 km NPS 42 Pipeline Loop	Incremental 100 MMscf/day addition to Liquefaction at Tilbury Plant (up to 135 MMscf/day total) Woodfibre LNG project at 237 MMscf/day	2025 or later
Up to an Additional 10,000 HP Added (up to 40,000 HP total) or additional 13 km NPS 42 Pipeline Loop (48 km total)	Incremental 150 MMscf/day additional Liquefaction at Tilbury Plant (up to 285 MMscf/day total) Woodfibre LNG project at 237 MMscf/day	2027 or later
Up to an Additional 10,000 HP Added (up to 50,000 HP total) or additional 6 km Pipeline Loop (54 km total)	Up to 400 MMscfd additional Liquefaction at Tilbury Plant (up to 435 MMscf/day total) Woodfibre LNG project at 237 MMscf/day	2029 or later

Figure 7-12 below shows how these proposed upgrades may be laid out along the existing CTS.

Figure 7-12: CTS Expansion Scenarios to Meet Potential LNG Load Growth

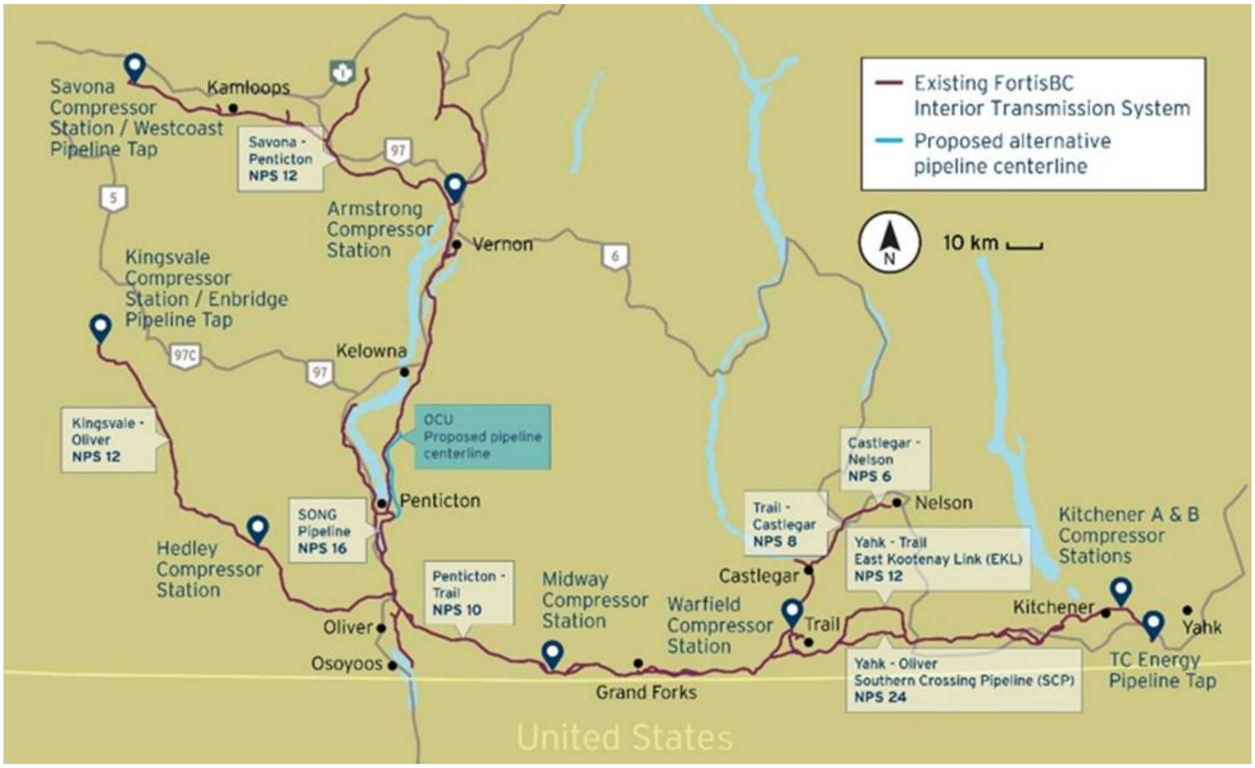


7.3.3 FEI Interior Transmission System

The ITS consists of 1,515 km of transmission pipelines operating at maximum operating pressures between 4,654 kPag[206] and 9,928 kPag. The ITS system interconnects supply from the Westcoast pipelines in the west and the TC Energy pipelines in the east. Gas received from the Westcoast pipeline at Savona typically supplies customers in the Thompson and North Okanagan regions, while gas received from the TC Energy Pipeline at Yahk supplies customers in the West Kootenay region via pipelines to Trail and Oliver. The FEI-owned SCP is a bi-directional transportation pipeline between Yahk and Oliver that in the winter moves gas needed to support peak demand in the Okanagan and Lower Mainland to Oliver. From the Oliver hub, referred to as the “Oliver-Y”, pipelines transport gas to serve customers in the South and Central Okanagan. In winter periods, the Kingsvale-Oliver pipeline transports gas from the SCP via the Oliver-Y hub to Kingsvale for redelivery to the Lower Mainland through the Westcoast Pipeline. Figure 7-13 shows the layout of the ITS system.

[206] kPag = kilopascals (gauge pressure).

Figure 7-13: FEI Interior Transmission System



7.3.3.1 *ITS Configuration and Capacity*

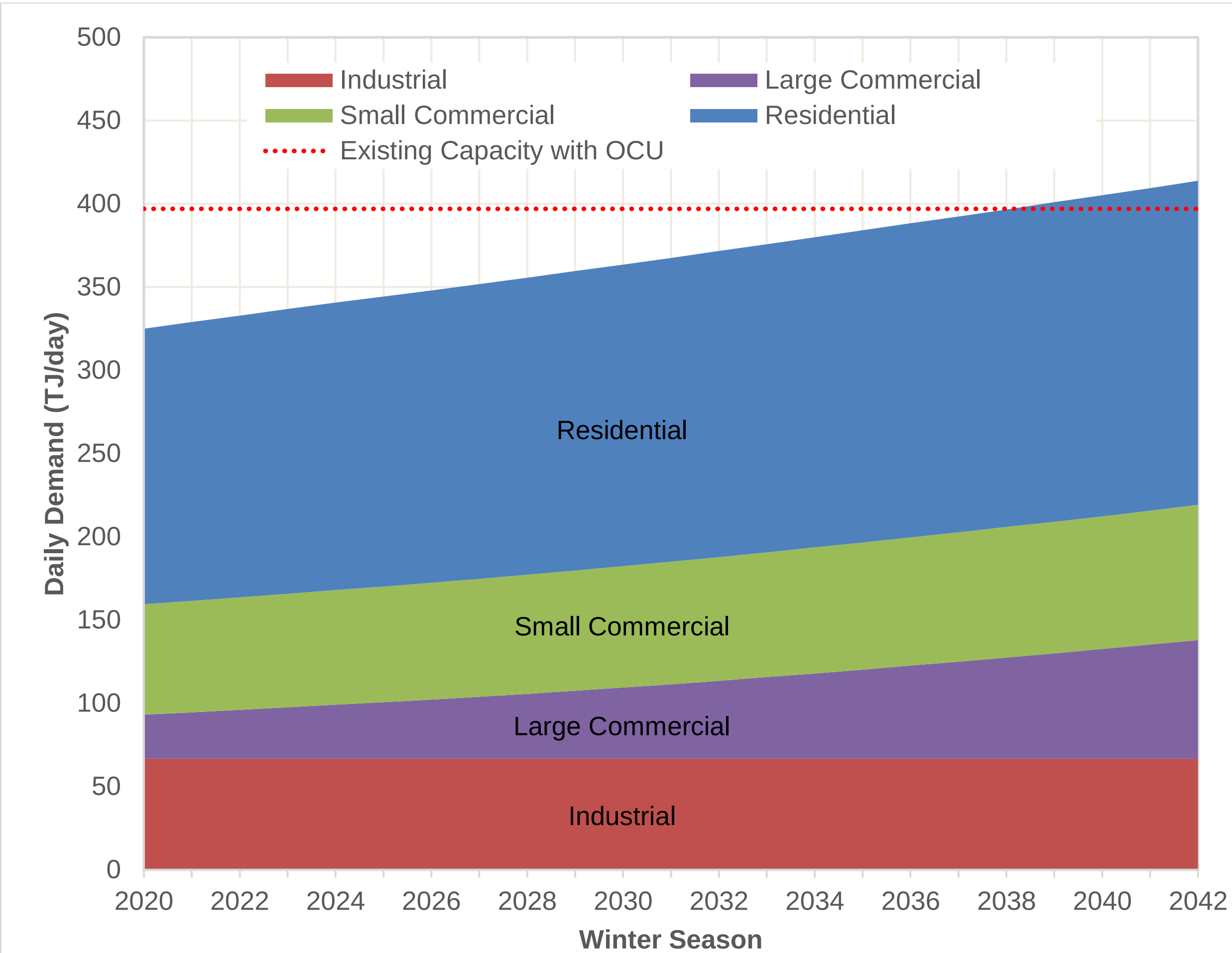
Approximately 60 percent of the current ITS Core and Firm Transportation customer demand is concentrated in the South, Central and North Okanagan regions. Growth in the Okanagan region has been, and continues to be, one of the main factors driving the location of current and future incremental capacity additions to the ITS. The ITS currently serves approximately 200,000 residential, commercial and industrial customers. Because the ITS is characterized by long pipeline lengths through several less-densely-populated areas, the system benefits from line pack effects—the "storage" of usable pressurized gas up to the pipeline MOP that can be drawn on to support short-term peak demand. The ability to draw down the gas that is stored in the ITS allows FEI to plan the ITS on a peak day, rather than a peak hour, maximum flow.

As previously described, gas is delivered to the ITS from two upstream pipelines—the Westcoast pipeline at Savona in the West and the TC Energy Pipeline at Yahk in the East. The ITS peak demand will reach pipeline capacity when the system cannot maintain minimum system pressures near the high load centres in the Central Okanagan region.

FEI currently has a CPCN Application for the Okanagan Capacity Upgrades (OCU) project in the regulatory review progress. The preferred alternative is an approximately 30-kilometre NPS 16 pipeline loop between Penticton and Kelowna reinforcing the existing NPS 12 pipeline currently in service.

The Traditional Peak Demand forecast for this region with the various customer types represented is shown in Figure 7-14

Figure 7-14: ITS Traditional Peak Demand Forecast

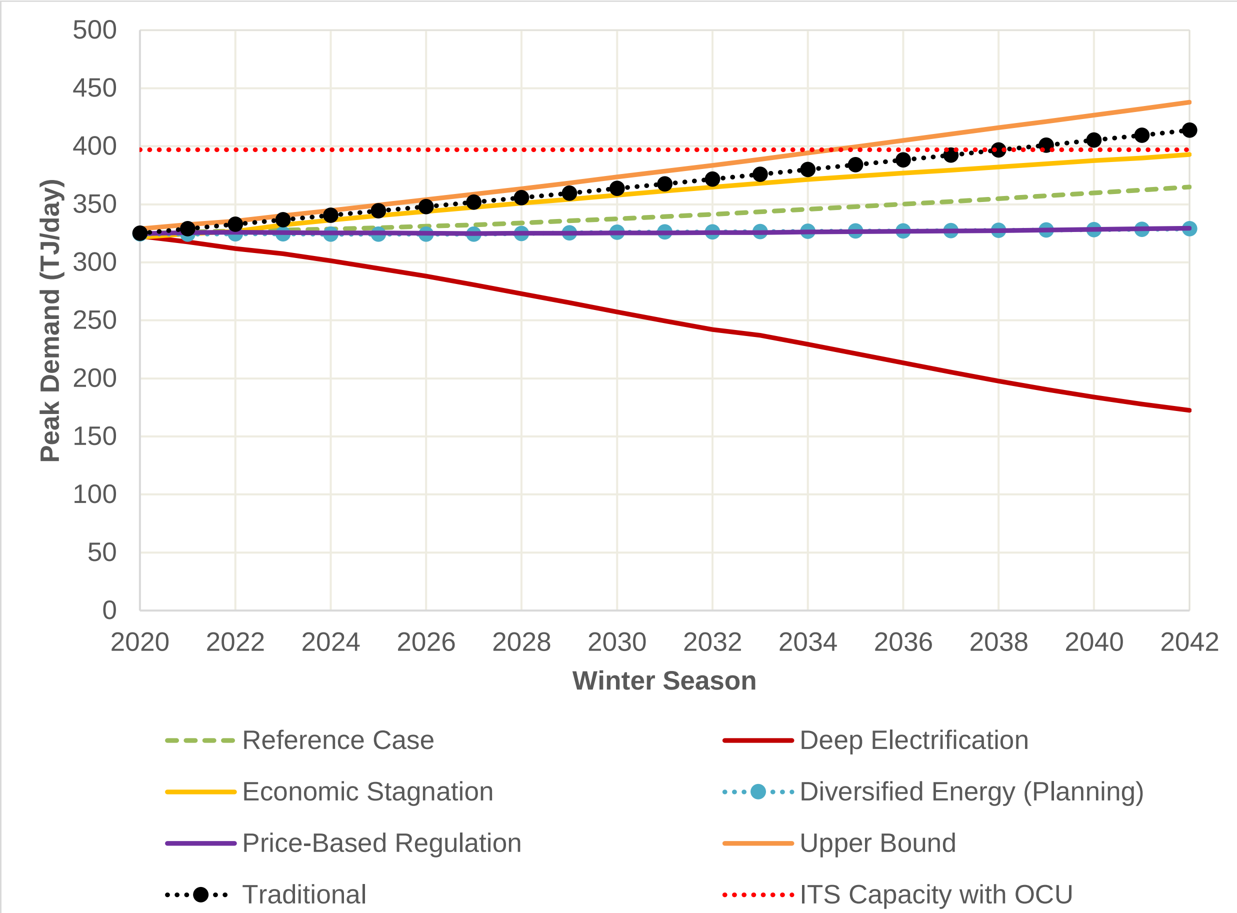


7.3.3.2 *ITS Peak Demand Forecast with End Use Peak Demand Scenarios*

Figure 7-15 shows the Traditional Peak Demand forecast and the forecasts derived from the end use scenarios for the area served by the ITS. The forecasts show a wide range of peak demand, with the Upper Bound, Traditional, and Economic Stagnation scenarios being the three highest forecasts. The Reference Case Scenario shows lesser growth in peak demand in the forecast and all other scenarios show no growth or a decline in peak demand with the Deep Electrification Scenario showing the greatest peak demand decline.

With the OCU project installed as proposed (shown as the ITS Capacity with OCU line in Figure 7-17), the current Traditional Peak Demand forecast projects that the next capacity constraint could occur by the winter of 2038- 2039. With the Upper Bound forecast, that capacity constraint might appear up to three years earlier. All other forecasts should be met with the capacity available in the ITS once the OCU project is completed.

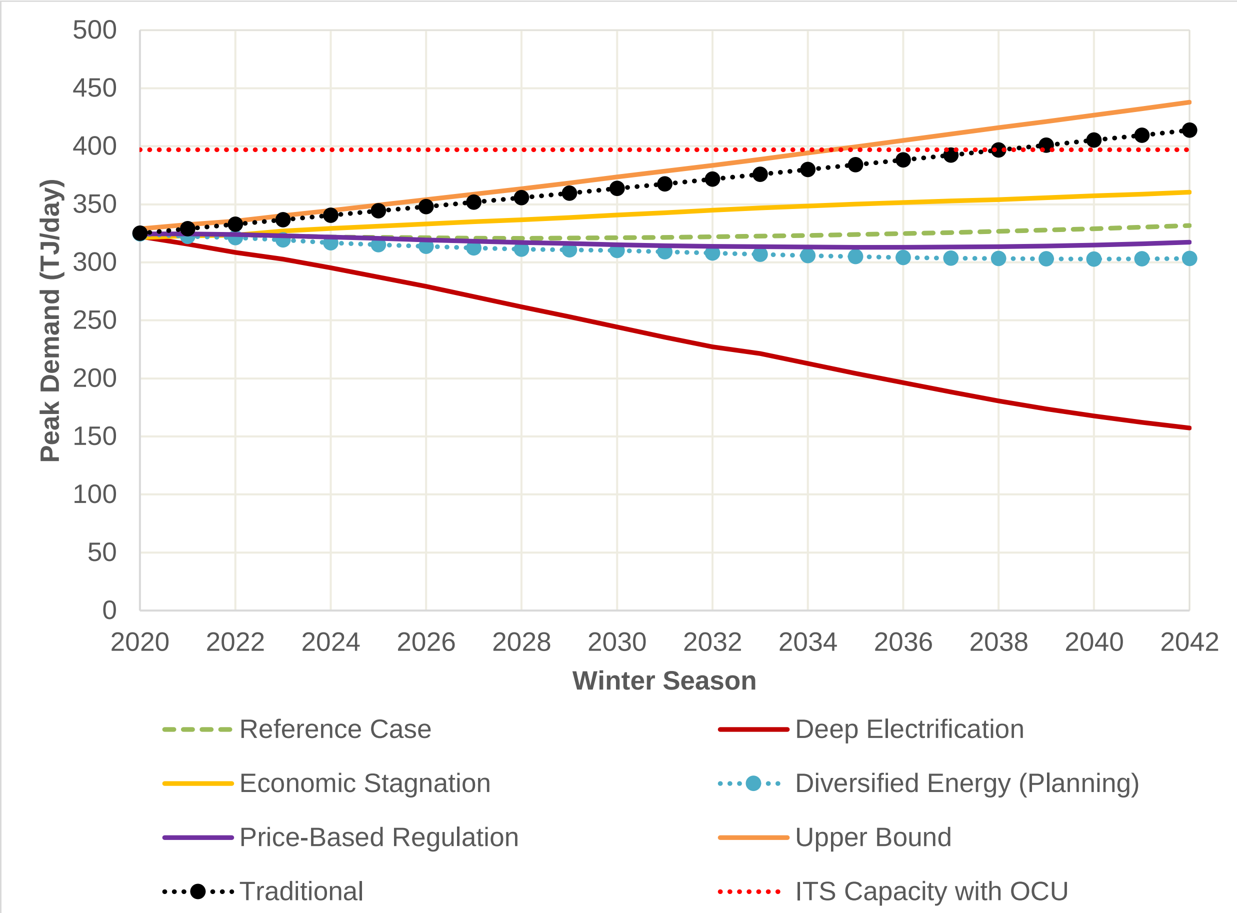
Figure 7-15: ITS Demand-Capacity Balance Using End Use Peak Demand Forecasts



7.3.3.3 *ITS Peak Demand Forecast with End Use Peak Demand Scenarios with DSM*

Figure 7-16 shows the end use scenarios with DSM program impacts added (as described in Table 5-3). Applying the impacts of DSM using the end use peak demand method moves all end use scenario forecasts lower, apart from the Upper Bound and Traditional forecasts where no DSM is applied. The Upper Bound continues to exceed the Traditional forecast. The Economic Stagnation scenario shows less growth through the forecast. The Reference case shows very slight growth in peak demand. The remaining scenarios show moderate to more significant decline in peak demand through the forecast horizon.

Figure 7-16: ITS Demand-Capacity Balance Using End Use Peak Demand Forecasts with DSM



7.3.3.4 *ITS System Expansion Alternatives*

The three reinforcement alternatives described below have been identified to meet the demand forecast and would be required, in addition to completion of the OCU project, by the winter of 2038-2039 for the Traditional forecast and could be required for the winter of 2035-2036 to meet the Upper Bound forecast. The proposed OCU project provides sufficient capacity to meet the capacity requirements of all other peak demand forecasts though the forecast period.

Alternative 1 one would be the most moderate capital expansion that could meet the future peak demand requirements within the ITS. Alternative 3, if built to support resiliency, would provide better security of supply to customers in the Okanagan communities.

7.3.3.4.1 ALTERNATIVE 1 – COMPLETION OF THE OCU PROJECT WITH ADDITIONAL COMPRESSION

The first alternative solution to address the capacity constraint in 2038 requires additional compression to be added to the Savona Compressor Facility, increasing the compressor horsepower (HP) there by at least 1000 HP. This solution would also include an upgrade to the four-kilometre Coldstream lateral pipeline in addition to the completion of the preferred alternative of the OCU project (a 30-kilometre pipeline loop between Penticton and Kelowna). These additional upgrades can move the capacity constraint to beyond 2042.

7.3.3.4.2 ALTERNATIVE 2 – PIPELINE EXTENSION TO THE OCU PROJECT

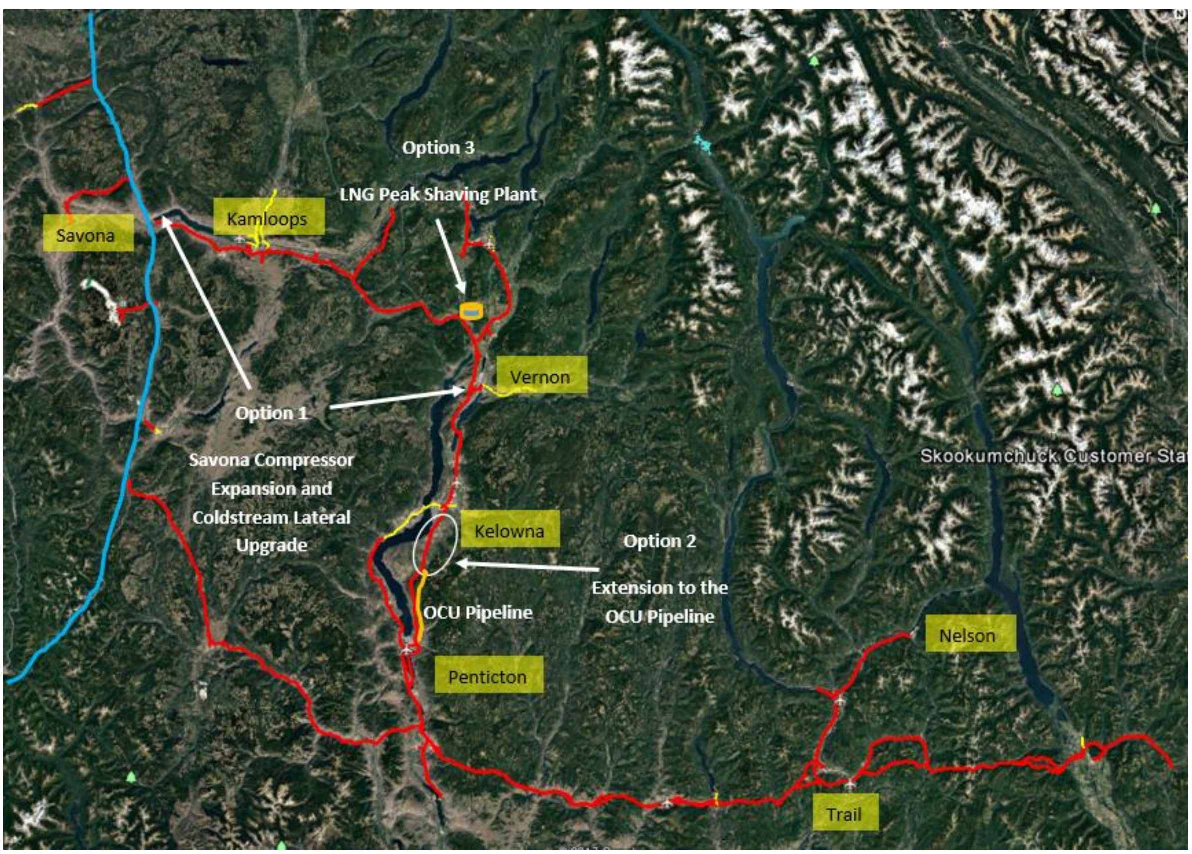
The second alternative is an extension of the OCU project further north by installing approximately 13 kilometres of NPS 16 pipeline towards Kelowna from its currently-proposed termination point between Penticton and Kelowna.

7.3.3.4.3 ALTERNATIVE 3 – LNG STORAGE FACILITY

The third alternative is an LNG storage facility located close to Vernon. An LNG facility located closer to the load centre allows natural gas to be moved into storage in times of low gas demand when excess pipeline capacity is available, and provides on-system delivery to the region during periods of high demand. Sized appropriately, this alternative could also provide a higher level of resiliency for the Thompson-Okanagan region like what the TLSE can provide in the Lower Mainland system to protect against short duration upstream supply interruptions or shortages to the ITS in the Thompson-Okanagan region.

Figure 7-17 below shows the potential locations of the three system resource expansion alternatives on the ITS.

Figure 7-17: Location of Possible ITS Reinforcement Alternatives



7.3.3.5 *Potential New Industrial Load*

Based on the FBC 2021 LTERP filed with the BCUC in August 2021, a simple cycle gas-fired turbine (SCGT) power generating plant was identified as one of the preferred long-term options in the Okanagan area to meet growing peak electricity demand. Such a plant could be installed in two phases between 2031 and 2035. The potential to add a 100 MW SCGT, expanding to 148 MW by 2035, proposed to be fuelled by RNG, would drive additional expansion of the ITS. The upgrade options would depend on the future location of the facility in the Kelowna area. Adding this load would impact the preferred ITS expansion options and would support an extension of the OCU project much further north into the Kelowna area than is previously described in Option 2. For the Traditional forecast, a future SCGT would require an OCU pipeline extension just before the generating station's proposed in-service date of 2031.

7.3.4 Transmission Laterals

FEI operates transmission laterals that connect the Westcoast and TC Energy pipelines to supply industrial users and to supply distribution systems serving communities in north-central and southeastern BC. The Cache Creek/Ashcroft Lateral has been identified as the only lateral to have insufficient capacity to meet the forecast demand throughout the 20-year planning horizon.

The Cache Creek/Ashcroft Lateral is served by the Westcoast pipeline in the Thompson region. The lateral delivers gas to Cache Creek and Ashcroft, which are located approximately 70 km west of Kamloops. The lateral consists of a combination of two pipelines and has been at its capacity to meet peak demand for several years; however, there is no forecast growth in customer accounts or demand in this system. Reductions in available supply pressure from the Westcoast pipeline are increasing the possibility of curtailment to an industrial customer on the lateral. An addition of a 19-22 km pipeline loop would be required to meet current Firm Transportation service to the industrial customer. FEI continues to work cooperatively with this customer to manage demand under peak conditions to avoid the need for the pipeline loop.

7.3.5 Distribution System Capacity

By convention, FEI has reported on infrastructure operating at or below 3100 kPag as distribution assets, which are further divided into:

- IP systems operating above 700 kPag and up to 3100 kPag; and
- Distribution pressure systems operating at or below 700 kPag.

For ease of operation and maintenance, safety to the public and reliable service, distribution networks operate at a relatively low pressure. In general, FEI operates its distribution networks at a MOP of 420 kPag; on Vancouver Island and the Sunshine Coast, FEI typically operates its distribution networks at a MOP of 550 kPag. Supply resources for distribution systems include:

- *Pressure regulating stations* – the capacity of a distribution network can be reinforced by the addition of a new regulating station; and

- *Distribution pipelines* – the capacity of a distribution network can be reinforced by increasing the cross-sectional area of a distribution pipe section. Distribution pipelines operate at a lower pressure, and can be installed by replacing an existing pipe with a larger diameter pipe, adding a parallel pipe (a loop) or by introducing gas into the network from an alternate source (a back feed).

Since distribution systems operate at a low pressure through relatively small diameter pipes, there is little line-pack capability for managing hourly demand fluctuations. Therefore, capacity requirements for distribution systems are based on peak hourly demand rather than peak daily demand.

Distribution system improvement projects generally occur more frequently and are smaller in scale than transmission system projects. Distribution system improvement projects are routinely identified as part of the capital planning process and are not discussed in any detail here.

The 2017 LGTRP identified systems where some significant changes were being assessed. The following is an update on the status of those projects as well as other significant work proposed or underway in the distribution systems that have been identified since the 2017 LTGRP.

7.3.5.1 *Metro Vancouver DP and IP Systems*

Construction on the LMIPSU projects referred to previously in Section 7.3.2 was fully completed and in the fall of 2021, when the projects entered into service. The LMIPSU projects replaced an existing 20 km NPS 20 IP pipeline between Coquitlam Gate Station in Coquitlam and 2nd Avenue and Woodland Drive Station in Vancouver with a new high capacity NPS 30 pipeline. This new pipeline significantly improves the capacity and security of supply to more than 250,000 gas customers in the region. A 300 metre replacement of a portion of the NPS 30 IP pipeline was also completed in the fall of 2021, just east of Fraser Gate Station in South Vancouver. The project upgraded the seismic resiliency of this pipeline to meet current seismic design requirements.

As mentioned in Section 7.3.2, the BCUC approved a CPCN for the PGR project in June 2021. The Pattullo Gasline is scheduled for replacement before the existing Pattullo Bridge is demolished following the planned construction of a new bridge. The PGR project will construct a replacement for the Pattullo Gasline via a new overland NPS 20 IP pipeline connecting the new Coquitlam IP NPS 30 pipeline to the existing NPS 20 (700 kPa) pipeline in east Burnaby.

7.3.5.2 *Revelstoke Propane System*

FEI operates a satellite, off-grid propane distribution system that serves residential and commercial customers in the Revelstoke area. Due to its geographic location, Revelstoke is located too far away to economically connect to the natural gas grid. Consequently, propane is transported by railcar and tanker truck to Revelstoke where it is then off-loaded into storage tanks, vapourized as needed and distributed to customers through an underground pipeline system. As a result of growth in demand, FEI replaced and increased the capacity of Revelstoke's second propane vapourizer in 2018 to provide full redundancy in meeting peak demand on the system.

In October 2020, FEI received approval for the Revelstoke Propane Portfolio Cost Amalgamation Application that provided a favourable reduction in energy costs for FEI's propane customers in Revelstoke. Core demand growth in Revelstoke is forecast to increase and FEI continues to assess the impact of the amalgamation on Core and Industrial demand. FEI expects to expand the propane system with additional storage tanks and some pipeline looping when increased demand warrants the expansion.

7.3.5.3 *Whistler Distribution System*

The Whistler distribution system is supplied by the VI Transmission System at Squamish. From Squamish, an NPS 8 pipeline with an operating pressure of 2069 kPag follows the Highway 99 corridor north to Whistler. The pipeline was commissioned in 2009 and the Whistler distribution system was converted from propane to natural gas that summer, prior to the 2010 Winter Olympics.

Since the commissioning of the pipeline in 2009, there has been sustained growth in the community. In late 2014, a series of phased system improvements were proposed to be installed between 2015 and 2020 that would result in extending the pipeline approximately 5 km further north into the community, along with another Gate Station facility to address growth.

In 2016, BC Transit announced its intention to convert the Whistler transit fleet to CNG and construct a CNG fueling facility at its existing transit site on the north side of Whistler. The facility began operating in late 2017. As a result of this substantial load near the northern extremity of the system, the need arose to advance the future system improvement phases from future years to the present. For the winters of 2017-2018 and 2018-2019, while FEI worked on completion of the IP pipeline extension and the new gate station, FEI installed and operated a portable small-scale LNG peak shaving unit in the northern part of the Whistler system. This temporary installation provided support for peak demand requirements for surrounding gas customers as well as the initial needs of the BC Transit CNG fueling compressors. FEI completed the required pipeline and station facilities in July 2019.

7.3.5.4 *Gibsons Distribution System*

The community of Gibsons is supplied with natural gas by a 19 kilometre IP pipeline from Sechelt Gate Station which is in turn served by the VITS. The capacity of the IP pipeline is insufficient to meet current peak demand without temporary mitigation measures. These temporary mitigation measures will be insufficient beyond 2023, thus requiring additional upgrades. FEI has completed the project scope and cost estimate development for a local peak shaving CNG unit in the Gibsons distribution system area to offset the peak demand support required of the IP pipeline supplying the distribution system. Several alternatives were considered for this project (including IP pipe installation), and a local CNG peak shaving facility was determined to be the preferred and lowest cost alternative. This project was included in the FEI FBC 2024-2024 MRP application as a Major

Project: the FEI Sunshine Coast Capacity Upgrade (Section C.3.3.3.7). Through the development of the preliminary project cost estimate, it was determined that this project no longer meets FEI's CPCN materiality threshold of $15 million. The Gibsons Capacity Upgrade project will be identified in FEI's Annual Review for 2023 Delivery Rates application. This project would become FEI's first operational non-pipe solution installed within a distribution system and will provide valuable information on using non-pipe solutions as alternatives to address system capacity.

7.4 INTEGRATION OF RENEWABLE AND LOW-CARBON GAS

FEI's framework to transition to a low-carbon energy future is its Clean Growth Pathway, discussed in Section 3. The Clean Growth Pathway is a diversified approach that is technology agnostic. At this point in the energy transition, it is important to maximize the number of decarbonization pathways available and explore business models that meet energy demands and maximize the use of existing assets, thereby avoiding the costs that would come with the complete reengineering of BC's energy sector. In the 2022 LTGRP, the Clean Growth Pathway is represented by the Diversified Energy (Planning) Scenario.

FEI is planning for gas supply resources made up of increasing amounts of renewable and low-carbon gas over the next 20 years and beyond. The components of this resource mix are expected to include RNG, hydrogen, natural gas, and smaller amounts of syngas and lignin, supplemented later in the planning period by CCUS. The amount of each resource to be acquired and delivered to customers throughout the planning period will ultimately be predicated by several variables, including:

- **Quantity and Timing of Resource Availability**: Although FEI has modelled the mix of renewable and low-carbon gas in certain proportions over time in the LTGRP planning scenario, the actual amount of each component that is acquired and delivered to customers could vary from the forecast amounts over the planning horizon based on a number of important factors, including resource costs and supply project opportunities and development. Renewable and low-carbon gases with the highest volume potential over the planning horizon are RNG and hydrogen. In particular, RNG is interchangeable[207] with natural gas and has wider availability so will make up a greater proportion of the resource mix in the near term. RNG will continue to be a large part of the resource mix throughout the planning horizon and beyond. While hydrogen resource development is underway, it is expected to become more widely available and make up an increasing proportion of the resource mix later in the planning horizon beyond 2030.
- **Resource Development and Delivery:** Many pathways exist for bringing the benefits of renewable and low-carbon gas to FEI's customers; however, there are several ways in which these resources can be developed and delivered to customers which will ultimately

[207] The physical properties of renewable natural gas, such as specific gravity, viscosity and heating value, etc., falls within the range of the physical properties of FEI's conventional sources of natural gas. The capacity impacts and gas supply resource needs are comparable, and both sources of methane can utilize the same upstream and on-system infrastructure.

determine the capacity impact and the overall system upgrade scope and timing. The following discusses the various modes of production and delivery and explains some of the capacity impacts associated with each.

i. **Off-System Supply and Off System Delivery:** Off-system supply is where FEI acquires renewable and low-carbon gases in other regions and the gas transportation and consumption is conducted completely outside of FEI systems. This process achieves carbon reduction and credit for FEI customers with the environmental attributes associated with renewable and low-carbon gas. However since FEI customers continue to physically receive conventional natural gas through FEI infrastructure the capacity requirements to meet peak demand forecasts remain the same on the FEI system. This capacity impact of off-system supply and delivery has the same neutral effect regardless of the form of the off-system energy delivered. The incorporation of these types of off-system supplies will play an important role while the transition to renewable and low-carbon gas occurs over the planning horizon until more on- or near-system resources that flow directly through FEI systems are developed.

ii. **CCUS:** processes for carbon capture at the customer location will not change the system capacity required to meet the peak demand. The process does not change the amount of conventional natural gas that would be flowing through the system to support customers using these processes.

iii. **On-System Hubs:** Local production and supply of renewable low-carbon gas will be developed. These local hubs, whether they produce RNG, or hydrogen or syngas and lignin will have some ability to free up pipeline capacity as the local demand served by this production no longer needs to be transported through the upstream transmission pipeline. For hubs that in addition to serving local demand inject RNG or electrolytic hydrogen (known as green production) into the transmission system as well there can be an additional capacity benefit on the system, however with hydrogen there can also be some offsetting capacity reduction where hydrogen blends are present in the transmission system or if conventional natural gas delivered through the upstream transmission pipeline is used as a feedstock for hydrogen production, by reformation or pyrolysis (known as blue or turquoise production respectively). The impacts of hydrogen blends on capacity are discussed further in Appendix D-3.

iv. **Off-System Supply and On-System Delivery:** Off-system supply of RNG and hydrogen physically delivered into FEI transmission systems from upstream pipelines will produce no net change in FEI transmission system capacity to meet peak demand forecasts if the supply is RNG. If the supply is a blend of hydrogen, there will be some capacity reduction for the reasons discussed below and in Appendix D-3.

- **Location:** Given the length of the planning horizon, the geographic location where renewable and low-carbon supply production is physically delivered to FEI's customers is not yet known in detail. Production facilities for RNG and hydrogen supplies are expected to be developed both on FEI's system and, over time, in locations where these low-carbon gases can be injected into the existing upstream gas infrastructure. While many potential projects are in the concept and development stages, the location of all those that will proceed during the next 20 years is uncertain. In particular, the extent to which such resources are developed and delivered to customers on one portion of FEI's system will impact the amount of RNG and natural gas that will still need to be delivered on other portions of the system over the planning horizon.

Although FEI is securing about as many contracts for supply within BC as outside of BC, the larger producers, in the near term, are outside of the province. Therefore, in the early years of the planning horizon, FEI's supply will predominantly be acquired and used outside of FEI's service territory. As a result, during this early part of the planning horizon, the system capacity impacts will remain largely unchanged from what FEI would have otherwise anticipated without renewable gases, as the transmission and distribution systems continue to predominantly move conventional natural gas. By 2030 and through the end of the planning horizon, on-system delivery of renewable gases supplied within FEI systems or by upstream pipeline systems will expand.

As FEI incorporates renewable gases into the gas distribution and transmission systems, the physical properties of these gases, such as density and energy content per standard volume, can have an impact on capacity. Gases with physical properties within the range of conventional gas, such as RNG, will have no net impact on delivery capacity. Delivering hydrogen or a blend of hydrogen and natural gas or hydrogen and RNG, where the gas density and energy content are different from traditional natural gas supply, will change the energy delivery capacity. The following sections provide some additional detail and examples of the impacts on system capacity and infrastructure requirements of introducing hydrogen gas blends.

Refer to Appendix D-3 for additional discussion on system planning considerations regarding hydrogen and hydrogen / natural gas or RNG blends

7.4.1 Integration of Renewable and Low-Carbon Gas in FEI Systems

7.4.1.1 *Overview of System Planning Considerations in Integrating Renewable and Low-Carbon Gas*

Each of FEI's regional pipeline systems have unique considerations with regards to the potential opportunities to bring on renewable and low-carbon gas to displace the need for pipeline delivery of conventional gas. From now until 2030, FEI expects a larger share of on-system renewable and low-carbon gas contribution will come from on-system RNG, syngas and lignin production, and CCUS. By 2042, as technology advances to produce hydrogen electrolytically, by pyrolysis or reformation, hydrogen is expected to be a larger share of FEI's fuel mix. By 2030 and through the rest of the planning horizon FEI's on system supplies will be increasingly enhanced by off-system production of renewable gases that is delivered into and through FEI systems.

Existing end use equipment such as furnaces, boiler and other residential and commercial appliances can burn a blended mix of methane and low concentrations of hydrogen. In its approach to delivering hydrogen, FEI assumes that (1) gas equipment will evolve to be able to utilize higher concentrations of hydrogen mixed with methane, and (2) some gas equipment (industrial process equipment, for example) could be able to fuel switch between hydrogen and methane when necessary. Some customers may also choose to install equipment that will be hydrogen dedicated. The eventual mix of these types of equipment throughout FEI's service territory is yet to be determined and would influence how adoption and distribution of renewable and low-carbon gases progress in each system.

As it is still early in the development of the production and delivery of hydrogen along with other renewable gases, FEI does not yet have sufficient definition to provide projections on their specific impact to the capacity of the system. Hydrogen has the most complex requirements from a system planning perspective. Considerations for hydrogen distribution is a likely and flexible way that the system can be expanded later in the forecast period considering the number of factors, yet to be fully determined, that may need to be defined and managed.

Table 7-2 provides an overview of FEI's system planning considerations for integrating renewable and low-carbon gas into regional transmission systems. Sections 7.4.1.2 to 7.4.1.4 then discuss further details regarding specifics within each regional transmission system.

Table 7-2: Overview of Considerations for Integrating Renewable and Low-Carbon Gas in FEI Systems

Fuel Type / Other Considerations	Regional Transmission and Distribution Line Considerations		
	VITS	CTS	ITS
RNG (on-system)	• Supply potential • No detrimental impact on transmission system capacity • Reliable supply from local on-system hubs will reduce upstream supply requirements and improve available capacity	• Supply potential • No detrimental impact on transmission system capacity • Reliable supply from local on-system hubs will reduce upstream supply requirements and improve available capacity	• Supply potential • No detrimental impact on transmission system capacity • Reliable supply from local on-system hubs will reduce upstream supply requirements and improve available capacity

Fuel Type / Other Considerations	Regional Transmission and Distribution Line Considerations		
	VITS	CTS	ITS
Hydrogen	• Supply potential from blue or turquoise production potential may require system upgrades • Green hydrogen hub will reduce upstream supply requirements and improve available capacity, but reduce available capacity downstream	• By 2030, hydrogen production anticipated with hydrogen and RNG in similar proportions. • By 2042, hydrogen supplied from upstream of Huntington Control Station and comprises a much larger portion of the fuel mix • With upstream supply, hydrogen separation facility at Huntingdon anticipated • Dedicated hydrogen “backbone” pipeline likely	• Supply potential from blue or turquoise production potential may require system upgrades • Green hydrogen hubs will reduce upstream supply requirements and improve available capacity, but reduce available capacity downstream
Syngas and Lignin	• Supply potential	• No supply potential currently identified	• Supply potential
LNG and Industrial Project Impacts	• Woodfibre LNG project may preclude hydrogen blending upstream (at Eagle Mountain) • Management of hydrogen at FEI’s Mount Hayes LNG facility would be required	• Flow of hydrogen likely to be separated from transmission system at Huntingdon control station due to large scale LNG production at Tilbury and Woodfibre LNG project	• Management of hydrogen at any future LNG facilities would be required •
System Upgrade Requirements	• Scope and location of system upgrades not yet feasible to determine as supply volumes and locations are currently in early stages of development	• Local supply hubs and small dedicated systems eventually connected to upstream by dedicated hydrogen “backbone” • Scope and location of system upgrades not yet feasible to determine as supply volumes and locations are currently in early stages of development	• Renewable and low-carbon projects could offset the need for upgrades • RGSD project under development could provide significant support for delivery of hydrogen and other renewable gas • Scope and location of system upgrades not yet feasible to determine as supply volumes and locations are currently in early stages of development

7.4.1.2 *The VITS*

For the VITS, there is opportunity to develop supply from on-system local RNG hubs. The RNG production can be blended in the transmission or distribution systems at the point of production. As described above in Section 7.4, RNG supply hubs, once reliable production has been developed, could offset some need for future pipeline capacity to support peak demand because of the reduced need to move the gas from upstream of the local hub. The VITS could also accept any RNG that is produced and injected in upstream transmission systems (such as the CTS, Westcoast, TC Energy and possibly the RGSD). RNG entering the VITS from upstream would not offset future capacity upgrades as the physical properties of the gas that determine the capacity requirements are the same as if conventional natural gas were supplied.

There are also several existing industrial locations where syngas and lignin production could meet local needs and displace the need for pipeline delivery (and capacity) of conventional gas to those locations.

To integrate hydrogen into the VITS, with the possibility of the Woodfibre LNG project entering service within the next few years and given the impacts of hydrogen blends on pipeline capacity and larger scale LNG production, FEI is not currently considering allowing hydrogen blends into the system at Eagle Mountain (the start of the VITS). FEI would achieve this by controlling the flow of hydrogen in the upstream CTS. However, downstream of the Woodfibre LNG plant there is potential to produce hydrogen in local hubs to be used locally or to be blended into the transmission or distribution system. This integration of hydrogen would require some means of removing hydrogen at FEI's Mount Hayes LNG facility when the plant in liquefying. As described in Sections 7.4 and Appendix D-3 green hydrogen supplied by these local hubs can provide a capacity benefit by offsetting the upstream gas supply otherwise required, but also reduce the existing capacity in the downstream system where hydrogen blends would flow. Blue or turquoise hydrogen production on system (produced from conventional natural gas supplied from upstream) may not provide any upstream benefit. As a result, these hubs could drive some future system upgrades in portions of the VITS.

At present, FEI expects a larger share of the renewable and low-carbon gas contribution will come from on-system RNG, syngas and lignin production, and some CCUS, with hydrogen forming a lesser part of the blend early in the forecast period until processes to produce hydrogen are in a more advanced stage of development. Until hydrogen and other renewable and low-carbon projects on the VITS are developed further and production rates and locations are more clearly defined, it is not yet feasible to identify and develop any specific system upgrades to support these energy supplies.

7.4.1.3 *The CTS*

FEI expects that as RNG supplies in the CTS develop, they will be blended in both the distribution system and the transmission system. These local hubs as the production becomes sufficiently reliable to support peak demand will provide some offset to upstream pipeline delivery (and capacity) of conventional natural gas to those location. Most of the supply will be produced within the CTS until later in the forecast period when off-system RNG production becomes available and can be delivered into the upstream pipeline systems supplying the CTS. At present there is potential for any significant syngas and lignin production identified within the CTS.

For hydrogen supplies, as with the VITS, the development of large scale LNG production in the CTS and the capacity impacts of hydrogen blends entering the VITS at Eagle Mountain need to be considered when addressing the distribution and blending of hydrogen in the system. Hydrogen at locations like Tilbury and Eagle Mountain, and possibly other industrial locations using methane as a feedstock would require hydrogen to be removed to accommodate production. By 2030, FEI expects to have developed hydrogen production within portions of the CTS at various locations and will be developing upstream supply. FEI is also expecting the potential for some, but not large quantities of hydrogen delivered from pipelines upstream of Huntingdon Control Station by that time. The proportions of hydrogen and RNG delivered in the system by 2030 may be similar. By 2042, however, FEI expects that most of the hydrogen used in the CTS will be supplied from the pipelines upstream of Huntingdon, and hydrogen will comprise a much larger portion of the renewable and low-carbon gas delivered.

To keep the blended hydrogen from the upstream pipelines out of the CTS as it begins to arrive in more significant quantities after 2030 would require a hydrogen separation facility at Huntingdon and a dedicated hydrogen pipeline that would ultimately connect to FEI's initial hubs. This pipeline would share a common alignment with FEI's existing CTS pipelines so that hydrogen could be blended directly into the distribution systems at the gate stations served by the CTS. This would allow the distribution system to receive a controlled blend of conventional gas, hydrogen and RNG, while leaving the CTS to deliver natural gas and RNG to the LNG production at Tilbury and the VITS-supplying Woodfibre LNG project via the Eagle Mountain Compressor facility in Coquitlam. This approach to introducing hydrogen along a dedicated "backbone" that connects earlier established local hubs allows some flexibility to control the increasing delivery of hydrogen in the system.

An alternate approach would be to accept increasingly higher blends at Huntingdon into the CTS directly as the supply increases and install multiple separation facilities throughout the CTS at locations like Tilbury LNG where it is necessary to separate the hydrogen. This requires re-blending the hydrogen collected at these locations back into the CTS downstream of the facility and adds a greater level of complexity to the system required for the delivery of hydrogen. Another concern with this approach is that directly blending hydrogen into the CTS would increasingly reduce the capacity of the CTS, which may expand upgrade requirements to support LNG expansion by increasing the capacity upgrades necessary for LNG as well as increasing the scale of hydrogen separation (and downstream re-blending of hydrogen) at the Tilbury LNG facility if future phases of LNG expansion occur.

As it is still early in the development of the production and delivery of hydrogen along with other renewable gases in the CTS, FEI does not yet have sufficient definition to provide projections on their specific impact to the capacity of the system. The hydrogen "backbone" described earlier is a likely and flexible way that the system can be expanded later in the forecast period considering the number of factors, yet be fully determined, that may need to be defined and managed.

7.4.1.4 *The ITS*

The ITS presents a variety of potential future options to meet FEI's carbon reduction goals including RNG, syngas and lignin and hydrogen that could all be produced and consumed directly by industrial customers and other local consumers. There are a variety of potential future off-system supply options as well, for each renewable and low-carbon gas, from the Westcoast system in the west at Savona and Kingsvale and the TC Energy system in the east at Yahk to help meet carbon reduction goals.

There is opportunity to develop supply from on-system local RNG hubs. RNG supply hubs, once reliable production has been developed, could offset some need for future pipeline capacity to support peak demand because of the reduced need to move the gas from upstream of the local hub. The ITS could also accept any off-system RNG that is produced and injected in upstream transmission systems. RNG entering the ITS upstream at Savona, Kingsvale or Yahk would not offset future capacity upgrades as the physical properties of the gas that determine the capacity requirements are the same as if conventional natural gas were supplied.

Similar to the VITS, in the ITS there are also several existing industrial locations where syngas and lignin production could meet local needs and displace the need for pipeline delivery (and capacity) of conventional gas to those locations.

Hydrogen sources, supply could also be produced and injected on-system into nearby distribution systems or injected into the ITS for wider consumption at local supply hubs. Green hydrogen supplied by these local hubs can provide a capacity benefit by offsetting the upstream gas supply otherwise required, but also reduce the existing capacity in the downstream system where hydrogen blends would flow. Blue or turquoise hydrogen production on system (produced from conventional natural gas supplied from upstream) may not provide any upstream benefit. As a result, these hubs could drive some future system upgrades in portions of the ITS. The ITS could also accept any off-system hydrogen that is produced and injected in upstream transmission systems hydrogen entering the ITS upstream at Savona, Kingsvale or Yahk. As described earlier and as discussed in Appendix D-3 introducing hydrogen blends at the source of the system will reduce some of the available capacity and could drive some additional future upgrades requirements than would be required with conventional natural gas supplies. The upgrade requirements and system capacity will look different depending on the range of hydrogen supplied into the system from each upstream source.

Currently FEI is developing the RGSD pipeline. Should the potential project proceed, the pipeline and system upgrades which include additional compressor facilities along FEI's SCP. The RGSD would allow FEI to receive and deliver off-system hydrogen production from TC Energy and on-system supplies along the ITS and SCP to other locations along the ITS, but also as envisioned will have the capacity to move additional hydrogen and conventional gas required for the CTS via a new NPS 30 hydrogen ready pipeline between Oliver and the Lower Mainland.

As mentioned previously there are a significant number of other combinations of supply from Westcoast and TC Energy that could ultimately occur in the ITS. As these opportunities are developed into defined projects and specific sources of supply for each renewable gas, the specific capacity upgrade requirements required within the ITS to accommodate delivery of renewable gases will become more clearly defined.

7.5 SYSTEM RESILIENCY

Broadly speaking, gas system resiliency depends on a combination of pipeline diversity, ample storage, and the ability to manage load. Establishing system resiliency enables the gas transmission and distribution systems to effectively respond to system disruptions and avoid or minimize impacts of those disruptions. FEI applies and leverages two of the three key elements, storage and pipeline diversity, in both the transmission and distribution systems to build infrastructure that along with the third element, load management support, provide end to end resiliency while connecting FEI consumers with the region's gas supplies.

FEI has provided safe and reliable natural gas service in the province for many years. To provide reliable service, FEI has maintained the integrity of its assets, and ensured the adequacy and security of gas supply. FEI has also completed a number of projects that have significantly enhanced the resiliency of its system, such as the SCP and Mt. Hayes LNG facility. FEI's system exhibits a high level of reliability and has to date proven resilient to system failures and unforeseen events in the region. While FEI has long regarded resiliency as an important system attribute, the T-South incident (discussed in Section 3.2.2.3) underscored the benefits that would come from new investments in system resiliency.

FEI provides a comprehensive discussion of system resiliency across all FEI systems and the PNW in Appendix E. This section summarizes the resiliency of each of the transmission systems and the distribution system and TP lateral system infrastructure projects FEI is currently developing, or considering, to enhance resiliency

7.5.1 Transmission System Resiliency

In order for the gas system to avoid and effectively respond to disruptions, FEI must establish a resilient system. The high-level resiliency considerations for each transmission system are:

- ***The Vancouver Island Transmission* System:** The Mt. Hayes LNG facility supports VITS resiliency by providing LNG inventory and vapourization capacity, which can support the system for several winter days in the event of a supply disruption and can indirectly support supply disruptions upstream of the CTS through displacement of load requirement from the CTS. As it is connected to the Mt. Hayes LNG facility the VITS has a high level of resiliency in meeting peak winter demand and supply disruptions. FEI has therefore not presently identified or considered projects to increase resiliency for the VITS.
- ***The Coastal Transmission System*:** To enhance resiliency in the CTS, as discussed in Section 6.3.2 and 6.3.3, since the T-South incident, FEI has filed an application with the BCUC for the TLSE project to address resiliency for FEI's Lower Mainland systems. FEI is also considering new regional pipeline infrastructure to build on the resiliency provided

by the TLSE project and add pipeline diversity to the CTS and broader region. The RGSD project would expand the SCP from Oliver to the Lower Mainland to increase the CTS's supply diversity. In the medium term, FEI's AMI project will be beneficial in enhancing FEI's CTS load management capabilities. These projects will add key components to FEI's portfolio approach to resiliency while providing other benefits for customers.

- ***The Interior Transmission System*:** The ITS is dependent, in the Okanagan region, on supply from both the Westcoast system supplying the ITS at Savona, west of Kamloops, and the supply from TC Energy supplying the ITS and SCP near Yahk in the Kootenays and entering the Okanagan region at Oliver. Although the ITS has some diversity of supply, interruption of one of the two supplies in a period of higher demand could result in loss of supply to customers in portions of the ITS. As a result, FEI is looking at the need to improve resiliency in the ITS. FEI is examining options to improve resiliency in this area of the Interior, which are discussed below.

The infrastructure projects FEI is currently developing, or considering, to enhance resiliency are described below.

7.5.1.1 *Regional Gas Supply Diversity (RGSD) Pipeline*

As described earlier in Section 6.3.3 the RGSD project is being developed to add resiliency to the Lower Mainland system and enhance the resiliency and supply diversity of the broader regional pipeline infrastructure in BC and the PNW. As part of the project approximately 238 km of NPS 30 pipeline would extend FEI's Southern Crossing pipeline from Oliver to the Lower Mainland. Four new compressor stations would be installed between Yahk and Oliver on the existing Southern Crossing pipeline. With the upgrades the project will have the capacity to increase FEI's existing supply along the Southern Crossing pipeline and into the Lower Mainland at Sumas from 115 TJ per day to approximately 500 TJ per day and is planned to have the metallurgical capability to support FEI's plans to deliver hydrogen across BC and the PNW.

7.5.1.2 *Interior Transmission System (ITS) Resiliency*

Increased resiliency and supply diversity within the high-population centres in the Thompson Okanagan region of the ITS can be accomplished through either extensive pipeline looping and compression or through a centrally located LNG supply that could provide short-term supply like that proposed by the TLSE project in the Lower Mainland.

Option 1 – LNG Storage

As described in Section 7.3.3, an LNG storage facility close to Vernon could, if suitably sized, provide a higher level of resiliency to protect against upstream supply interruptions or shortages to the ITS in the Thompson-Okanagan region, in addition to addressing future capacity needs in the latter part of the forecast period.

Option 2 – Pipeline Looping and Compression

Pipeline looping from both the northwest (Savona) and from the South (extending the OCU pipeline) is another option to increase resiliency. Looping from Savona would extend east past Kamloops towards Vernon, along with additional pipeline looping from the south extending the OCU project pipeline from its terminus near Chute Lake north around Kelowna and past Vernon. Additional compressor units would also be installed at Savona to accommodate a higher flow rate if the gas supply from Yahk is interrupted. Pipeline upgrades and compressor power upgrades at FEI's Armstrong compressor would also be undertaken to allow discharge towards Kamloops in the event supply from Savona is interrupted.

7.5.2 Distribution System and TP Lateral System Resiliency

FEI distribution systems are inherently resilient in that they have evolved as communities have expanded. As such, there is a high degree of interconnection within the systems allows the continuation of service to the majority of customers in the system, and results in outages caused by system damage to be limited in scope compared to transmission system incidents and supply disruptions. In addition, the duration of outages while repairs are completed can be much less extensive, most often a few hours or less. This is due to the pipeline's low operating pressures, smaller pipeline sizes, and more routine and less incident-specific regulatory system requirements. There are very few locations within FEI distribution systems where many customers would be at risk of extended outages in winter conditions. As a result, FEI gas customers enjoy a high degree of reliability and most never experience an unplanned outage. Nevertheless, FEI is reviewing distribution system resiliency options in locations where large numbers of customers are vulnerable to pipeline failure and where the ability to restore service in the event of an outage may extend to several weeks or months.

7.5.2.1 *Major DP, IP and TP Lateral Pipeline Crossings*

The risk of prolonged service interruptions in distribution pipelines is almost exclusively limited to single feed gas lines at major water crossings where the line is inaccessible or otherwise extremely difficult to repair. FEI is examining options to improve resiliency at select points of the distribution systems, including at the Ironworkers Memorial Bridge in the Lower Mainland and at Okanagan Lake between Kelowna and West Kelowna.

A NPS 24 IP pipeline located on the Ironworkers Memorial Bridge provides the only gas supply to more than 45,000 customers in North Vancouver and West Vancouver. Loss of this crossing would result is an extensive outage for these customers. Providing a second redundant crossing to the Northshore communities would significantly improve the resilience of this portion of the Metro Vancouver distribution system.

In the Interior region, West Kelowna is supplied by an NPS 8 IP pipeline that crosses Okanagan Lake between Kelowna and West Kelowna. While the system may require capacity upgrades later in the forecast period that could entail looping the lake crossing, looping the crossing would address capacity constraints but would not improve resiliency. In anticipation of future resiliency needs, FEI is studying alternatives for the crossing that would improve the resiliency of supply to West Kelowna, Summerland and Peachland.

Other than service to the communities mentioned above, there is a limited number of similar water crossings in FEI's distribution systems where large numbers of customers are at risk of extended supply outages because of crossing failures.

Despite the inherent resiliency of distribution systems, FEI is in the process of developing criteria to more clearly define projects where single points of failure would cause disruption to significant numbers of customers and where service would be unable to be restored in a timely manner. Such failures would result in a risk of customers being without supply for extended periods in winter conditions and thus would be prioritized in planning analyses for resiliency. In some cases, small transmission lateral bridge and water crossings provide the sole source of gas supply to communities, and therefore present similar risks in the event of a supply failure. To develop the criteria to identify these projects, FEI is reviewing the maximum capability of temporary "non-pipe" solutions such as a CNG or LNG "virtual pipeline" arrangement to support communities in a sustained manner through a winter period in the rare circumstance that a failure of the single supply occurs. Defining this capability and establishing the feasibility, timeliness of mobilization, and cost of implementation will help define how many new projects should be considered to improve resiliency for systems too large to be supported by non-pipe solutions. Additionally, not all single-feed crossings will have the same probability of failure, so criteria to establish the risk associated with each location will provide a basis of establishing the priority of identified resiliency projects. As mentioned previously, FEI's DP, IP and TP lateral systems are generally highly resilient, and the criteria developed are not expected to produce many projects of significant scope or cost.

7.5.2.2 *Metro Vancouver LMIPSU System Resiliency*

In Section 3.6 of the PGR project CPCN Application[208], FEI described the impact of its preferred alternative on system resiliency. While the PGR project would erode the resiliency provided by the recently completed LMIPSU project to be fully resilient under the coldest design conditions, the LMIPSU nonetheless remains a substantial improvement to the Metro Vancouver distribution system. It continues to support system resiliency in the event of a failure of supply at either of the two major gate stations serving the region by preventing service interruptions up to nearly the coldest day in a typical winter. However, for FEI to recover the incremental resiliency eroded by the PGR project, an approximately 5100 m long 508 mm (20") IP pipeline loop in South Vancouver would be required. This would be a significant project very similar to the scope of the current PGR Project.

In the process described above of developing criteria to identify other resiliency projects, FEI expects to identify and prioritize other proposed projects that would address more urgent locations where a failure of a single feed would result in customers being without gas at any time of year.

[208] Application for a Certificate of Public Convenience and Necessity for the Pattullo Gas Line Replacement project Decision and Order C-2-21.

As a result, at this time, FEI is not intending to file an application for a project to restore the eroded distribution system resiliency resulting from the PGR project prior to the submission of its next LTGRP. In the interim the installation of enhanced metering with the AMI project, if approved, may provide additional information to FEI useful in evaluating the need to recover resiliency. Further consideration for the potential need and timing for this project will be provided in a subsequent LTGRP application.

7.6 *OTHER MAJOR SYSTEM PROJECTS*

FEI has several other significant system projects either in progress, before the BCUC, or in development. These are described below.

7.6.1 The Okanagan Capacity Upgrade (OCU) Project

FEI continues to forecast a capacity deficit in the Okanagan region of the ITS. At present, the CPCN Application[209] for the project is adjourned. In the interim, FEI continues to prepare contingency plans for temporarily addressing the capacity deficit until a permanent capacity upgrade solution is approved and installed.

7.6.2 Transmission System Laterals In-Line Inspection (ILI) Capability

FEI operates transmission pressure laterals across the province served from FEI-operated transmission systems or the Westcoast and TC Energy pipelines. These laterals range from several hundred metres to several tens of kilometres in length. A total of more than 400 km of these pipeline laterals are between NPS 6 and NPS 10 and currently are not configured to allow ILI tools to be used as part of FEI's pipeline integrity management programs. ILI technology is an effective tool for detecting and subsequently repairing pipeline corrosion and defects prior to leaking or rupture.

In January 2020, FEI received approval to move forward with the Inland Gas Upgrade (IGU) project[210] and is currently in progress on this multi-year project to upgrade transmission laterals for ILI capability or install pressure control station to reduce pressure sufficiently to avoid the need for ILI activities on some lateral systems.

[209] Application for a Certificate of Public Convenience and Necessity for the Okanagan Capacity Upgrade project (Application): https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/201116-fei-okanagan-capacity-upgrade-cpcn-ff.pdf?sfvrsn=adf84903_2.

[210] Application for a Certificate of Public Convenience and Necessity for Approval of the Inland Gas Upgrade project (IGU project or the project): https://fbcdotcomprod.blob.core.windows.net/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/181217-fei-igu-cpcn-application-ff.pdf.

7.6.3 Southern Crossing Pipeline Class Location Project

Urban development around existing pipelines can drive changes in pipeline class location as defined in CSA Z662[211] and necessitate changes to increase pipeline safety factors. Pipeline safety factors can be increased by either:

- Decreasing pipeline operating pressures at existing or new pressure control stations; or alternatively
- Replacing the identified pipeline segment in populated areas with higher grade and or thicker walled pipe.

Installing additional mainline valves may also be necessary in either case. Decreasing pipeline operating pressure to increase the safety factor will reduce the capacity of the pipeline and is not a viable option given the capacity this pipeline currently requires and would need in the future to deliver FEI requirements for renewable and low-carbon gas. Replacing the pipeline segments with higher grade or thicker walled pipe can maintain or increase operating pressures and capacity. The SCP is an NPS 24 pipeline operating between Yahk and Oliver in the BC Southern Interior. The Class Location project will address the installation of six kilometres of pipe replacement and one new mainline valve between 2024 and 2028 to sustain established pipeline operating pressure and pipeline safety factors.

7.6.4 Advanced ILI on Pipelines Currently Inspected with ILI

Advanced Electro-Magnetic Acoustic Transducer (EMAT) ILI capability for pipelines that are already ILI-capable is currently being proposed by FEI. FEI's CPCN Application for the Coastal Transmission System Transmission Integrity Management Capabilities project is currently before the BCUC and FEI is developing a similar application for the ITS. EMAT technology can detect Stress Corrosion Cracking (SCC) and cracks in alignments currently not detected by traditional ILI tools. The implementation of this technology includes upgrades such as:

- Alterations of the sending and receiving barrels to accept the newer tools;
- Alterations to the transmission pipelines so that the new tools can traverse them without hindrance or interruption to ensure successful data collection;
- The installation of flow control equipment or transmission loops to facilitate the control (i.e., reduction) of the gas flow velocity to ensure successful data collection; and
- Capacity upgrades to facilitate operation at reduced pressures when SCC features are detected and subsequently investigated and corrected.

7.6.5 Reliability Upgrade to Langley Compressor Facility (Existing Units)

The Langley compressor facility consists of two 7,500 HP units. With large industrial load additions like the Woodfibre LNG project, the Langley compressor units would need to run for

211 https://www.csagroup.org/store/oil-gas-pipeline-systems/.

periods of several days to weeks in winter periods. The current units are undergoing some upgrades, and to support increased service hours would require the installation of a cold recycle loop in the facility and a fuel condition system that are scheduled to be completed in 2023 and will be funded by FEI's sustaining capital budget. With increased operation, compliance with air quality permit and requirements to ensure compliance are currently under way. The Vancouver airshed environmental regulations continue to change and the Canadian Ambient Air Quality Standard is expected to become more stringent in terms of emission requirements. At this time, it is unclear if changes will necessitate premature replacement of the units to meet a more stringent emission criterion. If the current units are not able to meet new emission requirements, it is expected that they will be upgraded to address both the environmental requirements and the long-term availability concerns with Original Equipment Manufacturer (OEM) model support. As indicated in Section 7.3.2.4, additional phases of LNG expansion could drive the need for an additional compressor unit at Langley in addition to the units currently installed.

7.7 RECOMMENDATIONS FOR SYSTEM REQUIREMENTS TO MEET GROWTH AND THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

FEI's gas system must be improved to meet future demand growth and optimize operation of the whole system. With annual increases in forecast peak demand, potential new sources of demand from LCT and industrial sources, and the introduction of renewable and low-carbon gas in significantly increasing quantities, the VITS, CTS and ITS could all require capacity-enhancing projects to meet peak demand forecasts while enabling FEI's Clean Growth Pathway. To address system capacity, FEI plans to:

- Accelerate efforts to study and develop solutions for understanding the system's capacity to support increasing production and delivery of renewable and low-carbon gas;
- Refine reinforcements that would be required to maintain system reliability and resilience for Core customers as LNG expansion occurs on the CTS and VITS;
- Refine criteria to identify and prioritize projects to address system resiliency in all FEI systems;
- Refine and implement mitigation plans to address the capacity shortfall in the Okanagan region of the ITS until an OCU project solution is approved and implemented; and
- Continue evaluating other major system projects outlined in Section 7.6 and submit CPCN applications for these projects if required.

FortisBC Energy Inc.
2022 LTGRP

Section 8:

STAKEHOLDER, INDIGENOUS AND COMMUNITY ENGAGEMENT

Table of Contents

8. STAKEHOLDER, INDIGENOUS AND COMMUNITY ENGAGEMENT

8.1 *INTRODUCTION*

In this section, FEI provides details of its engagement activities, including the process, the stakeholders and Indigenous groups with whom FEI engaged through this process, common themes that emerged, and FEI's responses to some of the feedback raised. Connecting with customers, Indigenous groups, communities, and other stakeholders on long-range planning issues is of critical importance to FEI. Effective stakeholder and rights holder engagement provides valuable insights for incorporation into the long-range planning process, including demand and supply forecasting analysis, the transition to renewable and low-carbon gases, DSM program development, and the development of an Action Plan for implementing FEI's preferred resource solutions to meet the future energy needs of customers. The feedback and input provided during the LTGRP process also supports FEI's continued commitment to evolving and continually improving its engagement process for future FEI energy planning initiatives.

When seeking input and feedback during the resource planning process, the BCUC's Resource Planning Guidelines encourage utilities to "focus such efforts on areas of the planning process where it will prove most useful and to choose methods that best fit their needs."[212] For this 2022 LTGRP, FEI undertook a number of initiatives to offer customers, stakeholders, and Indigenous groups the opportunity to participate in discussions to inform the planning process. These activities continued until the first quarter of 2022. FEI has an external website for its resource planning and stakeholder engagement, which includes all of FEI's presentation materials and meeting notes from its engagement sessions: https://www.fortisbc.com/about-us/projects-planning/natural-gas-projects-planning/natural-gas-planning-stakeholder-engagement.[213]

FEI has adjusted how it has consulted and engaged with stakeholders and Indigenous groups due to the COVID-19 pandemic. Prior to 2020 and the start of the COVID-19 pandemic, FEI had been consulting with stakeholders and engaging with Indigenous groups in person through the RPAG and community engagement workshops. However, since the start of the pandemic in March 2020, engagement has been conducted by virtual meetings. While in-person engagement is preferred, virtual meetings have continued to promote stakeholder and rights holder engagement and enabled them to provide valuable feedback and input into the 2022 LTGRP development process.

The remainder of this Section is organized as follows:

- Section 8.1 describes the feedback received from Resource Planning Advisory Group (RPAG) workshops and how the feedback is addressed in the LTGRP;

[212] Issued December 2003, p. 5, online at: http://www.bcuc.com/Documents/Guidelines/RPGuidelines_12-2003.pdf.
[213] FEI confirms that, by providing this link, it considers the webpage and the documents linked on the webpage to be part of the record of this proceeding.

- Section 8.2 describes the feedback received from engagement workshops with First Nations community representatives and how the feedback is addressed in the LTGRP or other FEI initiatives;
- Section 8.3 describes the feedback received from consultation workshops with representatives from communities served by FEI and how the feedback is addressed in the LTGRP; and
- Section 8.4 describes other FEI consultation and engagement activities that directly or indirectly inform the resource planning process, such as discussions with advisory groups, government, industry associations, and other stakeholders.
- Section 8.5 provides a summary of other engagement activities not directly related to, but which helped inform, the 2022 LTGRP and the development of the Clean Growth Pathway.

8.2 THE RESOURCE PLANNING ADVISORY GROUP (RPAG) PROVIDED KEY INSIGHTS AND FEEDBACK TO FEI

8.2.1 FEI Held Six Workshops with the RPAG

The RPAG is a technical working group that engages representatives of municipalities, provincial government, customers, public interest associations, environmental organizations and intervener groups in the development of the LTGRP. RPAG members bring significant knowledge and experience to the process and provide key insight and feedback to FEI. The table below provides an overview of the organizations represented in the RPAG.

Table 8-1: RPAG Members

Organizations Represented at RPAG Meetings
Avista Utilities
BC Business Council
BC Hydro
BC Ministry of Energy, Mines and Low Carbon Innovation
BC Public Interest Advocacy Centre
BC Sustainable Energy Association
BC Utilities Commission (as an information provider and observer)
Building Owners and Managers Association
Canadian Biogas Association
Canadian Institute of Plumbing and Heating
City of Abbotsford
City of Burnaby
City of Campbell River
City of Kamloops
City of Kelowna

Organizations Represented at RPAG Meetings
City of New Westminster
City of Prince George
City of Surrey
Clean Energy Association of BC
Climate Action Secretariat
Commercial Energy Consumers of BC
Community Energy Association
District of Saanich
Enbridge
Enbala
Metro Vancouver
Midgard Consulting (Representing Residential Consumer Intervener Association)
MoveUP
Northwest Gas Association
NW Natural
Northern Alberta Institute of Technology
Pacific Northern Gas
Pembina Institute
Puget Sound Energy
Roger Bryenton and Associates
Selkirk College
SFU Renewable Cities
Union of BC Municipalities
University of Victoria
Village of Keremeos

FEI held six RPAG workshops between 2021 and 2022 to review key steps in the LTGRP process, discuss plan inputs, gather feedback on the results of the LTGRP process to date, and provide input into FEI's decision to use the Diversified Energy (Planning) Scenario as the planning scenario in the LTGRP. Attendees participated by asking questions and providing discussion throughout each presentation. An overview of presentation content is outlined in Table 8-2. An interactive tool (discussed in Section 8.2.3) was also utilized to gather crowd-sourced feedback regarding demand drivers and scenarios.

The first two RPAG sessions were held in early 2021. Members of the RPAG and the Energy Efficiency and Conservation Advisory Group (EECAG), FEI's consultant Guidehouse, and FEI staff attended the sessions. FEI and Guidehouse presented the findings from the Pathways Report.[214] FEI provided background information on the long-term resource planning process and objectives, an overview of the Pathways Report regarding the comparisons of the Diversified and

[214] Appendix A-2: Pathways for British Columbia to achieve its GHG reduction goals.

Electrification Pathways for BC to achieve its GHG reduction goals, and the implications of the pathways for resource planning purposes. Discussion included how various components of the Pathways Report and FortisBC's Clean Growth Pathways pillars were included within the LTGRP demand forecasts and scenarios. RPAG members expressed a strong commitment to reducing GHG emissions and in that context, there was general support for ensuring a long life for gas infrastructure, addressing the costs of decarbonization and impacts of climate change, and providing affordable energy and a resilient energy system for all customers. There was also general support for FEI to use the Diversified Energy (Planning) Scenario as FEI's planning scenario for the 2022 LTGRP.

In the subsequent four RPAG meetings, topics of discussion were key initiatives such as accelerating the procurement of renewable and low-carbon gas, evolving the hydrogen future, supporting and expanding a resilient gas infrastructure, developing innovative DSM approaches, and FEI's response to the Roadmap. Table 8-2 below outlines meeting dates and major topics discussed and Section 8.2.2 discusses feedback received through the RPAG sessions.

Table 8-2: Overview of RPAG Meetings and Major Discussion Topics

RPAG Meeting	Topics Discussed
January 25, 2021 2022 LTGRP Kick-off	• Resource planning process and objectives • BC's energy planning landscape • Presented Pathways Report • FortisBC's 30BY30 target as an important step in the low-carbon transition • The LTGRP engagement plan for 2021
February 12, 2021 FortisBC: Joint Gas and Electric BC's GHG Reduction Pathways and Implications for the LTGRP and Long-term Electric Resource Plan (LTERP)	• Background on LTGRP and demand side planning • Presentation of *Pathways for BC to achieve 80 percent GHG reduction through comparison of the Electrification and the Diversified Energy Future* • Feedback on the Pathways Report • Illustrative demand forecast scenarios and drivers
June 17, 2021 Demand Forecast and Renewable Supply Scenario	• LTGRP update on Traditional Annual Method and BAU forecast • FortisBC outlook and considerations for renewable gas supply • Critical uncertainties and renewable supply alternatives modelling • Reference case demand forecast and alternate scenarios • Crowd forecasting activity
November 3, 2021 Demand-side Management Scenarios	• DSM scenarios • System planning and gas supply

RPAG Meeting	Topics Discussed

December 1, 2021
System Planning and Gas Supply
	• Renewable gas – FEI's comprehensive review filing
	• System planning overview:
	  ○ Annual and daily peak demand
	  ○ Capacity impacts of renewable and low-carbon gas
	  ○ Regional forecasts and infrastructure upgrades
	• Gas supply – market conditions and portfolio planning
	• Infrastructure transition to renewables and resiliency

February 10, 2022 Overview of 2022 LTGRP submission	• Status of the 2022 LTGRP submission and overview of RPAG feedback received to date • The Diversified Energy (Planning) Scenario – FEI's planning scenario • Regional Gas Supply Diversity (RGSD) project and its role in the Clean Growth Pathway • Development of the LTGRP Action Plan

8.2.2 FEI Received and Addressed Feedback from the RPAG

The feedback received from the RPAG has been useful in developing the 2022 LTGRP. Through the RPAG workshop sessions, stakeholders have been able to provide FEI with input on many areas including scenario development for demand forecasting, system planning, gas supply and DSM. This feedback is particularly critical at this pivotal time as FEI transitions to a low-carbon future.

Some of the feedback received during these sessions related to the opportunities and risks for customers and stakeholders under the different pathways. For example, there was mention by some stakeholders of the economic development potential relating to the Diversified Pathway for communities, such as through the development of RNG and hydrogen production. Some members expressed their concern for urgent climate action and advocated for more intense electrification and allocation of renewables to "hard to decarbonize sectors". Some members highlighted the benefits of maintaining the gas system in providing an affordable, reliable, and resilient complementary energy system that optimizes the use of both the gas and electric systems to deliver energy in BC. Some members were interested in system capacity planning, the impacts of renewables, and how to make the system hydrogen-enabled. There was general support for developing BC clean energy projects. The costs of decarbonization were highlighted in most sessions, but it was acknowledged that any pathway to deep decarbonization will result in significant costs.

Table 8-3 below outlines examples of feedback FEI received from the RPAG and where the feedback was incorporated into the LTGRP.

1 **Table 8-3: Overview of General Feedback Received and Where it is Addressed in the Plan**

Feedback	2022 LTGRP sections where feedback topics are addressed
FEI should respond to the CleanBC Roadmap to 2030 targets in the Diversified Energy (Planning) Scenario (although it was acknowledged that the October 25, 2021 announcement came late into the LTGRP process).	Section 2.2.2.2 explains the Road Map in the context of the Planning Environment. Section 4.5.1 provides background on the development of the Diversified Energy (Planning) Scenario and Section 9 provides an overview of GHG emissions in relation to the provincial cap.
FEI should review its provincial carbon accounting methods and approach in presenting lifecycle carbon accounting. This is especially relevant for LNG, LNG exports and potential double counting of, for example, industrial customers.	Section 4 describes LCT, Global LNG and new Large Industrial Demand. Section 9 describes analysis of FEI's GHG emissions.
FEI, BC Hydro and the Province should work together in resource planning to ensure alignment of demand, supply and cost scenarios in developing long-term energy scenarios to meet the needs of British Columbians.	FEI is continuing its work to collaborate where it makes sense and each utility sits on the others external advisory group.
Discussion was raised regarding the potential allocation of RNG specifically to "hard to decarbonize" end users such as industrial, Heavy Duty Road, marine and others.	Sections 6 and 7 discuss the allocation of renewable and low-carbon gas to sectors and regions. Section 9 discusses GHG reductions for FEI's Clean Growth Pathway.
FEI should provide a consolidated resiliency plan and explain why LNG storage is required as part of the resiliency plan.	Section 3.2.2.3 introduces Appendix E – Gas System Resiliency Plan which includes an overview of where resiliency is discussed in the LTGRP.
FEI should explain the breakout of transportation demand (CNG and LNG) and where it fits in demand curves and GHG emission reduction results. FEI should provide this information for LNG projects and provide an overview of how much of total demand will be allocated to the LNG export market.	Sections 4.4.2 and 4.6.2 provides an overview of the demand forecasts for LCT. Section 9 provides an overview GHG emissions pertaining to transportation. The LNG export market is not discussed in the LTGRP.
FEI should demonstrate how BC communities, including Indigenous groups, can develop clean energy projects that can feed into gas infrastructure as part of the Clean Growth Pathway.	Section 3.2.2.5 discusses economic development opportunities for the Clean Growth Pathway.
FEI should project the costs of decarbonization at customer group levels (residential, commercial and industrial).	Section 9 provides rate impacts at the customer group level.
FEI should provide clarity on the highest performing DSM measures in the CPR and provide access to the CPR.	Section 5.4.7 provides an overview of highest performing DSM measures in DSM analysis. The CPR is available in Appendix C-1.

Feedback	2022 LTGRP sections where feedback topics are addressed
FEI should provide annual demand and daily peak demand comparisons for sectors and regions.	Section 4 provides annual demand by customer group and Section 7 provides peak demand for customer groups and regional transmission systems.
The longevity of DSM and energy efficiency programs is going to be critical. There is a need to be focused on building envelope insulation in addition to mechanical systems. FEI should ensure DSM models incorporate all gaseous fuels including natural gas, RNG and hydrogen as each unit of energy saved benefits customers overall.	Section 5 provides the DSM analysis, program area descriptions, and long-term plan for implementation, including consideration for these measures and fuels. FEI anticipates that new information on these measures and continued modelling improvements for the next LTGRP will further enhance understanding of their impact on energy use and emissions.
FEI should explain the benefits of the Regional Gas Supply Diversity (RGSD) project over the Westcoast T–South expansion, especially as compared to the ability of electrification to significantly reduce demand for gas.	The RGSD project is discussed in Sections 6.3.3 and 7.5.1.1 and other sections of the LTGRP.

As resource planning is an iterative and ongoing process, some of the feedback and recommendations received from the RPAG during this planning period may be considered by FEI in the next iteration of the resource planning process, to the extent they remain relevant. Examples of forward-thinking feedback for consideration in the next resource plan include recommendations that FEI:

- Provide more information on renewable and hydrogen/low-carbon gas pricing and long-term market pricing models. FEI should compare the Diversified Pathway with a plan that involves other renewables such as solar and wind.
- Provide economic outlooks on the full costs over the long term, to all ratepayers resulting from the electrification pathway, as these will ultimately be borne by ratepayers.
- Expand the crowd-sourced “slider tool” for the next LTGRP consultation so FEI can gather a range of feedback to support the development of unique scenarios.
- Apply DSM savings equally to all fuels (natural gas, renewable and low-carbon gas).[215]
- Examine the cost per tonne of emissions reductions for electrification, as the costs may or may not be higher than for gas DSM initiatives, although consider that some measures perform better than others. Air Source Heat Pumps are not the only answer for GHG emission reduction initiatives. FEI should consider how to run GHG emission reduction scenarios to determine the best options for BC.

[215] Although the ability to apply DSM savings equally to all fuel types is discussed in the 2022 LTGRP, this analysis cannot be completed in time for the March 31 submission date since such analysis will require reconfiguring the software.

FEI will consider each of these recommendations and, if feasible and useful, include them in the next LTGRP filing.

8.2.3 Stakeholder Expert (Crowd) Opinion Forecast

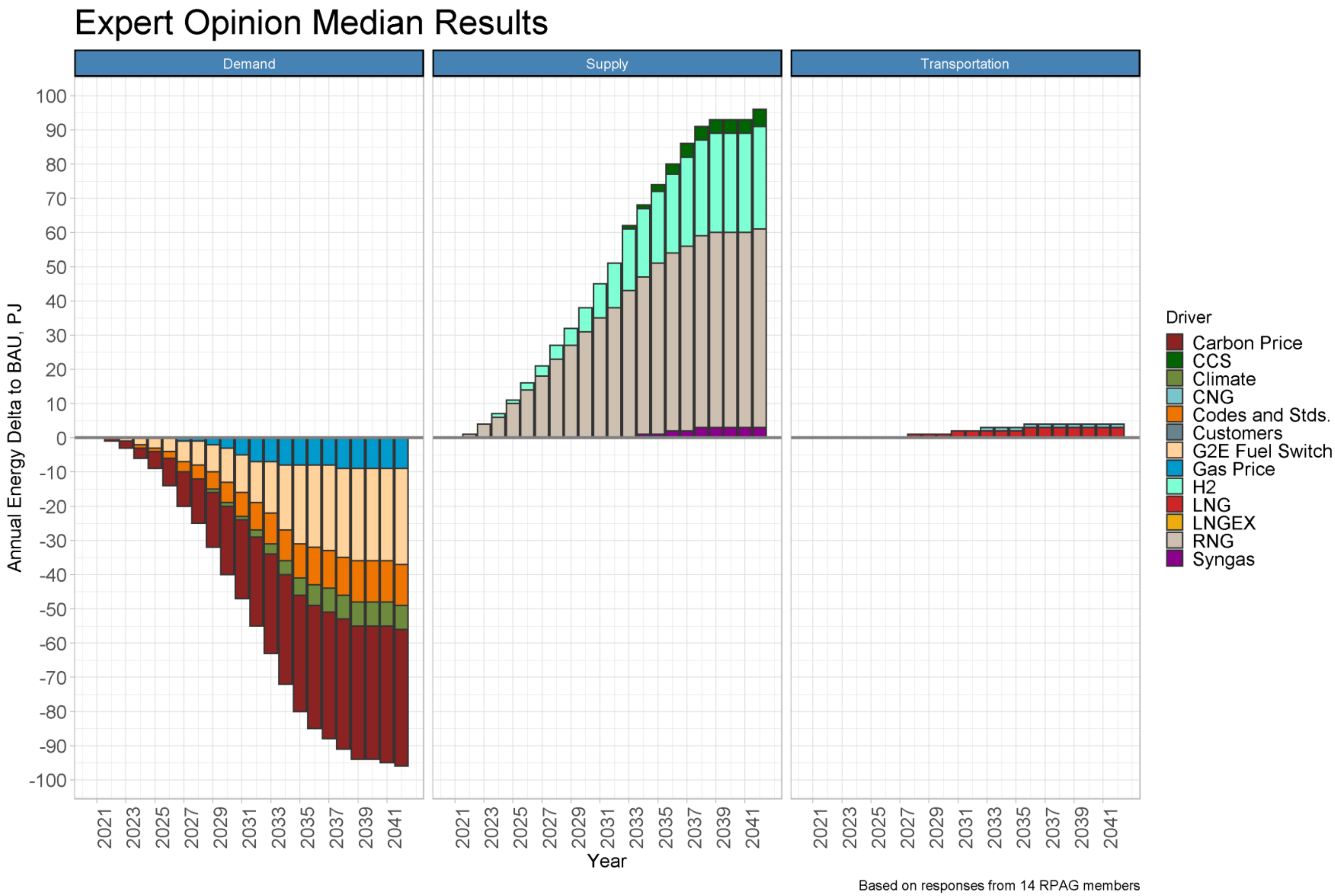
At the June 21, 2021 RPAG meeting, FEI introduced the Expert (Crowd) Opinion Forecast and "Slider" forecasting tool (Expert Opinion Tool). Stakeholders were given an introduction to the exercise and a website link via email after the session. Stakeholders were invited to use the tool to develop their own forecast scenario and to then submit the results to FEI. The exercise was anonymous, but an option was made available for participants to identify their affiliation. The invitation was sent to 31 stakeholders. FEI received responses from 14 RPAG members.

The exercise asked participants to estimate the impact of a number of drivers[216] over the 20-year period of the LTGRP. FEI selected those drivers that were not reflected in the historical data used to develop the BAU forecast at the level that would likely be experienced in the future. Drivers were provided to explore the impacts of variations in demand, supply, transportation and the Woodfibre LNG project.

Once the data was collected, FEI prepared the following figure using the median of each of the 14 responses.

[216] Drivers in the Expert (Crowd) Opinion Tool analysis and shown in Figure 8-1 legend: 1. Carbon Price 2. CCS – Carbon Capture and Storage 3. Climate 4. CNG – Compressed Natural Gas 5.Codes and Stds.- Codes and Standards. 6. Customers 7. G2E Fuel Switch – Gas to Electric Fuel Switch 8.Gas Price 9. H2 – Hydrogen 10. LNG – Liquified Natural Gas 11.LNGEX – LNG Export 12. RNG – Renewable Natural Gas 13. Syngas.

1 **Figure 8-1: Median Results from the Expert (Crowd) Opinion Forecast**



2

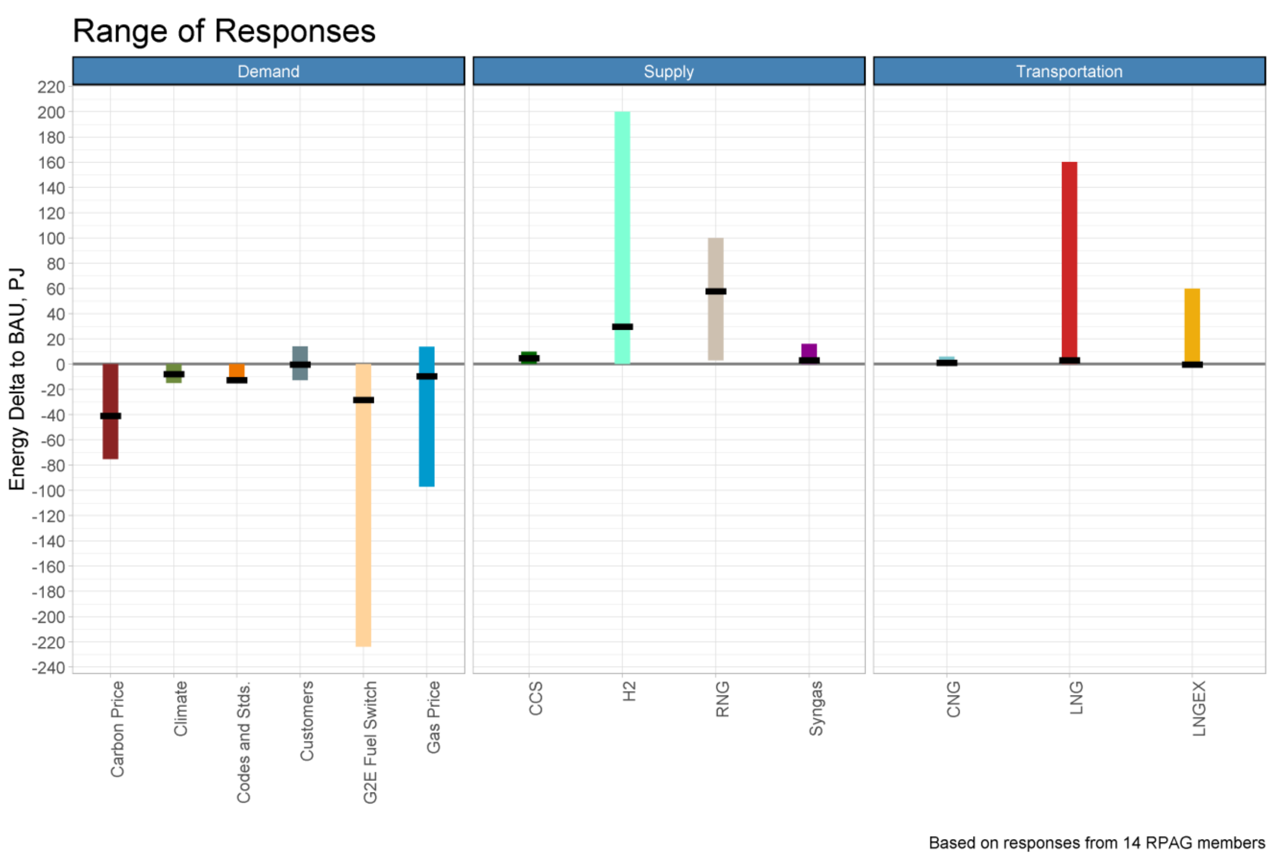
FEI makes the following observations from the Expert (Crowd) Opinion Tool Median Results:

- From the Demand plot, the largest impact in 2042 is expected to come from increased carbon prices at 40 PJ, and gas-to-electricity fuel switching at 28 PJ;
- By 2041, the median aggregate reduction in demand is forecast to be 96 PJ, relative to the BAU forecast;
- From the Supply plot, the largest contributors are RNG at 58 PJ, and Hydrogen at 30 PJ;
- By 2042, the median aggregate supply from non-traditional sources is forecast to be 96 PJ; and
- The median impact from transportation is 4 PJ. In the LTGRP, this demand category is referred to as ‘Low-carbon Transportation and Global LNG’ and in this analysis includes CNG, LNG and LNG export from FEI.

Of the 14 responses, eight felt that the Woodfibre LNG project would not go ahead and therefore the median demand from the Woodfibre LNG project driver is 0 (and not shown on the chart).

The following figure shows the ranges of the responses for each driver. This plot indicates where there is both uncertainty and agreement across the drivers. The black “tick” indicates the median response for each driver.

Figure 8-2: Range of Responses from the Expert (Crowd) Opinion Forecast



The key observations from the Range of Responses include the following:

- The responses for gas to electric fuel switching showed the widest range of all the drivers, ranging from no impact up to a reduction of 225 PJ. The median response was lower at 28 PJ;
- The impact from adding hydrogen to the supply also showed a very wide range of responses, topping out at 200 PJ. Once again, the median response was a more modest 30 PJ, and less impactful than the median response from RNG at 58 PJ; and
- Finally, the LNG driver also showed a significant range, from zero to 160 PJ. For this driver, the median response was close to zero at just 3.5 PJ.

The crowd forecast exercise seemed to be effective in providing RPAG members with a better understanding of the critical inputs that can impact the demand forecast versus those that have little to no impact. For the 2022 LTGRP, the sample size (i.e., the number of crowd participants) was small and so likely contains a level of bias. Therefore, FEI did not create a crowd opinion forecast scenario for analysis in the demand forecast Section 4. However, the results clearly indicate that the stakeholders who responded shared the view that decarbonization is of great importance to them. Support from some RPAG members and FEI's experience suggests the exercise is worth continuing and building upon for the next LTGRP as a means of engaging those outside of FEI in these important discussions.

8.3 *DIALOGUE AND ENGAGEMENT WITH INDIGENOUS GROUPS*

8.3.1 FEI Recognizes and Respects the Constitutional Rights of Indigenous Peoples

FEI recognizes and respects the constitutional rights of Indigenous Peoples. FEI's Statement of Indigenous Principles[217] aims to ensure the Company's business operations are conducted with respect for Indigenous people's social, economic and cultural interests. To support meeting this objective, FEI establishes an open dialogue with First Nations communities at the earliest opportunity during its planning stages so that expectations for Indigenous engagement are understood and addressed in the process and that Indigenous input is incorporated. FEI coordinated engagement with the FBC resource planning team in the shared service territory to ensure First Nations community representatives were able to provide meaningful input into both FBC's LTERP application and FEI's LTGRP application.

FEI is committed to developing and maintaining relationships with First Nations communities within whose territories FEI works and operates within. Understanding, respect, open communication and trust continue to be FEI's aim when working with Indigenous peoples and

[217] Appendix A-8: FEI's Statement of Indigenous Principles, online at: https://www.fortisbc.com/in-your-community/indigenous-relationships-and-reconciliation/our-statement-of-indigenous-principles.

First Nations communities throughout the province. FEI, in keeping with it's Statement of Indigenous principles:

- Upholds a high standard of engagement, through clear and open communication on an ongoing and timely basis;
- Promotes awareness and understanding of Indigenous issues within its workforce, industry and communities where FEI operates; and
- Works to better understand Indigenous culture, values and world views through ongoing community engagement on matters including FEI's resource planning process.

8.3.2 FEI Supports Implementation of the United Nations Declaration for the Rights of Indigenous Peoples

FEI supports the implementation of the UN Declaration into law in BC under the provincial Declaration Act.[218] FEI also recognizes the elevated status of the UN Declaration at the federal level, where the UNDRIP Act[219] was assented to on June 21, 2021. This legislation mirrors and builds upon the legislative framework developed in BC.

FEI continues to learn from the UN Declaration and is committed to actions that move towards reconciliation with Indigenous peoples. FEI acknowledges the principles of the UN Declaration, and the Declaration Act will play a significant role in energy policy and the regulatory environment over the twenty-year planning horizon of this LTGRP. FEI is committed to aligning its resource plans with provincial policy, and will continually review its engagement process to ensure that FEI is engaging in meaningful dialogue with Indigenous groups regarding its resource plans as reflected in FEI's Action Item 4 in Section 10.

8.3.3 Engagement Process

FEI works to meaningfully engage with First Nations communities and Indigenous groups to gather input and feedback on the Company's various planning initiatives. Throughout the preparation of this LTGRP, First Nations communities from across the gas and electric service areas were invited to attend either regionally focused community engagement meetings or Indigenous-specific engagement workshops. This section details the feedback and input provided by First Nations and Indigenous groups during this engagement process.

While FEI invited several communities to participate in the process, not every community responded to FEI regarding LTGRP engagement opportunities. FEI also invited First Nations communities to discuss alternative engagement options, such as individual community meetings. Accordingly, FEI engaged directly with community representatives who confirmed their interest in participating in the LTGRP engagement sessions and planned workshops directly with these communities. FEI appreciates the engagement of First Nations and acknowledges that many communities are managing multiple priorities and may not have the available capacity to

[218] Declaration on the Rights of Indigenous People's Act, S.B.C. 2019, c. 44.
[219] United Nations Declaration on the Rights of Indigenous Peoples Act, S.C. 2021, c.14.

participate in LTGRP engagement workshops. Regardless, FEI will continue to engage with First Nations communities in its service area to identify opportunities for dialogue on long-term energy planning initiatives.

8.3.4 FEI Held Five Engagement Sessions

Throughout 2021 and into early 2022, FEI planned five virtual engagement workshops directly with First Nations community representatives and Indigenous groups across the FEI service area. This included two workshops within the shared service territory, which focused on both FBC's LTERP process and a high-level overview of FEI's LTGRP process. These workshops were held on February 4, 2021 and March 3, 2021 and were attended by community representatives from the Ktunaxa Nation and the Okanagan Nation Alliance. Two additional virtual engagement workshops were held with First Nations located in the Lower Mainland and Fraser Valley regions of the province on January 13, 2022 and January 18, 2022. Another engagement workshop was planned for First Nations community representatives in the North-Central Interior region of the province, but was ultimately cancelled due to low interest. Various external factors including the COVID-19 pandemic, and severe weather events (e.g., wildfire evacuation alerts and orders), may have impacted the capacity of communities to participate in LTGRP engagement sessions throughout 2021 and 2022.

First Nations community representatives were also invited to the various regional community engagement workshops discussed in Section 8.3, for Vancouver Island, the Sunshine Coast, and the North-Central Interior regions. Multiple community representatives from the Treaty 8 and Secwe̓pemc Nations participated in the May 20, 2021 regional community engagement workshop for the North-Central Interior.

8.3.4.1 *FortisBC Shared Services Territory Engagement*

During the February 4, 2021 and March 3, 2021 workshop sessions, FEI provided an overview of the Pathways Report and key aspects of FBC's LTERP and FEI's LTGRP. Given the timing of the engagement, aspects of the FEI LTGRP were discussed at a high level during these engagement workshops as further work was required by FEI to complete key aspects of the LTGRP, such as a final analysis of demand scenarios, resource options, and system needs. FEI provided an overview of its preliminary outlook for customer demand, including the Reference Case, potential load drivers and scenarios, and supply-side resource options available to meet future energy demands.

FEI sought feedback from First Nations community representatives in attendance on their energy priorities for the future. Some key themes and areas of interest that were identified as important to community representatives in the February 4, 2021 and March 3, 2021 meetings, specific to the LTGRP or FEI's broader energy planning process, included:

- Ensuring the UN Declaration and energy priorities of Indigenous groups are considered in the development of the LTGRP;

- How the LTGRP informs the planning process for specific capital projects;
- Cost and affordability are key priorities, as many community members deal with high electricity and natural gas bills;
- Opportunities for additional energy efficiency collaboration with local communities as a means to reduce high energy bills, and support local housing improvements and community development projects; and
- Interest in expanding natural gas service to communities not currently served by FEI.

Other key energy priorities identified during the February 4, 2021 meeting included cost effectiveness, energy resiliency, environmental protection, and economic growth. One group indicated that economic growth and partnership opportunities help community development and therefore indirectly foster energy affordability. Multiple representatives also identified interest in FEI's involvement in hydrogen development and potential future partnership opportunities as these technologies develop.

During the March 3, 2021 meeting, community representatives expressed their main priority as having access to cost effective energy. Economic growth for the community is also an important consideration. One representative asked FEI about its discussions on environmental reclamation activities and GHG reduction initiatives with industrial partners in the region. FEI described its ongoing relationships with customers, including industrial ones, to continue to explore opportunities for decarbonizing the natural gas system and enhancing the local environment where FEI operates.

Discussions during these sessions reinforced FEI's understanding of the importance of the UN Declaration and FortisBC will continue to assess its resource planning process to ensure that Indigenous energy objectives and the UN Declaration are considered in both FBC and FEI's future project plans. FortisBC shared its commitment to acting on the key principles of the UN Declaration and ensuring that FortisBC's engagement is conducted in alignment with the values of its Statement of Indigenous Principles. FortisBC clarified that any capital projects that may result from the findings of FBC's LTERP and FEI's LTGRP would require separate BCUC approval, including future engagement related to those applications. FortisBC also confirmed that its resource plan objectives are aligned with current BC energy policy and the *Clean Energy Act*, which encourage the development of clean and renewable resources and support the development of First Nations communities (discussed in Section 1.5).

8.3.4.2 *FEI Service Territory Engagement*

For the May 20, 2021, January 13, 2022 and January 18, 2022 engagement sessions, an overview of the Pathways Report and key aspects of the FEI LTGRP were provided. This included a high-level overview of system considerations and DSM scenarios for the FEI LTGRP. FEI sought feedback from First Nations communities on the LTGRP and on their energy priorities for the future.

During the May 20, 2021 community engagement workshop session, one community representative raised concern over the engagement process and felt that FEI had not provided enough notice for the individual to actively participate in the process. FEI acknowledged this concern and FEI will continue to work closely with communities going forward to ensure invitations to engagement sessions on resource planning and other FEI initiatives are delivered to where known, the representatives directly responsible for those initiatives in the community.

Another community representative inquired about Canadian LNG and potential leverage foreign investors may have on Canada's LNG projects. They raised concerns about the potential implications of foreign investment on the cost of domestic natural gas supply and inquired about protections in place from foreign investment associated with Canadian LNG export projects. FEI clarified that it is not in a position to speak to any government protections that may or may not be under consideration when it comes to LNG exports internationally. FEI highlighted the review of market conditions for natural gas production and supply in the region, which was conducted for the 2017 LTGRP, and provided a link to this review. FEI also clarified that it includes any necessary actions to safeguard its customers from these type of risks in the Action Plan contained within the LTGRP.

One community that was invited to the May 20, 2021 session did not attend but provided written correspondence to FEI in July, 2021, in response to the FEI invitation for this session. A community representative identified to FEI that formal terms for engagement identifying process and capacity support would be required for the community to provide a comprehensive review of FEI's LTGRP. The representative communicated that engagement on planning activities, including the LTGRP, in their territories requires capacity of their experts, leadership and territorial authorities. FEI responded and committed to holding a direct meeting with the community to review the engagement process and specific aspects of FEI's LTGRP. FEI also offered the community an opportunity to participate on FEI's RPAG and to discuss capacity support options for engagement on the LTGRP process. Capacity support was offered to other communities on an as-required basis throughout the engagement process on the LTGRP. FEI held further meetings with community representatives outside of the LTGRP process to discuss engagement on utility planning along with a range of other FEI initiatives that were of mutual interest to the community and FEI. FEI is continuing engagement with the community on a range of opportunities and energy issues, such as long-term energy planning. The feedback provided by the community on FEI's engagement process has been integrated and considered in the development of Action Item 4 within Section 10 of this filing.

Key themes relating to the LTGRP identified during the January 13, 2022 and January 18, 2022 engagement sessions with First Nations communities in the Lower Mainland and Fraser Valley included:

- Discussion on the regulatory review process of the LTGRP and how FEI will continue to engage First Nations communities on the LTGRP after it is filed with the BCUC;
- Interest in the transition towards renewable energy supply and trade-offs associated with the electrification and diversified energy pathways identified in the LTGRP;

- Clarification on the steps FEI and the Province are taking to encourage renewable energy collaborations with First Nations communities and to navigate the challenges associated with the transition to low-carbon energy solutions, such as rate impacts and affordable energy supply over the twenty-year planning horizon;
- FEI providing greater transfer of its energy expertise and knowledge to communities through local, low-carbon project partnerships;
- Further information on the process for First Nations communities to access FEI energy efficiency programs, such as ECAP;
- Feedback to FEI on the value energy efficiency programs have in improving housing conditions for community members and contributing to more affordable energy service; and
- Opportunities and best practises that FEI should consider for future LTGRP engagement, such as early engagement, in-person meetings, capacity funding, open forums between communities and direct engagement with Chief and Council or community leadership.

During the January 13 and 18, 2022 sessions, community representatives also inquired about multiple FEI major projects. One representative inquired about FEI's Advanced Metering Infrastructure (AMI) project and asked if FEI could provide further information on the potential rate impacts to community members and workforce impacts associated with the project. FEI clarified that workforce impacts resulting from the AMI project are still being assessed and reiterated its commitment to continued support for those whose jobs may be affected by the project. Regarding rates, FEI clarified that rate impacts from the AMI project are expected to be minimal for individual customers and FEI provided all attendees in the session a website link to the project application, which is currently under regulatory review with the BCUC. Another representative requested that FEI provide additional notifications to their community regarding permitting amendments on the Eagle Mountain Woodfibre LNG project. FEI acknowledged this feedback and the complexity of specific permit amendment applications through the BC Oil and Gas Commission's project permitting process. The representative identified earlier notifications from FEI, with greater detail on the purpose of the upcoming permitting amendments, as a practise that would further support the engagement process with the community. FEI noted this feedback and provided this information to the Woodfibre LNG project team to support ongoing and future project engagement with the Community.

Additional feedback was provided during these sessions for FEI to consider in both its resource planning process and its broader business operations. One representative inquired about FEI's plans for long-term economic partnerships with First Nations communities. They identified target setting on contracting opportunities and connecting First Nations communities to the local gas system as two areas where they would like to see more action from FEI moving forward. FEI acknowledged their concerns and outlined the continued work taking place through FEI's Progressive Aboriginal Relations (PAR) certification process, to assess key areas of business development including how we support procurement and employment opportunities for First Nations Indigenous groups. After the session, FEI committed to following up with the Community on opportunities or challenges associated with extending natural gas service to community members. The representative also asked FEI about Indigenous awareness training for employees, and FEI outlined its internal training program, which includes a commitment to have at least 85 percent of all employees complete Indigenous awareness training by the end of 2022.

A key theme of discussion in the January 18, 2022 workshop revolved around Reconciliation and the varying perspectives community representatives had on this term and its meaning. One representative stated that FEI should not use the term "Reconciliation" given how much further we have to go collectively to understand the "Truth" that precedes "Reconciliation". Another community representative saw Reconciliation as a much broader discussion that needs to be started. Given that Reconciliation may be understood differently to each individual, the representative stated that further discussion is needed to define its meaning and we need to give one another a chance to work together as we share opportunities along the road to Reconciliation. The representative also identified multiple actions FEI should consider in its business operations within the context of Reconciliation. These actions include:

- Continued engagement with community leadership;
- Providing access to career development opportunities for community members;
- An active presence in schools to educate youth on employment opportunities in the energy sector;
- Continued information sharing through culturally appropriate and/or community networks; and
- Offering equity partnership opportunities to First Nations communities, such as through co-ownership of development projects.

FEI acknowledged this feedback and thanked the participants for sharing their perspectives on Reconciliation and broader actions FEI can take to build stronger relationships and partnerships with First Nations communities moving forward. FEI sees much of the feedback provided on Reconciliation as consistent with its Statement of Indigenous Principles and consistent with FEI's ongoing activities to provide greater access to business development and employment opportunities for Indigenous peoples, such as through PAR certification. This reinforces the importance of FEI taking action on feedback provided and continuing to engage with First Nations communities early and often on a wide range of utility planning processes. This continual engagement is critical to creating strong relationships and identifying strategies that create meaningful business development and employment opportunities for Indigenous peoples through FEI's business operations. Within the context of this LTGRP, continued and evolving engagement is reflected in an Action Plan described in Section 10 of the Application.

8.4 COMMUNITY ENGAGEMENT WORKSHOPS

8.4.1 FEI Held Online and In-Person Community Engagement Workshops

In recognition of the importance of considering diverse community perspectives, FEI relied on community engagement workshops for its development of the LTGRP. When planning for the future, FEI informs participants about the resource planning process and considerations, while gathering feedback from representatives throughout FEI's service territory. Community participants in the resource planning process bring significant local knowledge and perspectives to the process and provide key insights and feedback to FEI. FEI views consultation as an ongoing process, just as resource planning is an ongoing activity.

Table 8-4 below provides an overview of the variety of organizations that were invited to participate in these events for the 2022 LTGRP development.

Table 8-4: Community Engagement Participants Represented a Variety of Organizations

Types of Organizations Represented at Community Engagement Sessions
Community planners/developers/operations managers
Energy and sustainability managers and professionals
First Nations community representatives
Municipal community leaders and elected officials
Energy and sustainability non-profit organizations
Real estate builders and developers
Large businesses/manufacturers
Industrial customers
Local businesses and business associations
Economic development representatives, including Chamber of Commerce and Board of Trade members

Multiple community engagement workshops were held in regions across BC from 2019 through to 2022. Three community engagement workshops were held in person within FortisBC's shared services territory in the fall of 2019, and eleven online workshops were held in 2020 and 2021, involving a total of 117 registered participants.

Meetings in FortisBC's shared services territory were conducted in collaboration with the FBC electric resource planning group and therefore included presentations and discussions regarding FBC electricity resource planning as well as FEI gas resource planning. This made for the most efficient use of time for those within the combined gas and electric services areas and provided a comprehensive point of view on the diversified pathway where electrification and gas decarbonisation items were considered.

In these workshops, FEI provided background information on the long-term resource planning process and objectives, an overview of the Pathways Report regarding the comparisons of the Diversified and Electrification Pathways for BC to achieve its GHG reduction goals, and their implications for resource planning. Discussion included how various components of the Pathways Report and how climate action pillars in FortisBC's Clean Growth Pathway were included within FEI's LTGRP demand forecasts and scenarios. The impact of accelerating renewable and low-carbon gas supply and emerging energy and emissions policy were key topics of discussion. FEI presented plans to meet the future needs of customers and communities, and discussed issues affecting energy supply and demand, DSM, renewable and low-carbon gases, and LCT. FEI's resiliency plans were also discussed, including its plan to expand LNG storage facilities to provide safe, reliable and affordable energy to meet the demands of British Columbians.

8.4.2 FEI Received Feedback from Communities

Table 8-5 lists FEI's engagement sessions and summarizes the feedback that was given to FEI in support of resource planning and other FEI initiatives.

Table 8-5: Overview of Community Engagement Sessions – Feedback on Key Discussion Topics

Meeting Date and Location	Themes and Feedback
FEI / FBC Combined in-person sessions in the FortisBC shared services territory (SST) October 8, 2019 – Kelowna October 9, 2019 – Osoyoos October 10, 2019 – Rossland – natural gas and electric long-term resource planning was discussed although feedback presented pertains to LTGRP	• Continue to provide reliable energy supply. • Continue to provide programs to help customers and communities manage the need to balance energy costs and reduce GHG emissions. • Coordinate initiatives with municipalities and enable municipalities to work together on energy plans. • Support opportunities for community development and economic growth for clean energy projects such as wood waste into renewables. • Provide more educational resources for customers and communities regarding energy savings and new technologies. • Suggest increased data sharing and collaboration to improve stakeholder planning processes and support regional growth and development. • GHG emission reduction opportunities are critical, but affordability and carbon tax impacts need to be considered. Will need to monitor both electricity, natural gas and renewable costs over time through the energy transition. • Transportation, EVs, LCT discussed from a cost and GHG reduction perspective, noting that transportation provides a huge opportunity for GHG reductions. • Highlighted the benefits of integrating gas and electric energy systems to increase reliability and optimize costs. • Emphasized unique requirements in rural communities including energy costs, operations practicalities, capital costs generally and new construction specifically. Signalled energy advisor shortage for Home Renovation programs. • One attendee noted that BC Housing was favoring electric heat pumps (since these are viewed as 'greener' than natural gas) but wondered if renewable gases could provide a balance of being cheaper and "green."

Meeting Date and Location	Themes and Feedback
December 2 and 3, 2020 (SST)	• Provide incentives for customers to hit lower consumption targets as an opportunity to educate about conservation. A change in culture and behavior is needed to impact GHG reduction. • Discussed approaches FortisBC is taking to balance affordability and GHG reduction in presenting the Pathways Report and FortisBC's 30BY30 initiative. • Emphasized unique requirements in rural communities and need for increased funding for clean energy projects including for individual homes. • Discussed the unknowns surrounding the upcoming building retrofit code which will have big impact but implementation may be delayed. Encouraged FortisBC to engage with government to ensure building retrofit visions align with SST communities. • Discussed how FEI/FBC reconcile fuel switching programs and the opportunity for customers to choose the right fuel for the right application.
October 14 and 16, 2021 – Lower Mainland/ and South Coast	• Urgent need for FEI to be part of the solution for climate action and reducing the need for conventional natural gas, especially in light of fracking practices. • Some attendees are concerned about LNG export and GHG emissions while others noted the global competition for natural gas as a risk to BC energy supply. • Concern that FEI continues to advertise and promote natural gas use and connections when gas consumption needs to be reduced with FEI replying that maintaining and growing the gas system is vital for decarbonisation as costs are shared across customers. • Diversified Energy (Planning) Scenario with complementary and robust gas and electric systems will be more resilient in the long-term. • Requested FEI to provide more gas consumption information to local governments including percentage of renewable and percentage of fracked conventional gas. FEI responded that it is exploring enhancements to Community Energy and Emissions Inventories reporting with the Climate Action Secretariat. • Encouraged FEI/FBC and BC Hydro to work together on long-term resource planning to serve British Columbians. • Discussed supply concerns in the long-term, including conventional, renewable and low-carbon sources and cost implications. • The requirements for FEI to enable hydrogen distribution and concern expressed for the environmental impacts of blue hydrogen. • Support for decentralized energy systems and ways for trading and interacting with energy distribution at a local and even neighbourhood level. • Support for expanding FortisBC's activity in renewable projects for gas and electricity generation. • Suggestion for FortisBC to connect customers in projects that support waste heat recovery and energy redistribution. • An attendee shared their community's experience during the 2018 T-South incident in terms of high costs and risks associated with relying on one energy system. • An attendee provided innovative approaches to expanding DSM program eligibility and noted need for removing DSM regulatory constraints to expand project opportunities.

Meeting Date and Location	Themes and Feedback
November 9, 2021 – Vancouver Island South November 18, 2021 - Vancouver Island North	• Urgent need for FEI to be part of the solution for action on climate change. • Local energy sources on Vancouver Island of paramount interest to diversify the supply in order to promote resiliency and mitigate the impacts of extreme weather events. • Diversified Energy (Planning) Scenario with complementary and robust gas and electric systems will be more resilient in the long-term. • Requested information on how local governments can access RNG. • Extend gas service to rapidly growing developments on Vancouver Island. • Resource planning needs to account for all costs of externalities and risks when planning for the energy transition and account for the full life cycle of GHG emissions. • Support for development of hydrogen projects but indicated a desire for more information about the environmental safety of all kinds of hydrogen (blue, green, etc.). • Bring together economic alliance associations for a larger voice in regional planning of BC's energy future.
November 23, 2021 – Southern Interior	• Energy affordability and housing affordability is a top priority for the region and low income segments are already struggling to manage utility bills. • Discussed how FEI will incorporate the CleanBC Roadmap to 2030 in LTGRP in terms of reaching GHG reduction targets. • Interest in locally-sourced renewable projects. • Diversified Energy (Planning) Scenario with complementary and robust gas and electric systems will be more resilient in the long-term. This pathway is even more critical in rural and colder parts of the province where electric outages are more common. • Attendee noted the need for energy storage including battery in a decarbonized energy system.

The feedback received from these sessions as outlined in Table 8-5 above has been highly useful in developing the 2022 LTGRP. Through the community engagement sessions, attendees were able to provide FEI with input on climate action initiatives and balancing affordability with the costs of electrification and decarbonization. A broad range of recurring themes were of particular interest to community representatives and these resulted in extensive discussion and feedback. Examples of these key themes include:

- The need for urgent climate action and FEI's need to transition to clean energy by increasing access to a supply of renewable and low-carbon gas. Incorporating climate change and local adaptation considerations was viewed as central to developing a resilient and reliable low-carbon system;
- General agreement that the Diversified Energy (Planning) Scenario with complementary and robust gas and electric systems will be more resilient in the long-term and with the need to balance affordability with decarbonization initiatives;
- Energy affordability was top of mind, especially for low income customer segments;

- Economic development regarding clean energy projects was seen as a large opportunity;
- Support for FEI to continue to work with communities on DSM programs, providing funding, incentives and educational resources to help customers and communities manage energy costs and reduce emissions; and
- Support for FEI and BC Hydro to work together in resource planning to ensure the alignment of demand, supply and cost scenarios in meeting BC's energy needs into the future.

Overall feedback from these sessions highlighted the urgent need to respond to climate change while balancing the need for reliable, resilient and diverse energy systems. A number of sessions took place during the extreme weather events of November 2021 and communities highlighted the need for resilient systems while responding to the urgent call for action on decarbonization. Some attendees noted the economic development potential for clean energy projects in communities, such as the development of RNG and hydrogen production. Some participants were proponents for more intense electrification and the allocation of renewables to "hard to decarbonize sectors". Many highlighted the benefits of maintaining the gas system in providing an affordable, reliable, and resilient complementary energy system that optimizes the use of both the gas and electric systems to deliver energy in BC. Some sessions highlighted the unique requirements needed to serve rural communities. The cost of decarbonization was highlighted, but it was acknowledged that the low-carbon transition, either through electrification or decarbonization of the gas supply, will result in significant costs to British Columbians.

There were a number of specific examples of feedback received in LTGRP community sessions that were forwarded to appropriate FEI project teams. Examples include:

- An attendee wanted to know the solicitation process to develop an RNG project in their region and was connected with an FEI representative to explore the opportunity.
- Several attendees wanted to know how they could procure more RNG for their communities.
- One attendee had ideas for DSM program development and identified a need to reassess program and regulatory limitations in light of the urgency of responding to climate change.
- An attendee highlighted the need for a greater understanding of embedded emissions and full lifecycle costs in construction projects. This could lead to partnerships or new ideas on information exchange on renewable and low-carbon gas projects. Their organization is looking at its own construction in terms of embodied carbon. Their approach is to assess net reduction in carbon emissions over the project life on a full construction and operational level. However, cost is still an issue so wondered if FEI could help through incentive programs.
- One attendee shared an idea for demonstrating GHG consumption on utility bills which was forwarded on to the billing redesign team.

- A number of attendees requested enhanced gas consumption data in Community Energy and Emissions Inventories distributed through the Climate Action Secretariat for community energy plans. At this time, gas consumption is primarily fossil fuel, but FEI is determining the best way to designate the percentage of renewables and low-carbon gas for future reporting needs.
- A number of attendees were concerned about the use of fracked gas.
- A number of attendees supported opportunities for decentralized energy systems, the opportunity for FEI to assist with energy distribution at a neighbourhood level, and the development of renewable projects outside of gas distribution. Some of these types of initiatives are currently supported by FortisBC Alternative Energy Services and are not covered in the current LTGRP scope.
- An attendee highlighted FEI's competence in transactional services and customer end uses and proposed that FEI could address opportunities to connect separate organizations in joint waste heat recovery projects.
- A number of attendees asked about opportunities to extend FEI's service into new developments and rural communities.
- An attendee commented that there are broader environmental impacts, beyond GHG emissions reductions as the obvious cost, associated with all energy transition scenarios that sometimes get missed in climate action discussions. Knowing that GHG emissions are critical, FEI continues to try to understand and will consider addressing these other aspects in future resource plans.

8.5 *FEI UNDERTOOK OTHER ENGAGEMENT ACTIVITIES*

FEI undertakes engagement activities associated with its customer service initiatives, project applications and other undertakings that can also provide an important avenue for input into the LTGRP. The sections below summarize other engagement activities that FEI has undertaken that have provided feedback for the evolution of the Clean Growth Pathway and the LTGRP. Although these activities were undertaken in support of initiatives other than the LTGRP, the provide important insights for consideration in the LTGRP.

8.5.1 Discussions with the BCUC

The BCUC's Resource Planning Guidelines encourage utilities to seek regulatory input from BCUC staff during resource plan preparation. To that end, a representative of the BCUC attends RPAG meetings in an observer capacity. FEI receives feedback from the BCUC through other filings and regulatory processes that inform the LTGRP and, in some cases, resulted in directions to FEI regarding content to be included in the LTGRP. The BCUC has also engaged FEI and BC Hydro in a separate project to share data and collaborate on building a number of resource planning scenarios to better understand the implications of decarbonization pathways.

8.5.2 FEI's Consultation on the Clean Growth Pathway and Low-Carbon Transition Initiatives

In 2018, FortisBC released its plan to reduce emissions, the Clean Growth Pathway, as part of the consultation surrounding the Province's CleanBC strategy. In 2020, FEI released the Pathways Report illustrating the benefits of the Clean Growth Pathway in relation to a deep electrification pathway as two alternative pathways BC can take for a low-carbon energy future.

Throughout the development of the Pathways Report, FEI engaged with all levels of government, including local government officials. FEI was able to present the findings from the Pathways Report as one of the first studies that provides British Columbians with a long-term view of the costs of energy planning in the low-carbon transition. FEI continues to conduct consultation with all three levels of government about the importance of the gas system in a clean energy future.

8.5.3 FEI's Consultation on Decarbonizing the Built Environment

In response to climate action goals, FEI conducted research about how best to reach CleanBC's 2050 decarbonization goals through consultation on approaches to be taken in decarbonizing the built environment. From April through June 2021, FEI engaged with 41 organizations including 21 industry stakeholders, 5 departments in the provincial government and 15 local government advisors. This engagement was undertaken for the purposes of receiving general feedback from stakeholders on the clean energy transition, and to understand stakeholders' current knowledge on FEI's solutions to achieving the province's GHG reduction objectives.

Some of the key themes and questions resulting from these discussions that FEI has addressed and will continue to address include:

- The need for more education on renewable and low-carbon gas including how they are generated, their ecological footprint, air quality impacts, and supply potential from BC sources;
- How low-income customers could be supported through the low-carbon transition; and
- The Climate Solutions Council[220] emphasized the need for urgent climate action and proposed the need for a pathway to zero-emissions, not 80 percent. Short/mid-term actions should consider the net-zero goal and avoid underutilized assets if new projects do not get used in the longer term.

8.5.4 FEI's Consultation on the Comprehensive Review and Revised Renewable Gas Program Application (RG Program Application)

The RG Program Application, filed with the BCUC in December 2021, provided opportunities to continue to educate a broad range of stakeholders on renewable gas considerations, and to

[220] Climate Solutions Council. Online at: https://www2.gov.bc.ca/gov/content/environment/climate-change/planning-and-action/advisory-council.

exchange information on how FEI can support local community climate action strategies. FEI engaged with 176 individual stakeholders, including interveners and interested parties, industry, associations, an environmental non-governmental organization, community associations, local and provincial governments, and RPAG. The subset of industry engaged included: builder/developers, energy consultants, trades, building and trades associations, manufacturers and a renewable gas supplier. The proceeding has received a large number of letters of comment from stakeholders; 94 expressed support while 18 were not in support of all or parts of the RG Program Application.

Consultation was generally consistent with previous discussions, including scepticism related to the amount of renewable and low-carbon gas supply. The majority of participants generally were in favour of the 100 percent renewable and low-carbon gas service offering to all new residential buildings. Local governments, such as the City of Burnaby, City of Prince George and the City of Delta, expressed appreciation for the plans to provide all new residential buildings with 100 percent renewable and low-carbon gas. There was also general interest in how FEI would address decarbonization of the existing building stock which will continue to be an ongoing topic of discussion and concern for the impact on cost of RNG for customers as a transportation fuel. These topics are important as FEI increases the supply of renewable and low-carbon gas, and proposes to decarbonize the gas supply for all sales customers. Overall, many stakeholders expressed support for FEI's direction in addressing decarbonization and their corollary support for the RG Program Application.

8.5.5 2021 Conservation Potential Review Technical Advisory Committee (TAC)

The 2021 CPR informed the 2022 LTGRP's DSM analysis. FEI established a Technical Advisory Committee (TAC) consisting of a group of knowledgeable members of the public with significant interest, stake, and experience in determining energy conservation potential in BC. They provided technical advice and feedback throughout the development of the 2021 CPR, holding 6 workshops at key deliverable milestones and completing reviews of the initial measure list and of the 2021 CPR draft report.

8.5.6 DSM Plan Development for 2023 and Future Years

A key input in the development of the next DSM expenditures application is feedback from various program stakeholders, trade and industry representatives, and interested parties. Entities that have been consulted to date include communities, customers, contractors, manufacturers, trade associations, government, First Nations, vendors, interest groups, and the EECAG. Consultation has taken place through virtual workshops, surveys, interviews, and conference calls. Directional feedback to date has included the following:

- Continue to support Energy Advisors
- More education, training and resources for customers, contractors and consultants
- Broaden the collaboration within the value chain

- Energy concierge and financing support needed for deep energy retrofits
- Support hybrid systems and gas heat pump adoption
- Expand eligible measure set

8.6 SUMMARY OF STAKEHOLDER CONSULTATION AND COMMUNITY ENGAGEMENT ACTIVITIES

FEI has a strong record of conducting effective stakeholder and community engagement. Continuing its practice from the 2017 LTGRP, FEI has consulted a dedicated RPAG and hosted a number of Indigenous group and Community Engagement workshops to receive diverse perspectives on FEI's planning activities across the communities that FEI serves. Workshops in the Southern Interior provided the opportunity for FBC and FEI to receive feedback on long-range planning topics for both utilities.

These initiatives adhere to the BCUC stakeholder input guidelines contained in the BCUC's Resource Planning Guidelines and have been beneficial to the development of this plan. The information gained through these activities informs FEI's market research and analysis and assists with the identification of long-term planning issues of concern to a number of stakeholder and rights holder groups and of interested stakeholders who may become more engaged in the LTGRP process.

RPAG workshops provided valuable feedback and inputs on long-term planning from a diverse and knowledgeable stakeholder group. In particular, the workshops assisted FEI in updating and solidifying its demand scenarios and in providing instructive feedback on FEI's decarbonization strategy. Much of the discussion focused on receiving feedback on FEI's analysis of the gas utility's long-term role as a key component of the critical infrastructure required to meet BC's long-term clean energy needs. FEI has taken the RPAG feedback into consideration in developing the LTGRP (as illustrated in Table 8.3), and in developing the Outcomes of FEI's Clean Growth Pathway (Section 9) and the Action Plan (Section 10).

Indigenous engagement sessions provided a critical forum for FEI to receive input on long-term resource planning and to learn more about the key energy priorities of local First Nations communities within its service territory. Multiple representatives expressed gratitude to FEI for the opportunity to participate in these sessions underscoring the value of ongoing dialogue. Upon completion of these sessions, FEI followed up directly with community representatives to answer any outstanding questions and to explore potential opportunities identified during the sessions. FEI continues to engage with community representatives from First Nations across the province to explore options to help meet their energy needs.

FEI is committed to evolving its engagement processes, integrating First Nations community feedback into the energy planning process, and continuing action on FEI's Statement of Indigenous Principles and the key principles of the UN Declaration. Based on the feedback received during these engagement sessions, FEI has developed an Action Plan item in Section

10 of the LTGRP which outlines future actions FEI will take to engage with First Nations community representatives on energy planning. This Action Item will support future FEI resource plans and will ensure FEI is engaging meaningfully with First Nations communities on long-term energy planning initiatives.

Community engagement workshops facilitated the sharing of valuable long-term planning information and provided opportunities for feedback from attendees. In particular, the workshops assisted FEI in identifying energy issues and planning opportunities in local governments and local organizations. Attendees appreciated the opportunity to learn about FEI's initiatives and energy issues in BC, make direct connections with FEI staff in an open and consultative format, and offered feedback on FEI's long-term plans. Some attendees stressed the importance of GHG emission reduction initiatives in light of the extreme weather events being experienced in BC. FEI was able to share the Clean Growth Pathway, which envisions the decarbonization of the gas system as being key to BC's clean energy transition. The workshop discussions were robust and customer-focused, and they demonstrated that FEI's long-term planning considerations align with stakeholder expectations. FEI has taken feedback received from the community session participants into consideration in the development of the 2022 LTGRP.

The information gathered through these activities is incorporated into the LTGRP process in a number of ways, such as by informing FEI's planning and analysis, helping to determine the inputs in the Diversified Energy (Planning) Scenario, the Action Plan and general feedback that may help inform FEI's long-term corporate vision. As FEI's resource planning process is ongoing, FEI recommends continuing with the RPAG, Indigenous group and community engagement activities as part of its next long-term resource planning process in order to build on the interest and feedback gained through these initiatives. This process is even more critical as FEI responds to the need for urgent climate action in developing its low-carbon transition plan over the planning horizon.

FortisBC Energy Inc.
2022 LTGRP

Section 9:

OUTCOMES OF FEI'S CLEAN GROWTH PATHWAY

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9. OUTCOMES OF THE CLEAN GROWTH PATHWAY

9.1 INTRODUCTION

FEI's vision for the future of energy in BC is that of a diverse, integrated and resilient network of energy infrastructure and services, building on the strength and benefits of both the existing gas and electric energy delivery networks in the province. FEI's role in this future is to utilize, grow and strengthen its gas transmission and distribution systems for the continued delivery of safe, secure and reliable energy to customers, while reducing carbon emissions for customers through the four pillars of its Clean Growth Pathway. As FEI proceeds down this pathway, the continued commercialization of existing technologies, advancements in new technology and innovation will enable deeper carbon emission reductions, while putting BC at the forefront of emerging industries such as those that will drive BC's future hydrogen economy.

This section presents some of the key outcomes of FEI's 2022 LTGRP based on planning for its Clean Growth Pathway, and is organized as follows:

- Section 9.2 provides an overview of the estimated GHG emission reductions associated with the initiatives and recommendations set out in the 2022 LTGRP;
- Section 9.3 describes the influence that FEI's plans will have on markets for the various energy services and initiatives described in the 2022 LTGRP;
- Section 9.4 discusses the rate impacts of the Diversified Energy (Planning) Scenario, on both customer rates and average bills; and
- Section 9.5 discusses key drivers that could impact the need for infrastructure and gas supply resources for FEI's customers over the 20-year planning horizon.

9.2 GHG EMISSION REDUCTIONS IN THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

FEI's Diversified Energy (Planning) Scenario, in which FEI models future changes needed to pursue its Clean Growth Pathway, is projected to meet the emissions reductions required by the GHGRS cap on natural gas utility emissions in the CleanBC Roadmap for the Buildings and Industrial Sectors. This scenario also helps BC achieve substantial emission reductions in the transportation sector by providing low-carbon transportation fuels. Although the LTGRP planning horizon extends 20 years to 2042, the emission reductions discussed in this section are presented for 2030 and 2040 to allow for comparison against the provincial emission reduction targets at these carbon reduction milestone years established by the BC Government.

9.2.1 Residential, Commercial and Industrial Demand

GHG emissions from FEI's residential, commercial and industrial customers will be subject to the GHGRS cap on emissions from buildings and industry. This section presents the emissions and emission reductions for these customers (categorized in Section 4 as the Residential, Commercial and Industrial Demand Category) as a result of FEI's Clean Growth Pathway initiatives as modelled in the Diversified Energy (Planning) Scenario. Emission reductions for these customer groups come from changes in demand (before DSM), reductions in demand as a result of DSM, the transition to renewable and low-carbon gas supply and additional actions that are not yet modelled in the LTGRP demand forecast modelling as discussed in Sections 9.2.1.1 through 9.2.1.4. Section 9.2.1.5 provides the GHG emission reduction results for other future scenarios modelled by FEI.

In this section, FEI presents emission reductions using the end use emission factor in order to align with the GHGRS. Section 9.2.2.3 presents emission reductions for all four pillars of FEI's Clean Growth Pathway using life cycle emission factors. A complete listing and explanation of the emission factors used is presented in Table 1-2 of this LTGRP.

9.2.1.1 *Demand Reduction (pre-DSM)*

The impact of natural efficiency[221] and some electrification of end use demand in the Diversified Energy (Planning) Scenario results in slightly reduced overall demand in these customer groups over the planning horizon as shown in Figure 4-9. This demand reduction corresponds to GHG emission reductions of 0.3 Mt CO_2e per year in 2030 and 0.4 Mt CO_2e per year in 2040.

9.2.1.2 *DSM*

Section 5 of the 2022 LTGRP recommends that FEI pursue the High DSM Setting with the resulting gas savings presented in Figure 5-5. In the Diversified Energy (Planning) Scenario, this high level of energy savings results in 0.9 Mt CO_2e reductions in 2030 and 1.3 Mt CO_2e reductions in 2040.

9.2.1.3 *Renewable and Low-Carbon Gas Supply*

FEI's transition to renewable and low-carbon gas supplies has the largest impact on GHG emission reductions for residential, commercial and industrial customers. Acquiring and allocating 60.2 PJ of renewable and low-carbon gas supply by 2030 to these customer groups results in emission reductions of 3.0 Mt CO_2e. In 2040, the allocation of 99 PJ of renewable and low-carbon gas to these customer groups results in 4.9 Mt CO_2e of GHG emission reductions.

9.2.1.4 *Additional Reductions*

After completing the demand and supply modelling for the 2022 LTGRP, FEI identified further opportunities for additional emission reductions which FEI expects to incorporate into its Clean Growth Pathway. These additional emission reduction opportunities, which have not yet been modelled, consist of:

[221] Efficiency improvements that occur through the natural replacement of older, less efficient equipment with newer, more efficient equipment without the influence of DSM incentives.

- **Additional demand-side measures not modelled in the 2021 CPR**: Three promising energy efficiency technologies have emerged in recent months as having a higher potential impact on gas demand than was modelled in the 2021 CPR or in the 2022 LTGRP. These are deep energy retrofits, gas heat pumps and hybrid heating systems. As discussed in Section 5.4.4, FEI expects that these technologies will provide additional energy savings to those modelled in the 2021 CPR and the 2022 LTGRP DSM Analysis.
- **Additional reductions from FEI's transition to renewable and low-carbon gas supplies – particularly from higher than modelled CCUS implementation**: Interest in and expectations for the role of CCUS in reducing carbon emissions globally have continued to accelerate as exemplified in the federal government's investment tax credit for CCUS technologies announced in the April, 2022 Federal Budget[222]. As the technology advances, there are many opportunities for implementing CCUS at industrial sites that use natural gas or other fossil fuels for process applications. Employing CCUS along with RNG production is garnering a lot of interest and has the potential to remove additional carbon from the natural carbon cycle[223].

FEI expects these opportunities to result in a further 0.9 Mt CO_2e reductions or more by 2030. FEI is still considering how these additional opportunities feed into the emissions reductions later in the planning horizon and so has not included them in its assessment of 2040 emission reductions at this time. FEI will formally include these additional opportunities in its demand and GHG emission modelling for the next LTGRP.

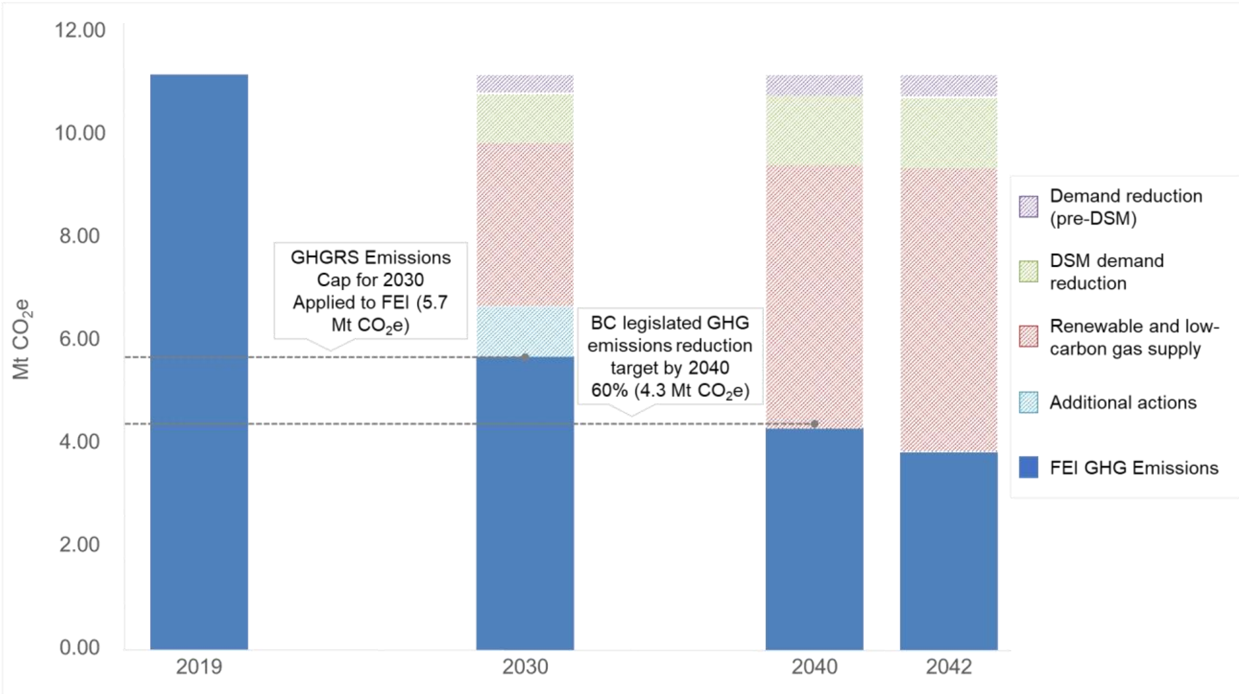
FEI anticipates that as it proceeds along its Clean Growth Pathway, additional new opportunities and information will continue to arise for further potential GHG emission reductions for residential, commercial and industrial customers.

9.2.1.5 *Meeting the Greenhouse Gas Reduction Standard for Gas Utilities*

The Province's Clean BC Roadmap states that the GHGRS emissions cap on gas utilities will be approximately 6 Mt CO_2e in 2030. Accounting for the fact that FEI is not the only gas utility in BC, the portion of the cap that applies to FEI is estimated to be 5.7 Mt CO_2e. Figure 9-1 shows that, when summed, the GHG emission reductions discussed in Sections 9.2.1.1 through 9.2.1.4 meet the GHGRS cap for gas utilities. Further, FEI's modelling of GHG emissions reductions for the Diversified Energy (Planning) Scenario meets the Province's 2040 target emission reductions and makes net-zero GHG emissions by 2050 for these customer groups plausible.

[222] Online at: https://budget.gc.ca/2022/report-rapport/tm-mf-en.html#a3_2.
[223] CCUS employed in conjunction with RNG production is considered carbon negative because it sequesters carbon from the natural carbon cycle. It is considered separately from industrial CCS or direct air CCS because the implementation of bioenergy with carbon capture and storage is directly tied to RNG production.

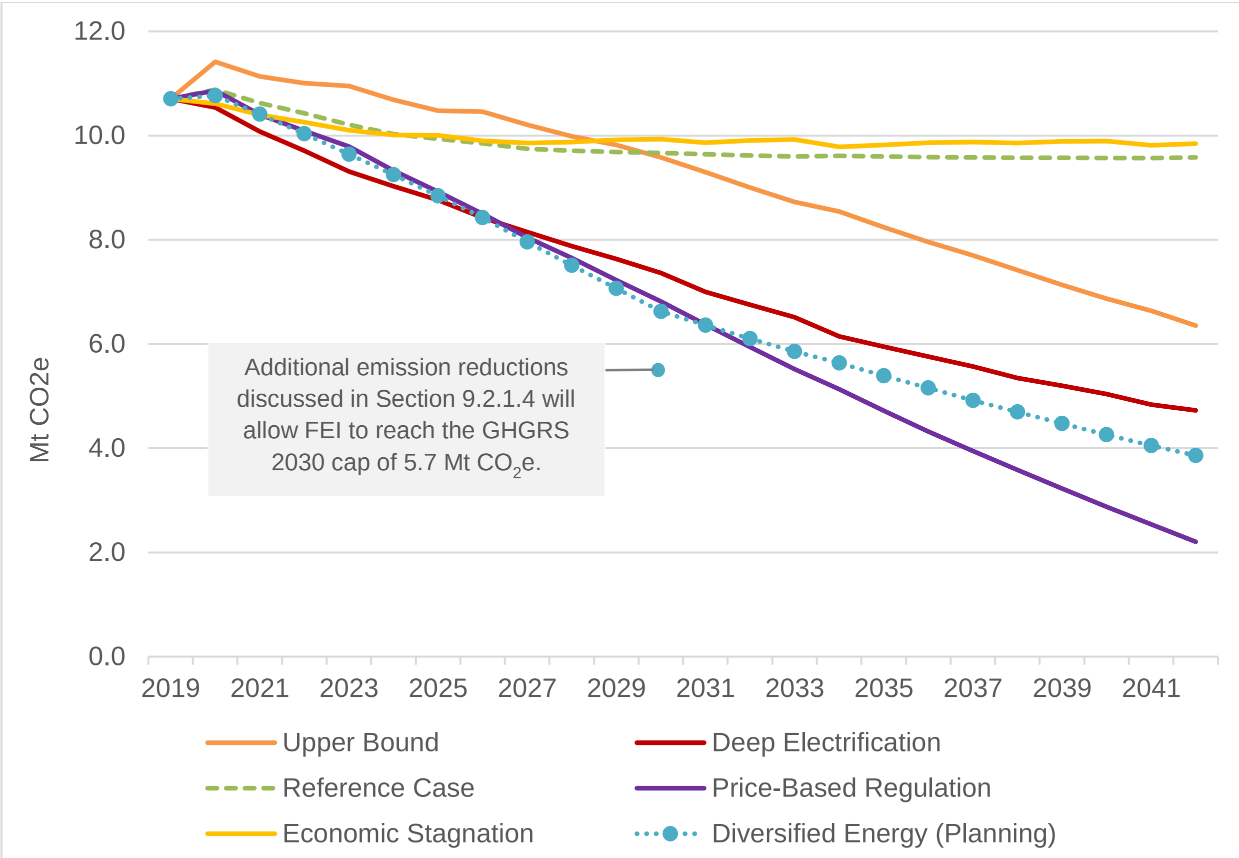
Figure 9-1: GHG Emission Reductions for Residential, Commercial and Industrial Customers Meets the GHGRS for the Diversified Energy (Planning) Scenario



9.2.1.6 *GHG Emission Reduction Comparison for Other Future Scenarios*

FEI modelled emission reductions for the Reference Case demand and for the demand and supply modelled for the alternate future scenarios described in Section 4, including the Diversified Energy (Planning) Scenario. The results are presented in Figure 9-2. The GHG emissions in this figure are shown using end use emission factors consistent with Figure 9-1. In Figure 9-2, the Diversified Energy (Planning) Scenario does not include the additional reductions discussed in Section 9.2.1.4 since they were identified after the demand and supply modelling for the 2022 LTGRP was completed. With these additional reductions, FEI reaches the GHGRS 2030 cap on emissions. Figure 9-2, therefore, provides a comparison of the different demand and supply inputs modelled for each scenario in terms of GHG emissions reductions. Note that the additional reductions discussed in Section 9.2.1.4 are not included in these results as they have not yet been added to the modelling.

Figure 9-2: GHG Emission Reductions (End Use) Modelled for the Reference Case and Alternate Scenarios – Residential, Commercial and Industrial Customers

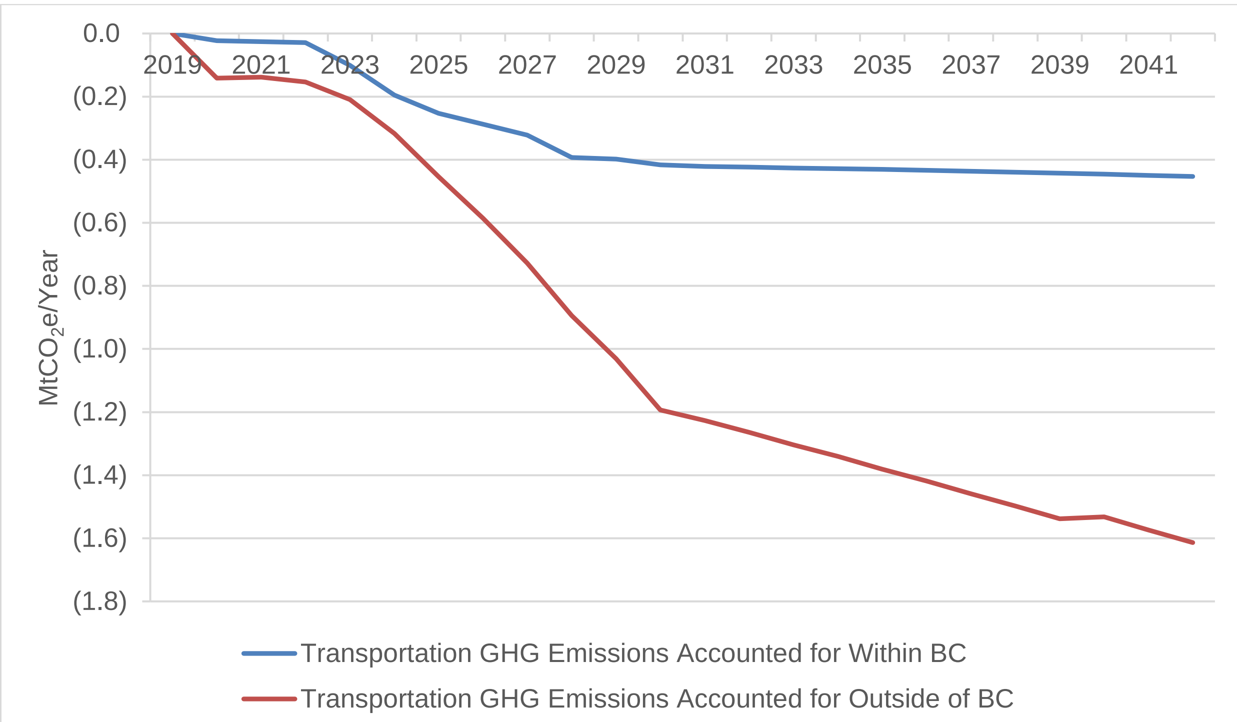


Over the long term, the Diversified Energy (Planning) Scenario has similar emission reductions to the Deep Electrification Scenario, with somewhat deeper reduction in the Diversified Energy (Planning) Scenario driven by growth in the supply of renewable and low-carbon gases. The Price-Based Regulation Scenario also has similar emission reductions since the use of price signals rather than regulation drive high levels of investment in energy conservation and in renewable and low-carbon gas production in BC. These trends accelerate later in the forecast period more than in the Diversified Energy (Planning) Scenario. The Upper Bound Scenario also shows substantial GHG emission reductions. However, since in this scenario all relevant factors that can influence growth in gas demand are doing so and there is little electrification taking place, the production and use of renewable and low-carbon gas, though still high, do not displace as large a proportion of natural gas use as in the Diversified Energy (Planning) Scenario. The Economic Stagnation Scenario has similar emission reductions to Reference Case since in that scenario, energy and carbon policy is less of a focus for government, stalling the low-carbon transition. As discussed in Section 4, the Reference Case by definition considers that conditions in place or sure to be implemented as of the base year (2019) extend over the forecast period.

9.2.2 Low-Carbon Transportation and Global LNG

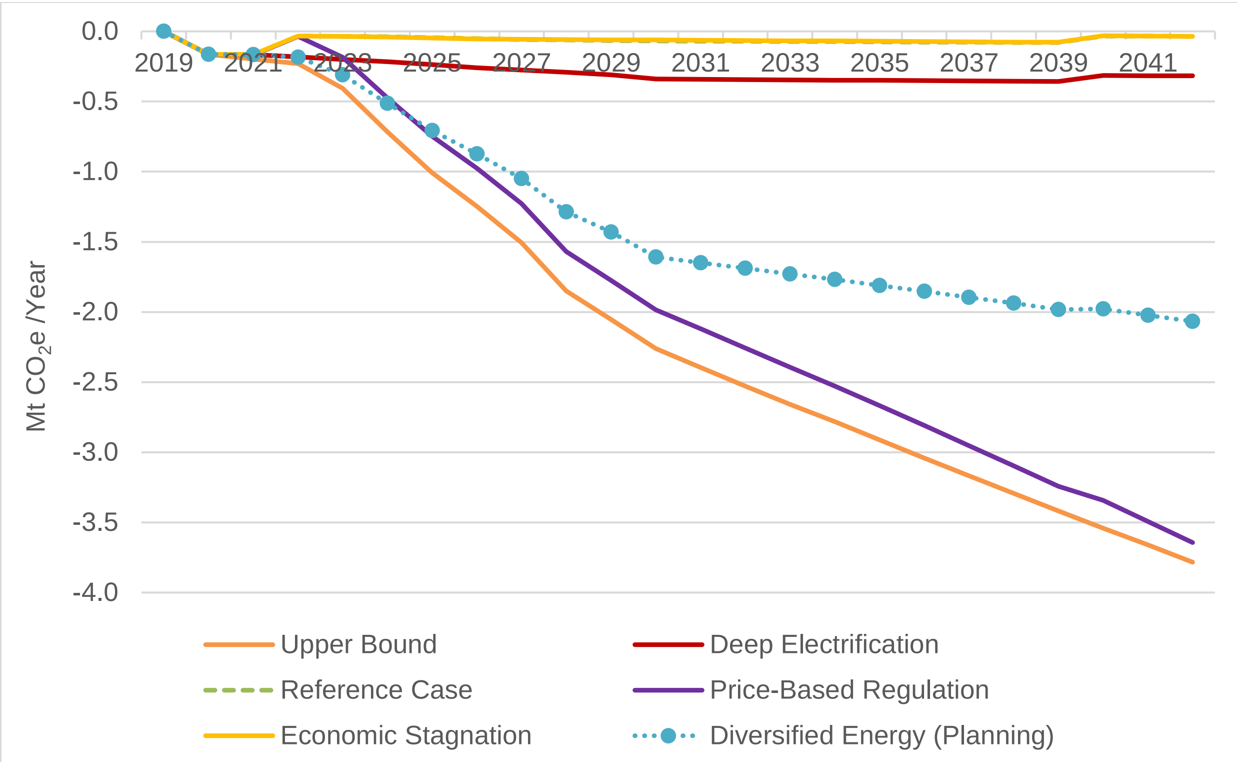
Figure 9-3 presents the emissions reductions that result from growth in FEI serving low-carbon transportation fuels and global LNG exports in the Diversified Energy (Planning) Scenario. These emission reductions are separated into those that would occur within BC, and so would contribute to reductions in BC's GHG emissions inventory, and those that are either in other inventories other than BC or, though occurring, are not captured in any inventory. FEI is not inferring ownership of any carbon credits with regard to Figure 9-3, but simply stating the emission reductions that will occur when natural gas displaces higher-carbon fuels for these uses. The total potential for carbon reductions as a result of serving this demand is much greater than FEI has modelled in the Diversified Energy (Planning) Scenario and shown in Figure 9-3.

Figure 9-3: BC and Global Emission Reductions (Life Cycle) in the Diversified Energy (Planning) Scenario from Serving the Transportation and Global LNG Markets



To provide a comparison of emission reduction results across the Reference Case demand and alternate future scenarios, Figure 9-4 shows total life cycle emission reductions that occur as a result of demand from low-carbon transportation and global LNG customers. The planning environment conditions present in the Upper Bound and Price-Based Regulation encourage higher investment in low-carbon transportation infrastructure, logistics and gas delivered by FEI than is expected to occur in the Diversified Energy (Planning) Scenario. On the other hand, the conditions present in the Deep Electrification and Economic Stagnation Scenarios do not encourage diversified energy solutions, hindering such investments and resulting in minimal carbon reductions for these high energy users that are difficult to decarbonize.

Figure 9-4: Total Emissions (Life Cycle) for Serving Low-Carbon Transportation and Global LNG Demand for the Reference Case and Alternate Scenarios



9.2.3 Total GHG Emission Reductions for FEI's Clean Growth Pathway

GHG emission reductions from FEI's Clean Growth Pathway are transformational. In order to provide a complete picture, the reductions from serving both the residential, commercial and industrial, and the low-carbon transportation and global LNG customers throughout the planning horizon are shown in Figures 9-5 and 9-6 based on life cycle emission factors (those discussed in Section 9.2.1 are based on end use emission factors to be consistent with the GHGRS). Figure 9.5 shows the Diversified Energy (Planning) Scenario total emission reductions broken out into reductions that are accounted for by BC and those that are accounted for outside of BC.

Figure 9-5: Total GHG Emission (Life Cycle) Reductions for the Diversified Energy (Planning) Scenario – BC and Outside of BC

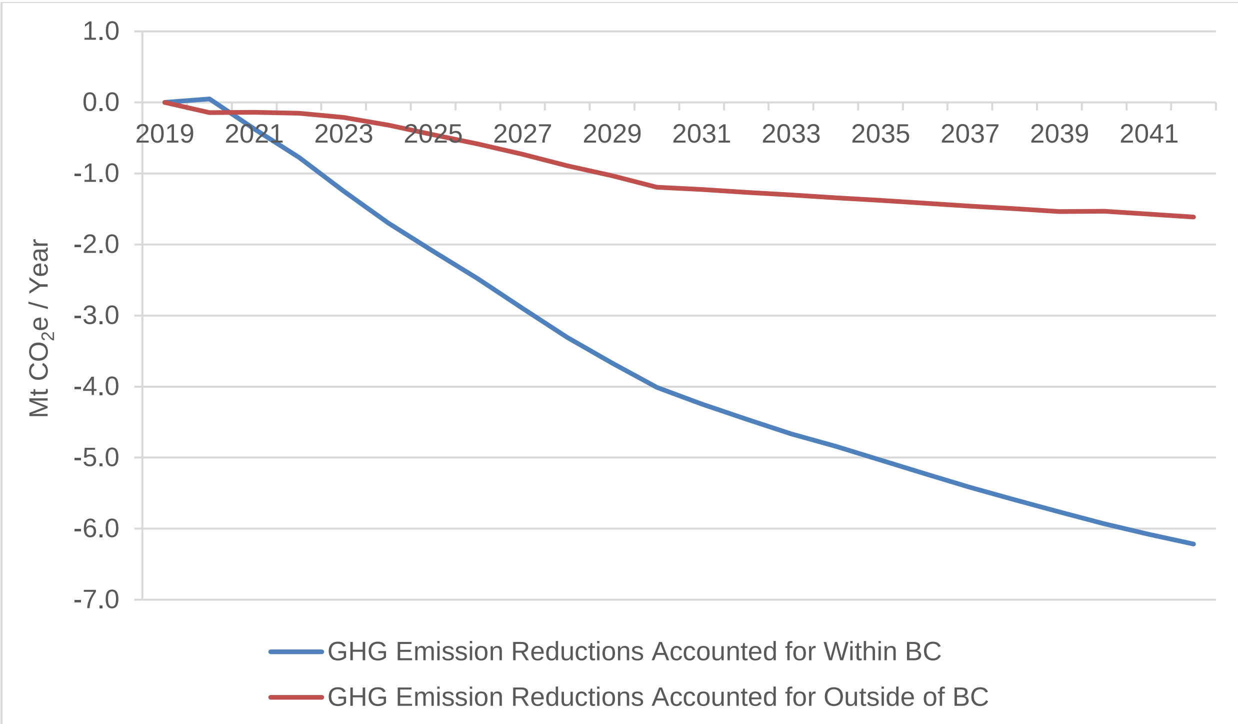
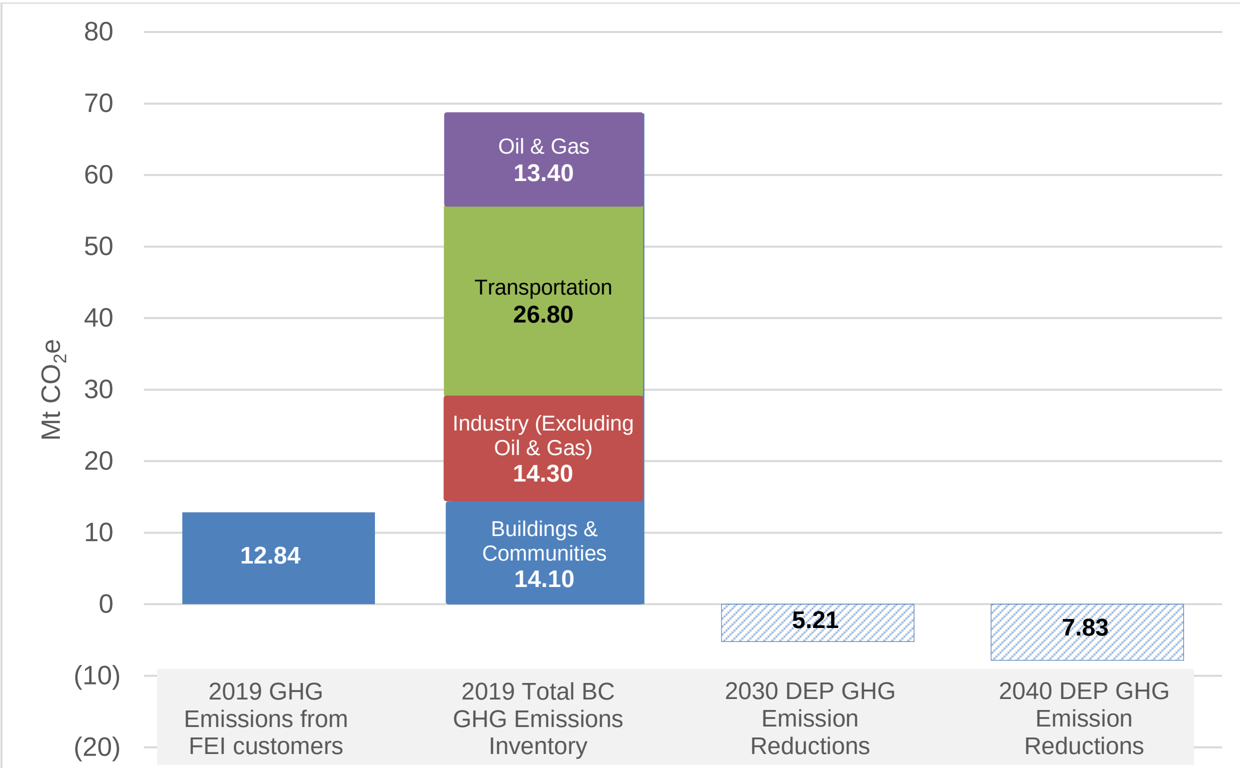


Figure 9-6 shows total emission reductions from the DEP Scenario in 2030 and in 2042 (the final year of the LTGRP planning horizon), compared to the 2019 base year emissions from FEI's customers and to 2019 emissions included in the BC inventory. The purpose of this figure is only to provide a comparison of total GHG emission reductions associated with FEI's Diversified Energy (Planning) Scenario next to base year (2019) emissions for FEI's customers and for total BC emissions for context and comparison purposes. There is no intent to infer ownership of carbon reduction benefits or allocation to BC or other emission inventories within this figure.

Figure 9-6: Comparison of Total Emission (Life Cycle) Reductions for FEI's Diversified Energy (Planning) Scenario[224] in 2030 and 2042 to FEI 2019 Customers and to 2019 Total BC GHG Emissions Inventory



9.3 *FEI'S CLEAN GROWTH PATHWAY WILL TRANSFORM CERTAIN MARKETS AND INFLUENCE OTHERS*

FEI's Clean Growth Pathway involves maintaining both the gas and electric infrastructure as part of BC's future energy system, leveraging FEI's existing infrastructure to reduce risks associated with the low-carbon transition. This foundation allows for more flexible and innovative solutions to be more easily developed and deployed. Through ongoing innovation, decarbonization is accelerated, contributing to provincial GHG emission reduction targets at a more rapid pace. In this pathway, the gas infrastructure continues to grow and thrive by adding new customers, communities, and commercial and industrial processing activities in order to maintain a viable infrastructure where rates continue to be shared across a diverse set of customer segments that can support the additional costs incurred through the clean energy transition. The industrial sector, in particular, is the most difficult to decarbonize and direct-to-customer clean energy projects may be one of the most viable solutions.

Table 9-1 illustrates how FEI's investments in decarbonization will support ongoing market transformation across the energy services supply chain.

[224] Diversified Energy (Planning) Scenario is referred to as DEP in this figure

Table 9-1: FEI's Investments in Decarbonization Initiatives Support Market Transformation Over the 20-Year Planning Horizon

Market Being Influenced	Anticipated Outcome in 2042
Decarbonization of fuel types through transitioning to renewable and low-carbon gases	
Renewable and low-carbon gases transition	By 2042, FEI's forecast annual demand will be increasingly supplied by renewable or low-carbon gases in the form of hydrogen, RNG, syngas and lignin, and some CCUS associated with gas production or consumption. By 2030 and through the rest of the planning horizon FEI's renewable and low-carbon gas will be increasingly supplied by BC based production. This initiative represents a transformational change within traditional gas supply markets.
Hydrogen production and distribution	Hydrogen will make up an increasingly large portion of the renewable and low-carbon gas supplies that FEI will rely on over the planning horizon. This demand for hydrogen will catalyse the development of BC's hydrogen economy and the development of innovative energy solutions in BC that use hydrogen as the key, low-carbon fuel. FEI's existing gas delivery system will enable this transition from natural gas to renewable and low-carbon gas in a number of different ways as outlined in Section 7, including the development of hydrogen hubs, the potential repurposing and upgrading sections of the existing gas grid to reliably supply clean, low-carbon hydrogen and the potential for dedicated hydrogen infrastructure.
Industrial decarbonization	The renewable and low-carbon gases that FEI will leverage to implement its Clean Growth Pathway offer some of the best opportunities for decarbonizing industrial processes within BC. FEI anticipates being a catalyst in the transformation of industrial energy use through its future supplies of RNG, hydrogen, syngas and lignin, and the use of CCUS in association with energy generation and/or use.
Carbon Capture, Utilization and Storage	Since the time that FEI undertook its modelling for the supply of renewable and low-carbon gas, the role that FEI expects CCUS to play in the Clean Growth Pathway has grown. FEI anticipates that CCUS will become increasingly commercially available and contribute to GHG emission reductions in FEI's fuel mix earlier in the planning horizon.
Electrification	The electrification of a degree of current gas load is expected to happen over the planning horizon as one of the solutions to reduce carbon emissions in the Diversified Energy (Planning) Scenario. Total electrification of FEI's existing gas demand, however, creates challenges for electricity capacity requirements that FEI considers are not plausible. FEI's Clean Growth Pathway is based on using the right energy, for the right purpose at the right time.
Low-Carbon Transportation and LNG	
Low-Carbon Transportation	FEI is not anticipating a complete transformation of the transportation sectors it is targeting with its low-carbon fueling supply and services. FEI's Clean Growth Pathway will, however, substantially reduce GHG emissions from one of the hardest to decarbonize sectors and catalyse the development of a marine bunkering industry in BC.

Market Being Influenced	Anticipated Outcome in 2042
DSM Reduces Energy Consumption in Residential, Commercial and Industrial Sectors	
Demand-side Management and high efficiency equipment	Heat pumps (gas and electric), dual-fuel heating systems, deep energy retrofits, building envelope upgrades and HVAC control systems will reduce energy requirements as BC's building stock is transformed to high performance. Waste heat recovery and integrated community energy systems offer some of the emerging innovations that will allow FEI to reach the GHGRS emissions cap for gas utilities.
Decarbonization in Commercial and Industrial Processes	Innovative technologies, process improvements and waste heat recovery will be implemented to help transform commercial and industrial processes toward higher efficiency and low-carbon emissions.
Enabling Activities to Support Market Transformation	
Clean energy workforce capacity	Workforce training and capacity building across the clean energy supply chain ensures decarbonization success.
Utility, government, rightsholder and stakeholder collaboration on climate action	All stakeholders collaborating on an approach to BC's energy system, understanding that there needs to be a multi-faceted approach to decarbonization.
Policy and regulatory environment supportive of decarbonization	Policy and regulatory environment are supportive of a diversified, complementary approach to meeting BC's energy needs.

9.4 RATE IMPACT IMPLICATIONS OF THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

To provide context for FEI's long-term volume forecasts Figures 9-7 through 9-10 provide a 20-year directional view at the potential impact on customer rates under the Reference Case, Diversified Energy (Planning), Deep Electrification, and the Upper Bound Scenarios for Residential (RS 1), Small Commercial (RS 2), Large Commercial (RS 3), and Industrial General Firm Service (RS 5) customers, respectively.

Considering the volume of information presented, FEI has only included the results for these four scenarios since they provide a representative overview of the implications for rates that different futures will have. The figures below do not consider future rate design changes and are not indicative of a detailed rate forecast; rather, they simply provide a directional, 20-year view of how FEI's rates are influenced by these scenarios over time.

The analysis on effective rate impacts compares the changes in rates to the current 2022 approved rates with the following assumptions:

- The 20-year annual demand for each scenario includes DSM and low-carbon transportation;

- The long-term DSM expenditures for each scenario are under the High DSM setting discussed in Section 5.4.1;
- Commodity costs are based on a mix of supply of conventional natural gas and renewable gas, and midstream (i.e., storage and transport charges) costs assumed an escalation of by inflation;
- Carbon tax under the Diversified Energy (Planning) and Deep Electrification scenarios assumes annual escalation until it reaches $170 per tonne in 2030 as discussed in Section 2.2.1.4.2. For the Reference scenario, carbon tax is assumed to remain at $50 per tonne while for the Upper Bound scenario, carbon tax is assumed to be eliminated. For all scenarios, the bill impact analysis includes the avoided carbon tax resulting from the mix of renewable and low carbon gas in the commodity costs. For example, assuming FEI's gas supply includes 5 percent mix of renewable and low carbon gas in 2023, then the carbon tax is applied to the 95 percent of conventional natural gas only with no carbon tax on the remaining 5 percent;
- The 2022 approved delivery margin as the baseline cost of service plus annual escalation by inflation as well as the incremental cost of service for the capital expenditures on FEI's major transmission systems (VITS, CTS, and ITS) related to capacity upgrades, integrity, and resiliency depending on the peak demand forecast in each scenario;
- The incremental cost of service (including any offsetting revenue) related to FEI's major capital projects recently filed (or expected to be filed) or approved by BCUC, including:
  - Inland Gas Upgrades (IGU) CPCN;
  - Pattullo Gas Line Replacement (PGR) CPCN;
  - Tilbury LNG Storage Expansion (TLSE) CPCN;
  - Advanced Metering Infrastructure (AMI) CPCN;
  - CTS and ITS Transmission Integrity Management (TIMC) CPCNs;
  - OIC Tilbury Phase 1B; and
  - Woodfibre Gas Pipeline.
- The effective rate impacts are based on the average use per customer (UPC) between 2022 and 2042 under the Diversified Energy (Planning) Scenario:
  - Residential (RS 1): 60 GJ per year
  - Small Commercial (RS 2): 293 GJ per year
  - Large Commercial (RS 3): 3,253 GJ per year
  - Industrial General Firm Service (RS 5): 18,542 GJ per year

Figure 9-7: Cumulative Effective Rate Impact (2022 – 2042) – Residential RS 1, Avg. UPC 60 GJ

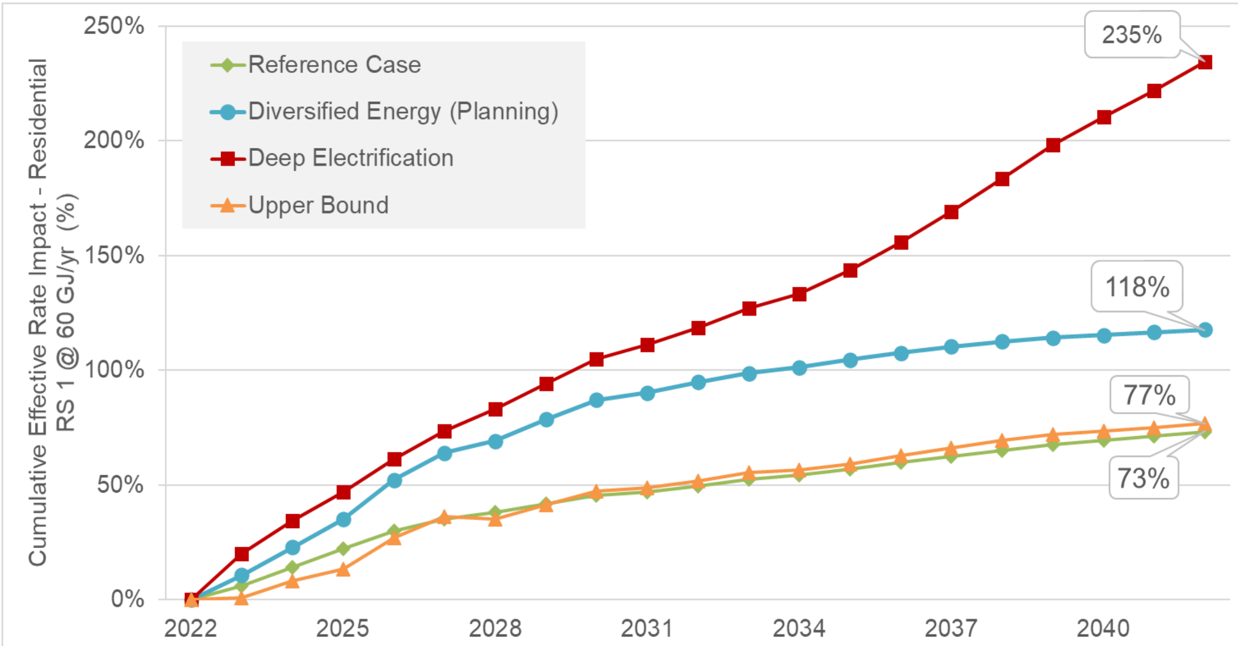


Figure 9-8: Cumulative Effective Rate Impact (2022 – 2042) – Small Commercial RS 2, Avg. UPC 293 GJ

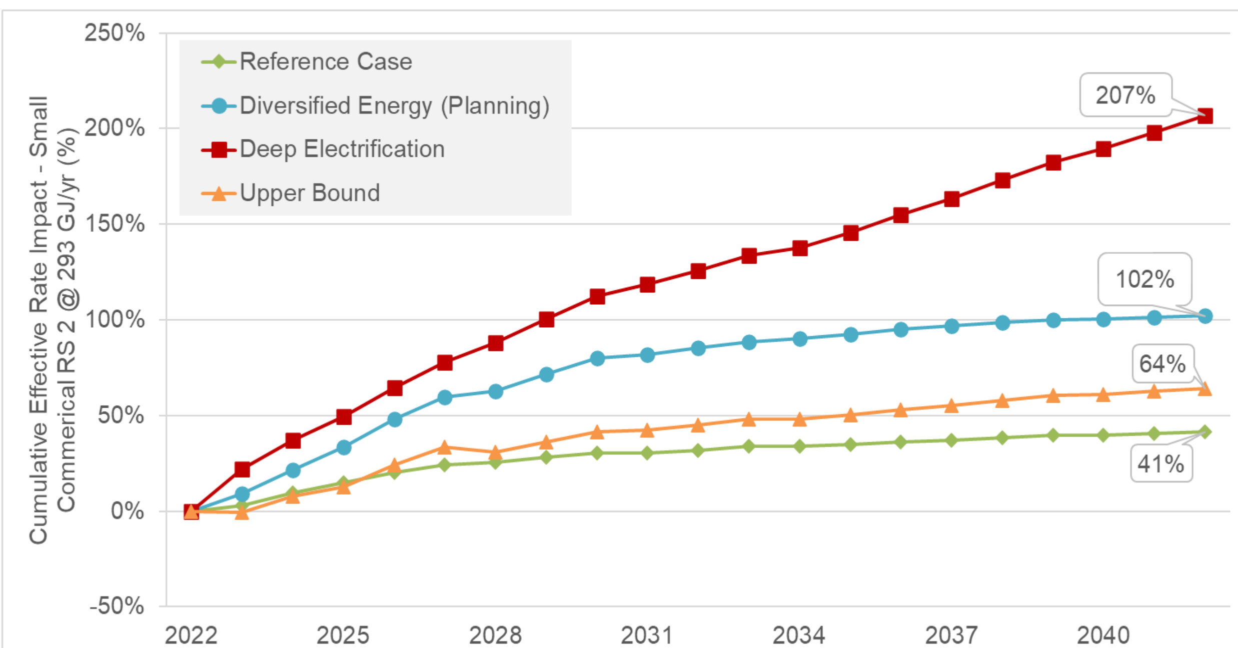


Figure 9-9: Cumulative Effective Rate Impact (2022 – 2042) – Large Commercial RS 3, Avg. UPC 3,253 GJ

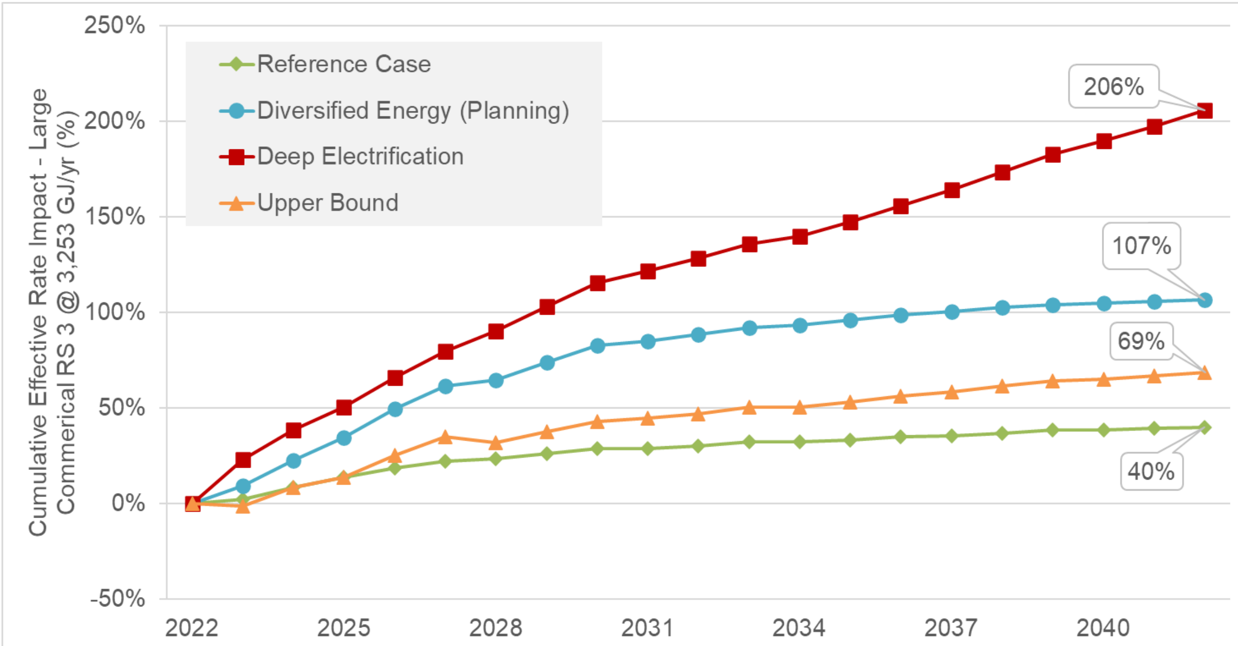


Figure 9-10: Cumulative Effective Rate Impact (2022 – 2042) – General Firm Service RS 5, Avg. UPC 18,542 GJ

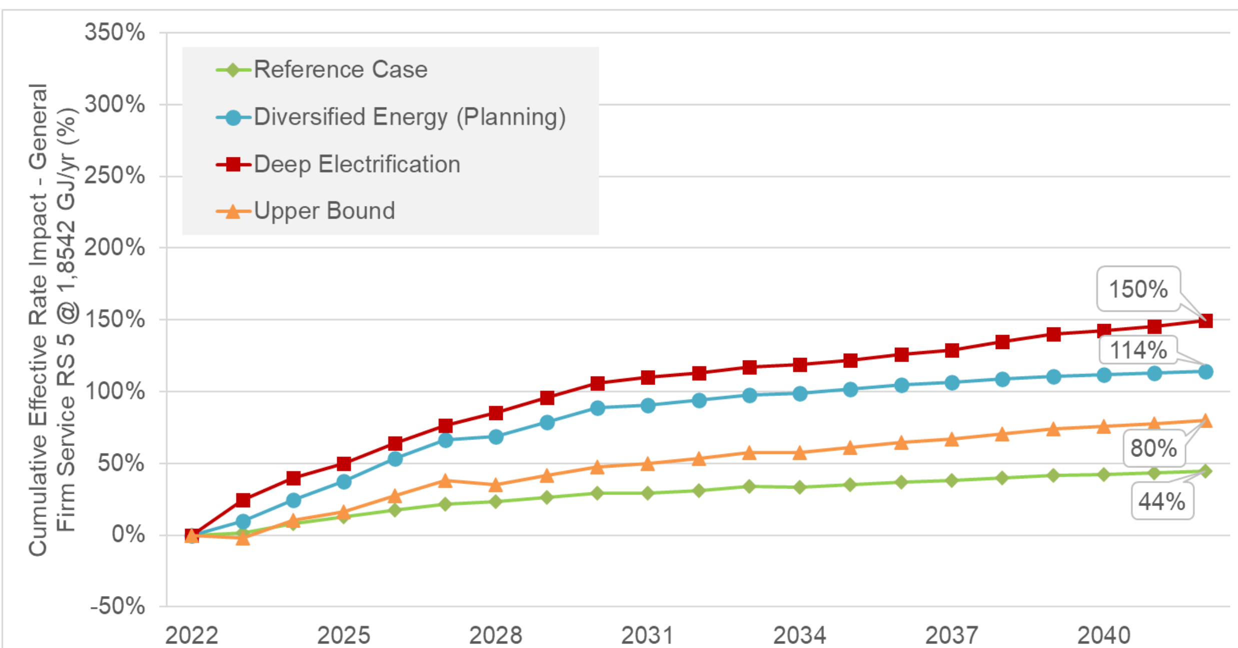


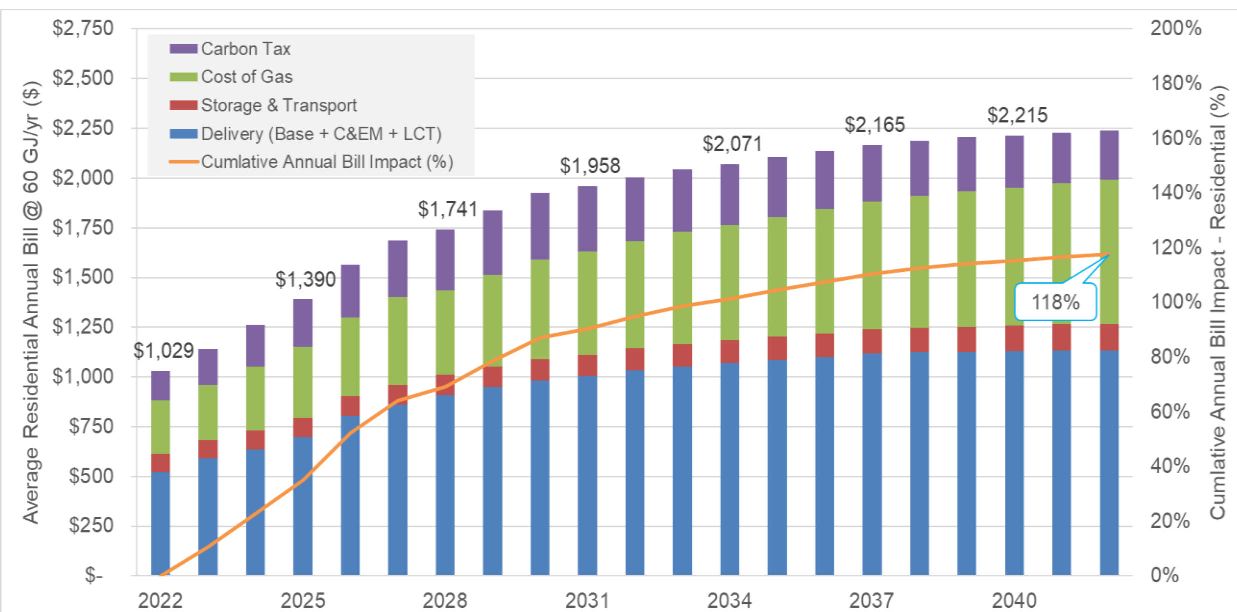
Table 9-2 below summarizes the cumulative effective rate impact projections as well as the equivalent annual rate impact over the 20-year period for each scenario.

Table 9-2: Summary and Comparison of Average Projected Delivery Rate Changes

	Average UPC (2022 - 2042)	Effective Rate Change (2022 - 2042, %)							
		Reference		Upper Bound		Diversified Energy (Planning)		Deep Electrification	
		Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual
Residential (RS 1)	60	73%	2.8%	77%	2.9%	118%	4.0%	235%	6.2%
Small Commercial (RS 2)	293	41%	1.7%	64%	2.5%	102%	3.6%	207%	5.8%
Large Commercial (RS 3)	3,253	40%	1.7%	69%	2.6%	107%	3.7%	206%	5.7%
General Firm Service (RS 5)	18,542	44%	1.9%	80%	3.0%	114%	3.9%	150%	4.7%

The cumulative effective rate impacts shown in the figures above are made up of individual impacts in all components of FEI's rates, including delivery, cost of gas, storage & transport, and carbon tax. Using Residential (RS 1) as an example, Figure 9-11 below provides a breakdown of the annual bill projections for the average residential customer under the Diversified Energy (Planning) Scenario from 2022 to 2024. It can be seen that the total residential bill is estimated to increase from approximately $1,029 in 2022 to $1,958 in 2031, and to approximately $2,215 in 2040 under the Diversified Energy (Planning) Scenario. The cumulative effective rate increase by 2042 under the Diversified Energy (Planning) Scenario is driven by increases in all three components – 50 percent due to the delivery rate impact, 41 percent due to commodity related impacts (cost of gas and storage & transport), and 9 percent due to carbon tax increases.

Figure 9-11: Breakdown of the Cumulative Effective Rate Impact for Residential RS 1 under the Diversified Energy (Planning) Scenario



9.5 KEY DRIVERS IMPACTING THE NEED FOR INFRASTRUCTURE AND GAS SUPPLY RESOURCES ON FEI'S CLEAN GROWTH PATHWAY

The 2022 LTGRP has identified a number of key drivers that are impacting the need for resources, including both very traditional drivers for gas utilities as well as new and emerging drivers. No single one of these drivers is mutually exclusive of the others. There are many interrelationships among them. In many cases, proposed actions are aimed at addressing a number of these drivers and needs. For example, advancing the RGSD project as discussed in Section 6, addresses a number of the drivers including regional gas transmission constraints, improving diversity of supply, improving system resiliency and enabling the transition to renewable and low-carbon gas.

Table 9-3 summarizes key drivers impacting resource needs discussed in the 2022 LTGRP, indicates where in the LTGRP these drivers are discussed in more detail and identifies which Action Items presented in Section 10 are intended to address them over the next four years.

Table 9-3: Summary of Key Drivers impacting Resource Needs in the 2022 LTGRP

Key Drivers of Resource Needs[225]	Discussed in LTGRP Section(s)	Supporting Action Item(s) in Section 10									
		1	2	3	4	5	6	7	8	9	10
i. Increasing **DSM programs** to reduce demand and GHG emissions, continued exploration of innovative technologies leads to energy savings and deeper decarbonization.	3.4 5.1 – 5.7		√						√		
ii. Meeting **customer and demand growth** on FEI's system. Demand growth is primarily expected in the Low-Carbon Transportation and global LNG customer groups as well as the addition of a single large industrial customer – the Woodfibre LNG project.	4.1 – 4.9 7.3 7.4	√	√	√		√	√	√		√	√
iii. Addressing **regional supply constraints** resulting from demand growth in the Pacific Northwest. Gas supply resources in the region are becoming increasingly constrained and FEI needs to bring forward a solution(s) that protects the interests of its customers.	2.2.4 6.1 – 6.4					√	√		√	√	
iv. Improving access to **gas supply and system resiliency**. Weather extremes and aging	3.2.2.3 6.2.4 6.3	√				√	√	√	√	√	√

225 Numbering of key driver does not imply order of priority.

Key Drivers of Resource Needs[225]	Discussed in LTGRP Section(s)	Supporting Action Item(s) in Section 10									
		1	2	3	4	5	6	7	8	9	10
regional infrastructure are driving the need to improve system resiliency for serving FEI's customers.	7.5 App. E										
v. Meeting a **2030 GHG Reduction Standard** for gas utilities and a **legislated 2040 emission reduction target** on behalf of customers through the four pillars of the Clean Growth Pathway.	3.1 – 3.8 5.1 – 5.7 6.2.3 7.4 9.1 - 9.6	√	√	√	√	√			√	√	
vi. Incorporating an increasing proportion of **renewable and low-carbon gas into** FEI's gas supply portfolio. RNG and hydrogen will make up the largest proportion with smaller amounts of syngas and lignin anticipated along with CCUS. Regional and on-system gas supply resources need to address this shift.	3.3 6.2.2.2 6.2.3 7.4.1 9.1 – 9.6	√			√	√		√	√	√	√
vii. **Improving supply diversity** for sources of natural gas, renewable natural gas and hydrogen. Improving access to more production and trading areas will reduce price risk for customers, open up more optionality for supply and improve the resiliency of FEI's gas supply.	6.1-6.4 App. D	√				√	√		√	√	
viii. **Preparing for and participating in BC's emerging hydrogen economy.** FEI will be a catalyst for the development of a hydrogen economy in BC. Work is underway to better understand the implications of this transition for FEI's infrastructure and services as well as for FEI's residential, commercial, and industrial customers and communities.	3.3.3 6.2.2.2 6.2.3 7.4.1	√		√	√	√			√	√	√

9.6 *SUMMARY*

Key outcomes of FEI's Diversified Energy (Planning) Scenario are transformational reductions in carbon emissions, influences on energy related marketplaces, implications for customer rates and the need for new resources. As reflected in the discussion of these key outcomes above, the 2022

LTGRP highlights FEI's four pillars of the Clean Growth Pathway, the extent to which FEI initiatives contribute to BC's overall GHG reductions, and how variations in demand over the planning period can influence customer delivery rates. Since decreases in demand (whether through market trends or DSM programs) place upward pressure on delivery rates while increases in demand lead to the reverse effect, FEI will continue to explore opportunities for demand growth on the distribution system. This includes monitoring and, where applicable, participating in efforts to test and implement innovative natural gas energy technologies that help meet FEI's customers' needs while also supporting BC energy objectives.

FortisBC Energy Inc.
2022 LTGRP

Section 10:

ACTION PLAN

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10. ACTION PLAN

This Action Plan describes the activities that FEI intends to pursue over the next four years based on the information and recommendations provided in this 2022 LTGRP. FEI has built its Action Plan based on the Diversified Energy (Planning) Scenario modelled on the Clean Growth Pathway to achieve the GHG emission reduction targets outlined in the Roadmap. The Action Plan sets FEI on a path to decarbonization that provides the most viable opportunity to meet British Columbia's energy needs and carbon reduction targets, in a cost effective, reliable, and resilient manner.

At the time of writing this 2022 LTGRP, FEI is still in discussions with the provincial government to fully understand the policy requirements of the CleanBC Roadmap and their impact on FEI. The legislation and regulations required to implement the Roadmap will be understood for the next LTGRP. Based on its current understanding of BC government policies, the following are FEI's Action Items for the 2022 LTGRP.

1. Accelerate the development and acquisition of renewable and low-carbon gas supplies to meet customer energy needs and contribute to provincial emission reduction targets (Clean Growth Pathway – Pillar One).

The continued use, sustainment and growth of FEI's infrastructure along with a transition to increased production, delivery and use of renewable and low-carbon gas supplies is key to maintaining reliability, resiliency and affordability of BC's overall energy network in a low-carbon future. FEI will:

- Continue to accelerate the adoption of RNG, hydrogen, syngas, lignin and CCUS by familiarizing customers with these products and by implementing service offerings and rates to support the growth of this renewable supply;
- Support development of the renewable and low-carbon gas supply industry and market in BC and other jurisdictions through supply purchase agreements and project partnerships;
- Support the development of BC's hydrogen economy through implementing hydrogen blending and hydrogen hubs, and plan for transitioning to hydrogen compatible infrastructure;
- Grow expertise and capacity within FEI and BC generally for advancing renewable and low-carbon innovation through research, evaluation, pilot projects and full-scale production and be a leader in supporting BC's decarbonization initiatives;
- Continue to seize emerging market opportunities to provide gas delivery service that will reduce GHG emissions such as in the marine and other transportation sectors; and
- Continue to seek out partnerships with Indigenous groups and others to develop and implement innovative, clean energy solutions as part of FEI's Clean Growth Pathway.

2. Pursue approval of DSM funding for the period beyond 2022 by submitting for BCUC approval a DSM expenditure plan in 2022 (Clean Growth Pathway – Pillar Two).

FEI's future DSM expenditure plans will be informed by the results of the 2021 CPR and the 2022 LTGRP DSM analysis. FEI will continue to examine the potential for all forms of DSM programs to optimize the use of BC's energy infrastructure by implementing programs that help meet customer energy needs while reducing energy bills and meeting BC energy objectives. FEI will continue to explore the opportunity for DSM programs to transition and evolve to address deep energy retrofits, greater than 100 percent efficiency equipment, innovative technologies and behaviour change programs. FEI will:

- Develop DSM expenditure plans for the next funding period(s) reflecting an adequate and cost effective portfolio of DSM activities guided by the High DSM Setting, and apply to the BCUC for acceptance of those expenditures;
- Assess the implications of increasing amounts of renewable and low-carbon gas over the planning horizon on FEI's DSM activities, program modelling and reporting tools. For example, FEI will assess the impact of these supplies on cost-effectiveness models to understand how these fuels impact program offerings in alignment with the Roadmap;
- Continue to examine the potential for DSM activities to reduce peak demand on FEI's transmission and distribution systems, and thus defer or avoid infrastructure investments. FEI will continue to monitor studies and advancements across the gas utility industry on DSM related non-pipe solutions as well as evaluations of the effectiveness of such initiatives. FEI will consider opportunities for studies or pilot programs for such activity on its own system; and
- Continue to work with federal, provincial and municipal governments and other potential partners to explore and identify ways in which FEI's DSM activities can continue to help meet government objectives while ensuring benefits for FEI and its customers. This activity will include examining and understanding the impact of any changes to the BC Demand-side Measures Regulation on FEI's DSM programming, if and when such changes are enacted.

3. Continue pursuing FEI's LCT and global LNG initiatives to address market opportunities for load growth in support of customer rates and reducing local and global GHG emissions. (Clean Growth Pathway – Pillars Three and Four).

FEI will continue expanding its LCT service to a growing customer base wherein the displacement of higher carbon fuels by natural gas, renewable natural gas, or potentially hydrogen will result in a substantial reduction in both GHG emissions and other pollutants into the atmosphere. FEI will also continue to explore opportunities for its infrastructure to deliver lower carbon natural gas to customers in the form of LNG to displace higher carbon fuels currently in use both locally and abroad, thereby reducing GHG emissions around the world. In addition to the reduction of GHG emissions, expanding load growth in these markets will help to optimize the use of FEI's existing infrastructure, thus reducing overall gas customer rates and supporting all aspects of FEI's Clean

Growth Pathway. LCT initiatives include the continuation of established programs that provide incentives and fueling infrastructure investment as have been enabled through the BC-LCFS. FEI will:

- Continue to seek out new customers and load growth in the marine transportation, heavy duty transportation and remote industry markets for providing LNG fueling services in accordance with the BC-LCFS;
- Continue to seek out new customers and load growth in the medium and heavy-duty vehicle market in accordance with the BC-LCFS;
- Work with partners on innovative solutions for delivering fueling services in these important market segments;
- Continue to seize opportunities available to FEI to provide LNG to other jurisdictions in the global market where it can be used to displace higher emitting fuels; and
- Continue to work with governments to ensure that the benefits of FEI's energy infrastructure for reducing emissions in the transportation and global LNG sectors are considered in future regulatory changes and government initiatives.

4. Continually improve engagement processes and activities with Indigenous groups and BC communities on FEI's long-term gas resource planning.

Continual improvement in the way FEI engages with Indigenous groups and stakeholder consultation activities is an important part of the evolving resource planning process. The level of interest in energy planning, the urgency to address climate change, and the future implications of energy related policy and decision-making are more complex than in past LTGRPs. Engaging these groups regarding the LTGRP is one avenue through which to identify potential collaborative relationships on clean energy projects. FEI will:

- Continue to assess and incorporate the use of new communication technologies to provide greater reach and improved input into the LTGRP;
- Assess and implement the resources needed to improve engagement with Indigenous groups in FEI's resource planning activities, including securing additional sources of capacity funding to increase participation;
- Continue to improve the integration of LTGRP engagement activities with those of other groups within FEI; and
- Develop its engagement plans for the next LTGRP with implementation to start following upon the conclusion of the regulatory process for the 2022 LTGRP.

5. Seek BCUC approval for a deferral account to capture the costs of advancing the development of the Regional Gas Supply Diversity (RGSD) project.

The RGSD project is a critical infrastructure investment necessary for implementing FEI's Clean Growth Pathway, resiliency improvements, and gas supply risk management. The RGSD project is the preferred and recommended solution to meet the need for new regional pipeline infrastructure driven by three market conditions which are outside of FEI's control:

- Constrained capacity on the T-South system;
- Forthcoming increases in regional demand; and
- Expansion of renewable energy supply due to government policy:[226]

These market conditions and related regional system capacity constraints are discussed in more detail in Section 6.3.3. While many of these conditions exist independently of demand on FEI's own system, they will nonetheless result in significant costs and risks for FEI customers. The implemented solution must adequately consider project costs and benefits from the point of view of FEI's customers. Specific benefits of the RGSD project include:

- Facilitating FEI's decarbonization goals by enabling access to more RNG and hydrogen;
- Providing opportunities to build long-lasting, clean energy partnerships with Indigenous groups;
- Strengthening system resiliency for FEI and across PNW;
- Increasing gas transmission capacity for the PNW;
- Improving diversity of supply for FEI customers and the PNW; and
- Improving price stability for FEI customers.

FEI first needs to bring the development of the RGSD project to a point of readiness for FEI to bring a CPCN application to the BCUC for consideration. As such, FEI will:

- Seek approval from the BCUC to create a deferral account to capture costs related to further development of the RGSD project.
- Subject to BCUC approval of the deferral account:
    - Expand engagement and partnership discussions with Indigenous groups based on the principles of the UN Declaration on the Rights of Indigenous Peoples and adhering to the BC *Declaration on the Rights of Indigenous Peoples Act*;

[226] FEI and the BC Government are both advancing the use of hydrogen as a low-carbon fuel to help meet government policy and regulation regarding carbon emission reductions in the BC (see Section 2). Flowing hydrogen though pipelines in different potential blends requires greater pipeline capacity to move the same energy compared to natural gas since hydrogen has a much lower energy, although the lower energy content is partially offset by higher velocity capability due to differences in the flow characteristics of the gases.

- Initiate and conduct the necessary work to develop the RGSD project in preparation for a CPCN application; and
- Based on the outcome of this work, submit a CPCN application to the BCUC for approval of the RGSD project.

6. Continue to develop and implement FEI's Gas System Resiliency Plan.

The T-South incident and recent extreme weather events that have impacted infrastructure throughout BC have reinforced the need to improve the resiliency of FEI's gas delivery to customers and, in doing so, help to build more resiliency into BC's overall energy system. By pursuing the Clean Growth Pathway, FEI will contribute to building energy resilience for BC by maintaining and improving the diversity of energy sources, supplies and services available to customers in the province.

On FEI's own system, the TLSE and RGSD projects together with the AMI initiative are cornerstones of FEI's resiliency plan. The TLSE and AMI project CPCNs are currently before the BCUC and the RGSD project is the subject of Action Item 5, above. In addition to these projects and pursuing its Clean Growth Pathway, FEI will:

- Continue its ongoing system resiliency review and monitoring across all regions of its service network;
- Further define resiliency criteria for application when identifying and selecting preferred project alternatives to meet system growth and/or sustainment on the gas grid; and
- Continue to monitor regional issues in the PNW for developments that could impact the resiliency of gas supplies for FEI's customers.

7. Plan for and prepare CPCN applications for near-term system requirements identified in Section 7 to support safe, reliable and cost-effective gas delivery to FEI's customers.

In addition to the projects discussed elsewhere in these Action Items, the following system infrastructure projects FEI intends to submit CPCN applications over the near term include the following:

- FEI submitted a CPCN application for the Okanagan Capacity Upgrade in January 2021 but the proceeding is currently adjourned. In the interim, FEI continues to prepare and implement contingency plans for temporarily addressing the capacity deficit until a permanent capacity upgrade solution is approved and installed;
- Further capacity constraints on the Vancouver Island Transmission System are not expected within the forecast period other than the upgrades that will directly support the addition of the Woodfibre LNG project demand. It is expected that the system will meet the Traditional Peak Method for all other firm demand;

- The Southern Crossing Pipeline Class Location project discussed in Section 7.5.3, addresses pipeline safety factors;
- In 2022, FEI will be filing an application for the implementation of EMAT ILI through the Transmission Integrity Management Capabilities project for the Interior Transmission System as discussed in Section 7.6.4; and
- The ongoing evaluation of major bridge crossings will determine if upgrades need to be considered to improve the resiliency of piping during a seismic event. Major DP, IP and TP Lateral Pipeline Crossings are discussed in Section 7.5.2.1 including the Ironworkers Memorial Bridge in the Lower Mainland and Okanagan Lake between Kelowna and West Kelowna.

As FEI's planning efforts were and continue to be undertaken to ensure that planned improvements optimize operation of the system as a whole, these system upgrade requirements were integrated with reinforcement options that were considered to meet FEI's capacity needs.

8. Continue monitoring, analysing and contributing to the energy planning environment while working with government on policy framework for deep decarbonization.

FEI's transition to renewable and low-carbon gas supply and other integrated energy solutions requires innovation and collaboration with all levels of government, Indigenous groups and stakeholders as the province works together in understanding the complementary roles of the gas and electric energy systems into the future. FEI will:

- Continue working to understand the many and evolving factors that influence FEI's long-term analysis in order to provide context, results and recommendations that will be made throughout the next LTGRP process;
- Continue to monitor market and policy developments which may impact the procurement and development of clean energy supply, regional gas supply, customer demand and pricing;
- Continue to advise the BC government, as appropriate, on the options available to maintain secure, reliable and resilient energy services to customers cost effectively, while lowering GHG emissions and reducing risks associated policy decisions, including how FEI can support a net-zero future in BC; and
- Continue efforts to collaborate with other utilities and energy solution providers on growing a diverse, reliable, resilient and affordable energy system throughout BC.

FEI's low-carbon transition will influence the renewable and low-carbon gas marketplace in BC and beyond. FEI's investments in the decarbonization of buildings and the commercial and industrial sectors will provide both environmental and economic benefits to British Columbians. FEI's research and development, collaborative partnerships and support for innovation will reveal potential challenges as well as identify opportunities to improve on the secure, reliable, cost-effective and lower-carbon energy that FEI continues to provide to its customers.

9. Protect and promote the interests of FEI's customers by securing reliable, cost-effective, long-term gas supplies that include increasing proportions of renewable and low-carbon gas.

Constrained pipeline and storage resources in the region during the winter season continue to be a major concern and market developments are increasing supply and pricing risks for FEI's customers. FEI will continue to monitor these changes, proactively assess challenges, and identify opportunities to enhance supply security, diversity and resilience in order to meet the LTGRP objectives. With the advancement of renewable and low-carbon gas supply resources in the region, FEI's future infrastructure is also being planned to support the transition to a lower carbon future by providing increased resiliency and supporting a broader range of supply resources. FEI will:

- Manage supply risk and price volatility in the region by maintaining access to supply hubs (Station and AECO/NIT), hedging any supply exposure to the Huntingdon/Sumas market with financial hedges, utilizing a variety of storage and transportation resources, and using different pricing structures and contract terms;
- Continue using financial hedging strategies as approved by the BCUC in FEI's PRMPs and, where applicable, request BCUC approval for an expansion of financial hedging strategies via future PRMPs;
- Continue to support the regulatory approval processes for the TLSE project which will significantly increase the resiliency of FEI's natural gas system in the event of a critical disruption of regional pipeline supply;
- Evaluate opportunities within FEI's service territory to improve infrastructure resiliency and supply diversity, which will support diversity, reliability, and decarbonization over the long term;
- Evaluate opportunities to contract for long-term, non-recallable storage capacity at Mist, which will help manage security of supply concerns in the gas supply portfolio;
- Continue to accelerate the acquisition of renewable and low-carbon gas supplies for inclusion in FEI's gas supply portfolio as part of FEI's Clean Growth Pathway; and
- Assess the firmness of renewable and low-carbon gas supplies for year-round delivery to customers and assess the evolving marketplace for opportunities to apply traditional portfolio risk mitigation mechanisms to these renewable and low-carbon supplies.

10. Continue monitoring for and evaluating system expansion needs across FEI's service regions.

Key to providing a safe, reliable, and secure supply of gas to customers is identifying when and where any capacity constraints may appear and planning for the infrastructure and system resources that FEI requires to construct over the planning horizon. Growth in peak demand is among the most significant challenges for FEI's long-term planning. Contingency plans for higher or lower than forecast peak demand are inherent in the regional system capacity plans outlined in Section 7.3. Planning for and integrating hydrogen into FEI's gas network is a new challenge. Although still in early stages of consideration, the potential for non-pipe solutions to help defer or avoid infrastructure continues to gain attention in the gas utility industry. Given all of these factors, the location of each load addition or renewable and low-carbon gas initiative will have unique implications for FEI's infrastructure, adding to the challenge of assessing the system implications before such locations are known. FEI will:

- Continue monitoring customer and peak demand growth on FEI's system and assessing the implications for capacity related infrastructure requirements;
- Continue to assess the implications for FEI's infrastructure of introducing hydrogen into the pipeline system or otherwise leveraging FEIs pipeline network to enable hydrogen or other renewable and low-carbon gas service;
- Refine reinforcements that would be required to maintain system reliability and resilience for Core customers as LNG expansion occurs on the Coastal Transmission System and the Vancouver Island Transmission System;
- Refine criteria to identify and prioritize projects to address system resiliency in all FEI systems;
- Refine and implement mitigation plans to address the capacity shortfall in the Okanagan region of the Interior Transmission System until an Okanagan Capacity Upgrade project solution is approved and implemented;
- Continue evaluating other major system projects outlined in Section 7.5 and submit CPCN applications for these projects if required; and
- Continue to explore innovative opportunities for implementing DSM and non-pipe solutions to delay or avoid new infrastructure through further studies and potential innovative DSM pilots.

11. Prepare and submit FEI's next LTGRP.

As discussed throughout this LTGRP, the energy planning environment is rapidly changing and FEI is undergoing an important shift to decarbonize the energy it delivers to customers. These changes have implications for FEI's services and infrastructure that continue to need further study and discussion as part of the long-term resource planning process. As such, FEI believes the period between filing this LTGRP and filing its next LTGRP should be shorter than the previous interval. FEI anticipates filing its next LTGRP approximately 2 to 3 years following the conclusion of the regulatory process for its 2022 LTGRP.

Appendix A-1

CLEAN GROWTH PATHWAY TO 2050

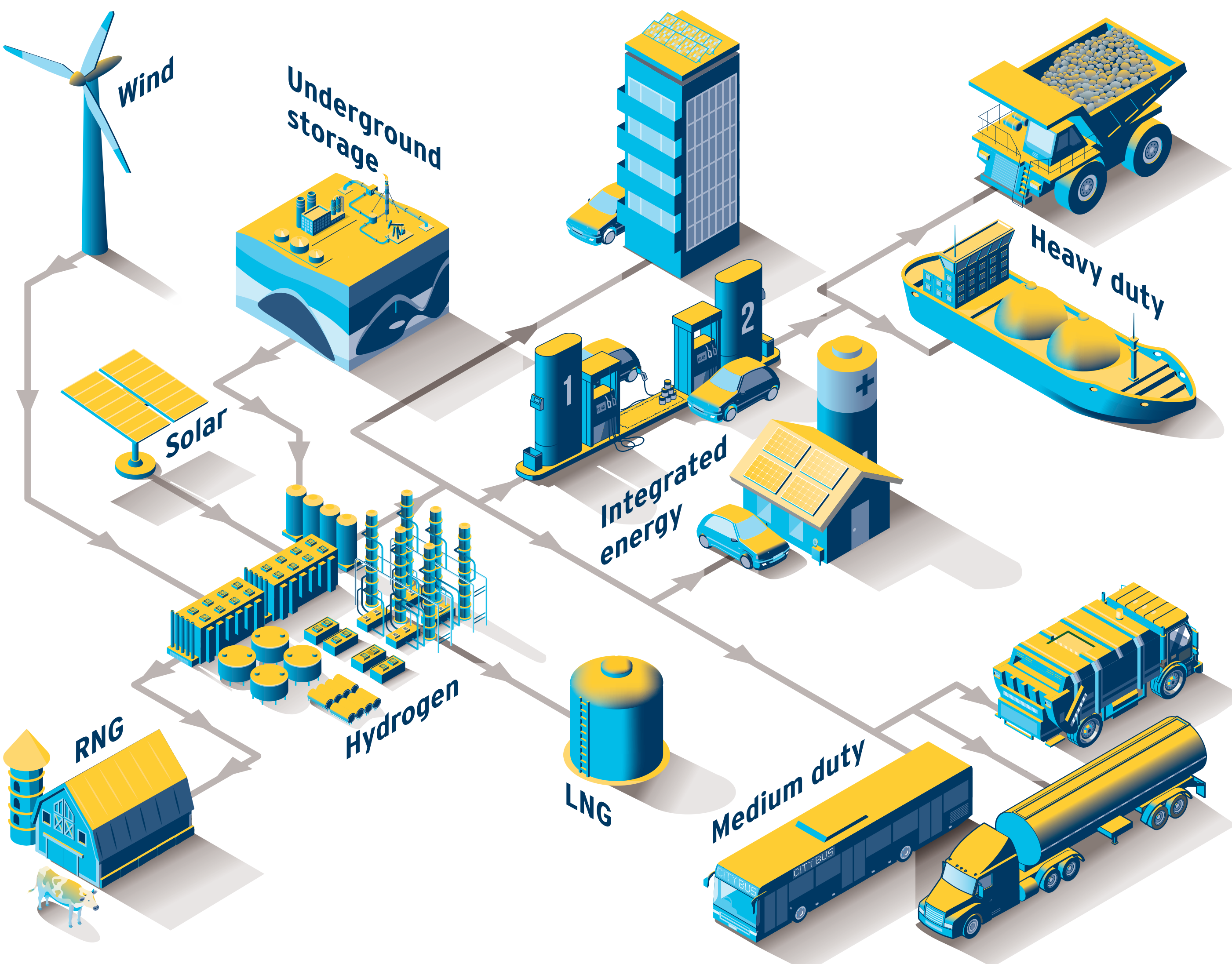
Clean growth pathway to 2050

Contents

Affordability, clean energy and efficiency: FortisBC's clean growth pathway

We believe FortisBC has an important role to play in helping British Columbia move to a low-carbon, renewable energy future. We see ourselves as an energy delivery company that has climate and economic solutions in the buildings and transportation sectors. Millions of British Columbians we serve in communities across the province look to us to deliver energy safely, reliably and affordably every day. As a subsidiary of our Canadian-based parent company, Fortis Inc., one of the largest energy companies in North America, we're committed to helping British Columbia achieve its climate goals and addressing climate change solutions in a global context. We're focused on providing practical solutions that can be implemented today by leveraging our existing infrastructure.

Figure 1: FortisBC's role in driving BC's sustainable prosperity



This paper presents FortisBC's pathway to align with the provincial government's goal to significantly reduce greenhouse gas emissions (GHG) while supporting economic growth and maintaining affordability and customer choice. Our approach combines several strategies that together outline a clear pathway to significant emissions reductions and signal a paradigm shift in the way we relate to energy.

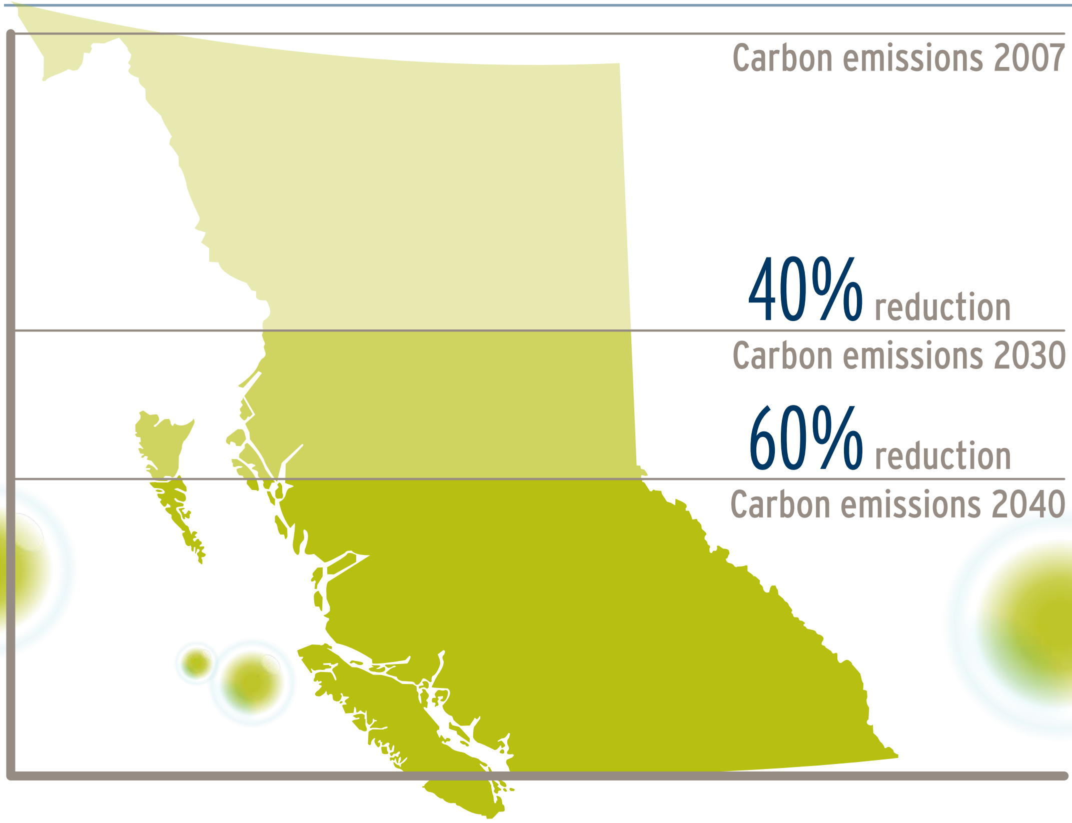
Our pathway calls for four significant shifts in our energy systems to foster market transformation:

- making significant investments in both low and zero carbon vehicles and infrastructure in the transportation sector
- transitioning from higher carbon energy sources to lower carbon sources by ramping up Renewable Natural Gas (RNG) and hydrogen deployment to achieve a ten per cent zero-carbon fuel supply by 2030 and a thirty per cent supply by 2050
- positioning BC as a vital domestic and international Liquefied Natural Gas (LNG) provider to lower global GHG emissions
- tripling our investment in energy efficiency in the built environment and developing innovative energy projects in BC's communities

Introduction

British Columbia (BC) has committed to achieving deep carbon reductions in greenhouse gas emissions by 2050. The province recently updated its climate targets to a 40 per cent reduction in carbon emissions from 2007 levels by 2030, and a 60 per cent reduction from 2007 levels by 2040. Achieving these long-term targets will require immediate and coordinated action by policy makers, regulators and industry. The province will need more than aspirations to achieve real, timely results.

Provincial Carbon Emission Goals



We believe we have a significant role to play in helping the BC Government deliver on its climate and energy goals. Our pathway is based upon our commitment to investing in projects that will make life more affordable for British Columbians, improve efficiency, reduce GHG emissions and drive innovation. By strategically managing BC's existing energy infrastructure and investing in new low-carbon energy supply, we see a long-term opportunity to continue creating sustainable, good-paying jobs across BC.

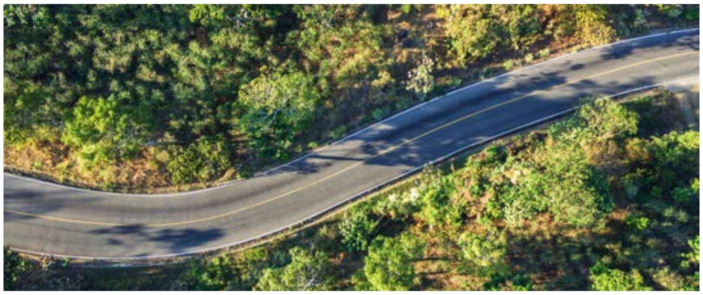
In 2015, BC's emissions were 63 million tonnes (Mt) of CO_2e. Most emissions fall into three categories: transportation, buildings and industry. We recommend any sectoral targets being considered should be proportionate to the sector's share of GHG emissions and the ability to deliver cost-effective emissions reductions using our current infrastructure.

25%

of BC's CO_2 emissions are from commercial transportation

For example, the commercial transportation sector is the largest contributor to BC's emissions at 25 per cent. The provincial government can achieve large emission reductions in transport using today's commercially-available technology. Practical and affordable solutions that can be implemented immediately should be differentiated from aspirational goals that require technology breakthroughs.

A made-in-BC pathway



As a utility serving gas, electric and alternative energy customers, FortisBC recommends developing an integrated, system-wide evaluation of achieving the province's carbon reduction objectives. Because FortisBC delivers the most energy to consumers of any entity in the province, we have a keen interest in British Columbians understanding the system-wide impacts of various pathways that meet the province's GHG emissions targets. BC's electric and gas energy systems work in tandem to provide reliable energy to British Columbians. Both systems complement one another, providing redundancy and a low-cost solution to delivering energy to British Columbians. FortisBC believes that the provincial pathway should be guided by strong analysis and pursue a strategy that utilizes 'every tool in the toolbox': all of our provincial energy resources and existing infrastructure will be needed to achieve long-term GHG emissions reductions.

Many low-carbon pathways have emphasized the importance of the electrification of end-uses. We agree that electricity will play a key role in reducing emissions but we also caution that there are significant challenges to this strategy. Notably, the direct substitution of electricity for gas to meet heating load, coupled with growth in other areas like electric vehicles, would far exceed the available electric infrastructure and add significant costs to the existing system which would be borne by all BC residents.

FortisBC supports the provincial government's commitment to undertake a review of BC Hydro and incorporate the findings into the Clean Growth Strategy. As we consider how best to transition to a sustainable and innovative economy, we believe there is a need to reflect the real cost of all energy in our long-term goals and strategies.

FortisBC believes that gas—as an energy carrier—will continue to be a critical component of a decarbonized energy system in BC. Gas infrastructure in the province is a multi-billion dollar asset that provides reliable, safe, affordable and high-quality energy services to British Columbians. This infrastructure is designed to serve difficult-to-decarbonize end-uses such as building and industrial heating and heavy-duty freight. Additionally, BC's gas infrastructure is equipped to handle decarbonization pathways that use drop-in fuels such as RNG and hydrogen, along with other key mitigation options like carbon capture and storage. The provincial government and stakeholders like FortisBC need to work to define the key role of the gas system to achieve our GHG reduction objectives and develop policies and other support mechanisms to leverage this system in a low-carbon transition.

Transportation

The transportation sector accounts for 39 per cent of BC's total emissions, making it the most important sector where we can achieve significant and immediate carbon reductions with technology that is available to us today. FortisBC is a leader in North America, providing innovative and clean technology that lowers emissions throughout the transportation sector.

BC's transportation sector accounts for

39%

of our CO_2 emissions

The decarbonization of BC's transportation sector will require the use of all tools available to us including:

- cleaner transportation systems, including increased investment in fuelling infrastructure, clean trade corridors
- displacing high-carbon fuels with cleaner fuels like natural gas, RNG, biofuels or hydrogen
- cleaner vehicles that use alternative fuels, electric power or hybrid technologies

Cleaner transportation systems

BC Ferries new Salish Orca is fuelled by natural gas—an innovative and clean solution that will provide benefits to BC Ferries' customers and the provincial economy.

Marine

The marine sector represents a massive GHG reduction and economic opportunity that should be the top priority in the province's Clean Growth Strategy. BC has had excellent early success in advancing liquefied natural gas (LNG) in the domestic marine sector that serves as a foundation to build upon for other markets.

BC Ferries launched their fourth LNG vessel this summer with a fifth expected next year and Seaspan Ferries now operates two LNG vessels in BC waters. With five LNG vessels in operation, BC Ferries, for example, expects to reduce their fuel costs by millions of dollars and CO_2 emissions by 21,500 tonnes annually, the equivalent of taking approximately 4,400 vehicles off the road per year. To put that in perspective, that's more than double the 2,200 battery electric vehicles that were purchased in all of BC in 2017.

The *Spirit of British Columbia* is the first vessel in the world to refuel LNG through delivery on a fully enclosed vehicle deck. In collaboration with BC Ferries, FortisBC developed a proprietary tanker truck technology to deliver fuel while on board the vessel. Innovative solutions like this help make it easier for transportation customers to make the switch to LNG.

The conversion of BC Ferries' two largest ships in the fleet, along with the introduction of three new natural gas-fuelled Salish Class vessels last year, improves sustainability and affordability for ferry users. FortisBC is proud to have partnered with BC Ferries to develop these innovative and clean solutions that will provide benefits to BC Ferries' customers and the provincial economy.

Clean Trade Corridors

FortisBC applauds the provincial government for initiating the Clean Transportation in BC Trade Corridors initiative. We see this multi-stakeholder collaboration as an essential forum to ensure that BC and Canada are in position to capitalize on international conventions that will reduce the use of dirtier fuels and drive the adoption of LNG in the marine sector. The group's mandate to improve competitiveness and reduce GHGs is well focused and timely—conventions set by the International Maritime Organization (IMO) will take effect by 2020 which is an incredibly short period to transition the practices of international vessels in BC's ports.

Marine vessels that regularly call at BC ports originate from ports of other countries are not included in the provincial emissions inventory, yet these vessels emit a significant amount of emissions when in transit and when berthed in our ports. GHG emissions from this segment of international marine transport are approximately 70 million Mt of CO_2e per year—greater than BC's total annual GHG emissions. These emissions should be considered as part of the province's global GHG reduction strategy by displacing high-carbon marine fuels with low-carbon LNG.

GHG emissions from international marine shipping currently represent around 2.6 per cent of total global emissions, but this share could more than triple by 2050 if measures are not taken to help speed a transition to a low-carbon environment in this sector. Following the Paris Climate Agreement, discussions began at the IMO to agree to an Initial Greenhouse Gas Strategy to stipulate significant measures to mitigate emissions. In April 2018, the IMO agreed on its first strategy to reduce GHG emissions in the international shipping sector to meet the Paris Agreement goals. The IMO strategy includes a target to reduce carbon emissions by at least 50 per cent compared with 2008 levels by 2050. This strategy presents a challenge for a sector that has traditionally faced significant barriers to innovation and an opportunity for BC to position itself as a low-carbon fuel provider in the form of LNG.

Low-carbon fuels such as LNG will be critical to achieving the IMO emission reduction targets. BC is well-positioned to assist in these efforts and become a world leader in LNG bunkering. The provincial government should consider developing policies to start addressing these emissions such as including the ability to generate compliance credits with the Renewable and Low Carbon Fuel Requirement Regulation if international marine vessels use lower carbon fuels such as LNG.

FortisBC was the first company in the world to offer onboard truck-to-ship LNG bunkering. This proprietary design was developed by collaborating with Seaspan Ferries, BC Ferries and their shipbuilders to create a customized solution to fit our customers' needs.

FortisBC has the infrastructure in place to be ready for 2020. FortisBC has completed construction of a $400-million LNG expansion project at our Tilbury facility which includes a new storage tank and additional liquefaction capacity. Plans are being developed to increase the Tilbury LNG facility's liquefaction capacity up to to three million tonnes per annum, expand LNG storage by another 92,000 cubic metres and provide ship loading facilities to serve these markets. Our Tilbury LNG facility is powered by electricity, creating safe, clean, low-GHG emitting LNG.

Expanding our natural gas liquefaction capacity by

92,000

cubic metres

Locally, other agencies such as the Port of Tacoma are also working to position themselves for success. Puget Sound Energy (PSE) is developing an LNG production facility that will enable LNG supply for marine and transportation markets in the region. This LNG facility will incorporate LNG liquefaction, storage and bunkering to the marine market. The project is scheduled to be completed in late 2019 and would compete with BC. FortisBC believes there is a limited window of time for BC to establish itself as an LNG bunkering hub before 2020. BC has an advantage as we have an ample supply of clean LNG available at globally competitive rates.

FortisBC recommends the following actions:

- Continue supporting the Clean Transportation in BC Trade Corridors initiative. Specifically, the opportunity to introduce a pilot program to convert drayage vehicles from diesel to compressed natural gas (CNG) and the advancement of the LNG bunkering in advance of 2020. The provincial and federal governments need to advance the regulation, financial tools for bunkering infrastructure and policies to establish BC as a global leader in LNG bunkering.
- Amend British Columbia's Renewable Low Carbon Fuel Reduction Regulation to generate credits for LNG bunkering that lower international shipping emissions.
- Work with the federal government to develop policies that account for the role of BC LNG in meeting global GHG reduction targets via Article Six of the Paris Agreement.

Cleaner fuels

FortisBC supports the provincial government's proposal to support the transition to cleaner fuels. We see RNG as being an essential component of this transition.

FortisBC was the first utility in North America to offer RNG to residential customers in 2011. RNG is a critical source of renewable energy that is helping the province achieve its GHG emission reduction target. Farms, landfills and other suppliers like the City of Surrey have teamed up with FortisBC to capture methane (CH4) from organic waste, which would otherwise escape into the atmosphere. This methane, also known as biogas, is purified to make RNG.

FortisBC's RNG program is enabled by a British Columbia Ministerial Regulation, the Greenhouse Gas Reduction Regulation (GGRR). The GGRR has facilitated the development of five operational projects which are forecasted to supply over 203,000 GJ of RNG this year. These facilities capture biogas, clean and upgrade the biogas into RNG, and inject the RNG into our distribution system. Since the RNG offering launched to residential customers in June 2011 and commercial customers in March 2012, over 9,000 customers have subscribed to this offering and have helped reduce GHG emissions an equivalent amount to removing 7,200 cars from the road.

Turning waste into fuel

Earlier this year, we joined the City of Surrey and the Government of Canada to open North America's first closed-loop waste management system. The facility will convert curbside organic waste into renewable biofuel to fuel the City's fleet of natural gas powered waste collection and service vehicles. Under this closed-loop system, waste collection trucks will literally be collecting their fuel source at curbside. Excess fuel will go to the new district energy system that heats and cools Surrey's City Centre.

Though FortisBC has achieved important early successes in the residential and commercial sectors, further work is required to grow BC's supply of RNG for use in the transportation sector. Innovations in biogas could boost our supply of RNG to between 25 and 46 per cent of FortisBC's annual natural gas demand by 2036. Power-to-gas, the process of converting electric power into carbon-neutral hydrogen, presents a further opportunity and could account for between five and 15 per cent of annual demand by 2036.

We believe that hydrogen will be a key driver towards reducing BC's carbon emissions, not only as an alternative fuel to enable the decarbonisation of heating, but as a means of storing renewable power (hydroelectric, solar and wind) and, through this, linking together the decarbonisation of the building, industry and transport sectors. We believe in taking a system-wide perspective of hydrogen as a technology that further integrates the electric and gas systems by acting as a high capacity storage medium for carbon-free power generation and a carbon-free fuel for heat and transport.

The potential of a low-carbon gas system

In our 2017 Long-Term Gas Resource Plan, FortisBC outlined a preliminary analysis of initiatives that could achieve significant GHG emissions reductions by 2030. Emissions reductions opportunities for FortisBC fall into three categories: i) decarbonizing pipeline gas with RNG, hydrogen and carbon capture and storage; ii) energy efficiency and demand-side management (DSM); and iii) fuel switching from more carbon-intensive energy to pipeline gas and LNG.

Should low-carbon gases like RNG and hydrogen achieve a notable share of the total supply in the gas distribution system, FortisBC estimates that the technical potential to reduce GHG emissions would be up to 2.7 and 5.0 Mt. This would reduce emissions from natural gas consumption by between 25 per cent and 42 per cent from 2007 levels in the industrial, commercial and residential sectors.

In the transport sector, FortisBC could achieve 0.3 Mt of domestic reductions and 10.7 Mt from international shipping by 2030. This highlights the significant potential for the gas system to be a key contributor to the province's climate objectives. Ambitious provincial incentives and other policy support would be required to expand the supply of low-carbon gas to this scale. But, maintaining a role for gas within a low-carbon transition ensures that customers maintain their choice of energy supply and lowers the technology risk and costs of a narrowly defined abatement pathway. Such a pathway would also ensure that provincial energy resources and infrastructure are leveraged for a made-in-BC solution.

Growing BC's low-carbon fuel sector will require a number of actions from the province:

- identify RNG as an essential component of the province's clean growth pathway
- address regulatory barriers to expanding utility investment in RNG projects
- streamline regulations to enable RNG production from agricultural waste
- provide support to advance the commercial production of hydrogen as a form of RNG

Domestic carbon reductions from international shipping of

10.7

metric tonnes

What is Renewable Natural Gas?

Renewable Natural Gas (RNG) is a carbon-neutral energy source, because it does not contribute any net carbon dioxide into the atmosphere. RNG is produced in a different manner than conventional natural gas. It is derived from biogas, which is produced from decomposing organic waste from landfills, agricultural waste and wastewater from treatment facilities. The biogas is captured and cleaned to create carbon-neutral RNG.

Peter Schouten, Owner Operator, Fraser Valley Biogas. One of FortisBC's first RNG suppliers.

Cleaner vehicles

Displace higher carbon fuels by expanding BC's natural gas vehicle sector

Commercial transportation accounts for 25 per cent of total GHG emissions in BC and more than half of these emissions originate from road freight transport. By increasing our efforts to displace higher carbon fuels in the heavy-duty vehicle and marine transport sectors, BC can achieve substantial emissions reductions.

By converting heavy-duty truck fleets and transit vehicles to LNG or CNG, we're helping the province meet its carbon emission reduction goals while helping operators save on fuel costs.

FortisBC natural gas for transportation customers are realizing anywhere from 25 to 60 per cent reduction in fuel costs. This helps improve the competitiveness of our private and public sector partners. Since initiating our efforts to introduce cleaner vehicles in 2010, we have eliminated more than 110,000 tonnes of CO_2e and displaced more than 145 million litres of diesel.

Natural gas can reduce GHG emissions by up to 30 per cent compared to diesel and gasoline. Additionally, switching to natural gas fuel can improve air quality: natural gas vehicles emit virtually no particulate matter, and they emit up to 95 per cent less nitrogen oxides (NOx).

FortisBC recommends the following actions:

- continue supporting investment in CNG transit vehicles and fuelling infrastructure to displace higher carbon fuels and reduce particulate emissions
- expand the GGRR and develop a BC Ports incentive program to convert the 1,700 trucks in BC's drayage sector to CNG or CNG/Hybrid trucks, covering the full cost of the vehicle and reducing both the particulate and GHG emissions associated with BC's ports
- expand eligibility for BC's CEV Specialty-Use Vehicle Program to include hybrid vehicles that include an alternative fuel, such as CNG or hydrogen
- undertake a review of Ministry of Transportation policy to permit low emission natural gas and hydrogen vehicles to use designated HOV lanes on key trade corridors such as Highway 99 and Highway 1

UPS' commitment to CNG

Earlier this year, we partnered with the world's largest package delivery company to launch a compressed natural gas fuelling station and vehicles in Vancouver, BC. Seven CNG highway tractors and 40 delivery trucks were added to the current Canadian UPS fleet of over 2,900 package cars, tractors and shifters. Presently, more than 40 per cent of the UPS fleet in Canada runs on alternative fuels. UPS Canada now joins over 800 transit buses, commercial vehicles and freight vehicles powered by natural gas here in BC.

Transform the light-duty transportation sector through electrification

The light-duty transportation sector accounts for 14 per cent of BC's total GHG emissions. This includes light-duty passenger vehicles and trucks that use gasoline or diesel. Electrification of this segment provides a promising pathway to reduce emissions, as cost and performance of the underlying battery technology has seen dramatic improvements in recent years. The automotive industry is responding with many new electric vehicle models arriving in the showrooms of almost every manufacturer.

Light-duty transportation accounts for

14%

of BC's total GHG emissions

Growth in the electric vehicle segment is happening in BC but further incentives will be required to achieve government's goal of 5 per cent of all new light-duty vehicle sales. EV sales in 2017 increased by 53 per cent compared to 2016 and were accelerated by an expanding lineup of fully electric vehicles. However, while there has been an increase in the sale of EVs since 2013, at approximately 1.7 per cent of total vehicle sales in 2017 for BC, EV sales are still a small portion of the overall market. FortisBC supports the province's proposal to continue providing vehicle incentives.

Additional EV charging infrastructure will be critical to advancing the adoption of EVs in the province. Without adequate charging infrastructure deployed throughout the province to allow zero emission vehicles to travel throughout BC safely and conveniently, it is unlikely that the EV market share will progress quickly. Further collaboration between the province, local governments and FortisBC and BC Hydro can address this gap.

We recommend that the province take the following actions:

- continue providing incentives for EV vehicles and infrastructure
- support increased utility investment in EV charging infrastructure in BC
- leverage existing FortisBC CNG fuelling infrastructure to include fast-charging EV stations
- develop measures to encourage charging station installations at businesses and other buildings as part of a smart grid

accelerate Kootenays

FortisBC is a core funder of the *accelerate* Kootenays initiative, a collaborative project that will address the charging infrastructure gap across the Kootenay region in Southeast British Columbia. Earlier this year, we opened five electric vehicle Direct Current Fast Charging (DCFCs) stations in the region, connecting the West Kootenays to surrounding regions for electric vehicle travel.

All West Kootenay stations were installed by Kootenay-based electricians, creating local employment opportunities for residents.

All are part of the broader *accelerate* Kootenays initiative which will ultimately facilitate the installation of 13 fast chargers and 40 Level two chargers in communities across the Kootenays, resulting in over 1,800 kms of connected electric vehicle travel. The fast-charging stations are critical infrastructure to allow electric vehicle drivers to travel to and through the region, and to facilitate increased adoption of electric vehicles locally.

Buildings & communities

FortisBC is uniquely positioned to be a key agent of the government's strategy to reduce GHG emissions in buildings and communities in a cost-effective, market-driven manner. We provide energy in the built environment through gas, electricity and as an alternative energy provider.

In 2017, we opened the door to our new LEED-equivalent Kootenay Operations Centre outside of Castlegar, BC.

The marketplace recognizes the affordable, high-quality, reliable and safe energy services delivered by FortisBC. Over three million British Columbians use natural gas every day with over 58 per cent of households using natural gas as their primary heating source. The preference for gas is reflected by our continued customer growth. In fact, 2017 was FortisBC's best-performing year for customer growth, with many new customers converting their home heating system from high carbon fuels such as heating oil. This emphasizes the foundational role of gas infrastructure in BC's energy system. To achieve the provincial government's GHG reduction objectives, consumer preference for gas as a low-carbon and affordable energy source should be recognized and harnessed.

Even though customer additions to FortisBC's gas system were at record-levels in 2017, the amount of gas used on a per customer basis declined by 1.8 per cent in 2017 on a weather normalized basis. This speaks to the success of energy-efficiency measures in the province including FortisBC's energy conservation programs, federal and provincial policies and the gradual but concerted shift in the built environment to more energy-efficient dwellings.

The unique aspect of the gas system is that it is specifically designed to address heating demand. Seasonal changes in heat demand (referred to as "peak load" or "peak demand") can be up to 400 to 500 per cent greater than FortisBC's average demand. For comparison, peak load in the FortisBC electric system is approximately 40 per cent higher than average load. If BC used electricity as the primary source for heat, the seasonal variability of heating load would create a huge need for energy storage. Hydropower could meet the storage requirement were it not for the magnitude of heat load in BC. The approximate peak-hour heating load in 2017 in FortisBC's gas system was over 12 GW of electrical capacity equivalent (at a one-to-one unit energy conversion basis). In other words, electrifying heating could require almost a doubling of the existing hydroelectric capacity in BC even before considering the electrification of some part of the transportation fleet or other energy end uses and the additional transmission and distribution requirements. Recognizing this, decarbonizing the gas flowing through the system while maintaining the use of that system is a prudent and low-cost strategy to ensure that BC achieves its climate targets.

Stronger codes and standards over time

We support stronger codes and standards that result in increased energy efficiency. We support an approach that is aligned with the current BC Building Code and BC Energy Step Code (BC ESC) targets. The BC ESC provides an incremental and consistent approach to achieving more energy-efficient buildings in a cost-effective manner while also reducing GHG emissions.

Codes and standards should stay consistent to achieve energy-efficiency gains

The BC ESC was developed after an extensive, multi-year engagement process. As a member of the Energy Step Code Council, FortisBC provided insights into the development of the BC ESC, particularly with respect to ensuring affordability needs for British Columbians are addressed, while supporting continuing innovation in the use of energy in buildings.

In addition to supporting long-term improvements in energy efficiency in the BC Building Code, the BC ESC ensures the consistency of building regulations in the province; a key to ensuring clear regulation for builders and developers looking to build in multiple municipalities. The BC ESC provides a provincial framework that replaces the patchwork of different green building standards that have been required or encouraged by local governments in the past. This allows local governments to play a leadership role in improving energy efficiency, while providing a single standard for industry, and build capacity over time.

The BC ESC focuses first on building envelope design with a goal of taking incremental steps to make buildings net-zero energy ready by 2032. It provides for a fuel neutral approach and focuses on the efficiency of buildings and equipment. By focusing on building and equipment efficiency, both overall energy usage and GHG emissions are reduced while building comfort is increased. While costs increase at higher levels of the code, energy usage decreases help offset the increase in overall costs to consumers. The BC ESC also provides flexibility to meet the changing needs and abilities of local governments, industry and technologies. It does this by providing local governments with the tools to pursue a long-term vision for the future of energy efficiency of buildings and related climate action initiatives. As a new code structure, the BC ESC, similar to other changes in the BC Building Code, requires time to learn, implement and see results. It is common practice to make changes to the code only every five to seven years to allow the industry and consumers to become familiar with the change.

Adding additional regulations into the BC ESC, such as the proposed GHG intensity (GHGi) requirement, before results of the adoption of the existing BC ESC are understood and realized would be premature and could lead to unintended consequences: higher energy costs, impaired housing affordability and a loss of choice for consumers. The provincial approach should support consumer choice, by allowing designers and builders to continue to choose gas, electricity, or other energy sources for their project. A fuel-neutral approach provides builders with the flexibility to make energy-efficient buildings using all the available technologies along with managing their costs. It also empowers builders and developers to pursue innovative, creative, cost-effective solutions, and allows them to incorporate leading-edge technologies as they come available. We believe that committing to the current

BC ESC is a prudent measure accounting for the scale of change that the new code presents to the market and the importance of aligning the code across the province.

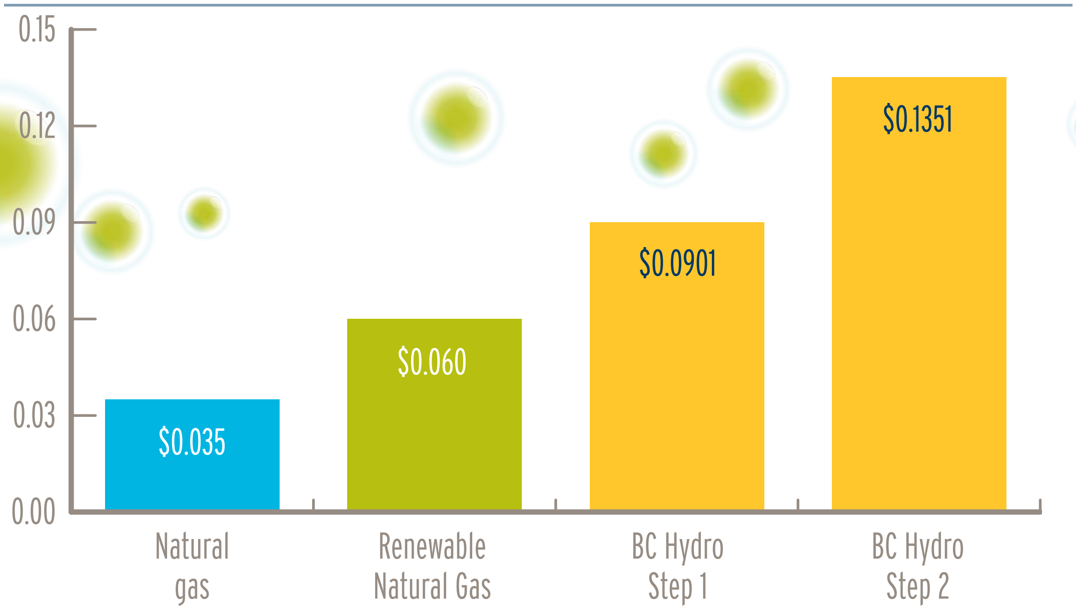
FortisBC has been, and continues to be, a strong advocate for the use of the BC ESC. For example, FortisBC and the City of Vancouver signed a Memorandum of Understanding (MoU) which ensured that the City would introduce pathways that used the BC ESC for builders to comply with the City's Zero Emissions Building Plan. Under these compliance pathways, builders can choose to follow the BC ESC without additional requirements such as a GHGi target. FortisBC also committed to developing a DSM program based on the BC ESC in the MoU. By having new pathways aligned with the BC ESC, FortisBC could provide DSM incentives to lower the costs of achieving the BC ESC to builders in Vancouver while still achieving meaningful improvements in the energy efficiency and GHG reductions of new buildings. Were the province to allow a patchwork of BC ESC along with municipally-specific GHGi requirements, FortisBC would not be able to provide DSM incentives to moderate the affordability pressures of new ambitious codes that restrict access to the gas system.

BC should seek alignment with national codes and standards to ensure consistency with other jurisdictions as it considers a new code for retrofits. The federal code for alterations to existing buildings should serve as a template for BC, as suggested. Because of the scale of the retrofit challenge, clear goals and objectives need to be identified to ensure that all players in this sector have a role. FortisBC is exploring innovative partnerships to demonstrate building energy retrofits and we believe that large GHG reductions consistent with the province's long-term GHG objectives are possible while still maintaining connection to the gas system.

Finally, we recommend that any further changes to the BC Energy Efficiency Standards Regulation should be aligned with federal standards to ensure consistency for equipment manufacturers. We agree with the Canadian Homebuilders Association that it is likely that manufacturers will focus efforts on areas with the greatest market share, national and international, and BC's initiatives may not be as lucrative to encourage the necessary research and development in comparison to federal approaches.

Maintaining affordability for BC energy consumers

Residential gas $/kWh price comparison



Affordability is the key concern among BC residents and FortisBC customers while producing energy locally is the top policy priority for government to consider. As we transition to a low-carbon economy, care must also be taken to ensure that we pursue cost-effective strategies that will not result in higher costs for energy consumers.

Consumer priorities on energy issues

In August 2018, FortisBC commissioned Innovative Research Group to conduct a survey on consumer priorities on energy issues. The survey found that:

- **For 42 per cent of respondents affordability is the top priority in their personal energy choices**, followed by the environment (24 per cent) and reliability (22 per cent).
- When it comes to government policy, the top priority is **helping the economy by producing energy locally (28 per cent)**, followed by affordability (27 per cent), with environment third (21 per cent).

The survey was conducted between August 3 and 14, 2018 among a sample of 1,328 randomly-selected British Columbians. The survey used a mixed-method online and phone methodology. Interviews in English (n=1,024) were conducted using a representative online panel and in-language interviews in Cantonese, Mandarin, and Punjabi (n=304) were conducted over the phone. Results were weighted to a sample size of n=1,200 based on age, gender, region of the province and mother tongue.

We also believe that regional differences in BC should be taken into account. For example, policies that restrict choice will disproportionately impact energy consumers outside of the Lower Mainland and Southern Vancouver Island that reside in BC's colder regions. Similarly, regions that rely on BC's natural gas industry to drive the provincial economy, should also be taken into account.

FortisBC's RNG, while more expensive than natural gas, is still approximately half the price of electricity in BC and with a lower carbon intensity. This demonstrates the potential for the gas system to achieve significant, affordable GHG reductions with low-carbon drop-in fuels such as RNG and hydrogen. To achieve this potential, supportive policies that provide incentives and opportunities to invest in low-carbon gas supply will be needed over the long-term. These investments will only happen as long as the gas system remains a viable productive asset and consumers have the choice to continue to connect to and use gas.

It is for all these reasons that we believe an approach that targets increased energy efficiency and allows for consumer choice and innovation is consistent with the broader government objectives: making life more affordable and growing the BC economy while taking action on climate change.

Incentives tied to energy efficiency and building improvements

We support increasing energy-efficiency incentives. FortisBC is seeking to significantly expand energy-efficiency investments in our DSM portfolio. Our proposal currently before the British Columbia Utilities Commission (BCUC) includes more than doubling energy efficiency spending from 2016 levels by 2019 and with further increases over the next four years. By 2022, we are committed to investing more than $96 million annually, approximately tripling our 2016 spending.

Committed to investing more than
$96 million
annually by 2022

FortisBC estimates that this increased funding would effectively double annual natural gas energy savings and GHG emissions reductions, with the majority of savings occurring in the built environment. Annual energy savings would be in the order of one million GJ of gas which will in turn lead to reductions in GHG emissions of approximately 50 thousand tonnes of CO_2e per year.

We are also seeking approval to expand our electricity DSM portfolio. In our 2019 to 2022 DSM Plan, which is currently before the BCUC for review, we are seeking a 21 per cent spending increase over what we put forward in our long-term DSM Plan. We expect to achieve 17 per cent more energy savings than set out in the long-term plan, or 130 GWh over the plan period.

Through assisting customers in moving to higher-efficiency equipment, supporting the BC ESC and advancing energy conservation in BC overall, our expanded energy efficiency programs will positively impact the province and support the achievement of BC's GHG emissions reduction goals. These measures will also support the BC government's commitment to improving affordability: individual customers will reduce their energy consumption and their energy bills.

FortisBC is supportive of the proposal to develop an incentive program to complement existing utility-led energy-efficiency programs focused on retrofits. We believe that if utility and provincial actions are well-designed, they could leverage each other and strengthen participation. We advocate for the provincial government to continue to work closely with utilities in designing this program.

Advanced Metering Infrastructure (AMI) is a valuable tool in helping our customers across BC improve energy efficiency and reduce GHG emissions in residential and commercial buildings. This technology is providing FortisBC's electric customers with more control over how they use energy. To date, we have installed over 134,000 AMI meters in our electric service territory and we seek to extend these benefits to our natural gas system. This technology is the foundation of a more modern natural gas system that improves the customer experience by empowering them to access data to make informed decisions about their energy use. With advanced meters, our natural gas customers will have the information they need to inspire mindful choices like using digital control to better manage use of heating appliances or making energy-efficiency upgrades to their homes. This technology could also help facilitate more investment in behind the meter solutions by identifying buildings well suited to energy-efficiency upgrades and integrating those solutions to the broader system to maximize energy-efficiency gains. We recommend that the provincial government provide support for wider deployment of AMI across BC's natural gas network.

Support for low-carbon innovation

FortisBC is well-positioned to identify innovation investments to reduce the carbon footprint of BC's energy system. FortisBC is interested in investing in core research focused on opportunities relevant to BC. This could include ultra high-efficiency gas-fired heat pumps, hydrogen production technologies, measures to reduce the carbon intensity of natural gas such as carbon capture and storage, and near zero GHG engines in vehicles. Without innovation funding from FortisBC or other agencies focused specifically on addressing GHG emissions within BC's unique energy system and fully integrated gas supply, transitioning the gas system to align with the provincial climate targets will be even more challenging.

We recommend that the province consider mechanisms for utility-led innovation investment aimed at reducing GHGs or directing a portion of Innovative Clean Energy (ICE) funding to utility-led projects.

FortisBC also seeks to expand BC's supply of clean energy. Wood and forest residues could significantly expand the amount of RNG supply in BC but, to unlock this potential, focused support for innovation from the public and private sectors will be needed. Of the total supply potential for RNG, wood has the largest share representing approximately 50 per cent of natural gas consumption in Canada. There are a number of other co-benefits of harnessing the potential of wood feedstocks for RNG. These include reducing GHG emissions in BC's forestry-based industries while providing them with new, meaningful financial benefits. This could increase the competitiveness and international market share of Canadian forest industries and boost employment in the sector. However, there are still important technological gaps and high costs associated with wood-based RNG production meaning that, to-date, there has been limited RNG production from wood. The provincial government should identify RNG from wood feedstocks as a key priority for its innovation and climate objectives and work with the forestry sector, FortisBC and the research community to realize this opportunity.

We are supportive of new policies that will support utility investment to broaden our supply of clean energy to include new forms of alternative energy. For example, FortisBC Alternative Energy Services (FAES) is a leader in providing cost-effective, high-performance thermal energy solutions (TES) in BC's building sector. For example, our Marine Gateway and Telus Gardens energy systems in Vancouver, both use renewable and recycled energy to improve efficiency and emissions by 50-80 per cent compared to conventional systems. To date, FAES has invested more than $62 million in high-efficiency energy systems which we own and operate on behalf of our customers.

To date, FAES has invested more than

$62 million

in high-efficiency energy systems

In order to accelerate FAES' contribution to providing highly efficient and low-carbon energy systems, we propose that government support a move to facilitate adoption of a regulated pooled cost model for TES providers. This recommendation would ultimately lead to faster market adoption of TES solutions.

Another example of low-carbon, FortisBC-led innovation is the proposed Ellison Community Solar Pilot project that could be the largest utility-owned solar project in BC. Interest in solar is on the rise and we seek to provide an easy, affordable option for our customers who want to use solar energy to meet a portion of their electricity needs. Our aim is to develop a solar program for customers who are interested in solar, but the upfront cost, placement, operation or maintenance of a rooftop system is not desirable. The province should create opportunity for future utility investment in clean energy projects where there is consumer demand for these offerings.

Energy-efficiency labelling information

FortisBC supports the province's goal to improve information for building owners and residents on the energy performance of buildings. As the province develops this program, total energy consumed, carbon footprint and overall cost should all be included in the energy labeling information. FortisBC looks forward to working with the province to further develop this proposal.

A clean growth program for industry

Industry is an important part of the Provincial economy and our customer base. Of FortisBC's million customers, less than a thousand are industrial clients, yet these firms consume approximately one-third of FortisBC's total gas demand. To these customers, gas is a low-cost, efficient, reliable and high-quality fuel source. FortisBC is proud to be the energy supplier of choice to the industries that propel BC's economy.

FortisBC agrees with the provincial government that reducing GHG emissions must happen alongside a strengthening economy. Reducing GHG emissions through investment, technology and sustainable growth must be fostered in a framework to ensure BC's businesses and industries are not put at a competitive disadvantage. The intention to develop an effective Clean Growth Program for Industry is an important objective of the provincial government. To this end, we believe that an incentive-based approach for industry is an important development.

We also believe that BC needs to be in alignment with the rest of Canada. The federal government's output-based system in the Carbon Pricing Backstop provides more relief to industry while still maintaining the same marginal incentive to reduce GHG emissions. BC should commit to reviewing and evaluating outcomes from the two systems. If the federal approach demonstrates better outcomes for emissions and the economy, then BC should adopt this system to create a level playing field for industries across Canada.

Industrial incentive

We believe that setting the performance benchmark at the level of the cleanest facilities in the world is an ambitious but achievable starting point as many industries in BC are already world-leading environmental performers. Because the Clean Growth Program for Industry aims to improve the international competitiveness of BC's industries, we support the benchmark level as the best performing international firm or facility.

Industries within BC or Canada should not be used to set the benchmark. This would force domestic firms to compete against each other and incur costs with no impact on their international competitiveness. As provincial carbon policy costs begin to align under the Pan-Canadian Framework, the incentive for domestic firms to reduce their carbon emissions is evened. In fact, BC's approach to tax all of a firm's carbon emissions up to $30 per tonne applies significantly more carbon costs than the approach used in the federal output-based allocation system which applies the carbon price only on emissions above the benchmark. This means that even with an aligned price on carbon, BC firms would be disadvantaged compared to other provinces.

A Canadian first

Climate change is a global issue, and FortisBC is committed to being part of the solution. One of the ways we're doing this is by exporting liquefied natural gas (LNG) to countries like China that are looking to significantly reduce their greenhouse gas emissions.

Late last year, FortisBC notched a milestone by delivering the first shipment of LNG from Canada to China. Since then, our shipments have continued, with the most recent one arriving in Shanghai in May.

As China's LNG imports continue to increase, analysts predict it could one day eclipse Japan as the world's biggest importer of natural gas. This presents a unique opportunity for FortisBC, which has the only two LNG storage facilities on Canada's West Coast.

FortisBC's LNG facility in Delta, BC has been operating since 1971 and in order to meet the growing demand for LNG it recently underwent a $400-million expansion.

This market shift is about more than just an economic opportunity for Canada. Underlying this trend is the fact that natural gas is a strong energy option for countries like China that are looking to transition from high-carbon fuels to cleaner and more affordable alternatives.

FortisBC offers an abundant supply of LNG that meets high environmental standards. In fact, when FortisBC's Tilbury LNG plant expansion is operational later this year it will be one of the cleanest LNG facilities in the world.

The additional GHG reduction that would be achieved by using domestic firms for the performance benchmark is marginal while simultaneously not improving the competitive position of BC firms in the international market. Because BC's firms compete for market share against international firms, ensuring that carbon costs are moderated compared to the next best international performer should be the key objective. We believe this makes both economic and environmental sense. Incentivizing firms to achieve the lowest carbon intensity than the next best global performer ensures that carbon leakage is minimized while firms in BC are allowed to grow.

The provincial government should use a consistent approach when setting the benchmark across all industries. This means that determining the benchmark for incumbent industries such as mining and pulp and paper should be the same as for nascent industries such as LNG exports. A consistent approach ensures industries of the future can compete for global markets just as today's industries can. FortisBC also supports the principle of consistency regarding the threshold to enter the program at 10,000 tonnes of annual GHG emissions. This will ensure that all large industries can access carbon tax incentives. The government should monitor this threshold and consider opportunities for smaller firms to opt-in to the program.

A threshold of
10,000 tonnes
will ensure all large industries can access carbon tax incentives

The threshold and the benchmark should also account for all emissions whether from combustion, process or fugitive. Firms that demonstrate real investments in technologies and practices that reduce process and fugitive emissions should be able to report those savings toward their emission intensity.

Clean Industry Fund

FortisBC supports the creation of the Clean Industry Fund as a way to invest carbon revenues into direct emissions reductions and innovation in low-carbon technologies. The fund should only be available to firms that are participants in the Clean Growth Program. The fund should be additional to existing government funds for innovation and technology and focused on industrial improvements. The scope for funding should be broad and include direct facility-level improvements, research and development, pilots and demonstrations and projects across the energy supply chain that will lower the carbon intensity of fuels. FortisBC anticipates that it would be a recipient of funds to develop leading technologies in, for example, efficiency, RNG and hydrogen that would improve the carbon intensity of industrial clients.

Investments from the fund should allow projects that achieve both short and long-term GHG reductions and be fuel neutral. A common and agreed framework to evaluate proposals that emphasized cost-effective short term reductions or long-term projects with high reduction potential should be negotiated with Clean Growth Program participants.

FortisBC believes that the government should target industry specific reductions along with system-wide initiatives that could reduce the carbon intensity of all industries. A priority list of actions could be developed in consultation with industry to earmark fund dollars for high-payoff strategies. We believe that one such strategy is to support clean gaseous fuels such as RNG and hydrogen. A specified and focused tranche of support from the fund could have an outsized role to improve the carbon intensity of all industries in BC.

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Appendix A-2

PATHWAYS FOR BRITISH COLUMBIA TO ACHIEVE ITS GHG REDUCTION GOALS

PATHWAYS FOR BRITISH COLUMBIA TO ACHIEVE ITS GHG REDUCTION GOALS

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August 2020

NAVIGANT
A Guidehouse Company

PREPARED FOR
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Energy at work

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FOREWORD

In 2018, FortisBC Energy Inc. (FortisBC) developed its Clean Growth Pathway to 2050, which outlined actions the company would take to help British Columbia (BC) achieve its greenhouse gas (GHG) emissions targets. The Clean Growth Pathway takes a diversified approach to GHG reduction by using BC's electricity and gas infrastructure. As owners and operators of reliable gas, electric, and thermal energy infrastructure, FortisBC will have a key role in leading the transition to lower carbon energy. As a regulated utility, FortisBC is accountable to the BC Utilities Commission and obligated to serve the interests of over 1 million homes and businesses across BC.

The provincial government's CleanBC plan aims to significantly reduce provincial GHG emissions and strengthen BC's economy. FortisBC delivers more energy to consumers than any other entity in the province and will be critical to ensuring BC can efficiently, reliably, and affordably achieve its plan. To help do so, FortisBC commissioned Guidehouse to chart a viable path for BC to achieve its 2050 targets while identifying solutions that are in the best interest of its customers.

FortisBC and Guidehouse worked with the BC Ministry of Energy, Mines and Petroleum Resources and the Climate Action Secretariat to ensure that CleanBC, provincial data, and projects are included in the analysis as much possible.

The goal of this report is to generate dialogue and solutions-focused thinking on how BC can achieve the transition to a lower carbon energy system while building understanding on factors such as maintaining a flexible, reliable, and resilient provincewide energy system. The report's analysis presents two pathways to achieving GHG emission reductions; neither reflect what is an expected future outcome by either Guidehouse or FortisBC. FortisBC welcomes an ongoing discussion on the merits and key challenges of the various pathways available. FortisBC has a long-standing role in serving British Columbians and, by engaging with the communities it serves, the company aims to continue providing low carbon, affordable, and reliable energy in the decades to come.

Guidehouse is a leading global provider of consulting services to the public and commercial markets with broad capabilities in management, technology, and risk consulting. We help clients address their toughest challenges with a focus on markets and clients facing transformational change, technology-driven innovation, and significant regulatory pressure. Across a range of advisory, consulting, outsourcing, and technology/analytics services, our teams help clients create scalable, innovative solutions that prepare them for future growth and success. Headquartered in Washington, DC, the company has more than 7,000 professionals in more than 50 locations. Guidehouse recently completed the Gas Decarbonisation Pathway 2020-2050 study for the Gas for Climate consortium; the study analyzes the transition toward the lowest cost climate-neutral system in Europe by 2050.

1. EXECUTIVE SUMMARY

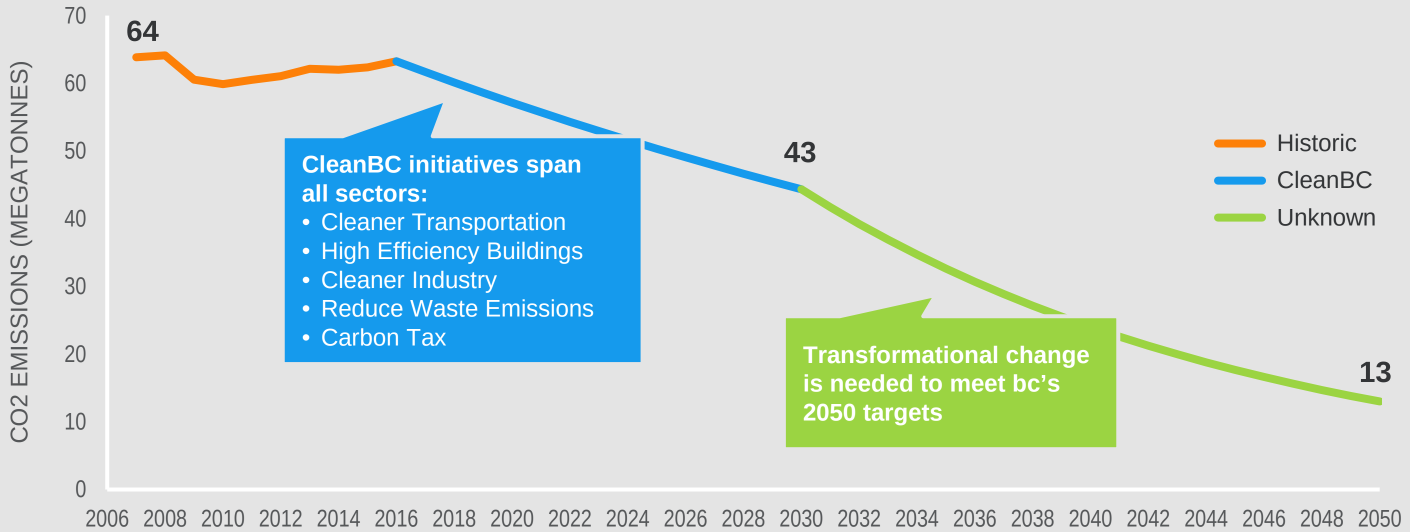
As part of its Climate Change Accountability Act, British Columbia (BC) has committed to reducing greenhouse gas (GHG) emissions to 80% below 2007 levels by 2050. The CleanBC plan puts the province on a path toward this goal, but only sets in action initiatives designed to meet a 2030 target (30% reduction below 2007 levels).[1] The pathway to meeting the 2050 goal is definable but a challenge. (Figure 1).

FortisBC commissioned Guidehouse to explore the role of the company's energy delivery system and the advantages that system could provide under ambitious decarbonization in the province. Over the past several years, Guidehouse has conducted detailed analyses of the role of utilities in decarbonization in Europe and North America.

Guidehouse experts have consistently found that a moderate, targeted approach to electrification tied with deployment of renewable gases while fuel switching away from petroleum is the most cost-effective and resilient method to achieve a lower carbon energy future.

To estimate the gas system's societal value, Guidehouse developed two energy pathways: an Electrification Pathway that focuses on deep electrification of all sectors, and a Diversified Pathway that includes a mix of expanded electrification and advances in low carbon gases and gas delivery infrastructure. The Diversified Pathway reflects the climate initiatives included in FortisBC's Clean Growth Pathway to 2050.

FIGURE 1. BC GHG EMISSIONS AND TARGETS



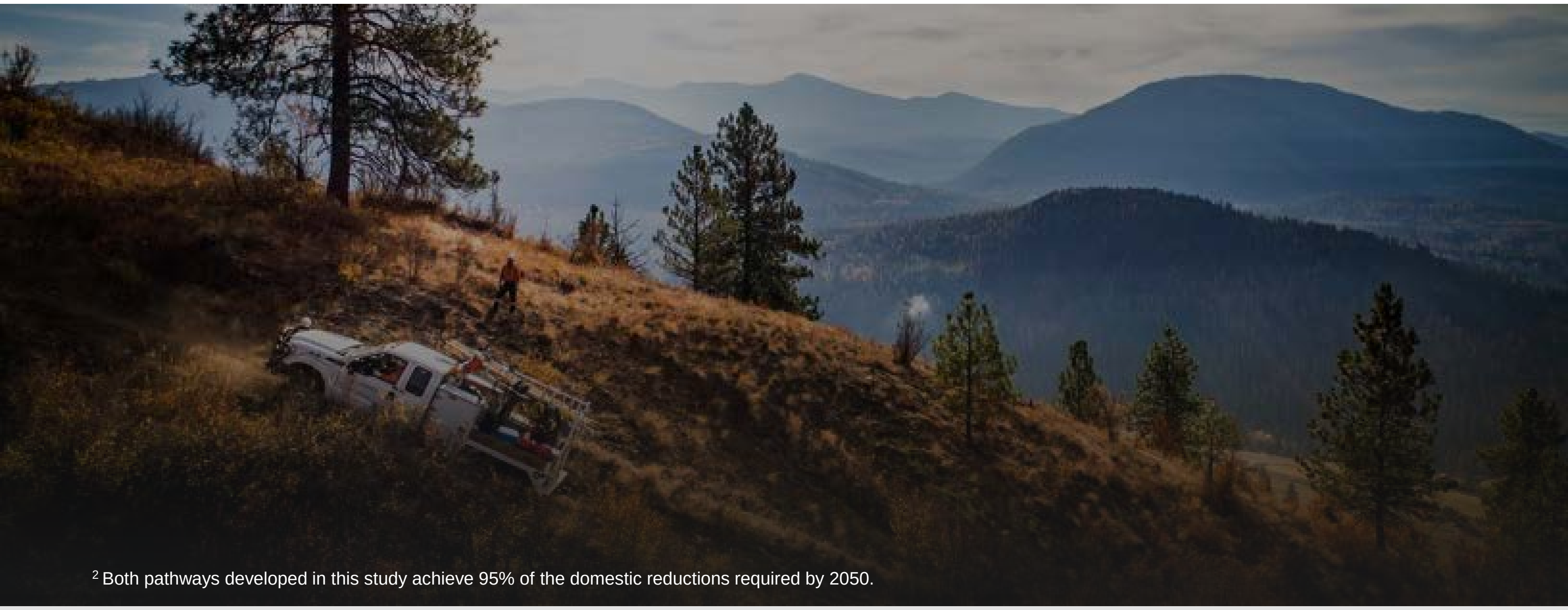
Source: Government of Canada – Canada's Greenhouse Gas Inventory; Government of British Columbia – CleanBC; Guidehouse Analysis

[1] The 30% reduction represents an adjustment of the interim 40% reduction by 2030 target, originally set in the Climate Change Accountability Act. The adjustment aligns with the provincial government's CleanBC plan, while the 80% reduction by 2050 target set in the Climate Change Accountability Act still stands.

The study's core conclusions are as follows:

- The Electrification and Diversified Pathways both achieve significant domestic GHG reductions in-line with the provincial government's 2050 targets.[2]
- The Diversified Pathway uses gas infrastructure and saves in excess of $100 billion by 2050.
- Both scenarios face challenges, including massive energy infrastructure deployment, and require significant technological improvement.
- Peak demand is an important factor that needs to be considered.
  - The Diversified Pathway will more efficiently meet customers' peak energy use.
- Peak demand in the Electrification Pathway would require thousands of megawatts of firm renewable electricity generation and energy storage to be built, which is made more difficult by the challenges of developing new large-scale hydroelectric power stations.

- Policy decisions made today will have long-term implications beyond the 2030 time horizon of CleanBC. Consequently, BC's approach to climate policy should consider how factors like peak demand will be met well beyond 2030 and what the long-term implications will be for costs.
- Hydrogen can be a key low or no carbon fuel that can be injected into the existing gas system. Hydrogen produced from renewable electricity can be stored in the gas system for use in peak times, which helps increase the value of renewable electricity in decarbonization pathways.
- The gas system provides valuable reliability and resiliency to the province's energy system. As decarbonization progresses, this resiliency increases in importance. As the gas system grows into serving new markets where decarbonization is more difficult, the system will be relied on as a fundamental tool. For example, liquefied natural gas (LNG) for international marine vessels is one of the primary near-term options to make meaningful GHG reductions.

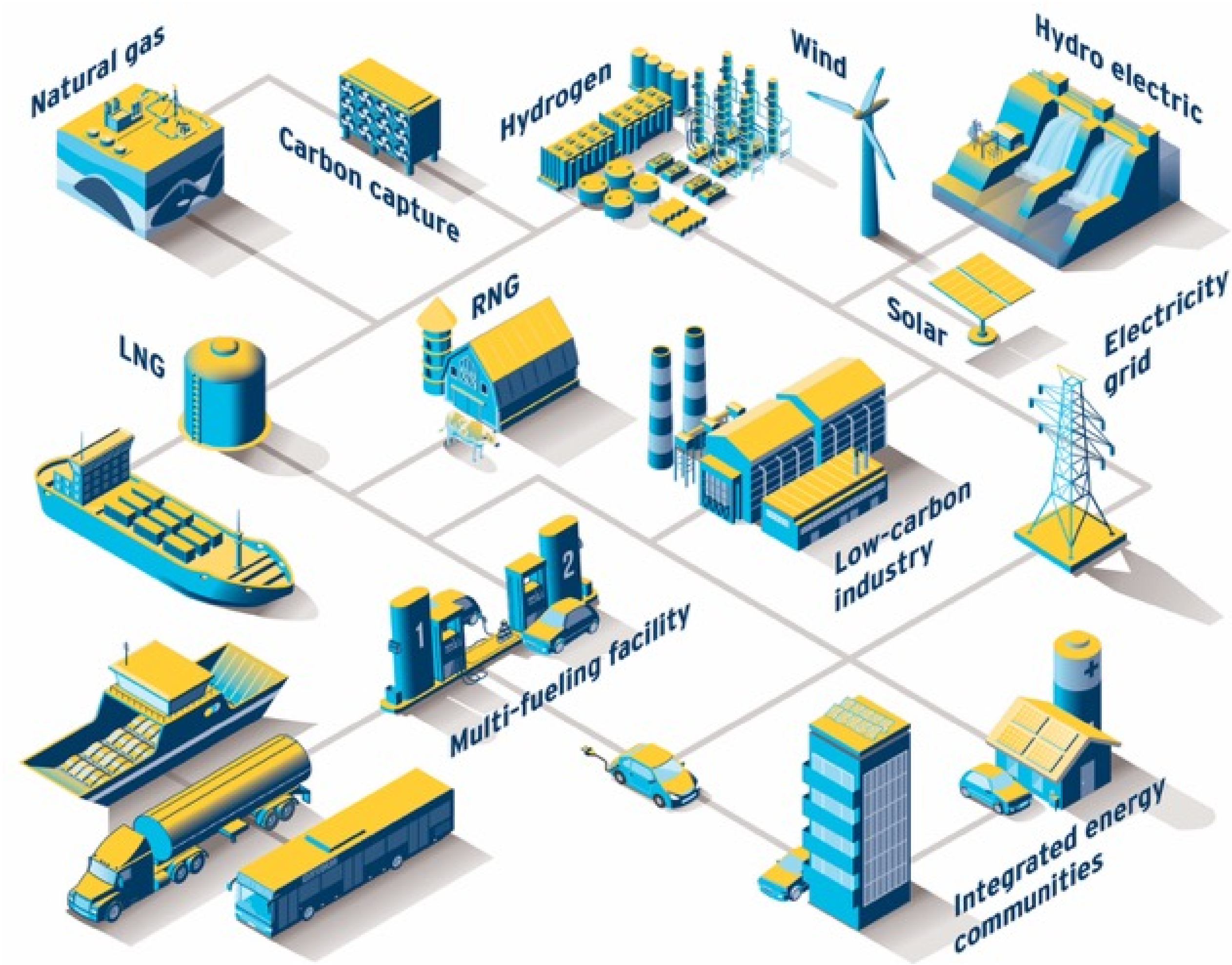


[2] Both pathways developed in this study achieve 95% of the domestic reductions required by 2050.

FortisBC's Clean Growth Pathway to 2050 is a diversified and flexible approach that supports BC's energy needs and GHG reduction targets. In 2050, gas infrastructure transports renewable natural gas (RNG), low carbon hydrogen (largely made from renewable electricity), and synthetic methane developed from captured carbon and hydrogen as well as natural gas. The system delivers this low carbon energy for specific end uses with high energy needs: space and water heating, medium and heavy duty (MHD) road vehicles, marine transportation, and industrial processes (Figure 2).

The Clean Growth Pathway also supports targeted electrification. Excess renewable power that would otherwise be curtailed or stored using expensive applications such as batteries or mechanical storage could instead produce hydrogen for use in the gas system.[3] In addition to providing flexible peak capacity, gas systems are key in stabilizing and securing the power grid, underpinning firm dispatchable electricity capacity and providing longer duration and affordable energy storage. Furthermore, Guidehouse's Gas for Climate study[4] demonstrates that deploying gas-fired dispatchable power (hydrogen and biomethane) as compared to more expensive solid biomass-fired dispatchable power can lead to annual cost savings of €54 billion across Europe.

FIGURE 2. FORTISBC'S CLEAN GROWTH NETWORK TO 2050



[3] It is unlikely that battery storage alone will be sufficient to meet the energy storage needs of the Electrification Pathway.

[4] Guidehouse, *Gas Decarbonisation Pathways 2020–2050*, April 2020, https://gasforclimate2050.eu/?smd_process_download=1&download_id=339.

POLICY IMPLICATIONS

To moderate costs, reduce risks, enhance GHG reduction options, and maintain a reliable provincial energy system while achieving the 2050 goal, a number of outcomes need to be pursued:

- **Policy should be focused on fostering an integrated low carbon energy system.** It is critical to acknowledge that electricity and gas complement each other—both are needed and can reinforce each other. Taking a systemwide view of energy infrastructure that recognizes the value and coordinates the gas and electric systems to manage decarbonization affordability and resiliency provides the greatest overall benefits for BC.
- **Focus electrification efforts where they are most effective** to maximize limited ability to expand clean and firm generation resources. For example, in the passenger transport sector.
- **Prioritize the expansion and supply of renewable gas through a coordinated strategy** that invests in research and development (R&D), addresses policy barriers, and offers incentives for renewable gas development.
- **Support new technologies** that leverage the GHG reduction potential of the gas system including gas heat pumps, compressed natural gas (CNG)- and LNG-powered commercial vehicles, and carbon capture and storage.
- **Maintain the operational and financial health of the gas system** to allow for continued investment in infrastructure and programs that align with the 2050 target.
- **Leverage the potential of the gas sector to reduce GHG emissions internationally** through LNG marine refuelling (referred to as bunkering) and LNG exports.
- **Consider the cost and source of energy post-2030** in current and ongoing policy decisions.

2. INTRODUCTION

This report discusses potential pathways for BC to achieve its 2050 GHG reduction target, focusing on the roles of the gas and electric systems in the province. The report takes a BC-specific view of decarbonization considering the province's unique energy systems and resources. The objective is to discuss the tradeoffs of different approaches and to emphasize important points to consider when embarking on a long-term decarbonization pathway. The report is organized into the following sections:

- **BC's Energy Systems:** Focuses on the roles of energy delivery infrastructure and key operational and practical considerations.
- **Study Approach:** Describes the methodology used to analyze decarbonization pathways for BC. This section also outlines the main differences between the pathways and the key inputs and assumptions that went into the analysis.
- **Study Results – Side-by-Side Comparison of Pathways:** Compares the outcomes of the analysis, pathways, and key considerations.
- **Other Benefits of Using the Gas System for Decarbonization:** Discusses other benefits, in addition to results from the analysis of decarbonization pathways, that emphasize the importance of the gas delivery system.
- **Conclusions:** Provides general conclusions of the study.

3. BC'S ENERGY SYSTEMS

BC has an expansive energy system that includes the following:

- A large electrical grid primarily administered by BC Hydro and FortisBC electric
- A gas system operated primarily by FortisBC gas and Pacific Northern Gas
- Vast amounts of renewable electric and natural gas resources

BC has a large supply of biomass that could be used to sustainably produce renewable energy such as RNG. BC is connected to the US and other Canadian provinces and territories through electric interties and natural gas pipelines.

BC'S NATURAL GAS AND ELECTRIC SYSTEMS TODAY

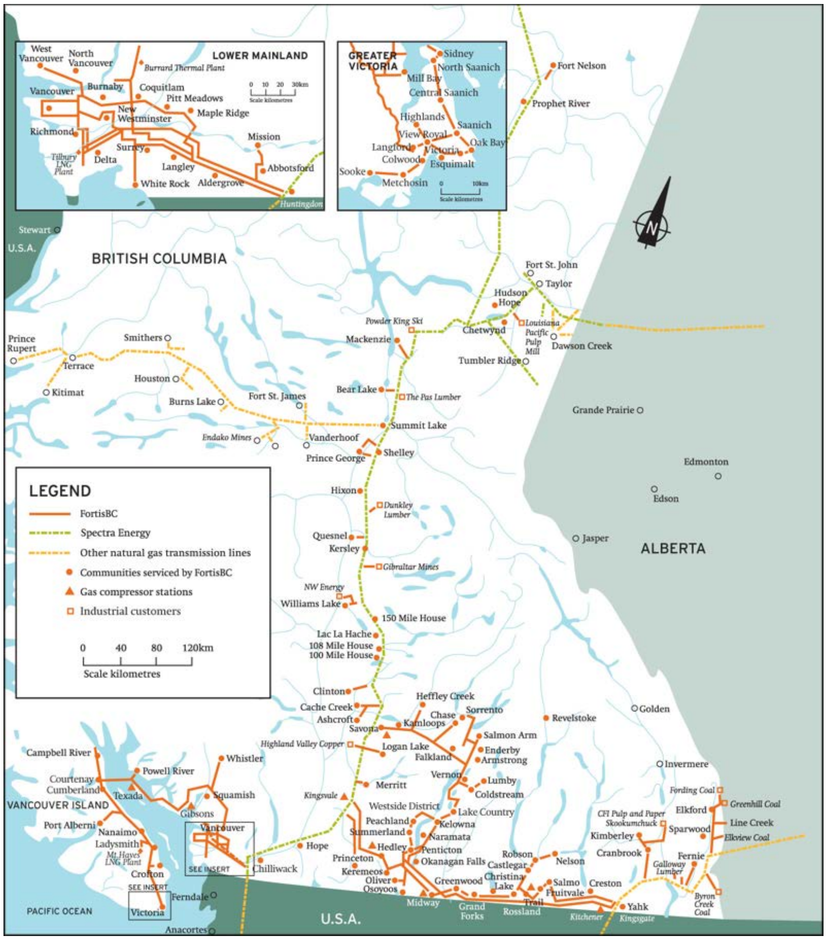
FortisBC operates approximately 49,000 km of natural gas transmission and distribution pipelines in BC. This infrastructure, along with the natural gas pipelines owned by Pacific Northern Gas, TC Energy, Enbridge, and other organizations, spans across the province. The system has multiple import/export points on the borders between Alberta, Yukon, and the US, as well as LNG on the west coast. All of this infrastructure is part of an integrated provincial system that represents billions of dollars of investment to supply natural gas to domestic markets and for export.

BC depends on energy delivered by the natural gas system (Figure 4). Over 30% of BC's total energy consumption[5] is transported through gas infrastructure.[6] Natural gas represents approximately 50% of residential and commercial end-use demand and almost 40% of industrial end-use demand in BC. The extensive coverage and interconnectivity of the gas network makes the system a critical vehicle to deliver low carbon energy to British Columbians.

BC also has an expansive electric system primarily administered by BC Hydro and FortisBC.

[5] Includes upstream energy consumption
[6] Canada Energy Regulator, "Canada's Energy Future 2019: Energy Supply and Demand Projections to 2040, Macro Indicators," accessed March 2, 2020.

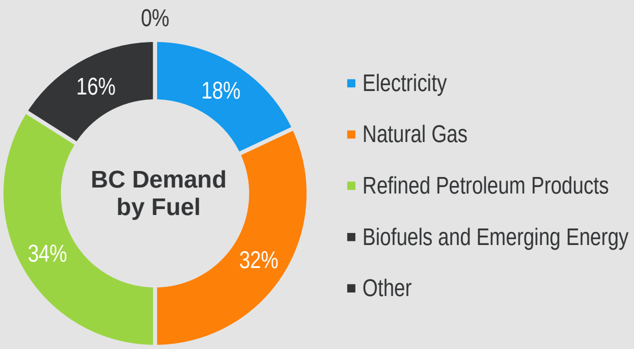
FIGURE 3. NATURAL GAS INFRASTRUCTURE SERVING BC

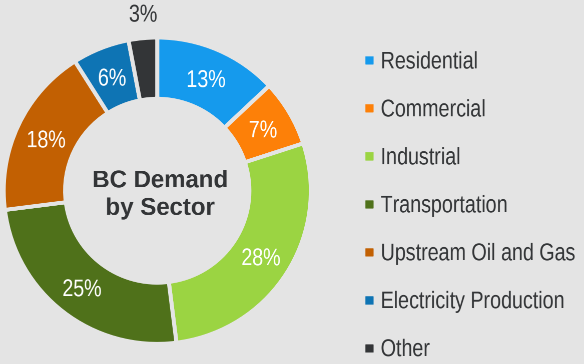


Combined, the two utilities serve over 2.16 million electricity customers through over 86,000 km of electric transmission and distribution lines. BC's electricity system is part of the Northwest Power Pool and is connected to Alberta and the US. Approximately 90% of BC's electric capacity is made up of hydro, with the remainder from wind, other renewables, and natural gas for peak electricity supply.

BC has large domestic resources of natural gas and electricity. In 2018, net electricity imports made up 2% of domestic generation. Over 90% of the natural gas consumed in BC is produced in BC (remaining supply is imported from Alberta). However, BC's total natural gas production is greater than its domestic demand and is exported to Alberta or the US. BC relies on deliveries from other provinces and from imports from the US for refined petroleum products like gasoline and diesel. BC imports almost double the volume of gasoline and diesel from Alberta and the US then it refines in domestic refineries.

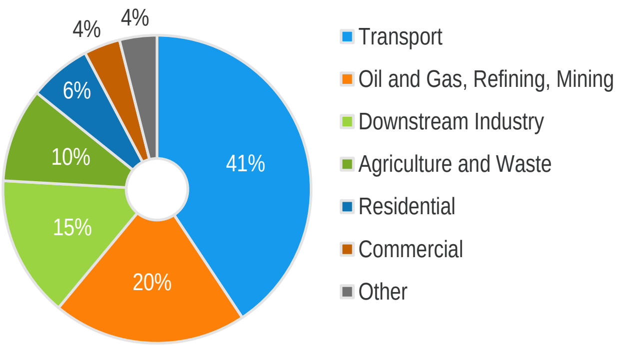
FIGURE 4. BC 2019 ENERGY DEMAND





Source: Canada Energy Regulator – Canada's Energy Future 2019 and CanESS (CANSIM)

FIGURE 5. BC EMISSIONS BY SECTOR



Source: BC GHG Inventory

The transport sector has the largest emissions footprint in BC, consisting of 41% of all GHG emissions (Figure 5). Industry, including oil & gas extraction and downstream manufacturing, makes up 35% of provincial GHG emissions. Residential and commercial buildings make up a comparatively smaller 10% of provincial GHG emissions.

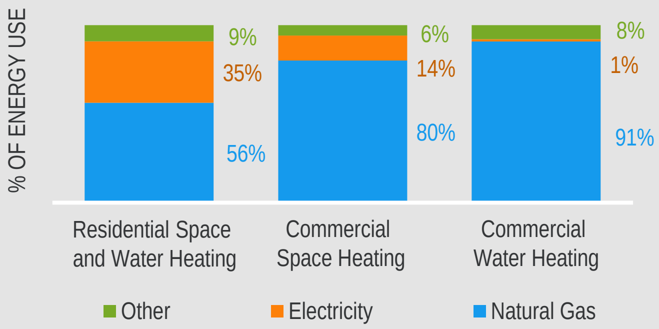
A focus on reduction of emissions across all sectors will be required to achieve the reductions targeted by 2050. Given the significant emissions associated with the transportation and industrial sectors, substantial efforts will be required in these sectors.

GAS SYSTEM IN BC ALLOWS FOR FLEXIBLE SUPPLY, SECURITY, AND STORAGE

Natural gas is one of the most flexible forms of energy because it can be stored relatively inexpensively for long periods of time. This flexibility allows the gas system to deal with large fluctuations in demand and volume, which is common in BC due to the seasonal nature of space and process heating loads in the province.

Most residential and commercial energy customers in BC depend on natural gas for space and water heating as well as cooking (Figure 6). Natural gas is also well-suited for combustion for heat. Many industries rely on natural gas because they can handle the high temperatures used in industrial applications. As well, natural gas use as a transport fuel for commercial vehicles and marine vessels is growing.

FIGURE 6. BC SPACE AND WATER HEATING BY SOURCE, 2016



Natural gas demand peaks in the winter and declines in the summer. Demand can be handled by the existing gas system seasonally. Figure 7 highlights the gas system's role in meeting peaks—i.e., the coldest days of the year.[7] On a summer day, throughput is approximately 3,000 MW, representing mostly water heating and industrial energy consumption. On an average winter day when most homes are using their gas heating systems, throughput on the system can increase by over three times and approaches the equivalent of 10,000 MW in electrical terms.

The gas system is designed to deliver significant volumes of energy to meet demand on very cold days. For example, on the coldest day in 2019, the volume of gas delivered was 40% higher than an average winter day and over three times the energy delivered on a summer day.

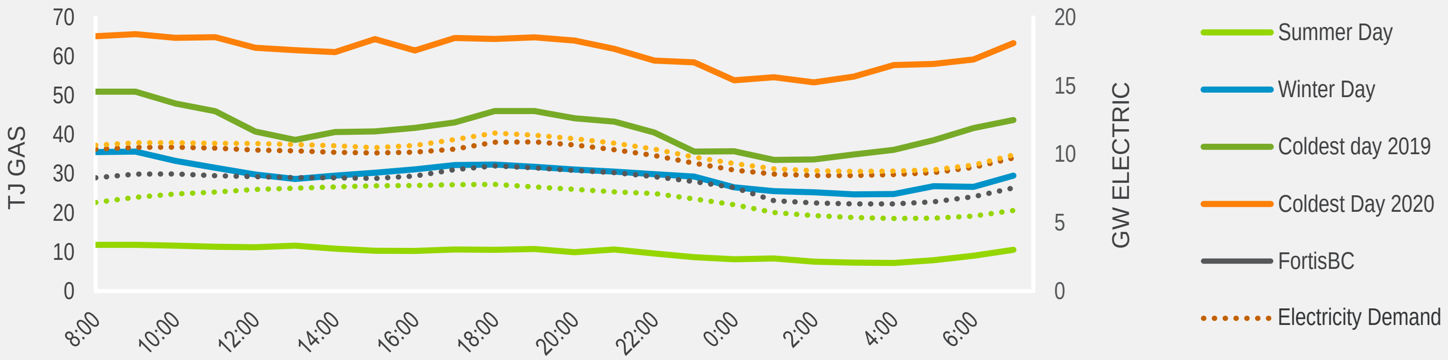
On a very cold day, such as January 14, 2020 when temperatures in the Lower Mainland approached -10°C, the energy delivered by the gas system can be double an average winter day and 50% higher than the coldest day in 2019.

The gas system provides critical versatility to meet peak energy demand. The electricity system needs to generate enough electrical energy at any one time to match the amount of consumption, whereas the gas system can store the energy and regulate flow on the system to meet demand. This means that electric systems need to have enough generating capacity to meet peaks while the gas system needs enough storage and pipeline throughput.

On January 14, 2020, the peak volume of gas delivered between 7:00 a.m. and 8:00 a.m. was equivalent to over 18,000 MW of electrical generating capacity, approximately 60% greater than the peak on the electric system during the same day and 50% larger than the entire hydroelectric generating capacity owned by BC Hydro (11,900 MW). While January 14, 2020 was one of the highest demand days on the gas system, some capacity remained to be distributed if demand continued to increase.

One of the gas system's main strengths is its ability to meet extreme peaks. It can store, ramp up, and deliver high volumes of energy on short notice and can handle large changes in volumes over time without operational, reliability, or financial strain. The electricity system would require significant investment to meet the province's space and water heating needs seasonally and daily in the electrification scenario.

FIGURE 7. HOURLY GAS AND ELECTRICITY DEMAND IN BC



Source: FortisBC

[7] Figure 7 represents actual natural gas flows in FortisBC's service territory. Electricity demand is gross telemetered load on BC's electricity transmission system.

The ability of natural gas to be stored adds to its value as a reliable energy source. FortisBC's affiliate, Aitken Creek Gas Storage, owns a large underground natural gas storage facility, which has over 90 PJ of gas storage to provide seasonal storage.[8] Gas storage is low cost—on average, the cost of storage at Aitken Creek is approximately $1 per GJ or 0.3 cents ($0.003) per kilowatt-hour in electricity storage equivalent.

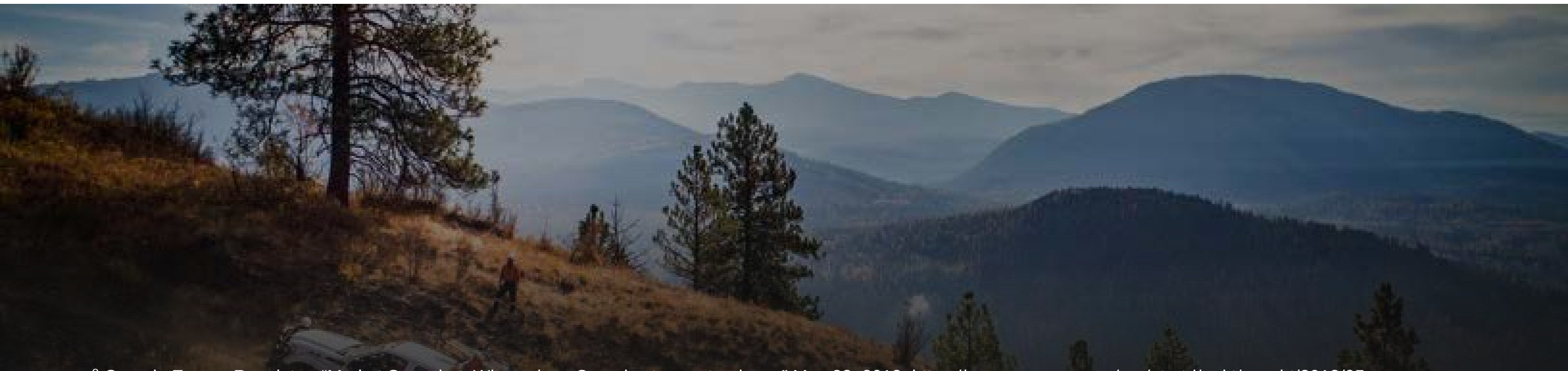
Although electric storage costs are falling significantly, they are still much more costly between $50 and $90 per GJ equivalent comparatively.[9] In addition to Aitken Creek, several smaller natural gas storage facilities exist throughout BC. Natural gas is injected into seasonal storage in summer months when demand is low and is withdrawn in the winter when demand for natural gas is higher. Low cost gas storage allows for year-round gas production and for production to deviate from gas consumption. Storage more effectively manages the costs of gas production and disruptions in production when they occur.

Gas can also be stored in the transmission pipelines themselves—typically referred to as line pack. Transmission pipelines operate within a minimum and maximum pressure as determined by the volume of gas in the line. Line pack can allow segments of the gas line, for short periods in a day, to deliver more gas per hour to consumers than is being delivered per hour by suppliers.

Line pack poses small incremental costs and can be cycled, meaning it can be maintained or used with relative ease. The estimated seasonal variation in line pack of FortisBC's transmission pipelines between a period of high demand and low demand can be as high as 0.15 PJ. In electrical terms, this would be equivalent to 40 GWh—over 30 times larger than the entire electrical energy storage capacity of utility-scale batteries in the US in 2018.[10]

Natural gas and the gas delivery system can serve a critical role in extreme conditions. Global climate change has resulted in the increased prevalence of wildfires, which can severely impact electricity systems. California has experienced severe wildfires in recent years, including a 2019 wildfire that resulted in mass evacuations and blackouts, leaving millions of people without electricity.[11] A study by the California gas and electric utilities indicated that Southern California Gas' natural gas storage assets has played a vital role in addressing emergency situations like extreme weather and wildfires.[12]

Over the past 20 years, the average number of hours a customer is without electric power in a year has increased. With the large expected growth in electricity demand, this trend is expected to continue, highlighting the importance of natural gas use as a heating source; its use is especially important during the cold winters experienced in many parts of BC.



[8] Canada Energy Regulator, "Market Snapshot: Where does Canada store natural gas," May 23, 2018, https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/snpsht/2018/05-03whrdscncstrngrlgs-eng.html.

[9] Lazard, *Lazard's Levelized Cost of Storage Analysis—Version 5.0*, November 2019, https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf.

[10] U.S. Energy Information Administration, "Most utility-scale batteries in the United States are made of lithium-ion," Today in Energy, October 30, 2019, https://www.eia.gov/todayinenergy/detail.php?id=41813.

[11] Newburger, Emma, "More than 2 million people expected to lose power in PG&E blackout as California wildfires rage," CNBC, October 26, 2019, https://www.cnbc.com/2019/10/26/pge-will-shut-off-power-to-940000-customers-in-northern-california-to-reduce-wildfire-risk.html.

[12] California Gas and Electric Utilities, *2018 California Gas Report*, 2018, https://www.socalgas.com/regulatory/documents/cgr/2018_California_Gas_Report.pdf

4. STUDY APPROACH

The Electrification and Diversified Pathways developed in this study achieve 95% of the domestic reductions required by 2050.[13] The remaining emissions are assumed to be addressed with continued advances in technology and changing consumer behaviors, as well as emissions reductions related to non BC-specific initiatives (e.g., commercial airline emissions reductions). The pathways differ in the extent to which renewable electricity and low carbon gas play a role in the scenarios. The Electrification Pathway aims to increase the use of electricity for all applicable end uses, so renewable and low carbon natural gas use is limited to those sectors where no alternatives are available. In the Diversified Pathway, renewable and low carbon natural gas is used to its full potential.

Guidehouse worked closely with FortisBC to characterize initiatives under each pathway that could contribute to reducing GHG emissions. The goal of the characterization was to identify, understand, and define GHG mitigation options relevant for BC and to develop a common understanding of initiatives to implement in the model and analyze deeply. Guidehouse leveraged other studies it conducted on the role of the gas system in decarbonization, as well as FortisBC's internal research group and BC-specific research, to build a set of technologies and initiatives that were characterized and input into the Canadian Energy Systems Simulator (CanESS), an economy-wide model. Guidehouse also used data from the BC Climate Action Secretariat to align modelling assumptions with those used in the CleanBC climate plan. Figure 8 highlights how initiatives were developed across four major sectors and modelled into the two pathways, which were compared to a business-as-usual (BAU) scenario.

FIGURE 8. PATHWAY DEVELOPMENT AND MODELLING

1. GHG MITIGATION INITIATIVES

BUILDING EFFICIENCY
- Improved building envelopes
- Building automation and controls

TRANSPORTATION
- # light duty EVs
- # heavy duty EVs and CNG vehicles
- # trips on E-public transit
- # of CNG buses

2. PATHWAY MODELING

FUEL SWITCHING
- Building heating and cooling
- Floor space serviced by heat pump
- Water heated with heat pump
- Floor space serviced by alternative fuels

RENEWABLE GAS
- Volume of RNG supply
- # of vehicle KMs fueled by RNG
- Litres of ethanol blends

BUSINESS AS USUAL SCENARIO
- Baseline energy demand and economic activity
- LTGRP
- Consensus alterations

COMBINED INITIATIVES SCENARIO SCENARIO
- Baseline energy demand and economic activity
- LTGRP
- Consensus alterations
- Electrification initiatives
- Low Carbon Fuels initiatives

ELECTRIFICATION INITIATIVES SCENARIO
- Baseline energy demand and economic activity
- LTGRP
- Consensus alterations
- Electrification initiatives

Note: LTGRP refers to FortisBC's Long-Term Gas Resource Plan. Source: Guidehouse

[13] This study develops two future scenarios to achieve BC's GHG reduction targets and analyzes the required changes to the energy system and incremental societal cost to the province. The intent of the study was to determine the extent of change required in BC to meet climate reduction targets. The economy-wide energy models used in this exercise are key tools to outline the magnitude of changes required over the coming decades. These models are built from historical data and are extrapolated into the future based on announced policy initiatives, observed historical trends, and other assumptions. As such, the results of this energy modelling engagement are intended to be indicative of possible future scenarios, but they are not intended to be taken as definitive results. Various opportunities for emissions reductions were not included in this analysis, including emissions trading, initiatives targeted at international sectors (e.g., airlines and shipping), etc.

Technologies and initiatives were selected with consideration for how practical and defensible they are. The total societal cost for each pathway was assessed by considering the consumer commodity costs, utility system costs, incremental infrastructure costs, consumer equipment costs, retrofit costs, and government subsidies (Figure 9). The costs of an underutilized gas system were also estimated to reflect additional costs to customers should gas system utilization be meaningfully reduced.

FIGURE 9. PATHWAY TOTAL SOCIETAL COST IMPACTS

ELEMENTS OF TOTAL RATES BUILDUP

Consumer Commodity Costs
- Forecasted global and local commodity prices
- Unit cost ($GJ)
- Total energy consumed by commodity (PJ)

Utility System Costs
- Electric Utility Revenue Requirement
- Gas Utility Revenue Requirement
- Subsidies/ Deferral Accounts
- Normalized by (GJ)

Incremental Infrastructure Costs
- Electric Supply and Capacity Costs
- Electric System Costs
- Natural Gas System Costs
- Transportation Fuel Supply Chain

Utility System Planning Cost Estimates
- IRP System Cost Factors

System Cost Modelling
- Capacity Expansion Modelling
- Powerflow Modelling

System Cost Estimates
- Capacity/ System Needs Analysis
- Assumptions-Based

Based on macro analysis, build up consumer rates with:
- Total wholesale energy and commodity costs
- Utility revenue requirements (inclusive of subsidies and deferrals)
- Estimates of incremental system costs

+

CONSUMER EQUIPMENT INVESTMENT

RETROFIT COSTS

UNDERUTILIZED CAPACITY COSTS

Source: Guidehouse

PATHWAYS

Table 1 shows how Guidehouse modelled the five major initiative categories differently across the two pathways. In general, the Electrification Pathway focused on energy efficiency, fuel switching to electricity for space/water heating, industrial processes, and transportation. The Diversified Pathway focused on energy efficiency, implementation of efficient gas end uses, and the deployment of renewable gas. **The analysis described in this section presents two pathways to achieving GHG emissions reductions. While both are theoretically potential pathways, they are not forecasts of the future.** Guidehouse welcomes an ongoing discussion on the merits and key challenges of various pathways available.

TABLE 1. INITIATIVES BY PATHWAY

Initiative	Electrification Pathway	Diversified Pathway
Electric Peak Demand	Peak demand increases to 21,600 MW in 2050, requiring 8,800 MW of new peak capacity versus the BAU case.	Peak demand increases to 17,700 MW in 2050, requiring 4,900 MW of new peak capacity versus the BAU case.
Renewable Gas	Of end-use natural gas demand, 35% (26 PJ) is served by renewable gas in 2050 (mix of hydrogen and renewable natural gas). Incremental 1.8 MT of carbon sequestered per year through carbon capture by 2050.	Of end-use natural gas demand, 73% (136 PJ) is served by renewable gas in 2050 (mix of hydrogen, renewable natural gas, and synthetic methane). Incremental 1.8 MT of carbon sequestered per year through carbon capture by 2050.
Transportation	Transition to 100% zero-emissions light duty vehicles. Significant role for MHD electric vehicles (EVs) (60% EV, 40% CNG/LNG and internal combustion).	Transition to 100% zero-emissions light duty vehicles. Significant role for gases in MHD vehicles (75% CNG, 20% EV, 5% fuel cell vehicles).
Fuel Switching	Transition 100% of residential and commercial space and water heating to electricity with electric heat pumps and other appliances, 20% of industrial fuel switching.	Transition up to 25% of residential and commercial space and water heating to electricity, 10% of industrial fuel switching.
Energy Efficiency	Improve envelope of 1.6 million homes and 436 million m^2 of commercial floor space.	Improve envelope of 1.7 million homes and 328 million m^2 of commercial floor space. Deploy gas heat pumps in ~70% of buildings.

Table 2 includes select modelling inputs that have a major impact on the results. These inputs have been informed by:

- Past engagements carried out by Guidehouse
- Pilot programs and research assessments carried out by FortisBC
- Discussions with key BC stakeholders
- Various public sources

The assumptions in the table represent theoretically possible future scenarios—they are not forecasts of the expected future by either Guidehouse or FortisBC.

TABLE 2. SELECT MODELLING INPUTS

Input	Assumption/Description
Cost of New Electricity Generation	$126/MWh was assumed in both pathways. This value represents an estimate of the expected cost of Site C[14] and is considered a conservative estimate of new renewable power costs. It is conservative because solar, wind, and energy storage costs are significantly higher and do not provide the same level of inter-seasonal storage. These higher priced renewable assets may need to be deployed due to the difficulty of developing large hydro in Canada. It is assumed that hydro resources will be available at the levels modelled in the pathways, which further assumes the deployment of multiple large hydro facilities (similar in size to Site C) in both pathways.
Renewable Gas Costs	RNG production costs were derived from Hallbar Consulting's report on RNG potential in BC and range from $14 to $28 per GJ.[15] It is assumed that progress will be made in wood-to-RNG technology to achieve the levels of RNG modelled in the two pathways. Green hydrogen (i.e., hydrogen produced with renewable electricity) and synthetic methane costs were developed from current production cost estimates (roughly $40/GJ for hydrogen, ~$10/GJ extra to create synthetic methane based off FortisBC pilot projects). These costs were extrapolated for the forecast, taking into consideration cost declines due to technology improvements. Guidehouse also aligned hydrogen production costs with the cost of renewable electricity because that is the primary input for producing green hydrogen. The weighted average cost across all renewable gases for each pathway in 2050 are: • Electrification Pathway: $19/GJ ($0.068/kWh equivalent) • Diversified Pathway: $23/GJ ($0.083/kWh equivalent) The Diversified Pathway renewable gas cost is higher because it requires more RNG at higher prices and includes a small amount of synthetic methane, which is the most expensive renewable gas.
Peak Demand Impacts	Annual hourly load shapes were selected or developed using public sources for each of the initiatives described in Table 1. These load shapes were applied to the energy consumption of each initiative to determine peak demand impact.
Electric Heat Pump Characteristics	Electric heat pump costs were modelled to align with the BC Conservation Potential Review, which included a specific assessment of the achievable potential of electric heat pumps in BC. The incremental cost for electric heat pumps was modelled as approximately $376 per residential household and $16,500 per 1,000 m^2 of commercial floor space. Electric heat pumps were modelled with 190% efficiency for both residential and commercial applications.[16] This efficiency depends on climate and likely will vary by region within BC.

[14] Guidehouse calculated a levelized cost of energy (LCOE) for Site C based off capital cost estimates from the BCUC Site C inquiry, historical financials from BC Hydro, and internal estimates. The results were benchmarked against Lazard's published LCOEs.

[15] Hallbar Consulting, *Resource Supply Potential for Renewable Natural Gas in B.C.*, March 2017, https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/resource_supply_potential_for_renewable_natural_gas_in_bc_public_version.pdf.

[16] The 190% value is a conservative estimate for heat pump efficiency, which aligns with a baseline assumed efficiency for air-source heat pumps in Guidehouse's 2019 BC Conservation Potential Review. This conservative assumption was used to attempt to represent provincial efficiency as a whole because heat pump efficiency is assumed to vary significantly by climate zone.

Input	Assumption/Description
Gas heat Pump Characteristics	Gas heat pump costs were derived from a heat pump feasibility study provided by FortisBC and interviews with developers.[17] Initial costs were set at roughly $6,800 and $45,000 for a residential home and commercial building, respectively. Both residential and commercial gas heat pumps were modelled with a 140% gas utilization efficiency. This efficiency depends on climate and likely will vary by region within BC.
Natural Gas System Utilization	The utilization of the gas system differs significantly between the two pathways. In the Electrification Pathway, the 2050 throughput drops to roughly 40% of the 2019 throughput. Conversely, the 2050 throughput of the Diversified Pathway is not significantly less than the 2019 throughput.[18] Electrification Pathway: • 2019 throughput = 200 PJ • 2050 throughput = 75 PJ Diversified Pathway: • 2019 throughput = 200 PJ • 2050 throughput = 186 PJ

CanESS, which Guidehouse used to complete the pathway modelling, is an integrated, multifuel, multisector, provincially disaggregated energy systems model for Canada. CanESS enables bottom-up accounting for energy supply and demand, including energy feedstocks (e.g., coal, oil, natural gas), energy-consuming stocks (e.g., vehicles, appliances, dwellings), and all intermediate energy flows (e.g., electricity), including interprovincial imports and exports that may offer incremental opportunities to contribute to achieving regional GHG reduction targets.

Note: CanESS projections were based on extended trends observed in historical data (key data sources include CANSIM, Natural Resources Canada, and Environment Canada) and projections obtained from the Canada Energy Regulator (CER, Energy Future 2017). In addition, CanESS projections account for the expected effects of all approved legislation and regulation (including the CleanBC plan) and was driven by the best publicly available data from government sources. (Canada Energy Regulator (CER), Canada's Energy Future 2017, https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2017/index-eng.html)

[17] Posterity Group, Prefeasibility Study on Natural Gas Heat Pumps, May 2017.

[18] Gas system utilization includes only gas consumed by the buildings, industry, and transport domestic end-use sectors. Natural gas throughput for LNG for marine vessels and for international export are excluded.

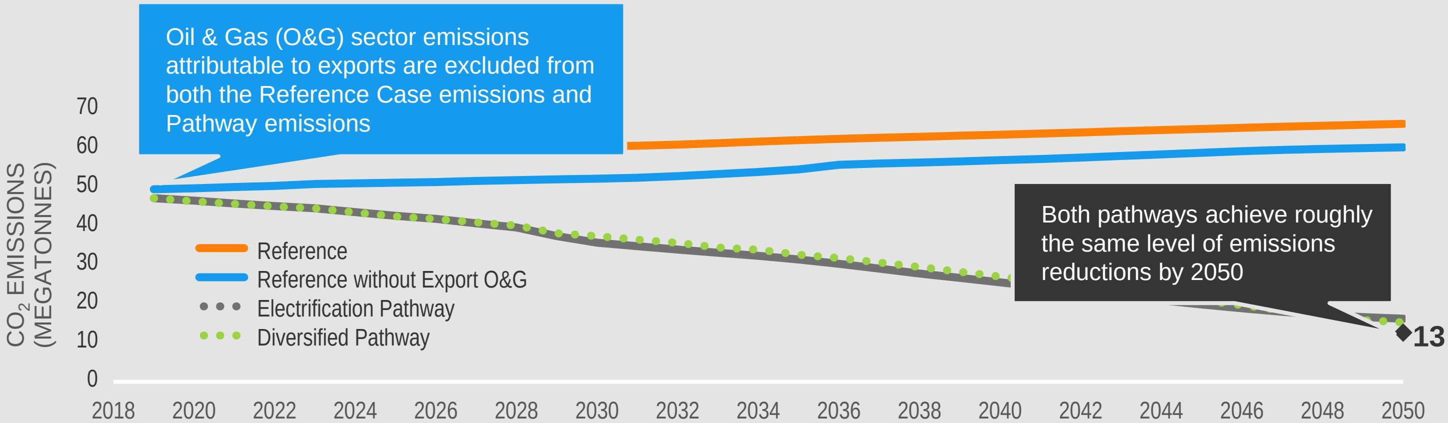
5. STUDY RESULTS – SIDE BY SIDE COMPARISON OF PATHWAYS

5.1 EMISSIONS REDUCTIONS

Each pathway meets 95% of the reductions required by 2050, representing greater than 32 million tonnes of CO_2e emissions avoided from BC annually in 2050 from a BAU scenario. The pathways use initiatives to different extents, but both pathways require transformative changes in every sector. The remaining 5% of emissions reductions must be achieved through initiatives that target sectors that cannot be modelled for BC in isolation—e.g., aviation fuel. These sectors are beyond the scope of this study.

The scope of this report is focused on BC's domestic GHG emissions. The pathways reduce domestic emissions by 80%. Emissions associated with energy exports, notably for LNG and other oil & gas for export, are separated out and are assumed to be addressed through a combination of nature-based carbon offsets, internationally transferred mitigation outcomes,[19] and technology improvements.

FIGURE 10. BRITISH COLUMBIA EMISSIONS REDUCTIONS UNDER ENERGY VISION PATHWAYS



Source: Guidehouse Analysis

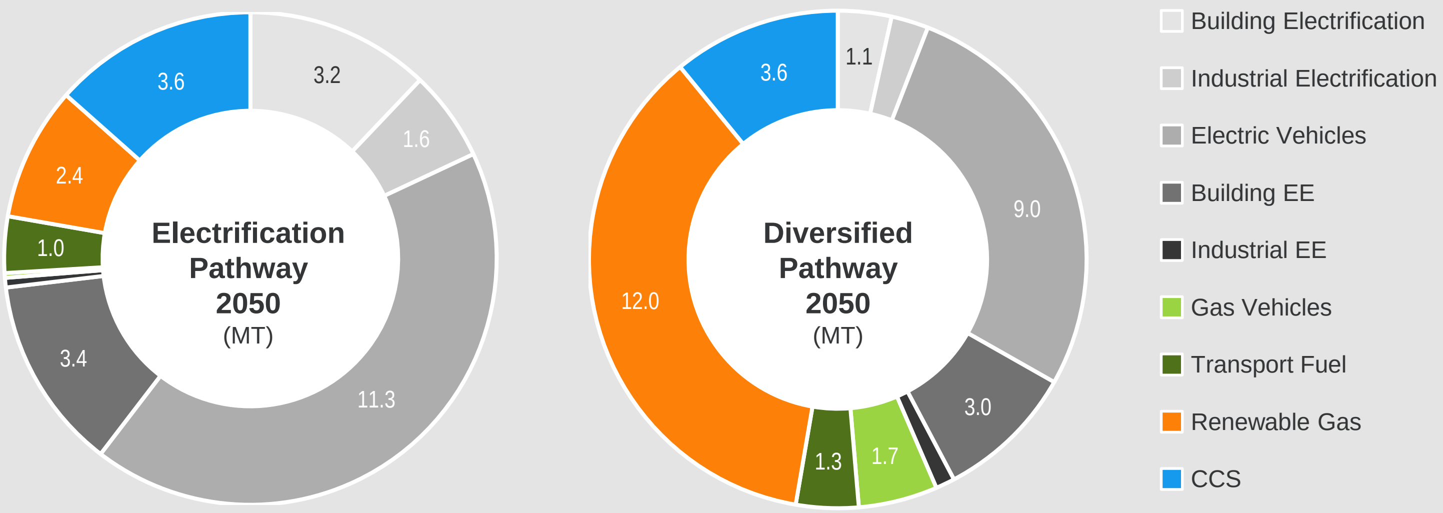
As Figure 11 shows, light duty EVs have a large role to reduce GHG emissions in both pathways, as both pathways were modelled to include the Zero-Emission Vehicles [20] Act; the Zero-Emission Vehicles Act requires 100% of light duty vehicles sold in 2040 to be zero-emissions vehicles.[21] MHD vehicles is the second-most impactful initiative in the Electrification Pathway, which has been modelled such that 60% of MHD vehicles on the road in BC are electric by 2050. The most impactful initiative to reduce BC's domestic GHG emissions in the Diversified Pathway is renewable gas, which results in over 5 million tonnes of emissions reductions in 2050 by transforming the natural gas fuel mix to be mostly made up of RNG and hydrogen. Energy efficiency in buildings is also a critical initiative in both pathways. This initiative results in over 3 million tonnes of reductions by 2050 through the implementation of improved building envelopes, high efficiency heat pumps, and commercial automated building controls.

[19] Internationally transferred mitigation outcomes are identified in the Paris Agreement to facilitate compliance with national GHG reduction goals through the trade of emissions reductions between nations.

[20] ZEVs are modelled in this study as EVs and fuel cell vehicles.

[21] Province of British Columbia, Zero-Emission Vehicles Act, May 2019, https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/clean-transportation-policies-programs/zero-emission-vehicles-act.

FIGURE 11. GHG REDUCTIONS BY INITIATIVE: 2050



* Note that summing up all the initiatives will not exactly match total emission reductions values in earlier slides. Source: Guidehouse Analysis

5.2 GAS SYSTEM ENABLES GHG EMISSIONS REDUCTIONS OUTSIDE BC

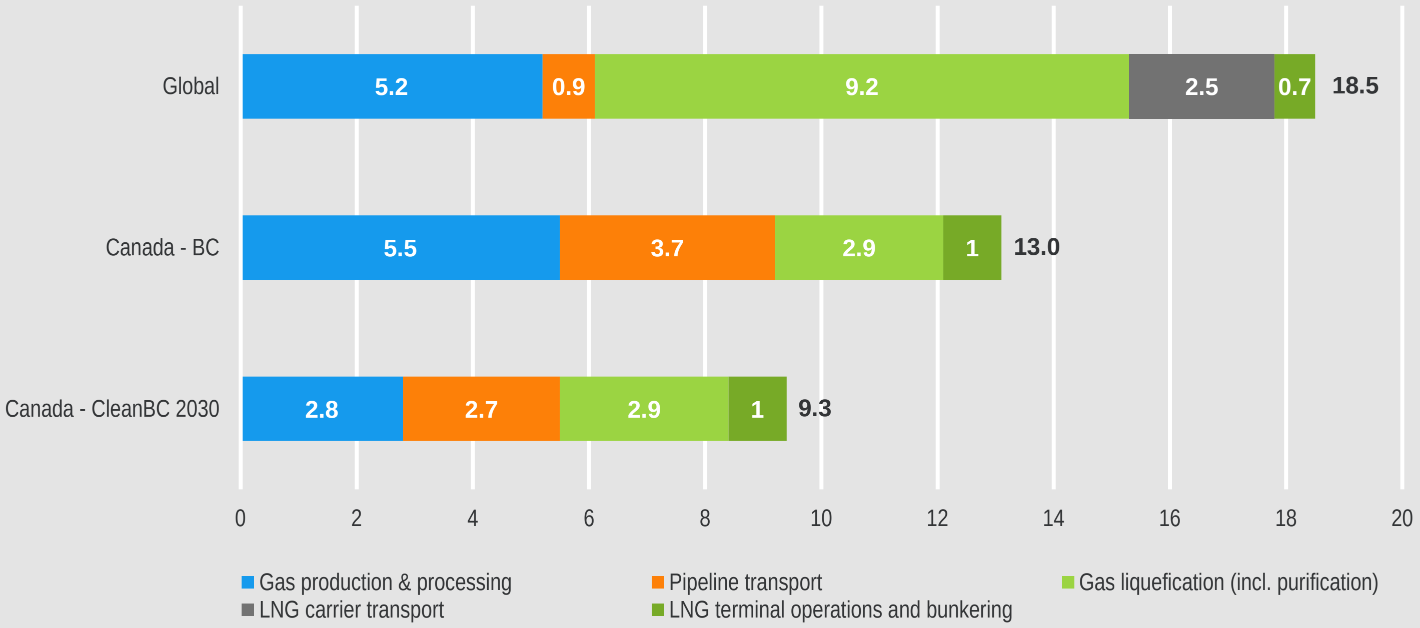
The gas system can also lead to GHG emissions reductions outside of BC. Although these reductions were not evaluated in this analysis, FortisBC has conducted separate evaluations on the role of the gas system to supply LNG to marine vessels and to displace carbon-intensive energy consumption in China with LNG exports. Both of these activities could have significant near-term emissions reductions.

For marine vessels, LNG from FortisBC's Tilbury facility has a 27% lower carbon intensity than the global average for LNG.

This means that LNG from FortisBC used in marine vessels would reduce life cycle emissions by between 20% and 27%. As the measures in CleanBC take hold, reducing methane emissions and extending electrification in natural gas production, LNG from BC could reduce GHG emissions by up to 30% and would make the carbon intensity of LNG from Tilbury half that of the global average. Because the GHG emissions associated with international marine vessels in their journeys to and from ports in BC are higher than BC's total annual GHG emissions, this would make an important contribution to global GHG reduction efforts.[22]

[22] thinkstep, *Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver: 2nd Project Phase*, 2020, https://www.thinkstep.com/content/life-cycle-ghg-emission-study-use-lng-marine-fuel-1 .

FIGURE 12. WELL TO TANK LNG CARBON INTENSITIES (g CO_2e/MJ)



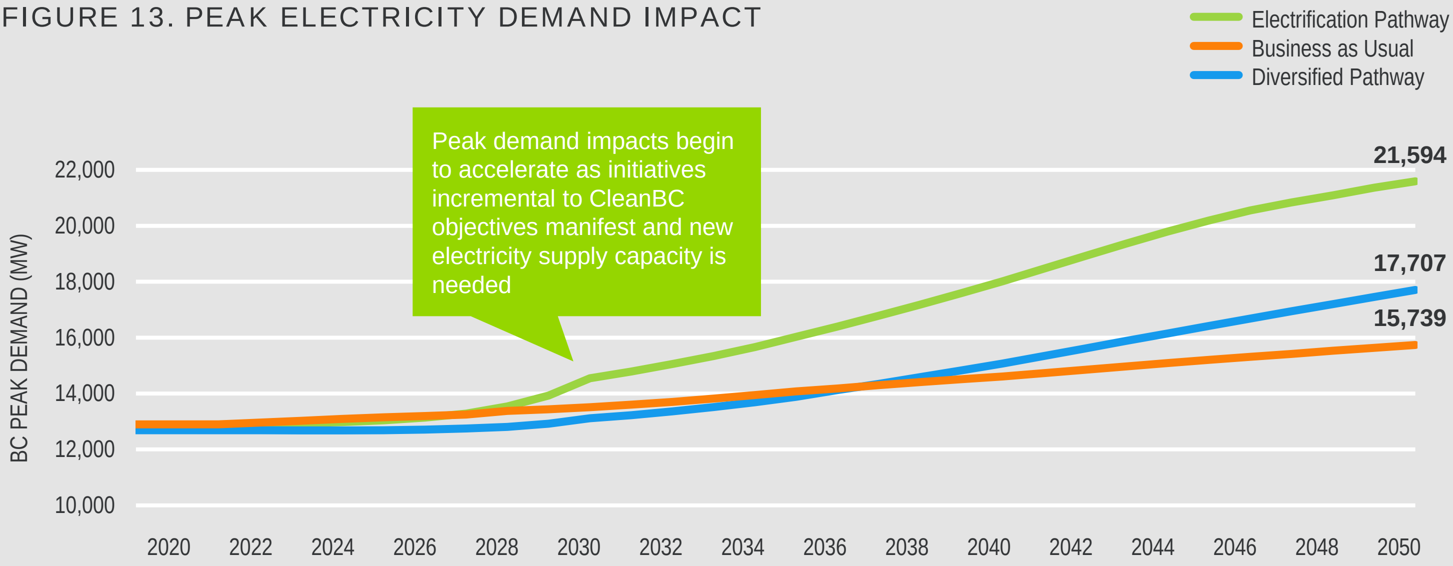
Source: Thinkstep, Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver: 2nd Project Phase, 2020

5.3 GROWTH IN LOW CARBON ENERGY SUPPLY

The 2050 peak demand of the Electrification Pathway is estimated to be 68% higher than the peak electricity demand of 2018. This will require the deployment of over 8,700 MW of peak capacity in the Electrification Pathway, which is double the requirement for the Diversified Pathway and triple the BAU requirement. The peak demand in both pathways increases from 2018 levels because of the significant deployment of EVs, electric heating, and fuel switching. However, the net increase in peak demand is significantly higher in the Electrification Pathway.[23] To achieve the 2050 GHG reduction targets, peak demand must be met with low or no carbon firm generating capacity. In this study, Guidehouse used the lowest cost supply option for peak capacity—hydroelectric generation. There are practical limitations to developing new hydroelectric generation in BC, however. This report does not assess those limitations but acknowledges other sources of peak capacity may be preferred.

[23] Peak demand impacts are based on conservative assumptions in both pathways (e.g., majority of MHD vehicle charging occurs in non-peak times).

FIGURE 13. PEAK ELECTRICITY DEMAND IMPACT

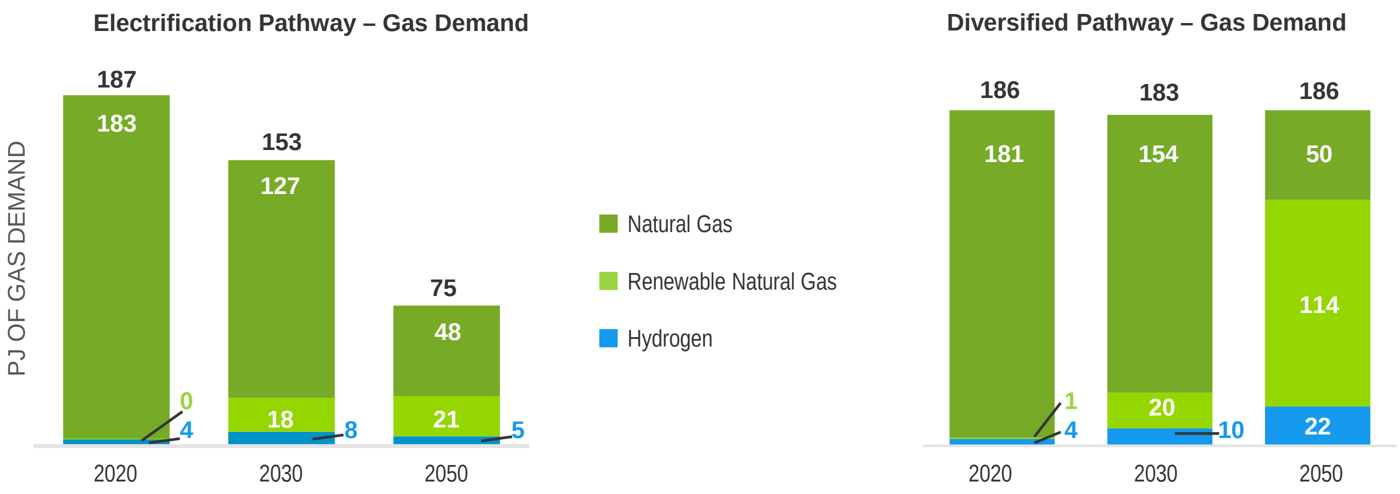


*Peak demand impacts are based on conservative assumptions in both pathways (e.g., majority of MHD vehicle charging occurs in non-peak times)
Source: Guidehouse Analysis

Natural and renewable gases are critical in the Diversified Pathway and support a more robust energy system in the province. Figure 14 shows that renewable gases will make up 35% of natural gas demand in the Electrification Pathway by 2050, aligning with current BC targets. Renewable gases make up 73% of natural gas demand in the Diversified Pathway.

In the Electrification Pathway, total gas demand declines by almost 60% between 2020 and 2050, while total gas demand (natural gas and RNG) remains flat during the same period in the Diversified Pathway.

FIGURE 14. END-USE GAS DEMAND IN EACH PATHWAY



Note: End-use natural gas demand includes consumption in residential and commercial buildings, industry, and transport but excludes gas consumption in upstream gas extraction, processing, and transmission.

Source: Guidehouse Analysis

TABLE 3. RENEWABLE GAS DESCRIPTIONS

Renewable Gas	Assumption/Description
Renewable Natural Gas (RNG)	RNG is natural gas created from renewable energy sources such as organic waste (i.e., from landfills) and agricultural waste. Guidehouse used a report by Hallbar Consulting commissioned by the Province of British Columbia, FortisBC, and Pacific Northern Gas to determine the level of RNG potential in BC and its associated production costs. The RNG amounts modelled in 2050 align with the long-term technical potential in the Hallbar Consulting report, which assumes improvements will be made in wood-to-RNG technology. It is assumed RNG can be injected directly into existing natural gas infrastructure without any associated complications, and all associated costs are covered in the production costs.
Hydrogen	Two types of hydrogen were considered in this report: green hydrogen, which is produced from an electrolysis reaction of renewable electric power with water, and blue hydrogen, which is produced from fossil fuel natural gas and cleaned up using carbon capture and storage. Blue hydrogen is cheaper than green, and its cost is not forecast to decline significantly in the forecast period. Guidehouse modelled the hydrogen mix to increasingly be composed of green hydrogen under the assumption that costs are likely to decline. Green hydrogen costs were based off production cost assessments from the *British Columbia Hydrogen Study*[24] and are forecast to decrease due to technology improvements. Guidehouse benchmarked these costs with production costs observed in other regions (e.g., Europe).[25] Green hydrogen costs are highly dependent on the price of electricity, so Guidehouse aligned the forecast to the cost of new renewable power in the future. Hydrogen was modelled to make up a maximum of 15% (by volume) of BC's natural gas mix to represent the estimated operational limitations of the gas system to incorporate higher volumes.[26]
Synthetic Methane	Synthetic methane is hydrogen that has been upgraded with CO_2 to create methane (CH_4) and that can be safely injected into the natural gas mix at any level. Synthetic methane is modelled as the most expensive renewable gas because its price includes the cost of hydrogen plus an incremental cost related to carbon capture and storage to provide the required CO_2. Guidehouse only modelled the production of synthetic methane when the requirement for renewable gas exceeded both the technical potential of RNG and the physical limit of hydrogen (i.e., 5% of the fuel mix).

Electricity's share of the energy supply increases significantly in both pathways. Refined petroleum, which makes up over 33% of total end-use energy demand in BC, will decline to less than 15% of end-use demand by 2050 in both pathways. This decline is due to the widespread adoption of vehicles that use alternative fuels to diesel and gasoline in both pathways—i.e., electric, fuel cell, CNG, and LNG. This analysis highlights the importance, costs and scarcity of low-carbon energy whether in the form of renewable gas molecules for the gas system or electrons through the electric grid.

Maximizing the potential of clean electrons or clean gas molecules should be pursued to harness the differences between these energy carriers. Because of the high cost of building new clean reliable electricity generation and transmission, electrification initiatives should be matched to their most effective and valued uses to reduce GHG emissions, while natural gas and renewable gas molecules should be delivered to end-uses where there are high-costs of electrifying and/or the GHG reduction potential is lower. This integrated approach to system-wide decarbonization should be pursued rather than a compartmentalized sector by sector approach.

[24] Zen and the Art of Clean Energy Solutions, British Columbia Hydrogen Study, June 2019, https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/zen-bcbn-hydrogen-study-final-v6.pdf.

[25] Guidehouse, Gas Decarbonisation Pathways 2020–2050, April 2020, https://gasforclimate2050.eu/?smd_process_download=1&download_id=339.

[26] A maximum hydrogen blend concentration by volume in FortisBC's gas system is being analyzed and depends on several factors. FortisBC is conducting feasibility studies to outline the minimum safe blending volume with the current system. The gas system can also adapt over the coming decades as scheduled maintenance, asset integrity, and operational management advancements and infrastructure upgrades offer opportunities to increase the system's compatibility with hydrogen.

Renewable gases have been an area of growing interest around the world. Large utilities in North America are moving to expand the supply of RNG into their portfolios. In Quebec, the provincial government has set a 5% RNG blend target by 2025 and has devoted $70 million to increase the production of RNG. Southern California Gas has set a corporate target to expand RNG supply to 20% of its throughput in 2030. In some European countries, promotion of biogas and RNG has been an ongoing policy objective. Denmark is producing over 15 PJ of biogas, with approximately 10% of the throughput through its gas grid being RNG. In France, the government has set an objective to inject 10% RNG into the country's pipelines by 2030.

Hydrogen is also taking on a larger role in meeting global energy needs. Natural gas utilities in France recently recommended the government set a hydrogen target of 10% of the natural gas mix in 2030, increasing up to 20% thereafter.[27] The Guidehouse Gas for Climate work in the EU demonstrates support in the EU for setting a binding mandate for 10% gas from renewable sources (i.e., RNG and green hydrogen) by 2030. [28] Hydrogen is being considered as a replacement fuel for coal in electricity production. The largest municipal utility in the US, Los Angeles Department of Water and Power (LADWP), announced it would transform a coal-fired plant to run on green hydrogen. LADWP plans to run the coal plant on a blend of 30% hydrogen, 70% natural gas by 2025. By 2045, the plant is expected to be run completely on hydrogen.[29]

5.4 COST COMPARISONS

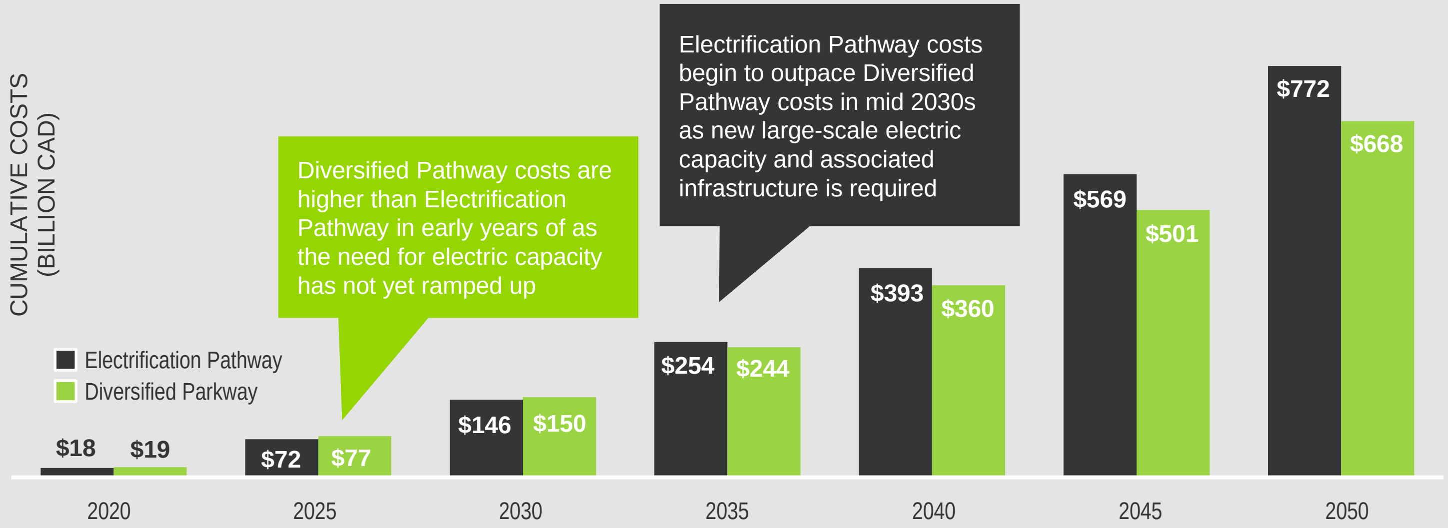
By 2050, the societal value of the Diversified Pathway is expected to be at least $100 billion higher than the Electrification Pathway. The cost of each pathway is roughly the same until the mid-2030s, when the costs of the Electrification Pathway rises much higher than the Diversified Pathway. This finding emphasizes the need to prioritize pathways over a longer time horizon because pathway costs represent incremental costs borne by society relative to the BAU case. These costs include commodity (the electricity and natural gas itself), infrastructure (the poles, wires, and pipelines needed to deliver energy), and initiative costs (the cost of efficient alternatives to existing equipment and fuel).

[27] Hydrocarbon Processing, "France plans hydrogen blending with natgas to tackle carbon emissions," November 15, 2019, https://www.hydrocarbonprocessing.com/news/2019/11/france-plans-hydrogen-blending-with-natgas-to-tackle-carbon-emissions.

[28] Guidehouse, *Gas Decarbonisation Pathways 2020–2050*, April 2020, https://gasforclimate2050.eu/?smd_process_download=1&download_id=339.

[29] Smith, Carl, "America's Largest Municipal Utility Invests in Move from Coal to Hydrogen Power," *Governing: The Future of States and Localities*, April 15, 2020, https://www.governing.com/next/Americas-Largest-Municipal-Utility-Invests-from-Coal-to-Hydrogen-Power.html.

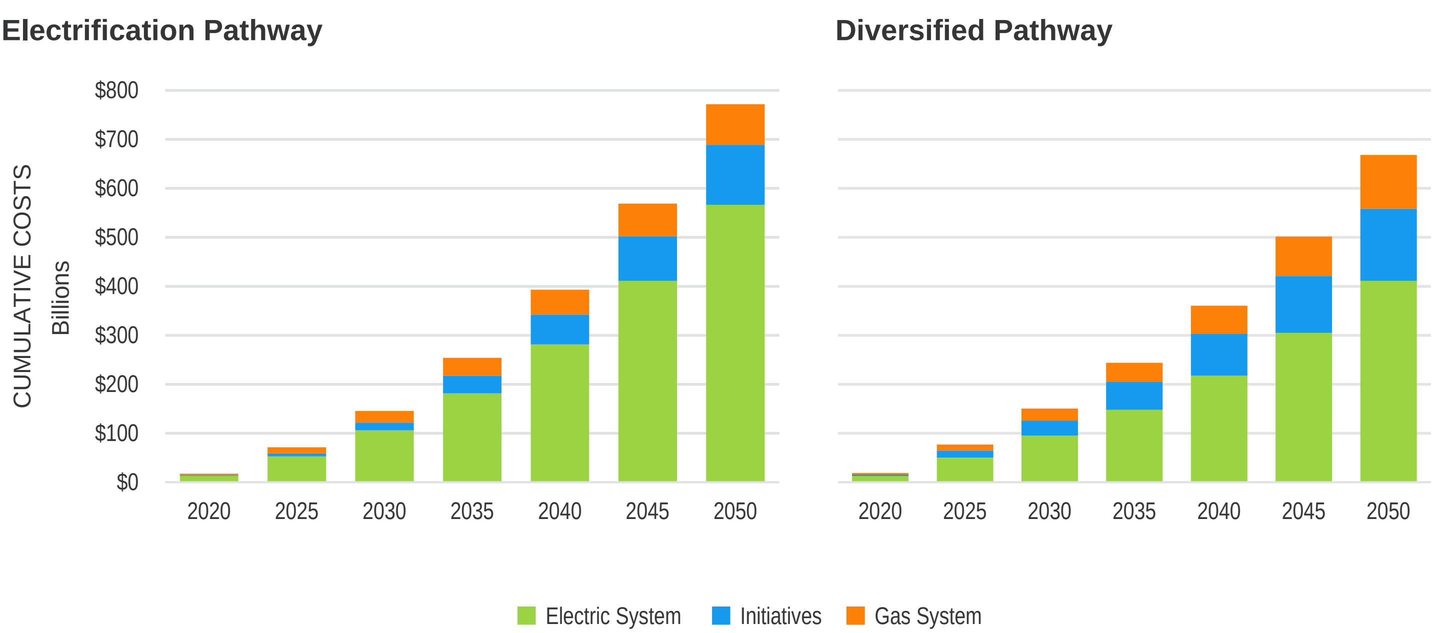
FIGURE 15. PATHWAY COSTS



Source: Guidehouse Analysis

The Diversified Pathway has higher initiative and gas system costs but significantly lower electricity system costs than the Electrification Pathway. Figure 16 compares the Diversified Pathway costs relative to the Electrification Pathway costs; the text following the figure describes the costs by component.

FIGURE 16. PATHWAY COSTS BY COMPONENT



Source: Guidehouse Analysis

- **$155 billion less spent on the electricity system:** Electricity system costs represent the incremental infrastructure needed to meet peak demand in both pathways. These costs include generation asset buildout, currently modelled to be the implementation of several large hydro generating stations in each pathway. These costs also include transmission and distribution infrastructure—this is money spent on the delivery system itself as opposed to the energy that passes through it. The Electrification Pathway has significantly higher electricity system costs due to the comparatively higher peak demand requirements.

- **$25 billion more spent on initiatives:** These initiatives are summarized in Table 1 and include vehicles, building envelope improvements, space and water heating, industrial process improvements, and renewable gases. The Diversified Pathway has higher initiative costs than the Electrification Pathway due to the large amount of renewable gas needed to decrease emissions. Further, the Diversified Pathway implements higher priced energy efficiency initiatives (e.g., gas heat pumps are more expensive than electric heat pumps).

- **$26 billion more spent on the gas system:** Gas system costs represent the expenses associated with the maintenance and operation of gas infrastructure. The Diversified Pathway has higher gas system costs because there is higher throughput during the forecast period.

The costs for both electric and natural gas ratepayers is higher in the Electrification Pathway as compared to the Diversified Pathway. Costs for electricity customers are higher because of the higher system costs in the Electrification Pathway, which are passed on to customers through electricity rates. Costs for natural gas customers are higher because significant reductions in gas consumption will not be enough to offset the cost of operating the system for a smaller number of remaining customers.

A cost sensitivity analysis was completed to determine the impact of a number of variables and found that cost drivers could increase the cost differential between the two pathways by $5 billion to $7 billion, or could narrow the gap by $5 billion to $12 billion. If conservative assumptions about key factors including the capital cost, the capital structure, or the cost of RNG or hydrogen are lower than expected, the cost differential between the two pathways will be greater. If these costs are higher, the Diversified Pathway will still be less expensive than the Electrification Pathway.

6. OTHER BENEFITS OF USING THE GAS SYSTEM FOR DECARBONIZATION

FortisBC asked Guidehouse to look at the total benefits of the gas system in BC. From a modelling perspective, the Diversified Pathway can achieve the same level of emissions reductions as the Electrification Pathway at a significantly lower cost in BC. In addition, the gas system can deliver other benefits related to security, stability, and flexibility that can advance BC's work toward a low carbon future.

GAS SYSTEM ALLOWS FOR A BROADER SET OF SOLUTIONS TO REDUCE EMISSIONS

Using the gas system to achieve GHG reductions diversifies the approach across multiple energy systems. A pathway that focuses on electrification could have higher risks should key barriers like developing new peak demand emerge. A broader approach to GHG reductions further into the scenario period could lower the risk of missing BC's 2050 target.

A significant amount of R&D has gone into various electrification and renewable technologies, resulting in widespread acceptance and economies of scale. For example, the cost on a dollars-per-watt basis of distributed solar PV has dropped over 55% between 2011 and 2018 (-11% compound annual growth rate). However, the opportunities for advancement in electrification may be reaching saturation and the development and improvement of some of these technologies is declining (e.g., the rate of solar PV cost declines is expected to slow down in the coming decade).[30]

There is more opportunity for R&D and efficiency improvements in the gas supply and corresponding end-use equipment that can be investigated alongside electrification initiatives. This opportunity could result in more economic development and societal benefit than if only electrification measures were prioritized.

Renewable gases are a major target for innovation and can play a vital role in the future of the natural gas industry. RNG, hydrogen, and synthetic methane all have great potential for the province. BC has the potential to be a major producer of RNG given its large forestry industry, which produces a large amount of woody biomass. Technical advancements are needed to more efficiently convert wood biomass waste to RNG, and researchers and organizations are identifying recommendations for technological improvement.[31] Assuming this technology meets its potential in the coming years, BC's RNG production potential could be 90 PJ per year, representing almost half of the natural gas currently delivered by FortisBC.[32] This estimate assumes only wood waste within a 50 km-75 km of natural gas compressor stations is used. If this radius can be expanded, BC's RNG potential would increase further.

[30] Navigant Research (now Guidehouse Insights), *Market Data: Solar PV Global Forecasts*, 3Q 2018, https://guidehouseinsights.com/reports/market-data-solar-pv-global-forecasts.

[31] Gas Technology Institute, *Low-Carbon Renewable Natural Gas (RNG) from Wood Wastes*, February 2019, https://www.gti.energy/wp-content/uploads/2019/02/Low-Carbon-Renewable-Natural-Gas-RNG-from-Wood-Wastes-Final-Report-Feb2019.pdf.

[32] Hallbar Consulting, *Resource Supply Potential for Renewable Natural Gas in B.C.*, March 2017, https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/resource_supply_potential_for_renewable_natural_gas_in_bc_public_version.pdf.

Hydrogen and synthetic methane also represent key initiatives to lower emissions in BC. Hydrogen and synthetic methane production technologies have not reached the limit of technical ability and offer a great opportunity for improvement through R&D and pilot projects.

Natural gas heat pumps are a gas-consuming technology that represent an opportunity for R&D and innovation. Gas heat pumps are more efficient than conventional gas space heating systems, but they have not yet reached their full market potential in Canada due to cost, availability, and other factors. However, there is strong federal support for gas heat pumps because they are expected to be instrumental in helping Canada meet its 2030 and 2050 emissions reductions targets.[33]

DROP-IN FUELS CAN BE MORE FEASIBLE AND COST-EFFECTIVE THAN FUEL SWITCHING

For many residences and businesses, switching to different heating systems may be difficult or undesirable. For policymakers focused on reducing GHG emissions, relying on broad-based fuel switching to different heating systems will involve mobilizing millions of building owners to switch. The policies and strategies to make this happen are not well understood or are infeasible.

Deploying low carbon drop-in fuels like renewable gas would leverage existing policy and regulatory frameworks and involve fewer players.[34] While it would be a challenge to develop the volume of low carbon fuels needed by 2050, governments and industry have experience in promoting low carbon energy in other sectors—notably in the electricity sector, where policy and financial incentives have led to a massive increase in renewable power investment. This model could be emulated for renewable gases.

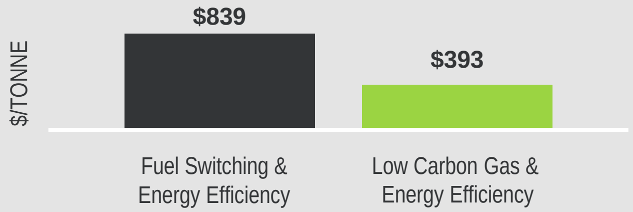
The findings in this analysis suggest drop-in fuels would be more cost-effective than fuel switching to electricity. The cost per tonne of reducing emissions in difficult-to-address sectors like buildings with renewable gases is approximately half that of fuel switching when accounting for the full system cost impacts. Figure 17 shows that the cost per tonne to reduce residential building emissions by fuel switching is higher than reducing residential building emissions using low carbon fuels in both pathways. The components of each option are summarized below:

- Fuel switching includes residential electric heat pump costs, electric system impact costs (i.e., system buildout to meet peak demand), and energy costs to switch from electricity to gas. Both electric system impact costs and energy costs are net of energy efficiency improvements.
- Low carbon gas includes the deployment of RNG/hydrogen and the implementation of gas heat pumps, building envelope improvements, and other efficiency measures.

[33] Energy and Mines Ministers' Conference, *Paving the Road to 2030 and Beyond: Market transformation road map for energy efficient equipment in the building sector*, August 2018, https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/2018/en/18-00072-nrcan-road-map-eng.pdf.

[34] Drop-in fuel refers to a fuel that can be added to an existing energy system without significant reconfiguration.

FIGURE 17. COST PER TONNE OF FUEL SWITCHING VS. LOW CARBON GAS AND ENERGY EFFICIENCY



Source: Guidehouse Analysis

SOCIO-ECONOMIC IMPACT OF AN OPTIMIZED GAS SYSTEM

The Electrification Pathway would eliminate portions of BC's natural gas industry. This elimination may result in the loss of thousands of jobs and billions of dollars of unused gas pipelines that the province has committed to financially. As a result, the province will have an under-utilized gas system, which does not provide a significant benefit. The cost to maintain and oversee this infrastructure will adversely impact British Columbians. In contrast, the Diversified Pathway optimizes the gas system to continue to deliver low carbon solutions, resulting in higher societal value.

GAS SYSTEM CAN BE USED TO REDUCE GLOBAL CARBON EMISSIONS

BC has significant natural gas resources, with remaining raw reserves of approximately 1,165 billion cubic metres. Over 60 billion cubic metres of natural gas was produced in 2018.[35] However, domestic use will likely decrease over time to reach BC's 2050 target. BC's natural gas can be exported as LNG to Asia to displace higher carbon fuels like coal, which could result in a net reduction of global GHG emissions. BC's LNG can also power large ocean vessels, which would displace higher emissions fuels like diesel and heavy oil. An analysis conducted by thinkstep concluded that LNG from BC used in marine shipping could reduce GHG emissions by up to 27%.[36]

As the policies in CleanBC are implemented (e.g., electrifying upstream gas production and implementing regulations to reduce methane emissions), the carbon intensity of the LNG supply chain in BC in 2030 would be half that of the current global average.

MAINTAINING THE GAS SYSTEM WILL SPEED INNOVATION AND ALLOW FOR FLEXIBILITY IN FUTURE TECHNOLOGY SOLUTIONS

We have modeled two pathways that both nearly achieve the required GHG emission reductions in 2050. Each pathway has been modelled by relying primarily on existing proven technologies and solutions. Continued innovation is expected to accelerate decarbonization, particularly in years after 2030. Maintaining both the gas and electric infrastructure as part of the future energy system will provide more flexibility in which innovative solutions can be easily developed and deployed. This will allow BC to achieve accelerated deployment of innovations in clean technologies and even faster decarbonization.

ROLE OF THE GAS SYSTEM IN OTHER JURISDICTIONS

Guidehouse carried out an analysis similar to this one for Gas for Climate, a group of European natural gas companies. The group commissioned a study to assess the possible role and value for gas used in existing gas infrastructure in a net-zero emissions EU energy system compared to a situation in which a minimal quantity of gas would be used.

[35] BC Oil and Gas Commission, *British Columbia's Oil and Gas Reserves and Production Report*, 2018, https://www.bcogc.ca/node/15819/download.

[36] thinkstep, *Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver: 2nd Project Phase*, 2020.

The Gas for Climate analysis[37] involved developing two scenarios to meet the EU's decarbonization requirements by 2050:

- **Minimal gas scenario:** Almost full electrification of buildings, industry, and transportation sectors.
- **Optimized gas scenario:** Moderate electrification of the abovementioned sectors, as well as large deployment of renewable and low carbon gases in select applications (heavy road transport, building heating in peak demand times, and some electricity production).

Guidehouse found the following conclusions from the Gas for Climate analysis:

- Both scenarios meet EU decarbonization requirements by 2050.
- Both scenarios need substantial quantities of renewable electricity.
- Green/blue hydrogen and RNG can help meet heating and industrial needs at low/no carbon.
- Significant benefits exist in the optimized gas scenario related to energy flexibility (i.e., gas and electric systems are used).
- Higher societal value of optimized gas pathway (over €200 billion annually across the energy system by 2050).
- The cost to decommission the gas infrastructure (in minimal gas pathway) is high.

The results of this analysis mirror that of the FortisBC study and support to the concept that gas networks have a clear role in a decarbonized future.

[37] Guidehouse, *Gas Decarbonisation Pathways 2020–2050*, April 2020, https://gasforclimate2050.eu/?smd_process_download=1&download_id=339.

7. CONCLUSIONS

This analysis indicates that the Diversified Pathway can achieve the same level of provincial GHG emissions reductions as the Electrified Pathway at a significantly lower cost to British Columbians. Although initiatives are used to different extents, both pathways defined in this study would require transformative changes in every sector of BC's economy. By 2050, the societal value of achieving the Diversified Pathway is expected to be in excess of $100 billion higher than the Electrification Pathway.

Other benefits of maintaining a robust natural gas system are preserved by adopting a strategically diversified approach. The existing gas infrastructure represents a vital component to servicing current energy demand and can continue to benefit BC by providing security, flexibility, and storage to the overall energy system. The gas system delivers cost-effective energy services, energy reliability, and significant economic benefits to the province. The gas system also provides an opportunity for a broader set of technologies and initiatives to help achieve BC's 2050 GHG reduction goal.

Appendix A-3

HYDROGEN STRATEGY FOR CANADA

HYDROGEN STRATEGY FOR CANADA

Seizing the Opportunities for Hydrogen

A Call to Action

December, 2020

DISCLAIMER

The Hydrogen Strategy for Canada (the “Strategy”) provides the perspective of numerous stakeholders from across governments, and industry, as well as Indigenous organizations, non-governmental organizations, and academia. While the Government of Canada led the development of the Strategy and consulted broadly with industry, the contents, findings, and recommendations expressed in the Strategy reflects a combined view and may not be unanimously endorsed by all of the participating organizations and their employees.

Aussi disponible en français sous le titre : Stratégie canadienne pour l’hydrogène
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Foreword to the Hydrogen Strategy for Canada

For more than a century, our nation's brightest minds have been working on the technology to turn the invisible promise of hydrogen into tangible solutions. Canadian ingenuity and innovation has once again brought us to a pivotal moment.

As we rebuild our economy from the impacts of COVID-19 and fight the existential threat of climate change, the development of low-carbon hydrogen is a strategic priority for Canada. The time to act is now.

The Hydrogen Strategy for Canada lays out an ambitious framework for actions that will cement hydrogen as a tool to achieve our goal of net-zero emissions by 2050 and position Canada as a global, industrial leader of clean renewable fuels.

This strategy shows us that by 2050, clean hydrogen can help us achieve our net-zero goal—all while creating jobs, growing our economy, and protecting our environment. This will involve switching from conventional gasoline, diesel, and natural gas to zero-emissions fuel sources, taking advantage of new regulatory environments, and embracing new technologies to give Canadians more choice of zero emission alternatives.

As one of the top 10 hydrogen producers in the world today, we are rich in the feedstocks that produce hydrogen. We are blessed with a strong energy sector, and the geographic assets that will propel Canada to be a major exporter of hydrogen and hydrogen technologies.

Hydrogen might be nature's smallest molecule but its potential is enormous. It provides new markets for our conventional energy resources, and holds the potential to decarbonize many sectors of our economy, including resource extraction, freight, transportation, power generation, manufacturing, and the production of steel and cement.

This Strategy is a call to action. It will spur investments and strategic partnerships across the country and beyond our borders. It will position Canada to seize economic and environmental opportunities that exist coast to coast. Expanding our exports. Creating as many as 350,000 good, green jobs over the next three decades. All while dramatically reducing our greenhouse gas emissions. And putting a net-zero future within our reach.

The importance of Canada's resource industries and our clean technology sectors has been magnified during the pandemic. We must harness our combined will, expertise and financial resources to fully seize the opportunities that hydrogen presents.

This strategy is the product of three years of study and analysis, including extensive engagement sessions, where we heard from more than 1,500 of our country's leading experts and stakeholders. But its release is not the end of a process. This is only the beginning.

Together, we will use this Strategy to guide our actions and investments. By working with provinces and territories, Indigenous partners, and the private-sector and by leveraging our many advantages, we will create the prosperity we all want, protect the planet we all cherish and we will ensure we leave no one behind.

The Honourable Seamus O'Regan
Canada's Minister of Natural Resources

Contributors

For the past three years, the Government of Canada, under the leadership of Natural Resources Canada, has been working with private sector stakeholders, Indigenous organizations, non-Government organizations, and governments at all levels to inform the development of a *Hydrogen Strategy for Canada*. This Strategy contains input from hundreds of companies, organizations and individuals sourced through a variety of different forums, workshops, teleconferences, bilateral discussions, and dialogue through existing working groups. While the Government of Canada led the development of the Strategy and consulted broadly with industry, the contents, findings, and recommendations expressed in the Strategy reflects a combined view and may not be unanimously endorsed by all of the participating organizations and their employees.

The Government has also commissioned a number of key studies on topics such as hydrogen codes and standards, awareness, demand modelling, and GHG emissions reduction potential. These studies along with key international reports, for example from the International Energy Agency and Hydrogen Council, have helped inform the development of the Strategy.

Zen and the Art of Clean Energy Solutions (Zen) is the lead author of this strategy on behalf of the Government of Canada. Zen together with the Institute for Breakthrough Energy + Emission Technologies (IBET) led the aggregated 2050 hydrogen demand modelling work to determine the potential role hydrogen can play in Canada's future energy system. The Strategy summarizes and integrates stakeholder inputs and previous studies, as well as recent modelling and analysis, into a single cohesive document.

The *Hydrogen Strategy for Canada* is a strategic directional document based on best available information at this time. Adjustments will be made as technology, research, codes and standards, the international hydrogen landscape, and policy evolves. Additional research and analysis outlined as recommended actions in this document are planned through the Implementation Strategic Steering Committee, dedicated Working Groups, and Regional Blueprints.

Consultations

Consultations were held with over 1,500 stakeholders from across the value chain to ensure engagement opportunities were as comprehensive as possible. Stakeholder groups include, but are not limited to the private sector, associations and NGOs, academia and research groups, Federal and Provincial Governments, and Indigenous Organizations, communities, and businesses.

Linkages with Industry Working Groups

The Government has also collaborated closely with the Transition Accelerator, the Canadian Hydrogen and Fuel Cell Association (CHFCA), the Canadian Gas Association, and other industry associations which are pursuing actions closely aligned with those identified in the Strategy. Once the strategy is released, Canada will establish a Strategic Steering Committee, with several targeted task teams, to ensure progress toward the recommendations in the strategy is made and measured.

Abbreviations

AHJ	Authority Having Jurisdiction
ASHP	Air Source Heat Pump
ATR	Autothermal Reforming
AZETEC	Alberta Zero-Emissions Truck Electrification Collaboration
BC-LCFS	British Columbia's Low Carbon Fuel Standard
BECCS	Bio-energy with Carbon Capture and Storage
BEV	Battery Electric Vehicle
BNQ	Bureau de Normalization du Québec
CAD	Canadian Dollars
CCUS	Carbon Capture Utilization, Storage
CEC	California Energy Commission
CFS	Clean Fuel Standard
CHFCA	Canadian Hydrogen and Fuel Cell Association
CHIC	Canadian Hydrogen Installation Code
CI	Carbon Intensity
CMMP	Canadian Minerals and Metals Plan
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CSA	Canadian Standards Association
DAC	Direct Air Capture
DOE	Department of Energy (US)
DRI	Direct Reduced Iron
EER	Energy Effectiveness Ratio
FCEB	Fuel Cell Electric Bus
FCEV	Fuel Cell Electric Vehicle
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GJ	Gigajoule
GW	Gigawatt
H_2	Hydrogen
HD	Heavy-Duty
ICE	Internal Combustion Engine
ICT	Innovative Clean Transit
IEA	International Energy Agency
IMO	International Maritime Organization
IP	Intellectual Property
IRAP	Industrial Research Assistance Program
LD	Light-Duty
LNG	Liquid Natural Gas
MCH	Methylcyclohexane
MJ	Megajoule
NG	Natural Gas
NH_3	Ammonia
NO_x	Nitrogen Oxides
NRC	National Research Council

OEM	Original Equipment Manufacturer
OpEx	Operating Expenditures
PEM	Proton Exchange Membrane
PJ	Petajoules
PSA	Pressure Swing Adsorption
RNG	Renewable Natural Gas
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolysis Cell
SO_x	Sulphur Oxides
SR&ED	Scientific Research and Experimental Development Tax Incentive Program
SDTC	Sustainable Development Technology Canada
TCO	Total Cost of Ownership
TRL	Technology Readiness Level
TWh	Terawatt-hour
VRE	Variable Renewable Energy
WGS	Water Gas Shift
ZEV	Zero-Emission Vehicle

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TIME TO ACT

The world's energy systems are undergoing radical transformation driven by the need to mitigate climate change. Development of an at-scale, clean hydrogen economy is a strategic priority for Canada, needed to diversify our future energy mix, generate economic benefits and achieve net-zero emissions by 2050.

The time to act is now. Governments around the world are releasing and executing hydrogen strategies that are building global momentum. In 2019, Canada seized this momentum by developing and launching a new Hydrogen Initiative under the Clean Energy Ministerial, designed to be the cornerstone for global hydrogen deployment.

Now, one year later, Canada is poised to leverage this momentum, to grow the domestic opportunity for hydrogen, while also benefiting from growth in global demand through export opportunities, guided by this Strategy.

This Strategy seeks to modernize Canada's energy systems by leveraging Canadian expertise – including increased participation from marginalized and underrepresented groups – through building new hydrogen supply and distribution infrastructure and fostering uptake in various end-uses, that will underpin a low-carbon energy ecosystem in the near- and long-term. It will set the foundation to do this over the next five years by:

- Encouraging early deployment HUBs in mature applications, and Canadian demonstrations in emerging applications;
- employing regulations, including the forth-coming Clean Fuel Standard to drive near-term investments; and
- framing new policy and regulatory measures needed to reach net-zero by 2050.

These activities in the short-term will be followed by the growth and diversification of the sector from 2025 to 2030. Thereafter, through rapid expansion until 2050, Canada will start to realize the full benefits of the hydrogen strategy.

Those benefits include:

- positioning Canada to become a world-leading supplier of hydrogen technologies;
- sparking economic recovery while growing domestic low-carbon fuel production to reduce emissions for the longer term, including unique opportunities for Indigenous communities and businesses;
- generating more than 350,000 high-paying jobs nationally; and
- employing hydrogen as a key enabler to reach net-zero emissions by 2050.

The International Energy Agency (IEA) has recommended that governments put clean energy solutions such as hydrogen at the heart of stimulus plans. Green infrastructure investments are key to achieving Canada's post-pandemic economic recovery, clean growth and climate change objectives.

By applying its world-class expertise at home, Canada can showcase hydrogen's real-world applications and benefits and the role hydrogen can play in transforming energy systems. Early deployment HUBs will set Canada on a path for widespread deployment in the mid- and long-term where hydrogen's decarbonization potential can be fully realized.

CONTEXT

Canada has played an important role in the development of the growing global hydrogen economy, starting more than a century ago with innovation in hydrogen production technology and four decades ago as pioneers in fuel cell technology. Canada continues to be an R&D and technology leader in the sector.

Under the Paris Agreement, Canada has committed to reducing GHG emissions by 30% below 2005 levels by 2030. It has also announced a target to achieve net-zero emissions by 2050, joining 72 other nations in this ambitious pledge. In a net-zero future, Canada's economy will be powered by electricity and low carbon fuels – with low carbon fuels expected to provide up to 60% or more of our energy needs. As the lowest carbon fuel, hydrogen is essential to decarbonizing the top third of Canada's most energy intensive and hard-to-abate end-use applications, and there is much work to do to roll out hydrogen at scale domestically.

Canada is not alone in seeing hydrogen as a critical part of the solution to combat climate change and improve air quality, while driving economic growth in a carbon-constrained world. Countries around the world have developed strategies to inform the optimal supply pathways and end-use applications for hydrogen, as well as to define export strategies.

The demand for hydrogen in global energy systems is dramatically increasing, with projections indicating at least a tenfold increase in demand over the next three decades. Studies indicate that hydrogen could provide up to 24%[1] of global energy demand by 2050. The number of countries with polices that support investment in hydrogen technologies is increasing, along with the number of sectors they target. Canada is uniquely positioned to become a large-scale exporter of hydrogen to serve this growing market, but domestic deployments must lead.

For three years, the Government of Canada, under the leadership of NRCan has been working with private sector stakeholders and governments at all levels to inform the development of the *Hydrogen Strategy for Canada.* The release of this strategy comes during unprecedented times. The world has been shaken by COVID-19, and there is daily evidence mounting that climate change poses an ever-increasing risk to the world's economies, habitats, biodiversity, human health, and our future way of life.

Canada has all the ingredients necessary to develop a competitive and sustainable hydrogen economy. The modernization of Canada's energy systems towards a low-carbon economy presents a unique opportunity to leverage Canadians' expertise to build new infrastructure assets to serve as a backbone for a low-carbon energy ecosystem across Canada with hydrogen playing an integral role, delivering up to 30% of Canada's end-use energy by 2050.

This strategy is a call to action. Achieving decarbonization targets requires bold action and radical transformation of Canada's energy system that must begin with the end in mind rather than working incrementally based on old paradigms.

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[1] Bloomberg NEF. (2020). *Hydrogen Economy Outlook*. Retrieved from https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf

CANADA'S ADVANTAGES

Canada has unique competitive and comparative advantages that position the country to become a world-leading producer, user, and exporter of clean hydrogen, as well as hydrogen technologies and services. A strong hydrogen economy will lead to financial, environmental, and health benefits for Canadians.

- **Rich in feedstocks to produce hydrogen**

  Canada has among the lowest Carbon Intensity (CI) electricity supplies in the world given our hydroelectric generation capacity and status as a Tier-1 nuclear region. Canada also has abundant fossil fuel reserves, world class CO_2 storage geology, potential for growth in variable renewables, large scale biomass supply, and freshwater resources. All of these can be leveraged to produce hydrogen.

- **Leading innovation and industry position**

  Canada is known for its leading hydrogen and fuel cell technology companies and expertise. As of 2017, there were >100 established companies, employing >2,100 people, generating revenues >$200 million. Canada also has significant expertise in carbon capture technology, one of the keys to the production of low CI hydrogen from fossil fuels.

- **Strong energy sector**

  Canada's energy sector accounted for 832,500 direct and indirect jobs as of 2019, with assets valued at $685 billion[1]. This skilled labour force coupled with strategic infrastructure assets position Canada to rapidly pivot to include at- scale hydrogen as an energy currency.

- **Established international collaborations**

  Canadian government, industry and academia are involved in international collaborations related to hydrogen that position Canada as a leader both from an innovation and commercial perspective.

- **Energy export channels to market**

  Canada's proximity to hydrogen import markets including Japan, South Korea, California, the UK, Germany, and all of Europe, along with export assets such as deep water ports, established pipeline networks, and an emerging LNG industry, position Canada to be an exporter of hydrogen as the global economy evolves.

- **Canada's Unique Starting Point**

  Canada is recognized as a global leader in the hydrogen and fuel cell sector, seen as a hub for technical expertise, intellectual property, and leading products and services. Canada is one of the top 10 hydrogen producers in the world today. An estimated three million tonnes are produced per year from natural gas. Canada is home to the largest clean hydrogen production facility in the world to produce hydrogen from natural gas with carbon capture and permanent storage for the resulting CO_2 emissions.

By leveraging these advantages to develop a vibrant and robust clean hydrogen economy, Canadians will benefit from:

- **Economic growth and jobs**

  Canada's hydrogen economy will create new green jobs in R&D, manufacturing, and services supporting increased participation from traditionally marginalized and under-represented groups as part of an inclusive transition. Hydrogen will become a new export currency for both regional energy economies in Western, Central, and Eastern Canada, as well as in the international market. This will allow

[1] NRCan. (2018). *10 Key Facts on Canada's Energy Sector*. Retrieved from https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/pdf/10-Key-Facts-on-Canada_s-Energy-Sector-2018-en%20.pdf

Canadian energy companies to move up the value chain as a fuel provider in a zero-emissions future. If Canada fully seizes the opportunity presented by hydrogen, it could lead to more than 350,000 sector jobs and direct revenues of over $50B/year by 2050.

- Transformative opportunity for Canada's petroleum sector

  Hydrogen is critical to transforming oil and natural gas industries to net-zero emissions. It provides an opportunity to leverage Canada's diverse talent pool, valuable energy reserves, and infrastructure assets in a way that is carbon-free at the point of use, providing a future pathway to utilize these assets.

- Energy resilience

  Hydrogen can act as an energy carrier to enable increased penetration of renewables by providing time shifting and energy storage capabilities. Hydrogen adds optionality in a future net-zero mix, complementing other energy vectors such as direct electrification and biofuels, and serving as a bridge between energy grids in an integrated energy system.

- Cleaner air

  Hydrogen does not produce greenhouse gases, black carbon, particulates, SO_x, or ground-level ozone at the point of use. When used in an electrochemical fuel cell, it emits only water and heat. Increased hydrogen adoption leads to cleaner air, with improved health outcomes for Canadians.

- Meeting decarbonization goals

  Hydrogen uniquely closes the gap in hard-to-abate, energy intensive applications such as long-range transportation, high-grade heat production, and as a feedstock in industrial processes. Hydrogen has the potential to make significant contributions to Canada's required GHG emission reductions by 2050.

CANADA'S OPPORTUNITY

Clean hydrogen has the potential to deliver up to 30% of Canada's end-use energy by 2050, abating up to 190 Mt-CO_2e of GHG emissions through deployment in transportation, heating, and industrial applications.

With Canada's strong starting position, emissions reductions from an optimistic transformative scenario could contribute up to 45 Mt-CO_2e reduction by 2030. This scenario is more likely to be achieved with strong pricing and regulatory incentives in place at the federal and provincial level to drive hydrogen adoption, supported by immediate and aligned action across government and industry. Canada's recently announced Strengthened Climate Plan, including carbon pricing, the Clean Fuel Standard and the $1.5 billion dollar Low-carbon and Zero-emissions Fuels Fund, is already putting in place foundational federal initiatives that will enable the broad suite of measures contemplated in this Strategy. Benefits realized by hydrogen will accelerate beyond the 2030-timeframe, with potential under the transformative scenario to contribute up to 190 Mt-CO_2e reductions per year, by 2050.

H_2 Opportunity

	2030	2050
% of Delivered Energy	6%	30%
Hydrogen Demand	4 Mt-H_2	20 Mt-H_2
GHG Emissions Abated	up to 45 Mt-CO_2e	up to 190 Mt-CO_2e

Production

Canada's rich feedstock reserves, skilled energy labour force, strategic energy infrastructure assets, and leading position in innovation in hydrogen and fuel cell technologies position Canada to become one of the top three global producers of clean hydrogen.

Canada is one of the top ten global producers of hydrogen today, producing an estimated 3 million tonnes (Mt) annually via steam methane reformation (SMR) of natural gas. While SMR is not considered a clean hydrogen pathway without carbon capture, Canada is well placed to transition to clean pathways going forward. Canada has established production supply chains, primarily in Alberta for fuel upgrading/refining and nitrogen fertilizer production that can be leveraged in the near term. By 2050, Canada could grow production by a factor of seven to meet domestic demand, producing >20 Mt of low CI hydrogen per year, with potential for significant expansion to meet global demand.

Hydrogen can be made from a variety of feedstocks, including water and electricity, fossil fuels, biomass and as a by-product from industrial processes. The CI of the hydrogen pathways can vary significantly, and Canada must be focused on developing cost-effective, low CI pathways in the near and mid term while ultimately transitioning to an increasing percentage of renewable or zero-emission feedstocks over the long term. Canada is working with countries around the world to develop a common methodology to determine and independently certify the CI of hydrogen, which will be necessary to facilitate trade.

Hydrogen production in Canada is expected to be based on a mix of pathways. The aggregate hydrogen demand projected in 2050 highlights the need for Canada to explore all low CI hydrogen production opportunities.

- Electrolytic Hydrogen

  Hydrogen can be produced from water via electrolysis using clean electricity. Canada is the sixth-largest global producer of electricity in the world and has one of the lowest carbon intensity grids due to our vast hydroelectricity generating assets. There are also synergies between hydrogen production, nuclear and renewable electricity. Hydrogen can be produced via electrolysis using off-peak nuclear electricity in the near term, while high-temperature thermal processes or coupling with small modular reactors are viable in the longer term. Hydrogen can also play a role in daily to seasonal storage of variable renewable resources, enabling a higher penetration of intermittent renewables on the grid.

- Hydrogen from fossil fuels

  Clean hydrogen can be produced from fossil fuels when combined with Carbon Capture Utilization, and Storage (CCUS) or the carbon can alternatively be sequestered in the form of solid carbon. Canada is the world's fourth largest producer of natural gas. Provinces with the highest natural gas and petroleum reserves are Alberta, British Columbia, and Saskatchewan, and the Atlantic Provinces, and these provinces are best suited for hydrogen production from fossil fuels.

- Hydrogen from biomass

  Hydrogen can be derived from the gasification of dry biomass. This is considered to be both renewable and carbon neutral. Most provinces in Canada have access to biomass residues through forest and agriculture sectors.

- Industrial by-product hydrogen

  Hydrogen in Canada currently produced as a by-product of industrial processes including chlor-alkali and sodium chlorate production can be captured, purified, and used directly. Vented hydrogen from large-scale plants can be sufficient to support some near-term needs, but is limited in supply.

The hydrogen supply network in Canada could include both large-scale centralized plants in Canada's natural-gas rich provinces or in regions with high penetration of low-cost renewables, and smaller-scale distributed electrolytic production near demand centers. Delivered hydrogen costs of $1.50-3.50/kg are projected to be achieved as production scale is realized and investment is made in distribution infrastructure.

Industry and Provincial Governments will play an important role in determining which hydrogen production pathways will come to fruition in Canada, and over what timeframes.

End-Use

Domestic deployment of hydrogen is critical to supporting Canada's world-leading hydrogen and fuel cell sector, as well as to meeting climate change objectives. The earlier deployment starts, the sooner scale and user acceptance will be achieved, allowing the realization of longer-term projections on uptake and associated benefits.

Adoption of hydrogen will be focused on energy-intensive applications where it offers advantages over alternative low-carbon options. This includes using hydrogen as a fuel for long-range transportation and power generation, to provide heat for industry and buildings, and as a feedstock for industrial processes.

- **Fuel for Transportation**

Hydrogen can be used directly as a fuel in fuel cell electric vehicles, which have twice the efficiency of combustion engines and zero harmful emissions at the tailpipe. Hydrogen combustion and co-combustion engine technology is also under development as a transitional opportunity.

Fuel cell light-duty passenger vehicles are commercially available today globally, and in limited numbers in Canada. The Government of Canada has set federal targets for zero-emission vehicles (ZEV) to reach 10% of light-duty vehicles sales per year by 2025, 30% by 2030 and 100% by 2040. Canada considers battery electric vehicles (BEVs), fuel cell electric vehicles (FCEVs), and plug-in hybrid electric vehicles (PHEVs) to qualify as ZEVs. BC and Quebec have led provincially with the adoption of consumer purchase incentives for ZEVs and sales regulations. Both of these provinces have started to deploy hydrogen fueling infrastructure and light-duty FCEVs.

Battery electric vehicles are expected to take a significant portion of the market share for light-duty applications in Canada. FCEVs offer choice for consumers desiring longer range and faster fueling times and are well suited to larger passenger vehicle platforms.

Public transit agencies around the world are shifting towards low- and zero-emission vehicles. Fuel cell electric buses (FCEBs) are commercially available today, with more than 2000 FCEBs[1] in service worldwide, and approximately half of those are powered by Canadian technology. Canada has unique potential for a 'made-in-Canada' solution with New Flyer Industries and Ballard Power Systems leading the market with commercial fuel cell electric bus deployments in North America.

The zero-emission bus (ZEB) initiative[2] underway in Canada encourages government to support school boards and municipalities in purchasing 5000 ZEBs over the next five years. Canada can leverage the local supply chain to provide economic value if FCEBs are a portion of the mix. These buses are well suited to longer routes and cold weather climate that Canadian transit agencies service.

Fuel cells are expected to play a significant role in medium- and heavy-duty trucks, rail, and ships that have operations with high power demand, coupled with energy-intensive and long duty cycles. For example, heavy-duty trucks travelling long distances would require many heavy batteries, reducing the load capacity beyond that which would be acceptable to operators. Long charging times could also impact operations negatively. The improved energy density and fast fill characteristics of fuel cell electric trucks will likely make them an optimal choice for certain applications.

[1] Ballard. (2020). *Fuel Cell Electric Buses*. Retrieved from https://www.ballard.com/docs/default-source/web-pdf's/white-paper_fuel-cell-buses-for-france_final-english-web.pdf?sfvrsn=939bc280_0

[2] CUTA. (2019). *New federal government unveils its priorities*. Retrieved from https://cutaactu.ca/en/blog-posts/new-federal-government-unveils-its-priorities

There is a similar value proposition for hydrogen use in mining equipment, including material handling vehicles. Hydrogen presents an opportunity to reduce widespread reliance on diesel for mining vehicles and stationary power equipment. Hydrogen offers the added benefit of reducing harmful exhaust emissions, especially in underground mines. The Canadian Minerals and Metals Plan (CMMP) aims to capitalize on opportunities to strengthen Canada's competitive position within the global mining sector and emphasizes the importance of developing and adopting alternative energy sources, such as hydrogen.

In the near term, as costs and availability of fuel cells challenge uptake, hydrogen-diesel co-combustion in truck applications offers an alternative pathway to create the demand for hydrogen and support infrastructure development.

♦ Fuel for Power Generation

Hydrogen can be used as a fuel for power production through either hydrogen combustion in turbines or electrochemical conversion in stationary fuel cell power plants. Hydrogen provides load management, long-term energy storage, and a path to market that enables the growing use of intermittent renewables.

In the longer term, hydrogen can play a role in greening Canada's electricity grids where there is still a reliance on fossil fuels for power production. Hydrogen can also provide stability for off-grid renewables-based power solutions in remote communities and remote industrial sites such as mines that are today largely dependent on expensive, highly emitting diesel power.

♦ Heat for Industry

As a heating fuel, hydrogen is a cleaner-burning molecule that can be a substitute for the combustion of fossil fuels in applications where high-grade heat is needed and where electric heating is not technically or economically the best solution.

In Canada's oil and gas sector, low CI hydrogen can offer emissions reduction benefits in both upstream extraction (combusted as a heat source) and downstream refining (used as a chemical feedstock). For example, in upstream operations, low CI hydrogen can replace natural gas combusted to produce steam for steam-assisted gravity drainage (SAGD) in-situ bitumen production. Hydrogen can lower the CI of conventional refined petroleum products in this way and could offer a compliance pathway for the federal Clean Fuel Standard.

Other heavy industry in Canada that relies on a large amount of high-grade heat production includes cement and steel manufacturing, the pulp and paper sector, and industrial processes relying on steam production. These sectors can also reduce emissions by converting to blends of hydrogen and natural gas or pure hydrogen for heat production.

♦ Heat for Buildings

Hydrogen can play a role in reducing emissions in heating applications in the built environment. Natural gas (NG) utilities are looking to decarbonize the NG grid by introducing both Renewable Natural Gas (RNG) and hydrogen as alternative low-carbon chemical fuels. Canada's cold climate results in heating accounting for almost 80% of energy use in the home.[1] Since NG is used for both space heating and water heating, hydrogen is gaining increased attention from utilities as a low-carbon option, either as a blend with natural gas or as a replacement fuel. Several jurisdictions in Canada and worldwide are conducting pilot projects to determine the technical feasibility of blending hydrogen into existing natural gas systems. Codes and standards work will be required to support opportunities for the potential blending of hydrogen.

Due to possible technical constraints, beyond blending limits of ~20% by volume, dedicated

[1] NRCan. (2017). *Residential Sector*. Retrieved from https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/handbook/handbook_res_00.cfm

hydrogen pipelines start to become an attractive alternative. In a net-zero future where distributed combustion emissions need to be largely eliminated, hydrogen may become the new chemical fuel of choice for heating in Canada, and utilities will play an important leadership role in that transition.

- **Feedstock for Industry**

Hydrogen is used as a feedstock in several industrial processes in Canada today. Most feedstock hydrogen is currently produced via steam methane reforming.

Hydrogen is used as a feedstock for:

- Petroleum refining
- Bitumen upgrading
- Ammonia production
- Methanol production
- Steel production

The greatest use of hydrogen globally today is for refining and upgrading crude oil, where hydrogen-based processes remove impurities like sulphur and process heavy hydrocarbon chains into lighter components. The majority of hydrogen required for refining is produced on-site from either dedicated production facilities or as a by-product. Because of this integration of hydrogen production within refining facilities, production is primarily supplied by natural gas reforming methods. The most significant opportunity to reduce emissions associated with hydrogen in the oil and gas industry is retrofitting existing conversion technology with carbon capture and storage or deploying new clean hydrogen technology that does not produce CO_2.

Availability of low cost, low CI hydrogen can create new industry in Canada. This includes methanol production and liquid synthetic fuel production, an innovative process combining clean hydrogen and carbon captured from the air to produce carbon-neutral, energy-dense liquid fuels that are well suited to applications such as aviation and large marine vessels. Renewable nitrogen fertilizer production also presents an opportunity for a new Canadian industry.

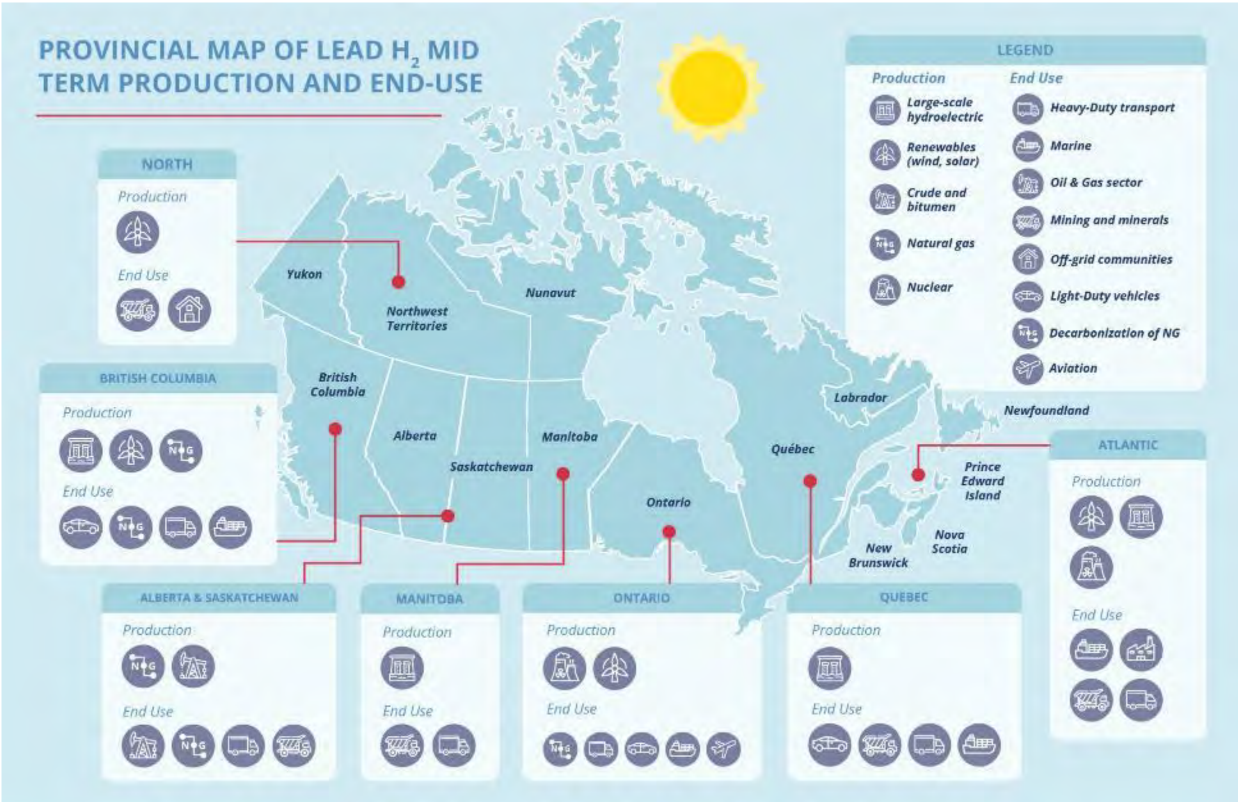
Export

With worldwide demand for hydrogen increasing, the global market is expected to reach more than $2.5T by 2050. There is a significant export opportunity for Canada as energy importers are actively looking to Canada as a potential supplier.

As an energy rich nation with significant clean hydrogen production capacity, established international trade partnerships, and strategic infrastructure assets such as deep water ports and established pipeline networks, Canada is positioned to become top global supplier of clean hydrogen. A 2019 BC study shows an export potential of $15 billion by 2050 from that province alone. Another recent study indicated that hydrogen exports could reach ~$50 billion by 2050[1], doubling the economic potential of the domestic market projected for Canada in that same timeframe. With import countries looking to decarbonize their energy systems, hydrogen could contribute to a significant portion of the energy export market share in the coming decades.

Just as Canada is working to capture the global LNG export market, we can build on this experience to advance a hydrogen strategy with strong early actions and a national plan that builds on Canada's regional strengths. Taken together, we can lead in the emerging hydrogen export market.

[1] The Transition Accelerator. (2020). *Towards Net-Zero Energy Systems in Canada: A Key Role for Hydrogen*. Retrieved from https://transitionaccelerator.ca/wp-content/uploads/2020/09/Net-zero-energy-systems_role-for-hydrogen_200909-Final-print-1.pdf



REMAINING CHALLENGES

Economic and Investment

The factors limiting hydrogen use in some applications today are economic rather than technological, where hydrogen is not yet cost-competitive compared to other conventional fuel options.

While hydrogen can be among the lowest cost alternatives for reducing carbon emissions on a dollar-per-tonne-abated basis, a challenge today is that even with some form of carbon pricing, GHG emissions are not always adequately reflected in the market cost of baseline fuels. Implementation of the federal Clean Fuel Standard will be an important step forward.

The cost of end-use applications that rely on fuel cells is also a barrier to adoption, and R&D and scaled-up manufacturing processes are needed to drive down costs. Development of supporting infrastructure requires significant coordinated investments, which is challenged by uncertain demand creating high risk for investors.

Achieving scale is also critical to economic competitiveness of the industry. While the sector must ultimately be self-sustaining, strong policy and fiscal support are needed in the next 5-10 years to attract and de-risk industry investment.

Technology & Innovation

Canada was an early leader in the hydrogen and fuel cell sector and is recognized worldwide as a region rich with technical expertise, intellectual property, and leading products and services. While some hydrogen and fuel cell technologies are at a level of commercial readiness, support for R&D is needed to reduce costs further, develop solutions in the less mature applications and discover new breakthrough technologies to benefit the sector. Continuing to stay at the forefront of innovation is critical to sustaining Canada's competitive advantages.

Other countries have been rapidly increasing investment to support innovation in the sector, whereas between 2008 and 2016, Canada slowed investment in fundamental research in this sector. While more recently, Canada has again committed to being a global leader in clean tech innovation, this gap in support has resulted in the fact that some Canadian companies developing research centres and/or moving parts of their operations to other countries where there is more support for technology advancement. It is important for Canada to act now to prevent loss of critical intellectual property.

Policy & Regulation

Clean hydrogen projects around the world have primarily been in regions with a combination of supporting policies and regulations. Policies and regulations that encourage the use of hydrogen technologies include low carbon fuel regulations, carbon pricing, vehicle emissions regulations, zero-emission vehicle mandates, creation of emission-free zones, and renewable gas mandates in natural gas networks. Mechanisms to help de-risk investments for end-users to adapt to regulations are also beneficial.

Canada currently lacks a comprehensive and long-term policy and regulatory framework that includes hydrogen. Where policies are in place, they are not consistent across regions resulting in a 'patch-work' approach that slows adoption.

Availability of Hydrogen Infrastructure

Domestic supply of low CI hydrogen is limited in many parts of Canada today, and this is preventing both pilot and commercial rollout. For some applications, there is a need to transport and store hydrogen from the site of production to the end-user. This includes refueling infrastructure for transportation applications.

Over time, as domestic production and demand grow, there will be a need for dedicated infrastructure such as hydrogen pipelines and liquefaction plants. Ensuring that these crucial assets can be built in a coordinated and timely manner will be essential to ensuring low cost, low CI hydrogen can be delivered to both domestic and international markets.

Codes & Standards

The deployment of hydrogen is in the early stages across many jurisdictions and sectors in Canada, and there are gaps in existing codes & standards that need to be addressed to enable adoption. Harmonizing codes and standards across jurisdictions will ensure that best practices are applied across the global hydrogen economy to facilitate the growth of trade and export markets.

Awareness

There is a lack of awareness about the opportunities and safety around hydrogen within the general public, as well as within industry and government. Increased awareness about hydrogen as a viable decarbonization pathway that is safe and provides economic benefits is critical to establishing a vibrant hydrogen sector.

PATH FORWARD

Vision for 2050

If Canada seizes the opportunities for hydrogen, by 2050 the country could realize the following:

- Up to 30% of Canada's energy delivered in the form of hydrogen
- Canada is one of top 3 global clean hydrogen producers, with domestic supply >20 Mt/year
- Established supply base of low carbon intensity hydrogen with delivered prices of $1.50 - $3.50/kg
- >Five million FCEVs on the road
- Nationwide hydrogen fueling network
- >50% of energy supplied today by natural gas is supplied by hydrogen through blending in existing pipelines and new dedicated hydrogen pipelines
- New industries enabled by low-cost hydrogen supply network
- ~350,000 hydrogen sector jobs
- >$50 billion in direct hydrogen sector revenue for the domestic market
- Established and competitive hydrogen export market
- Up to 190 Mt-CO_2e annual GHG reduction

Near Term: Laying the Foundation

The focus of the next five years will be on laying the foundation for the hydrogen economy in Canada. This includes planning for and developing new hydrogen supply and distribution infrastructure to support early deployment HUBs in mature applications while supporting Canadian demonstrations in emerging applications. Regulations such as the Clean Fuel Standard will be fundamental to driving near-term investment in the sector. Introduction of new policy and regulatory measures will also be needed.

Mid Term: Growth and Diversification

Activities to stimulate the sector in the next five years will be followed by growth and diversification of the sector in the 2025 – 2030 timeframe. As the technology matures and the full suite of end-use applications is at or near commercial technology readiness levels, hydrogen use will be focused on applications that provide the best value proposition relative to other zero-emission technologies.

Long Term: Rapid Market Expansion

In the 2030-2050 timeframe, Canada will start to realize the full benefits of a hydrogen economy as the scale of deployments increase and number of new commercial applications grows, supported by Canada's foundational supply and distribution infrastructure.

RECOMMENDATIONS AND IMPLEMENTATION

Recommendations

The release of this strategy is the first step in the next phase of Canada's hydrogen journey. The recommendations will inform the development of concrete actions by all players across the hydrogen ecosystem.

In the implementation phase following the release of the strategy, there will be ongoing engagement with public, private and Indigenous stakeholders to continue the momentum, initiate and track activities related to the recommendations, follow progress, and identify new priority areas as the market evolves. Actions will be coordinated through a Strategic Steering Committee and Working Groups.

The Strategy's recommendations have been developed in consultation with stakeholders and represent actions needed to lay the foundation and maintain momentum for maximizing the benefits of hydrogen in Canada's future energy system mix.

There are 32 recommendations across the eight pillars of the *Hydrogen Strategy for Canada*. Not all of these actions will happen at once - the figure on page XXII outlines how Canada must sequence actions to seize the hydrogen opportunities over time, cementing its essential role in our low-carbon future.

The Strategy's recommendations represent sector-wide themes, highlighted throughout the Strategy. Recommendations have been proposed in eight pillars:

Pillar 1: Strategic Partnerships *- Strategically use existing and new partnerships to collaborate and map out the future of hydrogen in Canada.*

Pillar 2: De-Risking of Investments *- Establish funding programs, long-term policies, and business models to encourage industry and governments to invest in growing the hydrogen economy.*

Pillar 3: Innovation *- Take action to support further R&D, develop research priorities, and foster collaboration between stakeholders to ensure Canada maintains its competitive edge and global leadership in hydrogen and fuel cell technologies.*

Pillar 4: Codes and Standards *- Modernize existing and develop new codes and standards to keep pace with this rapidly changing industry and remove barriers to deployment, domestically and internationally.*

Pillar 5: Enabling Policies and Regulation *- Ensure hydrogen is integrated into clean energy roadmaps and strategies at all levels of government and incentivize its application.*

Pillar 6: Awareness *- Lead at the national level to ensure individuals and communities are aware of hydrogen's safety, uses, and benefits during a time of rapidly developing technologies.*

Pillar 7: Regional Blueprints *- Implement a multi-level, collaborative government effort to facilitate the development of regional hydrogen blueprints to identify specific opportunities and plans for hydrogen production and end use.*

Pillar 8: International Markets *- Work with our international partners to ensure the global push for clean fuels includes hydrogen so Canadian industries thrive at home and abroad.*

Strategic Partnerships

1. *Collaborate across multiple levels of government and with Indigenous groups through Intergovernmental Working Groups to establish priority areas for deployment and to share knowledge, best practices, and lessons learned through early deployments.*
2. *Expand public/private partnerships leveraging Canada's innovative clean technology companies and world-leading hydrogen and fuel cell expertise to accelerate deployment projects across the value-chain.*
3. *Foster cross-sector collaborations within domestic deployment hubs to show the economic and operational benefits of multiple applications operating as part of an integrated ecosystem.*
4. *Leverage international collaborations and pursue synergistic international initiatives to attract direct foreign investment and to accelerate opportunities for Canada in global markets.*

De-Risking Investments

5. *Implement long-term policies that create hydrogen demand certainty and de-risk the private sector investments needed to establish supply and distribution infrastructure.*
6. *Establish multi-year programming as well as a clear and long-term regulatory environment to support early production and end-use projects, including support to assess the feasibility of projects.*
7. *Develop regional deployment HUBs to demonstrate, validate, and implement business cases across the full value chain, from production and distribution to end-use.*
8. *Facilitate co-funding opportunities, leveraging multiple levels of government and the private sector.*

Innovation

9. *Develop strategic fundamental research priorities where Canada can sustainably excel and provide economic value; set technology performance and cost goals.*
10. *Establish dedicated funding for sustained RD&D to ensure Canada retains its leadership position in hydrogen and fuel cell technologies.*
11. *Leverage expertise in academia, government labs, and private sector labs to create regional research hubs and to encourage mission-oriented approaches to research, development, and pilot deployments.*
12. *Foster collaboration between Federal labs, industry, and academia as well as international partners, by supporting consortium-based projects for fundamental research and by coordinating reviews and information sharing.*

Codes and Standards

13. *Update, harmonize and recognize codes and standards (including the Canadian Hydrogen Installation Code) to enable deployments and to facilitate new technology and infrastructure adoption in early markets.*
14. *Establish a codes and standards working group, which includes inter-provincial Authorities Having Jurisdiction representatives, to share lessons learned and identify gaps in codes and standards.*
15. *Develop standards that are performance based versus prescriptive, and ensure hydrogen is not excluded from broader codes, standards, and regulations due to restrictive language.*
16. *Facilitate Canadian leadership and participation on international standard and certification efforts (e.g. development of global carbon intensity metrics, blending levels for hydrogen in natural gas systems), simplifying international trade.*

Enabling Policies and Regulations

17 *Ensure that governments at all levels consider hydrogen's essential role in Canada's energy future as they develop new policies, programs, and regulations.*

18 *Encourage governments to modernize and update existing policies, programs, and regulations to facilitate growth of domestic hydrogen production and end-use.*

19 *Ensure hydrogen is part of integrated clean energy roadmaps at national and provincial/ territorial levels.*

20 *Establish technology-neutral, performance-based standards to define a hydrogen carbon-intensity threshold. Establish tiered, time-based requirement for renewable hydrogen content in government supported projects.*

Awareness

21 *Support community engagement and outreach where deployment HUBs are established.*

22 *Establish awareness and outreach campaigns to educate government, industry, the public, and other important influencers about hydrogen safety, uses, and benefits.*

23 *Develop a suite of tools and resources for early hydrogen markets to help end-users quantitatively evaluate hydrogen as an option for their operations. Host the tools and resources through a central, government-run website.*

24 *Support collaborations between industry and academia to develop hydrogen-specific curriculums to build awareness, interest, skills development, and training to develop the next generation talent pool and prepare the labour force for new opportunities.*

Regional Blueprints

25 *Facilitate the development of regional hydrogen blueprints, as a multi-level government collaborative effort, to identify specific opportunities and plans for hydrogen production and end-use. Ensure federal participation to capture synergies with the Hydrogen Strategy for Canada.*

26 *Identify opportunities for the establishment of regional HUBs, comprised of projects along the entire value-chain.*

27 *Include utilities, major industry from adjacent sectors, and cleantech companies in development and implementation of blueprints.*

28 *Identify areas for alignment and replication with other provinces/regions to facilitate and accelerate overall adoption.*

International Markets

29 *Develop a strong Canadian brand, positioning Canada to be a global supplier of choice for low carbon hydrogen, and the technologies to use it.*

30 *Invest in infrastructure to connect Canadian supply to international markets, such as liquefaction assets for energy dense hydrogen transport and hydrogen pipelines from western Canada to the US.*

31 *Establish domestic flagship projects that highlight Canada's expertise, attract investments into the domestic market, and that can be replicated internationally.*

32 *Leverage existing international fora (e.g. Clean Energy Ministerial Hydrogen Initiative, G20, IEA) to showcase Canada's leadership, and advance new market opportunities.*

	NEAR-TERM (2020-2025) *Laying the Foundation*	MID-TERM (2025-2030) *Growth & Diversification*	LONG-TERM (2030-2050) *Rapid Market Expansion*
HYDROGEN PRODUCTION	***Carbon Intensity***		
	<36.4 gCO_2e/MJ		***Decreasing*** *over time*
	Renewable Threshold in Government Supported Projects		
	>33%		***Increasing*** *over time*
	Cost of Delivered Hydrogen		
	$5.0 – 12.0/kg		$1.5 – 3.5/kg
DISTRIBUTION+ STORAGE	***Gaseous Hydrogen***		
	250 bar	450+ bar	450+ bar
	Liquid Hydrogen		
	East Coast	Canada Wide	Canada Wide
	Pipeline		
	H_2/NG Blended	Blended + Dedicated H_2	Blended + Dedicated H_2
	Geological Storage		
			Salt Cavern
END-USE	*Commercial*		
	Pilot		New industry spinoffs
REGIONAL HUB	Regional high profile hub development incorporating full value chain at scale	Hub expansion, corridor connections, and new hub initiations	Full Pan–Canadian rollout and inter-provincial trade + and cooperation
RD&D	Sustained RD&D in advanced materials, hydrogen production and storage technologies, CCUS, and end-use applications		
ACHIEVEMENTS	***Hydrogen Production***		
	3 Mt/year (high CI)	4 Mt/year (low CI)	20 Mt/year (low CI)
	% of Overall Energy Delivered by Hydrogen		
	1.6%	6.2%	30%
	GHG Reduction		
		Up to 45 Mt	Up to 190 Mt


WHY HYDROGEN IN CANADA?
Rich in Feedstocks
Low carbon intensity grid, abundant fossil fuel reserves, fresh water
Established International Collaborations
Strong Energy Sector
Head Start: One of top 10 H_2 producers in world
Leading Innovation & Industry Position
>100 H_2 and Fuel Cell companies
Skilled labour force, strategic infrastructure assets
Energy export channels to market
Unique Competitive and Comparative Advantages

Economic Growth
• New green jobs
• Moving up the fuel value chain
• Export potential
Decarbonization
Closes the gap in hard-to-abate, energy intensive applications
Clean Air
Improving the health of Canadians through reduced emissions in transportation, heating and industry
Energy Resilience
Carbon free energy carrier enabling increased renewables
Transformative opportunity for Canada's petroleum sector
...Creating Benefits for Canadians

1. Why Hydrogen in Canada?

Canada has all the ingredients necessary to develop a competitive and sustainable hydrogen economy, from rich feedstocks to produce hydrogen and world-leading innovation, to a strong energy industry and vast international relationships. This places Canada in a unique and advantageous starting position on the road to establishing a clean hydrogen economy. If Canada fully capitalizes on its advantages, by 2050 Canadians can benefit from more than $50B in domestic revenues, the conventional oil and gas sector can be transformed, a vibrant export market can be established, and the use of hydrogen can reduce emission by up to 190Mt-CO_2e while improving air quality across the country.

CANADA'S ADVANTAGES

Rich in Feedstocks

Canada has one of the lowest carbon intensity (CI) electricity supply systems in the world, abundant fossil fuel reserves, world-class CO_2 storage geology, large scale biomass supply, and freshwater resources, all of which can be leveraged to produce hydrogen.

Canada is the sixth-largest global producer of electricity, generating 652 TWh of electricity in 2017.[1] Sixty-seven percent of Canada's electricity comes from renewable resources and 82% from non-GHG emitting sources. Canada is the world's third-largest producer of hydroelectricity, making up 60% of today's total generation capacity.[2] Canada also has significant potential to expand the deployment of variable renewables such as wind and solar. Electricity from wind energy is one of the fastest-growing sources of electricity in the world and Canada. Wind accounts for 4% of electricity generation in Canada today, and both wind and solar photovoltaic deployments are growing. Canada is a Tier-1 nuclear supplier, and 14.6% of nationwide electricity generation comes from Canada's nineteen operating power reactors at four nuclear-generating stations in Canada. Canada is exploring the potential to expand nuclear capacity through small modular reactors that can provide non-GHG emitting power in remote communities, building on Canadian innovation in this sector.

Canada has the third-largest oil reserves in the world as well as one of the largest proven natural gas reserves, and at current rates of consumption can meet the country's needs for 300 years, with enough

[1] NRCan. (2020). *Electricity facts*. Retrieved from https://www.nrcan.gc.ca/science-data/data-analysis/energy-data-analysis/energy-facts/electricity-facts/20068

[2] IEA (2020). Key World Energy Statistics 2020. Retrieved from https://www.iea.org/reports/key-world-energy-statistics-2020

remaining for export[1]. Canada is home to one-fifth of the world's large-scale carbon capture utilization and storage (CCUS) projects in operation, and a number of leading CCUS innovators that can be leveraged to support emissions reductions in multiple sectors - including low carbon intensity hydrogen production. Canada has a large supply of renewable forest biomass, as well as access to forest industry by-products and residues. B.C., Ontario, Alberta, Quebec, and New Brunswick are the provinces with the largest biomass capacity and generation. Finally, Canada has 7% of the world's fresh water. Water is an important feedstock in the production of hydrogen using electrolysis powered by clean electricity.

Leading Innovation, Intellectual Property, and Industry Position

As a result of early leadership in RD&D and clean tech development Canada is known for its leading hydrogen and fuel cell technology companies and expertise. As of 2017, there were more than 100 established hydrogen and fuel cell companies spanning the full value chain, employing more than 2100 people in direct jobs within Canada, and generating revenues in excess of $200 million. The sector spends upwards of $90 million in revenue per year to keep Canadian companies at the forefront of innovation.[2] There are new and established hydrogen and fuel cell companies as well as large energy companies and utilities developing and deploying hydrogen solutions in most provinces within Canada. British Columbia, Ontario, and Quebec host the largest clusters of companies in the sector.

Increasing global demand for hydrogen has led to export market opportunities for Canadian companies. For example, more than half of fuel cell buses deployed around the world contain Canadian fuel cell powertrain technology.[3] Canadian companies are well positioned to supply technology, products and services in support of hydrogen production, distribution, storage, and fueling infrastructure, and end-use applications such as trains, heavy-duty vehicles, material handling equipment, marine and aviation propulsion systems, and back-up and stationary power solutions. Canadian technologies in areas related to electrolyzer products and advanced storage materials and engineered solutions also play a significant role in renewable energy systems across the world, integrating with wind and solar technologies. A Canadian supply chain has emerged that provides parts, components, testing equipment, and engineering and financial services to global hydrogen and fuel cell technology developers. Strategic partnerships between industry, academia, and federal labs have been instrumental in developing new intellectual property (IP) and training the next generation of talent for the sector.

Since 2012, Canadian funding to hydrogen clean tech and innovation has dropped, allowing other countries to catch up. Reinvesting in RD&D will enable Canada to capitalize on our head start and maximize Canadian technology penetration in emerging global markets. However, technology development alone will not secure Canada's place in global markets. Following the release of the Hydrogen Strategy, it will be critical to continue to engage on an industrial strategy to further quantify the opportunity and set Canada on a clear path to secure our place in the Global hydrogen economy.

To grow clean hydrogen production in Canada, renewed support for CCUS is also required. Canada's early leadership in this technology space is slipping, as competing countries are strengthening policy incentives and funding to drive RD&D and commercial deployment. Canada needs to take similar action to level the playing field with the US and other countries, and entice our world-renowned technology developers to deploy their expertise at home in support of domestic reductions as well as abroad to capitalize on the growing multi-billion-dollar global market for CCUS climate solutions.

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[1] CAPP. (2018). *Canada's Energy Mix*. Retrieved from https://www.capp.ca/energy/canadas-energy-mix/

[2] CHFCA. (2018). *Canadian Hydrogen and Fuel Cell Sector Profile*. Retrieved from http://www.chfca.ca/wp-content/uploads/2019/10/CHFC-Sector-Profile-2018-Final-Report.pdf

[3] Ballard. (2020). *Fuel Cell Electric Buses*. Retrieved from https://www.ballard.com/docs/default-source/web-pdf's/white-paper_fuel-cell-buses-for-france_final-english-web.pdf?sfvrsn=939bc280_0

Strong Energy Sector

Canada's energy sector is critical to supporting the restart and recovery of the Canadian economy as it emerges from the COVID-19 pandemic. It accounted for 832,500 direct and indirect jobs as of 2019 , with assets of valued at $685 billion as of 2019.[1] It was also , and the energy sector was responsible for directly and indirectly contributing 10.2 percent % to Canada's nominal GDP in that same timeframe.

A key component of this is the hard hit oil and gas industry, which is facing exceptional challenges due to fall in oil prices and a collapse in global oil demand because of the pandemic. Despite this, the petroleum sector remains an engine of recovery, employing 576,000 Canadians, including 11,000 Indigenous people, working in 4,500 companies across Canada.

Further reinforcing the energy sector's strength and resilience is that existing and developing energy infrastructure assets can be repurposed for clean hydrogen. For example, Canada's extensive network of natural gas transmission and distribution pipelines could act as large-scale energy storage and distribution networks for hydrogen, carrying either a blend of hydrogen and natural gas or pure hydrogen over the long term.

Storage assets such as depleted wells, saline aquifers and salt caverns can be an important enabler for wide-spread deployment by serving as permanent CO_2 storage, and potentially for storing hydrogen at scale. In addition, Canada already produces abundant hydrogen from natural gas in the oil and gas sector used for upgrading and refining petroleum products, and these hydrogen generation assets can be leveraged and combined with new assets to produce abundant low CI hydrogen.

Canadian talent in the energy sector is extensive and spans all levels of the value chain in a wide range of areas relevant to hydrogen for at-scale production. From strategic R&D in the chemicals industry, to manufacturing of components and products ranging from materials to complete turnkey solutions, to construction and service and maintenance expertise, Canada's energy labour force is well positioned to pivot to bring hydrogen into the energy fold.

Established International Collaborations

Canada has several bilateral and multi-lateral agreements in place, which formalize and strengthen collaboration with countries and regions around the world, including Germany, the EU, Portugal, and Japan. Over the last three decades, Canada has been a founding member of several international initiatives across the value chain and continues to leverage these strategic partnerships to advance global collaboration on hydrogen.

- Canada was a founding member of the IEA Hydrogen and Advanced Fuel Cell initiatives, which evolved into the current Technology Collaboration Programs (TCPs) - designed to coordinate private and public researchers to accelerate R&D, demonstrations and advance innovation on a global basis.
- Canada is a founding member and key partner in the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE). Member countries have committed to commercializing fuel cell and hydrogen technologies to address awareness and essential codes and standards.

- Most recently, Canada led the development and launch of a Hydrogen Initiative under the auspices of the Clean Energy Ministerial (CEM). Canada co-leads this Initiative, comprised of more than 20 member countries, with the objective to be the cornerstone of global hydrogen collaboration and to incorporate hydrogen's essential role in the global energy transformation in discussions of energy Ministers from around the world.

Canadian industry has also initiated international collaborations to accelerate and leverage R&D efforts and share learnings related to business case and practical deployment considerations. For example, the Canadian Hydrogen and Fuel Cell Association (CHFCA) and Australian Hydrogen Council (AHC) recently signed an MOU to strengthen collaboration between Canada and Australia in the commercial deployment of hydrogen and fuel cell technologies, including in mining and transportation applications.

Several of Canada's most important energy partners, including Japan, South Korea, China, and the US have released national strategies or announced significant investments into their hydrogen economies (see Figure 10). This recent interest is driven by multiple factors and forces but some of the most important include:

- The movement toward decarbonization across all sectors;
- The increasing penetration of variable renewable energy sources;
- The uncertainty of future investments in the oil and gas sector; and
- The rapidly falling costs of hydrogen production technologies.

Unlike previous rounds of excitement around hydrogen, today's interest is driven by the realization that hydrogen will be an essential tool to address climate change. While there are still many challenges to overcome, the message is clear: hydrogen will have a critical role in a carbon neutral future and most of the world's largest economies are already developing the strategies and investments required to make this a reality.

Energy Export Channels to Market

With over $100 billion in exports[1] as of 2017, Canada has established trade relationships for existing energy commodities such as natural gas, crude, refined petroleum products, and electricity that can be leveraged to offer a new low-carbon fuel to the market.

In addition, Canada's proximity to hydrogen import markets including Japan, South Korea, California, and Europe, along with export assets such as deep-water ports, a developing Liquefied Natural Gas (LNG) industry, and established pipeline networks as well as natural gas and oil transportation companies, position Canada to be an exporter of hydrogen as the global economy evolves.

[1] CER. (2017). *Market Snapshot: Energy's Share of Canadian Exports Growing Again*. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/snpsht/2017/09-03nrgshrcndnxprts-eng.html

OUR UNIQUE STARTING POINT

Canada has played an important role in the advancement of hydrogen production technology and storage and distribution equipment and has been a pioneer in fuel cell technology for more than 40 years. Canadian ‘hydrogen firsts’ include the first patent for electrolysis technology in 1915, and the first major breakthrough in proton exchange membrane (PEM) fuel cell power density in the early 1990s to prove the technology as viable for transportation applications.

Canada has a head start in deploying both production and end-use applications. For example, Canada deployed the first industrial-scale production of hydrogen in the 1920s, the first fuel cell bus demonstration in the 1990s, and the first fuel cell forklift and light-duty fuel cell electric vehicle in the early 2000s.

Today, Canada is one of the top 10 hydrogen producers in the world today, with an estimated 3 million tonnes of hydrogen produced per year. Most hydrogen in Canada is produced by the chemical industry and the oil and gas sector from fossil fuels. Geographically, most hydrogen is produced in Western Canada, followed by Central Canada and Atlantic Canada. With the anticipation of Canada’s federal low carbon fuel standard, existing users of hydrogen, including refinery operations, are exploring alternative pathways for hydrogen production. Alternative production pathways include electrolysis or steam methane reforming (SMR) of natural gas coupled with CCUS, to use cleaner hydrogen as a feedstock and compliance pathway to reduce carbon intensity of conventional fuels.

Industrial gas companies operate in both Ontario and Quebec, with hydrogen production and liquefaction assets. Air Liquide’s addition of a 20 MW proton exchange membrane (PEM) electrolyzer at its plant in Bécancour, Quebec which it describes as the largest in North America, increases the facility’s production capacity by 50%. Over and above this, there are a number of other new hydrogen production projects in development across Canada.

Canada continues to be an R&D and technology leader in the sector. For example, Canadian heavy-duty fuel cell engine technology powers more than half of worldwide fuel cell electric buses in revenue service in a range of international markets and climates. In 2018, Canadian technology was used in the first hydrogen powered commuter train. Novel hydrogen production techniques are being pioneered across the country, positioning Canada as a global leader in next-generation clean hydrogen generation. Canada’s expertise and technologies are exported and used in countries around the world, demonstrating the opportunity for growth and deployment on an international scale.

Despite this success, there are currently few large-scale domestic hydrogen projects. This impacts Canada’s global competitiveness in several ways. First, Canadian companies are not able to point to relevant examples of local deployments when promoting their technologies abroad. Second, Canadian talent is being drawn to other jurisdictions where there are more opportunities to develop hands-on experience. Finally, industrial clusters supporting hydrogen technology development, deployments and supply chains are unable to build or retain a critical mass of activity.

While domestic deployments are limited, the sector is not starting from zero. There are activities related to low CI hydrogen production and use happening across Canada, as shown in Figure 2. There are strategic hydrogen production and liquefaction assets in Eastern Canada, and end-use applications range from deployments of light-duty FCEVs and hydrogen retail fueling infrastructure, to pilot projects to explore blending of hydrogen into natural gas networks to decarbonize natural gas. There are also many projects in development and regional studies being conducted to explore hydrogen opportunities. This infographic does not include production and use of grey hydrogen in the oil and gas and nitrogen fertilizer production sectors. These industries represent an opportunity for conversion to low CI supply, providing important anchor tenants as production capacity of low CI hydrogen in Canada is expanded.

Current global momentum on hydrogen presents a significant opportunity for Canada if it is able to continue to be a leader in technology development supported by new local deployments. Without local projects and active investment, other countries will erode this first mover advantage and Canada's technology is at risk of becoming outdated. Now is the time to act and invest in Canada's hydrogen future.

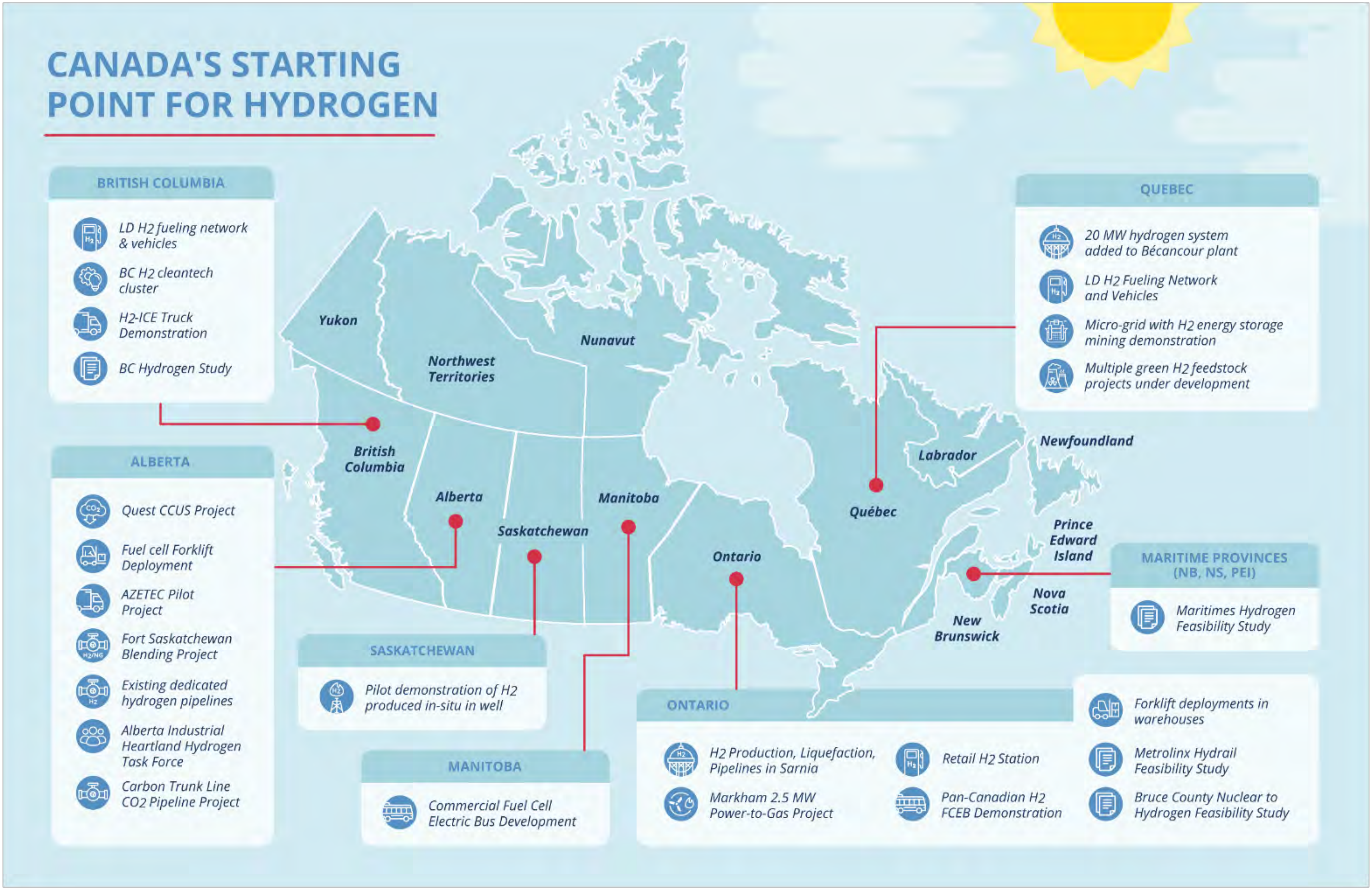

Figure 2 – Canada's Starting Point for Low-CI Hydrogen Production and Use

HYDROGEN AT SCALE DELIVERS REAL BENEFITS FOR CANADIANS

Economic Growth

Canada's hydrogen economy will create new jobs in R&D, manufacturing, and services. Hydrogen will also become a new export currency for both regional energy economies in Western, Central, and Eastern Canada, and in the international market. This will allow Canadian energy companies to move up the value chain as an end-use fuel provider in a zero-emission future. Canadian companies already export goods and services related to hydrogen and fuel cell technologies, as well as in adjacent complementary sectors like CCUS, throughout the world. Growth of domestic deployments will serve as important reference projects to help these Canadian businesses continue to thrive and grow.

If Canada seizes the hydrogen opportunity, the domestic market for direct hydrogen and related product sales could be worth more than $50 billion per year by 2050, with additional opportunity related to indirect revenues and export offering the potential to approximately double the value of the sector. It is estimated that more than 350,000 Canadians could be working in the hydrogen sector by 2050, providing an opportunity to pivot some of the >800,000 workers in traditional energy sector jobs as well as create new jobs. This also provides the potential to create more equitable and inclusive workforces, by mobilizing participation from underrepresented groups including but not limited to women, youth, and people with disabilities. Hydrogen production and use also provides opportunities for Indigenous communities and organizations to lever their existing resources to open new market opportunities.

Transformative Opportunity for Canada's Petroleum Sector

Hydrogen is critical to achieving a net-zero transformation for oil and natural gas industries. It provides an opportunity to leverage valuable energy and infrastructure assets, including fossil fuel reserves and natural gas pipelines, in a way that is carbon-free at the point of use, providing a pathway to maximize these valuable assets in a 2050 carbon neutral future. The petroleum sector is an important part of Canada's energy sector and contributor to the Canadian economy, especially in Alberta. The recent decline in oil prices has had a large impact on Canada's oil and gas industry, which in turn creates ripple effects in other industries. Advancing a hydrogen economy will reduce the carbon intensity of conventional fuels and provide opportunities to diversify the sector.

In a net-zero energy system of the future, distributed combustion of fossil fuels like natural gas will be limited, meaning that gas utilities must transform their current suite of products and services, if they are to remain competitive. Renewable natural gas and landfill gas can displace natural gas, but supply is limited. Hydrogen produced at scale can be the long-term answer for Canada's natural gas utilities to stay competitive in a carbon constrained future.

The role of hydrogen in Canada's petroleum sector will shift over time. Initially low CI hydrogen offers a compliance pathway to reduce carbon intensity of conventional fuels. In parallel as the demand for hydrogen as a transportation fuel grows through increasing deployments of fuel cell vehicles, the sector will determine how best to participate in the value chain. Liquid synthetic fuels combining non-emitting hydrogen with CO_2 recovered through direct air capture may also play a role as a feedstock for GHG neutral, energy-dense liquid fuels for end-use applications like industrial processes as well as large marine vessels and aircraft still utilizing internal combustion engines.

Energy Resilience

Hydrogen is a versatile energy carrier that can be created from a number of different pathways, and this diversity of feedstock creates resilience in Canada's energy system. Hydrogen can help regions reliant on energy imports to become more energy independent. Hydrogen can also be the energy vector to tie disparate energy systems together into a more optimized and resilient, integrated energy system.

Hydrogen does not compete with direct electrification, but rather can help enable increased penetration of renewables by providing time shifting and energy storage capabilities. While the primary source of renewable energy in Canada is hydroelectricity which comes with inherent energy storage capability, wind power capacity has been growing steadily in the last 10 years. Electricity from wind energy is one of the fastest growing sources of electricity in the world and in Canada, now making up 4% of the national electricity generation with Ontario and Quebec leading in capacity.

As seen in countries like Germany, hydrogen can be the best option for utility scale energy storage as electricity grids reach greater penetrations of variable renewables as a ratio of the overall mix. Prince Edward Island by way of example, with 98% of local electricity generation coming from wind, currently relies on importing dispatchable grid power from New Brunswick. Hydrogen could be a solution to provide dispatchable power to increase energy independence and could also be used directly for heating in the winter as a hybrid system to offset seasonal spikes in electric heating demand. The flexibility of hydrogen as an energy carrier provides customizable options for each region in Canada.

Cleaner Air

When hydrogen is used in an electrochemical fuel cell, it emits nothing but water, completely eliminating particulate emissions, SO_x, NO_x, and ground-level ozone. When combusted, it is cleaner burning than other chemical fuels. Increased hydrogen adoption leads to cleaner air, and cleaner air means improved health outcomes for Canadians.

Although substantial efforts have been made to improve air quality in Canada over the last few decades, indicators suggest that outdoor air pollution continues to be an important public health issue in Canada[1]. Approximately 2% of deaths, excluding deaths from injuries, can be attributed to ozone exposure and 0.8% to fine particulate exposure, and the proportion of deaths that can be attributed to ozone shows an increasing trend. Global deployment of hydrogen in zero-emission fuel cell vehicles is focused both on meeting health-based air quality standards and greenhouse gas emission reduction goals. It is anticipated that more cities will impose further restrictions and bans on PM2.5-emitting diesel trucks to improve air quality for their citizens through initiatives such as the C40 Cities program.[2]

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[1] Environment and Climate Change Canada. (2018). *Air health trends.* Retrieved from https://www.canada.ca/en/environment-climate-change/services/environmental-indicators/air-health-trends.html

[2] C40 Cities Climate Leadership Group, Inc. (2020). *About* C40. Retrieved from https://www.c40.org/about

Meeting Decarbonization Goals

Hydrogen's ability to contribute to decarbonization of energy systems is the biggest driver for adoption.

Under the Paris Agreement, Canada committed to reducing GHG emissions by 30% below 2005 levels by 2030, setting a 2030 target of 511 Mt. The Government of Canada has also announced a target to achieve net-zero emissions by 2050. The magnitude of the challenge is 729 Mt-CO_2e reduction over the next 30 years based on 2018 emissions levels. In reality that challenge is far greater, as increasing population and economic growth will be competing forces in the efforts to decarbonize.

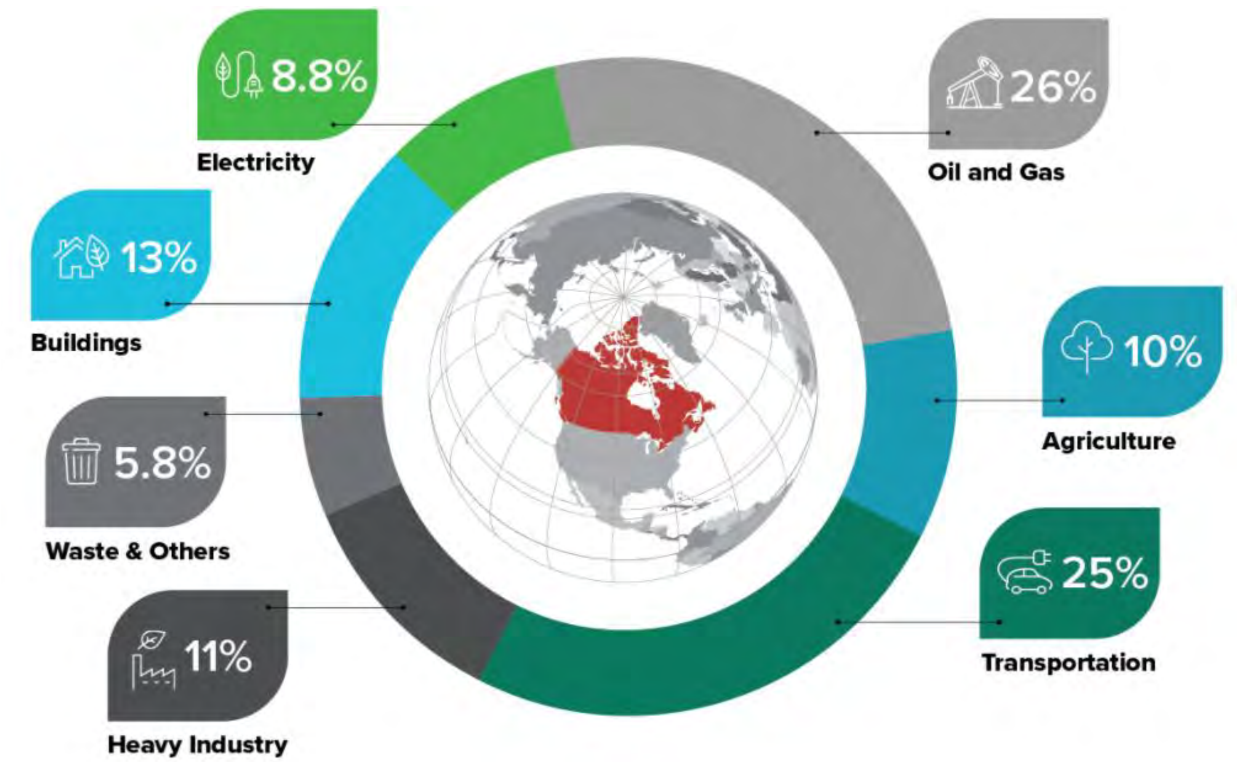


Figure 3 – Canada's 2017 GHG Emission Inventory[1]

Distributed combustion of carbon-based fuels is a significant contributor to Canada's GHG emissions in oil and gas, transportation, buildings, electricity, and heavy industry sectors.

Many levers will be needed to achieve Canada's net-zero emissions target by 2050. Low CI hydrogen shows the potential to contribute to the 2050 GHG reduction challenge, addressing the toughest third of applications where other options like direct electrification may not be technically or economically favourable. Applications such as long-range transportation, high-grade heat for industry and buildings, and for use as a feedstock in industrial process are best served by low carbon intensity hydrogen.

[1] Government of Canada. (2017). *Canada's actions to reduce emissions*. Retrieved from https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/reduce-emissions.html

2. What is Hydrogen?

Hydrogen's decarbonization potential is garnering significant global interest as a critical element in net-zero energy systems. However to fully understand the economic and environmental opportunities that hydrogen presents, it is important to understand some hydrogen fundamentals. Hydrogen is a versatile, carbon-free energy carrier that can be produced from a variety of feedstocks that are abundant across Canada. Hydrogen can be converted to electricity through a fuel-cell in electric vehicles and power generation equipment, combusted to produce heat, or used as a feedstock in a range of chemical and industrial processes.

HYDROGEN FUNDAMENTALS

Hydrogen is the first element on the periodic table as it is the simplest and lightest element on earth – approximately fourteen times lighter than air. Hydrogen is the most abundant element in the universe, accounting for about 75% of all mass. In its natural and gaseous state, hydrogen is invisible, odorless, tasteless, and non-toxic, making it difficult to detect. Like electricity, hydrogen is an energy carrier that transports useable energy created elsewhere to another location. Hydrogen has the highest energy per mass of any fuel; the energy in 1 kg of hydrogen is the same as approximately 2.8 kg of gasoline. However, hydrogen has a low volumetric energy density and as a result cost-effective distribution and storage is a challenge.

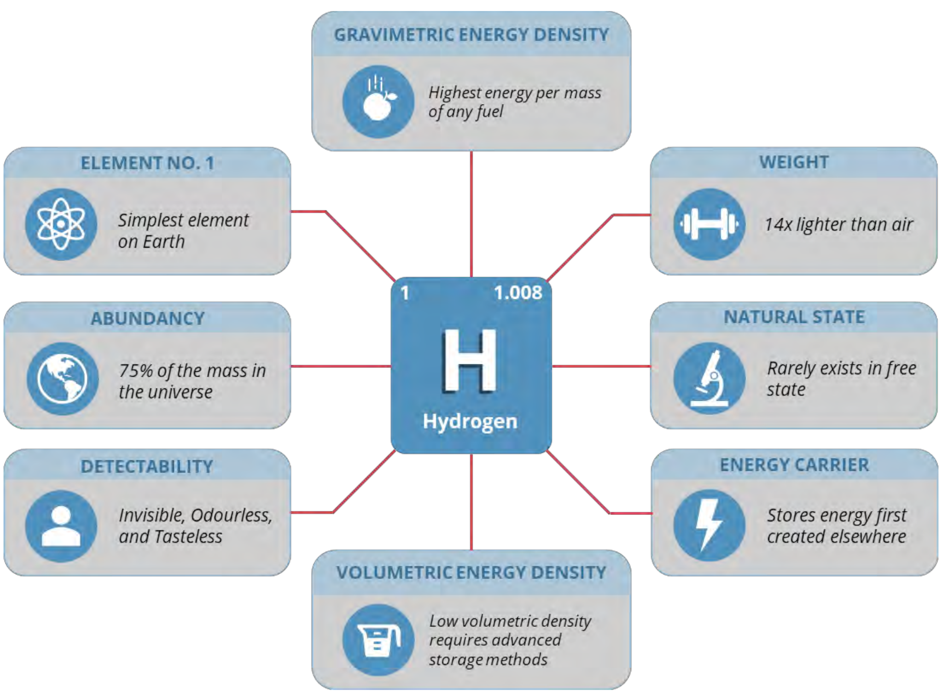


Figure 4 – What is Hydrogen?

Its ability to produce electricity with limited by-products makes hydrogen a desirable alternative fuel. The chemical reaction between hydrogen and oxygen produces electricity, heat, and water, with no pollutants or carbon emissions released at the point of use. Hydrogen is also a clean burning fuel when combusted. Despite the abundance of hydrogen in the universe, it is rarely found in its natural state on earth and is commonly found bonded in other sources such as water (H_2O) and methane (CH_4). Electrolysis and steam methane reforming are common practices used to extract hydrogen from water and methane, respectively.

Benefits

Hydrogen is a versatile and unique energy carrier that enables economic and environmental benefits and can play a significant role in decarbonization of energy systems. As a compressed gas or liquid, hydrogen is a multifaceted energy carrier. It has the highest energy per mass of any fuel allowing it to transfer large amounts of energy from its point of production to end-use application. Hydrogen can be produced from clean energy sources and is carbon and pollutant-free at its point of use when used in a fuel cell.

Hydrogen is suitable for energy-intense applications where electrification is challenging or limited, and where applications currently relying on low-cost natural gas are more suited to energy-dense chemical fuels. Similarities between natural gas and hydrogen include their safety considerations, ability to be transported over long distances via pipeline or road, and versatility as energy carriers, making hydrogen an excellent alternative to natural gas in a range of applications.

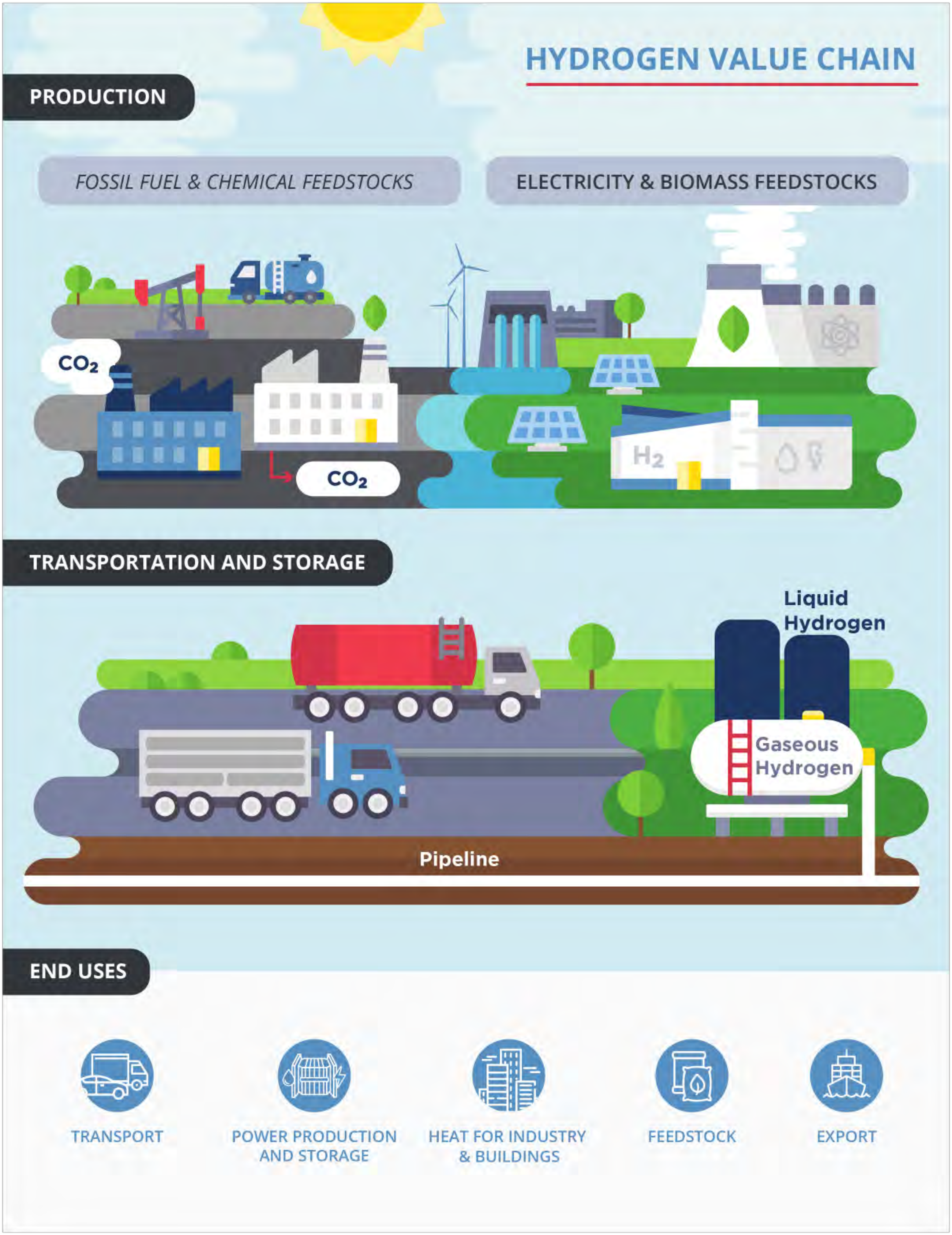
Figure 5 – Key Benefits of Using Hydrogen

Hydrogen use as a fuel for FCEVs is quickly becoming an attractive zero-emission alternative for transportation, especially heavy-duty vehicles and transit buses that require energy dense fuels. Hydrogen can also be used as a fuel for power generation which allows for load management, and energy storage. This enables the growth of the variable renewable power sector.

Hydrogen can be burned directly or as a blend with natural gas to reduce carbon emissions in providing building heat and high-grade heat for industry.

Hydrogen is commonly used as a feedstock for industrial processes such as petroleum refining, bitumen upgrading, ammonia production, methanol production, and steel production.

For more information regarding hydrogen's end-uses, refer to *Hydrogen End-Use Opportunities*.


HYDROGEN VALUE CHAIN
PRODUCTION
FOSSIL FUEL & CHEMICAL FEEDSTOCKS
ELECTRICITY & BIOMASS FEEDSTOCKS
CO_2
CO_2
H_2
TRANSPORTATION AND STORAGE
Liquid Hydrogen
Gaseous Hydrogen
Pipeline
END USES
TRANSPORT
POWER PRODUCTION AND STORAGE
HEAT FOR INDUSTRY & BUILDINGS
FEEDSTOCK
EXPORT

GLOBAL MOMENTUM FOR CLEAN HYDROGEN

Current Global Hydrogen Production by Energy Source

Figure 7 shows the global production of hydrogen by energy source in 2018. The total global production of hydrogen in 2018 was 144 Mt, in which 67% of production was deliberate, and 33% was produced as a by-product to industrial processes.[1]

Most of the hydrogen produced today is made from fossil fuels. In 2018, 48% of total hydrogen produced worldwide was derived from natural gas. Hydrogen production from coal, which is mostly due to its popularity as an energy source in China, accounted for 18% of production. Electricity and oil each contributed 0.48%, and the balance was produced as a by-product of another industrial process such as sodium chlorate and chlor-alkali production.

Current Global Hydrogen Demand

Global demand for hydrogen in 2018, displayed in Figure 8, was 115 Mt-H_2.

Applications utilizing pure hydrogen accounted for 60% (69 Mt-H_2) of all demand. Pure hydrogen for oil refining and ammonia production were the most common end-uses, accounting for 33% and 27% of total demand, respectively. The remainder of pure hydrogen use in 2018 included transport, chemicals, metals, electronics, and glass making industries.

Demand for mixed hydrogen covered the remaining 40% (46 Mt-H_2) of the market with other end-uses such as heat generation from steelworks arising gases and by-product gas from steam crackers accounting for 23% of total demand. Other uses of mixed hydrogen included production of methanol and direct reduced iron steel (DRI).

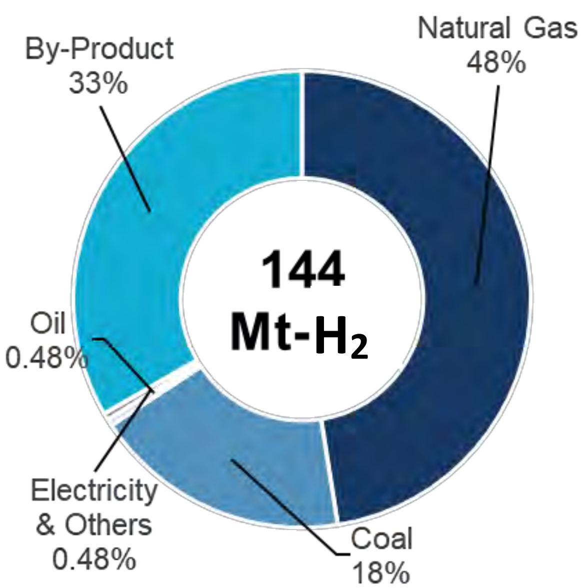


Figure 7 – Global Hydrogen Production by Energy Source (2018)[1]

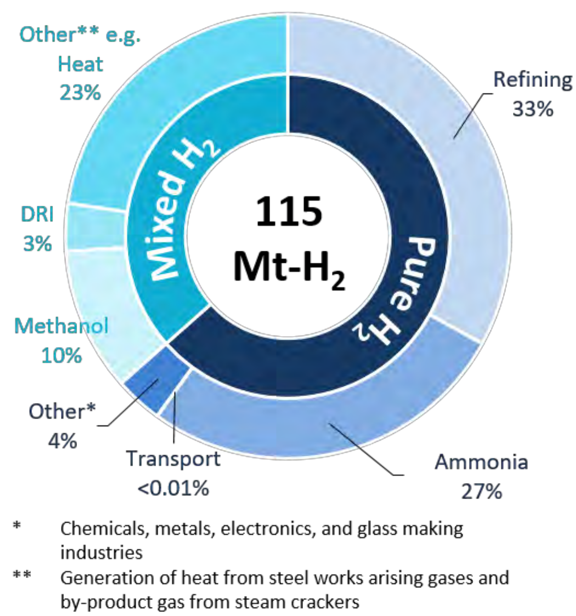


Figure 8 – Global Hydrogen Demand by End-Use (2018)[1]

[1] IEA. (2019). *The Future of Hydrogen*. Retrieved from https://www.capenergies.fr/wp-content/uploads/2019/07/the_future_of_hydrogen.pdf

Interest in hydrogen in the global energy transformation is growing rapidly with projections indicating at least a tenfold increase in demand in the coming decades. Since 2010, global demand for hydrogen has grown by a moderate 28%. However, studies indicate that hydrogen, backed by the right incentives, investments, and policies, could provide between 18% and 24% of global energy demand by 2050[1], with some countries being much higher. The five largest consumers of hydrogen are expected to be China, the EU, Japan, South Korea and California, based on their existing strategies and targets.

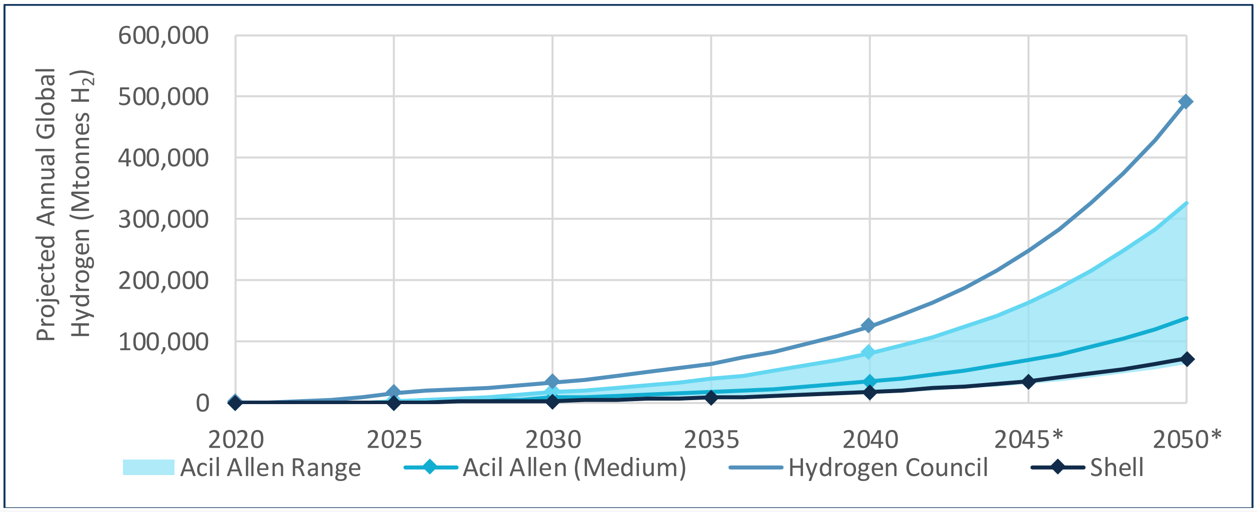


Figure 9 – Ranges of Estimates for Annual Global Hydrogen Demand

Countries around the world are developing strategies and roadmaps to inform their unique paths toward a hydrogen economy. These country- and region-specific strategies seek to make optimal use of supply pathways and end-use applications for hydrogen to power their clean economies and to position themselves in the international market. The number of countries with polices that directly support investment in hydrogen technologies is increasing, along with the number of sectors they target. Figure 10 shows announcements of national or regional strategies, major project plans, and other major plans or investments in the last two years. According to the Hydrogen Council, as of January 2020, 18 governments, whose economies account for more than 70 per cent of global GDP, have developed hydrogen national strategies.[2]

[1] IEA. (2019). *The Future of Hydrogen*. https://www.capenergies.fr/wpcontent/uploads/2019/07/the_future_of_hydrogen.pdf

[2] Hydrogen Council. (2020). *Path to hydrogen competitiveness: A Cost perspective*. Retrieved from https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf

Figure 10 – International Momentum on Hydrogen

3. Canada's Production & Distribution Opportunities

Canada is well positioned to become a top global producer of clean hydrogen. Specifically, hydrogen can be made from a variety of Canadian feedstocks, including water and clean electricity, fossil fuels, biomass and as a by-product from industrial processes. The scale of projected domestic and global hydrogen demand will require Canada to maximize use of all low carbon intensity pathways across the country. This will give all regions the opportunity to benefit from their unique mix of production, based on local resources and economic factors and Canada's extensive natural gas pipeline network, combined with new storage and distribution assets, can be leveraged to move hydrogen from production to end-use locations.

PRODUCTION PATHWAYS

Hydrogen is a chemical energy carrier that can be made from a variety of feedstocks, including water and electricity, fossil fuels including natural gas and crude oil, biomass, and as a by-product from industrial processes. Canada has a distinct advantage as a hydrogen producer owing to its significant low-cost hydrocarbon resources and abundant clean electricity supply from sources including hydroelectricity, nuclear, wind and solar. The various ways hydrogen is produced, from input feedstocks to output bulk gas, are known as its production pathways. All energy carriers, including fossil fuel and electricity, experience conversion losses when they are produced, distributed, and used. These losses accumulate along the production pathway and affect the overall efficiency of the energy carrier. In the same way, the carbon intensity of the various processes in the production pathway add up to the overall carbon intensity, typically expressed in grams-CO_2e/MJ. In evaluating hydrogen production pathways, together and relative to other energy carriers, the conversion efficiency, carbon intensity, feedstock availability, cost, and storage and distribution impacts must all be considered.

Hydrogen molecules do not generally exist on their own in a free state in nature but are found in many abundant compounds. Hydrogen must be produced from feedstocks using energy inputs. When investigating viable local hydrogen pathways, the availability of both feedstocks and energy sources should be considered. Hydrogen also has the advantage of being carbon free at the point of use, making it ideal for both distributed and centralized consumption. When combusted, hydrogen does not produce greenhouse gases, particulates, SO_x, or ground-level ozone, although there can be NO_x emissions. When used in an electrochemical fuel cell, it emits nothing but water. However, production of hydrogen can lead to greenhouse gas emissions and the production pathway defines the carbon intensity. Given that a big driver for the use of hydrogen in Canada is the GHG reductions it can offer, it is important for Canada to focus future hydrogen production on economic low carbon intensity pathways.

Canada is a major hydrogen producer today with an estimated 3 million tonnes produced annually primarily via steam methane reforming of natural gas for industrial uses including fuel refining and nitrogen fertilizer production, ranking in the top ten of global hydrogen producers. While steam-methane reforming alone is not considered a low carbon intensity hydrogen pathway, Canada is well placed to transition to clean pathways going forward.

Colours are often used to represent the different hydrogen production pathways. For reference, common colour definitions are provided in Table 1. While this terminology is widely used, definitions and delineations are not standardized and can lead to ambiguity. In this section, the various production pathways will instead be described in terms of their input feedstocks and estimated carbon intensities.

Canada has among the lowest CI electricity supplies in the world given our hydroelectric generation capacity and status as a Tier-1 nuclear region, abundant fossil fuel reserves, world class CO_2 storage geology, potential for growth in variable renewables, large scale biomass supply, and freshwater resources, all of which can be leveraged to produce hydrogen.

Table 1 – Common Hydrogen Feedstock and Production Pathways Being Researched and Deployed

Production Process		Feedstock & energy source	Pros and Cons	Examples
GREY	Produced by steam methane reformation **without** carbon capture and sequestration (CCS)	**Feedstock:** natural gas, gasified coal	Pros: lowest cost, abundant Cons: highest carbon intensity	Canada produces approximately 3 million tonnes of grey hydrogen per year primarily for industrial use.
BLUE	Produced from fossil fuels by steam methane reformation, pyrolysis or other processes **with** carbon capture and sequestration (CCS).	**Feedstock:** natural gas, coal, crude bitumen	**Pros:** low-cost, abundant, low CI, pyrolysis offers scale and siting flexibility **Cons:** SMR pathway siting is constrained by CCUS, feedstock is not renewable	Alberta's Quest project
GREEN	Produced from water by electrolysis using renewable electricity such as hydroelectricity, wind or solar.	**Feedstock:** Water **Energy source:** Renewable electricity	**Pros:** lowest carbon intensity, scalable **Cons:** highest cost, opportunity cost - competes with electrification demand	Air Liquide's 20 MW electrolyzer plant in Becancour, Projects developing in BC to support hydrogen fueling network.
NUCLEAR	Produced from water by electrolysis or high temperatures from nuclear energy	**Feedstock:** Water **Energy source:** Uranium / nuclear electricity	**Pros:** low carbon intensity **Cons:** limited availability and siting constraints	Feasibility study planned in Bruce County.

An overview of mature Canadian production pathways is shown in Figure 11. Additional emerging technologies are under development and also show promise.

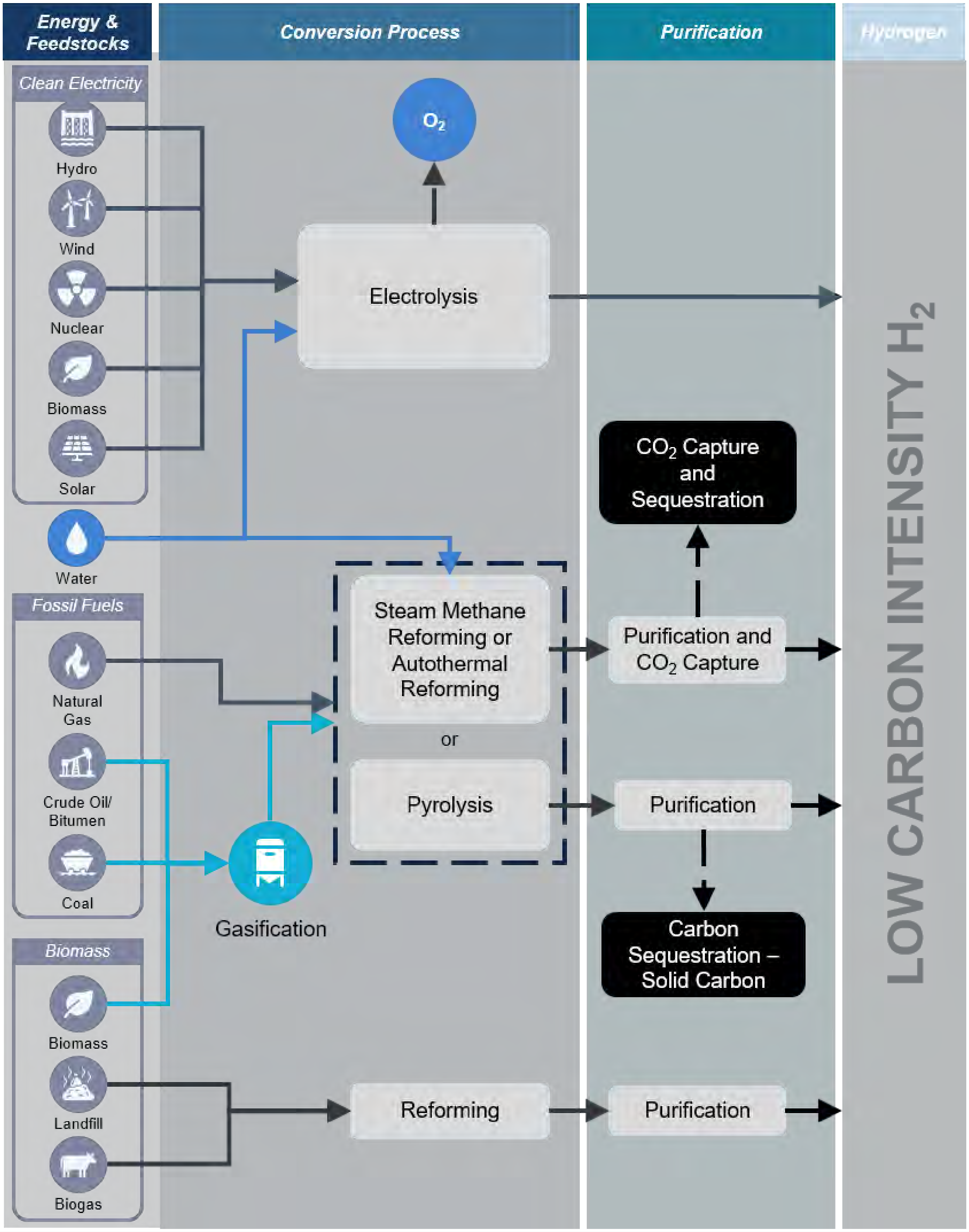


Figure 11 – Hydrogen Production Pathways in Canada

Hydrogen Production from Water & Electricity

Canada is well positioned as a producer of hydrogen from electricity given that 67% of Canada's electricity supply comes from renewable sources and 82% from non-GHG emitting sources[1]. Canada is also the world's third largest producer of hydroelectricity. These large, predictable, and low-carbon sources of electricity are favourable for the large-scale production of hydrogen using electrolysis.

Electrolysis is the process by which electricity is used to split water into hydrogen and oxygen. In this process, water is split into hydrogen and oxygen using an electric current and an electrolyte or membrane. About 9 L of freshwater is required for every 1 kg of H_2 and 8kg of O_2 produced. The resulting hydrogen is very pure and can be used directly in transportation and other end-uses without further processing. The oxygen, while often vented, can also be used in medical or industrial applications.

The main electrolyzer technologies are alkaline, Proton Exchange Membrane (PEM) and Solid Oxide Electrolysis Cells (SOEC). Alkaline is an older technology that has been in use for over a century. It operates best with a constant load, has low capital costs and can scale to larger than 150 MW. PEM electrolyzers rely on the same membrane technology as PEM fuel cells. They can be operated at a range of loads and can respond dynamically making them advantageous for electrical utilities looking for flexible demand to pair with variable renewables. The final technology, SOEC, is still being commercialized and operates at high temperature. There is potential to combine these electrolyzers with output heat from nuclear power plants, and geothermal and solar thermal systems.

Renewables & Hydro

Canada is the world's third largest producer of hydroelectricity. The provinces with the greatest portion of hydroelectric power production are:

- Manitoba: 96.8% hydroelectric generation
- Quebec: 95% hydroelectric generation
- Newfoundland and Labrador: 93.7 % hydroelectric generation
- Yukon: 92% hydroelectric generation
- British Columbia: 90% hydroelectric generation

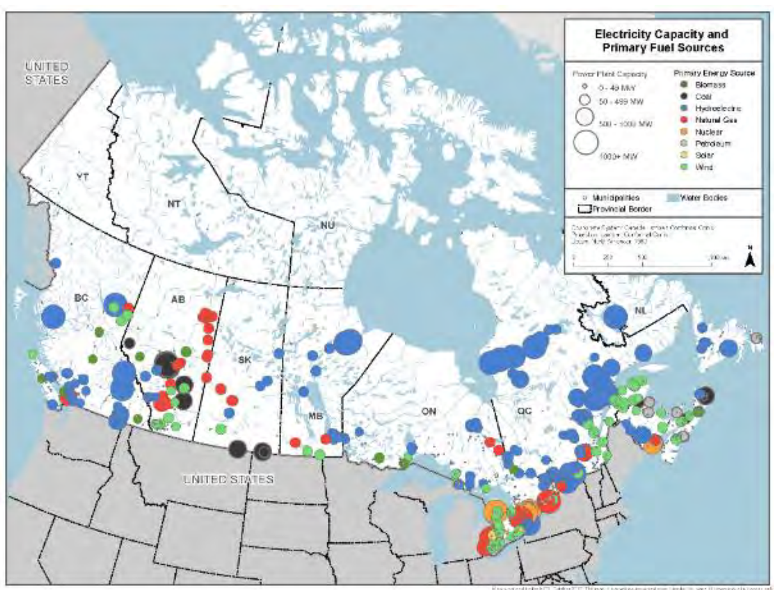


Figure 12 – Electricity Capacity and Primary Fuel Sources per Province in Canada

[1] NRCan. (2020). *Electricity facts*. Retrieved from https://www.nrcan.gc.ca/science-data/data-analysis/energy-data-analysis/energy-facts/electricity-facts/20068

In these provinces, the electric utility providers could play an important role in the hydrogen value chain. Electrolyzer farms co-located at generation facilities can provide grid regulation services, and the hydrogen produced can provide an alternative high-value revenue stream for the utilities. Decentralized production via electrolysis can also be co-located close to demand centers. Electrolyzers are inherently scalable, and many equipment manufacturers have developed containerized solutions that are easy to site.

Independent Power Producers, for example operating run of river, wind, or solar power generating assets, can also play an important role in the value chain, particularly in provinces where power purchase agreements are up for renegotiation.

As increasing wind and solar are brought into Canada's energy mix, they offer the potential to expand the production of low carbon hydrogen and reduce costs for variable supply. Hydrogen can in turn improve the economics of variable renewables by providing large-scale energy storage that optimizes the utilization of these power generation assets. For example, Ontario curtailed in the order of 6-8 TWh of renewable electricity in 2016 that resulted in significant lost revenue, that could instead have been used to produce hydrogen.[2] Canada ranks 9th in the world for both wind and solar installations. Generation from wind farms and solar photovoltaic panels grew from a negligible amount in 2005 to approximately 5% of total electricity generation in 2018, with Canada's wind power capacity at 13.0 GW and solar power capacity at 2.9 GW. The majority of the wind facilities in Canada are located in Ontario, Quebec, and Alberta, while Ontario is home to over 98% of Canada's solar installations.

Nuclear

Nuclear reactors produce electricity as well as process heat that can be used in the production of low CI hydrogen. Large reactors are suitable for large-scale centralized hydrogen production, while small modular reactors will be more suitable for distributed hydrogen production. Hydrogen can be made via electrolysis using inexpensive off-peak electricity from existing nuclear power plants. There are efforts underway to study the economics of nuclear hydrogen production in Ontario at the Bruce Nuclear Generating Station. Opportunity for nuclear hydrogen production today is in Ontario, where three of the four nuclear generation stations are located, and in New Brunswick.

Small modular reactors are under development in Canada and around the world. Some small modular reactor designs can produce high temperature process heat, which enhances the overall efficiency of hydrogen production (see below). Commercial deployment of advanced reactors and small modular reactors is not expected to be a near-term opportunity but offers a longer-term opportunity for production of hydrogen.

High Temperature Nuclear and Electrolysis

There are several hydrogen production pathways that utilize the high temperature heat produced by nuclear reactors. One method is to use the steam produced by nuclear reactors as the reactant in the steam methane reformation process described above. This would eliminate the need to use natural gas to create steam and would simplify and lower the cost of carbon capture.

Using steam in the place of liquid water in an electrolyzer can also reduce the electricity input requirements as steam is easier to separate than water. SOEC electrolyzers, which operate at elevated

[1] CER. (2017). Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/nrgsstmprfls/mg/cnd-mp-lctrct-eng.pdf

[2] Environmental Energy Commission. (2018). *2018 Energy Conservation Progress Report, Volume One*. Retrieved from http://docs.assets.eco.on.ca/reports/energy/2018/Making-Connections-07.pdf

temperatures, could take advantage of the steam produced by nuclear reactors to improve the efficiency of hydrogen production and make use of heat that would otherwise go to waste.

As new nuclear reactor designs are commercialized, including small modular reactors, high temperature fission reactors, and eventually fusion reactors, the output water temperature will continue to increase. Thermochemical water splitting uses heat from 500-2000ºC and reusable chemical reactants such as cerium oxide and copper chloride to generate hydrogen. Because the process is a closed system, the chemicals are reusable. High temperature nuclear hydrogen production could be a valuable cogeneration process for Canada's next generation nuclear sites, improving the overall system efficiency.

Hydrogen Production from Fossil Fuels with CCUS

Canada has vast fossil fuel resources in the form of natural gas, crude oil, and bitumen. When combined with Carbon Capture, Utilization, Storage (CCUS), these resources can be converted into low CI hydrogen. This pathway has the advantage of being the lowest cost production method of large-scale, clean hydrogen based on today's technologies and commodity costs, and with Canada's fossil fuel reserves and CO_2 storage capacity can meet large-scale demand for many decades. This section summarizes the main commercial hydrogen production pathways from fossil fuels in Canada and their associated options for CCUS.

There is significant growth potential in CCUS and hydrogen production in Canada, which could have a major impact on emissions reductions. Based on recent analysis by the Transition Accelerator, there is an upper bound potential for eight times the current domestic production of hydrogen from natural gas in a 2050 net-zero energy system in Canada. The CCUS requirement for this magnitude of hydrogen production would be approximately 203 Mt CO2 per year. Given Canada's current CCUS operational projects capture and store about 4 Mt of CO2 per year, this would represent a significant increase in CCUS activity. These opportunities have also been identified in Alberta's Natural Gas Vision and Strategy goal of large-scale blue hydrogen production with CCUS deployment across the province by 2030.

TRANSITION PATHWAY FOR CANADA' OIL & GAS SECTOR

Canada has the potential to produce vast amounts of hydrogen from natural gas coupled with CCUS. Provinces with the highest natural gas production are Alberta and BC, followed by Saskatchewan, and these are the provinces most suited to this hydrogen production pathway.

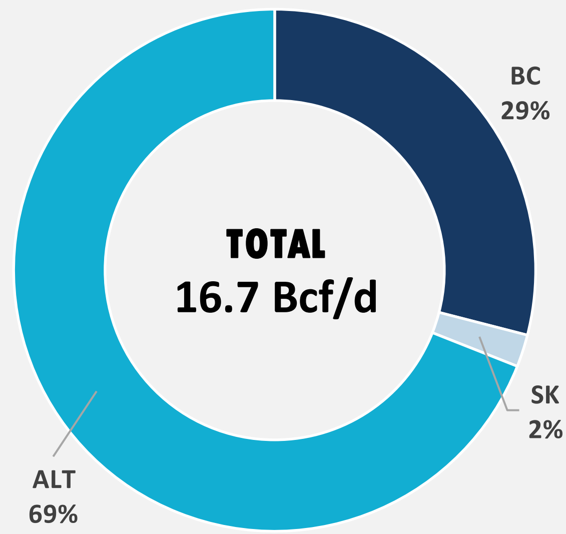


Figure 13 – Canada's 2018 Marketable Natural Gas Production by Province

In Alberta, a new Task Force has been announced to advance the hydrogen economy in Alberta's Industrial Heartland to seize this transformative opportunity. The Task Force will bringing together production, distribution and supply industries in the area to de-risk investments, with a particular focus on heavy-duty transport. This type of multi-facetted deployment, covering actions across the value-chain is an example of an early HUB for deployment.

Natural Gas

Canada is the world's fourth largest producer and sixth largest exporter of natural gas. Canadian marketable resources of natural gas can sustain current production levels for up to 300 years. However, when burned or utilized directly as methane, GHG emissions are released. If the methane is instead converted into hydrogen and combined with CCUS, the carbon intensity of the resulting fuel can be reduced by approximately 90%. Hydrogen production from natural gas offers a unique opportunity to leverage Canada's vast gas reserves to produce a low carbon intensity energy carrier while other production technologies are being scaled.

The carbon, when captured in the form of CO_2, can be used for enhanced oil recovery or as an industrial feedstock, provided the emissions do not go back into the atmosphere. It can also be stored underground provided the right sub-surface geology exists. The production of hydrogen from natural gas via steam methane reforming with CCUS will be constrained by the availability and accessibility of carbon storage geology. Alberta, BC and Saskatchewan have both large natural gas reserves and CO_2 storage potential making them favourable for this production pathway. In the production of hydrogen from natural gas via the pyrolysis pathway, the carbon is captured in the form of solid carbon and this enables distributed production close to demand without geological constraints.

There are three main commercially available methods to convert natural gas into hydrogen and carbon by-products: 1) Steam Methane Reforming (SMR) which uses high temperature water as an oxidant and a source of hydrogen, 2) Autothermal Reforming which use both water and air oxidants, and 3) Pyrolysis which relies on methane splitting into hydrogen and solid carbon using high heat.

In SMR, natural gas is used both as feedstock and as fuel to generate steam. In the first reaction, the methane is combined with steam (H_2O + Heat) to produce a synthetic gas consisting of CO_2, CO and H_2. The synthetic gas is then separated using a Water Gas Shift (WGS) reactor and Pressure Swing Adsorption (PSA). Adding carbon capture at various places in the process adds costs and reduces overall efficiency, but improves environmental performance. Capturing CO_2 from both the WGS and the PSA can reduce emissions by about 60%, while also capturing the flue gas CO_2 can achieve 90% total carbon capture at an additional cost of 45%[1]. SMR is the most widely used technology for hydrogen production in Canada and is expected to continue to be one of the primary pathways going forward, with the addition of CCUS to achieve lower carbon intensities.

[1] Layzell DB, Young C, Lof J, Leary J and Sit S. 2020. Towards Net-Zero Energy Systems in Canada: A Key Role for Hydrogen. Transition Accelerator Reports: Vol 2, Issue 3. https://transitionaccelerator.ca/towards-net-zero-energy-systems-in-canada-a-key-role-for-hydrogen

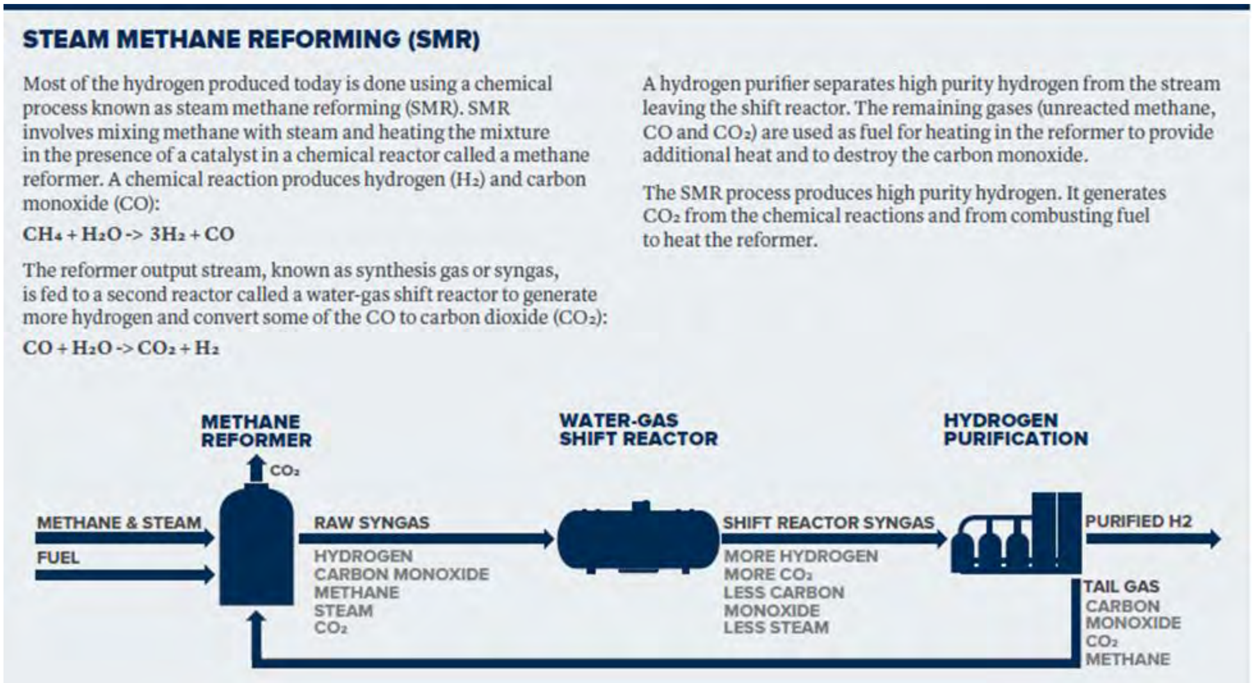


Figure 14 – Steam Methane Reforming (SMR) Process and Description[1]

Autothermal Reforming (ATR) is another technology that uses the heat produced in the reformer itself to achieve higher CO_2 recovery rates. All the CO_2 from the process is produced within the reformer so there is no additional flue gas from heat generation requiring decarbonization. This lowers the cost of CO_2 capture as the resulting gases are more concentrated. ATR is widely used in the ammonia and methanol industries and pilot ATR+CCUS plants are being planned in the UK and EU[2].

Pyrolysis is a developing hydrogen production technology which uses high temperature heat to split the methane molecule into its constituent elements. The result is a very pure form of hydrogen gas and solid carbon. The two main pyrolysis technologies are thermal and plasma pyrolysis. In thermal pyrolysis, heat from natural gas is used to break up the methane molecule. Some of the feedstock methane is not reacted and this is recaptured for use as the process fuel. This reduces the conversion efficiency and increases the CO_2 emissions. Plasma pyrolysis is a specific type of pyrolysis which uses an electric arc to generate a high temperature plasma. While there are significant heat losses, the overall system efficiency can be better than using the electricity to power an electrolyzer[3]. There are many other ways to provide heat to the pyrolysis system and systems based on microwave and photo catalysts are also being developed. The solid carbon is chemically stable and can be used in a variety of industrial materials such as rubber, plastics and in printers. Pyrolysis technology has been deployed commercially but remains limited primarily as a source of commercial solid carbon (thermal black). It is now being developed as an economic alternative to SMR for hydrogen production. Pyrolysis has the potential to produce distributed hydrogen at the point of use, using natural gas as a feedstock and leveraging existing distribution pipeline networks. Because the carbon is sequestered as a solid carbon, production does not need to be co-located where CO_2 can be sequestered.

[1] Global CCS Institution. (2019). *Global Status of CCS*.

[2] IEA. (2019). *The Future of Hydrogen*. Retrieved from https://www.capenergies.fr/wp-content/uploads/2019/07/the_future_of_hydrogen.pdf

[3] Ibid

Crude Oil, Bitumen, and Coal

In addition to Canada's natural gas reserves, there are also substantial resources in the form of crude oil and bitumen in the regions of Northern Alberta and Saskatchewan, and coal in Alberta and British Columbia. Gasification of crude oil, bitumen, or coal uses a process similar to gasification of biomass. The feedstocks are reacted with steam and/or oxygen at a high temperature producing a synthetic gas mixture that can be further separated into CO_2 and H_2. This process can take place in an industrial plant once the feedstock has been extracted, in which case CCUS would need to be employed to capture the resulting CO_2. In-situ gasification is an emerging technology currently being developed in Alberta and Saskatchewan for crude oil and bitumen feedstocks. In this process, the gasification takes place deep underground, such as in an existing oil field, and the hydrogen is filtered using a selective membrane. This has the advantage of leaving the CO_2 already underground and sequestered, saving cost and reducing complexity. The selection of reservoirs with appropriate geological properties to hold the CO_2 underground in a stable state is an important consideration for this technology.

Carbon Capture, Utilization, & Storage

To achieve Canada's net-zero by 2050 target, all hydrogen production will need to be carbon-neutral - which includes electrolytic hydrogen from non-GHG emitting electricity, or hydrogen produced from fossil fuels coupled with CCUS – or it will need to be offset, for example through direct air capture of CO_2. At present, fossil fuel derived hydrogen with CCUS is more cost-competitive than electrolytic hydrogen in Canada[1], particularly due to our abundance of low-cost natural gas.

[1] IEA, Energy Technology Perspectives, 2020

Canada has decades of experience in CCUS with leadership in technology innovation; an abundance of suitable geology for permanent CO_2 storage, notably in the Western Canadian Sedimentary Basin[1]; transferable expertise from the oil and gas sector; and growing markets and emerging pathways for CO_2 utilization. Canada is also home to one-fifth of the world's large-scale projects in operation, which has been enabled by the existing policy environment and a strong history of advancing the technology through public-private partnerships. However, challenges remain in terms of high technology costs for some applications, technical and commercial risks, required infrastructure investment, and competitiveness with other countries like the US, UK and Norway with stronger policy incentives in place. Canada's early CCUS leadership has included work to advance hydrogen production with CCUS. Projects include the Shell Quest Project, and the Sturgeon Refinery linked to the Alberta Carbon Trunk Line.

NRCan is considering opportunities for a CCUS sector that will leverage Canada's natural advantages and capabilities to support emissions reductions in industrial sectors (e.g. oil and gas, cement, iron & steel, chemicals, power), enable low carbon hydrogen, other CO_2 based fuels and products, and negative emissions solutions like direct air capture (DAC) and bioenergy with CCS (BECCS).

There is significant growth potential in CCUS alongside clean hydrogen production in Canada, which could have a major impact on emissions reductions. Based on recent analysis by the Transition Accelerator – a pan-Canadian, non-profit organization working on emissions reductions solutions for business and society – there is an upper bound potential for eight times the current domestic production of clean hydrogen from natural gas in a 2050 net-zero energy system in Canada. The carbon capture and storage requirement for this magnitude of clean hydrogen production would be approximately 203 Mt CO2 per year. Given Canada's current CCUS operational projects capture and store about 4 Mt of CO2 per year, this would represent a very significant increase in CCUS activity. These opportunities have been identified in includes Alberta's Natural Gas Vision and Strategy goal of large-scale blue hydrogen production with CCUS deployment across the province by 2030.

Capture & Compression

Capturing CO_2 at the point of conversion of fossil fuels into hydrogen is much easier than capturing it once released into the atmosphere. The concentration of CO_2 in the source gas process stream is a significant driver of cost and energy requirements of capturing CO_2, and these capture and compression costs dominate the overall costs of CCUS[2]. Large, high-concentration CO_2 emissions such as those from ethanol, natural gas processing, and hydrogen production typically have the lowest CO_2 capture costs[3]. Adding

NRCan. (2013). *North American Carbon Storage Atlas*. Retrieved from https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/files/pdf/11-1454_eng_acc.pdf

[2] National Petroleum Council. (2019). *Meeting the Dual Challenge - A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage*. Vol II. Chapter 2. Report available online at https://dualchallenge.npc.org

[3] National Petroleum Council. (2019). *Meeting the Dual Challenge - A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage*. Vol II. Chapter 2. Report available online at https://dualchallenge.npc.org

CCUS to SMR plants leads, on average, to cost increases of about 50% for CapEx and requires 10% extra fuel. It also leads on average to a doubling of OpEx as a result of CO_2 transport and storage costs[1].

The Shell Quest Project located in the Scotford Upgrader is a high profile SMR+CCUS project currently operating in Alberta capturing ~1.2Mt-CO_2/year. The captured carbon is dehydrated, compressed, and transported via pipeline ~65 km to a saline aquifer north of Redwater, AB, and injected more than two kilometres underground. In the five years since its start up, Quest has captured and safely stored five million tonnes of CO_2 at a lower cost than anticipated. According to Shell, the cost to operate Quest is about 35% lower than what was forecast in 2015, due to an excellent storage reservoir with significant capacity for CO_2 injection, and strong capture reliability. In addition, if Quest were to be built today, it would cost about 30% less as a result of capital efficiency improvements.[2] Other CCUS projects globally, such as the Northern Lights CCS project in Norway, have incorporated lessons from Quest – which has been sharing knowledge and lessons learned over the last five years to encourage more widespread implementation of CCUS.

CO_2 Transportation & Low-carbon Industrial Hubs

Compressed CO_2 can be transported by ship, pipeline and road. Pipelines are the most economical way of transporting CO_2 in large quantities onshore. The Alberta Carbon Trunk Line (ACTL) pipeline is a major CCUS project in operation and has the capacity to carry ~14.6Mt-CO_2/year along a 240km pipeline. It is supplied by two CO_2 sources, one of which is a byproduct of hydrogen produced via the gasification of heavy oil bottoms at the Sturgeon Refinery. The ACTL has 85% available capacity to facilitate CCUS uptake at additional hydrogen production and other high-emitting facilities in Alberta's Industrial Heartland.

As hydrogen production from fossil fuels scales up, more CO_2 pipelines more will be required to scale up CCUS deployment. Development of low-carbon industrial hubs are trending as a way to advance CCUS opportunities to spur innovation, enable new business models, and encourage development of cost-effective CCUS technologies at scale. Industrial hubs link emitting facilities with CO_2 storage or utilization projects, providing the benefit of shared CO_2 infrastructure, economies of scale, and decreased commercial risk across multiple stakeholders. CCUS hubs are best suited for regions where CO2 storage or utilization opportunities are near clusters of high emitting facilities.

[1] IEA. (2019). *The Future of Hydrogen*. Retrieved from https://www.capenergies.fr/wp-content/uploads/2019/07/the_future_of_hydrogen.pdf

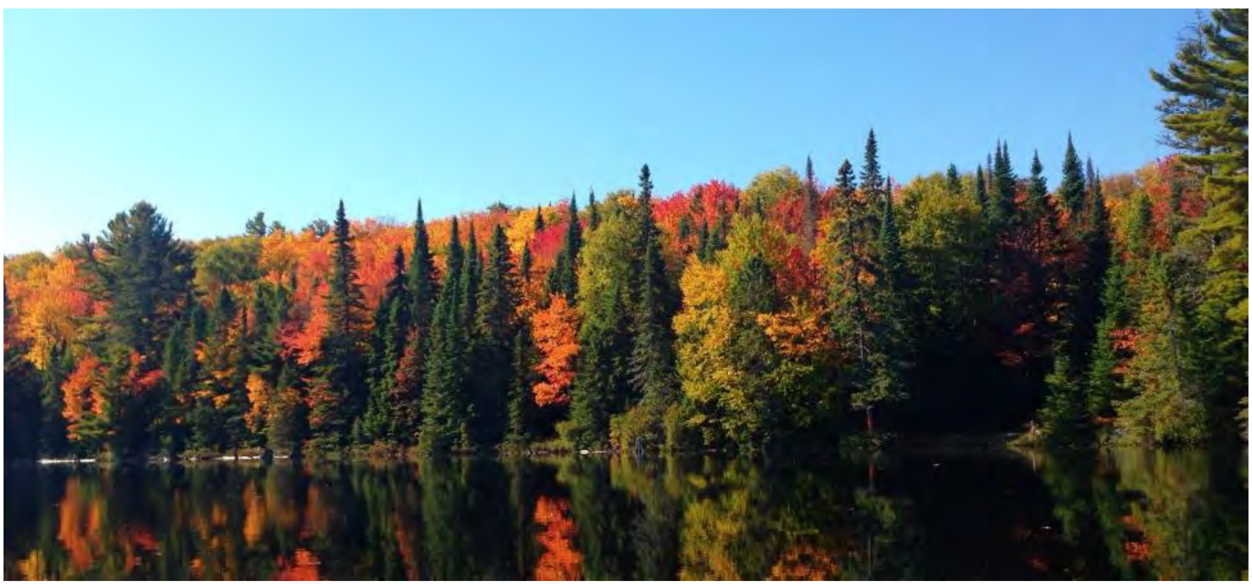
[2] Shell. (2020). *Quest CCS Facility Captures And Stores Five Million Tonnes Of CO2 Ahead Of Fifth Anniversary.* Retrieved from https://www.shell.ca/en_ca/media/news-and-media-releases/news-releases-2020/quest-ccs-facility-captures-and-stores-five-million-tonnes.html

Utilization & Storage

The last stage of CCUS is its long-term storage and sequestration underground or its use in industrial and commercial processes. CO_2 can be stored in porous sedimentary formations including depleted gas, crude oil, and bitumen reservoirs, deep saline aquifers, salt caverns and in coal seams. The long-term suitability of these options depends on their accessibility, the overlying cap rock formations and other factors. Canada is rich in geology that is suitable for CO_2 storage, including sedimentary basins, saline formations and oil and gas formations in proximity to a significant portion of emitting industries.[1] The Western Sedimentary Basin is a geological formation that covers Northern BC, Alberta, and parts of Saskatchewan and contains many potential sites for storage. Deep saline aquifers are the most secure and most widely available storage locations in Canada.

Overall, CO_2 storage is safe, permanent, and well-demonstrated in Canada, with decades of monitoring that proves that injected CO_2 remains within reservoirs. It is important to note that CO_2 storage and use, particularly for enhanced oil recovery, has been in commercial operation since 1972 with hundreds of millions of tonnes of CO_2 successfully sequestered all over the world. As an example of advanced protocols, California Air Resources Board (CARB) under the low carbon fuel standard (LCFS) rules allows negative emission CO_2 anywhere in the world to be sequestered and receive LCFS credits for the CO_2. As part of that they have a monitoring and verification protocol for ensuring that the CO_2 stays sequestered and anyone claiming the credit must comply with that protocol.

A number of new technologies and products are emerging that utilize CO_2 either as feedstock or offer long term sequestration potential, for example in the form of useful products like concrete, liquid synthetic fuels, and consumable beverages. A number of Canadian companies are leading in this space, offering complementary technology expertise that can ultimately also benefit the hydrogen sector.



[1] Dooley, J.J., R.T. Dahowski, C.L. Davidson, S. Bachu. N. Gupta and J. Gale. 2004. A CO2-storage Supply Curve for North America and its Implications for the Deployment of Carbon Dioxide Capture and Storage Systems, p7, http://uregina.ca/ghgt7/PDF/papers/peer/282.pdf.

Hydrogen Production from Biomass

Biomass gasification is considered both renewable and carbon-neutral and is a viable hydrogen production pathway in Canada. Plants consume CO_2 as they grow, so the release of CO_2 through this type of process is net carbon-neutral over its life cycle. Any renewable organic resources comprised of mostly carbon, hydrogen and oxygen can be used a biomass feedstock. Biomass gasification technology extracts hydrogen by gasifying and then reforming forest or agricultural residues or other dry organic wastes. Hydrogen production using bio-energy with carbon capture and storage (BECCS) presents an opportunity not only to decrease emissions on hydrogen production, but in other sectors as well, thanks to the carbon negativity of the process.

Forestry and Agricultural Biomass Gasification

Biomass gasification is a stable technology that uses high temperature steam (generally >700°C) and oxygen from the air to break down biomass into hydrogen and other products without combustion. Biomass gasification is generally undertaken in two stages, 1) An initial gasification stage, and 2) a water-gas shift reaction in which carbon monoxide (CO) is converted to carbon dioxide (CO_2), generating additional H_2. PSA is then used to purify the hydrogen and remove the CO_2.

The economies of scale associated with biomass gasification are substantial, so producing hydrogen in this way requires a centralized production model. Forest and agricultural biomass are in demand in Canada for producing liquid biofuels, renewable natural gas and co-processing in petroleum refineries. While technically viable, biomass gasification requires a large, dependable supply of locally-/regionally-sourced feedstocks to be a major production pathway. Incorporating existing forest product facilities into the hydrogen infrastructure network could capitalize on their position as an aggregator of biomass and serve to improve overall efficiency of resource use. There is also the potential to develop 'biohubs' to help with regional supply challenges. Arguments can be made for investing in biomass collection, storage and processing to support hydrogen production and should be explored further in regional hydrogen plans.

Landfill/Sewage/Agricultural Gas Reformation

Methane gas (CH_4) resulting from the breakdown of organic matter in landfills, sewage treatment plants and agricultural waste sites is another potential source of hydrogen from biomass. Similar to the natural gas SMR or ATR processes, the methane from these sources is collected, reacted with steam, and the hydrogen is separated out. The CO_2 from this feedstock originates from the atmosphere; therefore, the only additional emissions created from the process come from the heat require to generate the steam. Like solid biomass feedstocks, these gaseous waste streams are regionally specific, and are in limited supply. Given the increasing demand for renewable natural gas (RNG) as an alternative fuel, it is likely that these feedstocks will be used directly in methane form rather than be converted to hydrogen.

Other Hydrogen Production Pathways

Industrial By-Product Capture

Many industrial plants produce hydrogen as a by-product. In some cases, by-product hydrogen is captured and used as a feedstock in chemical production, and in others it is simply vented to the atmosphere. A 2019 *British Columbia Hydrogen Study*[1] found that, approximately 18.5 tonnes of relatively pure hydrogen is currently vented to the atmosphere every day in BC. This represents an important near-term hydrogen source for this province and an opportunity to create a new market for industrial plants to sell by-product hydrogen. This production method requires minimal cleanup and represents a low-cost, low carbon intensity hydrogen supply estimated at $0.88/kg prior to distribution and storage, based on the heating value of the fuel. Supply of by-product hydrogen in the near-term is low-cost relative to dedicated new production, and these chemical plants that currently vent hydrogen could become focal points around which near-term deployment HUBs are based.

The supply of this source of hydrogen in Canada that is not already utilized or sold is estimated at about 70,000 tonnes per year[2], or 190 tonnes per day. Canada's chlor-alkali and sodium chlorate plants tend to be located where electricity costs are lowest, including BC, Manitoba, Saskatchewan, and Quebec.

CANADA'S REGIONAL HYDROGEN PRODUCTION RESOURCES

The production pathways adopted in each region of Canada will depend on the availability of feedstocks, energy inputs, and in some cases suitable sites for CCUS. Each region/province will need to carefully consider their entire energy system before investing in any particular production pathway. Overall, the production pathway that makes the most sense for each region will minimize costs and carbon intensity while maximizing the use of local feedstocks and energy sources.

Industry and Provincial Governments will play a key role in determining which hydrogen production pathways will come to fruition over what timeframes in Canada, with government playing the role of establishing policy, for example setting CI limits, and industry determining the most economical pathways that fit within the limits. Overall, a balanced, regional approach to developing Canada's hydrogen supply from a mix of fossil fuel-derived and clean electricity-derived sources is anticipated to evolve. This diversification of fuel sources would best enable production volumes to support the development of domestic and export markets. Figure 15 shows the most likely potential pathways for each province/region based on their existing electrical grid and access to feedstocks.

[1] Source: ZEN and the Art of Clean Energy Solutions

[2] Source: Ekona Power, private market study

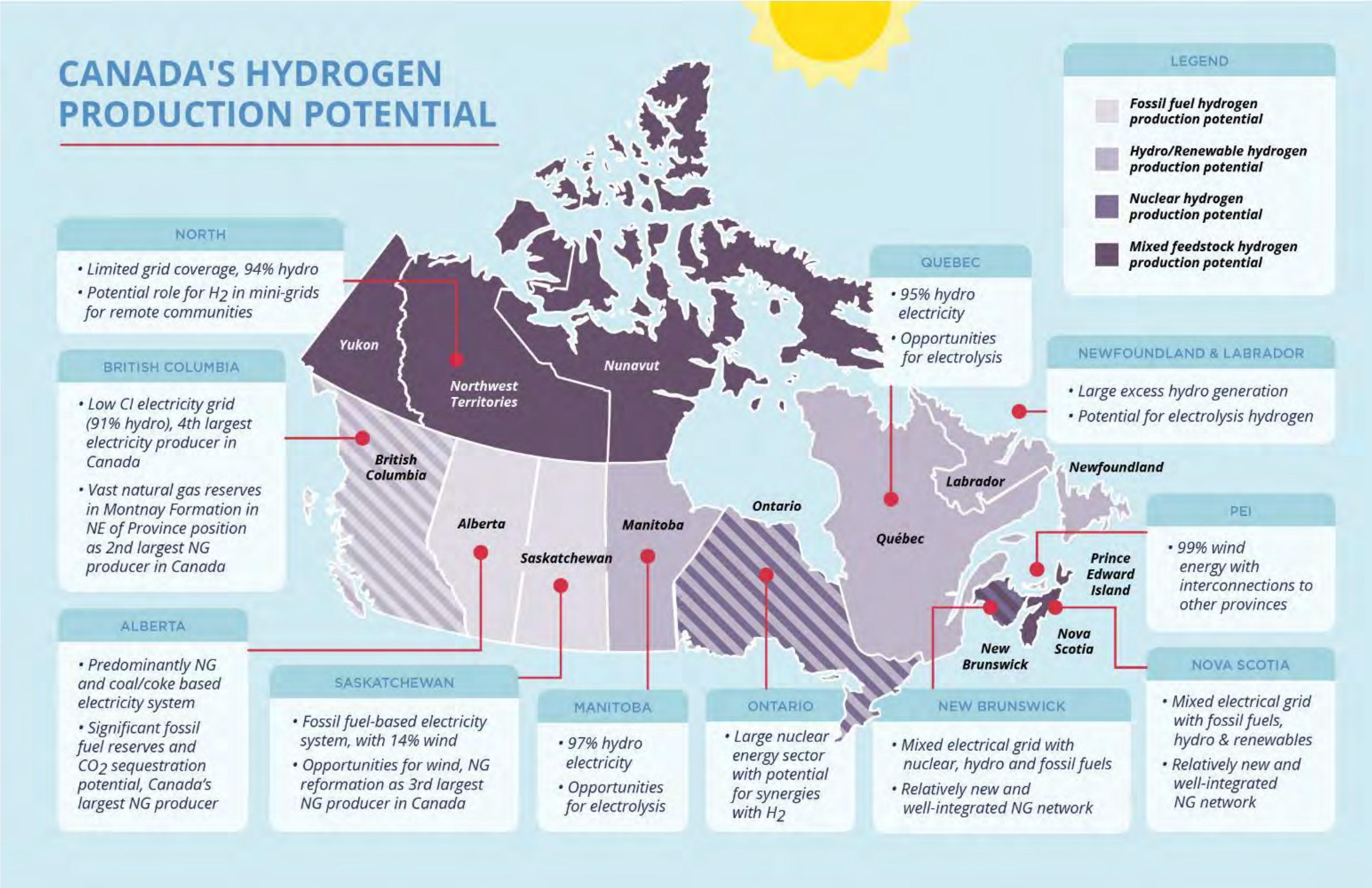


Figure 15 – Provincial Map of Potential Hydrogen Production Pathways

PRODUCTION PATHWAYS' COST & CARBON INTENSITY

The production cost of hydrogen for various pathways is influenced by technical and economic factors, including feedstock costs (e.g. natural gas, electricity), capital costs and ongoing operating costs. According to the IEA, fuel and feedstocks are the largest component of production costs and account for between 45% to 75% depending on where in the world the hydrogen is being produced[1]. Canada has one of the overall lowest cost of production in the world for both SMR+CCUS and hydroelectric electrolysis according to a 2018 report from the Asia Pacific Research Centre[2]. This cost advantage provides an opportunity for Canada to begin producing low-cost, low-CI hydrogen almost immediately. Currently, low CI hydrogen production at scale in Canada is lowest cost when using fossil fuel feedstocks compared to electrolysis pathways. While Canada has competitive electricity prices relative to international markets, costs need to be in the range of <$40/MWh to produce hydrogen at target price points. Industrial tariffs with high peak demand charges and tariff structures that do not recognize decarbonizing benefits can be a barrier to electrolysis pathways.

As demand grows, economies of scale and technical advances will further lower the cost of hydrogen production in Canada, and this will provide time for more renewables to be added to the grid for even lower carbon intensity production. Figure 16 compares projected bulk hydrogen production costs (not including distribution costs) by different pathways projected over time from a range of international and Canadian studies. By 2030, the cost of SMR+CCUS hydrogen is expected to be in the range of ~$1.00 - $2.00/kg-$H_2$ when produced at scale (>100 tons per day - TPD) in Canada based on studies out of Alberta and British Columbia, while the cost of electrolysis from dedicated renewables shows potential to be in the $3.20/kg-$H_2$ range in that timeframe.

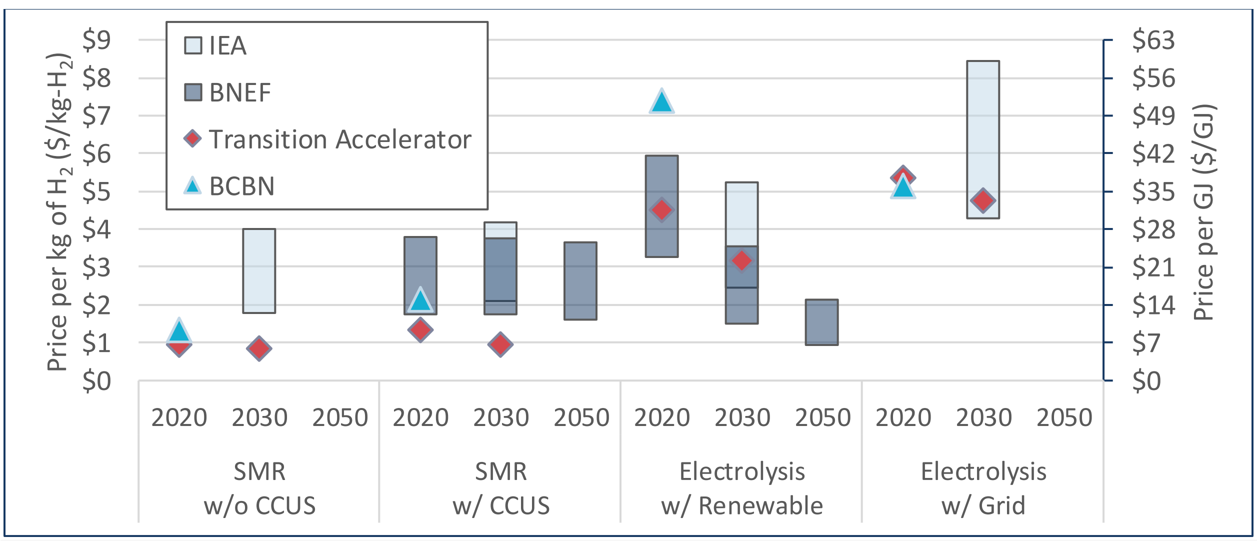


Figure 16 – Comparison of Hydrogen Production Pathway Costs 2020, 2030, and 2050[1,2,3,4]

BloombergNEF predicts the global levelized cost of hydrogen from large renewable energy powered projects will be cost competitive with low carbon hydrogen from natural gas via SMR w/CCUS by 2030. Their study shows that by 2050, renewable hydrogen could be produced for less than a dollar per kilogram[4]. This may not be directly applicable to Canada, but the general trend of renewable hydrogen

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[1] IEA. 2019. The Future of Hydrogen: Seizing Today's Opportunities.

[2] Asia Pacific Energy Research Centre, "Perspectives on Hydrogen in the APEC Region.pdf," Jun. 2018 [Online]. Available: https://aperc.ieej.or.jp/file/2018/9/12/Perspectives+on+Hydrogen+in+the+APEC+Region.pdf

[3] BCBN BC Hydrogen Study, Zen and the Art of Clean Energy Solutions Inc., 2019

[4] BloombergNEF: Hydrogen Economy Outlook, March 20, 2020,

costs coming down over time is valid and warrants further study regionally in Canada. However, this renewable hydrogen would be variable and not at the scale required on its own for large continuous petajoule energy applications. The situation in Canada may favour fossil fuel-based hydrogen over electrolytic hydrogen due to our inexpensive and plentiful natural gas and access to CCUS. However, it should be noted that scale and transportation costs are important factors that have a big impact on delivered cost of hydrogen, particularly as the market is developing. Hydrogen produced vis SMR + CCUS requires significant scale to be economical, which requires high capital investments and relatively long buildout timing. Electrolyzers are modular and easily scaled and can be situated close to end-use applications. It is therefore expected that both will play an important role.

The Carbon Intensity (CI) of hydrogen production is a method for comparing the end-to-end lifecycle GHG emissions of hydrogen as it moves from primary energy source/feedstock to delivered energy commodity. End-use can also sometimes be considered in the lifecycle analysis, but for simplicity this is separated from production pathway emissions herein. In the case of hydrogen made from natural gas via SMR + CCUS, this includes the upstream emissions required to recover the gas, and the emissions released during the SMR or ATR process (minus any CCUS). Upstream emissions vary regionally in Canada, and there are national and provincial efforts underway to lower emissions through actions such as reducing fugitive methane emissions and electrifying upstream equipment.

For hydrogen produced through electrolysis, the CI can be almost zero if produced from emission-free sources of electricity such as hydroelectricity, wind, solar, and nuclear. Hydrogen produced with electricity from a grid with mixed sources will have a CI relative to the mix of sources. For example, a grid fed from nuclear and renewables will have a much lower CI than one fed mainly from coal power plants. It is important to note that hydrogen produced through electrolysis is not necessarily cleaner than hydrogen produced through SMR, and as regions throughout Canada develop hydrogen supply, the CI measure is critical for comparing different production pathways and sources. Hydrogen can in fact help to lower the CI of electricity grids in regions with mixed generation sources that include generation from fossil fuels; this is discussed further in the end-use opportunities section. Figure 17 compares hydrogen pathway CI based on Canadian and international sources.

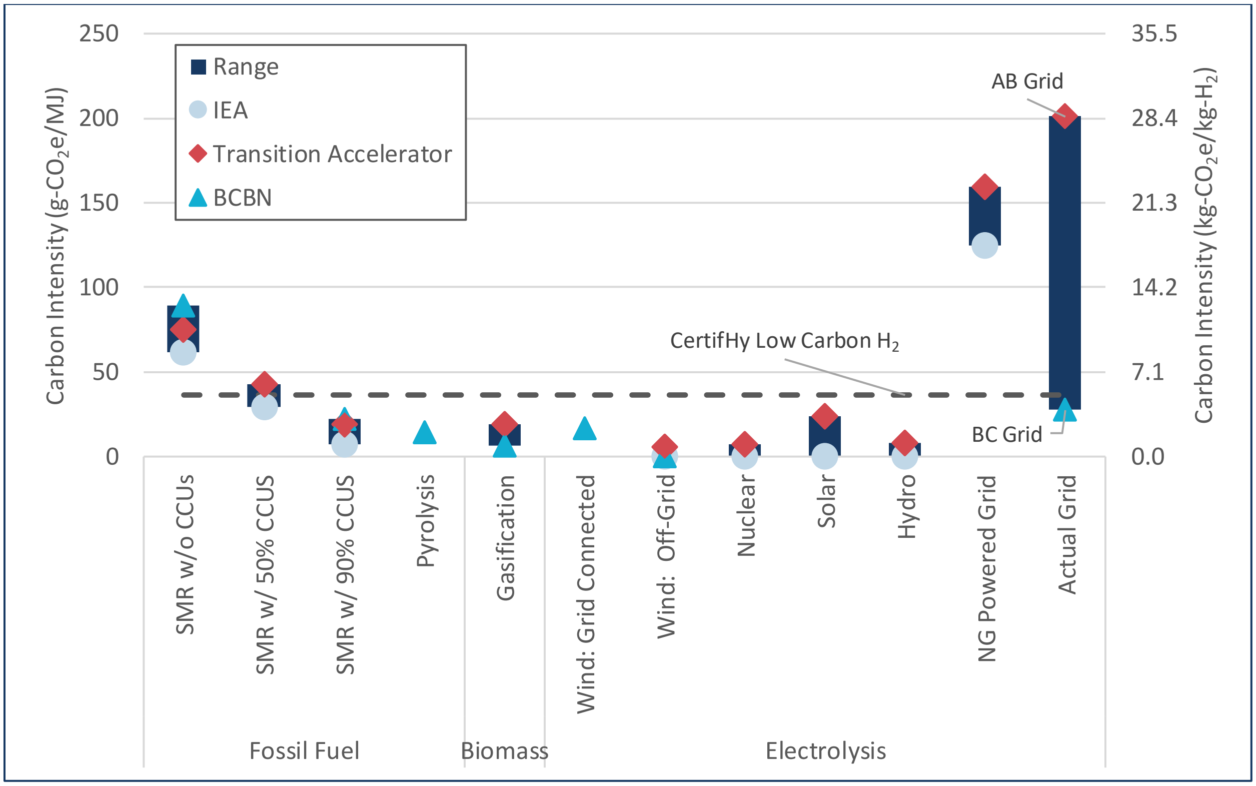


Figure 17 – Carbon Intensities of Hydrogen from Different Production Pathways[1,2,1,4]

It will be important for Canada to develop and adopt national definitions and standards for 'clean' hydrogen, whereby CI thresholds are established and can be independently certified. Hydrogen's decarbonization benefits will only be realized if Canada adopts low CI hydrogen, and any government investment in the development of new supply in Canada needs to reflect this. It is recommended that Canada coordinate efforts underway internationally, to facilitate trade in the longer term as well as benefit from extensive efforts that have already been initiated to quantitatively define and measure hydrogen CI from a range of pathways. For example, the European Commission has initiated a pilot program called CerifHy to develop an EU-wide Guarantee of Origin scheme for green and low carbon hydrogen that considers both the origin of the hydrogen and its greenhouse gas (GHG) intensity. The recommended threshold for GHG intensity is set at a 60% below the intensity of hydrogen produced from natural gas, currently set at 36.4 gCO_{2e}/MJ.[2]

Over time, the mix of production pathways will shift based on their overall CI reduction and their cost per tonne of CO_2 abated. This will likely eventually go from a blend of fossil fuel derived hydrogen with and without CCUS and hydrogen produced via grid connected electrolysis, to non-emitting and renewable sources with very low or zero CI. The timeframe for this transition is dependent on a number of factors including feedstock cost, demand and technical innovation, and market forces that will ultimately drive the production pathway development in Canada. However, the potential low cost of negative emissions means that Canada will likely use low cost hydrocarbons for a long time to come unless strong policy

[1] IEA. 2019. The Future of Hydrogen: Seizing Today's Opportunities.

[1]Asia Pacific Energy Research Centre, "Perspectives on Hydrogen in the APEC Region.pdf," Jun. 2018 [Online]. Available: https://aperc.ieej.or.jp/file/2018/9/12/Perspectives+on+Hydrogen+in+the+APEC+Region.pdf

[1] BloombergNEF: Hydrogen Economy Outlook, March 20, 2020,

[1] BCBN BC Hydrogen Study, Zen and the Art of Clean Energy Solutions Inc., 2019

[2]https://www.certifhy.eu/images/media/files/CertifHy_2_deliverables/CertifHy_H2-criteria-definition_V1-1_2019-03-13_clean_endorsed.pdf

measures are put in place. Production of hydrogen from fossil fuels without CCUS should be coupled with greater than 50% CCUS as soon as possible and move to predominantly greater than 90% CCUS by 2030.

The fossil fuels with CCUS pathway will dominate production until more renewable sources can be built and cost reduction makes the overall energy transition to renewables gain momentum. The drive for fuel switching to direct electrification will increase overall electricity demand over the same timeframe that hydrogen demand grows, and hence the market will make decisions for the best overall blend of pathways for hydrogen production with this as a consideration. It is recommended that in addition to establishing CI thresholds, provinces with input from the Federal Government set longer-term objectives to transition to renewable hydrogen supplies through establishing tiered thresholds of required renewable content over time should the economics make sense when compared against viable but non-renewable clean energy vectors. The CI thresholds and timing will likely vary by province based on local resource availability and economic factors. Canada needs policy to drive adoption of multiple pathways in order to ensure both decarbonization and ultimate sustainability goals are met. Establishing tiered CI thresholds will also ensure that electrolysis assets that are scalable and economic can be deployed to match demand in the early years as demand is growing, and do not get stranded as lower cost centralized hydrogen produced from fossil fuels with CCUS comes online.

One way to establish a balanced supply of clean hydrogen is to require that government funded projects utilize a portion of low carbon hydrogen. Provincial funding programs such as Emissions Reduction Alberta are already setting requirements, such as requiring domestic hydrogen supply, with the goal to stimulate hydrogen production supply chain development together with end-use rollout. Adding renewable content requirements is another important aspect to consider, and in regions with nuclear generation the definition can be focussed on non-emitting hydrogen rather than restricted to renewable. The federal Clean Fuel Standard (CFS) takes a technology neutral approach by using the CI of the fuel to determine eligibility for credits and then amount of credits awarded; it does not specifically provide extra credit for renewable pathways. The design of the CFS will incentivize the use of low CI fuels, thereby driving increasing uptake of lower CI hydrogen production pathways over time.

STAKEHOLDER INPUT: HYDROGEN PRODUCTION

Opportunities

- *Sixty-seven percent of Canada's electricity comes from renewable resources and 82% from non-GHG emitting sources which could be used for electrolysis*
- *Canada is one of the top ten global producers of hydrogen today, producing an estimated 3 million tonnes annually via steam methane reformation (SMR) of natural gas.*
- *Canada is the world's fourth largest producer and sixth largest exporter of natural gas.*

Challenges

- *Bias against certain pathways puts overall hydrogen industry at disadvantage and unlevel playing field in near term*
- *CI of grid for electrolysis may be very high in some regions for near-mid term*
- *Regionality of CCUS, lack of acceptance and concern over long term stability*
- *Predictable, long-term demand is critical before industry can invest in projects*
- *Cost of electricity for electrolysis pathway driven by peak demand and no special rate tariffs.*
- *Large capital investment to scale production requires demand to grow concurrently*

Findings

- *Focus on carbon intensity of hydrogen as primary near term performance-based metric.*
- *Government support for supply development to be limited to low CI pathways, with clear threshold set and independent certification capabilities established. Align with international standardization efforts (E.g. CertifHy @ 36.4 gCO_2e/MJ).*
- *Transition to increasing hydrogen with low to net-zero content is needed over time. Set increasing thresholds for renewable content in government supported projects over time. (e.g. 33% now to 50% by 2050)*
- *Strategic focus for Canada should be on CCUS innovation and engineering expertise given potential for low CI, low cost hydrogen derived from fossil fuels that rely on bulk CCUS potential.*

HYDROGEN STORAGE & DISTRIBUTION

Hydrogen can be stored and transported from the point of production to point of use in a number of ways. Storage and distribution must be considered from the outset as regional hydrogen deployment HUBs are built up across Canada. This part of the value chain has significant economic and emissions implications which affect the overall hydrogen delivered cost and GHG lifecycle emissions.

Hydrogen Storage

Hydrogen's low volumetric energy density makes storage a challenge, both as a bulk commodity at the point of production and in end-use applications such as fuel storage on-board vehicles. Physical storage, materials--based storage, and chemical carrier storage are the broad categories defining how hydrogen can be stored. The method of hydrogen storage is often based on the end-use requirement, including weight and volume available for energy storage.

Physical storage refers to hydrogen stored as either a compressed gas in high pressure cylinders, or as a cryogenic liquid in specialty insulated tanks. In end-use applications, such as on board vehicles, gaseous hydrogen is typically stored in high-pressure tanks with pressures ranging from 350 to 700 bar (5,000 to 10,000 psi). Hydrogen tanks for forklifts, buses and heavy-duty vehicles today generally use hydrogen compressed to a pressure of 350 bar. Light-duty vehicles store hydrogen at 700 bar as higher pressures allow for smaller tanks which can be fit more easily into conventional vehicle designs. In the future, liquid hydrogen may be used for onboard storage for certain applications such as trucks, similar to LNG trucks currently available. Bulk hydrogen for non-mobile applications can be stored as a compressed gas in tanks above and below ground, as liquid hydrogen in large insulated tanks, and in natural gas pipelines, salt caverns, and depleted wells. As volumes grow, for example if hydrogen is used to provide daily or seasonal energy storage, the ability to utilize existing pipeline networks or geological storage options becomes necessary due to both practical footprint considerations and cost.

Gaseous hydrogen can be stored effectively underground in salt caverns, as has been proven in projects in the UK, US, and throughout Europe. These regions are targeting the use of hydrogen for utility scale energy storage where bulk storage is required for technical and economic viability. Engineered salt caverns are utilized for NG storage in many provinces in Canada. These caverns are created by first boring a hole to storage depths and creating the storage space via solution mining, which dissolves the salt by pumping in fresh water and pulling out the brine stream. The compact structure and composition of salt rock formations make the structures inherently gas tight, and the cavern's only surface access is the borehole, which is plugged to prevent leakage. Dried and compressed hydrogen can be injected through the borehole and effectively stored in the cavern indefinitely. As demand for hydrogen grows around the world, depleted gas wells are also being considered for bulk storage of hydrogen and offer mid-term potential in Canada in a number of provinces.

Storage of hydrogen as a cryogenic liquid is another physical storage method. Canada has hydrogen liquefaction assets in both Quebec and Ontario, owned and operated by large industrial gas companies. Liquid hydrogen (LH_2) is a far denser energy carrier than gaseous hydrogen. However, hydrogen liquefies at -253°C , and requires approximately 10 kwh/kg-H_2 of energy to cool the gas to the liquid state, which is approximately 30% of the heating value of the hydrogen, resulting in increased economic costs. LH_2 must be stored at cryogenic temperature in insulated storage tanks to avoid boil off or evaporation of hydrogen similar to how LNG is stored. Moving hydrogen as a liquid becomes cost effective as higher quantities are needed. Liquid storage is also effective where the footprint is constrained at end-use locations, such as at retail fueling stations for light- and heavy-duty vehicles. Liquid hydrogen is typically vaporized and dispensed in gaseous form for most fuel cell vehicle applications today. However, applications such as rail or large marine vessels require high amounts of fuel and are considering storing liquid hydrogen onboard.

Emerging technologies allow hydrogen to be stored in the form of compounds called chemical carriers. There is more hydrogen in a litre of gasoline than in a litre of liquid hydrogen. Hence, liquid chemical carriers are easy to handle and can contain large quantities of hydrogen by volume. Methylcyclohexane (MCH) and ammonia (NH_3) are the most common chemical carriers used to store hydrogen.

Hydrogen can also be stored by adsorbing the gas on powders. One advantage of this method is that the amounts of energy required to adsorb (bind) the hydrogen to the powder should be less than required to form chemical bonds, as per the chemical storage methods above. As technologies advance, adsorbent storage may make it possible to store relatively high densities of hydrogen – comparable to compressed gases – at lower pressures. While promising technologies are available, more research is needed to show ultimate potential.

Hydrogen Distribution

Gaseous hydrogen is primarily transported in tube trailer trucks today, at pressures of up to 250 bar with 180-200 bar being more typical. Transport Canada regulates transport of gaseous hydrogen through the Transport of Dangerous Goods (TDG) Regulations. Steel tube trailers are most commonly employed for gaseous delivery today, but weight regulations limit how much can be delivered by each truck. A number of companies are developing 450 bar hydrogen storage delivery systems using composite materials to increase the amount of hydrogen that can be delivered by each truck, thereby reducing costs and transportation emissions.

Cryogenic liquid hydrogen is transported in liquid super-insulated, cryogenic tanker trucks. For hydrogen distribution at longer distances in moderate amounts where dedicated hydrogen pipelines are not an option, liquified hydrogen is currently the most economical distribution method due to its significantly higher energy density.

Distribution can add significantly to the final delivered cost of the fuel. The cost of delivering hydrogen as a compressed gas or a cryogenic liquid by truck is a function of distance; estimated costs from a recent BC study are shown in Figure 18.

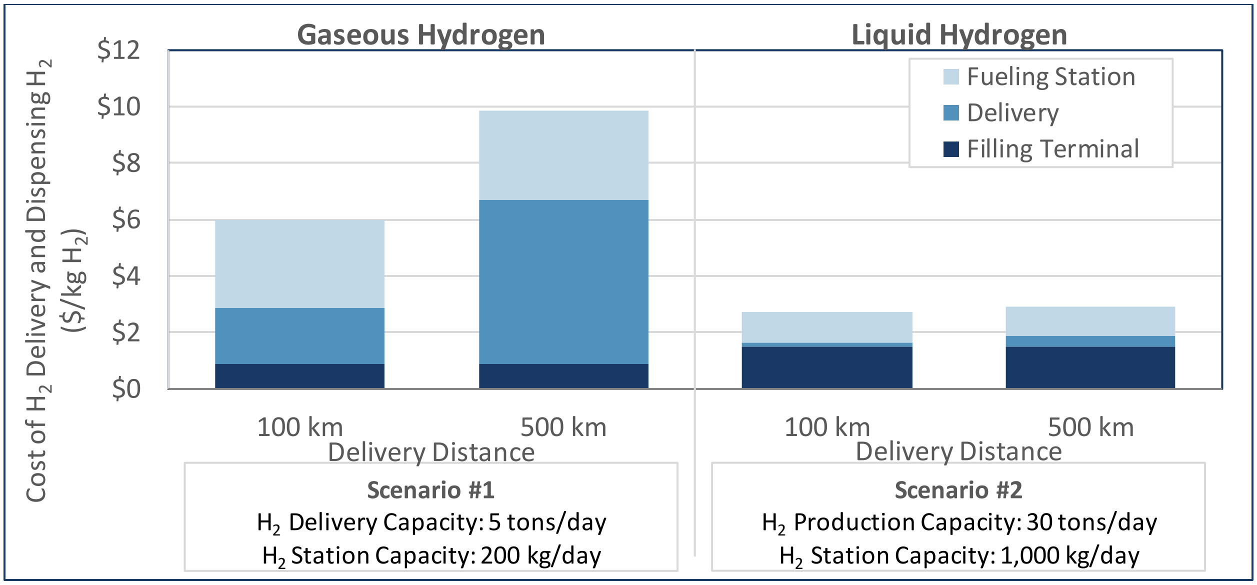


Figure 18 – Truck-Based Delivery Cost for Hydrogen as a Compressed Gas and Cryogenic Liquid[1]

Natural gas pipelines can be used to both store and transport hydrogen. Canada has one of the world's largest pipeline networks delivering natural gas from production areas to markets in both Canada and the US.

Hydrogen can be blended into NG pipelines, typically at pressures less than 100 bar, taking advantage of the inherent storage capacity in the network. Once blended into the NG pipeline, the hydrogen-NG mixture can be used in many applications in place of pure NG. Blend ratios of up to 20% hydrogen are being trialed around the world, with limited impact on infrastructure and end-use appliances. While there is a significant technology development focused on separation technologies, it is currently difficult to separate the hydrogen from the NG once blended. This may become viable in the mid term and would allow the separated hydrogen to be used in fuel cell applications.

Where pure hydrogen is required, dedicated hydrogen pipeline systems may become an attractive option for low cost transportation of hydrogen at scale, for example Figure 19 shows an existing dedicated hydrogen pipeline. The challenge with building hydrogen pipelines is the initial investment

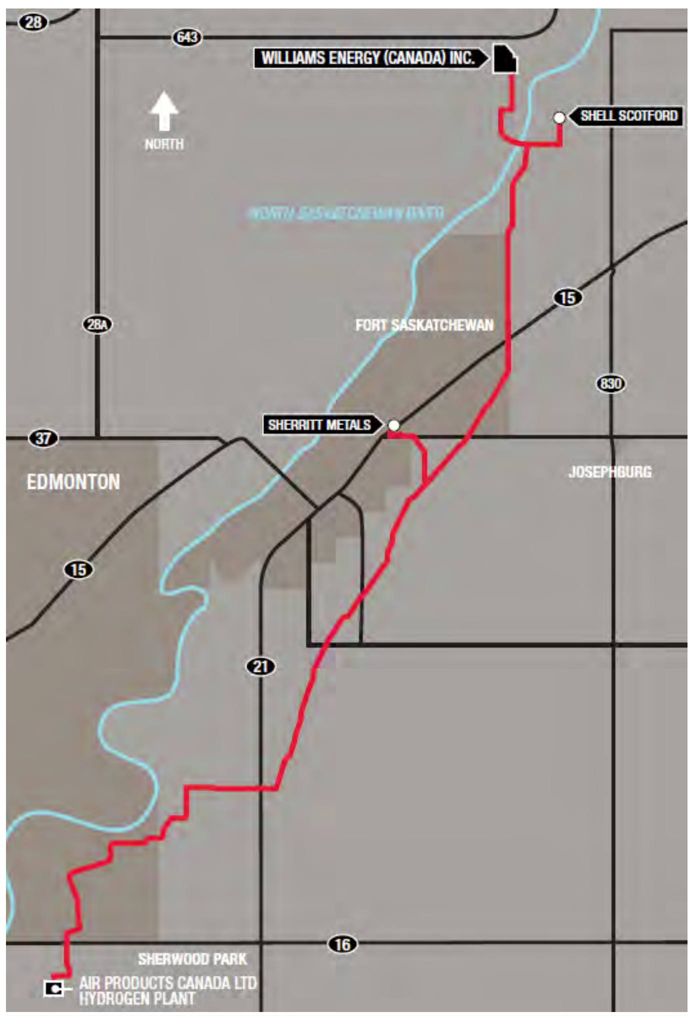


Figure 19 – Air Products Hydrogen Pipeline in Alberta

[1] BC Hydrogen Study, Zen and the Art of Clean Energy Solutions Inc., 2019

needed, and the risk of making these large capital investments while demand is growing and uncertain. Building new NG pipelines to allow for future conversion to hydrogen is an important consideration for NG utilities investing in new infrastructure. This is particularly true in regions like the Maritimes where the NG networks are still relatively new and in the growth stage. The US DOE has established dedicated technical targets for hydrogen pipelines including target capital costs of $520,000 $/mile[1] as a long-term target. Similar to the US, a backbone network of hydrogen pipelines could be a strategic infrastructure asset for Canada. This backbone would be fundamental to facilitating trade and cooperation across provinces. Once the infrastructure is in place, this is by far the lowest cost and lowest emissions means of bulk transportation. It is recommended that a dedicated infrastructure group study this potential further.

[1] https://www.energy.gov/eere/fuelcells/doe-technical-targets-hydrogen-delivery

STAKEHOLDER INPUT: DISTRIBUTION & STORAGE

Opportunities

- Canada already has dedicated hydrogen pipelines in Alberta, and an expanded buildout could give Canada a hydrogen advantage
- Canada has unique geological reserves including salt caverns and depleted NG wells that can be leveraged for bulk hydrogen storage
- Canada's extensive natural gas pipeline network can be leveraged to both store and transport hydrogen
- Hydrogen liquefaction assets will position Canada to distribute hydrogen locally and to global markets

Challenges

Canada is lagging other countries in developing standards for hydrogen in NG pipelines

Storage and transmission can be best optimized when regions collaborate across provincial boundaries

Hydrogen transportation costs can be significant if key infrastructure is lacking

Technical limitations exist for bulk storage and transport on rail and ship

Liquefaction is energy intensive and presents safety challenges, but is required for large scale distribution

Lack of technical data on feasibility of leveraging and modifying Canada's pipeline infrastructure to support large-scale hydrogen distribution

Findings

- *Fast-track regulatory approvals for high pressure gaseous distribution in Canada (450 bar)*
- *Accelerate updating Canadian codes & standards related to pipeline blending*
- *Begin scaling up natural gas injection and power-to-gas demonstrations in different regions including investment support, policy/regulatory incentives and support for R&D and innovation*
- *Scale H_2 transport and distribution networks starting with refuelling station networks in urban areas and in industrial clusters*
- *Invest in strategic liquefaction assets in Western Canada to complement Eastern Canadian assets*

4. Hydrogen End-Use Opportunities

The potential for hydrogen use in Canada is as diverse as the pathways to create it. Adoption of hydrogen will be focused on energy-intensive applications where it offers advantages over alternative low-carbon options. This includes using hydrogen as a fuel for long-range transportation and power generation, to provide heat for industry and buildings, and as a feedstock for heavy industrial processes, like steel and cement making. Domestic deployment of hydrogen will be critical to supporting Canada's world-leading hydrogen and fuel cell sector, as well as to meeting our climate change objectives.

Figure 20 – Hydrogen End-Uses

FUEL FOR TRANSPORTATION

Hydrogen can be used in transportation applications through several different pathways as shown in Figure 21.

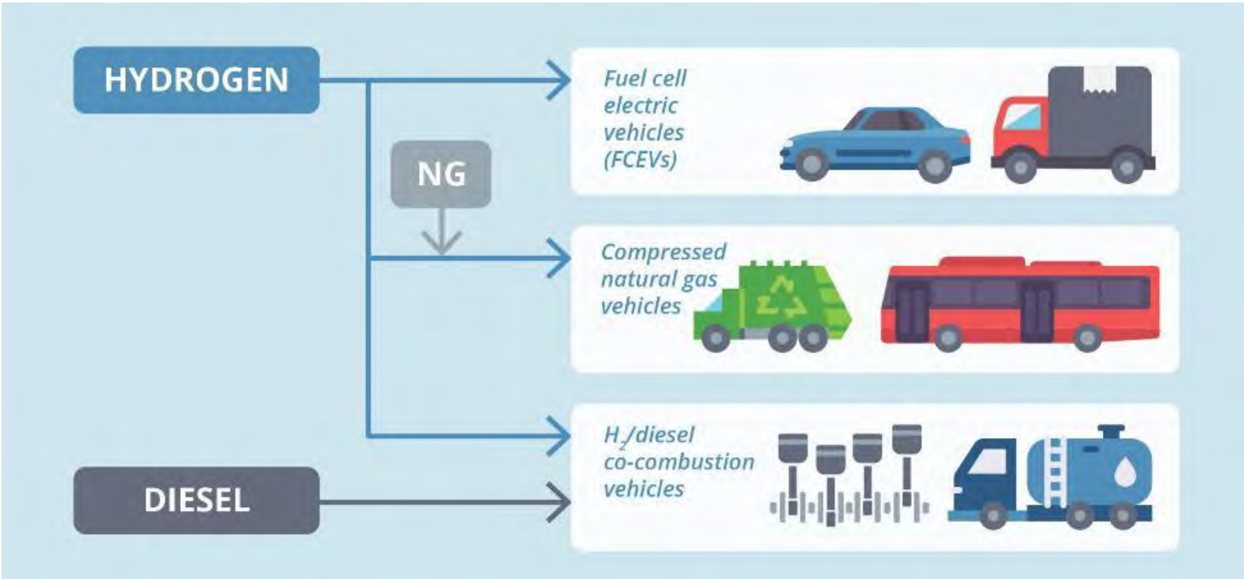


Figure 21 – Hydrogen Uses in Transportation

Hydrogen can be used directly as a fuel in fuel cell electric vehicles (FCEVs), which have two times the efficiency of combustion engines and zero emissions at the tailpipe. Fuel cell light-duty passenger vehicles and transit buses are commercially available today globally and deployed in limited numbers in Canada. Hydrogen FCEVs show strong promise in long-haul, heavy-duty trucking applications where batteries have limitations. The recently approved zero-emission truck regulation in California is driving significant activity by fuel cell system developers, tier 1 engine suppliers, and vehicle OEMs[1]. The focus is on quickly moving beyond the current pilot demonstration phase and developing commercially available medium- and heavy- duty trucks for the North American market in the next few years. Specialty industrial vehicles, trains, marine, and aviation applications are in the pilot demonstration phase and show long-term promise due to the high energy demands in these applications. In Canada, FCEVs can offer advantages in remote and Indigenous communities in colder climates where battery chemistries are negatively impacted. Fuel cells do not suffer the same inherent performance degradation in cold temperatures, and waste heat from the fuel cells can be used for cabin heating to further differentiate extended range of FCEVs in these cold climates.

In addition to being used directly as a fuel in FCEVs, hydrogen can enable higher amounts of renewable gas in natural gas supply networks that provide fuel for compressed natural gas (CNG) vehicles. For example, in British Columbia efforts are underway to recognize hydrogen as an eligible renewable gas under the CleanBC goal to achieve 15% RNG in the natural gas distribution system by 2030. Demand from CNG fleet operators to use lower emitting renewable gas is high, and hydrogen can help to meet that demand. There can be technical challenges related to using an H_2/CNG blend in some vehicles, including tank embrittlement in older type tanks, as well as NO_x emissions. However, with the right materials and engineering a hydrogen / CNG blend can reduce emissions of CNG vehicles and has been demonstrated

[1] Advanced Clean Truck regulation enacted by California Air Resources Board on June 25, 2020. https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks

in several pilot projects. As hydrogen separation technology matures and more hydrogen is present over a wider portion of the NG network, there is the potential for fueling stations with dual fuel sources – CNG and hydrogen – where the fuels are separated at the point of use.

Hydrogen can also be used in conjunction with diesel in internal combustion engine trucks using co-combustion technology. Co-combustion offers the advantage of lower entry cost for end-users, as existing diesel engines can be retrofit. However, these engines do not provide the efficiency advantages of fuel cells and they only reduce tailpipe emissions approximately proportionally to the percentage of hydrogen injected, which is anticipated to reach levels of up to 30%. Moreover, combusting hydrogen can lead to increased NO_x emissions. This technology is generally seen as an intermediate steppingstone toward the transition to FCEVs, and can play an important role in supporting hydrogen demand in the near term. This could help build out hydrogen fuelling infrastructure that will be compatible with heavy-duty FCEV trucks as that technology moves from pilot to commercial introduction.

Light-Duty Vehicles

Hydrogen will play an important role alongside electrification in the transition to zero-emission light-duty vehicles. The Government of Canada has set federal targets for zero-emission vehicles to reach 10% of light-duty vehicles sales per year by 2025, 30% by 2030 and 100% by 2040. Canada considers battery electric vehicles (BEV), fuel cell electric vehicles (FCEV), and plug-in hybrid electric vehicles (PHEV) as ZEVs. BC and Quebec have led provincially with the adoption of ZEV purchase incentives and sales regulations, and both provinces have started to deploy hydrogen fueling infrastructure and FCEVs in limited quantities. To date, approximately 110 light-duty vehicles are in operation in Canada, supported by 3 retail fueling stations in BC, 1 in Quebec, and 1 in Ontario. Four new stations are under development in BC, which will represent an important milestone as vehicle OEMs have indicated that 7-8 stations are needed in a region for coverage and redundancy to enable wider rollout of vehicles. BC also just announced funding for an incremental 10 new stations to continue to expand the network. It is expected that an additional ~150 LD vehicles will be deployed in the coming months as the new stations come online.

BEVs are expected to take a significant portion of the market share for light-duty applications in Canada. FCEVs offer choice for vehicle owners preferring larger vehicles, extended range, fast refueling, and no-compromise performance in cold climates. Canadian consumers have shown increasing demand for larger vehicles, with 80% of nationwide spending on new vehicles in 2019 going to trucks, vans, or SUVs.[2] This is an indication that consumers will continue to want choice and will not always focus on picking the highest efficiency vehicle option, but rather will weigh performance and vehicle size preferences in decision making. Trends such as autonomous driving and ride

Figure 22 – Hyundai Nexo in Vancouver's Modo Carshare Network[1]

[1] Modo. (2019). Image from: *Press Release: Hyundai NEXO Fuel Cell sees success with Modo, Vancouver-based carsharing co-operative*. https://modo.coop/blog/press-release-hyundai-nexo-fuel-cell-sees-success-with-modo-vancouver-based-carsharing-co-operative/

[2] Source: Statistics Canada. Table 20-10-0002-01 New motor vehicle sales, by type of vehicle

sharing may also drive greater demand for FCEVs given the higher energy intensive duty cycles required for these applications which are well served by hydrogen. Battery and charging technology continue to advance at a rapid pace, and larger vehicles with extended range are expected to reach the market in the near term. Ultimately both BEVs and FCEVs will have a role in decarbonizing LDVs.

FCEVs are likely to be more attractive for drivers in Canadian urban centers where a higher proportion of households live in multi-unit residential buildings (condominiums, apartments, townhouses with shared garages) where cost and strata bylaws can make retrofits of home charging stations expensive and difficult, providing they feel well-served by hydrogen fueling infrastructure. In addition, households which rely on street parking may opt for FCEVs over BEVs due to convenience. As market penetration rates of BEVs increase in urban centers, electric grid energy and demand capacity for vehicle charging may present an additional constraint. The addition of new electrical substations and distribution networks can be prohibitively expensive, and land may not be available. Hydrogen fueling can offer an important option to optimize overall ZEV infrastructure costs.

Although light-duty FCEVs are currently available on the market, they are still produced at a relatively small scale and one of the greatest impediments to deployment in Canada in the near-term is supply. Availability of refueling infrastructure is another key challenge, and the two are related as vehicle supply is limited in part because OEMs will deploy their limited number of vehicles only in regions with installed retail fueling networks. Regions with a combination of ZEV regulations and incentive programs to stimulate the buildout of fueling infrastructure have been the most successful in attracting deployments of FCEVs. Strategic regional partnerships leveraging public/private procurement can be another effective mechanism to solve this dual challenge.

Since FCEVs are currently produced in small volumes, they remain more expensive than comparable ICE vehicles or BEVs. Until technology advancements and production scale drive down costs, consumer subsidies will be important to support adoption. Incentive programs in Canada have price caps in place that exclude FCEVs at this time, due to their high costs[1]. One option to address this impediment to consumer adoption of FCEVs would be to stage incentive programs based on the maturity of each technology.

The adoption rate of FCEVs in Canada will be highly dependent on cost reduction driven by manufacturing at scale, the commitment to achieving national ZEV targets, as well as provincial policies and regulations around ZEVs and buildout of hydrogen fueling infrastructure.

Medium- and Heavy-Duty Vehicles

Buses

Public transit agencies around the world are shifting towards low- and zero-emission vehicles. Battery electric buses (BEBs) and Fuel Cell Electric Buses (FCEBs) are the two powertrains that are considered zero emission in transit applications. FCEBs are commercially available today, with more than 2000

Figure 23 – New Flyer's 40' Fuel Cell Electric Bus (Retrieved from NewFlyer Website)

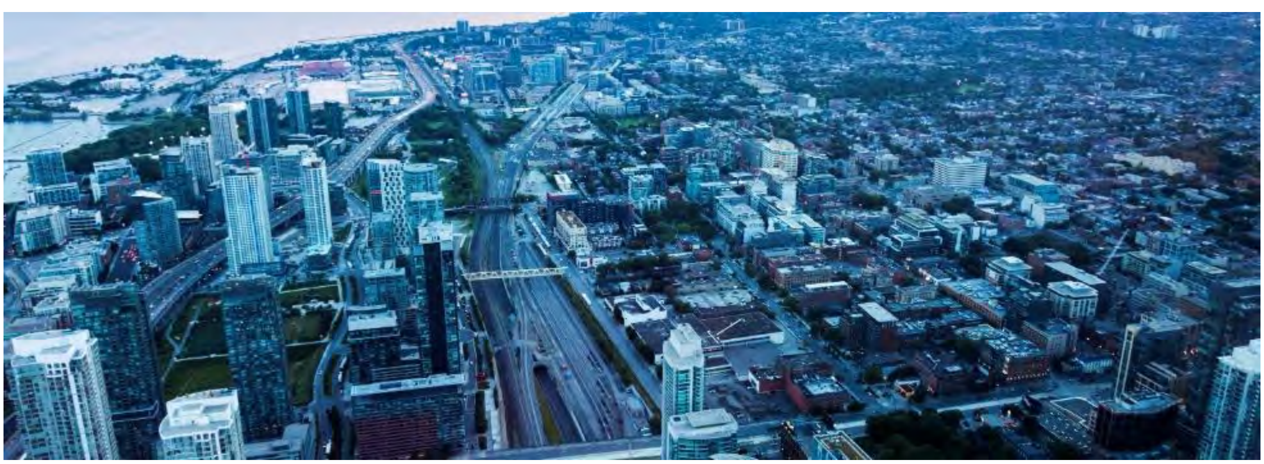
[1] https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/list-eligible-vehicles-under-izev-program

FCEBs[1] in service worldwide, and approximately half of those are powered by Canadian heavy-duty fuel cell engine technology. With over 15 years on the road and millions of kilometers in passenger service in a range of hot and cold climates, FCEBs have proven their performance. Canadian companies such as New Flyer Industries, Ballard Power Systems, Hydrogenics, and Dana TM4 hold positions in the FCEB value chain, offering a true 'Made-in-Canada' solution.

FCEB is the only zero emission technology that can match the performance of conventional diesel buses and are advantageous compared to BEBs on long routes with higher power requirements. FCEBs can also provide a one-to-one replacement ratio, meaning that transit agencies do not need to buy more vehicles to provide the same level of service as conventional buses. This is important from both a up-front cost and footprint perspective, as often agencies struggle to fit ZEV fleets into their constrained depot space. FCEBs can be refueled at comparable speeds and in a similar way as CNG buses, whereas BEBs require much longer charging times today.

California has been leading the way in zero emission transit in North America, with the adoption of the Innovative Clean Transit regulation (ICT) in 2018. This regulation requires that 100% of all new bus purchases be ZEB by 2029, and by 2040 all buses on the road in California must be zero emission. Large transit agencies were required to file transition plans with the California Air Resources Board (CARB) in summer 2020. As agencies moved from thinking about small scale pilots to planning full transitions, there has been an increase in interest for hydrogen FCEBs. Energy resilience considerations have also come into play, as several days of liquid hydrogen fuel can be stored on site in a compact footprint, providing continuity in service even in the case of grid brownouts that are increasing in frequency in California. California's deployments provide an excellent learning opportunity for Canadian transit agencies exploring ZEB options.

There are challenges limiting deployment of FCEBs in Canada today. There is currently no regulatory driver for agencies to transition to zero emission. While some agencies are exploring alternative fuel strategies to reduce emissions, a national commitment to zero-emission public transit would increase the pace of transition to full zero emission versus driving incremental change. Another challenge is that the initial deployment requires a significant capital investment for fueling infrastructure, and upgrades to maintenance facilities if the depot is not equipped with safety systems for CNG buses. While a strong business case can be made for cost effectiveness, compactness, and operational efficiency of hydrogen fueling over depot charging at scale (e.g. >20 buses), this makes it difficult for agencies to run an initial pilot to get familiar with the technology and train staff, a gating step in broader rollout.



[1] https://www.ballard.com/docs/default-source/web-pdf's/white-paper_fuel-cell-buses-for-france_final-english-web.pdf?sfvrsn=939bc280_0

Canadian cities need public transportation, and it must be zero emission for Canada to become carbon neutral and to improve air quality in urban centers. The zero-emission bus initiative[1] underway in Canada encourages government to support school boards and municipalities in purchasing 5000 zero-emission buses over the next 5 years. Canada's 'made-in-Canada' FCEB solution will provide economic value and critical local reference projects to the sector if fuel cell electric buses are a portion of the mix. There is an initiative underway to encourage 1000 of the 5000 buses to be powered by hydrogen. These buses are well suited to longer routes and cold weather climates that Canadian transit agencies service.

The adoption of FCEBs in Canada will be dependent on a successful pilot depot conversion in the next 5-7 years in order to gain acceptance and understanding of the technology among local agencies, and to test operational benefits on extended routes in Canada's cold climates. A depot conversion will also provide an opportunity to test the updated Canadian Hydrogen Installation Code published for review and provide experience to AHJs in terms of siting at-scale infrastructure at a depot. Bus costs are coming down due to increasing demand in other countries, and Canada could help drive this by coordinating larger procurements across agencies.

Trucks

Fuel cells are expected to play a significant role in trucking in applications where hydrogen's high gravimetric energy density combined with fast fueling times offer strategic benefits. For example, in heavy-duty trucks travelling long distances with heavy payloads, the weight of the batteries to provide the energy needed would result in reduced cargo load carrying capacity that is unacceptable to operators. Long charging times could also impact operations negatively in an industry where the bottom line is driven by the ability to move goods as quickly as possible. While showing significant promise, fuel cell trucks are in the pilot demonstration phase and are not yet commercially available.

Figure 24 – Fuel Cell Electric Drayage Truck
(Photo curtesy of Ballard Power Systems)

The past few years have seen heightened interest in fuel cells for class 8 long-haul trucks, known colloquially as freight trucks, semi-trucks or tractor-trailers. Nikola Motor, Toyota, Daimler, and Hyundai are all developing fuel cell powertrains for this market segment. Cummins Inc. acquired Canadian Hydrogenics Corporation and has been investing heavily in development. A number of demonstration projects have been piloted, including the Alberta Zero-Emissions Truck Electrification Collaboration (AZETEC) project, which will trial two class 8 fuel cell trucks on the corridor between Edmonton and Calgary using a Canadian-made hydrogen fuel cell propulsion system.[2] The initial project will start with two fuel cell vehicles and one refuelling station, with plans to expand in Phase 2 as part of the Alberta Industrial Heartland Hydrogen initiative.

[1] https://cutaactu.ca/en/blog-posts/new-federal-government-unveils-its-priorities

[2] Lowey, M. JWN. (2019). *$15-million Project to test Hydrogen Fuel in Alberta's Freight Transportation Sector*. Retrieved from https://www.jwnenergy.com/article/2019/3/15-million-project-test-hydrogen-fuel-albertas-freight-transportation-sector/

In June 2020, California adopted a rule requiring that more than half the trucks sold in the state be zero emission by 2035. This regulation aims to improve local air quality, a major health issue in the state that is negatively impacted by diesel truck emissions particularly in freight corridors, many of which run through disadvantaged communities. The regulation will also reduce GHG emissions, contributing to decarbonization objectives. This regulation has led to acceleration of activity in fuel cell truck development, and Canada stands to benefit as more commercial fuel cell trucks become available.

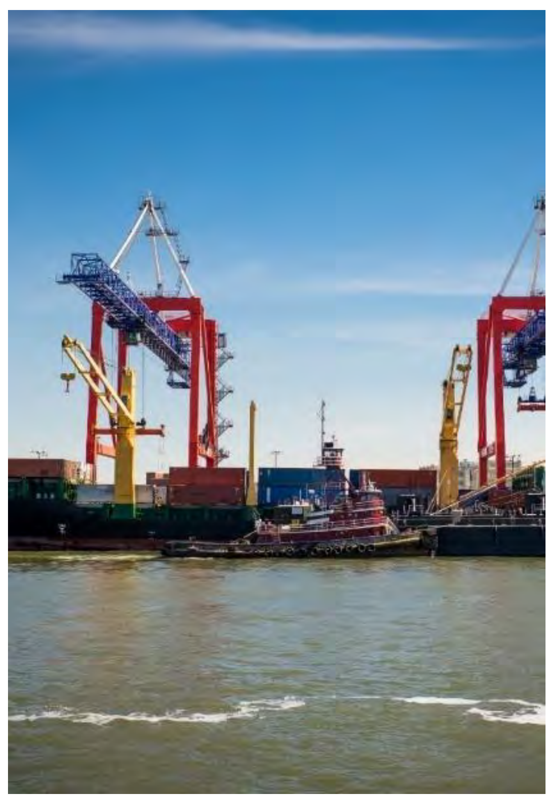
The current pilot under development in Alberta will be an important proof point for hydrogen deployment in the trucking sector, as will market evolution driven by the recently adopted mandate in California. Ultimately Canada will need a zero-emission option for long haul trucking to reach decarbonization goals. In September 2019, Canada was the first nation to endorse a pledge through the Global Commercial Vehicle Drive to Zero initiative to speed adoption of zero-emission and near-zero emission medium- and heavy-duty vehicles in urban communities by 2025 and achieve full market penetration by 2040. Commitments made to drive action in support of that pledge will impact the pace of adoption.

Other Transportation Applications

Goods Movement Equipment, Ports

There is a range of goods movement equipment powered by hydrogen fuel cells in operation today, with varying levels of commercial readiness. Fuel cell forklift trucks are commercial, with more than 35,000 units in operation across North America. Most deployments have been in the US in high-throughput distribution centers where the fuel cells offer a compelling business case over lead acid batteries through productivity improvements. The US Federal tax credit for fuel cell systems was instrumental in establishing this market and favored deployments in the US over Canada. However, there are fuel cell forklift trucks in both Alberta and Ontario with more deployments expected given the commercial competitiveness of these units.

Sea ports are users of heavy diesel equipment and are under pressure to reduce emissions that lead to poor air quality and contribute to global warming. Ports can be hosts for early deployment hubs of fuel cell equipment, with multi-modal transportation applications converging on a single location that can share hydrogen infrastructure at scale. Equipment used at ports tends to be high power with intesive duty cycles and can provide the fuel demand needed in a single location to drive scale and cost-effective deployment of fuel. Other goods movement equipment that can be deployed at ports includes drayage trucks, yard trucks, gantry cranes, straddle carriers, and rail yard switchers. Hydrogen fuel cell generators can also provide shore power for vessels in harbor, and power for transport refrigeration units staged at the port. Figure 25 shows the location of Canada's major ports. While the total number of vehicles may be small in terms of the overall opportunity for Canada, lighthouse projects hosted by ports can demonstrate the benefits of multiple end-use applications sharing common infrastructure and could be a significant catalyst for the sector in the next 5 years.



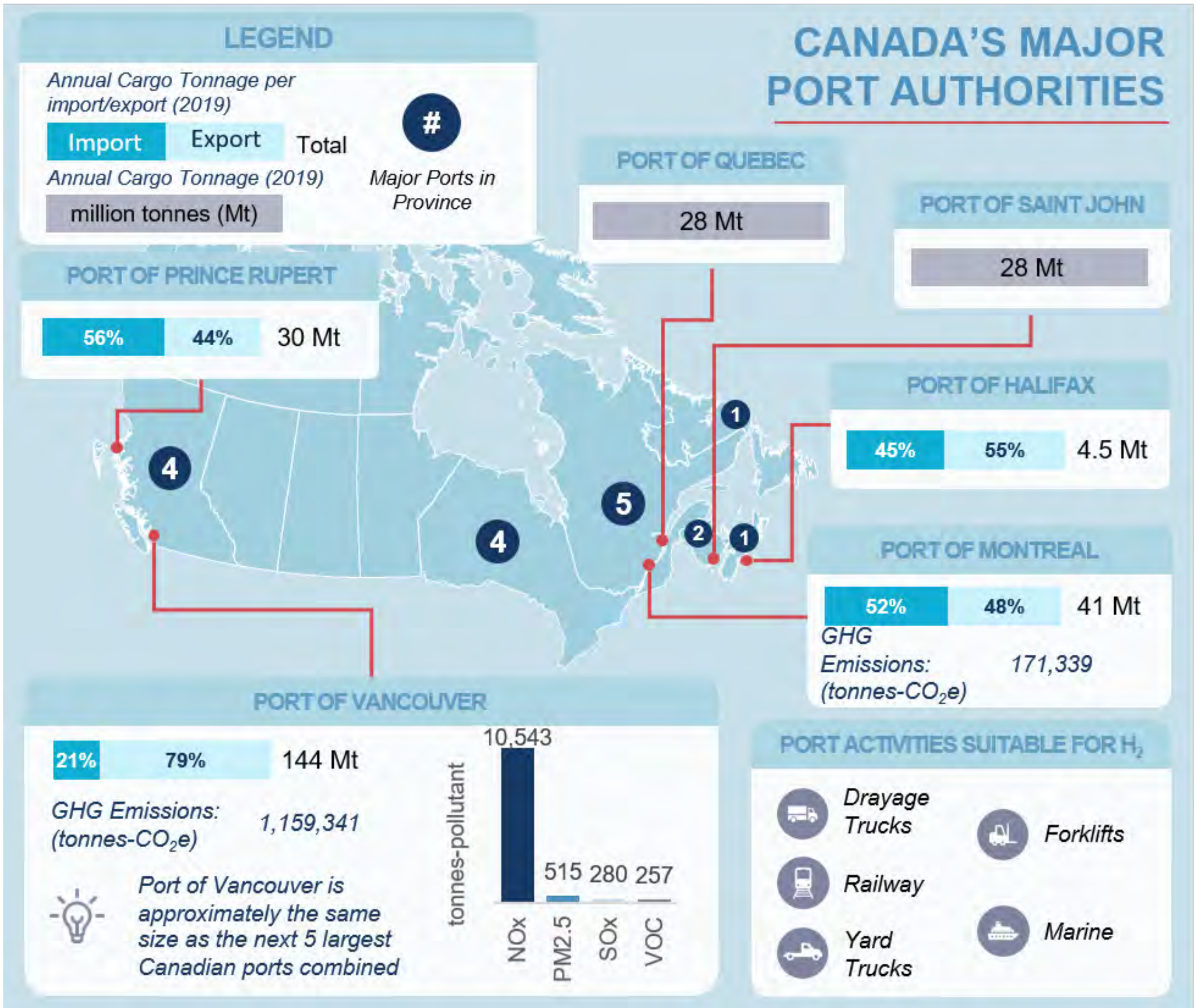


Figure 25 – Canada's Ports as Hosts for Early Hydrogen Deployment HUBs

Mining

There is a similar value proposition for hydrogen displacement of diesel in Canada's mining operations to reduce emissions. Canada's mining industry is one of the largest in the world. Producing more than 60 metals and minerals, Canada is among the top five worldwide producers of 14 different commodity metals and minerals[1]. Mines in northern and remote regions are largely dependent on expensive, high emission diesel power. Stakeholder consultation indicated that Canada's mining sector consumes approximately 2 billion litres of diesel on an annual basis. Hydrogen presents an opportunity to reduce widespread reliance on diesel power for both above ground and underground mining vehicles and can also be integrated into microgrid stationary power systems.

[1] https://www.statista.com/topics/3067/canada-s-mining-industry/#:~:text=Canada's%20mining%20industry%20is%20one,different%20commodity%20metals%20and%20minerals.

In heavy-duty mining vehicles, the high gravimetric energy density and fast fueling times offered by hydrogen in FCEVs provide technical and operational benefits and higher productivity. Zero emission fuel cells used in underground mining equipment eliminate diesel combustion exhaust emissions such as carbon monoxide, NO_X, and PM, and this can ultimately reduce the ventilation requirements in mines which can contribute 30-40%[1] of a mine's total operating costs. Heavy-duty vehicles powered by hydrogen can also reduce emissions from Canada's oil sands mines.

The Canadian Minerals and Metals Plan (CMMP) aims to capitalize on opportunities to strengthen Canada's competitive position within the global mining sector. The CMMP emphasizes the importance of developing and adopting clean technologies and alternative energy sources, such as hydrogen. As mining companies are faced with mounting social and economic pressure, it is evident they may need to go beyond what is demanded by law and the applicable industry environmental, social, and other standards if they wish to gain, or maintain, their "social license" to operate. NRCan's CanmetMINING have been studying and testing the potential for hydrogen in mines, including understanding safety considerations of bringing hydrogen into underground mines. This initiative has played an important role in informing Canada's hydrogen safety code development and will serve as a hub of information for the mining sector to understand opportunities for hydrogen in their operations.

Demonstrations of hydrogen in mining applications started in the early 2000s. In Canada NRCan supported a project at the Raglan Nickel Mine in Northern Quebec starting in 2015 where hydrogen is used as an energy storage solution to reduce diesel consumption in the site's stationary power generation system. Despite early demonstrations, the sector has been slow to adopt hydrogen in any meaningful way. However, there appears to be momentum in industry to start deploying hydrogen in mining operations and Canadian companies are playing a role. A number of mining companies are exploring fuel cells for ultra-heavy-duty haul trucks. Each of these vehicles is anticipated to use approximately 1 TPD of hydrogen, equivalent to running ~33 buses, showing the potential for a single mine site to deploy hydrogen at significant scale.

To move beyond single vehicle demonstrations, it will be important for OEMs such as Komatsu and Caterpillar to commit to developing commercially available hydrogen-powered equipment. Costs and a demonstrated business case continue to be a challenge in this sector, and ultimately hydrogen must be considered as part of the overall integrated ecosystem in the mining operations, together with other renewables, to optimize performance and economics.

Collaboration with other regions can help Canada advance deployment of hydrogen in mines. In July 2020, the Canadian Hydrogen and Fuel Cell Association (CHFCA) and Australian Hydrogen Council (AHC) signed a Memorandum of Understanding (MOU) to strengthen collaboration between Canada and Australia in the commercial deployment of zero-emission hydrogen and fuel cell technologies, including identifying opportunities for joint projects in mining. While international collaborations are important, Canada must also consider how deployment of made-in-Canada solutions could provide a competitive advantage to Canada's mining companies that are operating in an intensively competitive sector and protect potentially valuable IP. It will be important to see a Canadian hydrogen mining project as a proof point that the sector will consider adoption of hydrogen as a replacement to diesel, and the first step will be support for a feasibility study that looks at hydrogen as part of the overall mining operations.

[1] http://www.fchea.org/in-transition/2020/3/16/a-case-for-hydrogen-to-decarbonize-mining

Rail

Rail, marine and aviation applications are well suited to hydrogen because their energy intense duty cycles and long ranges make them particularly hard to electrify. There is increasing interest in hydrogen fuel cells for these applications, but to date activity has been primarily focused on European and Asian markets. These do show strong potential in Canada over the longer term, and early pilots in rail and marine can be integrated into port demonstration hubs leveraging solutions being developed for other markets to enable Canada to leapfrog from its current position.

Figure 26 – Alstom Hydrail with Hydrogenics Engine (Photo courtesy of Alstom)[2]

Hydrail offers a cost-effective way to electrify rail service compared with the traditional electrification approaches using overhead catenary wires or a third rail. Greenhouse gas emissions from diesel trains are a significant contributor to global warming and transit trains produce local air contaminant emissions that contribute to poor air quality in urban areas. Authorities are under growing pressure to reduce carbon emissions from rail service, but other electrification options are costly and require massive infrastructure upgrades. Hydrail trains require no electrification infrastructure, but rather run on existing unmodified tracks. Hydrail enables a gradual transition to electrification, one train at a time, versus alternative infrastructure rebuilds that disrupt service and require an upfront investment to electrify all trains concurrently.

Canadian companies are playing an instrumental role in the value chain in hydrail applications. Ontario-based Hydrogenics provided the fuel cell systems for the first commercial hydrogen powered trains that entered service in in Germany in 2018, built by French train manufacturer Alstom. The trains are capable of travelling 1,000 km without refuelling, which is comparable to a diesel alternative.[1] BC-based Ballard Power Systems is working on hydrail projects in Europe and in China. To date no hydrail trains have been deployed in Canada, but there has been interest supported by studies to investigate viability.

Canada is home to a large and well-developed coast-to-coast rail system that transports mainly freight, with 49,422 km of track.[3] The sector is dominated by CN, CP, and Via Rail which are regulated by the Railway Safety Act.

[1] Agence France-Presse. (2018). *Germany Launches World's First Hydrogen-Powered Train*. Retrieved from https://www.theguardian.com/environment/2018/sep/17/germany-launches-worlds-first-hydrogen-powered-train

[2] Alstom. (2019). *Alstom to tests its hydrogen fuel cell train in the Netherlands.* Retrieved from https://www.alstom.com/press-releases-news/2019/10/alstom-test-its-hydrogen-fuel-cell-train-netherlands

[3] Transport Canada, Overview of the Hydrogen Rail Status in Canada, March 2019

Figure 27 – Canada's Coast to Coast Rail System

Passenger rail transport in Canada serves 450 communities, with 12,500 km of rail. The most widely used passenger rail is along the Quebec City – Windsor Corridor, moving some 4 million passengers/year. Toronto, Montreal and Vancouver are host to commuter rail systems, and Calgary, Edmonton, and Ottawa currently have light rail systems in operation with new systems in construction in Edmonton, Waterloo and Toronto.

The most comprehensive look at Hydrail in Canada to date has been through the Metrolinx Hydrail study, published in 2018 to look at the feasibility of using hydrogen fuel cell (HFC) trains to electrify the GO networks as an alternative to electrification using conventional overhead wires in Ontario. The study concludes that it is technically and economically feasible to build and operate the GO network using HFC-powered rail vehicles, and the costs of building and operating a Hydrail System are equivalent to that of a conventional overhead electrification system. Implementation of a Hydrail system of this scale and complexity would be innovative and provides a unique set of risks and benefits that Canada could be at the forefront of studying. While no firm commitment to selecting Hydrail has been made, Metrolinx is intending to engage a contractor to upgrade the GO network using a Design-Build-Finance-Operate-Maintain (DBFOM) model. As part of the tender process, bidders will be able to propose both hydrail and overhead wire technology to electrify the GO network.

There are also hydrail passenger train projects proposed in BC both in the Fraser Valley corridor and the Okanagan, though neither has yet moved to the implementation phase.

While no concrete hydrail projects have been initiated in Canada, it is expected that advancements led by Europe and Asia using Canadian core IP will eventually lead to domestic deployments. Applications in Canada could include: rail yard switchers / shunt locomotives, passenger rail, and freight locomotives. Early studies assessing freight applicability of hydrail concluded that hydrail for freight switching is technically and economically feasible.[1] Retrofitting locomotives and replacing diesel engines with zero-emission fuel cell engines is a viable and cost-effective alternative to purpose built hydrail trains, which is an important opportunity given the long (50 year+) lifecycle of locomotives.

[1] Change2Energy Services, Assessment of the Design, Deployment Characteristics and Requirements of a Hydrogen Fuel Cell Powered Switcher Locomotive, June 2020

Marine

Marine applications also show strong potential for hydrogen adoption in Canada. Potential applications include hydrogen fuel cell propulsion systems as well as auxiliary power systems for ships. Fuel cell systems can also provide shore power for ships in harbor. The International Maritime Organization (IMO) is driving aggressive emissions reductions in the shipping industry through adopted emissions and energy-efficiency regulations. The IMO has identified ammonia (made with renewable hydrogen) and hydrogen used directly as a fuel as potential fuels of the future in a decarbonized shipping industry.

Early applications for hydrogen in marine include ferries, tugboats, and coastal and inland barges. Canada's extensive waterways make it home to over 180 different ferry routes with a route presently operating in each province and the majority of the territories. These ferries represent a mix of private and publicly operated routes as well as a mix of passenger, freight, and mixed-use ferries[1]. Canada does not currently have any marine hydrogen deployments, but a variety of studies have been initiated in the Maritimes, Ontario, and BC. Canada can benefit from activities led primarily out of Europe, such as hydrogen-powered car ferries under development in Norway.

Aviation

Hydrogen can play a role in the aviation sector as well, with hydrogen's high gravimetric energy density offering significant advantages as an aviation fuel. Hydrogen fuel cell power may also have a role in providing energy for on-board systems, reducing overall jet fuel consumption. While not yet commercial, there are a wide range of applications in the study and pilot demonstration phase. Applications range from Unmanned Aerial Vehicles (UAVs), or drones, to propulsion systems in manned aircraft. Big players like Audi, Aston Martin, Boeing, Daimler and most recently Hyundai, through their new urban Air Mobility Division, are exploring alternative approaches to aviation enabled by zero-emission technologies[2]. These news modes of transport could radically change mobility options in urban environments, reducing ground level congestion and reducing both GHG emissions and local criteria pollutants. In September 2020, Airbus unveiled three hydrogen-powered aircraft concepts that could enter service by 2035.[3] In some aviation concepts hydrogen is being considered as a fuel for auxiliary power units, rather than as the primary propulsion fuel.

The main alternative to hydrogen in zero emission aviation is lithium ion batteries. Hydrogen can offer advantages over lithium ion batteries given the higher energy density that can be achieved in heavier duty cycle applications, and the shorter refueling times. These advantages enable longer range and greater load-bearing capacity. UAVs for both commercial and military applications incorporating hydrogen fuel cells have been gaining traction. In 2019, Plug Power acquired Montreal-based EnergyOr to integrate the small, ultra-lightweight fuel cell technology into their product line.

Canada's aerospace industry contributes over 200,000 jobs and $25B annually to the Canadian Economy[4]. The sector is under intense pressure to maintain Canada's position in a climate with increasing competition, to tackle GHG emissions, and to address major industry disruptions caused by COVID-19. The industry has identified hydrogen fuel cells and hydrogen combustion as promising options to reduce CO_2 emissions.

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[1] https://canadianferry.ca/ferries-in-canada/

[2] https://newatlas.com/aircraft/hyundai-nasa-expert-flying-car-division/

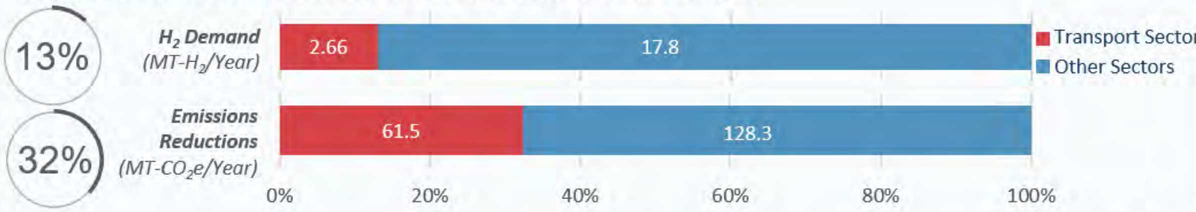
[3] https://www.airbus.com/innovation/zero-emission/hydrogen/zeroe.html

[4] AIAC, 2019

STAKEHOLDER INPUT: TRANSPORTATION

Opportunities

Transportation Sector Contribution in 2050 Transformative Scenario



- *1 in 4 LD vehicles could be an FCEV by 2050*
- *Fuel cells offer greatest advantages over batteries in HD applications with high payloads, long ranges, & intensive duty cycles*

5MM — *Light-duty vehicles*

160k — *Trucks*

6500 — *Buses*

Challenges

Lack of available hydrogen fueling infrastructure; requires clusters of 7-8 stations before vehicle OEMs will roll out FCEVs to a region

Higher vehicle costs due to lower maturity level and lower volumes

Perceived competition with BEVs vs complementary technology with each playing important role; for example, in heavy duty sector

Proven, commercially viable on-road applications, lack of vehicle supply impedes uptake. Other modes (e.g. rail, marine) in early deployment

Findings

- *Stronger policy / regulation supported by incentives and infrastructure investments to drive adoption of zero emission vehicles*
- *Existing programs / policies should reflect lower market maturity of fuel cell vehicles compared to other alternatives*
- *Coordinated H_2 fueling infrastructure investment plan, focused on hub regions and expanding to connector stations for both LD (700 bar) and HD (350 bar), co-located where possible*
- *High profile full depot FCEB pilot project to raise awareness and share data for transition planning*
- *Requirement for Canadian Transit Agencies to develop zero emission transition plans*
- *Federal ZEV procurement policy to add to demand certainty*
- *Pilot deployments of lower TRL transportation – trucks, rail, marine, aviation*

FUEL FOR POWER GENERATION

Hydrogen can be used as a fuel for power production through either hydrogen combustion in turbines or use in stationary fuel cell power plants. Combustion turbines designed to combust a blend of hydrogen and natural gas are currently commercially available. Existing natural gas turbines could likely operate with a blended hydrogen/natural gas fuel supply of up to 10% to 15% hydrogen by volume. However, major modifications to or replacement of infrastructure and equipment would be required to combust larger proportions of hydrogen in existing power plants. Turbines capable of combusting 100% hydrogen are in development and are expected by 2030. Hydrogen can also provide load management capabilities, daily and even seasonal utility scale energy storage capabilities, and is an enabler for the growing variable renewable power sector.

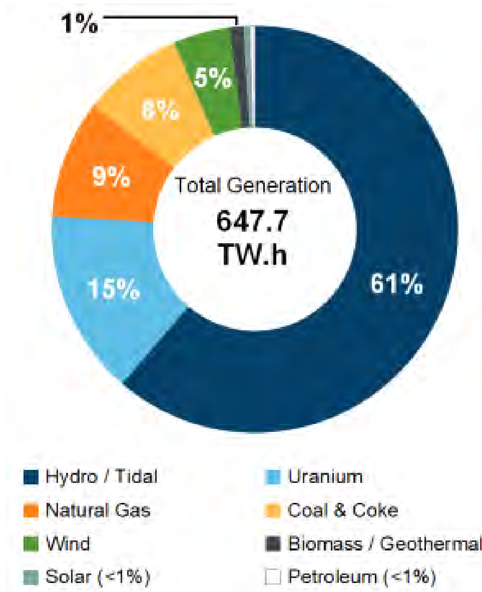


Figure 28 – Electricity Generation by Fuel Type in Canada, 2018, source: Canada Energy Regulator

While Canada's electricity grid is on average considered low carbon intensity, some regions are significantly higher than the average and rely on combustion of fossil fuels to produce power. Overall, approximately 17% of Canada's grid power is supplied via combustion of fossil fuels. Low carbon intensity hydrogen can help to reduce emissions related to power generation and can help green the electricity grid.[1] It is expected that the levelized cost of electricity from hydrogen-fueled combustion turbines will decrease and become cost-competitive on a lifecycle basis with natural gas-fueled combustion turbines by 2050.[2]

In Alberta for example, hydrogen made via conversion of NG or petroleum, with carbon abatement could be used in place of natural gas-powered turbines to provide dispatchable power. Nunavut is reliant on diesel for electricity generation, and hydrogen, either imported in liquid form similar to current diesel supply or generated locally through electrolysis from non-emitting electricity, can help to reduce the carbon intensity of electricity in the region as well as improve local air quality. Other provinces that are reliant on carbon emitting fossil fuels for power generation and that could benefit from low carbon intensity hydrogen for power generation include Saskatchewan, Nova Scotia, Northwest Territories, and New Brunswick.

[1] CER. (2018). *Provincial and Territorial Energy Profiles – Canada.* Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/nrgsstmprfls/cda-eng.html

[2] IEA technology perspecitves 2020

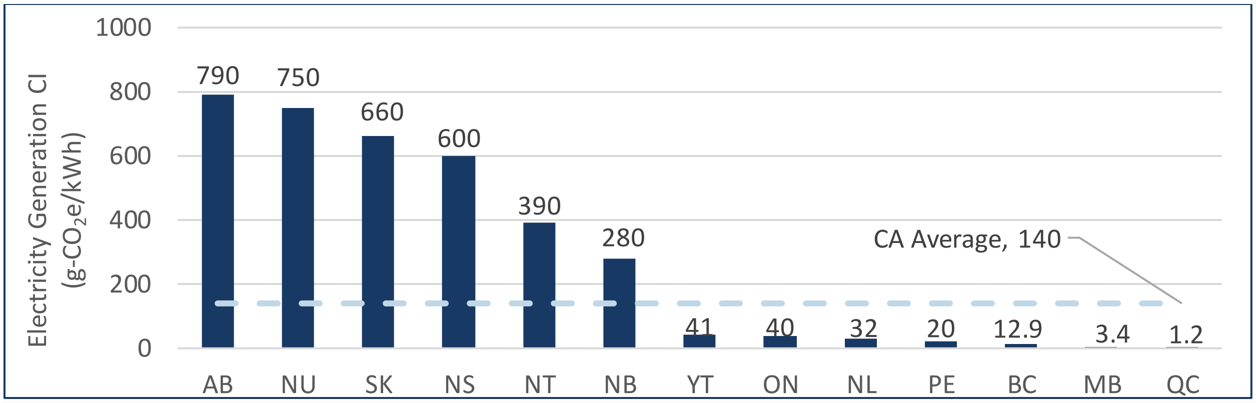


Figure 29 – Carbon Intensity of Provincial Electricity Generation Sources

Japan has been leading the way with vision for large scale power production, using imported hydrogen generating power through turbines. An 80 MW plant recently started operation, and their goal is to have a 1 GW plant in operation by 2030. Europe is also exploring the potential for power generation through both hydrogen turbines and turbines that run on a blend of hydrogen and natural gas. This technology will only be economically viable in Canada if large scale supply of low cost, low carbon intensity hydrogen is available.

Hydrogen as a utility scale energy storage vector can be an enabler for increased renewable penetration in the grid. Hydrogen can be produced via electrolysis from variable renewable power sources such as wind and solar, where power is not needed during off-peak times or the power producer can only secure low or even negative rates. Integrating hydrogen as energy storage can result in an improved business case. Hydrogen storage is a key factor in determining the feasibility of hydrogen use in the power sector, factors such as: geological location, volume stored and duration stored play a role in the cost of storing the hydrogen. The hydrogen can either be stored on site and used to produce electricity during peak demand times via a turbine or PEM fuel cell, or can be injected into the natural gas network as a means to decarbonize natural gas, or alternatively fed into dedicated hydrogen pipelines and used as a high-value transportation fuel or used as an industrial feedstock.

Hydrogen made from surplus renewable electricity via electrolysis and injected into the natural gas network is commonly referred to as power-to-gas (P2G). P2G provides a means of connecting the electric and natural gas energy systems; it can also be a key enabler of the transition from a fossil natural gas grid to a decarbonized one. Rising P2G interest in Europe has been driven by aggressive GHG reduction targets and an increasing supply of variable renewable electricity.

There are a few P2G projects in development in Canada. Canada's first P2G facility began operation in Ontario in July 2018 when a 2.5 MW PEM electrolyzer from Hydrogenics was installed under contract to the Ontario Independent Electricity System Operator (IESO). The electrolyzer provides grid energy demand response functions to the IESO and the hydrogen produced is injected into the Enbridge gas distribution network. There are several projects in development elsewhere in Canada, ranging in scale up to ~ 150 MW.

Hydrogen can also be integrated into renewable energy systems in remote and indigenous communities in Canada. Remote communities are defined as not being connected to North America's integrated electrical or natural gas grids, and they rely on costly and GHG emitting diesel generated electricity. Diesel generators are a source of criteria air contaminants, especially in small communities where air quality and health impacts may be an issue. Diesel can be displaced with either imported or locally produced hydrogen. The hydrogen can supply a microgrid system, either centralized, or distributed with co-generation of heat and power. Renewable energy sources can also be incorporated to produce hydrogen using electrolysis, reducing reliance on imported fuel.

HEAT FOR INDUSTRY & BUILDINGS

As a heating fuel, hydrogen is a cleaner-burning molecule that can be a substitute for combustion of fossil fuels in applications where high-grade heat is needed and where electric heating is not the best option. Hydrogen can be burned directly or blended with natural gas to reduce carbon emissions.

Heat for Industry

The industrial sector uses natural gas as a source of process heat, as a fuel for the generation of steam. When natural gas is combusted to generate heat, carbon emissions are released. It is very challenging to capture carbon emissions at the point of use outside of large industrial plants where there is the potential for capturing CO_2 from concentrated flue gas.

Canada's oil and gas sector is a significant contributor to GHG emissions, responsible for 26% of 2018 total emissions[1]. Low CI hydrogen can offer emissions reduction benefits in both upstream extraction (combusted as heat source) and downstream refining (used as a chemical feedstock, discussed in Hydrogen as a Feedstock section) processes. For example, in upstream operations, low CI hydrogen can replace natural gas combusted to produce steam for steam-assisted gravity drainage (SAGD) in-situ bitumen production. Hydrogen can lower the CI of conventional refined petroleum products in this way, offering a compliance pathway for the federal Clean Fuel Standard.

Other heavy industry in Canada that relies on large amounts of high-grade heat production includes cement manufacturing and the pulp and paper sector, and any industrial processes relying on steam production. These sectors can also reduce emissions by converting to blends of hydrogen and natural gas or pure hydrogen for heat production. A number of these sectors in Canada are investigating the opportunity to lower emissions through the use of hydrogen.

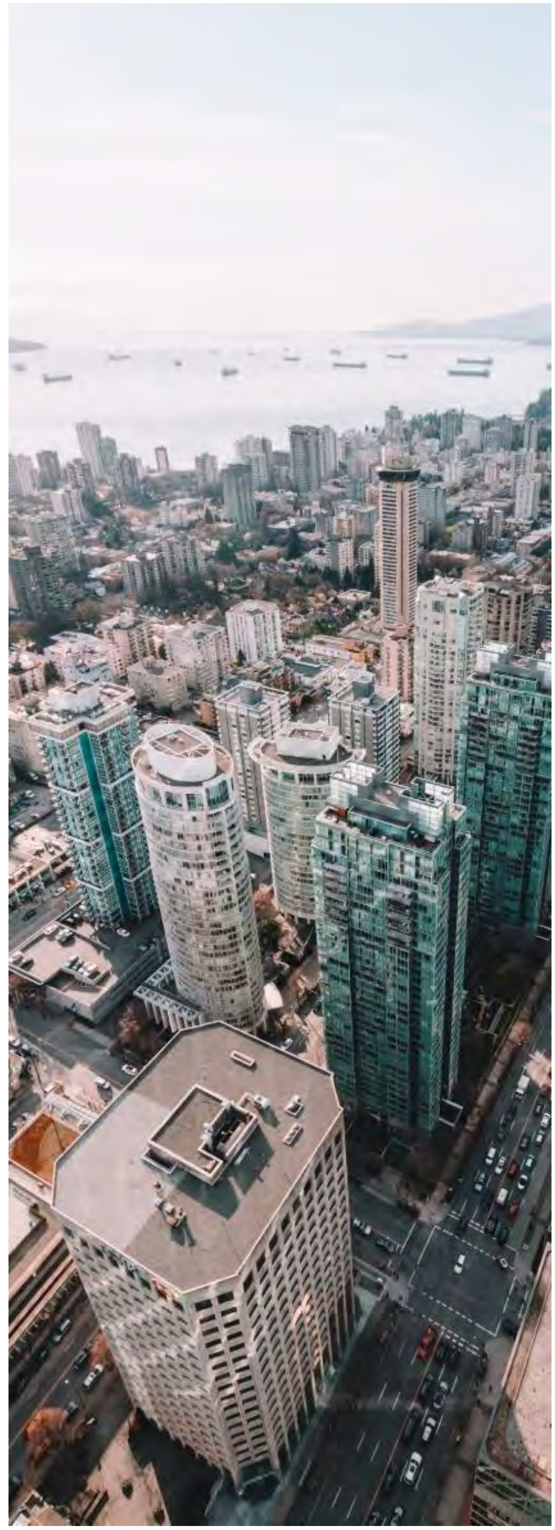
Integration of hydrogen generated via electrolysis directly at large industrial facilities can offer value-added benefits. For example, some of these sectors can leverage oxygen and / or waste heat produced in the electrolysis process. Oxygen can enhance combustion and enable a wider range of feedstocks to be used in cement kilns, and can be used in the pulp process in place of merchant oxygen. Industrial facilities typically have made investments in substations, which enables lower electricity rate tariffs and lower cost hydrogen. Hydrogen production for these industrial sectors can offer an opportunity to diversify business if excess hydrogen is produced and sold to generate a new revenue stream.

[1] Environment and Climate Change Canada. (2020). *National Inventory Report 1990 – 2018: Greenhouse Gas Sources and Sinks in Canada*. Retrieved from http://publications.gc.ca/collections/collection_2020/eccc/En81-4-1-2018-eng.pdf

Heat for Buildings

Hydrogen can also play a role in reducing emissions in heating applications in the built environment. Natural gas utilities are looking to decarbonize the natural gas grid by introducing both RNG and hydrogen as alternative low carbon chemical fuels. Canada's cold climate results in space heating accounting for >60% of energy use in the home, with water heating coming in second at >19%[1]. Natural gas is used for both in some provinces in Canada, and hydrogen is gaining increasing attention from utilities given it can be produced in high capacities compared to RNG which is in limited supply.

Several jurisdictions worldwide are piloting the blending of hydrogen into their natural gas systems as part of efforts to reduce emissions associated with home heating. Hydrogen blending has been started in Germany, Dunkerque in France (hydrogen blending of up to 20% in the GRHYD demonstration project), and Keele in the UK (hydrogen blending of up to 20% in the HyDeploy project at Keele University in 2019). The H21 Leeds City Gate project plans to convert Leeds into a city that is 100% fueled with hydrogen by 2028[2].



Technical Considerations

Implementing hydrogen blends into the natural gas network for use in both industrial applications and the built environment can impact pipelines, gas properties and safety systems, metering equipment, and end-use equipment and appliances. Many gas utilities around the world, including Canadian natural gas utilities in partnership with the Canadian Gas Association, are working to understand and overcome technical challenges around introducing hydrogen as a blend. Technical considerations include the following:

Material Compatibility - Embrittlement

Some metal pipes can degrade when exposed to hydrogen over long periods, particularly for the higher hydrogen concentrations and pressures that may occur when it is injected into high-pressure natural gas transmission systems. Embrittlement effects depend on the type of steel and on operating conditions and must be assessed on a case-by-case basis.

[1] NRCan. (2017). *Residential Sector*. Retrieved from https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/handbook/handbook_res_00.cfm

[2] https://rienergia.staffettaonline.com/articolo/33278/Hydrogen+is+the+key+for+a+green+European+gas+network/Chatzimarkakis#:~:text=In%20the%20Hydrogen%20Roadmap%20Europe,7%25%20by%20volume%20until%202030.&text=By%202050%2C%20hydrogen%20could%20provide,by%20European%20households%20for%20heating.

Natural gas transmission pipelines in Canada are typically made of high-strength steels and operate at higher pressures compared to distribution networks, making them more susceptible to hydrogen embrittlement. The steels used for natural gas distribution systems are not generally susceptible to hydrogen-induced embrittlement under normal operation. Other metallic pipes including iron (ductile, cast and wrought) and copper are free from embrittlement concerns as are the polyethylene (PE), polyvinylchloride (PVC) and elastomeric materials more common in recently installed natural gas distribution networks.

Pipeline Standards and Policy

The amount of hydrogen presently allowed in natural gas infrastructure is limited by country-specific codes and standards. International standards currently range from allowing hydrogen injection values of 0.1% (vol.) in the United Kingdom (UK) and Belgium to 12% (vol.) in Holland, and many countries are actively working to update or introduce standards. Standards defining hydrogen quality and allocable contamination levels are also needed. Hydrogen injection and quality standards have yet to be established in Canada and elsewhere in North America, and development of these standards is a critical step in enabling hydrogen blending in Canadian Provinces and Territories. Inter-provincial coordination is required given that pipelines cross borders in some cases.

Gas Properties and Safety Systems

Hydrogen has a lower volumetric energy density than natural gas. At any pressure, the volumetric energy density of hydrogen is about one third that of natural gas. Therefore, hydrogen injected into natural gas networks will result in a mixture with less energy on a volume basis. Delivering the same amounts of energy to end users would therefore necessitate increased volumetric flows. To accommodate higher flows as blend ratios increase, pipelines and distribution networks will need to increase system pressure and increase the density of the gas mixture flowing through the pipeline. Pipelines' pressure ratings may therefore constrain the amount of hydrogen injection into existing natural gas infrastructure.

Gas properties such as explosivity, flammability, ignition, dispersion, and ability to add odorants for leak detection are all different with hydrogen blends versus pure natural gas systems. Modeling and testing have been initiative to understand impacts and identify where safety systems need to be updated to accommodate blends. General findings indicate that blends of up to 20% hydrogen do not require modifications to safety systems. Further analysis and testing in the Canadian context is needed, and results will likely vary based on local natural gas networks.

Gas Metering

Hydrogen blends can influence the accuracy of existing gas meters. Studies have shown that gas meters would not need to be tuned for low hydrogen blend levels.[1] However, further validation testing is needed and new meters may be required for higher blending levels.

Appliances and End-Use Equipment

Appliances must be able to operate safely and at equivalent performance levels in order to introduce hydrogen blends into the built environment without requiring retrofit. Testing in Canada and other regions such as the UK and Australia implementing hydrogen blending shows that ratios up to 30% do not impact appliances[2] such as natural gas stoves, furnaces and fireplaces. Beyond those levels, modifications such as new burners may be required. Industrial equipment such as turbines, compressors, and boilers can also be impacted by hydrogen blends, as can some older CNG tank materials. For example, hydrogen

[1] Zen Clean Energy Solutions (2019). British Columbia Hydrogen Study.

[2] ATCO (2020). Retrieved from: https://www.atco.com/en-ca/for-home/natural-gas/hydrogen.html

produces more water vapour than natural gas for the same amount of energy delivered when combusted, which can lead to more condensate in boilers. In compressors designed to be leak tight for natural gas, hydrogen leakage can occur. Hydrogen also produces lower radiant heat than natural gas, which can impact industrial heating applications. Introduction of hydrogen blends with industrial customers will require significant study and pilot testing and must be evaluated on a case by case basis.

Canadian Context

While the allowable concentrations of hydrogen in natural gas pipeline networks remains an area of active research and evaluation, recent studies have concluded that transmission pipelines can accept hydrogen concentrations of between 5% and 20% (by volume) with minimal risk.[1] Hydrogen blending limits can be overcome by localizing portions of the natural gas infrastructure or end customers who can tolerate higher hydrogen concentrations, with the potential to have 100% dedicated pipelines in some regions of Canada.

Enbridge Gas in Ontario is one of the first utilities to propose a demonstration to blend hydrogen into the natural gas network, and BC and Quebec have enacted provincial policies that have stimulated R&D and development of pilot projects for blending hydrogen into the NG grid. ATCO in Alberta has announced a blending project in Fort Saskatchewan, Alberta where up to 5% hydrogen by volume will be blended in a section of the residential gas distribution network starting in 2021. Stakeholder engagement identified up to nine hydrogen projects currently being developed by utilities in Canada. However, hydrogen injection standards have yet to be established Canada and this is a challenge for broader rollout. Technical specifications and interface requirements for hydrogen blending will need to be established and pilot projects will support development of these standards.

Ultimately, utilities recognize that in a net-zero energy system of the future, distributed combustion of fossil fuels must stop, and this is a threat to their business. Renewable natural gas and landfill gas can displace natural gas, but supply is limited. Hydrogen produced at scale can be the long-term answer for Canada's natural gas utilities to stay relevant in a carbon-constrained future. Hydrogen provides an opportunity to utilize Canada's valuable natural gas pipeline infrastructure investments to deliver energy intense low carbon fuel for high-grade heating applications where electric heating is not the best option. In regions with heat pumps, hydrogen can also be used to provide heat during winter season with hybrid heating systems.

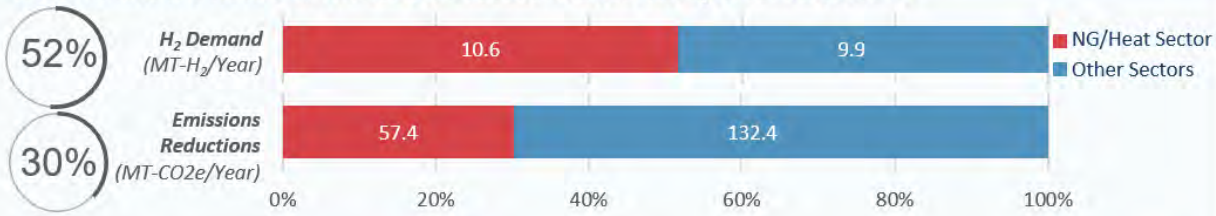
Blending low carbon intensity hydrogen into Canada's natural gas networks, for use in both industry and the built environment, provides the largest potential demand opportunity for hydrogen. However, it is also the most economically challenging given today's low-cost natural gas commodity prices in Canada, and when combusted, there is no efficiency improvement as there is in fuel cell applications. One benefit of hydrogen use in the natural gas network is that the hydrogen can be produced in bulk quantities close to injection points into the natural gas network, and does not have to be compressed to high pressures.

[1] Yoo Y., et al., (2017). *Review of Hydrogen Tolerance of Key Power-to-Gas (P2G) Components and Systems in Canada*. NRC-EME-55882. Retrieved from https://nrc-publications.canada.ca/eng/view/fulltext/?id=94a036f4-0e60-4433-add5-9479350f74de

STAKEHOLDER INPUT: HEAT FOR INDUSTRY & BUILDINGS

Opportunities

Decarbonized NG Networks & Heat Contribution in 2050 Transformative Scenario



- *By 2050, H_2 could make 86% by volume on average of the fuel in the gas network*

- *Blending of H_2 in the gas network at a low level is technically feasible today*

Challenges

Safety and reliability must be successfully proven in pilot stage before technology can be fully adopted

Impact to gas properties and equipment limitations complicate the direct substitution of H_2 into industrial processes

Natural gas is currently low cost in many parts of Canada, and while H_2 can compete with RNG the higher cost is a challenge particularly for industry

Lack of standards and research into defining blending limits in Canada

Findings

- *Define plan & approach to safely increase H_2 blending percentages, include regulators, AHJs and international organizations and standards bodies*
- *Develop and implement a federal Clean Fuel Standard to mandate the steady ratcheting down of fuel carbon intensities through upstream, process & end-use improvements*
- *Develop suite of public tools (e.g. TCO model) & resources to help end-users evaluate H_2 options*
- *Expand pilots for H_2-integrated mini-grids at industrial sites and along strategic transportation corridors to pool sources of supply and demand*
- *Increase research and development into end-use equipment and applications including boilers, safety and monitoring equipment, and embrittlement issues*
- *Increase awareness around hydrogen as option for low carbon heating, e.g. with municipalities*

FEEDSTOCK FOR INDUSTRY

The largest current use for hydrogen, both in Canada and globally, is as a feedstock in emission-intensive industrial sectors. The top four single uses of hydrogen today (in both pure and mixed forms) are: oil refining (33%), ammonia production (27%), methanol production (11%) and steel production via the direct reduction of iron ore (3%).[1] Most of this feedstock hydrogen is currently produced via SMR of natural gas without CCUS. Low CI hydrogen presents a major opportunity for these industries to lower the carbon intensity of their products and overall emissions.

Carbon pricing and regulations like the Clean Fuel Standard are expected to drive demand for clean hydrogen in these industries. However, most industrial applications are capital intensive and slow to change so large-scale demonstration could take up 10 years to materialize. These demonstration projects will also depend on significant financial support, policy support, technology enhancements, and energy market reform. The future competitiveness of hydrogen use in industrial applications will depend on the development of low-cost, low CI hydrogen production pathways such as electrolysis and SMR+CCUS.

Oil and Gas Industry

Hydrotreatment and hydrocracking are the two main uses for hydrogen in the oil and gas sector. In hydrotreatment, impurities such as sulphur are removed from the raw fuel stocks (e.g. crude oil and bitumen) to lower the sulphur content which causes air pollution when burned. Hydrocracking is a way to break up the heavy residual oils into higher-value products such as kerosene, gasoline, and diesel. For bitumen processing, around 10kg of hydrogen is need for each tonne of bitumen produced. For biofuels made from animal fats or vegetable oils, 38kg of hydrogen is required.[2]

The IEA projects a 7% increase in demand for hydrogen in the oil and gas sector under existing policies[3]. Tighter pollution regulations will increase demand for hydrogen as a feedstock but will also result in an overall decrease in fossil fuel demand. In the longer term the demand for hydrogen in this sector will also be highly dependent on the use of oil and gas as end-use fuels in a decarbonizing world.

The majority of hydrogen required for refining is produced on-site either from dedicated production facilities or as a by-product. Because of this integration of hydrogen production within refining facilities, production is primarily supplied by natural gas reforming methods or naphtha reforming. On-site hydrogen production is unable to address the hydrogen demand of larger refineries and these facilities

[1] IEA. 2019. The Future of Hydrogen: Seizing Today's Opportunities.

[2] Ibid.

[3] Ibid.

will typically rely on merchant gas suppliers. This option is particularly important for densely industrialized areas where shared hydrogen pipelines can be built to serve multiple customers.

The most significant opportunity to reduce emissions associated with hydrogen in midstream oil and gas is retrofitting existing conversion technology with carbon capture and storage. Hydrogen use is responsible for about 20% of global emission from refining (~230MtCO_2e/yr), according to the IEA. The Alberta Carbon Trunk Line project is an example of an operating CCUS plant which has been successfully implemented and is currently capturing around 4.5 tonnes CO_2/day (See Figure 30).[1]

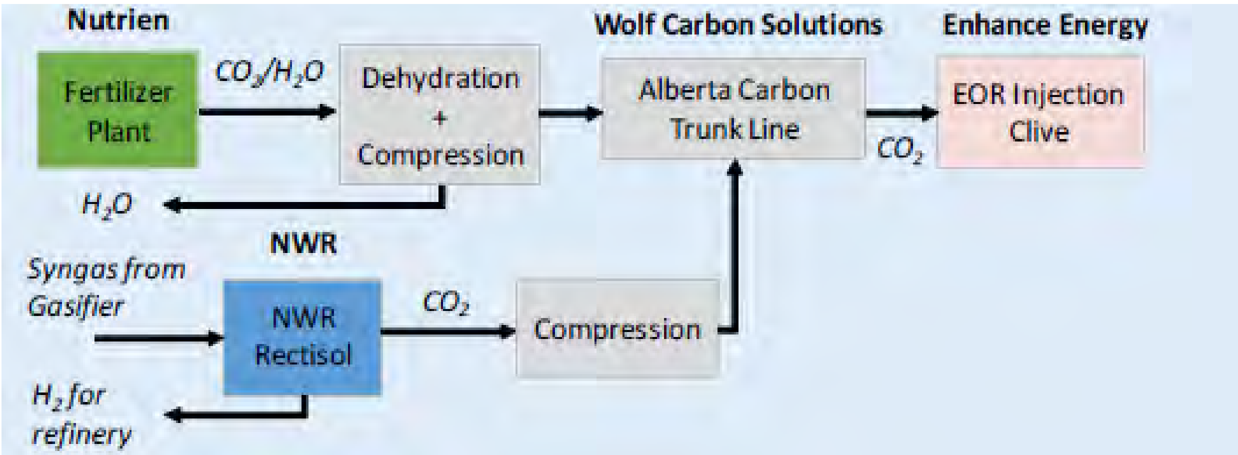


Figure 30 – The Alberta Carbon Trunk Line project[1]

There is also some potential to use electrolytic hydrogen in fuel upgrading, although the costs and carbon intensity of this pathway would depend heavily on the electricity source and the fuel end-use. Hydrogen can also replace natural gas in upstream operations, particularly in the oil sands where heat generation for extraction is a large source of emissions. In the Canadian context, this has the special potential to help decarbonize a portion of oil sands operations in Alberta.

Synthetic Fuels

Availability of low cost, low CI hydrogen has the potential to create new industry in Canada as well. This includes synthetic liquid fuel production, an innovative process combining non-emitting hydrogen and carbon captured from the air to produce carbon-neutral, energy dense liquid fuels that are well suited to applications such as aviation and large marine vessels.

Chemicals and Ammonia Production

Global demand for hydrogen in the chemical industry is mainly split between ammonia production at 31Mt H_2/yr and methanol production at 12MtH_2/yr. Other minor applications, such as plastics, solvents, and explosives account for approximately 3MtH_2/yr[2]. Ammonia (NH_3)is the main ingredient in nitrogen fertilizers such as urea and ammonium nitrate and is produced at large scale in Canada. Methanol (CH_3OH), also known as methyl alcohol is used for a variety of industrial processes and as a precursor to other chemicals such as formaldehyde, acetic acid, and many specialized chemicals.

[1] Layzell DB, Young C, Lof J, Leary J and Sit S. 2020. Towards Net-Zero Energy Systems in Canada: A Key Role for Hydrogen. Transition Accelerator Reports: Vol 2, Issue 3. https://transitionaccelerator.ca/towards-net-zero-energy-systems-in-canada-a-key-role-for-hydrogen

[2] IEA. 2019. The Future of Hydrogen: Seizing Today's Opportunities.

Demand for hydrogen in the chemicals industry is expected to grow from 46 Mt/yr today to 57 Mt/yr by 2030, driven by diverse industrial applications. The CO_2 emissions generated globally from ammonia and methanol production are around 630 Mt-CO_2/yr, with hydrogen production accounting for a large percentage. As with oil refining, the vast majority of this hydrogen (65% for ammonia and 30% for methanol) is produced from fossil fuel sources, with the rest coming from coal and by-product industrial processes. Adding CCUS to the hydrogen production pathways or using electrolytic hydrogen for these products would significantly decrease their overall carbon intensities.

Iron and Steel Production

The demand hydrogen in iron and steel production is the fourth largest after oil and gas and chemicals at 4MtH_2/yr.[1] As with the oil and chemical sectors, the hydrogen is used both as a feedstock and as a process fuel and is mostly derived from fossil fuel sources without CCUS.

Hydrogen is used in the direct reduction of iron-electric arc furnace (DRI-EAF) method of steel production which accounts for 7% of primary (i.e. non-recycled) steel production globally. By 2030 the hydrogen requirements for the DRI-EAF route could more than double, according to the IEA. By 2050 this method could be main process for primary steel production and lead to a 15X increase in hydrogen demand.

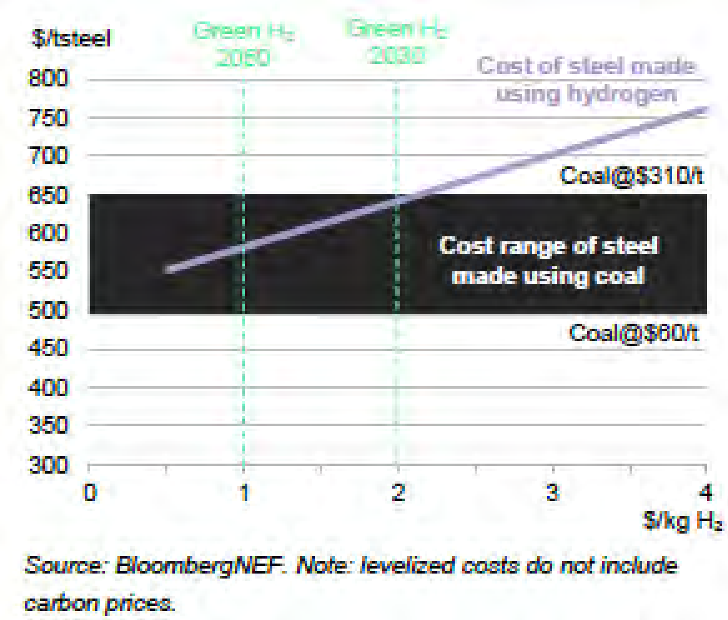


Figure 31 – Levelized Cost of Steel Production

Today, steel production is one of the world's largest emitters of CO_2, accounting for about 7 to 9 per cent of global CO_2 emissions from the global use of fossil fuels.[2] There are several ways the CO_2 emissions from steel production can be avoided or reduced. Most are still experimental or in the pilot phase but could substantially increase demand for hydrogen if implemented at scale. DRI-EAF using low-CI hydrogen as a reducing agent instead of coal, avoids the carbon emissions in the process. Currently pilot plants using this approach can run on up to 30 percent supplemental hydrogen, but higher percentages are technically feasible. Several ongoing global projects are currently testing the use of hydrogen for steelmaking. HYBRIT, a recently formed Swedish joint venture by SSAB, LKAB, and Vattenfall, is demonstrating low-carbon steelmaking using DRI with hydrogen from water electrolysis.[3]

[1] Ibid.

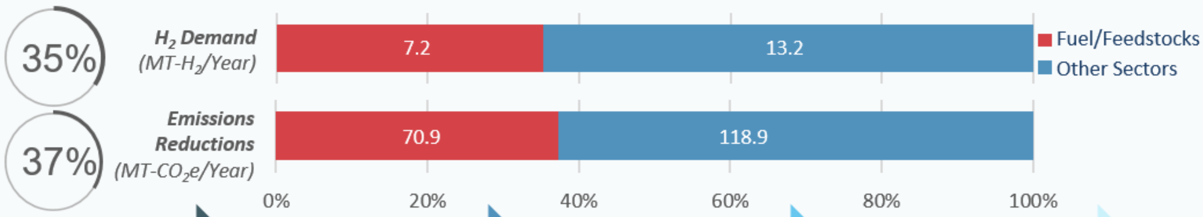
[2] World Steel Association. (2019a). Steel Facts. Retrieved from https://www.worldsteel.org/about-steel/steel-facts.html

[3] US Fuel Cell & Hydrogen Energy Association. *Road Map to a US Hydrogen Economy.* 2019.

STAKEHOLDER INPUT: INDUSTRIAL FEEDSTOCK

Opportunities

Fuel Production & Feedstocks Contribution in 2050 Transformative Scenario



Canada has electricity, fossil fuel reserves, CCUS potential, and a specialized workforce that can pivot into a new Low Carbon Fuel industry

The petroleum/ petrochem industry is already the largest user of H_2 and up-/mid-stream demand could grow substantially

The proposed federal Clean Fuel Standard has potential to drive significant GHG reductions and spur technology development for export

H_2 can be used as an energy source and feedstock in steel and ammonia production, displacing significant amounts of coal and NG

Challenges

Fuel production and industrial processes are optimized for scale and continuous operations; pilot scale projects can be less effective

Process, equipment, and safety implications of hydrogen blending into essential feedstocks needs to be understood and derisked

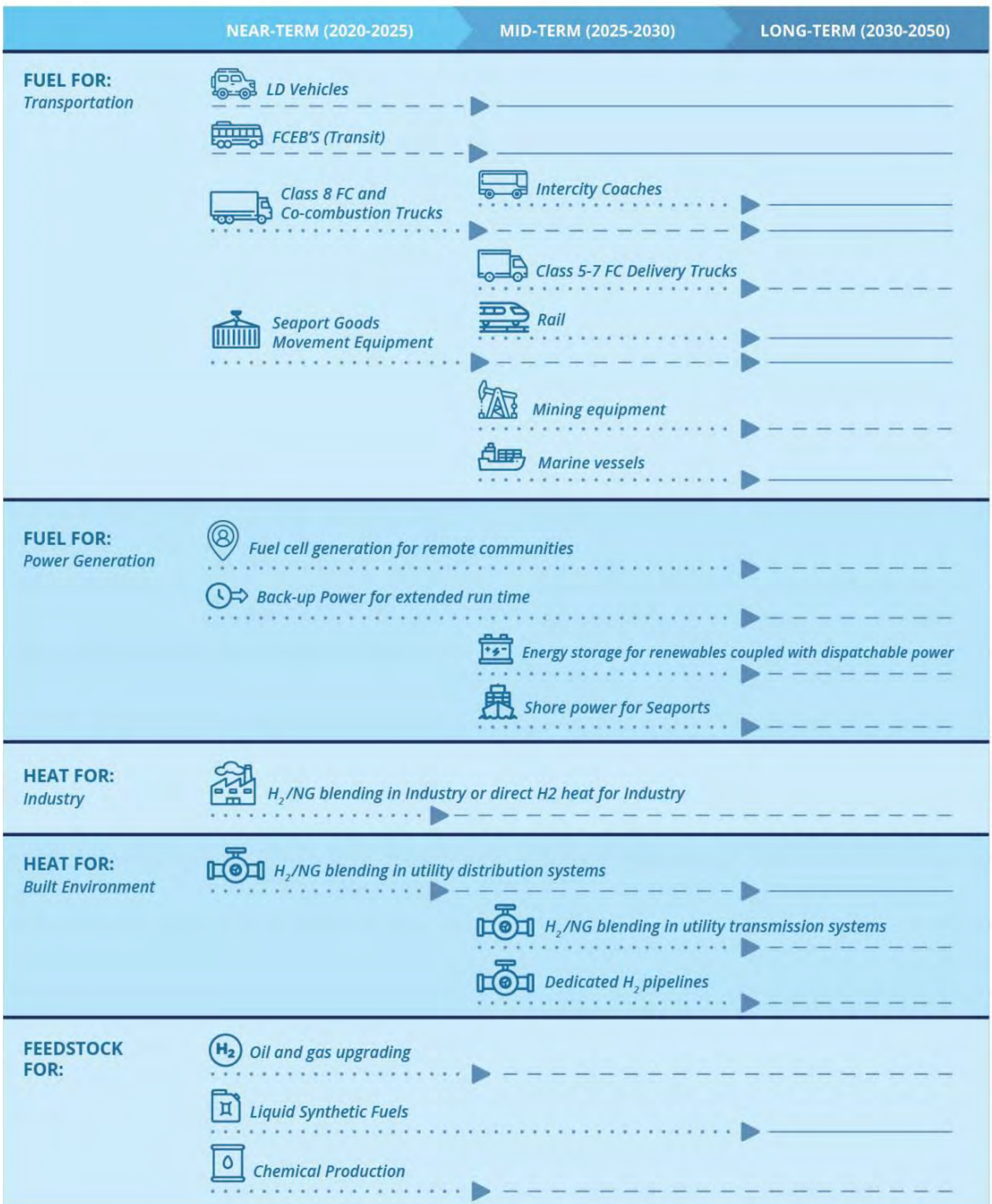
Predictable, long-term demand for LCF and industrial products is critical before industry can invest in these projects

CO_2 storage requirements will be significant in long term transition of sector

Findings

- *Ensure Canada's path to 2050 includes hydrogen and low carbon fuels as key components*
- *Implement CFS and recognize hydrogen role in pathways definitions*
- *Explore synergies between hydrogen and other bio-based renewable fuels, such as liquid biofuels, methanol, synthetic fuels, biogas and renewable natural gas (RNG)*
- *Ensure policy frameworks provide long term certainty that encourages private sector investment and innovation in actions across the hydrogen value chain, from production to end-use*
- *Begin developing international/overseas markets for exports of LCFs, steel and fertilizer—Canada should actively promote the low carbon intensity of its value-added products internationally*
- *Collaborate across upstream & down-stream industries to ensure supply & demand are matched*
- *Use of low-carbon products in domestic infrastructure could be encouraged to create a local market demand of low-carbon product and de-risk investment*

HYDROGEN USE IN CANADA



5. Putting it All Together: Canada's Hydrogen Opportunity

Hydrogen presents real pan-Canadian opportunities. Each region of the country can utilize their unique resources to produce and deploy hydrogen domestically as well as to supply a growing export market. According to modelling undertaken for this Strategy, hydrogen made through Canada's clean, abundant and diverse pathways has the potential to deliver up to 30% of end-use energy by 2050, while abating up to 190 MT-CO_2e of emissions if deployed in a transformative scenario, across all sectors of the economy from transportation, to power generation, to heating, to industrial applications. Implementing the hydrogen strategy can spark early economic recovery, and by 2050 build a $50B domestic hydrogen sector generating more than 350,000 high paying jobs from coast to coast.

HYDROGEN AS PART OF AN INTEGRATED ENERGY SYSTEM IN CANADA

Canada's hydrogen opportunity will be most optimally realized as regions develop the full hydrogen value chain tailored to local energy profiles and feedstocks for production, with end-uses prioritized to maximize decarbonization and economic benefits in operations specific to the region. Hydrogen's versatility as a fuel provides the ability to fundamentally transform Canada's energy landscape. Like electricity, hydrogen can serve multiple roles within the energy system from the upstream production of liquid fuels through to small-scale consumption in end-use appliances and equipment. However, unlike electricity, hydrogen can be shipped and stored in bulk quantities over extended periods. This allows it to act as a critical energy buffer between unpredictable production and end-use demand fluctuations. This temporal and geographic flexibility provides valuable redundancy and resiliency to the energy system and complements existing carriers such as electricity, natural gas, and liquid fuels. Hydrogen's ability to work as part of an integrated energy system will make it a critical part of the large-scale energy system transformation.

In the same way, road networks, railways and airlines work together to move goods from coast to coast, hydrogen, electricity, and fuel distribution networks can complement one another's strengths to make the whole system much stronger and more efficient (see, Figure 33). This is particularly important for two reasons. The first is the need to electrify as much of the economy as is technically and economically feasible. This includes most light duty forms of transportation, low-grade heat where economic (e.g. buildings), and some industrial processes. Electrification provides the most direct and effective way to decarbonize many sectors of the economy as it decouples energy use from GHG emissions at the point of use. This reduces emissions by improving overall efficiency of the process and it helps make the remaining emissions easier to manage by concentrating them at the point of production. As the electrical grid becomes cleaner, the GHG emissions for all electrified end-uses will come down. Hydrogen can play a role in supporting electrification by acting as an energy carrier for hard to electrify sectors such as high-grade heat, heavy-duty transport, and many industrial processes.

The second way hydrogen can complement wide-spread electrification is by acting as a storage medium and as an interface between the gas and electricity grids. While electricity can be stored in batteries and other chemical forms for days or weeks, the long-term, large-scale, and geographically flexible storage of electricity remains technically challenging and expensive. Hydrogen can be produced and stored when and where it is most convenient, shipped by road, rail, or water, or injected into the natural gas network for later use or reconversion back into electricity. This flexibility is critical as variable renewable energy sources make up an increasing percentage of the electricity generation mix. By providing a flexible source of demand that can ramp up and down as required throughout the day, electrolyzers can convert excess electricity from renewables into hydrogen that can used at later time. Reversing the process, fuels cells can convert hydrogen from storage back into electricity during periods of low sun and wind generation.

While *Section 3: What is Hydrogen?* and *Section 4: Canada's Production & Distribution Opportunities* discussed production pathways and end-uses independently, this section explores how hydrogen might be rolled out from a timing and regionality perspective as part of integrated energy systems. By looking at the overall projected demand for hydrogen by end-use application, possible scenarios are presented to show the range of both decarbonization and economic growth potential that hydrogen could offer in an Incremental versus Transformative Scenario.

Decisions about where hydrogen can most effectively be deployed, as the energy system transforms, will be influenced by economics, carbon abatement potential, function and performance of hydrogen in end-use applications relative to other options. With all low carbon energy vectors still undergoing rapid technology advancement and cost reduction, it is impossible to predict definitive scenarios. The cases presented should therefore not be viewed as forecasts or predictions, but rather as a set of two potential bookend scenarios. The Transformative Scenario is meant to represent the potential size of Canada's hydrogen opportunity if bold action is taken in the near term, whereas the Incremental scenario is based on a business as usual approach with lighter policy measures and a slower start to adoption.

Ultimately the timing and regionality of hydrogen's adoption in Canada is in the nascent stages, and all stakeholders can help influence what path we set ourselves on through strong leadership and initiative, and through a collaborative approach to development of the sector.

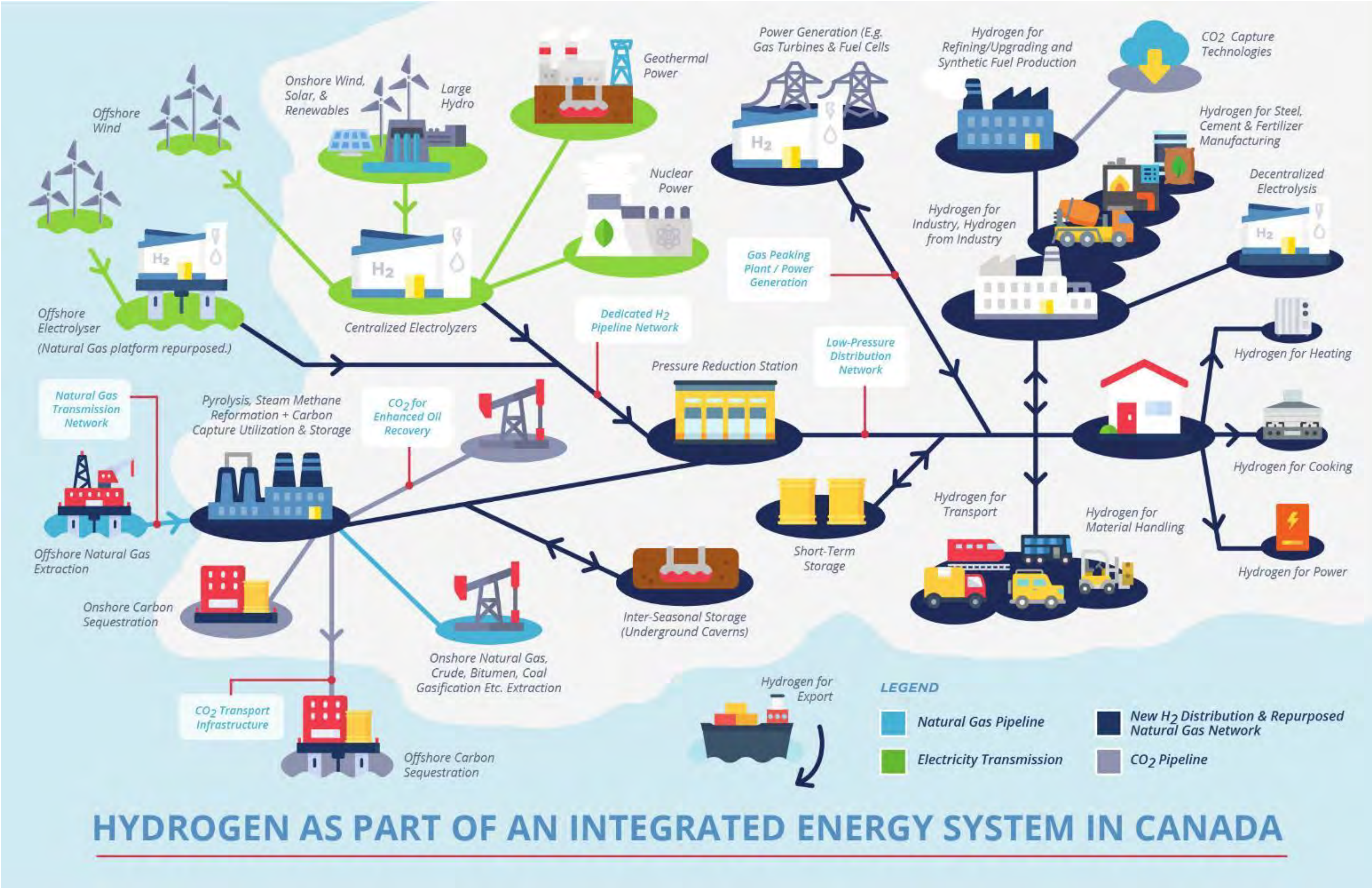


Figure 33 – Hydrogen as Part of an Integrated Energy System in Canada

ROLLOUT TIMING & REGIONALITY

Timing

Implementation in the Near-Term (2020 – 2025)

Hydrogen use in the near-term will be dominated by relatively mature market applications at or near the commercial market Technology Readiness Level (TRL) including FCEVs and FCEBs for transit operation. Pre-commercial applications such as heavy-duty trucks, seaport goods movement equipment, power generation, heat for industry and the built environment, and industrial feedstock applications will be introduced as pilot projects in regional HUBs. These regional HUBs will be strongly influenced by:

- ZEV mandates for passenger vehicles such as the existing legislation in Quebec and British Columbia;
- Carbon pricing and regulations like the Clean Fuel Standard driving low carbon hydrogen production for industrial applications including conversion of CO_2 into renewable methane at ethanol plants and biogas-to-RNG upgraders, production of renewable diesel and upgrading of transportation fuel products;
- Existing hydrogen generation, distribution and dispensing infrastructure that can be leveraged;
- Pilot results, codes, stands and regulatory approvals for blending hydrogen and natural gas to decarbonize the utility distribution system;
- Renewable gas targets for natural gas utilities where hydrogen qualifies as a pathway.

Local hydrogen production must be built concurrently with demand through end-use deployments within sub-regional HUBs in each province or region. Growing supply and demand in HUBs will bring down the cost of low-carbon intensity hydrogen pathways and spur the development of new sources of demand in several important ways. First, hydrogen production facilities can be built at scale capturing cost savings and using the diversity and longevity of demand to lower financing costs and improve project return on investment. Second, transmission and distribution costs are minimized as both supply and demand are co-located or in the same area. Finally, as many of Canada's industrial HUBs are already established users of hydrogen for refining, ammonia, and methanol, new low-volume buyers of hydrogen can scale their demand according to the timing of their needs.

There are several high potential areas to build out HUBs that have the potential to create self sustaining hydrogen economies more quickly, taking a holistic, energy system approach. These deployment HUBS bring supply and demand together but also bringing all key players together, to develop and implement regional plans that build on specific strengths and opportunities, while identifying the unique barriers and challenges, thereby improving the overall business case of each project. Specific projects and areas for early adoption include:

- The Alberta Industrial Heartland, near Edmonton, has several advantages to become one of the first hydrogen HUBs in Canada. It has access to plentiful natural gas and CCUS sites, an existing hydrogen pipeline and two CO_2 pipelines. This existing infrastructure would reduce the cost of new low-carbon hydrogen projects. It is also adjacent to the City of Edmonton, which has large potential demand for hydrogen in the transportation, space heating and electricity generation sectors.

- Coastal ports in BC, Ontario, Quebec, Manitoba and the Atlantic region are also high potential sites for hydrogen HUBs. Ports are concentrated centres of energy consumption for transportation and could also serve as the exit points for exported hydrogen.
- The transportation corridor between Montreal and Detroit is another high potential area as it connects demand for transportation with industrial and manufacturing centres. A regional hydrogen HUB along this corridor would allow supply and demand from multiple sources to be aggregated unlocking massive economies of scope and scale.
- Ethanol plants and landfill gas/biogas-to-RNG upgraders in provinces with access to hydroelectricity, such as B.C., Manitoba and Quebec, are potential sites for electrolyzers that can produce green hydrogen that can be combined with available CO_2 and produce RNG, and methanol.

Implementation in the Mid-Term (2025 – 2030)

In the mid-term, industrial clusters will serve as the starting points for expanding hydrogen use into other sectors and regions. For example, the production facilities and infrastructure built for industrial applications can be extended to supply hydrogen for residential heating, hydrogen refuelling stations or dispatchable power generation. Similarly, industrial clusters can be connected along corridors such as highways, railways, and pipelines to create larger and larger integrated networks.

As the technology matures and the full suite of end-use applications is at or near commercial TRL levels, hydrogen use in the mid-term will be focused on applications that provide the best value proposition relative to other zero-emission technologies. For example, FCEVs and FCEBs will enter the rapid expansion phase as the market for fuel cell and battery technology becomes more defined, for example where factors like range, gradeability, and fast fill times offer advantages for FCEBs.

Class 8 heavy-duty trucking in corridors that require heavy payloads and seaport goods movement equipment in regions with regulated airsheds will move into the commercial phase of deployment. New, larger scale hydrogen production in the mid-term will allow direct H_2 or H_2/NG blending for industry, the built environment and as a feedstock for chemical production and hydrocarbon upgrading to be commercialized in regional HUBs during this period.

Pre-commercial applications like Class 5-7 delivery trucks operating in urban zero-emission zones, passenger and freight rail where electrification of the line is prohibitively expensive, mining vehicles and marine vessels that require the energy density advantages that hydrogen offers, will all be piloted during this period.

Implementation in the Long-Term (2030 – 2050)

In the long-term, it is anticipated that with advances in battery and charging technology, there will be a more defined division between battery and fuel cell utilization in Canada. This is expected to result in the higher power demand applications (utility biased) predisposed toward hydrogen energy storage and the lower power demand applications (efficiency biased) using batteries for energy storage. New transportation applications will move into the commercial and rapid expansion phases during this period.

In parallel, economies of scale in the production of hydrogen and regulatory pressures could lead to accelerating growth in the blending of hydrogen in the natural gas distribution system while the Clean Fuel Standard will drive synthetic liquid fuel production for both the domestic and export markets. Power generation applications will continue to grow, albeit incrementally, lagging the transportation and industrial markets.

Regionality

Provincial regulations and policies, resource availability, geography and climate, infrastructure, and technology maturity will shape the timing and scale for hydrogen deployment across Canada. Figure 34 is a consolidated view of the most promising production and end-use applications in each Province in the mid-term. In the long-term, it is expected that most end-uses will be deployed across Canada.

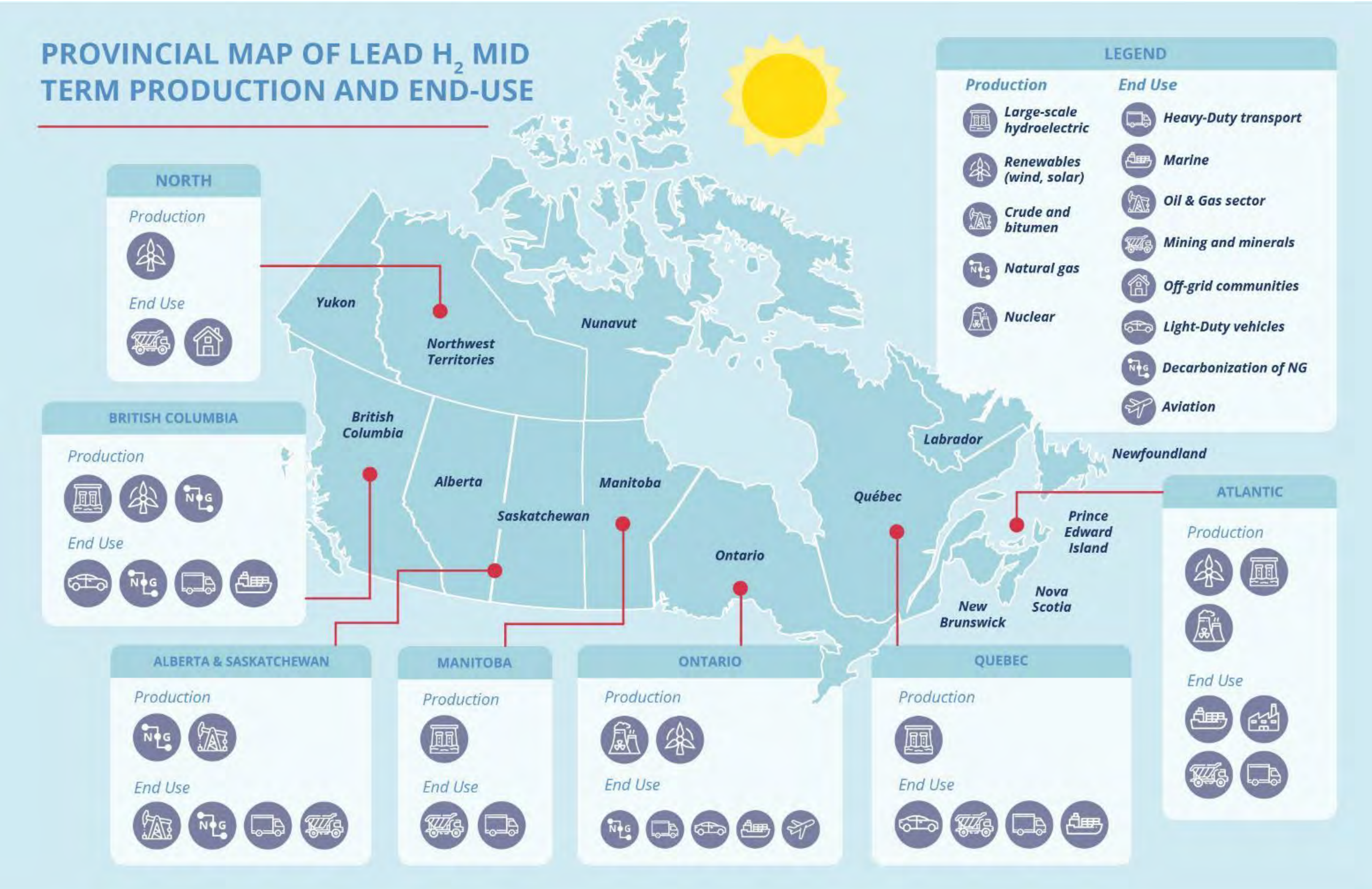


Figure 34 – Lead Mid Term Regional Production and End-Use Adoption Potential of Hydrogen Across Canada

QUANTIFYING THE OPPORTUNITY

The total primary energy supply in 2050 is expected to be delivered through several low carbon energy carriers including electrification, biofuels, hydrogen, and fossil fuels with carbon abatement. Modelling has been done to estimate potential adoption rates of hydrogen under ‘Incremental’ and ‘Transformative’ scenarios. The ‘Transformative’ scenario provides a directional estimate of the market size for hydrogen in key applications in achieving net-zero by 2050. In this ‘Transformative’ scenario, hydrogen could make up 31% of delivered energy, i.e., secondary energy use, in Canada by 2050 assuming economic and population growth are offset by efficiency improvements resulting in consistent energy consumption over time. This represents just over 20Mt of hydrogen demand per year in 2050, which is close to 3000 PJ of delivered energy. A more conservative Incremental scenario based on less aggressive policy assumptions shows opportunity for 8.3 Mt of hydrogen demand per year by 2050. Note that the Incremental scenario is not consistent with meeting net-zero targets in 2050. The demand by projected end-use application is shown in Figure 35.

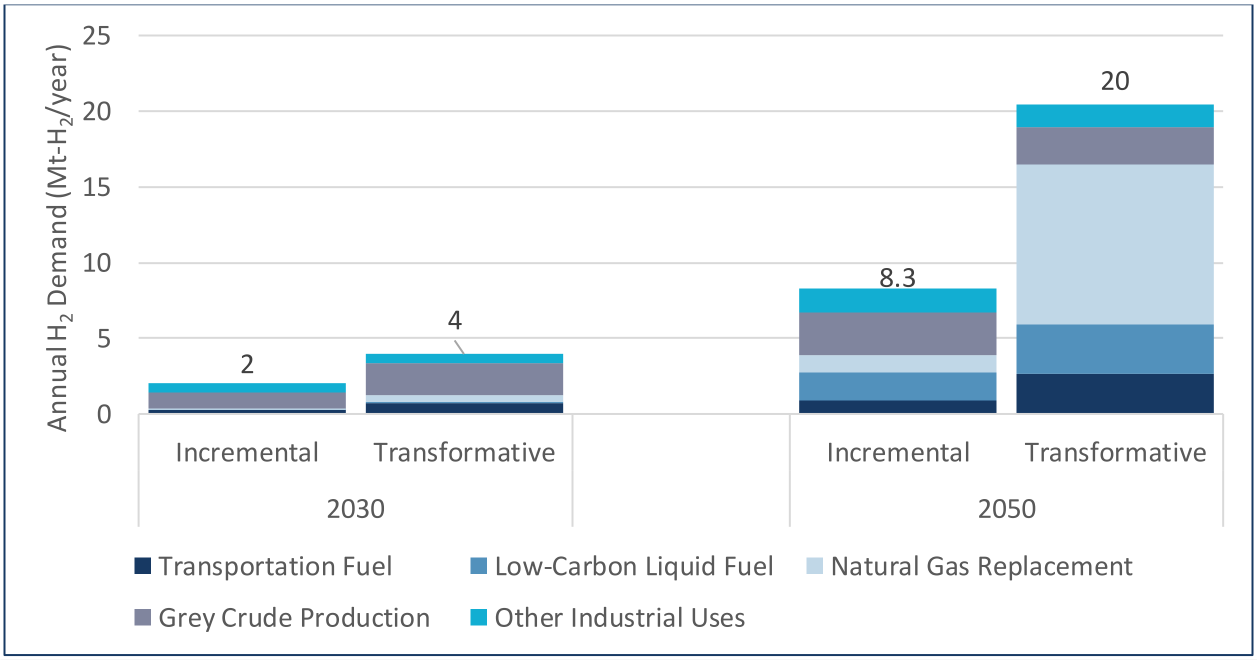
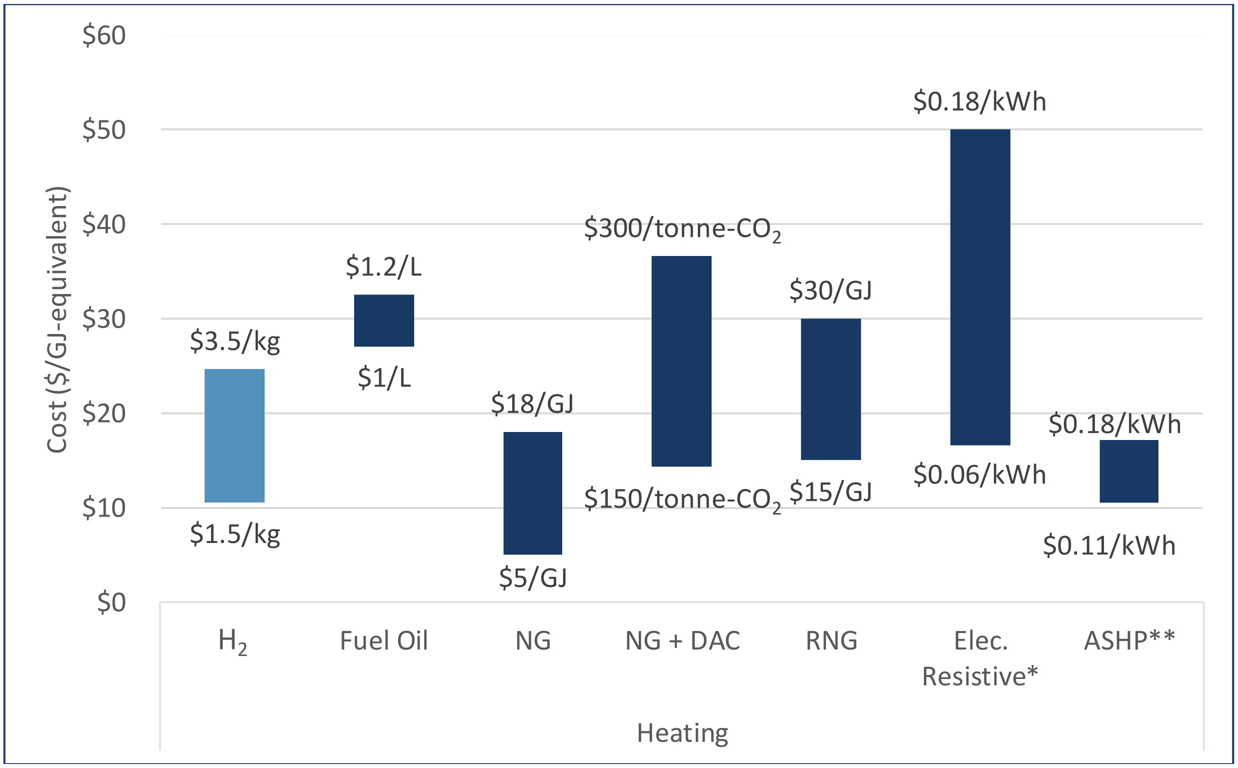


Figure 35 – Aggregate Demand Opportunity for Hydrogen in Canada

Ultimately the market will decide where best to deploy hydrogen once greater supply becomes available in Canada. The two big drivers will be cost competitiveness compared to alternative energy sources that can serve each end-use, and decarbonization potential which will ultimately be linked to the economics as carbon pollution pricing reflects the true price of emissions.

When comparing the cost of hydrogen to an incumbent fuel, it is important to consider the end-use application. For example, when used as a transportation fuel, hydrogen will be consumed in a fuel cell, which is significantly more efficient than a gasoline or diesel internal combustion engine (ICE). Therefore, the relative costs of the fuels cannot be compared on a simple $/GJ basis.

Figure 36 and Figure 37 shows the estimated cost of hydrogen relative to other fuels for heating and transportation applications. For both hydrogen and the alternative fuels, the costs shown reflect the total cost to the customer including production and distribution. The values are presented in $/GJ-equivalent, which takes into account the efficiencies of FCEVs and BEVs relative to ICE vehicles and air source heat pumps (ASHP) relative to electric resistive. As a heating fuel, hydrogen is more expensive than natural gas, but this value does not account for the increased costs of natural gas due to carbon. Over time, the delivered costs of all of the available fuels are likely to change. As a point of comparison, the figure shows the expected cost of natural gas used for heating for which the carbon emissions have been offset through direct air capture (DAC). Hydrogen for transport is cost competitive with gasoline and diesel, but will typically cost more than battery electric vehicles. Despite the additional cost, fuel cell vehicles will still be attractive in vehicle segments where operational requirements like longer range, improved performance in cold climates, and faster fueling are important.

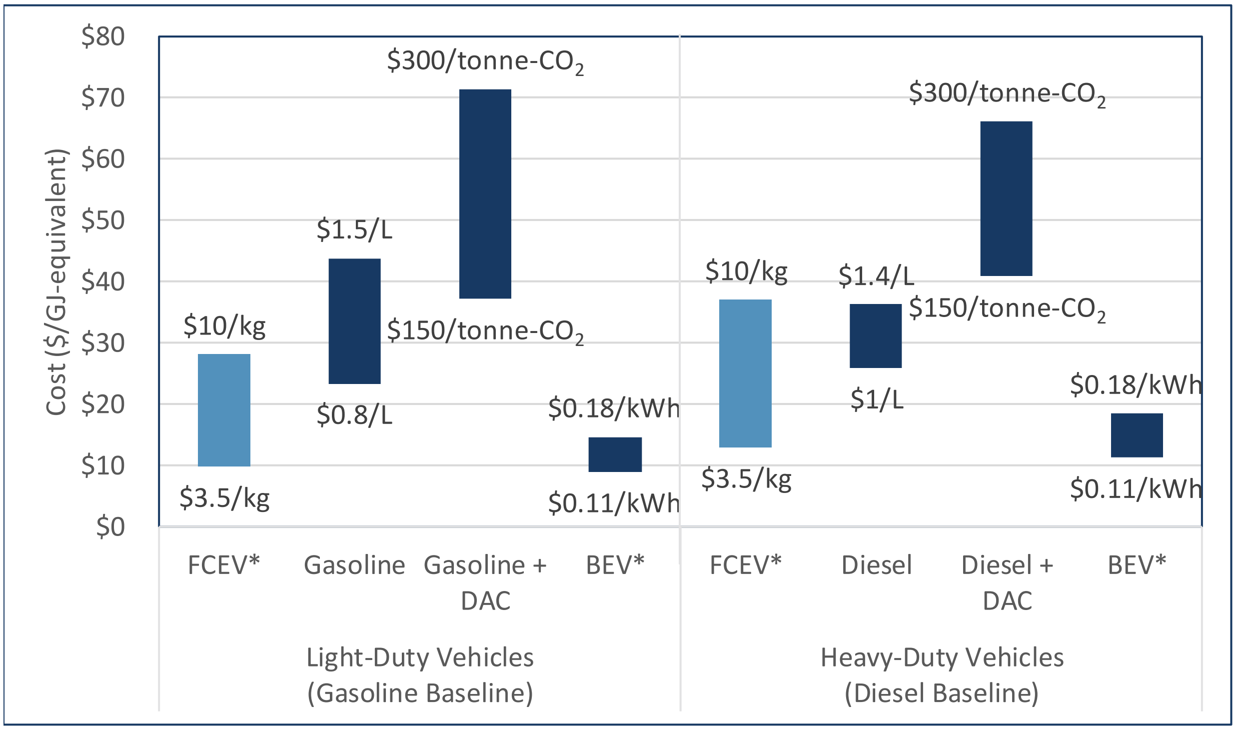


*The low price range for electric resistive heaters is less than for ASHP because resistive heaters may be used in industrial applications and therefore would be subject to rates for large scale industrial customers whereas ASHPs are typically in residential and commercial applications

**Coefficient of performance for ASHP = 2.92

Figure 36 – Hydrogen Cost Comparison as a Heating Fuel

The expected cost of hydrogen is dependent on the end-use application. As a heating fuel, it is assumed that the hydrogen will be produced in bulk and injected into the natural gas pipeline network in the short- to medium-term. The production takes place at or near the site of injection, so distribution costs are comparable to natural gas today, and the gas is only compressed to 100 bar, limiting compression costs. In the light- and heavy-duty vehicle sectors, it is assumed the fuel will be distributed via truck and compressed to 700 bar and 350 bar respectively. Comparable costs have been achieved in California for public transit applications.



*Energy efficiency ratio for light-duty vehicles: FCEV = 2.5, BEV = 3.4, energy efficiency ratio for heavy-duty vehicles: FCEV = 1.9, BEV = 2.7

Figure 37 – Hydrogen Cost Comparison as a Transportation Fuel

The emissions reduction potential of hydrogen is also dependent on the end-use application. Figure 38 and Figure 39 show the relative emissions reduction of hydrogen and electricity when used as a heating fuel or in a transportation application. The emissions reductions are compared to a natural gas baseline for the heating application, gasoline for light-duty vehicles, and diesel for heavy-duty vehicles. Negative numbers in these graphs indicate scenarios where emissions are increased relative to the baseline fuel.

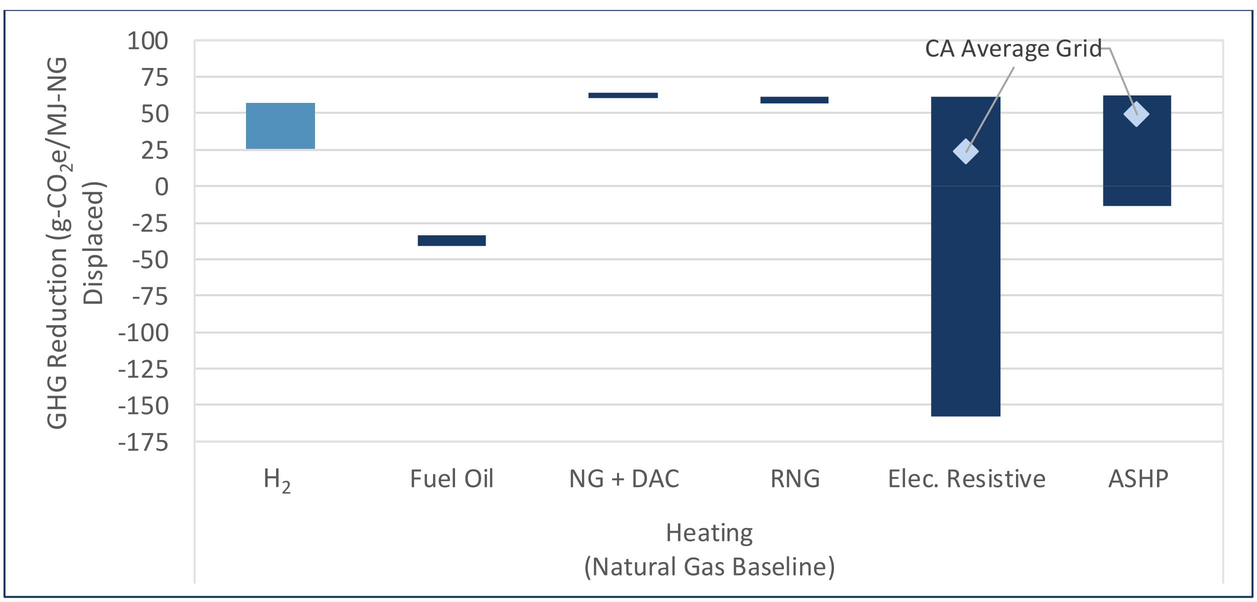


Figure 38 – GHG Emissions Reduction Potential of Hydrogen as a Heating Fuel

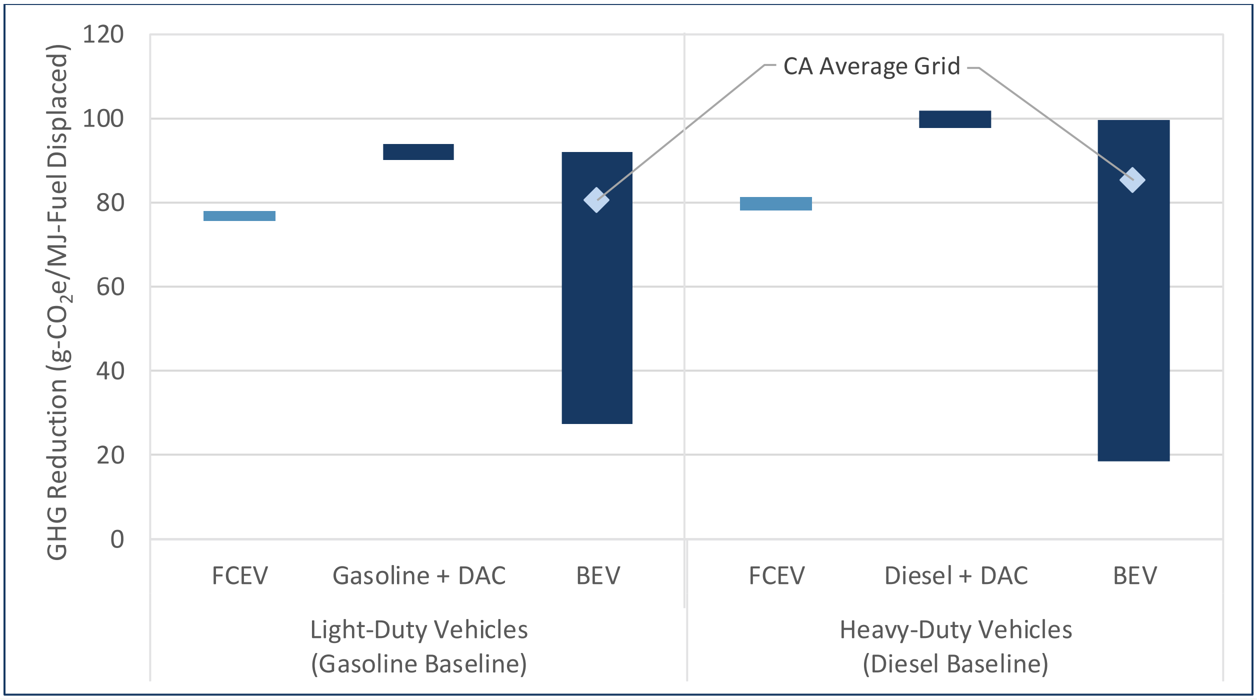


Figure 39 – GHG Emissions Reduction Potential of Hydrogen as a Transportation Fuel

The emissions reductions are dependent on the carbon intensity of the various energy sources. For hydrogen, the carbon intensity was assumed to be between 10.3-16.2 g-CO_2e/MJ when used as a heating fuel and 35.0-40.9 g-CO_2e/MJ when used as a transportation fuel to account for the additional energy required to liquify, compress, and distribute the hydrogen. These carbon intensities are consistent with large scale electrolysis and SMR with CCUS facilities, as described in the *Production Pathways' Cost & Carbon Intensity* section of this report.

The electrical emissions reduction potential is based on a carbon intensity of 140 g-CO_2e/kWh, which is the Canadian average. The lower bound (worst performing) shows the reduction potential based on Alberta's electric grid (790 g-CO_2e/kWh), which is the highest carbon intensity grid of any province in the country. The upper bound (best performing) represents Quebec's electricity grid (1.2 g-CO_2e/kWh), which is the lowest carbon intensity grid in the country.[1] In areas where the grid is particularly high-emitting, electrification will actually emit more than using natural gas or fuel oil. However, as the grid gets greener over time, the emissions reduction potential will improve.

[1] Canada Energy Regulator. (2020). Canada's Renewable Power Landscape 2017 – Energy Market Analysis. Retrieved from https://www.cer-rec.gc.ca/nrg/sttstc/lctrct/rprt/2017cndrnwblpwr/ghgmssn-eng.html

Cost and carbon intensity of each fuel are important factors that will drive adoption of the low carbon options for heating and transportation. A useful metric for comparison of different technologies is the incremental cost of hydrogen or other low carbon energy sources to the incumbent fossil fuel divided by the emissions reduction. This is often expressed in dollars per tonne of CO_2e abated ($/tonne-$CO_2e$). In transportation applications that employ fuel cells, hydrogen will cost less than gasoline or diesel resulting in a negative $/tonne-$CO_2e$ value. This provides a strong economic driver for adoption if capital costs are comparable. As a heating fuel, the cost of abatement in Canada is approximately $100-300/tonne-$CO_2e$, which is comparable to other low carbon options. While costs and carbon intensity are important factors, they are not the only limiting factors, there is also the operational differences, higher upfront capital costs and overall risk aversion (especially to new technologies). Further study is required to fully understand the costs of the entire value chain of each low carbon technology to assess the strength of each option.

The scale of aggregate demand in the 2050 Transformative scenario is significant and highlights the need for Canada to explore all low carbon intensity hydrogen production pathways. When considering pathways to satisfy future potential demand and optimize the potential for hydrogen, it is important to also consider the other changes that will be happening in the energy mix as Canada transforms all carbon emitting energy sources to carbon neutral sources . It is anticipated that direct electrification will play a significant role in reducing emissions in many sectors, from battery electric vehicles to heat pump adoption for building heat. Demand for electricity as an energy vector is expected to grow by at least 57%, and will be met through the deployment of additional renewable energy sources such as hydro, wind, and solar. Demand for bio-based liquid and gaseous fuels is also expected to grow. Natural gas on the other hand will have declining demand if not used to produce hydrogen, as any combustion related emissions in a net-zero energy system would need to be offset, for example through direct air capture. Figure 40 shows how much additional electricity generation or natural gas with CCUS capacity would be needed if all hydrogen is made though each of the pathways. The magnitude of energy feedstock needed highlights that a production strategy must be diverse, and that Canada will need to rely on fossil fuel pathways as well as the electrolysis pathway to meet decarbonization objectives.

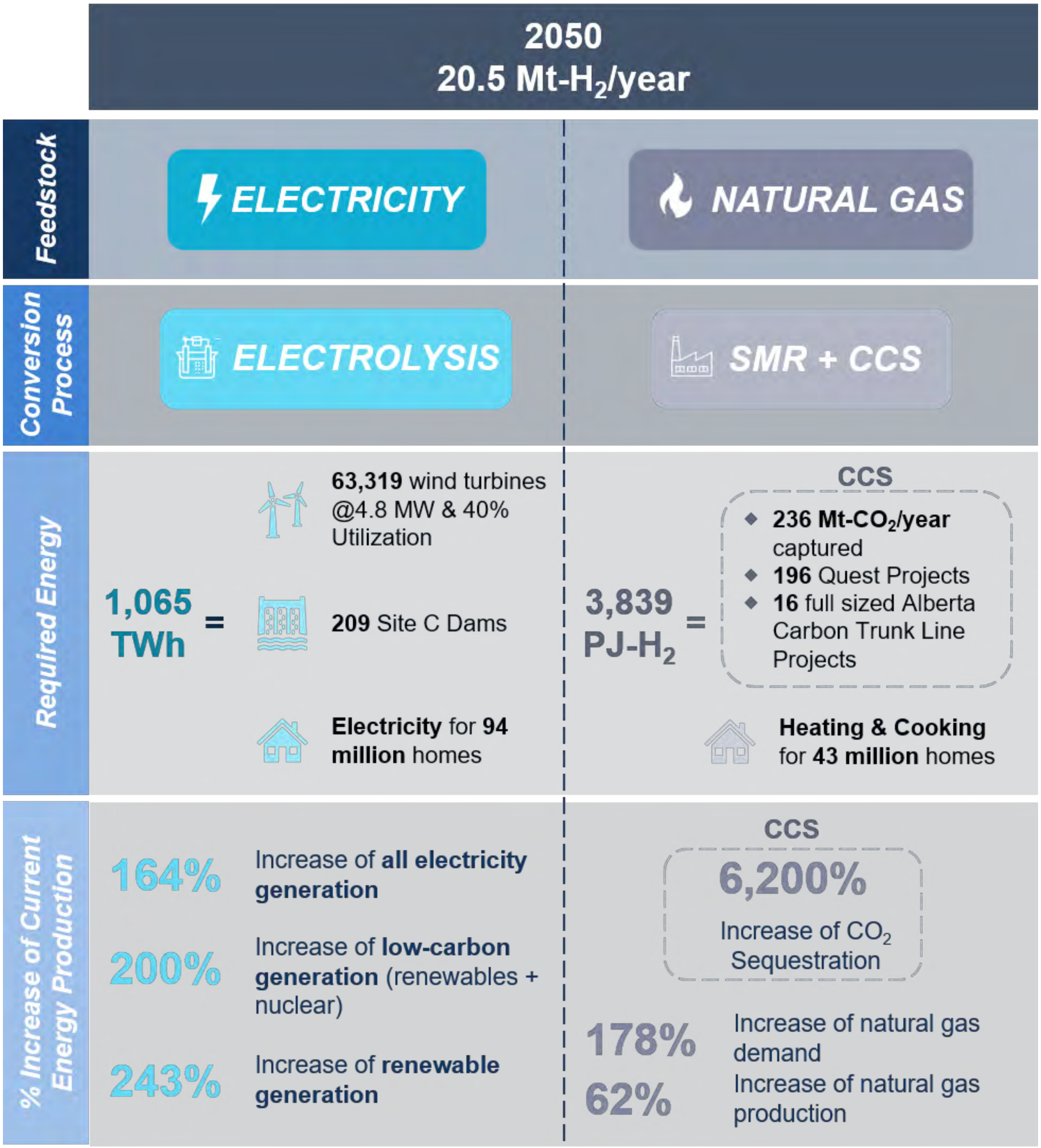


Figure 40 – 2050 Fossil Fuel vs Electrolysis Based Hydrogen Production

HYDROGEN'S DECARBONIZATION POTENTIAL

To evaluate the role hydrogen can play in reaching Canada's goal of becoming net-zero by 2050, modelling analysis was undertaken for an incremental scenario and a transformative scenario, to understand hydrogen's potential in the broader energy system, alongside electrification and other low-carbon fuels. These scenarios are more likely to be achieved with strong pricing and regulatory incentives to drive hydrogen adoption, and alignment action across government and industry.

Increased electrification with renewable and low CI power sources will play a large role in reducing emissions. It is well suited to many applications including light-duty BEVs and to provide heating when the use of heat pumps is cost effective. However, it will be impossible to grow clean electrical generation fast enough to meet demand if entire energy sectors electrify to meet climate targets. Hydrogen produced from natural gas and crude oil incorporating CCUS enables Canada to utilize its natural resources while limiting emissions as deployment of low CI electricity generating infrastructure grows. There are also end-use applications where electrification is challenging, including heavy-duty vehicles where the low energy density of batteries limits carrying capacity and where continuous operation of vehicles makes fueling time critical. In cases such as these, hydrogen is likely to become an important low CI option.

Similarly, low CI crude production, which includes traditional crude combined with indirect CCUS or enhanced oil recovery such that the net CO_2 emissions are near zero, and liquid and gaseous biofuels, will be an important part of the energy mix. These fuels serve effective substitutes for traditional crude and natural gas respectively as they can be incorporated into the current energy system without the need to replace or upgrade existing distribution and end-use infrastructure. The use of low CI crude and biofuels will be primarily limited by feedstock supply and economics. The cost to produce them will increase as the lowest hanging fruit opportunities for production are exhausted.

EVOLUTION OF THE ENERGY SECTOR

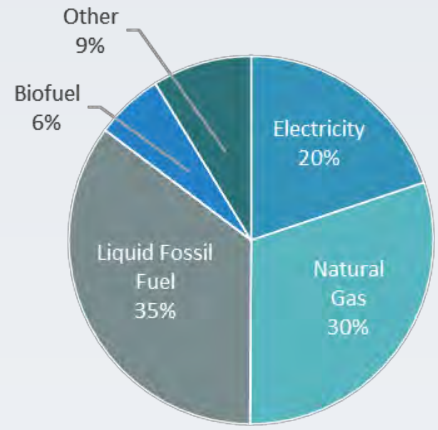


Figure 41 – Canada's 2017 Secondary Energy Demand

As demand for hydrogen grows, so will the need for other low-carbon energy sources.

Between now and 2050, high-emitting fuel sources will replaced by a combination of increased electrification, biofuels, low-carbon liquid fuels – including synthetic fuels and traditional crude offset through CCUS – and hydrogen.

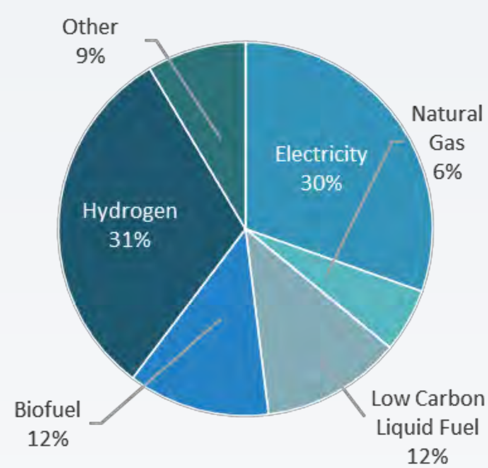


Figure 42 – Canada's 2050 Secondary Energy Demand Scenario

There are limited opportunities for cost-effective RNG production, which are likely to be maxed out on the path to net carbon neutrality. However, all low carbon fuels, including RNG will have a role in Canada's future.

Hydrogen demand was forecasted to essentially fill the gaps that electrification, and other low CI energy sources cannot reach or where they would be cost prohibitive. The analysis took into account the expected relative costs of each low CI energy source as well as the ability of technologies to meet end-use demand requirements.

The GHG emissions abatement potential was estimated by comparing hydrogen consumption to the incumbent energy source for each sector. In transportation applications, hydrogen is considered as a substitute for diesel and gasoline derived from crude oil; in the natural gas grid, hydrogen replaces natural gas; and in industrial uses, low CI hydrogen replaces either natural gas or grey hydrogen produced via SMR without CCUS depending on the specific application.

When applicable, the calculated emissions reductions account for the improved energy efficiency of fuel cells compared to internal combustion engines. In transportation applications, it was assumed that hydrogen would be used in fuel cells with energy effectiveness ratios (EER) of 1.9 for light-duty vehicles and 2.5 for medium- and heavy-duty vehicles. When used as a substitute for natural gas or as a feedstock for industrial processes, there is no efficiency gain relative to the incumbent fuel.

Figure 43 shows the transformational and incremental decarbonization potential from hydrogen in 2030 and 2050 by sector. In the Transformative case, hydrogen can reduce emissions by up to 45 Mt-CO_2e/year by 2030. In 2050, the emissions reduction increases up to 190 Mt-CO_2e /year. This simplified analysis assumes energy demand remains flat between now and 2050, with increased energy demand offset by energy efficiency improvements.

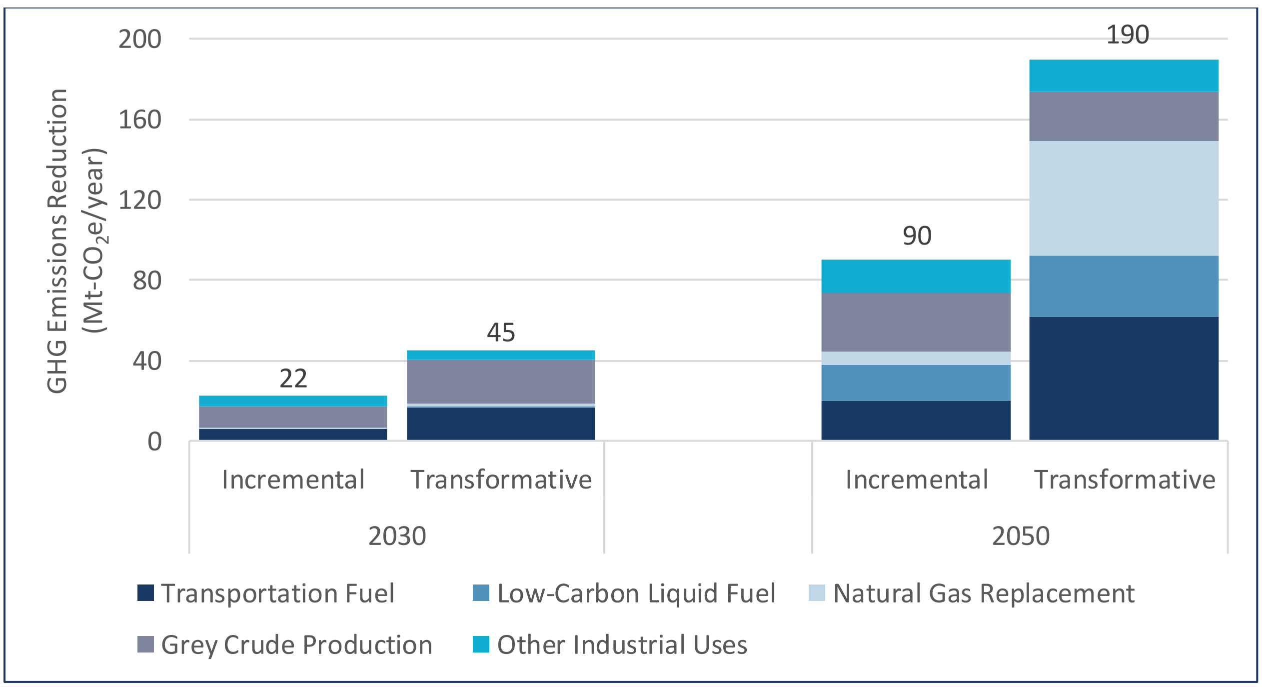


Figure 43 – Hydrogen Decarbonization Potential

Figure 44 shows the magnitude of emissions reduction from hydrogen relative to Canada's 2030 and 2050 targets.

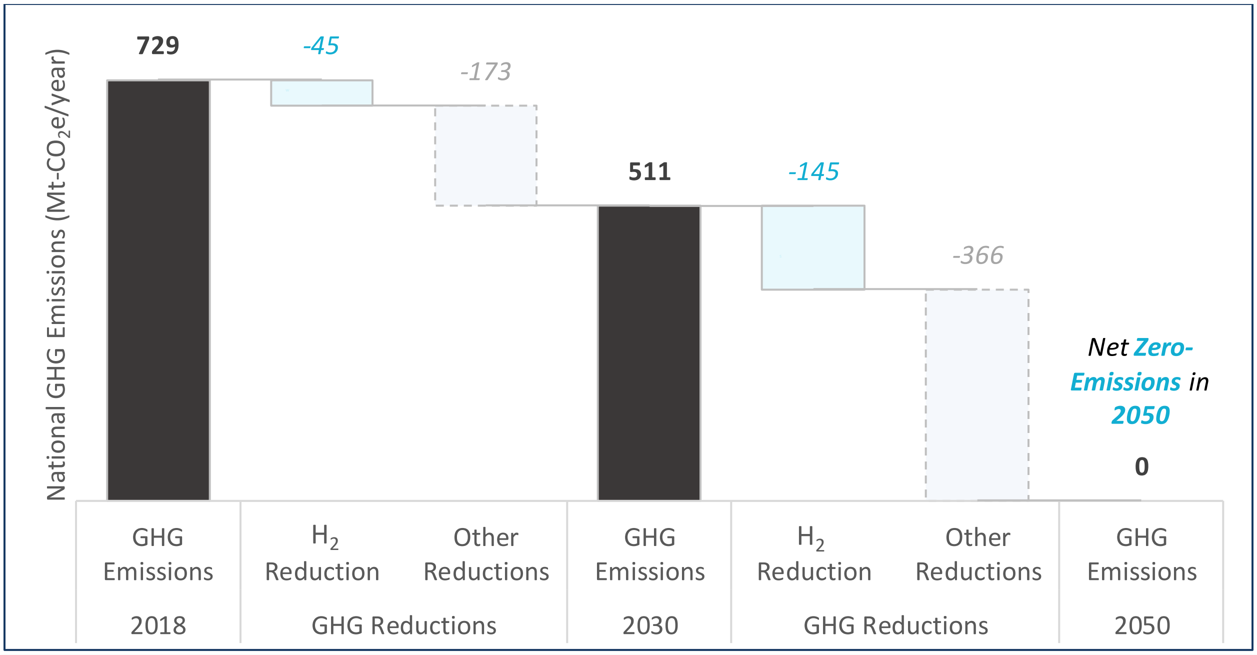


Figure 44 – Potential Role of Hydrogen in Reaching Canadian Decarbonization Targets – Transformative Scenario

ECONOMIC OPPORTUNITY

Domestic Market

Considering only the domestic demand for hydrogen production and revenues from the local manufacturing and services, the hydrogen and fuel cell sector has the potential to generate almost $50 billion in sector revenue in 2050 under the Transformative scenario (Figure 45). This figure is based on the estimated demand for hydrogen in 2030 and 2050 under the Incremental and Transformative modelling scenarios and assuming an average hydrogen sales price of CAD$2/kg. In addition, revenues from the manufacturing of electrolyzer equipment, fuel cell stacks and engineering and consulting services are estimated based on a conservative market share of 5% of the domestic market. The estimated value of the domestic market is expected to be almost **$50 billion per year** by 2050. This does not take in to account how the hydrogen market will indirectly benefit several other adjacent industries that would also contribute to economic growth and could lead to manufacturing opportunities in Canada, including SMR and CCUS facilities and equipment, H_2 pipeline development, and end-use applications in buildings, industry, and the natural gas grid.

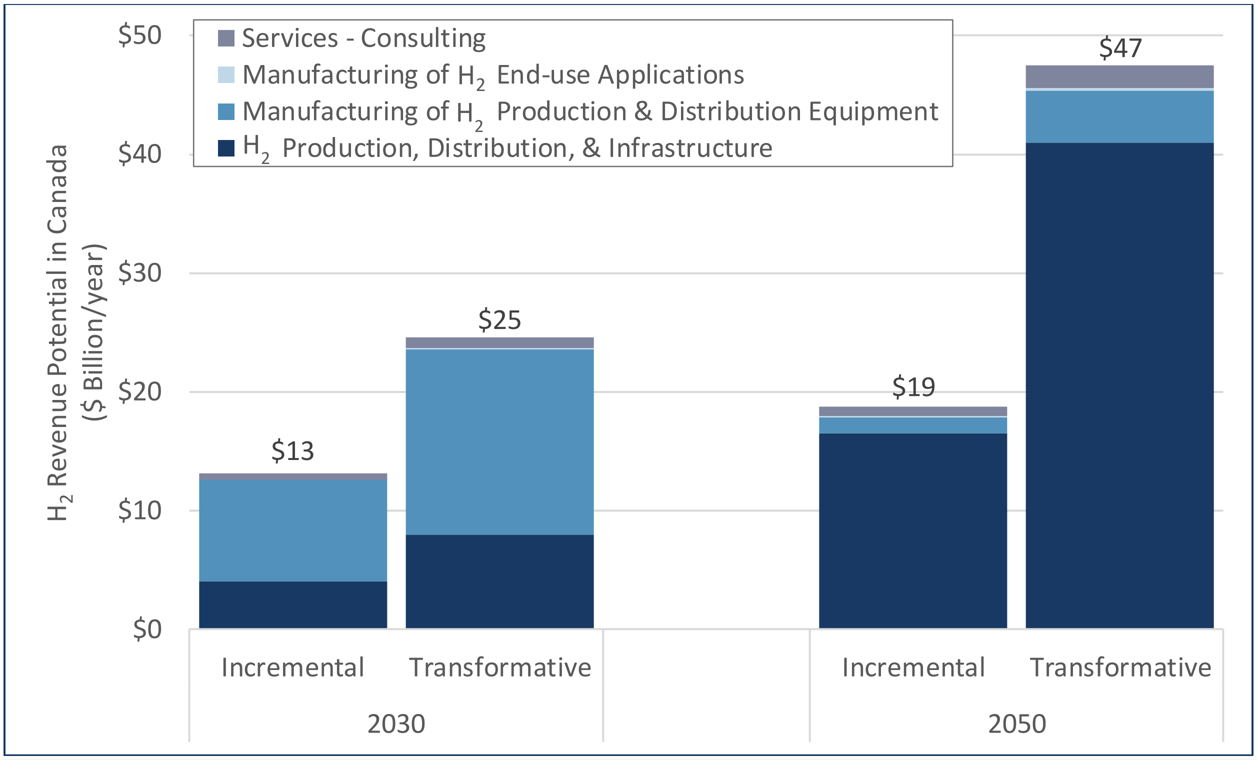


Figure 45 – Hydrogen Revenue Potential in Canada in 2030 & 2050

Based on the direct sector revenue estimates, the job creation potential for hydrogen in 2050, under the Transformation Scenario is more than **350,000** (Figure 46). This was calculated by multiplying the annual revenue for each subsector by a job multiplier based in similar industries (Table 2). For example, the number of jobs for the hydrogen production industry is based on the multiplier from the industrial gases industry. This number represents a combination of new job growth and retrained and reskilled labour.

Table 2 – Job Multipliers

Jobs per $M (jobs created each $M in revenue) [1,2]	
Jobs per revenue created in the machinery and equipment industry	12.2
Jobs per revenue created in the automotive industry	10.2
Jobs per revenue created in industrial gases	6.7
Jobs per revenue created in manufacturing of other transport equipment	14.5
Jobs multiplier –hydrogen	**6.7**
Jobs multiplier –equipment	12.3
Jobs multiplier –aftermarket	14.3

[1] These job multipliers are based on numbers from the US Fuel Cell & Hydrogen Energy Association's Road Map to a US Hydrogen Economy report (2019), adjusted to Canadian dollars. These projections should be seen as indicative of the order of magnitude of the number of jobs in the hydrogen industry and are subject to many uncertainties and unpredictable changes in economics and technologies.

[2] Source: McKinsey Global Institute Economics Research, GTAP input-output data

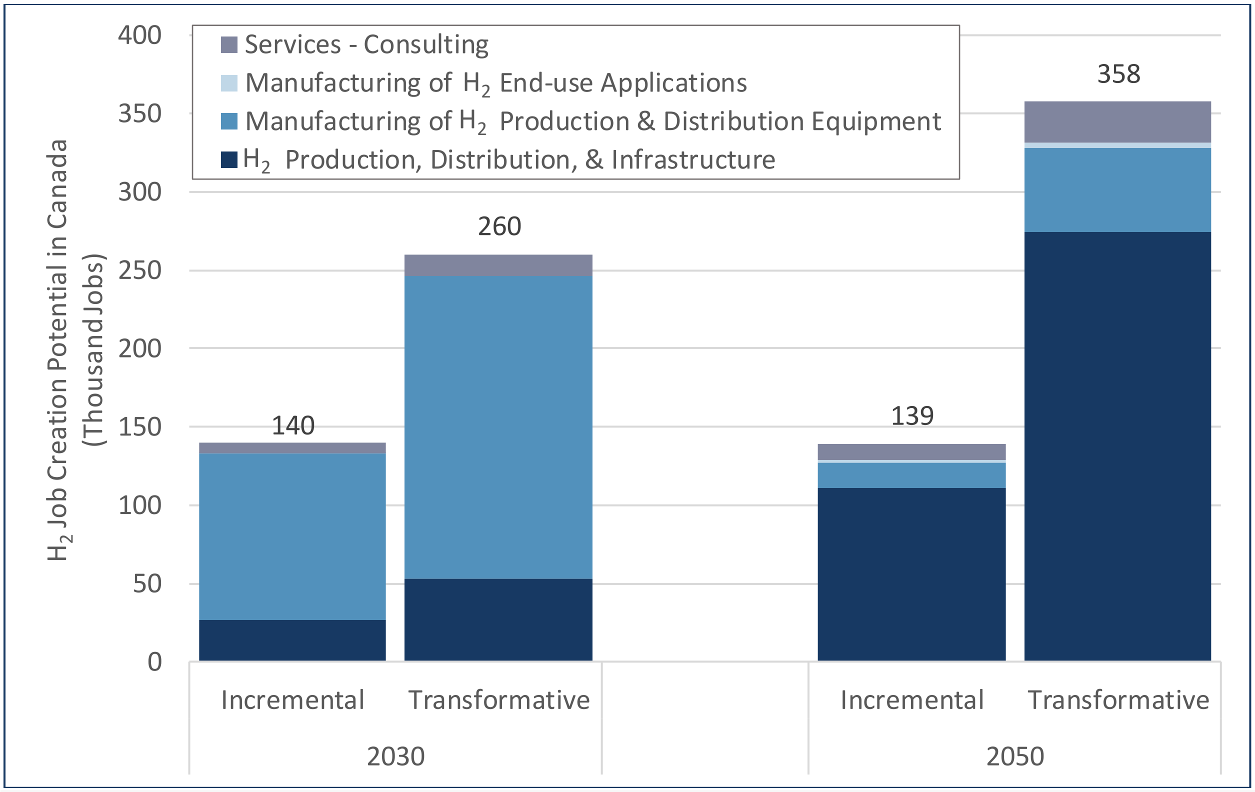


Figure 46 - Hydrogen Sector Job Creation Potential in Canada in 2030 & 2050

The energy transition will fundamentally shift the Canadian economy and alter value chains in many related sectors. One shift of particular importance is the transition away from the direct burning of fossil fuels without carbon abatement. Canada's energy sector accounted for 900,000 direct and indirect jobs as of 2017, with assets valued at $596 billion[1]. This industry's significant energy expertise and infrastructure can be leveraged to support the development of the future hydrogen economy in Canada. Hydrogen will be critical to achieving a net-zero transformation for oil and natural gas industries. It provides an opportunity to leverage our valuable energy and infrastructure assets, including fossil fuel reserves and natural gas pipelines, providing a pathway to avoid underutilizing or stranding these assets in a 2050 carbon neutral future. Leveraging these valuable assets will not only be instrumental in achieving the projected economic growth for the domestic market, but also presents the opportunity for Canada to position to become a leading global clean fuels exporter.

Opportunities for Indigenous Communities and Businesses

The energy sector is one of the largest employers of Indigenous peoples in Canada. As the energy sector transforms to adopt low carbon fuels, the emerging hydrogen economy will offer new opportunities for Indigenous communities through employment and new business creation.

The versatile production pathways of hydrogen and potential for scalable and distributed production facilities offers the potential for greater participation and ownership in the value chain than has been possible in the oil and gas and power sectors.

Hydrogen presents unique business opportunities for Indigenous communities with the capacity to take advantage of existing infrastructure, including renewable electricity, to produce, distribute and use hydrogen. These opportunities could outside of local communities as well. For example, Indigenous

[1] https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/pdf/10-Key-Facts-on-Canada_s-Energy-Sector-2018-en%20.pdf

communities and businesses could participate in early deployment HUBS whereby they could become fuel producers and distributors both for nearby communities and adjacent industry.

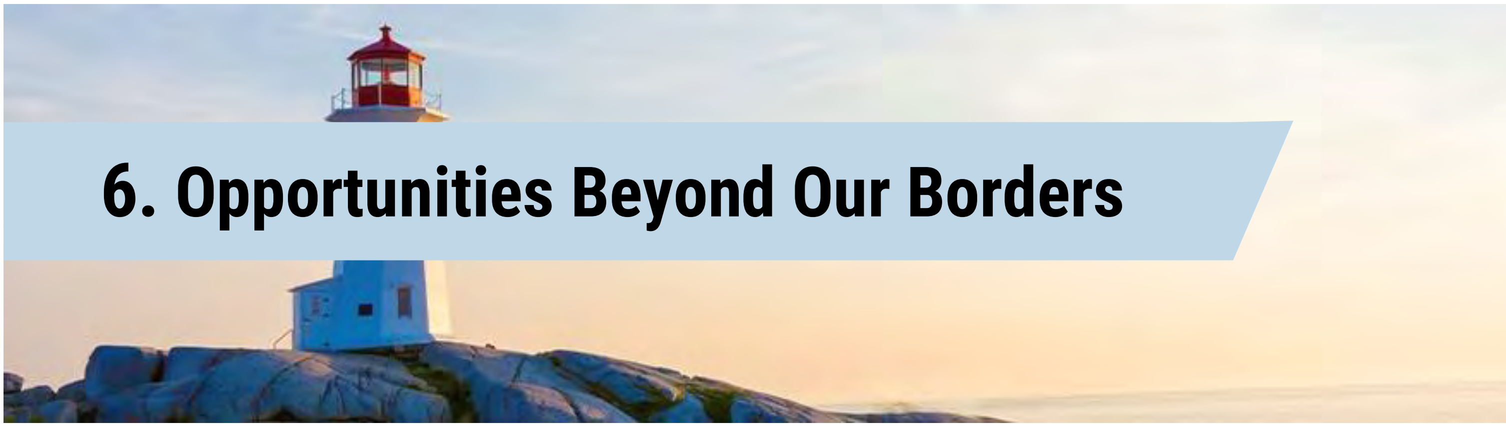
Many of Canada's remote communities house Indigenous peoples, and a large proportion of these communities are reliant on imported diesel for power generation. This leads to high operating costs and poor air quality. In the medium to longer term hydrogen can offer an opportunity for greater energy independence, as it can be made from local biomass and/or hydroelectric resources. Displacement of high-emitting diesel with hydrogen will result in improved local air quality and better health outcomes for community members.

As Canada invests in hydrogen infrastructure build-out, there is an opportunity for Indigenous peoples to participate. Some of the anticipated distribution corridors to move hydrogen from production to end-use locations will likely run through Indigenous lands. As such, skilled construction labour will be needed for build-out of production and distribution infrastructure assets, including future potential hydrogen pipelines. While there has been mixed support for traditional pipelines, hydrogen pipelines may offer a unique low environmental risk alternative to move energy within Canada, though local land disruptions through Indigenous territories will still need to be considered. Early and meaningful engagement on all aspects of hydrogen production, distribution and deployment will be essential.

Indigenous communities and businesses across Canada are already identifying hydrogen as a new opportunity for economic development, with environmental benefits. By leveraging the natural resources under their stewardship, as well as existing commercial facilities owned and operated by Indigenous-led businesses, new hydrogen opportunities are emerging. For example, the Penticton Indian Band is considering the development of a hydrogen-powered passenger railway service in the Okanagan Valley – a potential first in North America – mobilizing partners and experts throughout the region to advance a holistic vision of sustainable transport. In northeastern BC, Renewable Hydrogen Canada (RH_2C) is developing the Sundance Hydrogen project that includes Indigenous participation through operation of co-located greenhouses utilizing waste heat from electrolyzer plants that will provide fresh, local produce for the region. In Ontario, the Saugeen First Nation has formed a partnership with Bruce County to advance foundational hydrogen infrastructure, noting that the local geology can serve as a vast reservoir capable of storing hydrogen produced from local renewable resources and nuclear power. Once stored, the hydrogen can be supplied to markets as a low CI gaseous fuel; it can also be converted back to electricity to power the regional transmission grid. Similarly, Des Nedhe Development sees opportunities to include hydrogen refueling and EV chargers their existing conventional gas stations within Saskatchewan, as the next step in the transition to a lower carbon economy. They also see strong synergies between Canada's uranium mines, path to small modular reactors, and hydrogen as providing economic opportunities in the medium term.

The scale of Indigenous clean energy leadership and ownership has the capability to grow over the short and long-term. Going forward a holistic approach, to understand the potential role of hydrogen as part of broader energy pathways, in support of reconciliation, will be critical. Hydrogen deployment initiatives can be most effectively advanced through early and meaningful dialogue with Indigenous peoples.

As the Hydrogen Strategy emphasizes, collaborative, strategic partnerships are essential for growing the production and use of hydrogen across Canada. Partnerships that emphasize environmental protection, cultural recognition, community energy planning aligned with traditional values, economic development, and project participation, will be essential to maximize benefits for Indigenous peoples in the hydrogen economy.



6. Opportunities Beyond Our Borders

Momentum on hydrogen and fuel cell technology is growing globally, with market estimates ranging from \$2.5-\$11.7 trillion by 2050. Canada has the potential to produce large amounts of low-cost, clean hydrogen in excess of its domestic demand, creating an opportunity for Canada to become a supplier of choice of a new carbon-free energy export commodity. Canada, known for its leading hydrogen and fuel cell technology companies, is also well positioned to attract direct foreign investment, and continue to grow as a word-leading exporter of technology, products, and services.

EXPORT MARKET

Canadian governments, industry and academia have a long history of international collaboration to advance hydrogen production and use. These collaborations have included fundamental research, commercialization, deployment, and policy development. As a result, Canada is well positioned to continue as a global leader in both technology innovation and commercial developments. International collaborations accelerate advancements in R&D and product development, ensure codes and standards necessary for commercial rollout are harmonized, and build on policies and best-practises. They also position Canadian companies to showcase their products and expertise in international markets for export and to attract additional direct foreign investment.

With worldwide demand for hydrogen increasing, there is a significant opportunity for Canada to become a supplier of low CI hydrogen as a new carbon-free energy export commodity complementing Canada's energy exports of crude oil, natural gas, and transportation fuels. Canadian oil and natural gas exports alone totaled \$119 billion in 2019, and, with import countries looking to decarbonize their energy systems, hydrogen could take a significant portion of this share in the coming decades.[1] There is also potential to grow the export market for Canadian products, services, and intellectual property. A recent study indicated that hydrogen exports could reach \$50 billion by 2050, doubling the overall economic potential of the market projected for Canada in the same timeframe.[2] In November 2017, the Hydrogen Council estimated that the global annual sales for hydrogen and related equipment could be 2.5 trillion by 2050.[3] More recently in September 2020, the global investment bank Goldman Sachs estimated that the addressable market for hydrogen could be worth \$11.7 trillion by 2050, split between Asia, Europe and the U.S.[4]

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[1] Natural Resources Canada. (2020). *Energy and the Economy*. Retrieved from: https://www.nrcan.gc.ca/science-data/data-analysis/energy-data-analysis/energy-facts/energy-and-economy/20062#L4

[2] The Transition Accelerator. (2020). *Towards Net-Zero Energy Systems in Canada: A Key Role for Hydrogen*. Retrieved from https://transitionaccelerator.ca/wp-content/uploads/2020/09/Net-zero-energy-systems_role-for-hydrogen_200909-Final-print-1.pdf

[3] Hydrogen Council. (2017). *Hydrogen Scaling Up*. Retrieved from https://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf

[4] Barron's. (2020). *'Green Hydrogen' Could Become a \$12 Trillion Market. Here's How to Play It.* Retrieved from https://www.barrons.com/articles/goldman-sachs-says-so-called-green-hydrogen-will-become-a-12-trillion-market-heres-how-to-play-it-51600860476

Canada has the potential to produce large amounts of low-cost, low CI hydrogen in excess of its domestic demand. Leveraging the country's diverse range of hydrogen production feedstocks to create hydrogen for export could create substantial economic value. Canada has several strategic advantages for producing hydrogen for export including:

- Deepwater harbours and port infrastructure along both coasts, Hudson's Bay and the Great Lakes providing access to key markets in Asia, Europe and North America
- Abundant low carbon electricity, biomass, natural gas, and CCUS potential
- Integrated, country-wide natural gas and pipeline network
- Connected energy systems integrated with the large US markets, especially California and the East Coast
- A well-trained workforce with deep technical experience in the energy sector

A full analysis of the export potential for hydrogen is beyond the scope of the strategy in the near-term, but several key markets, technologies, and policies are recommended as a foundation. It is recommended that export opportunities be studied in depth following release of this *Hydrogen Strategy for Canada*, with the goal to create a specific action plan related to pursuing opportunities for export in parallel to the focus on establishing a vibrant domestic market.

TARGET MARKETS

Five key markets have been identified as potential export markets for Canada: The USA (particularly California and the Eastern US), Japan, South Korea, China, and the European Union. These have been identified based on their stated strategies, demand potential and proximity to Canada. As the global demand for hydrogen continues to evolve, new export markets in South America may also develop.

In the USA, the two main markets for hydrogen are expected to be in California and in the densely populated North Eastern states. California's estimated demand for hydrogen could be as large as 1 to 4 million tonnes by 2050. The state has strong governmental regulations and supportive funding for hydrogen infrastructure and fuel cell vehicles. The Innovative Clean Transit Regulation and Zero Emission Vehicle Mandates are expected to create significant demand for hydrogen in the transportation sector. The state also has significant renewable natural gas and energy storage requirements which could be partially addressed with imported hydrogen. For the market in the Northeastern US, there are potential opportunities to reuse elements of the LNG and other infrastructure already in place in Atlantic Canada. The ports, rail, highway and pipeline interconnections between the Maritimes and the Eastern US could provide a route to market for hydrogen generated in Central Canada and Quebec.

In Asia, Japan, South Korea, and China have ambitious hydrogen strategies. Japan and South Korea will need to rely on imports to meet the bulk of their demand. The estimated demand for hydrogen in Japan could be between 5-35 million tonnes per year in 2050 according to the Ministry of Economy, Trade and Industry. The country has already begun investigating supply options with Australia, who have, in turn, developed an aggressive and ambitious hydrogen export strategy. In South Korea's National Hydrogen Economy Roadmap, the estimated demand in 2050 is between 4 and 20 million tonnes per year, with limited domestic production potential similar to Japan. China has plans to make significant investments in hydrogen and fuel cell vehicles. The demand is expected to be between 18 to 160 million tonnes per year by 2050. China may eventually be able to become self-sufficient in its production when coupled with the large renewable and nuclear energy systems it is developing.

In Europe, Germany is leading the development of its hydrogen economy based on renewable energy and electrolysis. The German Government expects that around 2.7 to 3.3 million tonnes (90 to 110 TWh) of hydrogen will be needed by 2030, with significant upside growth in the 2030 – 2050 timeframe. To cover part of this demand, Germany plans to establish up to 5 GW of generation capacity including the offshore and onshore energy generation facilities[1]. They will also likely rely on imports of hydrogen to complement domestic production. In the rest of Europe, there are several hydrogen hubs being developed in the Netherlands, the UK, and Portugal. The Port of Rotterdam in the Netherlands is working to introduce a large-scale hydrogen network across the port complex, with the goal to make Rotterdam an international hub for hydrogen production, import, application and transport to other countries in Northwest Europe[2]. The hub will also enable Rotterdam to maintain its position as important energy port for Northwest Europe in the future, anticipating that demand for hydrogen will be growing.

British Columbia, with its proximity to East Asia, could be an export hub for Canadian hydrogen, leveraging local and Alberta production capacity provided transportation infrastructure is established to connect the two provinces. The British Columbia Hydrogen Study completed in 2019 shows export potential of $15 billion by 2050 from that province.[3] Atlantic Canada could be a potential export hub for Canadian hydrogen to serve the European market. The following image (Figure 47) highlights the international landscape for hydrogen production and demand, and identifies at a high level how Canada could explore serving these markets through export channels. Provincial and local leadership will be needed to develop identify and invest in developing strategy export hubs for Canadian hydrogen.

[1] The Federal Ministry for Economic Affairs and Energy, Germany. The National Hydrogen Strategy. June 2020.

[2] https://www.portofrotterdam.com/en/doing-business/port-of-the-future/energy-transition/hydrogen-in-rotterdam

[3] BC Hydrogen Study, Zen and the Art of Clean Energy Solutions Inc., 2019

Figure 47 – Canada's Potential as Hydrogen Exporter[1]

[1] Based on data and maps from BloombergNEF Hydrogen Economy Outlook. March 2020

ENABLERS

Innovation and Intellectual Property Leadership

Canada is recognized as a global leader in the hydrogen and fuel cell sector, seen as a hub for technical expertise, intellectual property, and leading products and services. In 2018, the industry generated revenue of $207 million and was responsible for 2,177 jobs[1]. According to a survey conducted by the Canadian Hydrogen and Fuel Cell Association in 2017, 86% of respondents' hydrogen and fuel cell facilities were located in Canada with BC, Ontario, Quebec and Alberta home to some of the largest industry clusters as shown in Figure 48.

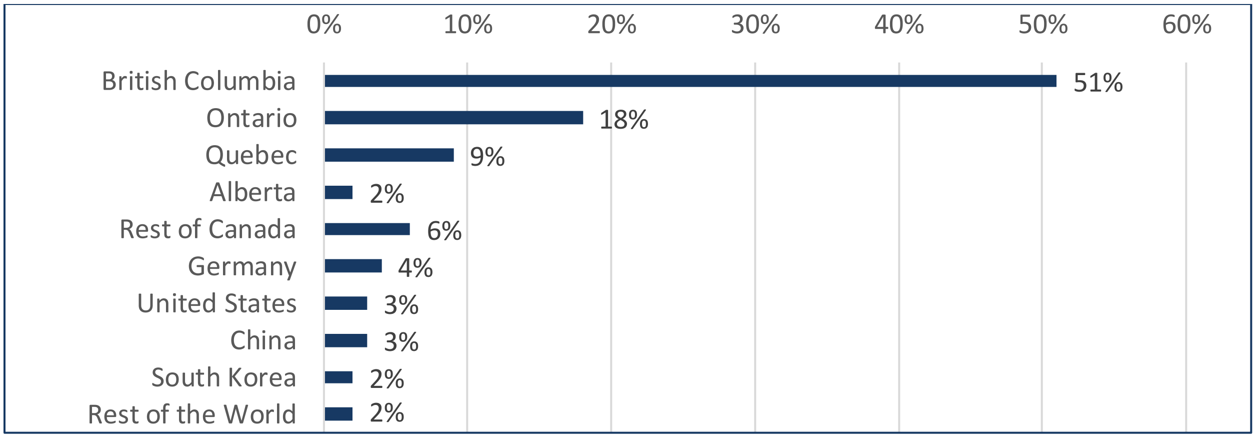


Figure 48 – Hydrogen and fuel cell facilities by region

Canadian companies, educational institutes, government agencies, and NGOs are involved with hydrogen and fuel cells across a range of sectors and areas of expertise from fundamental scientific research through to aftermarket sales and services. Many of these organizations have been involved with hydrogen and fuel cells for multiple decades and have strong interconnections and shared talent pools.

Domestic deployments will help Canadian companies across the value chain, both in providing a local market for their goods and services, and also by serving as local reference projects opportunities for Canadian companies looking to export products, services, or IP into international markets. A common theme heard from cleantech stakeholders is that international partners ask to see local reference projects to validate technology readiness and the business case.

Canadian companies in the sector are today generally relying on export markets to grow their business, given the relatively small Canadian market to date. Due to Canada's technology leadership, lead companies have attracted significant foreign investment, and international companies have set up shop in Canada to be able to leverage the local trained talent pool. This sector will continue to grow economic value for Canada, provide jobs, and attract foreign investment provided technology and innovation leadership is maintained.

Canadian companies in the hydrogen and fuel cell space are currently recognized as technology and product leaders, and today heavily rely on international sales of services and products to regions leading in hydrogen adoption. These companies will benefit from a growing domestic hydrogen economy, and can also grow from increased international sales as Canada builds on the opportunities outside our

[1] CHFCA. (2018). Canadian Hydrogen and Fuel Cell Sector Profile. Retrieved from http://www.chfca.ca/wp-content/uploads/2019/10/CHFC-Sector-Profile-2018-Final-Report.pdf

borders for the growing hydrogen sector. Canadian reference projects will validate the strengths and business case for Canadian products, facilitating international sales.

Staying at the forefront of innovation is critical to sustaining Canada's competitive advantages, and Canada is at risk of losing ground. Other countries have been heavily rapidly increasing investment in the sector whereas Canada has, in recent years, slowed investment in fundamental research. As a result, there have been examples of Canadian companies moving operations to other countries where there is more support for technology advancement. It is important for Canada to act now to prevent loss of critical IP.

Stakeholder engagement highlighted areas in which Canada can excel in hydrogen innovation. Canada already has a leading fuel cell sector with expertise ranging from fundamental materials to complete systems and vehicles. Building on these strengths to maintain leadership should be a key area of focus. As Canada transitions to deployment, there are opportunities for innovative solutions in hydrogen production technologies, as well as important complementary technologies such as CCUS and hydrogen storage unique to Canada's geology, such as use of depleted wells for both carbon storage and hydrogen storage either as a blend or pure fuel. Canada can also develop expertise in engineering and integration using deployment HUBs to strengthen local skills. Deployment HUBs also present an opportunity to nurture skills development and training, to ensure workers and communities are equipped with the skills needed to succeed in a clean energy future. In this way, Canada can showcase how, youth, women, Indigenous peoples, and other underrepresented Canadians can become the backbone of a low-carbon economy, through focused efforts from industry and governments.

Storage Technologies

Hydrogen storage and transport from production hubs to users' sites will be one of the more challenging obstacles for the large-scale global adoption of hydrogen. Liquefaction and chemical storage, in the form of chemical carriers such as ammonia or liquid organic hydrogen carriers, in particular will need to be developed to enable the safe and cost-effective transport of hydrogen from Canada to export markets around the world. Canada is currently investing in large scale Liquefied Natural Gas (LNG) infrastructure including seaports and liquefaction facilities that could potentially be adapted for hydrogen.

As countries develop hydrogen import strategies, it is expected that emissions from both production and transportation will be considered in the overall lifecycle analysis to determine decarbonization potential as an important decision metric. Canada will need to participate in international R&D related to transportation technologies if bulk export is deemed to be a strategic priority in the export roadmap.

Standards and Regulations

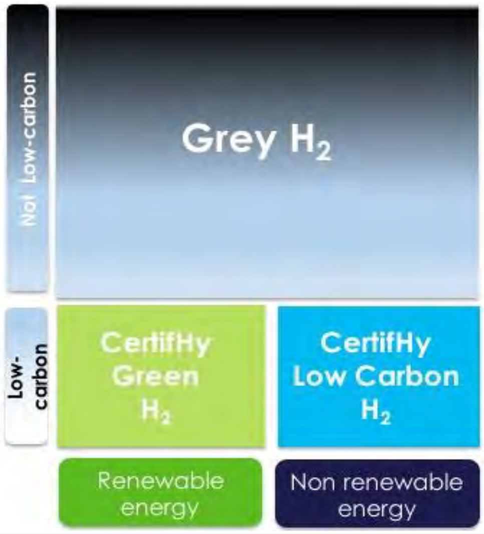


Figure 49 – CertifHy Green and Low Carbon Hydrogen Definitions

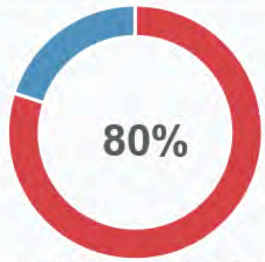
Other countries are also pursuing the same export markets and Canada will need strong policies and investments to remain competitive. The Canadian hydrogen industry will need to be integrated with export markets in terms of codes and standards, carbon intensity tracking, and renewable gas standards. Of particular importance is how other countries will value hydrogen produced from fossil fuel and non-renewable feedstocks. For example, the European CerifHy[1] Guarantee of Origin initiative label both the carbon intensity and the source of the hydrogen, distinguishing between renewable energy origins and non-renewable energy. Given Canada is focusing on all sources of low CI hydrogen, it will be important for Canada to participate in these types of activities. Branding and promoting Canada's low carbon fuels will be important to gain market acceptance. Branding and claims will need to be backed by certified lifecycle analysis.

[1] https://www.certifhy.eu/project-description/certifhy-1.html

STAKEHOLDER INPUT: CLEANTECH & INNOVATION

Opportunities

- *Canada has been a pioneer in fuel cell technology for more than 40 years and is home to some the world's leading hydrogen companies*



- *Canadian fuel cell technology is used in over 80% of applications worldwide and Canada has a global IP leadership*

- *The global market for hydrogen could be worth between $2.5T and $11.7 in 2050 and employ 30M people*

Challenges

Decline in research and development has impacted Canada's early lead in innovation

Larger countries investing heavily in national research programs has pulled talent and IP away from Canada

Lack of domestic deployments means no local market and no 'living labs' to spur collaboration & innovation

Investors in Canadian companies need to be able to see examples of technology deployments domestically

Findings

- *Establish domestic deployment hubs that highlight local technology, and encourage cross sector and international collaborations*
- *Time is of the essence. Need to quickly accelerate development and support multi-year research priorities or Canada will lose innovation edge*
- *Targeted technical research in strategic areas is needed in near term to inform the development of codes and standards and commercialization of cross-cutting H_2 technology applications.*
- *Encourage mission-oriented approaches to focus research, development and demonstration (RD&D).*

7. Remaining Challenges

Canada has a strong head start in hydrogen and fuel cells and is well positioned to realize the opportunities offered by a vibrant domestic and export hydrogen economy. However, there are challenges we must work to overcome. With global competition increasing, targeted actions across the hydrogen value chain are needed to overcome these challenges and position Canada for success.

ECONOMIC & INVESTMENT

The factors limiting hydrogen use in many applications today are economic rather technological, as hydrogen is not yet cost competitive compared to conventional fuel options. For example, hydrogen used as a carbon-free heating fuel is ~5X more expensive than natural gas. While hydrogen can be cost competitive with some RNG sources, conventional natural gas is typically used as the benchmark. Hydrogen can be among the lowest cost alternatives for reducing carbon emissions on a dollar-per-tonne-abated basis. A challenge today is that GHG emissions are not always adequately reflected in the market cost of baseline fuels. Implementation of the federal Clean Fuel Standard as well as carbon pricing, will be important steps forward.

Achieving scale is also critical to economic competitiveness of the sector and to ensuring access to an affordable and abundant source of clean hydrogen. The market for low CI hydrogen in Canada is in the very early stages, and the large capital investment to scale production requires that demand grow concurrently with supply. Predictable, long-term demand is therefore critical before industry can invest in large-scale projects.

Costs of end-use applications are also a barrier to adoption, which can limit demand and associated scale. In transportation applications, FCEVs are more expensive than BEVs and PHEVs, due to low production volumes. Further work is also needed to drive down core fuel cell stack, balance-of-plant, material and manufacturing costs, as well as other vehicle speciality component costs such as hydrogen storage tanks. Investment in R&D is needed to achieve cost parity with alternatives, as is investment in manufacturing processes and facilities to achieve scale. Build out of refueling infrastructure also requires high upfront capital investment. For light duty FCEVs, multi-station refuelling networks providing accessibility and redundancy must be established before OEMs will deploy larger numbers (100s) of vehicles. This is an economic challenge for station developers who are required to make significant capital investments with uncertainty in fueling demand growth over time. For transit agencies looking to deploy FCEBs, the upfront infrastructure costs are high, and makes running early pilot deployments a challenge. While at-scale hydrogen infrastructure has been proven to be very cost effective, getting to scale is a challenge for transit agencies that are cash constrained and risk adverse.

Some applications, such as using hydrogen blended with natural gas as a heating fuel, do not require new or retrofit end-use equipment. However, the economic challenge is that, as described above, the incumbent fuel is very low cost. In addition, utilities will need to make investments in pilot projects and codes and standards development to develop this market.

While the sector must ultimately be self-sustaining, temporary support is needed in the next 5-10 years to attract and de-risk industry investment. This includes through investments in foundational infrastructure and subsidies to encourage end-use adoption and drive to scale up. Attracting investment from international sources will also be important..

TECHNOLOGY & INNOVATION

While some hydrogen and fuel cell technologies are at a level of commercial readiness, sustained support for R&D is needed to further reduce costs, develop solutions in the less mature applications, and discover new breakthrough technologies to benefit the sector. Current short term funding cycles in R&D may limit private sector investment in Canadian innovation. Commitment to support long term R&D for advanced technologies is therefore a current policy gap. Continuing to stay at the forefront of innovation is critical to sustaining Canada's competitive advantages.

Other countries have been rapidly increasing investment in the sector whereas Canada has, in recent years, slowed investment in fundamental research. Canada is also lagging other countries in starting hydrogen pilot projects. As a result, there have been examples of Canadian companies developing research centres and/or moving parts of their operations to other countries where there is more support for technology advancement. It is important for Canada to take action now to prevent loss of critical IP.

Technology development and innovation are needed for core materials, end-use products, as well as in the hydrogen production, storage and distribution value chains. Adjacent and complementary areas such as CCUS will also be critical to Canada's leadership in the sector. Technology development and innovation require local deployments to foster collaboration between industry, academia and international partners. Critical hands on experience can be gained to understand market needs and develop practical and commercially ready solutions. Canada's lack of domestic deployments is currently hampering innovation in the sector.

POLICY & REGULATION

Clean hydrogen projects around the world have primarily been in regions with a combination of supporting policies, regulations, and GHG reduction targets.

There is currently a lack of comprehensive, long-term policy and regulatory frameworks that include hydrogen in Canada. Where policies are in place they, are not consistent across regions resulting in a 'patch-work' approach that slows adoption. Achieving long-term 2050 targets represents a radical transformation of the energy sector and requires clear, coordinated efforts.

Policies and regulations that encourage the use of hydrogen technologies include low carbon fuel regulations, carbon pollution pricing, vehicle emissions regulations, zero emission vehicle mandates, creation of emission-free zones, and renewable gas mandates in natural gas networks. Mechanisms to help de-risk investments for end-users to adapt to regulations are also needed.

A more cohesive national framework with a common vision could provide a clear signal of the importance of hydrogen and avoid a patchwork of policies and regulations across jurisdictions.

HYDROGEN & INFRASTRUCTURE

Domestic supply of low CI hydrogen is limited in many parts of Canada today, and this is preventing both commercial and pilot rollout of end-use applications. For some applications, there is also a need to transport and store hydrogen from the site of production to the end-user. This includes refueling infrastructure for transportation applications. Build out of supply and distribution infrastructure must be timed concurrently with growth in demand, and this can be difficult to coordinate and requires a regionally focused development approach.

Other challenges related to infrastructure include the significant carbon storage requirements for long-term transition of the petroleum and low carbon fuels sectors, as well as the storage of high volumes of hydrogen for integration at existing nuclear sites. Geological storage, such as in depleted wells and salt caverns, will be limited to certain regions, and also require high up-front investment to be validated for hydrogen storage.

Over time, as domestic production and demand grow, there will be a need for dedicated infrastructure such as hydrogen pipelines and liquefaction plants. Ensuring that these crucial assets can be built, in a coordinated and timely manner, will be essential to ensuring low cost, low CI hydrogen can be delivered to both domestic and international markets.

CODES & STANDARDS

The deployment of hydrogen is in the early stages across many jurisdictions and sectors in Canada, and there are some gaps in existing codes & standards that need to be addressed to enable adoption.

Complex local and regional issues related to the certification of new hydrogen deployments may take significant time and effort to resolve. Harmonizing codes and standards across jurisdictions (provincial and international) will ensure that best practices are applied across the domestic and international hydrogen economy to facilitate the growth of trade and export markets.

Applications that have not yet been piloted in Canada and are in the precommercial stage represent important areas of focus. For example, blending of hydrogen into natural gas systems has been demonstrated around the world in numerous power-to-gas projects. Lack of developed and adopted codes and standards in Canada related to this end-use application is currently one of the main rate limiting steps.

Canada is also working with countries around the world to develop and align codes and standards, through efforts like the Canada/US Regulatory Cooperation Council. These efforts also include developing and aligning common methodology to determine the CI of hydrogen production pathways.

AWARENESS

There is currently a lack of awareness about the opportunities for hydrogen and around safety issues, both by the public, as well as within industry and government.

Limited domestic hydrogen deployments have further resulted in a lack of tangible case studies to increase awareness and support long-term planning and buildout. For example, mine safety and reliability must be successfully proven in the pilot stage before technology can be fully adopted.

Increased awareness about hydrogen as a viable decarbonization pathway that is safe and provides economic benefits is critical to establishing a vibrant hydrogen sector. Targeted awareness campaigns in certain industry sectors, including providing easy tools for end-users to evaluate hydrogen options, will be an important step in supporting adoption.

There is currently a lack of awareness regarding how hydrogen fits with other decarbonizing energy vectors in a net-zero future. While deployment of hydrogen and increasing electrification are in fact highly complimentary, perceived competition may limit adoption. This must be addressed with a targeted awareness campaign to show how these applications can work together.

In addition to the need for awareness of the opportunities for hydrogen and around safety issues, there is also the need for targeted awareness of the career opportunities for talented and skilled labour in the hydrogen economy. This includes the transition of mid-career workers and the training of the next generation of workers to the low carbon technology sector.

8. Seizing Canada’s Hydrogen Opportunity

Canada’s hydrogen opportunity is substantial. Canada has all the right ingredients and comparative advantages to develop a robust and thriving domestic hydrogen market. Canada’s resources are suited to producing vast amounts of clean, cost competitive hydrogen that can decarbonize our hard-to-abate end-use sectors from coast to coast. Deployment of hydrogen will lead to economic, environmental, and health benefits for Canadians, and will support Canadian companies at the forefront of the hydrogen and fuel cell sectors. While the immediate priority is on establishing at-scale domestic rollout of hydrogen, the opportunities for export of Canadian hydrogen, as well as products, services, and intellectual property also shows strong potential driven by growth in the worldwide demand for hydrogen.

The *Vision for Hydrogen in Canada in 2050* shows the magnitude of the hydrogen opportunity in Canada. If we embrace hydrogen as a strategic and necessary element of Canada's transition to a more inclusive and equitable clean energy future it can play a pivotal role in helping us achieve net zero by 2050 while maintaining the affordability, reliability and sustainability of Canada's energy supply. Aligning around a common vision is critical to setting us on the right path now.

The *Roadmap to 2050* outlines actions in the next 5 years to lay the foundation for the domestic hydrogen rollout in Canada, grow and diversify the sector in the mid-term, and achieve rapid market expansion in the long-term.

The time to act is now, and the release of this strategy is just the starting point. A set of eight recommendation pillars with specific actions are outlined as guidance for the various committees, working groups, and government and industry players who will together move this forward through the implementation plan.


VISION FOR HYDROGEN IN CANADA IN 2050
Fueling network across Canada
>5 million Fuel Cell Electric Vehicle
H_2
20 Mt H_2 and 30% of Canada's energy system
>50% H_2 in NG pipeline and dedicated H_2 pipelines
New industries enabled by low-cost hydrogen
Up to 190 Mt CO_2e annual GHG reduction
CO_2
H_2
Large distributed domestic supply of low-cost, clean hydrogen: $1.50–3.50/kg
Canadian H_2 Sector revenue > $50B
One of top 3 global clean hydrogen producers
Economic growth with > 350,000 sector jobs

ROADMAP TO 2050

Near-Term: Laying the Foundation

The focus of the next 5 years will be on laying the foundation for the hydrogen economy in Canada. This includes developing new hydrogen supply and distribution infrastructure to support early deployment HUBs in mature applications while supporting Canadian demonstrations in emerging applications. Early actions are fundamental to driving investment in the sector, as is the introduction of policies, such as carbon pricing and regulatory measures needed to move Canada forward on a path to achieve net zero targets. Regulations such as the Clean Fuel Standard will be fundamental to driving near-term investment in the sector, in addition to introducing new policy and regulatory measures that will advance Canada to achieve net-zero emissions by 2050. To achieve medium- and long-term goals, innovation investment must be made early. Early stage, 'breakthrough' R&D can take 5-10 years to realize and may require additional work to fully mature. Even later stage support for process efficiency or cost reduction can take several years, followed more time for piloting and demonstration.

Canada's petroleum sector is a major driver of investment, with $52 billion in 2019. Despite the oil price downturn and uncertainty over the COVID-19 recovery, an opportunity exists for government to partner with industry to drive commercial hydrogen projects as part of the sector's net-zero agenda. Similarly, the chemical industry can move to adopt clean hydrogen as a feedstock with government involvement.

Emerging hydrogen use in the near-term will be dominated by mature market applications at or near commercial market readiness including oil and gas upgrading, ethanol plants and landfill gas/biogas-to-RNG upgraders, forklifts, light-duty FCEVs, and FCEBs for transit operation. Pre-commercial applications such as heavy-duty trucks, seaport goods movement equipment, power generation, heat for the built environment, and industrial feedstock applications will be introduced as pilot projects in regional HUBs.

These regional HUBS will be strongly influenced by:

- Regulatory approvals for blending hydrogen and natural gas to decarbonize the utility distribution system.
- Availability of technical evidence from pilots to inform the safe integration of fuel cells into domestic regulatory regimes, i.e. Railway Safety Act, Motor Vehicle Safety Act.
- The best form of renewable gas in a regional context, i.e. the best use for hydrogen, RNG and biogas.
- Zero-Emission Vehicle mandates for passenger vehicles such as the existing legislation in Quebec and British Columbia.
- Variances in CFS compliance plans that will drive low carbon hydrogen generation for industrial applications including the upgrading of transportation fuel products.
- Existing hydrogen generation, distribution and dispensing infrastructure that can be leveraged e.g. liquefaction capacity in Quebec, or steam methane reforming with carbon sequestration in Alberta.

Mid-Term: Growth and Diversification

Activities to stimulate the sector in the next 5 years will be followed by growth and diversification of the sector in the 2025 – 2030 timeframe. Early deployment HUBs will grow and new ones will be initiated, connected by corridor infrastructure. In order to reach the opportunities outlined in the 2050 Transformative scenario, Canada should aim to be 10-20% of the way there by 2030 in terms of deployment volumes and GHG abatement.

As the technology matures and the full suite of end-use applications is at or near commercial technology readiness levels, hydrogen use in the mid-term will be focused on applications that provide the best value proposition relative to other zero-emission technologies. For example, fuel cell electric vehicles and transit buses will enter the rapid expansion phase as the market for fuel cell and battery technology becomes more defined. Fuel cells will gain traction where charging times, energy requirements, range, grade ability, and operation in extreme climates make battery technology technically challenging for specific market segments. Class 8 heavy-duty trucking in corridors that require heavy payloads and drayage equipment in regions with regulated air sheds will be commercially deploy.

New, larger scale hydrogen production in the mid-term will allow hydrogen/natural gas blending for industry, the built environment and as a feedstock for chemical production and hydrocarbon upgrading to be commercialized in regional HUBs. Clean large-scale hydrogen production in the upstream segment of the oil and gas sector will provide low cost hydrogen at volumes that can benefit other sectors.

Deployment in pre-commercial applications like Class 5-7 delivery trucks, operating in urban zero-emission zones, passenger and freight rail where gantry infrastructure needed to electrify the line is prohibitively expensive, mining vehicles and smaller domestics marine vessels continues to grow. Similarly advancement and growth in liquid synthetic fuel and methanol production, can be expected.

A regulatory framework and market ready technologies are expected to enable deployment of hydrogen in mining operations in a variety of good movement and stationary power applications. As increasing renewables are introduced into electricity grids, pilots to explore hydrogen as a utility scale energy storage medium will be required.

Long-Term: Rapid Market Expansion

In the 2030-2050 timeframe, Canada will start to realize the full benefits of a hydrogen economy as the scale of deployments increase and number of new commercial applications grows, supported by Canada's foundational backbone supply and distribution infrastructure.

In the long-term, it is anticipated that with advances in battery and charging technology there will be a more defined division between battery and fuel cell utilization in Canada for transportation purposes. This will result in the higher power demand applications (utility biased) predisposed toward hydrogen energy storage and the lower power demand applications (efficiency biased) using batteries for energy storage. New transportation applications will move into the commercial and rapid expansion phases during this period.

As the percent of hydrogen in NG systems increases, dedicated hydrogen pipelines will become an attractive alternative.

As low CI hydrogen is more widely available throughout Canada, existing heavy emitting industries will be able to adapt their operations, including, ammonia and nitrogen fertilizers, and low carbon steel.

	NEAR-TERM (2020-2025) *Laying the Foundation*	MID-TERM (2025-2030) *Growth & Diversification*	LONG-TERM (2030-2050) *Rapid Market Expansion*
HYDROGEN PRODUCTION — *Carbon Intensity*	<36.4 gCO_2e/MJ		***Decreasing*** *over time*
Renewable Threshold in Government Supported Projects	>33%		***Increasing*** *over time*
Cost of Delivered Hydrogen	$5.0 – 12.0/kg		$1.5 – 3.5/kg
DISTRIBUTION+ STORAGE — *Gaseous Hydrogen*	250 bar	450+ bar	450+ bar
Liquid Hydrogen	East Coast	Canada Wide	Canada Wide
Pipeline	H_2/NG Blended	Blended + Dedicated H_2	Blended + Dedicated H_2
Geological Storage			Salt Cavern
END-USE — *Commercial* / *Pilot*			New industry spinoffs
REGIONAL HUB	Regional high profile hub development incorporating full value chain at scale	Hub expansion, corridor connections, and new hub initiations	Full Pan–Canadian rollout and inter-provincial trade + and cooperation
RD&D	Sustained RD&D in advanced materials, hydrogen production and storage technologies, CCUS, and end-use applications		
ACHIEVEMENTS — *Hydrogen Production*	3 Mt/year (high CI)	4 Mt/year (low CI)	20 Mt/year (low CI)
% of Overall Energy Delivered by Hydrogen	1.6%	6.2%	30%
GHG Reduction		Up to 45 Mt	Up to 190 Mt

TIME TO ACT

The time for Canada to act is now. Governments around the world are developing plans for green and inclusive energy recoveries while releasing and executing hydrogen strategies that are building global momentum. In 2019 Canada seized this momentum by developing and launching a new Hydrogen Initiative under the Clean Energy Ministerial, designed to be the cornerstone for global hydrogen deployment. Now, one year later, Canada is poised to again leverage this momentum to grow the domestic opportunity for hydrogen production and end-use, while also benefitting from growth in global demand.

Although the COVID-19 pandemic has shaken all sectors of the economy, the recovery also presents a unique opportunity to build back better to advance a greener and more equitable energy future. The International Energy Agency has recommended that governments put clean energy solutions such as hydrogen at the heart of stimulus plans. Green infrastructure investments are key to achieving the post-pandemic economic recovery, clean growth, and climate change commitments of the Canadian Federal Government. Recovery from the economic impacts of COVID-19 will take many years. Stimulus funding may represent a unique and critical investment opportunity for the foundational infrastructure and skills need to support the sector. If the opportunity is wasted, Canada risks losing its competitive head start as austerity measures kick in during the anticipated recovery period.

Recommendations

Recommendations have been developed in consultation with stakeholders and represent actions needed to lay the foundation for maximizing the benefits of hydrogen in Canada's future energy system mix. These recommendations will inform development of concrete action plans in the implementation phase immediately following the release of this strategy. The recommendations in this section represent sector-wide themes. Recommendations have been proposed in eight pillar areas:

- ***Pillar 1: Strategic Partnerships*** *- Strategically use existing and new partnerships to collaborate and map out the future of hydrogen in Canada.*

- ***Pillar 2: De-Risking of Investments*** *- Establish funding programs, long-term policies, and business models to encourage industry and governments to invest in growing the hydrogen economy.*

- ***Pillar 3: Innovation*** *- Take action to support further R&D, develop research priorities, and foster collaboration between stakeholders to ensure Canada maintains its competitive edge and global leadership in hydrogen and fuel cell technologies.*

- ***Pillar 4: Codes and Standards*** *- Modernize existing and develop new codes and standards to keep pace with this rapidly changing industry and remove barriers to deployment, domestically and internationally.*

- ***Pillar 5: Enabling Policies and Regulation** - Ensure hydrogen is integrated into clean energy roadmaps and strategies at all levels of government and incentivise its application.*

- ***Pillar 6: Awareness** - Lead at the national level to ensure individuals, communities, and the private sector are aware of hydrogen's safety, uses, and benefits during a time of rapidly developing technologies.*

- ***Pillar 7: Regional Blueprints** - Implement a collaborative, multi-level, collaborative government effort to facilitate the development of regional hydrogen blueprints to identify specific opportunities and plans for hydrogen production and end use.*

- ***Pillar 8: International Markets** - Work with our international partners to ensure the global push for clean fuels includes hydrogen so Canadian industries thrive at home and abroad.*

A series of four concrete actions and rationale are provided for each of the eight pillars in the following section.

Pillar 1: Strategic Partnerships

1. *Collaborate across multiple levels of government and with Indigenous groups through Intergovernmental Working Groups to establish priority areas for deployment and to share knowledge, best practices, and lessons learned through early deployments.*
2. *Expand public/private partnerships leveraging Canada's innovative clean technology companies and world-leading hydrogen and fuel cell expertise to accelerate deployment projects across the value-chain.*
3. *Foster cross-sector collaborations within regional deployment HUBs to show the economic and operational benefits of multiple applications operating as part of an integrated ecosystem.*
4. *Leverage international collaborations and pursue synergistic international initiatives to attract direct foreign investment and to accelerate opportunities for Canada in global markets.*

Rationale

Hydrogen is an energy vector that crosses geographical boundaries, ties energy systems such as the electricity and natural gas grids together, and whose benefits are best demonstrated in integrated deployments that span multiple end-use applications. Stakeholders identified that better information sharing and collaboration across regions and sectors is needed to develop Canada's hydrogen economy. Strategic partnerships are needed across levels of government and regions, between the public and private sector, with Indigenous groups, across industry sectors and academia, and with international partners.

Coordination across all levels of government will be essential to align policies and programs and identify areas for collaboration. Coordination of this type is best carried out through an intergovernmental working group. Similarly, to ensure the unique perspectives, needs, and priorities of Indigenous groups are fully represented, a dedicated Indigenous working group could be considered.

Government and industry must work closely together, with each playing important but distinct roles and each bringing resources, expertise, and perspectives to the table. Strategic partnerships between governments and industry are also essential in successfully growing domestic hydrogen deployment. Early adoption is likely to occur in areas which bring together governments, fuel producers, end-users, and other key players, in a HUB concept, which ensures supply and demand grow together.

High profile domestic deployment HUBs or 'lighthouse projects' will be important to show the business case for hydrogen at scale. These early domestic deployment HUBs should be encouraged to include pan-Canadian participation where practical, and to include targeted outreach activities and information sharing. Initiation of these projects has already started with many 'shovel-ready' projects proposed as green stimulus recovery initiatives.

Canada cannot do this alone. While Canada demonstrated early leadership in both hydrogen and fuel cells, activity and investment in hydrogen has been accelerating around the world with other nations developing comprehensive plans for their own domestic and export markets. Canada can learn from international partners as well as help grow international trade opportunities by sharing learnings from domestic activities. International partnerships will range from government collaborations on policy approaches, to research collaborations in shared areas of interest, to participation in international codes and standards development, to the development of trade opportunities. International partnerships can be facilitated through the Hydrogen Initiative with International Energy Agency as Operating Agent, as well as Canadian Trade and Investment support channels.

Pillar 2: De-Risking Investments

5 *Implement long-term policies that create hydrogen demand certainty and de-risk the private sector investments needed to establish supply and distribution infrastructure.*

6 *Establish multi-year programming as well as a clear and long-term regulatory environment to support early production and end-use projects, including support to assess the feasibility of projects.*

7 *Develop regional deployment HUBs to demonstrate, validate, and implement business cases across the full value chain, from production and distribution to end-use.*

8 *Facilitate co-funding opportunities, leveraging multiple levels of government and the private sector.*

Rationale

It is estimated that $5B - $7B of combined public and private investment will be needed in the five years to lay the foundation of a strong national hydrogen economy that will maximize emissions reductions and provide long-term economic growth for the sector. Attracting this magnitude of investment from domestic and international sources requires actions across several fronts to de-risk investments.

Governments at all levels, as well as private sector stakeholders will all have a role to play in de-risking these investments.

Long-term policies such as the federal Clean Fuel Standard (CFS) and carbon pricing are important steps toward creating an environment of higher certainty for investors. The CFS could recognize hydrogen as a pathway to reduce the CI and resulting credit burdens on conventional fuels. The CFS could also provide credit generation and financing opportunities for projects that generate clean hydrogen. While the CFS does not preclude these pathways, there is an opportunity to be more explicit in how hydrogen can be considered as a compliance mechanism.

Long-term government climate policies like carbon pricing that reflect the externalities of climate change, air pollution, related health issues, and energy security can also provide a signal to stimulate investments. Governments can also provide market certainty by leading through example with strong procurement policies. This has been successful in Quebec where the provincial government's procurement of FCEVs in Quebec City spurred the buildout of fuelling infrastructure by industry.

Tax deductions to corporate, institutional, and individual investors made in the cleantech space is another mechanism to de-risk and attract investments, as is expanding the 100% accelerated capital cost allowance to all cleantech investments including those in hydrogen.

The market for low CI hydrogen in Canada is in the very early stages. While the sector must ultimately be self-sustaining, temporary fiscal support to de-risk investments across the value chain is needed in the next 5-10 years, while the market matures.

Canada can learn from other regions like California, where established multi-year funding commitments have been effective. For example, the California Energy Commission provides funding for hydrogen infrastructure build-out in conjunction with a Low Carbon Fuels Standard program that offers capacity payments to provide revenue certainty while demand for hydrogen grows.

Funding models should evolve over time. In the early stages resources could support projects that span the entire value-chain, both through regional deployment HUBs and large-scale projects. Considerable up-front work is required to develop complex projects of this nature, from a technical and economic perspective, before domestic projects can move into the implementation phase. Support for feasibility studies should be considered as an essential first step in project development.

Pillar 3: Innovation

9. *Develop strategic fundamental research priorities where Canada can sustainably excel and provide economic value; set technology performance and cost goals.*

10. *Establish dedicated funding for sustained RD&D to ensure Canada retains its leadership position in hydrogen and fuel cell technologies.*

11. *Leverage expertise in academia, government labs, and private sector labs to create regional research hubs and to encourage mission-oriented approaches to research, development, and pilot deployments.*

12. *Foster collaboration between Federal labs, industry, and academia as well as international partners, by supporting consortium-based projects for fundamental research and by coordinating reviews and information sharing.*

Rationale

Canada was an early leader in the hydrogen and fuel cell sector and is recognized worldwide as a region for technical expertise, intellectual property, and leading products and services. While some hydrogen and fuel cell technologies are at a level of commercial readiness, support for RD&D is needed to further reduce costs, develop solutions in the less mature applications, and discover new breakthrough technologies. Continuing to stay at the forefront of innovation is critical for sustaining Canada's competitive advantage. Other countries have been rapidly increasing investment in the sector, and Canada's leadership role is in jeopardy. As a result, there have been examples of Canadian companies developing research centres and/or moving parts of their operations to other countries where there is more support for technology advancement. It is important for Canada to act now to prevent loss of critical IP and cleantech jobs.

Canada already has a leading fuel cell sector with expertise ranging from fundamental materials to complete systems and vehicles. Building on these strengths by identifying priority areas, in consultation with industry and academic stakeholders, where Canadian researchers can excel will be essential to maintain leadership. Canada also has complementary technologies such as CCUS and hydrogen storage which are unique to Canada's geology. Canada can also leverage existing expertise in engineering and systems integration using deployment HUBs to strengthen local skills and knowledge while promoting a more diverse and inclusive workforce.

A mission-oriented approach would set a clear direction and align the efforts of participants across the energy ecosystem, while using the full range of government instruments to generate investments and innovation across the economy.

Funding for advanced research and development must come from both the public and private sector. Stakeholders identified gaps and limitations such as how much Canadian government funding can be used as "match funding" on international collaboration projects.

Collaboration across federal labs, industry, and academia is ultimately needed to both drive innovation and to develop the next generation talent pool in the sector. Canada has seen talent being recruited by other regions and efforts are needed to fight the "brain drain". Without top talent, innovation will slow. To attract new young talent to the sector, students must be able to see a linkage to industry opportunities and this can be facilitated through industry/academia collaborations, through industry sponsored student competitions, as well through internships and co-op placements. A Canadian mechanism to establish targets and priority areas modelled after the U.S. DOE's Multi-Year Research, Development, and Demonstration Plan could be used to provide guideposts to drive towards common goals. Reviews to track progress and share information could be coordinated in an annual merit review type format.

Canadian expertise in hydrogen technology development, both within academia, and in the private sector, is recognized around the world. Sustained resources to support innovation will also enable Canadian researchers to build and strengthen collaboration internationally. International collaborations will ultimately accelerate hydrogen deployment both at home and abroad.

Pillar 4: Codes and Standards

13 *Update, harmonize and recognize codes and standards (including the Canadian Hydrogen Installation Code) to enable deployments and to facilitate new technology and infrastructure adoption in early markets.*

14 *Establish a codes and standards working group, which includes inter-provincial Authorities Having Jurisdiction representatives, to share lessons learned and identify gaps in codes and standards.*

15 *Develop standards that are performance based versus prescriptive, and ensure hydrogen is not excluded from broader codes, standards, and regulations due to restrictive language.*

16 *Facilitate Canadian leadership and participation on international standard and certification efforts (e.g. development of global carbon intensity metrics, blending levels for hydrogen in natural gas systems), simplifying international trade.*

Rationale

Deployment of hydrogen technologies, including fuels cells, and refueling infrastructure, is in the early stages in many parts of Canada. It is important that codes & standards are in place that support deployment, and keep pace with new technology and innovation. Wherever possible, these standards should be performance-based rather than prescriptive to ensure that innovation is not restricted in this emerging sector.

Canada has a mature and effective standardization framework led by the Standards Council of Canada, and national standards development organizations (SDOs) like the Bureau de Normalization du Québec (BNQ) and CSA Group. However, these organizations are dependent on resources, and subject area expertise from industry and governments, to facilitate their work.

One of the foundational pieces in Canada is the Canadian Hydrogen Installation Code (CHIC) which sets the installation requirements for equipment that produces, uses or dispenses hydrogen. Although the CHIC was first of kind globally when it was developed in 2010, it has not been kept up to date, to include the most recent advancements and understanding. This has forced domestic hydrogen deployment activities to reference more recent codes from other jurisdictions internationally. This difference between established industry practices and the national code has led to inconsistencies in how Authorities Having Jurisdiction (AHJ's) recognize certify hydrogen projects across the country. While an updated version of CHIC is currently being finalized, going forward more timely updates to the code and recognition/implementation by the Provinces will be essential to facilitating the installation and operation of new hydrogen equipment in Canada.

As one of the key applications for hydrogen, the decarbonization of natural gas requires regulatory changes within the provinces to allow the use of hydrogen in natural gas distribution and transmission networks. These regulatory changes (e.g. expanding the definition of renewable gas) will be underpinned by detailed technical codes and standards, for example for material compatibility, design, testing, for key system components.

The revision, development, and adoption of key codes and standards is an essential component to enable Canada to seize the hydrogen opportunity. This work will require a coordinated effort between industry, the SDO's, national testing laboratories, and the Provincial and Federal governments, as well as Authorities Having Jurisdiction. As part of the implementation plan, it is recommended that a dedicated codes and standards working group be formed that includes industry across the value chain, SDO's, national testing laboratories, academia and the Provincial and Federal governments. Working group members should work through a Standardization Collaborative to clearly identify gaps in Canada's hydrogen codes and standards, and to develop a prioritized action plan to close gaps. As broader codes and standards are developed (e.g. definition of RNG in natural gas networks), it will be important to establish performance based standards that do not exclude hydrogen.

One of the most effective ways to accelerate domestic adoption of hydrogen is to focus on harmonizing Canadian standards with international requirements for safety, performance, and reliability, especially in jurisdictions where Canadian suppliers are working extensively. Harmonized standards allow Canadian companies to support multiple markets with the same equipment design, avoiding costly customization, unnecessary certification testing, and potential barriers to market entry.

Pillar 5: Enabling Policies and Regulations

17 *Ensure that governments at all levels consider hydrogen's essential role in Canada's energy future as they develop new policies, programs, and regulations.*

18 *Encourage governments to modernize and update existing policies, programs, and regulations to facilitate growth of domestic hydrogen production and end-use.*

19 *Ensure hydrogen is part of integrated clean energy roadmaps at national and provincial/ territorial levels.*

20 *Establish technology-neutral, performance-based standards to define a hydrogen carbon-intensity threshold. Establish tiered, time-based requirement for renewable hydrogen content in government supported projects.*

Rationale

Canada's net zero future will be powered by two things, electricity and low carbon fuels. Hydrogen shows the potential to make up to 30% of Canada's delivered energy in a net zero future, closing the gap in the toughest and most hard-to-abate energy intensive sectors. The critical role that hydrogen can play in our net-zero future should be considered as governments develop their own long-term climate policies, programs, and supporting regulation.

Similarly, there is an opportunity to lever existing policies, programs, and regulations to align with and support a path to being net-zero, which includes hydrogen.

The regions that have been most successful in stimulating the adoption of hydrogen have developed a combination of regulations and programs that work hand-in-hand, and stakeholders have indicated that this is what is needed as a cohesive pan-Canadian approach. Regulatory tools can either require adoption of alternative technologies or inhibit the use of conventional technologies. A zero-emission vehicle mandate and creation of emission-free zones or imposing high road taxes on internal combustion engine vehicles are all examples of policies which have been implemented in jurisdictions around the world. In Canada, both BC and Quebec have implemented ZEV mandates, and these are the provinces where FCEVs are being deployed and investments in infrastructure are being made.

Emissions standards are another mechanism to drive adoption of low- and zero- emission vehicles that are considered less prescriptive than ZEV mandates.

Canada has some existing policies, program, and regulations in place to drive towards decarbonization and sustainability goals. An important early activity will be to modernize and update existing policies, program, and regulations to ensure they are inclusive to hydrogen.

To meet long-term decarbonization goals, Canada will need to support all low carbon pathways, including electrification, low carbon fuels, and hydrogen. An overall integrated clean energy roadmap at the national level, and sub-national level could help identify the best role for each low carbon pathway and will identify how each pathway can be synergistic. For example, hydrogen is sometimes seen as competing with direct electrification. However, using hydrogen as a utility-scale energy storage medium can in fact enable higher penetration of variable renewables on the grid and aid in increased electrification. Roadmaps need to try to overshoot in all pathways to address the inherent uncertainty involved in the radical transformation that will need to occur in Canada's energy mix to meet carbon neutrality by 2050.

Ultimately both the CI and sustainability of feedstocks used to make hydrogen are important. In the near term, the focus needs to be on setting clear CI threshold for hydrogen. New policy should be considered to drive increasing non-emitting content in hydrogen supply to make sure that Canada develops energy sources that can be replenished in a reasonable timescale.

Pillar 6: Awareness

21 *Support community engagement and outreach where deployment HUBs are established.*

22 *Establish awareness and outreach campaigns to educate government, industry, the public, and other important influencers about hydrogen safety, uses, and benefits.*

23 *Develop a suite of tools and resources for early hydrogen markets to help end-users quantitatively evaluate hydrogen as an option for their operations. Host the tools and resources through a central, government-run website.*

24 *Support collaborations between industry and academia to develop hydrogen-specific curriculums to build awareness, interest, skills development, and training to develop the next generation talent pool and prepare the labour force for new opportunities.*

Rationale

Stakeholder engagement consistently highlighted a lack of awareness within the public, as well as within industry and government about hydrogen opportunities and safety issues. Increased awareness about hydrogen as a viable decarbonization pathway that is safe and provides economic benefits is critical to establishing a vibrant and inclusive hydrogen sector.

One of the best opportunities to drive awareness is to deploy hydrogen domestically in projects that are high profile and include awareness and outreach campaigns. Projects that provide an opportunity for the general public to interact with hydrogen as a fuel – for example fuel cell buses, hydrail or fleet vehicles such as car sharing services – provide a greater opportunity for outreach. Funded projects should require an element of outreach through program design.

A targeted hydrogen outreach campaign should be coordinated across the country and offered regionally to a range of stakeholders via different channels under a common brand and banner. This can include technical sessions and general campaigns to raise consumer awareness about hydrogen.

Governments, industry, academia, Indigenous organizations, and non-Government Organizations all can play an important role in supporting the development of tools that enable end-users to evaluate hydrogen as an alternative fuel in their operations, ensuring these materials meet their needs, and that of the general public. Examples include an online total cost of ownership tool for transit agencies, to compare lifecycle costs of a fuel cell bus to alternatives.

Sectors that are heavy users of diesel, such as the mining sector where there are multiple potential uses of hydrogen and each operation is unique, could benefit from a publicly available online tool that provides directional cost and business case assessment. There is a need for other basic tools, such as conversion factor tools and case study information, that could be shared in a centralized portal such as regularly maintained website.

As the hydrogen economy grows in Canada, the availability of a diverse and skilled workforce is essential. To attract the next generation of talent to the industry and/or encourage retraining from adjacent sectors with complementary skillsets, there needs to be a clear linkage to the growth in well-paid employment opportunities. This includes reflecting these emerging opportunities in labour market information available to Canadians to support their education and career choices. Industry/academia collaborations can support training, provide important new IP to benefit industry, and show students that there is a growing industry open to participation from all corners of society. Together, we must work to increase workforce participation from marginalized and underrepresented populations—including but not limited to women, youth, people with disabilities, and Indigenous peoples—to build a more inclusive and equitable low carbon energy sector. Early education outreach in elementary and high schools that includes hydrogen as part of Canada's overall clean energy future is also important.

Pillar 7: Regional Blueprints

25 *Facilitate the development of regional hydrogen blueprints, as a multi-level government collaborative effort, to identify specific opportunities and plans for hydrogen production and end-use. Ensure federal participation to capture synergies with the Hydrogen Strategy for Canada.*

26 *Identify opportunities for the establishment of regional HUBs, comprised of projects along the entire value-chain*

27 *Include utilities, major industry from adjacent sectors, and cleantech companies in development and implementation of blueprints.*

28 *Identify areas for alignment and replication with other provinces/regions to facilitate and accelerate overall adoption.*

Rationale

Hydrogen represents a truly pan-Canadian opportunity: from Western Canada with its abundant natural gas resources and carbon capture expertise, to Eastern Canada with its vast hydroelectricity resources. Hydrogen can be produced by a wide range of mature and emerging pathways. Local energy and feedstock resources as well as geological considerations will dictate the ultimate pathway(s) for producing hydrogen in each region. Most Canadian provinces can become producers of hydrogen for local use or export. Similarly, while there are opportunities to deploy hydrogen in a variety of end-uses across the country, these opportunities, particularly in the early deployment stages, depend on local industry interest, economic factors, as well as local policies and regulation.

For hydrogen to gain traction in Canada, projects which span the entire value chain from production, to distribution and storage, to end use will play a key role. This can be facilitated by the development of regional HUBs which can grow supply and demand concurrently. Governments at all levels will play important roles in supporting local deployment.

To seize these regionally diverse opportunities, the Hydrogen Strategy is complemented by a series of regional blueprints to guide the way. BC, Alberta, Quebec, and Atlantic Canada have already initiated activities to identify the opportunities and benefits hydrogen can offer their regions as a first step to releasing blueprints.

There is an opportunity to leverage local strengths, including research centres, major industries, and cleantech leaders, to contribute to the development and implementation of regional blueprints.

It is recommended that a diverse set of stakeholders be consulted in the development of these blueprints, including provincial and municipal governments, Indigenous groups, utilities and independent power producers, large established industrial players in adjacent sectors, end users, potential hosts for regional deployments including ports and industrial network clusters, as well as the cleantech sector and solution providers.

While local government and industry will take the lead in establishing these regional blueprints, there are benefits to having pan-Canadian coordination. This will help to avoid duplication and to identify areas for collaboration. Support will also be required to overcome common challenges across regions or for addressing issues that are critical to Canada developing and maintaining strategic advantages in the sector. There is a role for all levels of government to identify and enable the development of the pan-Canadian infrastructure assets which are needed to connect regional HUBs and support widespread adoption.

Pillar 8: International Market

29 *Develop a strong Canadian brand, positioning Canada to be a global supplier of choice for low carbon hydrogen, and the technologies to use it.*

30 *Invest in infrastructure to connect Canadian supply to international markets, such as liquefaction assets for energy dense hydrogen transport and hydrogen pipelines from western Canada to the US.*

31 *Establish domestic flagship projects that highlight Canada's expertise, attract investments into the domestic market, and that can be replicated internationally.*

32 *Leverage existing international fora (e.g. Clean Energy Ministerial Hydrogen Initiative, G20, IEA) to showcase Canada's leadership, and advance new market opportunities.*

Rationale

Momentum is growing globally, with countries around the world developing their own hydrogen strategies backed by significant investments, resulting in growing demand for hydrogen and the technologies to use it. Canada has advantages that position us to become a domestic producer and user of hydrogen as well as energy exporter, supplying clean hydrogen and hydrogen technologies into growing international markets. Important actions are required in the near term to secure the position of Canada's supply chain in global markets to fortify clean production, manufacturing, expert hydrogen sector services, and jobs in Canada.

Branding and promoting Canada's low carbon fuels, including hydrogen, will be important to gain market acceptance. This includes ensuring Canadian hydrogen production pathways are backed by certified lifecycle analysis. In considering the export of hydrogen, it is important to participate in international standards development activities underway to set thresholds and certify compliance with fuel standards.

For Canada to supply hydrogen to the European market, establishing aligned thresholds and ensuring third party certification systems are in place will be essential. Canadian natural gas pipelines cross borders into the US, and a top priority in anticipation of hydrogen blending into the pipeline is bilateral alignment on standards and certification with the US.

From the Canadian Pacific Railway to the St. Lawrence Seaway to the Trans-Canada Highway, the big projects that helped to build our country have always needed the vision and leadership of government. Now is the time to imagine a clean energy future enabled by new infrastructure assets such as hydrogen pipelines and hydrogen production and liquefaction plants that produce and move hydrogen within and across Canada and connect us to export markets. Development of infrastructure takes time, and Canada must identify enabling infrastructure for the sector.

Canadian technology is already powering a significant portion of hydrogen and fuel cell deployments globally. Over the next five years as domestic regional deployment HUBs grow and international markets develop, domestic deployments will provide reference projects that can highlight Canada's leadership. The experiences gained can be used to replicate similar projects in other countries using Canadian products, services, or intellectual property. A common theme heard from cleantech stakeholders is that international partners ask to see local reference projects to validate technology readiness and the business case.

Canada also leads and participates in several international partnerships, including the Clean Energy Ministerial, Mission Innovation, the IEA, and the International Partnership for Hydrogen and Fuel Cells in the Economy. These existing channels can be leveraged to showcase Canada's leadership in the hydrogen sector and advance new market opportunities.

Roles and Responsibilities

Development of a strong Canadian hydrogen economy requires a coordinated and collaborative effort between industry, governments, Indigenous organizations, utilities, academia, and non-government organizations driven by a common vision and strategy. The stakeholders in Table 3 were identified with roles and responsibilities in advancing he recommendations of this Strategy. For many of these activities, numerous stakeholders could play a role; however, the table aims to provide a general overview of the roles that key stakeholders could play during the early stages of hydrogen market development.

Table 3 – Stakeholder Roles and Responsibilities by Recommendation

● Responsible ◐ Informed/Consulted		Governments	Industry	Utilities	Academia	Indigenous	NGOs
Strategic Partnerships	Intergovernmental collaboration	●				●	
	Public/private partnerships	●	●	●		●	
	Cross-sector collaboration	●	●	●	●	●	●
	International collaboration	●	●	◐	●	◐	
De-Risking of Investments	Long-term policies	●					◐
	Multi-year programming	●					
	Domestic deployment HUBs	●	●	◐	◐	◐	◐
	Facilitate co-funding opportunities	●	◐	◐			
Innovation	Strategic research priorities	●	●	◐	●		
	Dedicated funding for RD&D	●	●	●	●	◐	◐
	Regional research HUBs	◐	●	◐	◐	◐	◐
	Consortium-based projects	◐	●	◐	●	◐	◐
Codes & Standards	Canadian Codes & Standards	●	◐	◐			◐
	Codes & Standards working group	●	●	●	◐		
	Performance based standards	●					◐
	International standards/certification	●	●	◐	◐		
Enabling Policies & Regulation	Hydrogen's role in new policies, programs, & regulations	●	◐	◐	◐	◐	◐
	Modernize existing policies, programs, regulations	●	◐	◐	◐	◐	◐
	Hydrogen in clean energy roadmaps	●				◐	◐
	Technology-neutral & performance-based	●					
Awareness	Awareness outreach in HUB regions	◐	●	◐	◐	●	◐
	Awareness on safety, uses, benefits	●	◐	◐	◐	◐	●
	Hydrogen tools and resources	●	●	◐	◐	◐	◐
	Industry/academia collaboration	◐	●	◐	●		
Regional Blueprints	Develop regional blueprints	●	●	●	◐	●	◐
	Identify regional HUBs	◐	◐		●	●	
	Diversify stakeholder input	●	●	●	●	●	●
	Alignment across regions/provinces	●	◐	◐	◐	●	◐
International Markets	Canadian brand	●	●	◐	◐	◐	
	Infrastructure Investments	●	●	●		◐	
	Domestic flagship projects	●	●	●	●	◐	●
	Leverage international relationships	●	●	◐	●	◐	◐

Implementation Plan

The release of this strategy is meant to serve as a catalyst for the next stages in Canada's hydrogen story. Following the release of this *Hydrogen Strategy for Canada*, there will be ongoing engagements with public, private, academia, and Indigenous partners. These engagements will be managed through a Strategic Steering Committee chaired by NRCan with committee members sourced from various sub-working groups (Figure 52). The Strategic Steering Committee and Working Groups will be tasked with building the momentum around the strategy, initiating and tracking activities related to the recommendations, following progress, and identifying new priority areas as the market evolves.

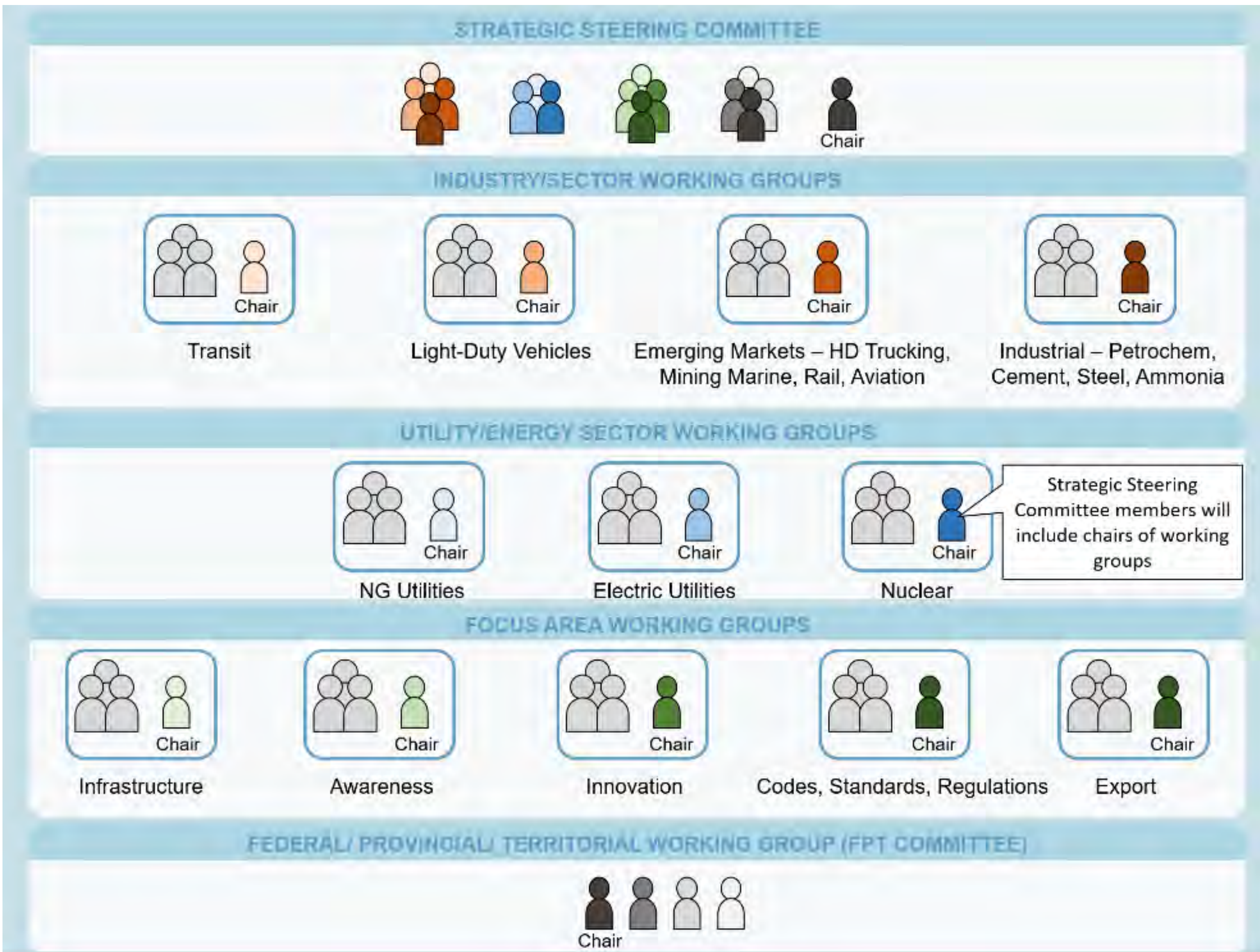


Figure 52 – Implementation Working Groups

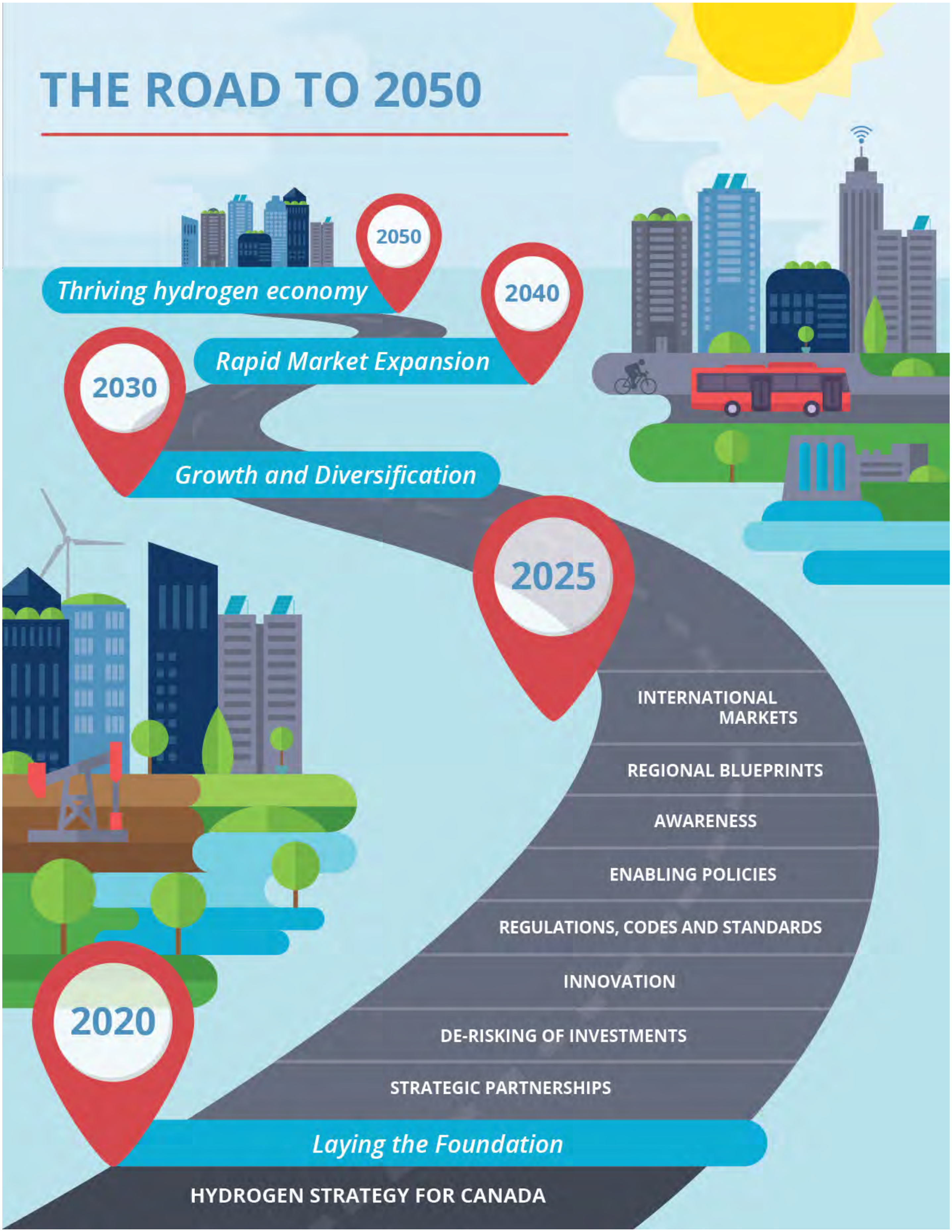
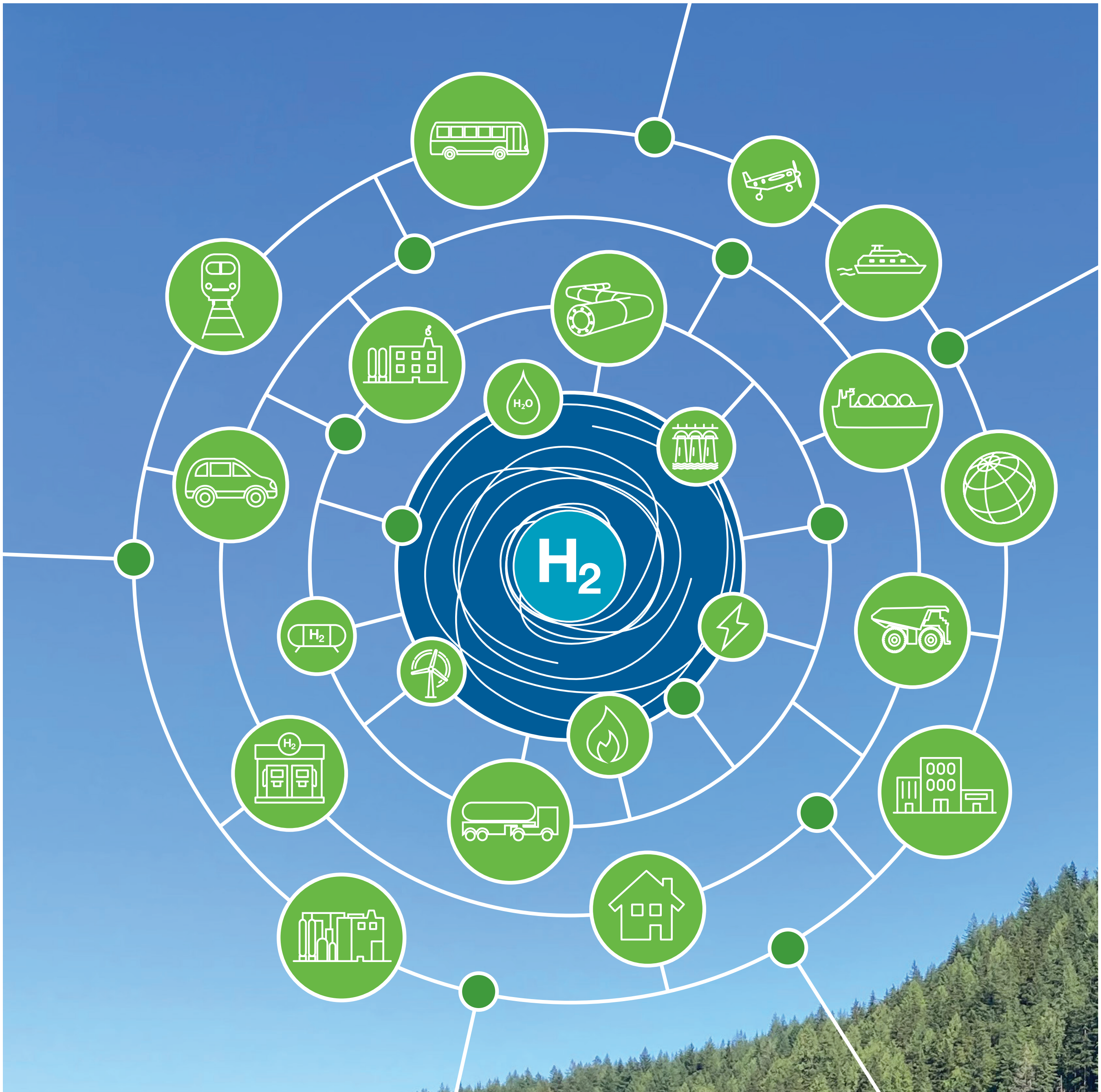


Figure 53 – Roadmap to 2050

Appendix A-4

BC HYDROGEN STRATEGY – BC GOVERNMENT STUDY



B.C. Hydrogen Strategy

A sustainable pathway for B.C.'s energy transition

British Columbia
cleanBC
our nature. our power. our future.

"For British Columbia to meet its CleanBC goals, we must shift how we produce and consume energy. Renewable and low-carbon hydrogen will play a critical role in our sustainable energy future. With our clean hydroelectricity, abundant natural resources and innovative companies, B.C. can be a world leader in the growing hydrogen economy – creating new cleantech jobs and opportunities for people across the province. The B.C. Hydrogen Strategy lays out the actions we will take together to realize this vision on the path to net-zero emissions by 2050."

Honourable Bruce Ralston
Minister of Energy, Mines
and Low Carbon Innovation

H2

Powering our transition to a lower-carbon future

"Hydrogen energy is essential to achieving carbon neutrality by 2050 and limiting global warming to less than two degrees Celsius. Canada is fortunate in that we not only have a leading fuel cell sector centred in B.C., but also leading hydrogen technology and production companies. This represents a huge opportunity for B.C. to produce the significant quantities of hydrogen that will be needed at home and abroad from our abundant, low-cost renewable power and also, when coupled with CO_2 sequestration, from our natural gas resource. Hydrogen will enable B.C. industries – from ports to trucking and mining to urban transportation – to thrive in a carbon-constrained world."

– Mark Kirby, President & CEO
Canadian Hydrogen and Fuel Cell Association

"There is significant momentum building globally for the development and deployment of fuel cells and hydrogen at commercial scale. Numerous countries in Asia, the Americas, Europe and Africa have national hydrogen strategies or initiatives in place, some with medium- and long-term deployment targets – all with a view to addressing societal issues including energy security and resiliency, economic growth and innovation, and environmental goals."

– Tim Karlsson,
Executive Director of the International Partnership for Hydrogen and Fuel Cells in the Economy

"Renewable electricity can help reduce emissions in road transport, low-temperature industrial processes and in heating buildings. However, fossil fuels have a significant advantage in applications that require high energy density, industrial processes that rely on carbon as a reactant, or where demand is seasonal. To fully decarbonize the world economy, it's likely a clean molecule will be needed and hydrogen is well placed to play this role. It is versatile, reactive, storable, transportable, clean burning and can be produced with low or zero emissions."

– BloombergNEF, *Hydrogen Economy Outlook*

"Hydrogen can help overcome many difficult energy challenges. It can decarbonize hard-to-abate-sectors like steel, chemicals, trucks, ships and planes. Hydrogen can also enhance energy security by diversifying the fuel mix and providing flexibility to balance grids."

- Fatih Birol, Executive Director of the International Energy Agency

"A huge step in the fight against climate change has been taken, as both governments and investors now fully grasp the role hydrogen can play in the energy transition. Now, to bring this potential to its full fruition, governments, investors and industrial companies must work together to scale up the hydrogen ecosystem around the world. Their collaboration in the coming months will allow for many of the projects around the world to become a reality and to turn hydrogen into a new, clean, abundant and competitive energy carrier,"

- Benoît Potier, Chairman and CEO of Air Liquide
and Co-Chair of the Hydrogen Council

Contents

Executive summary

British Columbia is committed to achieve net-zero emissions by 2050. It is an ambitious target given that two-thirds of the energy we use for transportation, buildings and industry currently comes from fossil fuels. Meeting our CleanBC goals requires a determined effort to increase energy efficiency, electrify the economy and switch to low-carbon fuels such as biofuels and hydrogen.

When burned or used in a fuel cell, hydrogen produces no carbon emissions. Large-scale deployment of renewable and low-carbon hydrogen will play an essential role in reducing B.C.'s emissions. Independent estimates suggest that hydrogen has the potential to reduce annual emissions by 7.2 megatonnes by 2050 – equivalent to 11% of the province's 2018 emissions.[1]

Because of its versatility, hydrogen is one of the only solutions for decarbonizing sectors of the economy where direct electrification is not practical, such as heavy-duty transportation and industrial heat. Hydrogen can be used in fuel cells to produce energy for transportation and stationary power systems, especially important for industrial sites and remote communities powered by diesel. When blended into the natural gas grid, hydrogen can displace fossil fuels to heat and power our homes and buildings. Hydrogen can also be used for producing low-carbon synthetic fuels to reduce emissions in transportation and industry.

Realizing the potential of hydrogen requires government, industry and researchers to work together. As part of CleanBC, the B.C. Hydrogen Strategy outlines the Province's plan to accelerate the production and use of renewable and low-carbon hydrogen and be a world leader in the growing hydrogen economy.

The strategy includes 63 actions to undertake over the short term (2020-2025), medium term (2025-2030) and long term (2030-beyond). These include:

- incentivizing the production of renewable and low-carbon hydrogen;
- developing regional hydrogen hubs where production and demand are co-located;
- financial supports for deploying fuel cell electric vehicles and infrastructure;
- expanding the use of hydrogen across different industrial sectors and applications;
- promoting the adoption of hydrogen in areas where it is most cost-effective in terms of emission reductions;
- creating the B.C. Centre for Innovation and Clean Energy to drive the commercialization of new hydrogen technology; and
- establishing ambitious carbon-intensity targets and a regulatory framework for carbon capture and storage.

B.C. has already implemented robust policies to encourage hydrogen use in the transportation sector. B.C.'s carbon tax and low carbon fuel standard (LCFS) are reducing emissions while incentivizing the switch to renewable and low-carbon fuels. CleanBC committed to increasing the stringency of the LCFS by doubling the required reduction in carbon intensity of transportation fuels to 20% by 2030. Introduced in 2019, the *Zero-Emission Vehicles Act* requires automakers to meet an escalating annual percentage of new light-duty zero-emission vehicle sales, including hydrogen fuel cell electric vehicles. Hydrogen is expected to play a larger role for medium- and heavy-duty vehicles by supporting larger payloads and range.

[1] Zen and the Art of Clean Energy Solutions, *BC Hydrogen Study - Final Report* (2019).

The Province also recently introduced policies to support the production of hydrogen. In 2021, the Province and BC Hydro introduced the Clean Industry and Innovation Rate to offer discounted electricity for hydrogen production. In addition, recent amendments to the *Greenhouse Gas Reduction Regulation* enable utilities to produce or purchase hydrogen for displacing fossil fuels in the natural gas grid.

Unlike most other jurisdictions, B.C. has the resources to produce both green and blue hydrogen with low carbon intensity. More than 98% of B.C.'s electricity is renewable, allowing us to leverage our clean electricity to produce green hydrogen via electrolysis. B.C. also has low-cost natural gas reserves, significant geological storage capacity and expertise in carbon capture and storage (CCS) technology, giving us the potential to produce blue hydrogen from natural gas with adequate and permanent CCS.

Not all types of hydrogen production are equal in terms of climate benefits. To reduce emissions and decarbonize the economy, the B.C. Hydrogen Strategy must focus on advancing and providing support only for renewable and low-carbon hydrogen pathways, with long-term targets for declining carbon intensity consistent with net-zero emissions by 2050. Our immediate priorities will be to:

- scale-up green hydrogen production using B.C.'s abundant supply of clean, renewable electricity; and
- establish a regulatory framework for CCS to enable blue hydrogen production while ensuring it has similar or lower emissions.

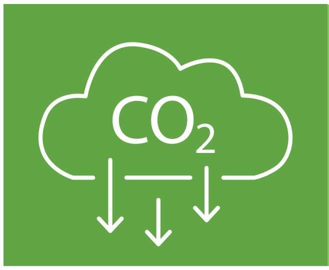
B.C. is already a world leader in hydrogen and fuel cell technology. Provincial support for innovation has led to the creation of a vibrant cluster of companies and expertise in hydrogen. More than half of Canada's companies active in the hydrogen and fuel cell sector are located in B.C. This local expertise has fuelled strong synergies between government, industry and post-secondary institutions.

B.C. is well-positioned to grow its hydrogen sector to meet the increasing demand for low-carbon solutions locally and around the world. Hydrogen is a clean energy solution for powering B.C.'s future as it presents an opportunity to reduce emissions, attract new investment and create skilled, well-paying jobs. Given our proximity to export markets, we could capture a significant portion of the global hydrogen market estimated to be greater than $305 billion by 2050.

Unlocking hydrogen's potential requires acting with urgency and working together to implement the B.C. Hydrogen Strategy. Accelerating the adoption of renewable and low-carbon hydrogen through policy, partnerships, innovation and infrastructure will help us achieve our CleanBC commitments and build a sustainable economy.

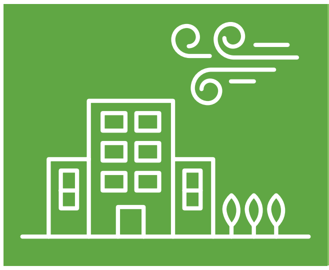
Objectives

Our vision is to become a world-leading hydrogen economy by 2050.

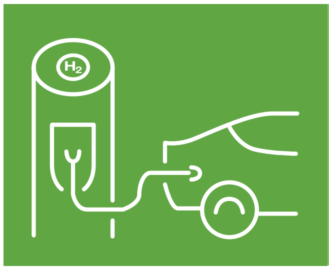


Promote innovation and investment in the production and deployment of hydrogen to achieve the energy system transformation required to meet CleanBC greenhouse gas (GHG) reduction targets

Create economic development opportunities across B.C. through increased and equitable employment in trades, cleantech and energy services



Improve air quality and reduce contamination and noise pollution in urban and remote communities



Make clean energy solutions more diverse, convenient, available and affordable for British Columbians

Fulfil our commitments under the *Declaration on the Rights of Indigenous Peoples Act*

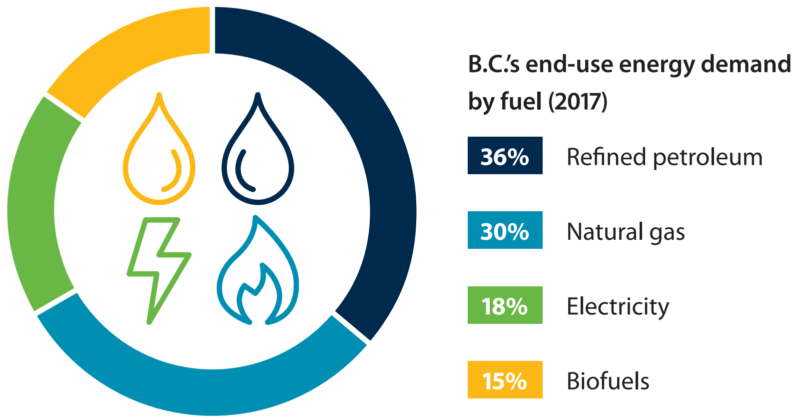
Energy and how it's used in B.C.

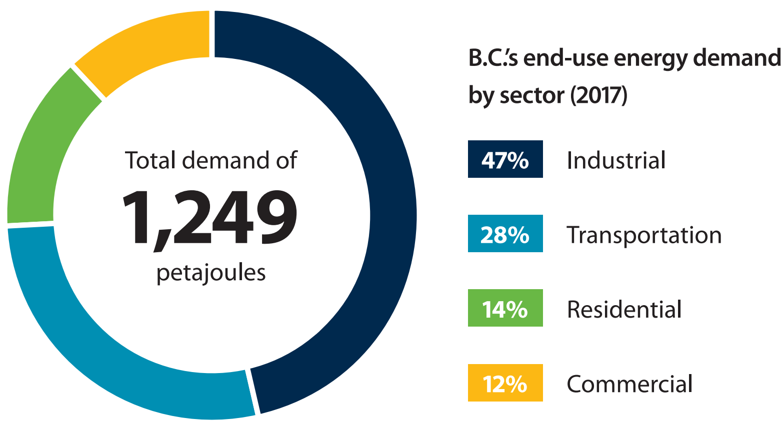
Hydrogen can help us make the essential shift away from higher-carbon fuel sources in all sectors, from industrial and transportation through to residential and commercial use.

Demand for energy in B.C. is highest in the industrial sector, followed by transportation, residential and commercial use. Hydrogen can be applied to each of these sectors in B.C. and could replace a significant percentage of demand currently met by fossil fuels.

Just under 70% of B.C.'s current energy demand is met through natural gas and refined petroleum products such as gasoline and diesel.[2] Hydrogen will play an important role in helping us transition away from these higher-carbon fuels to a cleaner, low-carbon energy system.

B.C.'s electricity is over 98% clean or renewable. Electrification of the economy is key to achieving our CleanBC goals, including fuel-switching from natural gas and diesel to electricity. But for many sectors that are dependent on these fuels, such as heavy-duty transportation and high-grade industrial heating, direct electrification is not practical. In these cases, hydrogen provides an effective solution.





2 Canada Energy Regulator, Provincial and Territorial Profiles - British Columbia (2019).

B.C.'s leadership in the hydrogen economy

B.C. is a recognized world leader in fuel cell innovation and hydrogen technologies, and the Province is committed to supporting research, development and commercialization in this sector as part of the global effort to reduce emissions.

The Government of British Columbia was an early supporter of fuel cell innovation, and today the province is home to the largest hydrogen and fuel cell sector in Canada, with 51% of companies located here. Their innovations are supported by the cutting-edge research conducted at B.C.'s universities and technical institutes, which are also training the next generation of talent working in this field.

A skilled workforce will be essential for our successful shift to cleaner energy solutions and the Province and industry both have a role to play. By helping shape programs at post-secondary institutions through program advisory committees and work-integrated learning, new graduates will be prepared to enter the workforce and contribute to the growing cleantech economy, including the hydrogen and fuel cell sector.

The synergies arising from industrial, post-secondary and governmental support for hydrogen have created the province's strong hydrogen sector. Exports of B.C. fuel cell and hydrogen technology to Asia, Europe and the US have enabled industry growth and product development. But if we are to fully benefit from the innovative technologies developed in our province, they need to be put to use here in B.C. That means we need to continue to invest and innovate across the sector. Doing so will enable us to realize our GHG reduction targets, remain a world leader in fuel cell innovation and hydrogen technology, and become a leading hydrogen economy.

Hydrogen BC (HyBC)
Fuelling hydrogen innovation in B.C.

Established in 2020 as the B.C. regional branch of the Canadian Hydrogen and Fuel Cell Association, HyBC supports the province's hydrogen energy ecosystem by co-ordinating the deployment of hydrogen infrastructure and applications province-wide. In partnership with the provincial government, HyBC has an initial mandate to promote the rollout of fuel cell electric vehicles and hydrogen fuelling stations. HyBC also works to ensure the safe operation of hydrogen infrastructure by sharing best practices developed in Canada and abroad while working across the province to build demand for low-carbon hydrogen.

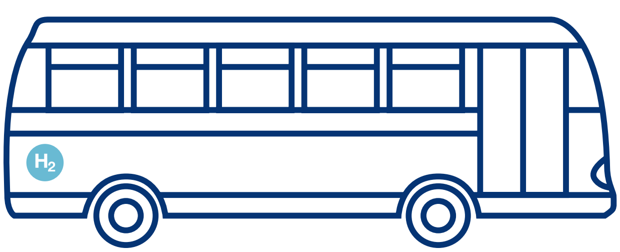
Institute for Integrated Energy Systems (IESVic)
A nexus of research and training

Since 1994, IESVic at the University of Victoria has charted feasible pathways to sustainable energy systems by developing technology and training the next generation of changemakers. IESVic was Canada's first major university-industry research partnership focused on fuel cells and hydrogen systems; with support from NSERC, Ballard Power Systems and others, an industrial research chair was created to focus on hydrogen storage and advanced liquefaction. IESVic faculty and students helped establish B.C. and Canada as world leaders in hydrogen and fuel cells, and IESVic continues to be an active research centre in fuel cell modelling, hybrid power trains, storage and techno-economics of the hydrogen economy.

Powertech Labs

Globally renowned for innovation

Wholly owned by BC Hydro, Powertech Labs is a world-renowned testing, consulting, and research and development organization that pioneered the design of turnkey hydrogen fuelling station packages. Powertech's Advanced Transportation group is a preferred partner for global industry leaders that bring hydrogen technologies to market. Powertech has amassed a profile of world firsts, including initiating a collaboration of leading automotive original equipment manufacturers that jumpstarted the development of hydrogen components used in all hydrogen fuel cell vehicles today, to designing and building the world's first fast-fill 70 MPa hydrogen station in Surrey, B.C., to its critical role in hydrogen fuelling protocols used around the world. Powertech will play a central role in the development of B.C.'s hydrogen economy and the successful implementation of the B.C. Hydrogen Strategy given its expertise in hydrogen equipment testing and design, the development of hydrogen codes and standards, hydrogen station and dispensing technology, hydrogen production and purification technologies, and materials testing. Powertech's relationship with BC Hydro and CleanBC will enable the company to maintain a leadership role as the deployment of hydrogen extends from the transportation to the energy sector.



Greenlight Innovation

The largest installed base of fuel cell and energy storage testing solutions in the world

Located in Burnaby, Greenlight Innovation is accelerating the shift towards sustainable transport and energy consumption by producing the world's best testing and development equipment for the research and manufacture of fuel cells, electric vehicles and energy storage systems. Since 1992, Greenlight has made the tools required to commercialize alternative energy technologies, and major automotive equipment manufacturers, leading universities and research institutions rely on Greenlight's advanced testing and manufacturing equipment to provide world-class results for their programs.

Ekona Power

Producing low-cost and low-carbon hydrogen from fossil fuels

Ekona is a Vancouver-based venture that is developing a novel methane pyrolysis platform for industrial-scale hydrogen production and natural gas infrastructure that delivers low-cost hydrogen while reducing GHG emissions by over 90%. Ekona's tri-generation pyrolysis solution is a unique combination of two technologies – pulse-methane pyrolysis (PMP) and direct carbon fuel cells (DCFC). Ekona's PMP produces hydrogen at costs comparable to conventional steam methane reformers, with valuable solid carbon as the principal byproduct. Ekona's DCFC efficiently converts byproduct carbon into electricity and pure CO_2, which can be sequestered or utilized.

Producing hydrogen in B.C.

Hydrogen can be produced from many different feedstocks available in B.C., including both fossil fuels and renewable resources.

Hydrogen is the lightest and most abundant element in the universe and is found in compounds such as water (H_2O) and natural gas (CH_4). When hydrogen is split from water or released from organic material, it becomes a versatile energy carrier that can be used in energy systems to generate electricity and heat.

Hydrogen can be produced from fossil fuels, biomass and clean electricity, and it is also a byproduct in some industrial processes. Several hydrogen production pathways are possible in B.C. to meet domestic and/or international demand. Determining how to produce hydrogen efficiently, cost-effectively, at scale and with minimal environmental impact is critical to building supply chains within the province.

Hydrogen production pathways are often represented by colours based on the production process used.

GREEN **hydrogen** is produced from renewable sources, such as using clean electricity (e.g., hydro or wind power) to split water into hydrogen and oxygen through a process called electrolysis. Green (or *renewable*) hydrogen has a low carbon intensity when produced using clean electricity.

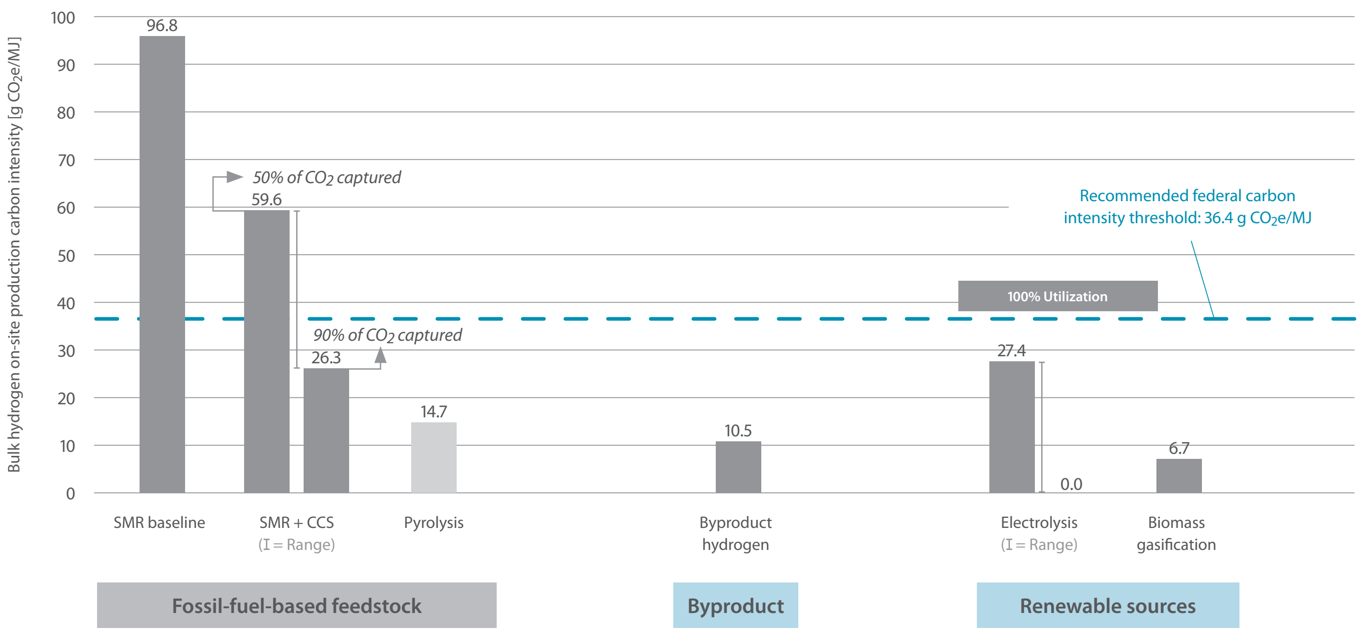
BLUE **hydrogen** is produced from non-renewable sources through steam methane reforming (SMR) with carbon capture and storage (CCS) or pyrolysis of fossil fuels, such as natural gas. With CCS, carbon dioxide is separated and sequestered underground, which reduces the carbon intensity of the produced hydrogen. With pyrolysis of natural gas, solid carbon is a byproduct. Blue hydrogen (or *hydrogen from fossil fuels with CCS*) has a low carbon intensity when produced using fossil fuel feedstock coupled with adequate and permanent CCS.

GREY **hydrogen** is produced from fossil fuel sources, but *without* CCS. Grey hydrogen does not have a low carbon intensity.

While describing hydrogen production pathways using colours is common, the terminology is not standardized and can lead to confusion around the carbon intensity of pathways and their effectiveness at reducing emissions.

In terms of climate benefits, not all hydrogen is created equal. To meet its emissions reduction targets, B.C. must focus on advancing and providing support only for renewable, low-carbon or zero-emission hydrogen pathways. The following table shows the GHG emissions intensity of different hydrogen production methods.

GHG emissions intensity of different hydrogen production methods



The carbon intensity of the production pathways shown above are modelled estimates and use a "cradle-to-gate" life-cycle analysis that includes emissions associated with feedstock production, transportation, losses, flaring, land use changes, hydrogen production and carbon capture and storage (if applicable). Data are from the B.C. low carbon fuel standard and *BC Hydrogen Study – Final Report* (2019). The actual carbon intensity of a specific hydrogen production project will depend on a number of factors.

In B.C., the carbon intensity of hydrogen will be determined using a rigorous life-cycle approach that accounts for all the emissions associated with its production. This includes emissions associated with feedstock development, transportation, hydrogen production and any CCS. The Province will work other jurisdictions to develop a common methodology for measuring and verifying the carbon intensity of hydrogen.

The federal *Hydrogen Strategy for Canada* and the European Commission recommend a carbon intensity threshold of 36.4 g CO_2e/MJ. B.C. will consider this target a starting point and will ensure that its regulatory frameworks relating to hydrogen production and use are aligned to achieve continued reductions in carbon intensity over time.

Through implementation of the B.C. Hydrogen Strategy, the Province will work to establish long-term, ambitious thresholds for declining carbon intensity consistent with ensuring that B.C. remains a world leader in hydrogen, decarbonizes the economy and achieves its goal of net-zero emissions by 2050.

Hydrogen storage and distribution

Hydrogen can be stored in either liquid or gas form for later use. It can be distributed in B.C.'s existing natural gas pipeline infrastructure or in dedicated pipelines, and it can also be compressed or liquefied for storage and distribution in tanks, convenient for delivery (generally by truck). Finally, hydrogen can also be stored in liquid chemical carriers, such as ammonia, or by bonding hydrogen to toluene, where high densities of hydrogen can be stored at lower pressures.

To overcome challenges associated with the transportation of hydrogen, B.C. is committed to reviewing hydrogen infrastructure requirements, supporting distribution trials and establishing an enabling regulatory environment for hydrogen distribution.

Hexagon Purus

Lightweight components for high-pressure vessels

Hexagon Purus is a world-leading provider of hydrogen type 4 high-pressure cylinders, complete vehicle systems and battery packs for fuel cell electric, battery electric and hybrid mobility applications. Type 4 high-pressure cylinders contain a non-metallic liner and are lightweight and cost-effective, which are important factors for high-pressure hydrogen storage across the medium- and heavy-duty commercial vehicle industry. Hexagon Purus's Global Innovation Office is in Kelowna, and the company is also investing in a new world-class engineering, prototyping and short series production factory near UBC-Okanagan for its hydrogen and battery electric products to support fuel cell vehicles, with completion planned in mid-2022.

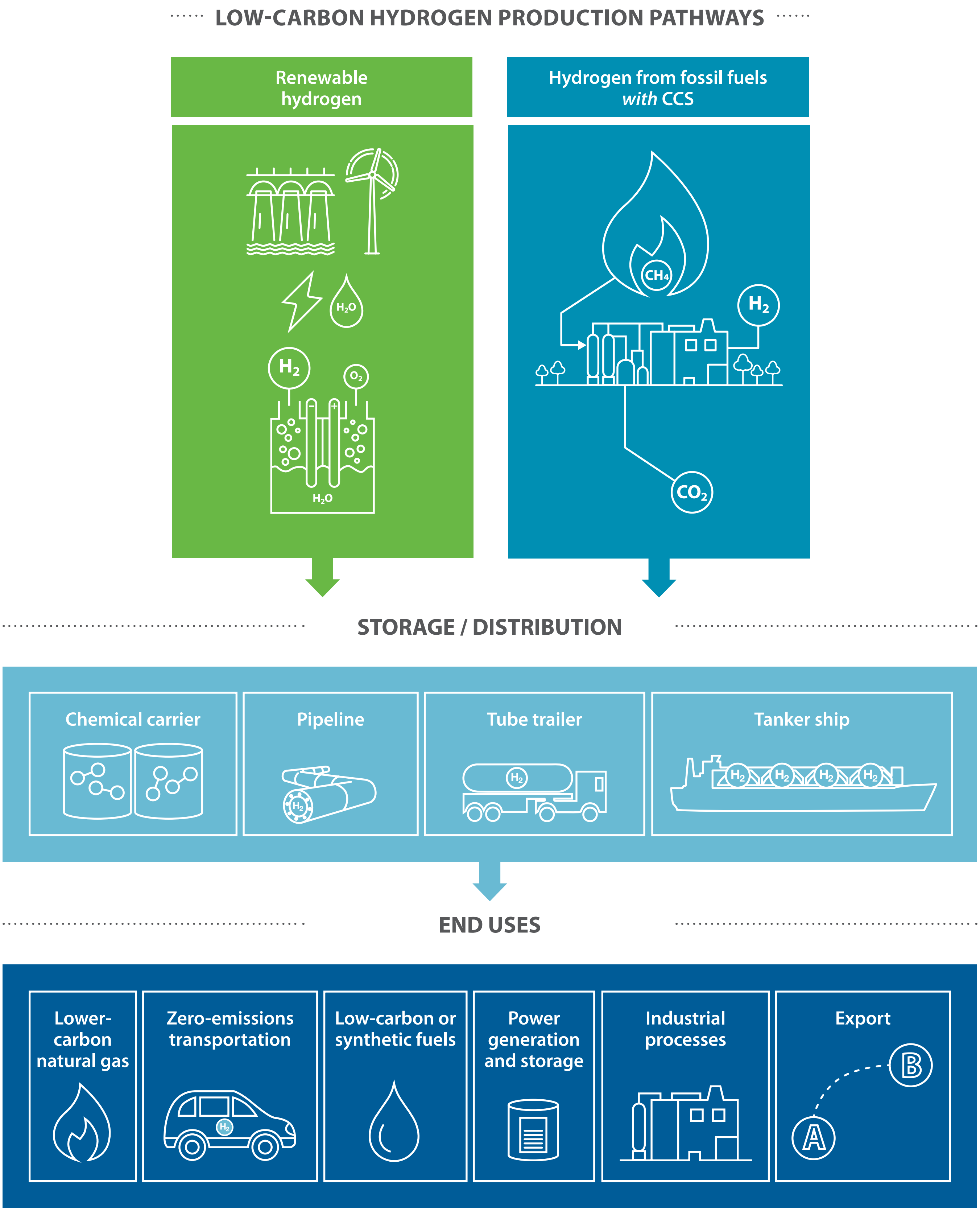
Ionomr Innovations

Technology that improves performance and reduces environmental impact

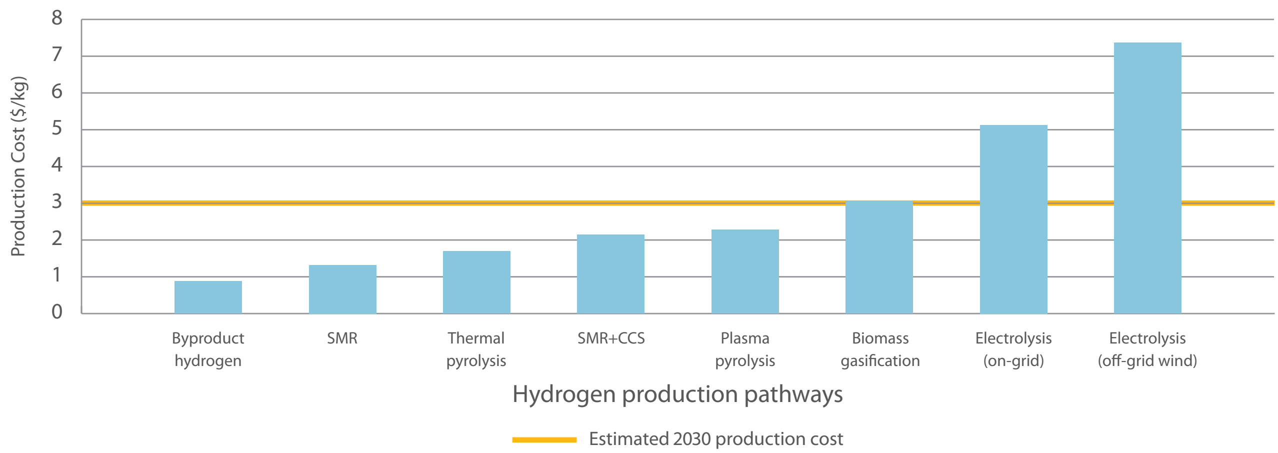
Ionomr's innovations are enabling the ultra-high-efficiency, lowest-cost fuel cell systems of the future. The Vancouver-based company's proton-exchange membranes (PEMs) and ionomer replace the toxic materials used in most electrochemical systems without compromising on performance or chemical durability. These materials allow existing fuel cells and PEM electrolyzers to achieve higher-efficiency targets and longer lifetimes, while minimizing the use of precious metals. Ionomr's anion-exchange materials are the first to unlock high-temperature strong alkaline systems, the largest improvement in 100 years to the alkaline electrolysis systems that form most renewable hydrogen deployments today.

"Ionomr's revolutionary ion-exchange materials enable the proliferation of hydrogen to its rightful leadership position in the future of abundant renewable and sustainable energy."

– Bill Haberlin, CEO
Ionomr Innovations


LOW-CARBON HYDROGEN PRODUCTION PATHWAYS
Renewable hydrogen
Hydrogen from fossil fuels *with* CCS
H_2O
H_2
O_2
H_2O
CH_4
H_2
CO_2
STORAGE / DISTRIBUTION
Chemical carrier
Pipeline
Tube trailer
Tanker ship
END USES
Lower-carbon natural gas
Zero-emissions transportation
Low-carbon or synthetic fuels
Power generation and storage
Industrial processes
Export
B
A

Cost of hydrogen production



Cost of bulk on-site hydrogen production by pathway in B.C. in 2020

Production costs are normalized to production scale of 100 tonnes per day.[3]

Grey hydrogen production methods, such as SMR, are currently the most cost-effective ways to produce hydrogen at scale and are the most commercially advanced technologies; however, SMR produces significant carbon emissions. CCS is one way to reduce the carbon emissions from this pathway.

Production costs for all pathways are heavily dependent on the price of inputs, such as natural gas and electricity. While B.C. has one of the lowest cost and cleanest electricity grids in North America, renewable hydrogen production at scale via electrolysis will require electricity rates in the range of $40/MWh. There is also a growing interest in dedicated electricity generation for hydrogen production using intermittent energy resources such as wind. It is expected that as the cost of these renewable electricity resources decline, so too will the cost of low-carbon hydrogen production. Building electrolyzers at locations with access to high-voltage electricity and transportation infrastructure will be necessary for renewable hydrogen production. BloombergNEF expects the levelized cost of hydrogen from large renewable-energy-powered projects will be cost-competitive with low-carbon hydrogen from natural gas via SMR + CCS by 2030.[4]

While modelling shows the costs of different hydrogen production pathways, the costs of delivered hydrogen will vary greatly depending on the location of the facility, method of production, transportation and storage requirements, and the state of the hydrogen (liquid or gaseous). The Province targets cost-parity or lower with the wholesale price of incumbent fuels for hydrogen production, such as gasoline or diesel for transportation or delivered diesel for remote communities. It is estimated that to be globally competitive, the price of hydrogen produced (excluding storage and transportation) would need to be less than $3/kg by 2030. Ensuring that hydrogen is widely available for domestic use and for export will depend on our ability to scale up the technology, keep the costs of inputs competitive within the industry, reduce transportation costs and ensure access to robust and efficient supply chains.

[3] Government of Canada, *Hydrogen Strategy for Canada* (2020).
[4] BloombergNEF, *Hydrogen Economy Outlook* (March 20, 2020).

Making electrolysis more affordable

In January 2021, the Province and BC Hydro announced the Clean Industry and Innovation Rate to help support and attract new innovative industries, such as hydrogen production, to B.C. by making it more affordable to connect into BC Hydro's grid. The Clean Industry and Innovation Rate is a seven-year discount from BC Hydro's standard industrial rate (20% discount for the first five years, 13% discount in year six and 7% discount in year seven) and is available to new customer plants that use a process to remove GHGs from the atmosphere or produce a renewable or low-carbon fuel. The Province continues to explore ways to make B.C. more competitive with lower-cost jurisdictions by analyzing additional rate structures that will make electrolysis more affordable and, in turn, reduce the cost of low-carbon hydrogen for consumers in B.C.

How we'll grow hydrogen production

2020-2025

- Stimulate hydrogen production through direct support and incentives
- Continue to provide policy support for increasing hydrogen demand certainty and de-risking the development of hydrogen production infrastructure
- Provide policy support to utilities who choose to produce or purchase hydrogen
- Advocate for increased production and consumption of hydrogen in B.C.
- Work with industry partners to establish hydrogen deployment hubs in B.C.

2025-2030

- Consider introducing alternative electricity rate designs to support hydrogen production
- Promote hydrogen production at scale to meet domestic and/or international demand
- Determine if brownfield sites can be used for industrial parks that include hydrogen production

2030-beyond

- Support long-term self-sufficiency in hydrogen supply and with it introduce new opportunities for economic development
- Support the development of hydrogen liquefaction, distribution and transmission infrastructure

Codes and standards

Existing agencies will play an important role in regulating the hydrogen industry and ensuring the safe production and responsible use of our natural resources, such as water and natural gas. We also need to make sure that regulations and permitting requirements are clear and consistent across sectors and jurisdictions to enable sector-coupling and ensure B.C. is set up for seamless trade opportunities, both regionally and abroad.

Hydrogen projects may need to be regulated based on the specific production pathway or end use. For example, hydrogen produced by SMR has parallels with oil and gas activities due to the use of natural gas, and there may be overlap with the regulatory approval processes in place for the oil and gas industry as determined by the BC Oil and Gas Commission.

Hydrogen projects require a clear path forward, and the Province will work to remove roadblocks and harmonize regulation and permitting in B.C. Many organizations have valuable expertise to share, including the CSA Group, Canada Energy Regulator, Canadian Hydrogen and Fuel Cell Association, Measurement Canada, FortisBC, Pacific Northern Gas, Enbridge, Technical Safety BC, the BC Oil and Gas Commission and the British Columbia Utilities Commission.

Ballard Power Systems
A world leader in hydrogen fuel cells

Burnaby-based Ballard is a leading global provider of innovative hydrogen fuel cell products and services that have the Power to Change the World.® Over its 40-year history, Ballard has invested more than $1 billion in research and development to advance fuel cell technology and has produced over 850 megawatts of proton-exchange membrane fuel cell products. Today, Ballard's 900+ employees design, manufacture and sell fuel cell products that power zero-emission transit buses, trucks, trains, marine vessels and forklifts and contribute to CO_2 emission reductions. Its heavy-duty fuel cell power modules lead the industry in performance, durability and overall road experience, having operated more than 50 million kilometres, and there are currently more than 3,000 hydrogen fuel cell electric buses and trucks powered by Ballard in operation globally.

"At Ballard, we are convinced that hydrogen can offer economically viable, financially attractive and socially beneficial solutions. We believe that hydrogen is needed to achieve deep decarbonization of our economy and meet Canada's emission reduction targets. With its natural resources and a local hydrogen and fuel cell technology cluster, British Columbia is facing a unique opportunity. A comprehensive hydrogen strategy for the Province will send a strong signal to investors, boosting economic growth and local jobs while positioning B.C. as a leader in the hydrogen economy."

– Randy MacEwen, President and CEO
Ballard Power Systems

How we'll regulate hydrogen production

2020-2025

- Review provincial, federal and international codes, standards and regulations for hydrogen production and establish a compatible regulatory framework
- Amend regulations to allow the BC Oil and Gas Commission to regulate hydrogen production, storage and transportation if produced from fossil fuels
- Amend *Water Sustainability Act* related regulations to include hydrogen production as an authorized industrial water use purpose and set new water fees and rentals
- Enable hydrogen as a pathway for natural gas utilities to reduce emissions
- Ensure regulatory frameworks relating to hydrogen production and use are aligned to encourage continued reductions in carbon intensity over time
- Establish carbon-intensity targets for hydrogen production pathways
- Provide support only for renewable or low-carbon hydrogen pathways
- Establish a working group made up of representatives from the hydrogen industry, regulatory agencies and government to implement B.C. Hydrogen Strategy actions

2025-2030

- Continue to implement the Low Carbon Fuel Standard Part 3 Agreements to advance hydrogen production, fuelling infrastructure, operation and maintenance projects
- Review sectoral opportunities for hydrogen offtake
- Develop carbon management frameworks to encourage at-scale production of low-carbon hydrogen and transition policy incentives from direct support to market-based mechanisms

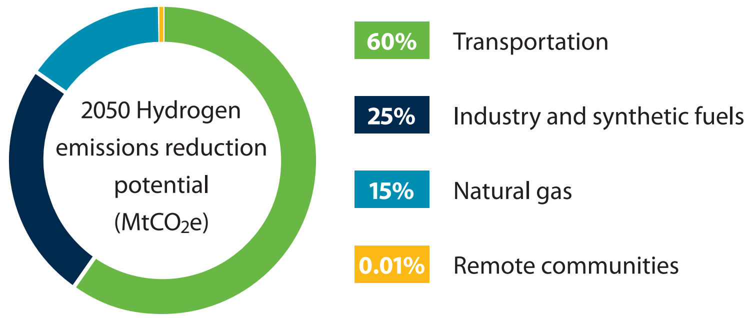
2030-beyond

- Achieve a clear and supportive regulatory environment for hydrogen production in B.C.
- Require a phased reduction in the carbon intensity of hydrogen produced and used in B.C.
- Explore policy framework mechanisms for long-duration energy storage using hydrogen

Using hydrogen in B.C.

Hydrogen will play a critical role in hard-to-decarbonize sectors where direct electrification is not practical, such as heating and power, transportation and industrial processes. The Province is committed to promoting the most cost-effective applications that result in the greatest climate benefit.

By 2050, hydrogen has the potential to reduce the province's emissions by 7.2 megatonnes of carbon dioxide equivalent (CO_2e) per year,[5] equal to 11% of B.C.'s 2018 emissions.[6] Hydrogen deployment in transportation applications is expected to account for 60% of these reductions as hydrogen fuel cells, often used in vehicles, offer greater efficiency than burning hydrogen. Applications in industry and synthetic fuels (25%) and natural gas (15%) make up the remainder of the potential reductions from hydrogen.



Blending hydrogen with natural gas to decarbonize heating and power

B.C. has an extensive network of natural gas pipelines that can be used to help meet our GHG reduction targets and grow the province's hydrogen economy. Natural gas represents the greatest source of carbon emissions in the built environment, where it is most commonly used for space and water heating in residential and commercial buildings, large multi-unit buildings, hospitals and schools. Industrial sites such as mines, pulp and paper mills, and refineries also rely on natural gas for direct heating and feedstocks.

One way to reduce emissions associated with natural gas use is by injecting hydrogen into the natural gas grid. When natural gas is blended with hydrogen, its emissions from combustion are reduced, providing a cleaner energy source. While the volume of hydrogen that can be directly injected into B.C.'s extensive pipeline distribution network depends on the point of injection and pipeline capacity, studies have shown that hydrogen by volume up to 5%-15% can be tolerated in the pipeline network with minimal disruption to appliances in homes and businesses.[7]

Blending hydrogen with natural gas is an innovative solution for natural gas utilities to meet environmental standards, including the CleanBC requirement that 15% of natural gas consumption must come from renewable gas by 2030.

It would also reduce some of the emissions associated with burning natural gas in appliances, power-generating equipment and industrial processes. More work will be done to understand the implications across the entire natural gas system. Since 80% of the natural gas produced in British Columbia is sold in the export market, injecting hydrogen in the high-pressure transmission system could have implications for downstream customers. Depending on the point of injection and volume of hydrogen injected, the Canada Energy Regulator, the BC Oil and Gas Commission or Technical Safety BC will be engaged to review the pipeline network for integrity and safety.

5 Zen and the Art of Clean Energy Solutions, *BC Hydrogen Study - Final Report* (2019).
6 Government of British Columbia, *Provincial Greenhouse Gas Emissions Inventory* (2020).
7 Zen and the Art of Clean Energy Solutions, *BC Hydrogen Study – Final Report* (2019).

Power-to-Gas: Integrating our electricity grid and gas infrastructure

Power-to-Gas (P2G) converts electricity into hydrogen through electrolysis, and the resulting hydrogen can then be injected into the natural gas distribution network for use in buildings, transportation or seasonal storage. P2G projects also allow utilities or communities to store surplus energy generated from intermittent renewable power, such as wind. Hydrogen can be stored in dedicated tanks for days, weeks and even months to be used when demand changes across the seasons. This stored hydrogen can also be injected into the natural gas distribution system or be used in a stationary fuel cell for electricity production when needed. P2G could be a powerful way for B.C. to integrate our clean electricity grid and our existing natural gas infrastructure to achieve our GHG reduction targets, improve system resiliency and increase energy storage.

FortisBC

Exploring how to incorporate hydrogen into the gas distribution network

An integrated gas and electric utility, FortisBC serves over 1.2 million customers across 135 communities and 57 Indigenous communities. To achieve its target of a 30% reduction in its customers' GHG emissions by 2030, FortisBC is exploring ways to increase the content of renewable and low-carbon gases like hydrogen in the gas supplied to its customers. The utility is currently progressing to pre-feasibility planning and technical analyses for introducing hydrogen into its gas distribution network and is evaluating large-scale projects for the centralized production of renewable hydrogen. Through its Clean Growth Pathway to 2050, FortisBC also plans to make significant investments in low- and zero-carbon vehicles and infrastructure and to grow renewable gas supply to achieve 15% of all gas it delivers by 2030.

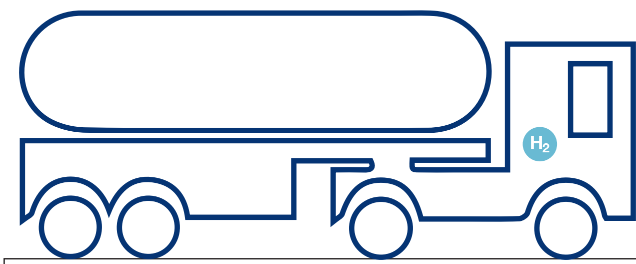
How we'll support blending hydrogen with natural gas
2020-2025
• Establish a regulatory framework for injecting hydrogen into the natural gas and propane distribution systems • Include hydrogen as a prescribed undertaking under the *Greenhouse Gas Reduction Regulation* • Partner with a utility to review the infrastructure requirements to accommodate up to 100% hydrogen in the distribution system • Support hydrogen injection trials into natural gas and/or propane distribution systems
2025-2030
• Mandate that new or modified natural gas or propane pipelines be hydrogen compatible • Support the introduction of hydrogen-tolerant equipment • Explore the role of hydrogen in meeting the CleanBC 15% renewable gas target
2030-beyond
• Support large-scale hydrogen injection into the natural gas and propane distribution systems

Fuelling our transportation sector

Transportation in B.C. emits over 25 million tonnes of CO_2e annually, accounting for approximately 41% of the province's total GHG emissions.[8] Meeting our emissions reduction goals will require a substantive change in how we choose to get around, the kilometres we travel, the vehicles we drive and how we fuel our transportation choices.

Hydrogen fuel cell electric light-duty vehicles are already being adopted by fleets in B.C., and in the near term greater opportunities for hydrogen vehicle deployment are opening up in the medium-, heavy-duty and off-road vehicle sectors. Medium- and heavy-duty hydrogen fuel cell electric vehicles are suitable for heavy payloads and can benefit from short refuelling times and greater operability range. Fuel cell vehicles can also operate in temperatures as low as -30°C with minimal impacts to engine efficiency, and the excess heat generated from the fuel cell stack keeps the engine and cabin warm.

There are currently few low-carbon solutions for planes, trains and ships that require energy-dense fuel. Here, the rapid innovation in hydrogen-powered transportation provides a promising pathway for increased hydrogen adoption in these transportation modes, which are hard to electrify. Hydrogen rail and ferry pilot projects are currently taking place in Europe with great success.

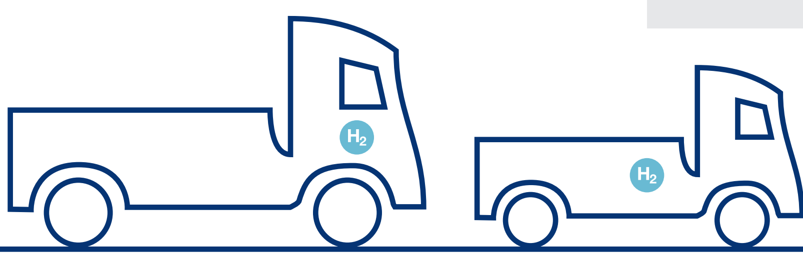


How does a fuel cell electric vehicle work?

Hydrogen fuel cell electric vehicles use hydrogen gas to power an electric motor. Hydrogen and oxygen are combined in the fuel cell to produce electricity, and the only byproducts are water and heat. These vehicles do not produce any tailpipe emissions when driven and are more efficient than conventional internal combustion engines.

Hydra Energy
Using waste hydrogen to displace diesel consumption in heavy-duty trucks

Delta-based Hydra Energy is removing barriers for hydrogen adoption in transportation and accelerating the commercial-scale deployment of hydrogen-fuelled heavy-duty vehicles. Hydra combines unprecedented innovation in hydrogen engine technology with a supply of low-carbon-intensity hydrogen fuel sourced from waste. Its Hydrogen as a Service™ model provides retrofits and fuelling infrastructure at no upfront cost to the fleet operator in exchange for an exclusive hydrogen fuel supply agreement. Heavy-duty diesel trucks can be retrofitted with Hydra technology to operate as dual-fuel, hydrogen-diesel vehicles without power, torque, range or payload loss while cutting GHG emissions and local air contaminants by 30-50%.



[8] CleanBC, *2020 Climate Change Accountability Report* (2020).

Zero-Emission Vehicles Act

The *Zero-Emission Vehicles Act* requires automakers to meet an escalating annual percentage of new light-duty zero-emission vehicle (ZEV) sales: 10% by 2025, 30% by 2030 and 100% by 2040. Although the targets start with light-duty vehicles, the legislation provides options to expand to other vehicle classes, including medium- and heavy-duty vehicles. The legislation aims to meet provincial GHG reduction targets and ensure British Columbians can benefit from a greater availability of ZEVs at more affordable prices.

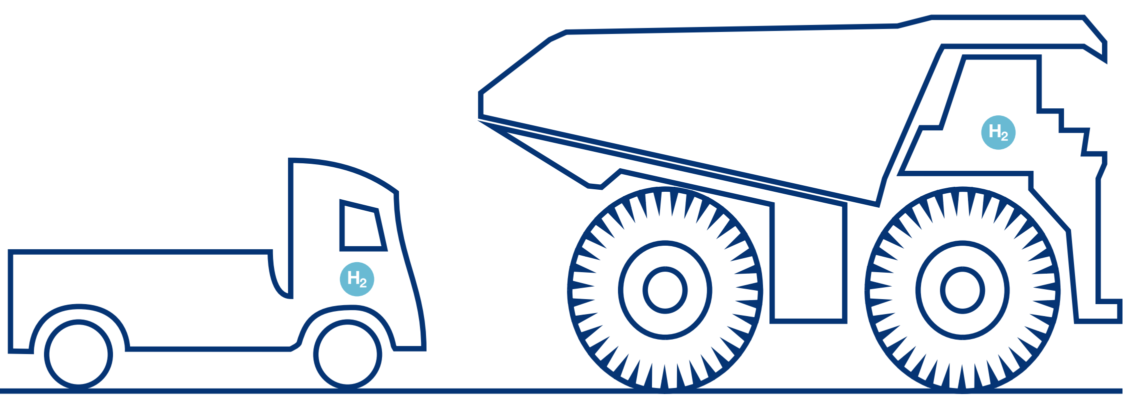
B.C.'s ZEV and FCEV Programs

The Province strives to remove barriers to adopting ZEVs, including hydrogen fuel cell electric vehicles (FCEVs). Through a comprehensive market transformation approach, the ZEV Act and Regulation, and the Go Electric program, support both the supply and demand for ZEVs in B.C. The Go Electric program provides financial support for the deployment of FCEVs, hydrogen fuelling stations and other hydrogen-powered technology and equipment through the Hydrogen Fuelling and Fleet program, Advanced Research and Commercialization program, the Commercial Vehicle Pilot program and the Speciality-Use Vehicle Incentive program. StrongerBC: BC's Economic Recovery Plan committed $30 million for a new Commercial Vehicle Innovation Challenge that will include supporting FCEV development. Additionally, the Go Electric Vehicle Rebate program supports the adoption of passenger FCEVs in B.C.

Loop Energy

More power, fewer materials

Burnaby-based Loop Energy develops world-leading zero-emission hydrogen fuel cell engines and fuel cell stacks for medium-to heavy-duty bus and truck applications. While fuel cell electric solutions have proven performance, cost remains an impediment to widespread adoption. Together with its partners, Loop Energy is commercializing zero-emission solutions that provide more power in a smaller system – with fewer materials and without compromising performance, range or economics.



Building out hydrogen fuelling infrastructure

In 2018, B.C. led the way when Canada's first retail hydrogen fuelling station opened in Vancouver with provincial government support. Since then, three more stations have been opened, two in Metro Vancouver and one in Greater Victoria. Vehicle manufacturers have targeted B.C. as a key market for the rollout of fuel cell electric vehicles in Canada thanks to the province's leadership in the fuel cell sector and the provincial government's commitment to expanding the hydrogen fuelling network as outlined in CleanBC. The Government of Canada is also supporting hydrogen fuelling stations across the country, and in 2019 Quebec's first retail hydrogen station opened for business with equipment designed and manufactured by B.C.'s Powertech Labs and Hydrogen Technology & Energy Corporation.

Hydrogen Technology & Energy Corporation (HTEC)
Experts in hydrogen fuelling infrastructure

HTEC builds, owns and operates hydrogen production facilities, distribution systems, and fuelling stations in B.C., Quebec, Alberta and California. The company began in 2005 and operates in North Vancouver. In collaboration with the Province and other partners, HTEC has opened four retail hydrogen fuelling stations in B.C., the largest network in Canada. Further, HTEC draws upon its deep industry experience, know-how and technologies to provide customized engineering services and packaged hydrogen production, processing, distribution and vehicle-fuelling solutions for its infrastructure platform and clients.

"Government policy will facilitate hydrogen's role in decarbonizing our world. Policies such as B.C.'s Zero-Emission Vehicles Act and low carbon fuel standard make it possible for fuel suppliers to deliver low-carbon-intensity fuels and give consumers the choice to drive hydrogen electric vehicles. HTEC couldn't lead the rollout of Canada's first network of hydrogen fuelling stations without the support of the Province and our other partners; we thank all for their shared commitment to fuelling the drive to hydrogen."

– Colin Armstrong, President & CEO
Hydrogen Technology & Energy Corporation

How we'll encourage the growth of hydrogen in transportation
2020-2025
• Pilot the use of hydrogen fuel cells in medium- and heavy-duty vehicles, marine, rail, aviation, off-road and other commercial transportation applications • Continue to leverage the Part 3 Agreement program to expand the public hydrogen fuelling station network across the province • Explore the roles FCEVs can play in supporting achievement of CleanBC commitments to make 10% of the BC government light-duty fleet ZEVs and reduce its emissions by 40% by 2030 • Provide monetary and non-monetary incentives for fuelling infrastructure and vehicle purchase • Allow medium- and heavy-duty vehicle sales to generate credits under the ZEV Act • Explore ZEV Act compliance targets for medium- and heavy-duty vehicle classes • ZEVs reach 10% of new light-duty vehicle sales by 2025
2025-2030
• Review and expand the pilot demonstration use of hydrogen fuel cells in medium- and heavy-duty vehicles, marine, rail, aviation, off-road and other commercial transportation applications • Include targets for medium- and heavy-duty vehicles in the ZEV Act • Support the development of hydrogen production and liquefaction infrastructure • ZEVs reach 30% of new light-duty vehicle sales by 2030
2030-beyond
• Continue to support the widespread use of hydrogen in medium- and heavy-duty vehicles, marine, rail, aviation, off-road and other commercial transportation applications • ZEVs reach 100% of new light-duty vehicle sales by 2040

Producing low-carbon and synthetic fuels

Using hydrogen to produce low-carbon and synthetic fuels is an opportunity to reduce emissions in B.C.'s transportation and refining sectors.

To increase the supply of cleaner fuels, CleanBC set out a target to ramp up production of renewable fuel in B.C. to 650 million litres by 2030. The B.C. low carbon fuel standard (LCFS) also requires fuel suppliers to progressively decrease the average carbon intensity of their fuels to achieve a 20% reduction in 2030 relative to 2010. This can be achieved by increasing the volume of biofuels blended with conventional fossil fuels or by supplying lower-carbon fuels such as hydrogen and electricity. Fuel suppliers generate credits by supplying fuels with a carbon intensity below the prescribed target. These credits can be used to comply with the LCFS or sold in the credit market to generate additional revenue. The LCFS encourages suppliers to offer lower-carbon fuels, such as hydrogen, in the B.C. fuel market.

In addition to setting annual carbon-intensity reduction requirements, the LCFS spurs growth in the clean fuels industry through the Part 3 Agreement Program. Under this program, fuel suppliers can obtain credits for undertaking projects that increase the use of low-carbon fuels sooner than would otherwise happen. The Province will continue to use existing policy mechanisms, such as the LCFS and the Part 3 Agreement Program to promote innovation while reducing GHG emissions resulting from the use of lower-carbon fuels. Since 2019, 23 projects have awarded over 800,000 credits and committed to investing over $450 million in emissions reductions in the B.C. fuels industry and the Part 3 Agreement Program to accelerate market transformation.

In the fossil fuel sector, hydrogen is used to refine crude oil into products that include gasoline, diesel and jet fuel. Since much of this hydrogen is currently produced from fossil fuels without CCS, finding ways to reduce the emissions from hydrogen production at refineries will also reduce the life-cycle emissions of these products. Hydrogen is also used in large quantities when making renewable fuels, such as co-processing biocrudes from renewable sources like canola oil or oil derived from animal fats (tallow). The Province is focusing efforts to deploy hydrogen use in low-carbon and synthetic fuel production, as these fuels can be used to decarbonize hard-to-abate sectors such as long-distance trucking, marine and aviation.

Carbon Engineering

Capturing carbon dioxide to make clean fuel

A licensed partner of Squamish-based Carbon Engineering Ltd., Huron Clean Energy is developing multiple clean fuel synthesis plants, beginning in B.C. and then deploying across Canada. Carbon Engineering's breakthrough Direct Air Capture and AIR TO FUELS™ technologies are used to create clean fuel out of air. When carbon dioxide captured from the atmosphere is combined with renewably generated hydrogen, clean fuel is produced. This clean, near-carbon-neutral fuel can be used in all existing transportation infrastructure as a replacement fuel or blended with current fuels such as gasoline, diesel or aviation Jet A to lower the carbon intensity of those fuels. Access to large quantities of low-carbon hydrogen produced in B.C. will be key in enabling these plants to deliver industrial quantities of clean fuels for the aviation and diesel markets.

Decarbonizing industrial processes

In addition to reducing the carbon intensity of fossil fuels used in hard-to-abate transportation sectors, low-carbon hydrogen can also be used to decarbonize industrial processes that are not practical to electrify or that require hydrogen as a feedstock. For example, many industrial processes require natural gas to produce process heat at temperatures that cannot be achieved through electrification. Additionally, the largest current use for hydrogen in Canada and internationally is as an essential feedstock in emissions-intensive industrial processes.

Hydrogen's decarbonization benefits and heating attributes mean that it can be used to displace natural gas and reduce the emissions from many high heat industrial processes. Industrial processes that require large amounts of high-grade heat include upstream fossil fuel extraction and downstream refining, cement manufacturing, pulp and paper processing, and other steam reliant processes.[9]

The demand for hydrogen today is driven by industries that require it as a feedstock, primarily in oil refining, ammonia production, methanol production and steel production.[10] As the vast majority of hydrogen used in these industries is produced from fossil fuels without CCS, low-carbon hydrogen presents an alternative that can reduce the carbon intensity of final products.

How we'll support industry to increase hydrogen use
2020-2025
• Evaluate the use of hydrogen across different heavy industries, such as at pulp and paper mills, cement plants, petroleum refineries and aluminum smelters to reduce emissions and create economic development • Support pilots for the use of low-carbon hydrogen for synthetic fuel production • Explore carbon-intensity targets under the low carbon fuel standard
2025-2030
• Review the success of pilot projects across B.C.'s industries • Support the use of hydrogen across industries in B.C., including refining biocrude and producing synthetic fuels • Support the use of hydrogen in small and medium-size industrial businesses • Support hydrogen's contribution to the CleanBC targets of producing 650 million litres of renewable or low-carbon fuels per year and the low carbon fuel standard reaching 20% reduction in carbon intensity by 2030
2030-beyond
• Where appropriate, support the use of low-carbon hydrogen in industrial processes, such as in pulp and paper mills, petroleum refining and aluminum smelting

9 Government of Canada, *Hydrogen Strategy for Canada* (2020).
10 International Energy Agency, *The Future of Hydrogen: Seizing Today's Opportunities* (2019).

Hydrogen hubs

One of the challenges facing hydrogen development in B.C., and around the world, is matching supply and demand. Regional hydrogen hubs overcome this challenge by co-locating hydrogen production and end-use applications. Through co-location, hydrogen hubs generate early and focussed opportunities for domestic hydrogen production and use in areas otherwise heavily dependent on fossil fuels by spurring and growing supply and demand, lowering costs and strengthening local hydrogen proficiency.

The concept of hydrogen hubs fits well with B.C.'s abundance of clean electricity and natural gas resources, established local hydrogen companies and variety of end-use applications. Supporting hydrogen hubs in B.C. is critical to accelerating domestic hydrogen supply and demand, while also realizing the significant economic opportunities in developing B.C.'s hydrogen export market. The Province is committed to identifying regions that can support and realize the greatest decarbonization benefits of hydrogen hubs, such as seaports, industrial sites and urban locations like UBC's city-scale hydrogen testbed.

Fuelling economic development

Hydrogen is both a clean energy solution and an economic development opportunity for B.C.

Hydrogen's key contribution to B.C.'s net-zero economy

Hydrogen is not only key in B.C.'s path to net-zero emissions by 2050, but also to building a prosperous low-carbon economy with new clean energy jobs. Home to Canada's largest cluster of hydrogen companies, B.C. has the unique opportunity to leverage an already successful local hydrogen sector to grow its hydrogen economy. Low-carbon hydrogen's decarbonization attributes present an opportunity for B.C. to reduce emissions and support the scale-up of B.C.-based hydrogen companies with expertise in low-carbon technologies and innovation. All of this will be in high demand as B.C. and many countries around the world pursue net-zero targets.

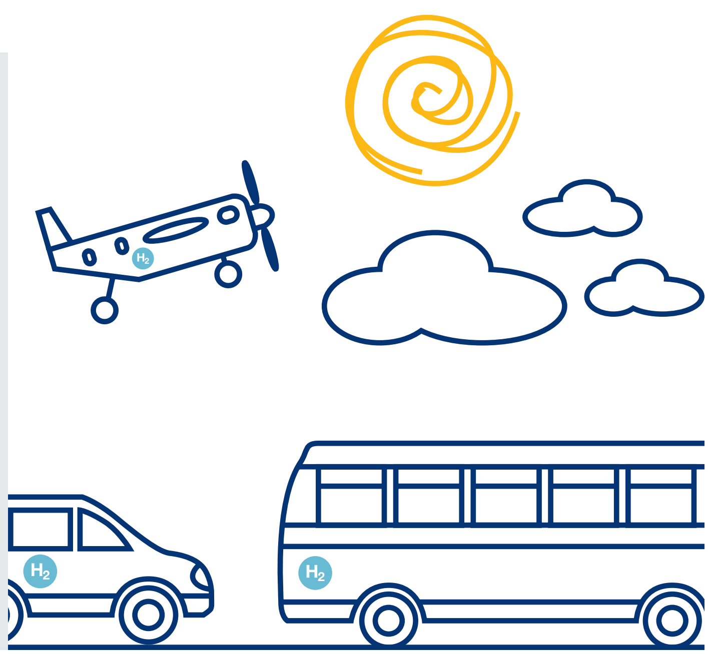
In April 2021, the Province committed $35 million to establish the Centre for Innovation and Clean Energy (CICE) as part of StrongerBC. The CICE will bring together innovators, companies, government and researchers to accelerate the commercialization of clean energy technology and products, including low-carbon hydrogen.

Zero-emission vehicles call for technicians with new skills

As zero-emission cars gain in popularity, there's a growing need for technicians and mechanics who can service these vehicles. The Province provided $325,000 in funding to the British Columbia Institute of Technology to develop a first-of its-kind training course for certified Red Seal automotive service technicians to upgrade their skills for zero-emission vehicles. The curriculum was designed in partnership with the City of Vancouver's green-fleet technicians and includes course modules for servicing battery electric, plug-in hybrid and fuel cell electric vehicles. The course will be offered throughout the province in Kelowna, Prince George and Victoria.

UBC's Hydrogen Hub
A city-scale testbed

With support from the Ministry of Energy, Mines and Low Carbon Innovation, the University of British Columbia has broken ground on a project that brings the production, distribution and end use of hydrogen together on one city block at the corner of Wesbrook Mall and Thunderbird Boulevard in Vancouver. The Integrated Energy Test Bed uses a solar array to charge electric vehicles and power a water electrolyzer. The produced hydrogen feeds a refuelling station for light- and heavy-duty fuel cell vehicles.



Hydrogen in Indigenous and remote communities

There are up to 50 remote communities in B.C. that are not connected to the natural gas or electricity distribution systems, and as a result experience energy-related challenges and opportunities that are very different from grid-connected communities. Numerous remote communities rely on diesel-powered generators to meet their power needs, and as part of CleanBC, the Province has set a target of reducing diesel generation of electricity province-wide by 80% by 2030.

Many Indigenous Nations are interested in adopting clean energy solutions that will reduce their carbon footprint, strengthen community resilience, achieve energy self-sufficiency and increase economic opportunities for their communities. Hydrogen is a potential energy resource to achieve each of these objectives, either from cleaner back-up power, fuel cell electric vehicles or increased economic activity. The Province will engage with interested Indigenous Nations to explore whether there are opportunities to be involved in developing, owning and operating hydrogen infrastructure and services.

Hydrogen-powered microgrids, which can deliver combined heat and power, have the potential to stimulate economic development opportunities. This may come in the form of employment, investment and potential for joint ownership with industry. Hydrogen-powered microgrids may also benefit communities by shifting reliance away from high-carbon-emitting generation technologies, lowering GHG emissions, improving air quality, reducing noise pollution and eliminating diesel spills.

Communities may consider building out hydrogen fuelling infrastructure to promote the uptake of fuel cell electric vehicles, which maintain high performance even during extreme cold or heat. Diesel-reliant communities may also be interested in integrating hydrogen with renewable resources to power their communities. For example, in areas where electricity can be generated from wind resources, communities could store energy using hydrogen for later use, thereby minimizing the impacts of intermittency.

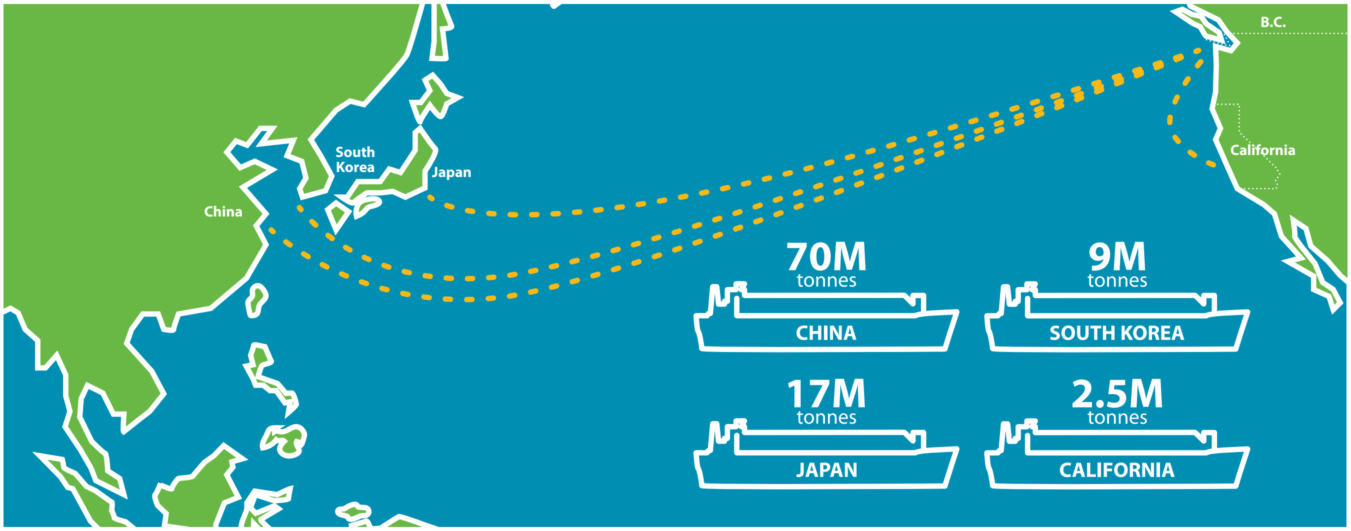
There are several potential applications for hydrogen in remote communities. The Province recognizes that a one-size-fits-all approach for hydrogen is not possible, as each community differs in size, climate, geography and energy requirements. Furthermore, production, storage and distribution costs may be a challenge depending on scale, technology and site location. The Province will look to understand the potential opportunities of hydrogen with interested communities and explore what options exist for capacity building and clean energy planning.

Declaration on the Rights of Indigenous Peoples Act

The Government of B.C. is committed to advancing reconciliation with Indigenous peoples through the implementation of the *Declaration on the Rights of Indigenous Peoples Act*. Consistent with this legislation, the Province acknowledges the need to consult and co-operate with Indigenous Nations early and in good faith to obtain their free, prior and informed consent relating to adopting and implementing hydrogen-related legislative or administrative measures that may affect them.

How we'll advance hydrogen as a source of clean energy in communities
2020-2025
Commission a comprehensive study for hydrogen in communities, including: • Education and engagement on the potential for hydrogen • Novel applications of hydrogen (e.g., phasing out propane) • Capacity-building tools for community clean energy and hydrogen projects • A case study with a small to medium-sized fossil-fuel-reliant community to investigate the feasibility of moving to 100% renewable energy with a hydrogen component
2025-2030
• Implement findings and results from the community feasibility study • Introduce capacity-building tools for community clean energy and hydrogen projects
2030-beyond
• Support the conversion of a small to medium-sized fossil-fuel-reliant community to hydrogen • Promote the installation of hydrogen to power communities

Exporting hydrogen



Demand projections by jurisdiction in 2050

Jurisdictions around the world are seeking ways to meet emissions reduction goals and are recognizing the role that hydrogen can play to help them meet ambitious targets. The global market for hydrogen is expected to reach more than 230 million tonnes in 2050. B.C. is well-positioned to meet a portion of this demand due to our extensive low-cost natural gas reserves, clean electricity, proximity to key trading partners and existing natural gas infrastructure that can be leveraged for exporting hydrogen.

The top export markets of China, Japan, South Korea and California are predicted to account for almost 50% of total global demand for hydrogen by 2050 with a combined market size of $305 billion.[11] If B.C. can capture even a fraction of this export market, it will result in significant export revenue for the province. Our proximity to these markets and their advanced plans for the adoption of hydrogen at scale further strengthens B.C.'s export potential.[12]

The *BC Hydrogen Study* estimates that B.C.'s potential production capacity could be over 2.2 million tonnes annually. Our experience and proven capabilities in producing and exporting natural resources makes for a potentially smooth transition to exporting hydrogen. This demand for hydrogen could be met through various production pathways, with transportation choices based on geography, volume, distance and end-use. The Province will continue to engage with industry stakeholders and our international partners to create export supply chains and foster support for hydrogen.

[11] Zen and the Art of Clean Energy Solutions, *BC Hydrogen Study - Final Report* (2019).
[12] ITM Power, Chiyoda Corporation, Mitsui & Co. and G&S Budd Consulting, *Centralized Renewable Hydrogen Production in BC - Final Report* (2019).

How we'll develop B.C.'s export market for hydrogen
2020-2025
• Collaborate with industry stakeholders and international partners regarding export opportunities • Promote B.C. internationally as an attractive jurisdiction for investment in hydrogen production for domestic supply and export • Continue to promote B.C.'s fuel cell technology abroad and promote the province as a supplier of low-carbon hydrogen to global markets
2025-2030
• Attract domestic and international investment for the development of supply chains to export hydrogen
2030-beyond
• Enable the construction of dedicated infrastructure for hydrogen export

Measuring our success

These Measures of Success will guide us as we continue to grow our vibrant and innovative hydrogen and fuel cell sector in B.C.

Measures of Success	
Jobs and prosperity	• B.C. maintains its position as a leader in fuel cell development with a diverse talent pool of highly qualified personnel • B.C. experiences job growth in trades as a result of a hydrogen production industry • Indigenous communities are supported in identifying possible pathways for partnerships and participation in the growing hydrogen sector
Competitive	• B.C. develops multiple hydrogen hubs that accelerate the growth of the local hydrogen economy • B.C. produces hydrogen that is a cost-effective energy resource for British Columbians • B.C. maintains its competitive position regarding the commercialization of hydrogen and fuel cell technology
Innovation	• B.C. continues to have a highly innovative hydrogen and fuel cell technology sector • B.C. has world-class hydrogen production supply chains as well as a supportive research and development environment
Clean	• The carbon intensity of hydrogen produced in B.C. declines over time • The hydrogen industry uses water sustainably and continues to look for innovative ways to maximize efficient water usage
Communities	• Benefits flow back to Indigenous and non-Indigenous communities where hydrogen production facilities are located • Hydrogen is a cost-effective option for diesel-reliant Indigenous and non-Indigenous communities to achieve their climate objectives
Hydrogen exports	• B.C. exports hydrogen to key markets and meets a portion of international demand • Hydrogen exports provide a net benefit to British Columbians • B.C. is seen as an attractive jurisdiction for domestic and international investment in hydrogen

Summary of policy actions

As outlined throughout this Strategy, the Government of British Columbia is committed to providing the policy, regulatory and infrastructure support needed to realize hydrogen's potential to help us meet our emissions reduction goals. The following actions for the next 10 years and beyond will enable us to achieve our vision to be a world-leading hydrogen economy by 2050.

How we'll grow hydrogen production
2020-2025
• Stimulate hydrogen production through direct support and incentives • Continue to provide policy support for increasing hydrogen demand certainty and de-risking the development of hydrogen production infrastructure • Provide policy support to utilities who choose to produce or purchase hydrogen • Advocate for increased production and consumption of hydrogen in B.C. • Work with industry partners to establish hydrogen deployment hubs in B.C.
2025-2030
• Consider introducing alternative electricity rate designs to support hydrogen production • Promote hydrogen production at scale to meet domestic and/or international demand • Determine if brownfield sites can be used for industrial parks that include hydrogen production
2030-beyond
• Support long-term self-sufficiency in hydrogen supply and with it introduce new opportunities for economic development • Support the development of hydrogen liquefaction, distribution and transmission infrastructure
How we'll regulate hydrogen production
2020-2025
• Review provincial, federal and international codes, standards and regulations for hydrogen production and establish a compatible regulatory framework • Amend regulations to allow the BC Oil and Gas Commission to regulate hydrogen production, storage and transportation if produced from fossil fuels • Amend *Water Sustainability Act* related regulations to include hydrogen production as an authorized industrial water use purpose and set new water fees and rentals • Enable hydrogen as a pathway for natural gas utilities to reduce emissions • Ensure regulatory frameworks relating to hydrogen production and use are aligned to encourage continued reductions in carbon intensity over time • Establish carbon-intensity targets for hydrogen production pathways • Provide support only for renewable or low-carbon hydrogen pathways • Establish a working group made up of representatives from the hydrogen industry, regulatory agencies and government to implement B.C. Hydrogen Strategy actions

2025-2030

- Continue to implement the Low Carbon Fuel Standard Part 3 Agreements to advance hydrogen production, fuelling infrastructure, operation and maintenance projects
- Review sectoral opportunities for hydrogen offtake
- Develop carbon management frameworks to encourage at-scale production of low-carbon hydrogen and transition policy incentives from direct support to market-based mechanisms

2030-beyond

- Achieve a clear and supportive regulatory environment for hydrogen production in B.C.
- Require a phased reduction in the carbon intensity of hydrogen produced and used in B.C.
- Explore policy framework mechanisms for long-duration energy storage using hydrogen

How we'll support blending hydrogen with natural gas

2020-2025

- Establish a regulatory framework for injecting hydrogen into the natural gas and propane distribution systems
- Include hydrogen as a prescribed undertaking under the *Greenhouse Gas Reduction Regulation*
- Partner with a utility to review the infrastructure requirements to accommodate up to 100% hydrogen in the distribution system
- Support hydrogen injection trials into natural gas and/or propane distribution systems

2025-2030

- Mandate that new or modified natural gas or propane pipelines be hydrogen compatible
- Support the introduction of hydrogen-tolerant equipment
- Explore the role of hydrogen in meeting the CleanBC 15% renewable gas target

2030-beyond

- Support large-scale hydrogen injection into the natural gas and propane distribution systems

How we'll encourage the growth of hydrogen in transportation

2020-2025

- Pilot the use of hydrogen fuel cells in medium- and heavy-duty vehicles, marine, rail, aviation, off-road and other commercial transportation applications
- Continue to leverage the Part 3 Agreement program to expand the public hydrogen fuelling station network across the province
- Explore the roles FCEVs can play in supporting achievement of CleanBC commitments to make 10% of the BC government light-duty fleet ZEVs and reduce its emissions by 40% by 2030
- Provide monetary and non-monetary incentives for fuelling infrastructure and vehicle purchase
- Allow medium- and heavy-duty vehicle sales to generate credits under the ZEV Act
- Explore ZEV Act compliance targets for medium- and heavy-duty vehicle classes
- ZEVs reach 10% of new light-duty vehicle sales by 2025

2025-2030
• Review and expand the pilot demonstration use of hydrogen fuel cells in medium- and heavy-duty vehicles, marine, rail, aviation, off-road and other commercial transportation applications • Include targets for medium- and heavy-duty vehicles in the ZEV Act • Support the development of hydrogen production and liquefaction infrastructure • ZEVs reach 30% of new light-duty vehicle sales by 2030
2030-beyond
• Continue to support the widespread use of hydrogen in medium- and heavy-duty vehicles, marine, rail, aviation, off-road and other commercial transportation applications • ZEVs reach 100% of new light-duty vehicle sales by 2040
How we'll support industry to increase hydrogen use
2020-2025
• Evaluate the use of hydrogen across different heavy industries, such as at pulp and paper mills, cement plants, petroleum refineries and aluminum smelters to reduce emissions and create economic development • Support pilots for the use of low-carbon hydrogen for synthetic fuel production • Explore carbon-intensity targets under the low carbon fuel standard
2025-2030
• Review the success of pilot projects across B.C.'s industries • Support the use of hydrogen across industries in B.C., including refining biocrude and producing synthetic fuels • Support the use of hydrogen in small and medium-size industrial businesses • Support hydrogen's contribution to the CleanBC targets of producing 650 million litres of renewable or low-carbon fuels per year and the low carbon fuel standard reaching 20% reduction in carbon intensity by 2030
2030-beyond
• Where appropriate, support the use of low-carbon hydrogen in industrial processes, such as in pulp and paper mills, petroleum refining and aluminum smelting

How we'll advance hydrogen as a source of clean energy in communities

2020-2025

Commission a comprehensive study for hydrogen in communities, including:

- Education and engagement on the potential for hydrogen
- Novel applications of hydrogen (e.g., phasing out propane)
- Capacity-building tools for community clean energy and hydrogen projects
- A case study with a small to medium-sized fossil-fuel-reliant community to investigate the feasibility of moving to 100% renewable energy with a hydrogen component

2025-2030

- Implement findings and results from the community feasibility study
- Introduce capacity-building tools for community clean energy and hydrogen projects

2030-beyond

- Support the conversion of a small to medium-sized fossil-fuel-reliant community to hydrogen
- Promote the installation of hydrogen to power communities

How we'll develop B.C.'s export market for hydrogen

2020-2025

- Collaborate with industry stakeholders and international partners regarding export opportunities
- Promote B.C. internationally as an attractive jurisdiction for investment in hydrogen production for domestic supply and export
- Continue to promote B.C.'s fuel cell technology abroad and promote the province as a supplier of low-carbon hydrogen to global markets

2025-2030

- Attract domestic and international investment for the development of supply chains to export hydrogen

2030-beyond

- Enable the construction of dedicated infrastructure for hydrogen export

H_2

Appendix A-5

CLEANBC ROADMAP TO 2030

BRITISH COLUMBIA

cleanBC

our nature. our power. **our future.**

Roadmap to 2030

LAND ACKNOWLEDGEMENT

We acknowledge with respect and gratitude that this report was produced on the territory of the Lək̓ʷəŋən peoples, and recognize the Songhees and Esquimalt (Xwsepsum), and W̱SÁNEĆ Nations whose deep connections with this land continue to this day.

CONTENTS

A MESSAGE FROM PREMIER JOHN HORGAN

Here in British Columbia, people share a deep connection to the clean water, abundant forests and rich farmland around us. Our province's landscape is a source of beauty, food and economic opportunities. It is a source of great pride for all of us. There is simply nothing more important than protecting this natural inheritance for future generations.

Today, the things we cherish the most in B.C. are at risk like never before.

While we are living through a time of uncertainty and overlapping crises, the greatest challenge we face now and into the future is climate change. The threat is no longer decades or even years away. The impacts are all around us – from devastating wildfires and intense heat waves to droughts and dying crops.

Three years ago, our government introduced CleanBC – North America's most progressive climate action plan. In that time, we have regulated carbon emissions from the biggest polluters, legislated strong climate targets, and made it easier for people and businesses to switch from fossil fuels to clean energy solutions.

The scale of the climate emergency we are living through demands that we act with even greater urgency.

We have accomplished a lot together, but there is so much more we need to do. As British Columbians, we know we can't afford to delay action. That's why we're taking the next big step on our continent-leading plan and introducing new measures so that we can meet our Paris emissions reduction targets for 2030 and reach net zero by 2050.

The CleanBC Roadmap builds on the progress we've made. It will help power more businesses and communities with clean, renewable hydro power. Working with large industry partners, it will ensure sector-specific plans to reduce their climate pollution. Most importantly, it will encourage innovation of clean alternatives, which will become more affordable to British Columbians.

In developing this Roadmap, we listened to input from people across British Columbia – including consultation with Indigenous leaders and expert advice from the Climate Solutions Council. As the plan is rolled out, we will seize the opportunity to build stronger partnerships with Indigenous peoples by ensuring they share in decision making and the prosperity created in the low carbon economy.

Tackling climate change is not only our greatest challenge. It's also an opportunity to build a stronger, more resilient B.C.

The world has changed since we first launched CleanBC. But our province is uniquely well-positioned to thrive in the emerging clean economy. We have abundant clean energy and renewable resources. We are strategically located as a gateway to the Asia-Pacific region and a major port to the rest of North America.

By far our biggest asset is our people. If the recent forest fires and the pandemic have taught us anything, it's that we're best when we work together. It is that same sense of common purpose that we must bring to the fight against climate change. No one person, or government, can turn things around on their own. It will take all of us doing our part to seize the opportunity in overcoming this historic challenge.

That's what this plan is all about. Working together to chart a path to a cleaner, brighter future with good jobs and opportunities – for everyone.

Honourable John Horgan
Premier of British Columbia

A MESSAGE FROM MINISTER GEORGE HEYMAN

When we launched CleanBC in 2018 we were very clear that our modelling left us with an emissions gap. We needed to intensify our focus across all sectors to hit our emissions reduction goal by 2030. We have since introduced legislatively enforced accountability measures that support the findings of recent landmark reports from the Intergovernmental Panel on Climate Change and others. In short, everyone needs to do more to address climate change.

CleanBC set out a series of actions to begin a 30-year journey to build opportunity, keep communities strong and sustain human and ecological health. In many respects it set a standard for others to reference given its comprehensive approach. The Roadmap to 2030 takes its lead from CleanBC and takes us even further. In fact, it takes us to 100 percent of the achievement of our 2030 emissions reduction target and sets the course to fulfill our net-zero commitment by 2050.

The Roadmap is a clear articulation of where we need to expand and accelerate our action to reduce greenhouse gas emissions. It takes note of where things are showing signs of early success and where renewed approaches are necessary. It creates the opportunity for new partnerships like bringing together B.C.'s burgeoning clean tech sector with traditional industries to position B.C. products and services for new and evolving markets. Increasingly global investors are recognizing climate-centred technologies as critical in how we transition to living better on the planet. British Columbia is ideally positioned to take advantage of these new opportunities and the Roadmap supports that case.

A number of the actions will show rapid results as we commit to meeting or exceeding the federal benchmark on carbon pricing, enact requirements for all new buildings to be zero carbon by 2030 and eliminate emissions from all new cars by 2035. As these new technologies come on stream we will increase clean energy and fuel efficiency to support the transition.

Like all maps, the purpose of the Roadmap is to set the direction and offer choices to guide our efforts as we continue to track progress. It will allow us to anticipate challenges and potential changes in course. It expands on the principles of fairness and equity so that costs and benefits are evenly distributed as we introduce new measures.

The plan laid out in the pages that follow is admittedly technical. The tables, charts and analysis tell a story to help decision-makers across all sectors reach our goals. They are tools to help construct that better future we all want for our children and their children. In developing this plan we have not lost sight for one moment that ultimately the Roadmap is about people. It is about our connection to place, a place that we are seeing with new eyes through the lens of reconciliation and renewed relationships with Indigenous peoples. Our success will ultimately be determined by the way our natural environment responds to our choices in this journey. I am confident that with the Roadmap focusing our efforts we will arrive at our destination and more importantly we will all arrive together.

George Heyman
Minister of Environment and Climate Change Strategy

EXECUTIVE SUMMARY

The need to take urgent action together to reduce the impacts of climate change and build a strong clean economy for everyone has never been clearer than it has this past year. Two international reports outlined the challenge ahead and called for faster action. The landmark study from the Intergovernmental Panel on Climate Change[1] provided the latest scientific consensus on climate change and was characterized as a 'code red for humanity' by leading scientific and climate experts.

In British Columbia, we saw the impacts first-hand with an unprecedented heat wave, severe droughts and dangerous wildfires this past summer. These events were a poignant example of how serious the climate crisis is and why we need to act now.

Challenges and opportunities

This spring, the International Energy Agency also released a detailed report[2] outlining the challenges and opportunities of meeting net-zero emissions globally by 2050. The report acknowledged that countries around the world are struggling to meet the moment with policies and plans to reduce emissions and create a vibrant, resilient low carbon future.

The last year saw growing recognition in the financial and business community that business-as-usual is no longer an option. Global investors like the Glasgow Financial Alliance for Net Zero – representing over $80 trillion (USD) in investment capital – have called for an accelerated transition to net-zero emissions by 2050 at the latest. Increasingly, investors are asking for detailed plans outlining how companies can prosper in a carbon-constrained world as a prerequisite for investment.

1 International Energy Agency. (May 2021). Net Zero by 2050. Available online: www.iea.org/reports/net-zero-by-2050
2 Intergovernmental Panel on Climate Change. (2021). Sixth Assessment Report. Available online: www.ipcc.ch/assessment-report/ar6

These significant developments in the global economy represent major opportunities for British Columbia. Our province's CleanBC plan includes a wide range of actions to reduce emissions, build a cleaner economy and prepare for the impacts of climate change. Launched in late-2018, CleanBC is helping improve how we get around, heat our homes and power our industry – setting us on the path to a cleaner, stronger future. It includes groundbreaking policies that are leading the way forward on climate change. For example, we were the first in the world to make it law that all new car and truck sales would be zero-emission vehicles by 2040. Since that time, we've seen the highest uptake in electric vehicle purchases on the continent, thanks in part to CleanBC incentives and investments that make 'going electric' more affordable and convenient.

Across B.C., we have seen industries and businesses respond both to CleanBC actions and to the new global economic environment. At least half of all emissions from large operators in B.C. are now covered by a corporate commitment to reach net zero by 2050. We've worked with industry to accelerate this transition by investing in new technologies that reduce emissions and support good jobs for people. And we are accelerating industrial decarbonization by utilizing one of B.C.'s strongest assets in the fight against climate change – our supply of clean, abundant, and affordable hydro-electricity.

While we have made enormous progress in a few short years, we know there is much more to do. B.C. has not been immune to the challenges faced by other jurisdictions trying to reach their targets.

As required by our climate accountability legislation, government presents the latest information every year on progress to our emissions targets. New emissions projections show the road ahead is significantly more challenging than when CleanBC was originally launched in 2018.

While there are several reasons for this shift – including revised emissions methodology from the federal government – it's clear that substantial new and sustained action is required to meet our commitments.

The CleanBC Roadmap to 2030 is our plan to achieve 100% of our emissions target while building a cleaner economy that benefits everyone. It includes a range of accelerated and expanded actions across eight pathways.

- Low Carbon Energy
- Transportation
- Buildings
- Communities
- Industry, including Oil and Gas
- Forest Bioeconomy
- Agriculture, Aquaculture and Fisheries
- Negative Emissions Technologies

The Roadmap will strengthen action in areas already showing positive results, as well as those at the earlier stages of transition. Each action is based on how affordable and available clean solutions are in each market – known as 'market readiness'. If low-carbon technologies are already available and affordable, for example, the

Roadmap will help increase their adoption on a wider scale through targeted supports, regulations and other policies. If technologies are limited in their availability and expensive, actions instead focus on supporting research, development, and commercialization to create affordable, clean options. This approach will help minimize costs and maximize benefits in the long run.

Foundational Roadmap actions include:

- A stronger price on carbon pollution, aligned with or exceeding federal requirements, with built in supports for people and businesses
- Increased clean fuel requirements and doubling the target for renewable fuels produced in B.C. to 1.3 billion litres by 2030
- An accelerated zero-emission vehicle (ZEV) law (26% of new light-duty vehicles by 2026, 90% by 2030, 100% by 2035)
- New ZEV targets for medium- and heavy-duty vehicles aligned with California
- Complete B.C.'s Electric Highway by 2024 and a target of the province having 10,000 public EV charging stations by 2030
- Actions to support mode-shift towards active transportation and public transit
- Stronger methane policies that will reduce methane emissions from the oil and gas sector by 75% by 2030 and nearly eliminate all industrial methane emissions by 2035
- Requirements for new large industrial facilities to work with government to demonstrate how they align with B.C.'s legislated targets and submit plans to achieve net-zero emissions by 2050
- Enhancing the CleanBC Program for Industry to reduce emissions while supporting a strong economy
- Implement programs and policies so that oil and gas emissions are reduced in line with sectoral targets
- A cap on emissions for natural gas utilities with a variety of pathways to achieve it

- New requirements for all new buildings to be zero carbon and new space and water heating equipment to be highest efficiency by 2030
- Implement a 100% Clean Electricity Delivery Standard for the BC Hydro grid
- A new program to support local government climate and resiliency goals with predictable funding
- Support for innovation in areas like low carbon hydrogen, the forest-based bioeconomy and negative emissions technologies
- Household affordability will continue to be a key focus, especially for those who need it most.

British Columbia's plan will be aligned with actions being taken at the federal, municipal and Crown corporation levels. When emissions reductions from these actions are considered, we expect B.C. to further surpass our 2030 emissions target.

These actions and others included in the Roadmap will help drive deeper emissions reductions at a faster pace and support clean economic opportunities.

In less than a decade, people across our province will live, work and play in a cleaner and more prosperous B.C. Almost all new vehicles sold in the province will be zero emissions. We'll see more people walking, biking and taking transit.

Our communities will be more comfortable with less pollution. New homes and buildings will no longer emit carbon pollution and will use energy much more efficiently, saving people money on their energy bills. They will be built using materials that are less carbon intensive. People will have more affordable options to retrofit their homes. The system that delivers natural gas to heat homes and businesses today will transition to also deliver cleaner fuels like renewable natural gas and hydrogen. And more of us will find jobs in the clean economy working to reduce pollution with innovative advanced technologies that are exported beyond our borders.

A central pillar of the Roadmap focuses on our abundant supply of clean and affordable hydroelectric power as an alternative to fossil fuels. B.C. is one of the few jurisdictions in the world with an electricity grid that can deliver close to 100% zero-emissions electricity to power our homes, businesses and vehicles. Further, by pairing this resource with our commitment to innovation and partnership between B.C.'s clean tech sector and traditional industries, we're ensuring B.C. is ideally positioned for a world that is increasingly focused on near-term emissions reductions and reaching net-zero emissions by mid-century.

The Roadmap recognizes that we are at a defining moment of change and need to make sure we're ready for a global economy that is rapidly moving towards a future defined by net-zero emissions. It also builds on other efforts across government including the upcoming Climate Preparedness and Adaptation Strategy and economic plan, as well as work to modernize the forest sector and implement the recommendations of the Old Growth Strategic Review.

Nature often offers the best solutions to strengthening our response to climate change. In British Columbia, we are blessed to have a natural environment that sustains our health, strengthens our communities and builds hope for the future. The Roadmap demonstrates that at the core of our approach to climate change is a foundational commitment to protecting and preserving our environment now and for future generations.

CHAPTER 1: CLEANBC AND THE ROAD TO 2030

1.1 Accelerating Climate Impacts, Accelerating Climate Action

Climate change is often called the defining issue of our time. It demands simultaneous action on two fronts: reducing greenhouse gas emissions and making sure our homes, communities, businesses and infrastructure can withstand the impacts of a changing climate in the years to come.

It's hard work, but British Columbians are rising to the challenge – changing our behavior (what we buy, how we get around, how we heat and cool our homes), our economy (what we produce and how we produce it), and our energy system (how much and what kinds of energy we use, as well as how often we use them). More and more people are choosing electric vehicles, installing heat pumps in their homes and buildings, and investing in low carbon technologies and approaches.

These trends are encouraging. At the same time, we know we need to do much more. The pace and scale of climate change are accelerating, threatening so much of what we hold dear.

B.C.'S NET-ZERO COMMITMENT

Like our current emission reduction targets, B.C.'s commitment to a net-zero future will be backed by legislation. We'll engage with Indigenous communities, local governments, business, industry and others in 2022 to ensure the legislation is consistent with the targets, and the paths to reach them.

Net zero means that any greenhouse gas (GHG) emissions from our economy are balanced by equivalent amounts of GHG removals from the atmosphere. Working to achieve this balance will advance our economy, create good jobs and help to keep us competitive.

Net zero and the new global economic context

On top of these changes, international markets are shifting and demand is growing quickly for new climate-friendly technologies and services, renewable energy and low carbon products. Dozens of countries, accounting for roughly 70% of global GDP, have now adopted net-zero-by-2050 targets. Our neighbours and partners in the Pacific Coast Collaborative – Washington, Oregon and California – are significantly ramping up their own climate actions. And almost 20% of the world's biggest companies – representing annual sales of nearly $14 trillion – now have plans to achieve net-zero emissions by 2050.[3]

During 2020, even with the global downturn created by COVID-19, investment in clean energy and climate solutions grew significantly. Companies and governments around the world put half a trillion dollars into renewable energy, electrified transport, electrified heat, energy storage, hydrogen production, and carbon capture and storage.[4] And B.C. clean tech companies are at the forefront of this transition – with four on the 2021 Global Cleantech 100 list.

GLASGOW ALLIANCE

Over 250 firms with more than $88 trillion in assets have joined forces to steer the global economy towards net-zero emissions. The Glasgow Financial Alliance for Net Zero, chaired by Mark Carney, UN Special Envoy on Climate Action and Finance and former Bank of Canada governor, brings together leading net-zero initiatives from across the financial system to accelerate the transition to net-zero emissions by 2050 at the latest.

Members include major asset owners and managers as well as banks with the power to mobilize trillions of dollars behind the transition to net zero.

Closer to home, the B.C. based Catalyst Business Alliance – a network of companies focused on clean growth – believes that climate change is the greatest risk to jobs and the economy. It champions strong climate and energy policy, and the creation of a resilient economy that benefits customers, employees, communities and the environment.

There's also a growing global movement to ensure that solutions are responsibly sourced and conform to high environmental, social and governance (ESG) standards. Investors with more than $120 trillion worth of assets under management have signed on to the United Nations Principles for Responsible Investment, which advocates a greater focus on ESG investing.

These developments support the business case for increasing our climate ambition. B.C. is well positioned to meet the interests of ESG investors with abundant clean energy, a vibrant clean tech sector, clean industries and a rich, diverse and growing bioeconomy.

3 Taking stock: A global assessment of net zero targets. (23 March 2021). Available online: www.eciu.net/analysis/reports/2021/taking-stock-assessment-net-zero-targets

4 BloombergNEF 2021 Executive Factbook. (March 2 2021). Available online: www.about.bnef.com/blog/bloombergnef-2021-executive-factbook

We're also making progress in partnership with Indigenous peoples, as part of our commitment to implement the Declaration on the Rights of Indigenous Peoples Act. The Province and Indigenous peoples are working together to develop a province-wide, whole-of-government action plan, setting out a path towards reconciliation. The plan will describe the long-term actions needed to meet the objectives of the UN Declaration, along with specific actions the Province will take in the next five years.

We've shown that working together with Indigenous peoples creates more opportunities for everyone. As the plan is implemented, we will have renewed opportunities to build stronger partnerships and better incorporate Indigenous rights, perspectives and interests into provincial climate plans and policies. We have heard clearly from Indigenous peoples about the importance of early and meaningful engagement, and that more can be done to increase capacity to ensure Indigenous peoples can participate most effectively. There is also enormous opportunity that comes with mobilizing Indigenous resources to build new economic opportunities while protecting the environment. We will further strengthen our consultation and engagement work on climate action, including with First Nations Economic Development Officers (EDOs) or similar leadership groups from Nations that don't have EDOs.

Ongoing engagement with Indigenous peoples has informed and shaped this Roadmap, the Climate Preparedness and Adaptation Strategy and our continued partnership on shared climate objectives. This includes work with the First Nations Leadership Council, which is developing a B.C. First Nations Climate Strategy and Action Plan.

These actions are consistent with our commitment to address our greatest challenges in ways that benefit people, communities and the environment, along with the economy. This Roadmap provides another set of opportunities to make our society more inclusive and sustainable – by putting people first and ensuring we consider and mitigate impacts to B.C.'s diverse populations.

> *"I would say with a pretty high degree of confidence that in the next three years a net-zero commitment and a plan to achieve it will be the norm for public companies"*
>
> – Mark Carney, UN Special Envoy on Climate Action and Finance and former Bank of Canada governor[5]

5 Financial Post. (September 21, 2021). Mark Carney says net-zero plan to be 'norm' for public firms in coming years. Available online: https://financialpost.com/news/economy/mark-carney-says-net-zero-plan-to-be-norm-for-public-firms-in-coming-years

1.2 How Does the Roadmap Work?

As we continue to implement the long-term actions in CleanBC, the Roadmap builds on our progress to date with an expanded and accelerated approach to meeting our targets and transforming markets for clean solutions. The Roadmap:

- Examines the eight key areas of our economy that generate emissions or can create solutions
- Assesses our progress in developing and deploying low- and zero-carbon products, approaches and technologies
- Sets out a series of pathways to support innovation in sectors where low carbon solutions are emerging, and drive deployment in sectors where they're already mature – helping to deliver more clean solutions, faster.

Some of the pathways are specific to economic sectors. Others cut across sectors to advance key objectives, such as developing our bioeconomy and exploring the potential of negative emissions technologies. Each pathway describes where we need to be by 2030 and maps out the most promising routes to get there – recognizing that some of these routes break new ground and will only reveal their strengths and weaknesses with time.

Foundational pathway actions to achieve our targets and advance market readiness for decarbonization include:

- Beginning in 2023, B.C.'s carbon tax will meet or exceed federal carbon price requirements, while considering impacts to household affordability. We'll also improve our industry programs to help meet our climate targets by supporting the adoption of new technologies while keeping our businesses competitive.
- New regulations will enhance the Low Carbon Fuel Standard, one of our most successful climate action measures. It requires fuel suppliers to make continuous reductions in their products' carbon intensity. We will double the target for renewable fuels produced in B.C. to 1.3 billion litres by 2030.
- We're accelerating our targets for zero-emission vehicles and we will set new standards for medium- and heavy-duty vehicles aligned with leading jurisdictions. By 2030, ZEVs will account for 90% of all new light-duty vehicle sales in the province (and targets of 26% by 2026 and 100% by 2035).

- We'll complete B.C.'s Electric Highway by 2024 and target having 10,000 public EV charging stations by 2030.
- A comprehensive Clean Transportation Action Plan in 2023 will support emission reductions by focusing on efficiency-first transportation options.
- A reduction of methane emissions from the oil and gas sector will lower emissions by 75% below 2014 levels by 2030, equivalent with the federal commitment. We'll also aim to eliminate methane emissions from oil and gas, mining, forestry and industrial wood waste by 2035.
- New large industrial facilities will be required to work with government to demonstrate how they align with government's 2030 and 2040 targets and submit plans to achieve net-zero emissions by 2050.
- The CleanBC Program for Industry will be enhanced to reduce emissions while supporting a strong economy.
- We'll implement programs and policies so that oil and gas emissions are reduced in line with sectoral targets.
- A greenhouse gas (GHG) cap for natural gas utilities – limiting emissions from the gas used to heat our homes and buildings and power some of our industries – will encourage new investment in low-carbon technologies and fuels (including renewable natural gas and hydrogen) and energy efficiency.
- By 2030, all new buildings will be zero carbon, and all new space and water heating equipment will meet the highest standards for efficiency.
- We'll implement a 100% Clean Electricity Delivery Standard for the BC Hydro grid.
- A new program will support local governments to continue taking climate action.
- We'll support innovation in areas like low-carbon hydrogen, the forest-based bioeconomy and negative emissions technologies.
- Household affordability will continue to be a key focus, especially for those who need it most.

Together, these measures will deliver significant reductions in GHG emissions. But the actions in this Roadmap are not just about climate change. Transforming our economy provides an opportunity to implement solutions that will also build on our broader social, environmental and fiscal priorities. These include:

- Advancing reconciliation with Indigenous peoples
- Improving people's health and well-being
- Spurring innovation in clean technologies that we can use and export to build a stronger economy and drive clean job creation
- Reducing inequalities so everyone has the opportunity to participate in, and benefit from, our growing clean economy
- Attracting investment based on sound ESG credentials.

This Roadmap will serve as an evolving plan to get us to our targets. Climate policy doesn't work if you set it and forget it, so the Roadmap will be updated as we move forward, learn from our experience and craft new solutions to meet our goals.

In the months and years ahead, we will continue to work with Indigenous peoples, recognizing their essential role as climate action partners. Many of the solutions we're developing and pursuing together will affect their territories, creating new opportunities for joint decision-making to advance self-government, self-determination and sustainable economic development in support of the Province's commitment to the *Declaration on the Rights of Indigenous Peoples Act*.

We will also continue working closely with local governments, industry, civil society partners and the independent Climate Solutions Council to further shape our pathways and hone our approaches to meet our targets for 2030 and beyond.

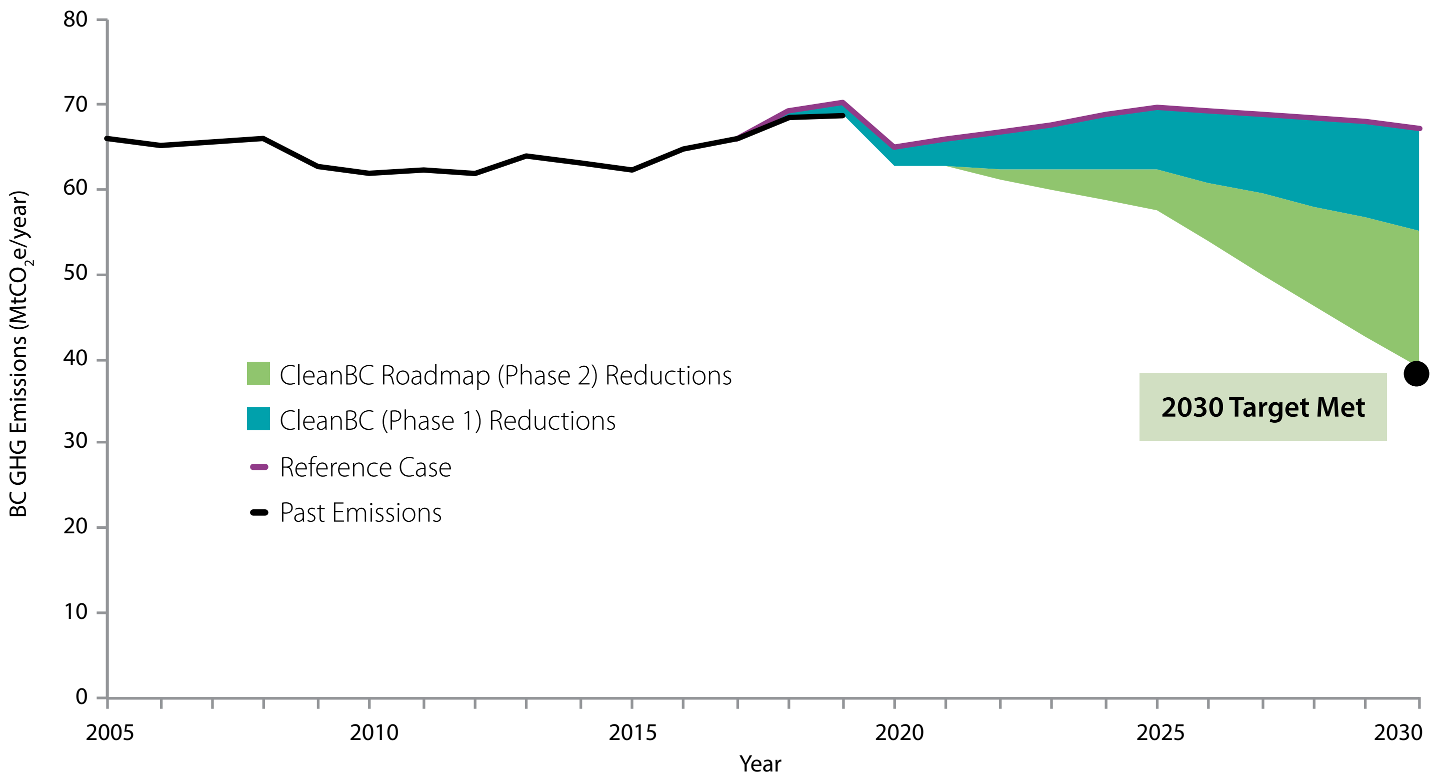
ENGAGEMENT WITH INDIGENOUS PEOPLES

Indigenous peoples across British Columbia were invited to contribute their knowledge and experience during engagements in 2021. The interests, opportunities, ideas and perspectives shared by Indigenous leaders and community members have helped shape the Roadmap to 2030. For example, through these conversations Indigenous peoples:

- Expressed interest in low carbon economic opportunities in their communities
- Affirmed the need for greater affordability and accessibility of CleanBC programs, leading to the commitment to a single-window access for all CleanBC incentives and programs and a renewed focus on affordability in program design
- Emphasized public climate education as key to support community decision making, understanding priorities and the importance of climate action, which influenced the Roadmap commitment to implement public awareness and education campaigns with a dedicated youth strategy
- Highlighted the importance of expanding clean transportation beyond ZEVs to ensure safe and reliable public transportation, which the Clean Transportation Action Plan's "efficiency first" approach will work to address
- Shared the need for cleaner transportation options suited to rural and remote living, contributing to the expansion of the Low Carbon Fuel Standard
- Expressed a desire for skills training to ensure participation in clean growth opportunities, as will be the focus in the upcoming workforce readiness framework
- Noted the high cost of transporting recycling and waste, leading to the commitment to a circular economy strategy.

In each pathway you'll find 'What we heard' boxes that provide examples of the perspectives of Indigenous peoples we worked with in the development of this Roadmap.

CleanBC Emissions Reductions



CLIMATE SOLUTIONS COUNCIL

B.C.'s Climate Solutions Council provides strategic advice on climate action and clean economic growth. It includes members representing Indigenous peoples, environmental organizations, industry, academia, youth, labour and local government. This Roadmap responds to many of the Council's recommendations, including:

- Increasing carbon tax in line with the federal benchmark while providing additional supports for emissions-intensive, trade-exposed industry
- Increasing the zero-emission vehicle standard for light-duty vehicles to between 80 and 100% by 2030
- Implementing medium- and heavy-duty, zero-emission vehicle regulations
- Supporting local governments
- Strengthening the Low Carbon Fuel Standard and implementing a new emissions cap for natural gas utilities.

By increasing the pace and scale of these and other CleanBC initiatives, the council says, "B.C. can both create more stable employment opportunities and achieve additional emission reductions that assist in getting the province on track for our 2030 climate change targets."

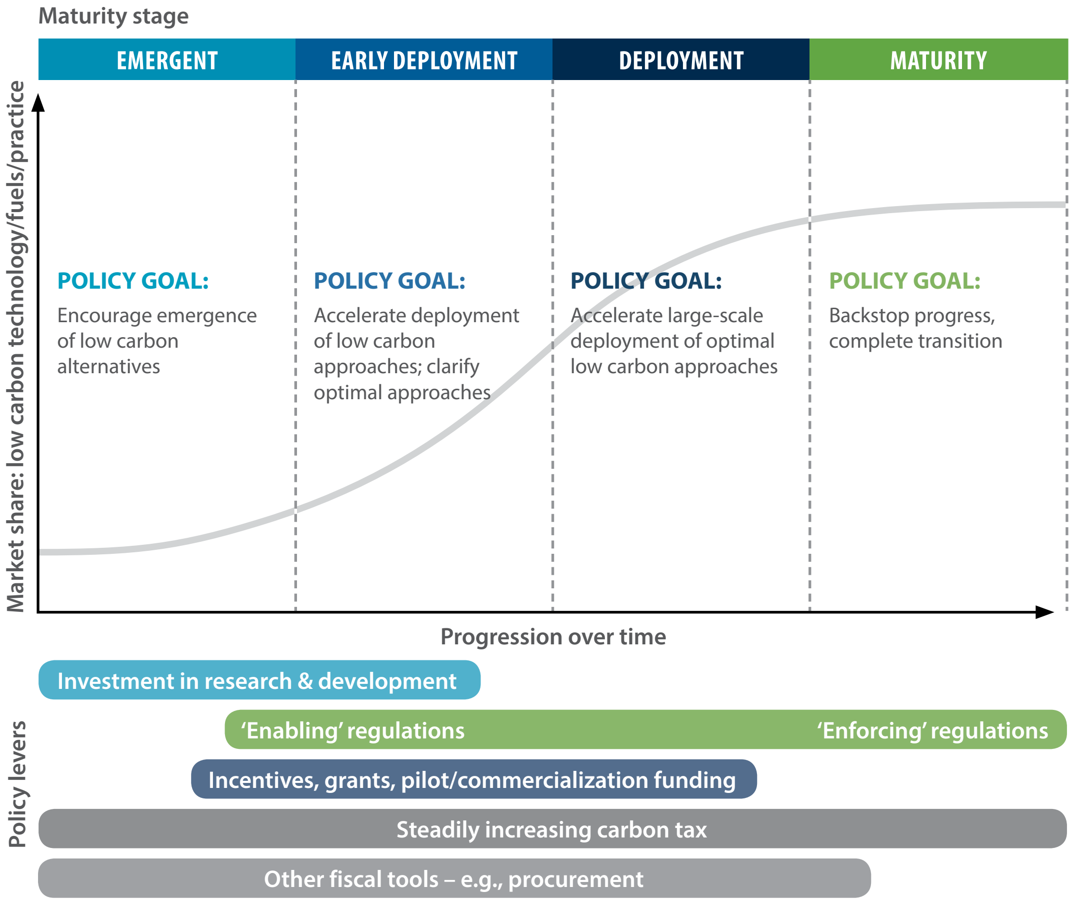
1.3 Climate Solutions – from Innovation to Wide-Scale Implementation

With CleanBC, our province began a set of bold, ambitious actions to transform our economy by shifting away from fossil fuels and towards clean, renewable energy and innovative technology. This Roadmap builds on our work to date and sets the stage for a broader, deeper transformation of large-scale societal systems – from how we produce and use energy to how we build low carbon, climate-resilient communities that keep us safe as the climate changes.

To reach this goal, we're focusing on tailoring approaches for each sector – recognizing that we need different tools for different market stages. Our actions will focus on growing markets for, and speeding up the adoption of, technologies we know are ready for deployment, such as zero-emission vehicles and heat pumps, while supporting research and development in areas where alternative solutions are still emerging.

In all cases, we will prioritize actions that solve unique problems or unlock co-benefits, such as improving people's health or achieving equity outcomes.

Stages of Market Readiness



Adapted from: Victor, D.G. et al. 2019. Accelerating the Low Carbon Transition: The case for stronger, more targeted, and coordinated international action. The Brookings Institution; and Meadowcroft, J. et al. 2021. Pathways to Net Zero: A decision support tool. Transition Accelerator Reports

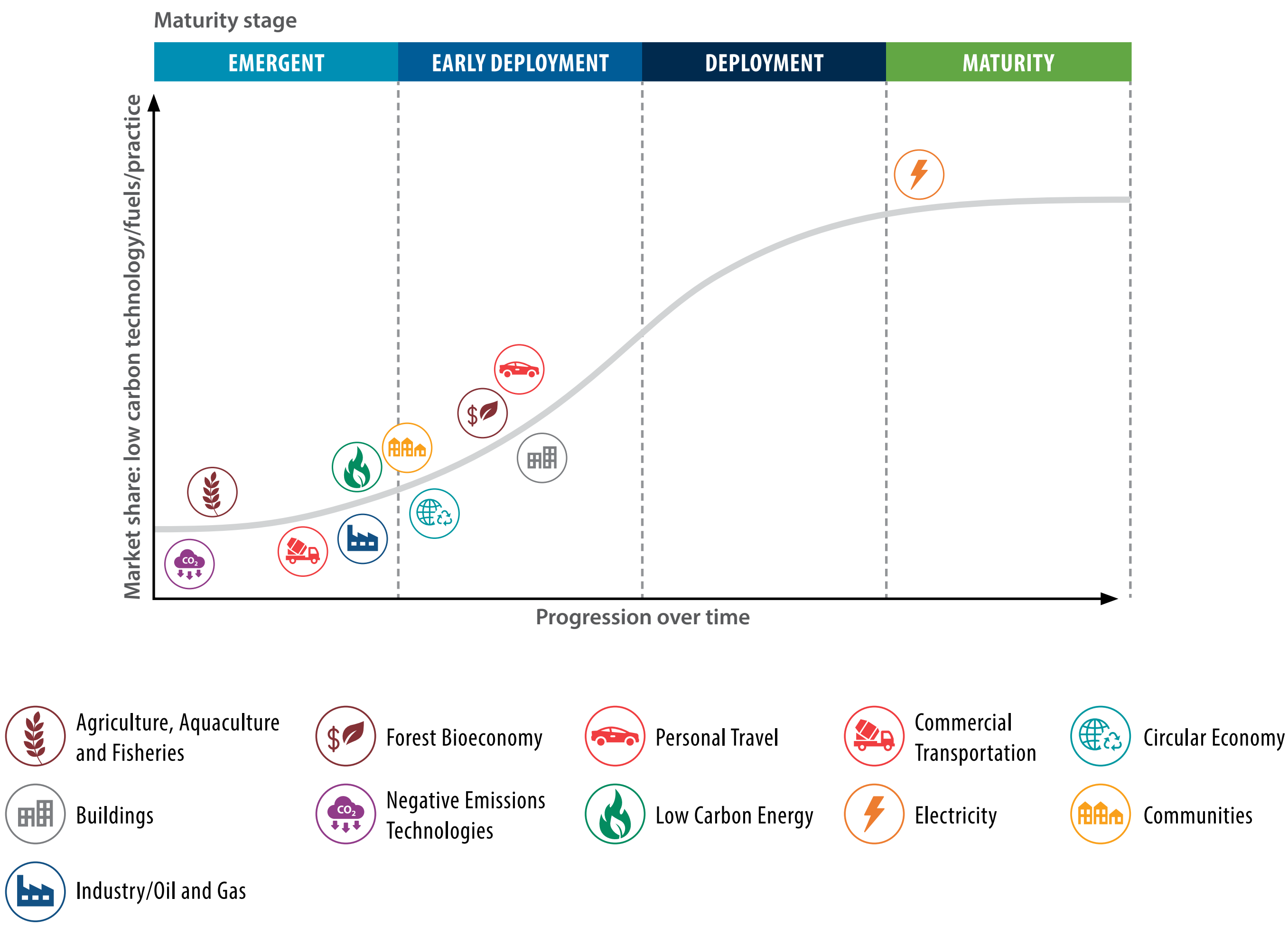
Market readiness indicators

To inform the types of actions needed to drive decarbonization, and to help us track our progress, we're developing a series of readiness indicators, which will be applied across the pathways. The indicators address key issues including:

- Market share of technologies, reflecting the extent to which low-emission solutions are being adopted
- Cost of transitioning to low-emission solutions
- Workforce and skills readiness, reflecting our capacity to adopt new approaches
- Economic and social opportunities, pointing to important co-benefits in areas such as reducing inequality and advancing reconciliation with Indigenous peoples.

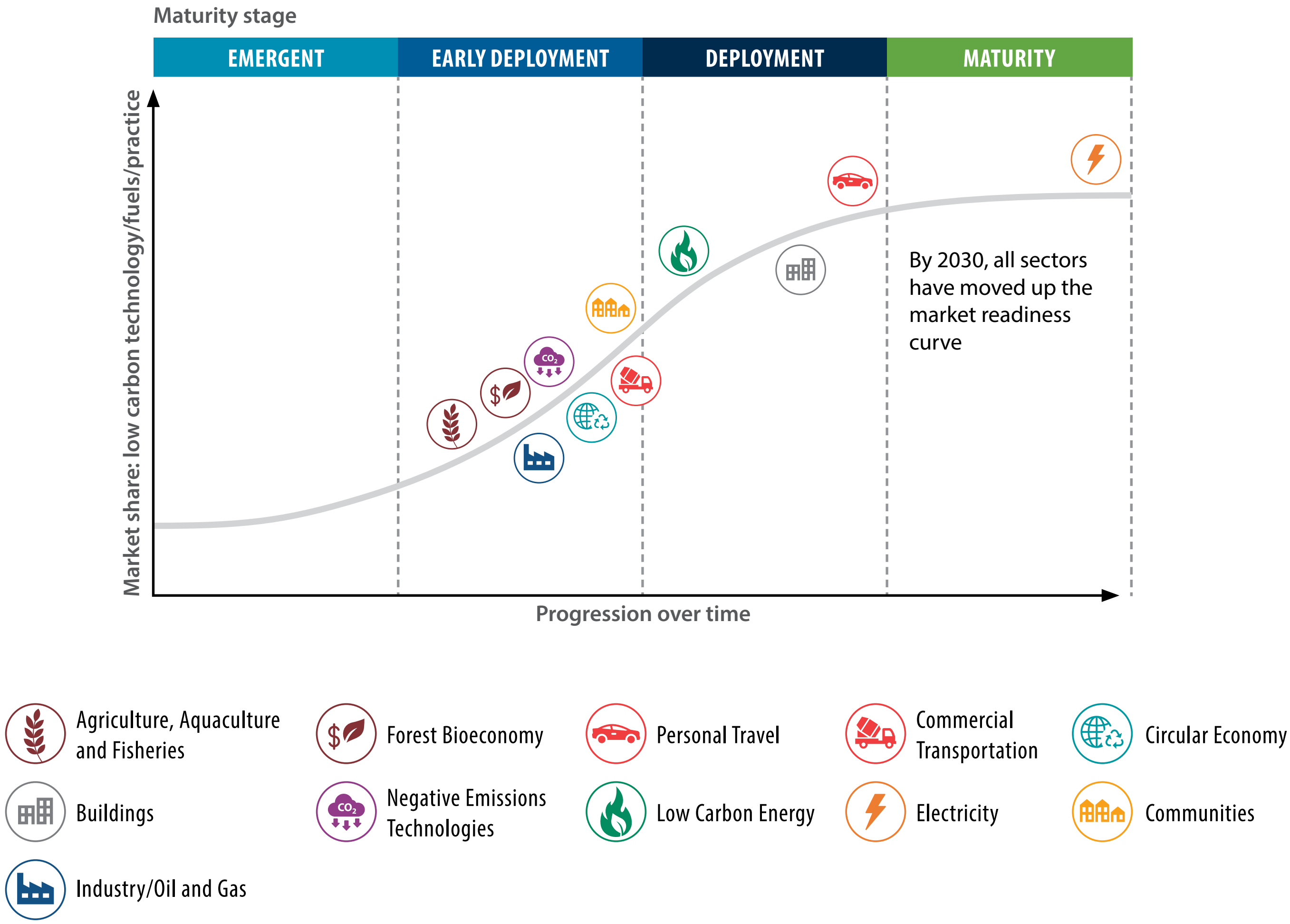
Based on these indicators, we've developed a baseline (below) showing where each of the pathways or Roadmap elements is starting from.

Current State of Market Readiness



By 2030, we will achieve the following advances in market readiness:

State of Market Readiness by 2030 with Roadmap



1.4 Modelling and Economic Analysis

To forecast the impacts of our climate actions, B.C. follows well-established best practices, using the best available data and sophisticated computer modeling. However, projections change over time as new information becomes available and methodologies are updated and it can be challenging predicting specific outcomes a decade or more away. As noted earlier, we now expect the measures in CleanBC (not including Roadmap actions) to achieve 32 to 48% of our 2030 targets – compared to the original estimate of 75%. The increased gap is due to several factors, including:

- Updated modelling: for example, new data on natural gas and electricity have lowered projected GHG reductions from industrial electrification
- Higher than expected emissions in sectors such as transportation and pulp and paper
- Changes in the federal approach to measuring emissions from sectors such as waste.

Detailed information on model updates and estimates are available as part of the 2021 Climate Change Accountability Report.

Through the measures in this Roadmap we expect to reach 100% of the 2030 emissions target.

Impacts on jobs and GDP

In today's economy, citizens and the global financial community are insisting that governments and companies have credible, long-term plans to reduce climate pollution – making this Roadmap an economic necessity.

Based on provincial data, we expect investment in Roadmap initiatives to generate approximately 18,000 direct and spinoff jobs with:

- GDP increases of 19% by 2030 and 89% by 2050 from 2020 levels
- Job growth of 7% and 37% by 2030 and 2050 respectively from 2020 levels.

These are conservative estimates; the economic benefits could be even greater if, for example, new clean technologies turn out to cost less than we expect. The Roadmap, like any credible climate plan, will increase the cost of fossil fuels. Government will minimize the impacts by continuing the Climate Action Tax Credit and providing increased support to help people and businesses reduce emissions and costs.

CHAPTER 2: PATHWAYS

The pathways presented here are not unlike a road network, intersecting in various places and offering multiple routes to reach our destination. They're also affected by a number of broader, overarching initiatives that provide a foundation for ongoing climate action in British Columbia.

Carbon pricing

A price on carbon pollution is one of the most effective and economically efficient ways to reduce GHG emissions. Consistent with the recommendations of the Climate Solutions Council, B.C.'s carbon tax will continue to meet or exceed any federal carbon price requirements for 2023 and beyond.

What we heard

In the consultations that informed this Roadmap, we heard from many local governments, the Climate Solutions Council, and others that the carbon tax needs to be raised and in line with the federal benchmark. From industry, we heard there is overall support for carbon pricing, along with concerns about competitiveness and carbon leakage.

Between now and 2030, we'll analyze the price and program options that best support meeting our climate targets while protecting affordability and competitiveness for people and businesses. We are working to develop mechanisms to support long-term funding for climate action in B.C., including preparing for the impacts of climate change.

The federal government has announced a carbon price of $170 per tonne in 2030, with annual $15 increases beginning in 2023. B.C.'s current price is $45 per tonne – already the strongest, most comprehensive carbon-pricing policy in Canada. Increasing the tax will support greater emissions reductions while encouraging sustainable growth and investment in new low carbon innovations.

At the same time, a higher carbon price can create challenges. For example, it can impact people who still depend on fossil fuels to get to work and heat their homes. It can also affect industries that sell their products in global markets, competing with producers who don't pay a carbon tax, or don't pay as much. Where carbon tax represents a significant operating cost that can't be addressed through investments in cleaner technologies, this can lead to carbon leakage – the movement of business, industry and jobs to places with lower carbon prices.

We'll explore other approaches to help make low-carbon options more affordable for low- and middle-income people in British Columbia. To promote greater fairness, we'll work with the federal government to explore ideas such as carbon border adjustments – ensuring that goods from places without strong climate policies face similar costs to those produced domestically. Through the CleanBC Program for Industry, B.C. uses carbon tax revenue to support emission performance improvements and competitiveness.

Government leadership

Every year since 2010, B.C. has achieved net-zero (carbon neutral) operations across the public sector, including health authorities, school districts, universities, and Crown corporations. As part of this Roadmap, we're building on our progress with the following new measures:

- Factoring climate considerations into government decision making, ensuring a focus on climate-resilient, zero- or low carbon projects. This priority will be delivered through capital projects as they include an assessment of these factors in their planning and approval processes
- Making zero-emission vehicles the default option for B.C. public sector fleets, with ZEVs accounting for 100% of light-duty vehicle acquisitions by 2027
- Requiring all new public sector buildings to align with our climate goals beginning with performance standards (2023) and moving to zero-carbon new buildings (2027)
- Developing and implementing a comprehensive strategy (2024) to transform our existing buildings portfolio to a low carbon and resiliency standard
- Implementing a public awareness and education campaign; this will include a dedicated strategy for connecting with youth and involving them in climate action
- Providing single-window access to all CleanBC incentives and programs.

Climate preparedness and adaptation

B.C.'s Climate Preparedness and Adaptation Strategy will be released in 2022, strengthening our capacity to anticipate and respond to the impacts of climate change in every part of B.C. These include sudden events like wildfires, floods and heat waves, as well as changes that happen more slowly like habitat loss, sea level rise and changes in growing seasons.

The strategy builds on the substantial work already underway in B.C. to adapt to climate change, lower long-term costs of impacts and help keep our communities safe, ensuring government programs and policies continue to achieve their goals as the climate changes. The strategy draws on a 2019 assessment of the greatest climate risks to B.C. and outlines actions to prepare for them in ways that respect and respond to the diverse needs of people and communities across B.C.

Circular economy

A circular economy refers to a system where, by design, there is no waste – in contrast to the traditional Western model, which can be described as take-make-waste: we take raw materials, make them into products, use them and throw them away. The circular approach emphasizes sharing, reusing, repairing and recycling – eliminating waste and reducing GHG emissions while making better use of our resources.

What we heard

In the consultations that informed this Roadmap, people from Indigenous and remote communities said they face significant challenges and expenses to transport recycling and waste, especially when they have to use barges, forest service roads, or planes. There is support for developing a circular economy, including expanding B.C.'s continent-leading extended producer responsibility recycling system.

Circular economy in action: B.C. is keeping plastics in use and out of the environment

Learn more at: **CleanBC.gov.bc.ca/success-stories**

With this Roadmap, we're taking more steps to advance the circular economy, especially in sectors such as agriculture and forestry. They generate byproducts that can be used to create low carbon building materials, renewable energy and other clean products – generating value and new opportunities while shrinking our carbon footprint.

We will develop a Circular Economy Strategy in 2022, supporting both our climate goals and our economy. Key components will include advancing the Plastics Action Plan and requiring more manufacturers to take responsibility for their products' eventual recycling, reuse or safe disposal.

The strategy will build on recent actions we've taken to expand our continent-leading recycling system, which will include electric vehicle batteries and chargers, mattresses, and electronic products such as solar panels, lithium-ion batteries and e-cigarettes.

A Workforce Readiness Framework: Preparing for a cleaner economy

The global transition to a low-carbon future will create new jobs in a range of sectors, and we want to make sure those jobs benefit people across B.C. A workforce readiness framework is being developed to ensure people are positioned for good jobs in a future, cleaner economy and that B.C. has the workers needed for sustainable economic growth and innovation.

Some jobs will be new. In other cases, existing jobs will evolve to incorporate new technologies, approaches and innovations. Some areas will see immediate changes while others will experience smaller shifts over time as we build a future workforce that is more inclusive, resilient and adaptable – in partnership with Indigenous peoples, industry, post-secondary institutions and others.

The framework will include measures to ensure B.C. has the number and diversity of workers to meet employers' needs; ensure there are opportunities for workers to upgrade their skills to adapt to changing jobs; and new training programs, standards and credentials that workers and employers are increasingly looking for as we transition to a low carbon economy.

The framework will guide work with industry, stakeholders, and Indigenous peoples to understand developing job growth opportunities and the skills needed for the current and future clean economy, and to identify barriers to train, attract and retain workers to support the just transition to a low-carbon economy.

EXTENDED PRODUCER RESPONSIBILITY (EPR) AND THE CLEANBC PLASTICS ACTION PLAN

B.C. has one of the strongest, most comprehensive recycling systems in North America known as Extended Producer Responsibility (EPR). EPR requires producers to take responsibility for the lifecycle of their products, including collection and recycling. B.C.'s EPR strategy recovers $46 million worth of materials annually and reduces greenhouse gas emissions by more than 200,000 tonnes of carbon dioxide equivalent. It generates an estimated $500 million annually through recycling programs, and collects approximately 315,000 tonnes of plastic from bottles, packaging and electronics. We're expanding this system to include electric vehicle batteries and chargers, solar panels, more types of lithium-ion batteries, mattresses and e-cigarettes.

B.C. is building on this leadership in EPR and developing the circular economy on plastics supported by the CleanBC Plastics Action Plan, which identifies actions to ban single-use items and reclaim more materials. These aims are bolstered by the CleanBC Plastics Action Fund that encourages innovation to turn used plastics into new products, as well as the Clean Coast Clean Waters initiative that supported the largest shoreline clean-up in the province's history. This initiative partnered with Indigenous and coastal communities, as well as local tourism operators and environmental groups. More than 550 tonnes of marine debris has been removed to date, with the majority of the material being reused and recycled.

2.1 Low Carbon Energy

Whether it's for producing food, lighting and heating our homes, moving people and goods or supporting industrial growth – energy underpins almost every aspect of our lives and economy in British Columbia.

To decarbonize our economy and accelerate the shift to clean technologies in the buildings, transportation and industrial sectors, we need to use energy more efficiently and replace fossil fuels with clean energy, including more clean electricity, renewable natural gas, low carbon hydrogen and liquid biofuels.

What we heard

In the consultations that informed this Roadmap, industrial operators said low carbon fuels can provide short-term flexibility as a substitute for natural gas but to ramp up production we need to address barriers, such as:

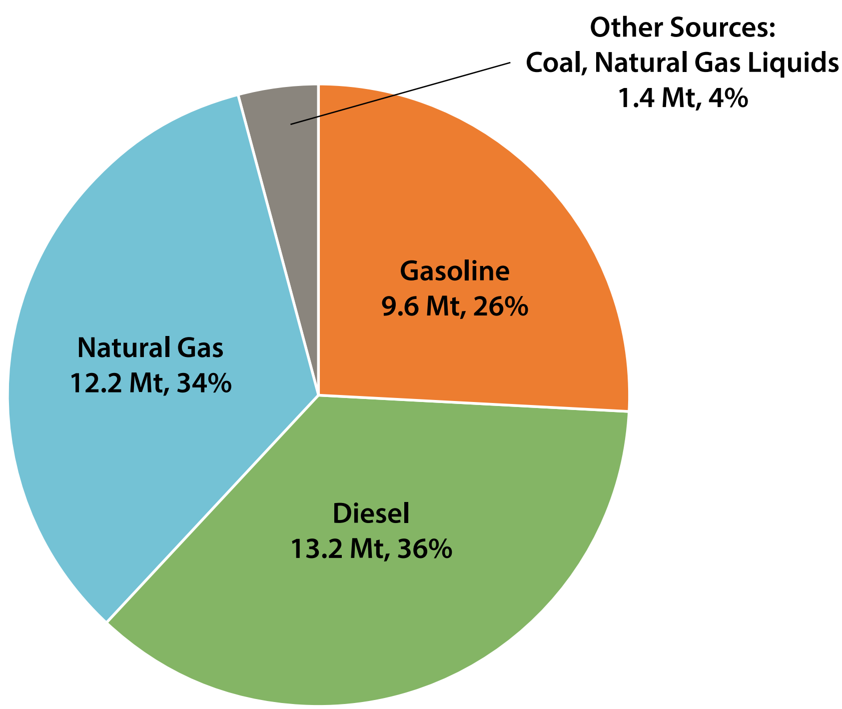
- *Biomass supply and uncertainties related to technology/capital purchases*
- *The impact of increasing transportation fuel costs on final production for certain industries*
- *The need for partnerships to implement the B.C. Hydrogen Strategy*

Indigenous peoples pointed to potential job creation opportunities through wood waste transfer facilities to create biofuel, as well as a waste collection program to support biofuel creation. There was also interest in more solar and wind power including cost sharing agreements.

Where we're starting from

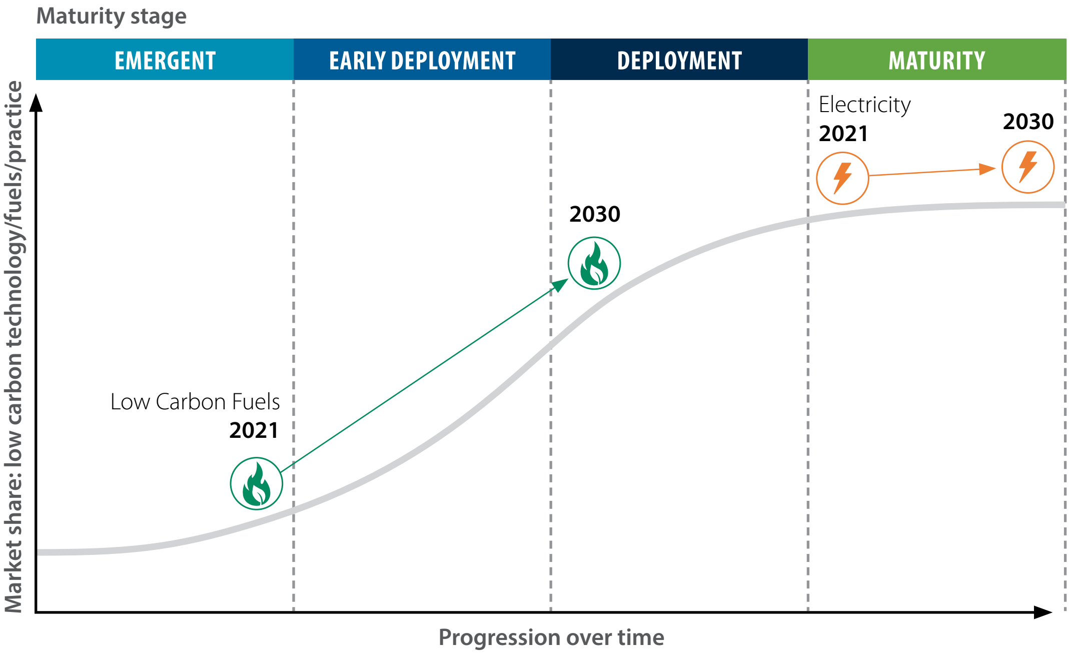
B.C. uses a diverse mix of energy types to meet demands from our transportation, industry and building sectors. Clean electricity currently accounts for only 19% of the total. Low carbon biomass and biofuels meet an additional 11%, and that proportion will rise in the future. However, most of our energy needs – the remaining 69% – are still met by fossil fuels, mainly in the form of refined petroleum products and natural gas. Fossil fuel production and consumption accounts for approximately 80% of B.C. emissions, underlining the need to move to cleaner fuels, faster. The pie chart below shows a breakdown of emissions by energy source.

2020 Emissions by Energy Source for Transportation, Buildings and Industry (Excluding Oil and Gas Sector)



Most of our electricity is clean and renewable, putting its market readiness stage at early maturity. Liquid biofuels are available but emergent, limited by a number of factors including the availability of feedstock, such as vegetable oils and tallow for products like renewable diesel. Low carbon gaseous fuels such as biomethane and hydrogen are also emergent, limited by factors such as capital investment, feedstocks and access to commercial-ready technologies.

Low Carbon Energy



KEY ACTIONS

- Expanding the Low Carbon Fuel Standard (LCFS)
- Implementing a GHG emissions cap for natural gas utilities
- Adopting a 100% Clean Electricity Delivery Standard
- Advancing BC Hydro's Electrification Plan
- Implementing the B.C. Hydrogen Strategy
- Indigenous clean energy opportunities review

THE PATH TO TRANSFORMATION – 2030 AND BEYOND

To maximize production of low carbon energy, we need a suite of regulatory and program initiatives that build on approaches we know work well and create incentives for new innovation.

Expanding the Low Carbon Fuel Standard (LCFS)

B.C.'s Low Carbon Fuel Standard is one of our most successful approaches to reducing GHGs from transportation. It requires fuel suppliers to progressively decrease the average carbon intensity of the fuels they supply to users in B.C.

With CleanBC, we increased its stringency by doubling the carbon-intensity reduction for gasoline and diesel from 10% to 20% by 2030. As part of this Roadmap, we intend to modernize the legislation governing the Low Carbon Fuel Standard, including to expand it to cover marine and aviation fuels beginning in 2023.We'll also consider new compliance options such as negative emissions technologies, while increasing the financial implications of failing to comply.

After careful assessment of impacts, we will raise our target beyond the current 20%, consistent with advice from the Climate Solutions Council, using 30% by 2030 as a starting point for further analysis and consultations. We will also double our commitment to develop production capacity for made-in-B.C. renewable fuels to 1.3 billion litres per year by 2030, creating new jobs and economic opportunities across the province.

Implementing a GHG emissions cap for natural gas utilities

B.C.'s existing pipeline infrastructure can play an important role in reducing greenhouse gases by transitioning away from delivering fossil natural gas to delivering renewable gas. B.C.'s gas utilities have been leaders in enabling this transition.

To help drive this transition, we will introduce a GHG emissions cap that will require gas utilities to undertake activities and invest in technologies to further lower GHG emissions from the fossil natural gas used to heat homes and buildings and power some of our industries.

Following further modelling and analysis, the cap will be set at approximately 6 Mt of CO_2e per year for 2030, which is approximately 47% lower than 2007 levels. Since emissions from gas consumption are linked to industry (excluding oil and gas) and the built environment, the cap is consistent with emissions targets for those sectors.

From waste to clean energy: B.C. companies are making the fuels of the future

Learn more at: **CleanBC.gov.bc.ca/success-stories**

Utilities will determine how best to meet the target, which could include acquiring more renewable gases as well as supporting greater energy efficiency. Measures in CleanBC allow gas utilities to use renewables such as synthetic gas, biomethane, green and waste hydrogen and lignin to achieve this.

The B.C. Utilities Commission will have a mandate to review gas utilities' plans, investments and expenditures to ensure they're aligned with the GHG emissions cap and cost effective, helping to keep rates affordable for people and businesses.

Adopting a 100% Clean Electricity Delivery Standard

B.C.'s abundant supply of clean electricity is one of our greatest allies in the fight against climate change. Currently, an average of 98% is from renewable sources, mostly hydro power.

As part of this Roadmap, we are committing to increase this to 100% – making our power even cleaner; creating new opportunities in areas such as the bioeconomy; and helping to attract new businesses by supporting their sustainability strategies. BC Hydro will meet the new standard by ensuring it has produced or acquired sufficient clean electricity to meet the needs of its domestic customers and phasing out remaining gas-fired facilities on its integrated grid by 2030.

Micro-hydropower provides clean energy and jobs for Kitasoo Xai'xais Nation

Learn more at: **CleanBC.gov.bc.ca/success-stories**

Advancing BC Hydro's Electrification Plan

BC Hydro will advance its Electrification Plan by offering customers incentives, tools and business-to-business support to help them run their homes and businesses with clean electricity – and to reduce the time it takes to connect to the grid.

Subject to the approval of the BC Utilities Commission, over the next five years, the Crown corporation plans to invest over $260 million to advance electrification, including more than $190 million to promote fuel switching in buildings, transportation and industry and more than $50 million to attract new customers – such as data centres and hydrogen producers – who can locate anywhere but see the advantages of B.C.'s clean, reliable, affordable hydroelectric power.

To help support and drive BC Hydro's focus on GHG reductions, we will add electrification and fuel-switching to its mandate, introduce an internal carbon price to evaluate electrification initiatives in regulatory applications, and enable investments in green hydrogen production and commercial vehicle incentives and infrastructure.

BC HYDRO'S INTEGRATED RESOURCE PLAN

BC Hydro is preparing an Integrated Resource Plan (IRP), which outlines how BC Hydro plans to provide reliable, affordable and clean electricity to meet customer demand now and into the future. It considers BC Hydro's 20-year projections of electricity demand in B.C. The IRP includes high and low load ranges and scenarios to account for a range of potential impacts, including support of CleanBC as policies and regulations are implemented and electrification ramps up to help achieve 2030 emissions reduction targets.

Implementing the B.C. Hydrogen Strategy

When burned or used in a fuel cell, hydrogen produces no carbon emissions. Hydrogen is one of the only solutions for decarbonizing sectors of the economy where direct electrification is not practical, such as heavy-duty transportation or industrial heating. When injected into the natural-gas grid, renewable hydrogen can displace fossil fuels for heating homes and businesses. Hydrogen can also be used for producing low carbon, synthetic fuels to reduce emissions in transportation and industry.

B.C.'s hydrogen sector is fueling green jobs

Learn more at: **CleanBC.gov.bc.ca/success-stories**

B.C. is the first province in Canada to release a comprehensive hydrogen strategy. The B.C. Hydrogen Strategy outlines how the Province will support the development of production, use and export of renewable and low carbon hydrogen for the next 10 years and beyond. It complements the federal hydrogen strategy, serving as a blueprint for regional development with 63 actions for the short term (2020-2025), medium term (2025-2030) and long term (2030-beyond).

Implementing the B.C. Hydrogen Strategy and developing our hydrogen economy will generate more clean economic opportunities, help reduce emissions and contribute to meeting our climate targets. The strategy's immediate priorities include scaling up production of renewable hydrogen, establishing regional hydrogen hubs and deploying medium- and heavy-duty fuel-cell vehicles.

OPENING THE B.C. CENTRE FOR INNOVATION AND CLEAN ENERGY (CICE)

With an initial $35 million provincial investment leveraging an additional $70 million from federal and private sources, the Centre for Innovation and Clean Energy will be a member-based, non-profit corporation, independent from government and private entities. The Centre will bring together innovators, industry, governments and academics to accelerate the commercialization and scale-up of B.C. based clean energy technologies. It will also be a catalyst for new partnerships and world-leading innovation to deliver near- and longer-term carbon emission reductions.

The Centre's initial focus areas for funding and project delivery will include:

- Carbon capture, utilization and storage
- Production, use and distribution of low-carbon hydrogen
- Biofuels and synthetic fuels (including marine and aviation fuels)
- Renewable natural gas
- Battery technology, storage and energy management systems.

The Centre will also initiate new technology pathways to accelerate larger reductions on the path to net-zero emissions by 2050.

Indigenous clean energy opportunities review

The actions in the Roadmap will open up a wide range of economic opportunities in B.C.'s low carbon energy sector. The Province is committed to working with First Nations to maximize the benefits for Indigenous communities. As a key step, the Ministry of Energy, Mines and Low Carbon Innovation and the First Nations Leadership Council, through their designate, the BC First Nations Energy and Mining Council, are launching a co-designed and co-led Indigenous Clean Energy Opportunities engagement process. Through the process, the Ministry and the Council will jointly engage First Nations to identify and support clean energy opportunities. They will also seek to collaborate with First Nations rights holders on the development of strategic clean energy policy and legislation, and meaningfully explore and develop policy, regulatory and program support to enable Indigenous participation within the growing and diverse clean energy sector.

2.2 Transportation

Transportation plays a major role in all our lives, connecting us to each other and the world. It's also our largest single source of GHG emissions, accounting for approximately 40% of our annual total in British Columbia. Actions that reduce these emissions have a wide range of benefits, from cleaner air and less congestion to better health, more clean jobs and economic development – benefits we'll see more of as we implement this Roadmap.

What we heard

In the consultations that informed this Roadmap, many groups supported accelerating and expanding zero-emission vehicle targets and enhancing funding and supports for active transportation. People in commercial transportation supported measures to predictably reduce emissions from medium- and heavy-duty fleets. In engagements with Indigenous peoples, we heard suggestions to expand clean transportation supports such as charging infrastructure, electric buses and public transportation, especially in the North.

Where we're starting from

The B.C. market for decarbonizing personal travel is at the early deployment stage. People can choose from more than 50 models of light-duty, zero-emission vehicles (ZEVs). However, these still cost about 20-40% more than equivalent non-ZEVs (before considering government rebates and lower maintenance and fuel costs). And more work is needed to build out the infrastructure for ZEV charging and hydrogen fueling. For active transportation, many communities still have significant gaps to fill to complete their networks for people of all ages and abilities.

The market for commercial travel is in the emergent stage, with ZEV solutions for medium- and heavy-duty vehicles starting to be deployed. Costs remain high and the commercial market is behind the personal market.

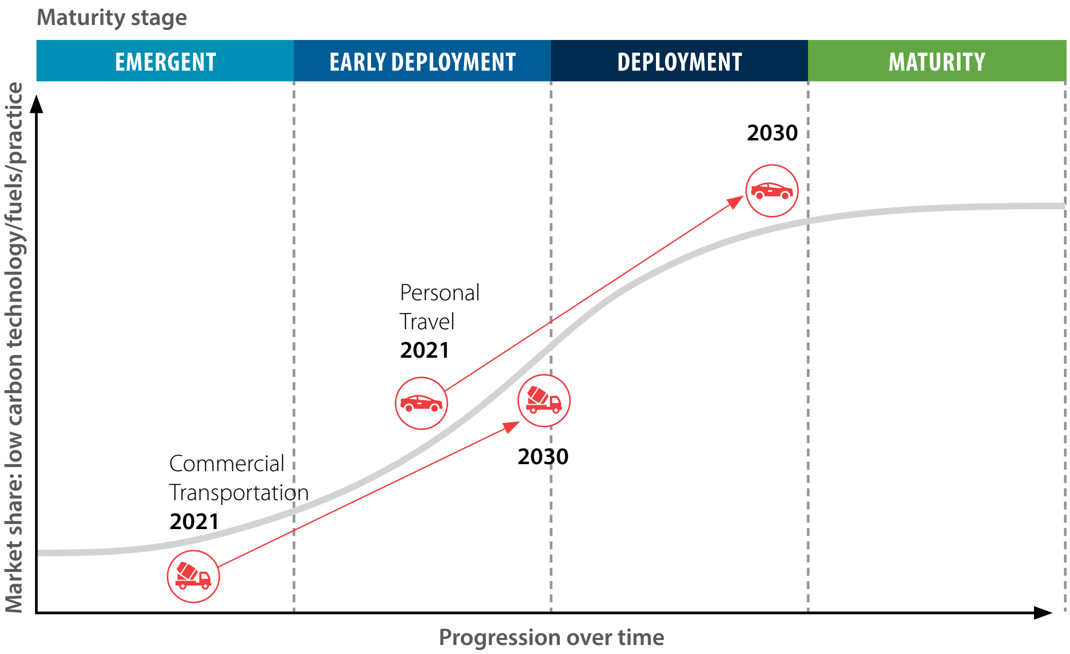
CLEANBC GO ELECTRIC COMMERCIAL VEHICLE PILOTS

The CleanBC Go Electric Commercial Vehicle Pilots program, launched in 2021, supports the switch to zero-emission commercial vehicles of all types, including trains, ships, trucks, construction and agricultural equipment, along with the necessary charging and fueling infrastructure.

The companion CleanBC Go Electric Specialty Use Vehicle Incentive program is supporting the transition for specialty vehicles, such as delivery trucks, passenger shuttles and a variety of other vehicles. Purolator is among the companies using the program to advance cleaner choices, running battery-electric trucks from its facility in Richmond.

More work is also needed to explore opportunities to move more goods by rail and shipping. This includes short sea shipping – using barges and waterways to get goods from ports to regional facilities. Ultimately, we expect there will be no single solution but a range of cleaner options for commercial transportation, reflecting the diversity of needs and opportunities.

Transportation



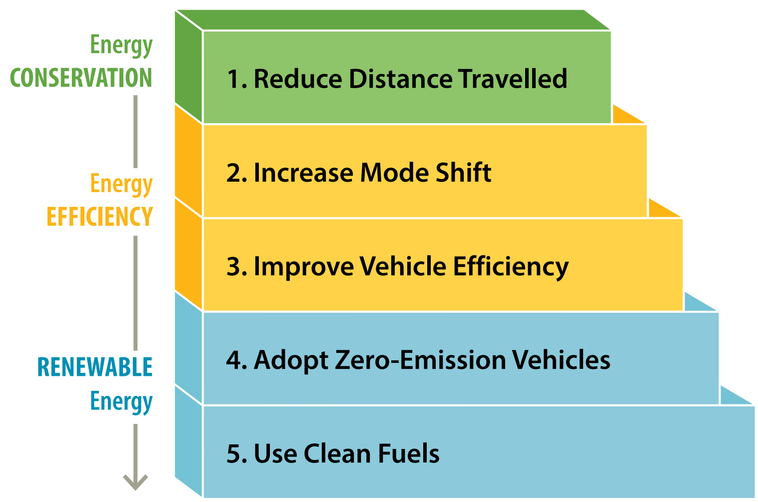
KEY ACTIONS

- Reducing distance travelled
- Encouraging "mode shifting" to more energy efficient forms of transport
- Accelerating the switch to ZEVs
- Expanding B.C.'s public charging network
- Making commercial transportation more energy efficient
- Improving vehicle efficiency
- Expanding the Low Carbon Fuel Standard (LCFS)
- Completing the Clean Transportation Action Plan

THE ROAD TO TRANSFORMATION - 2030 AND BEYOND

Meeting our targets in the transportation sector demands aggressive action in addition to our world-leading ZEV and fuel standards. With this Roadmap, we're working across five areas, from encouraging more walking and cycling to reducing the carbon intensity of fuels. This approach, illustrated below, is based on an efficiency-first model, consistent with energy conservation principles.

In 2023, the actions in this Roadmap will be complemented by a new Clean Transportation Action Plan, setting out our next set of actions to reduce transportation emissions by 27-32% (from 2007) by 2030. Specific actions will be consistent with advice from the Climate Solutions Council.



Reducing distance travelled

As part of this Roadmap, we will work to reduce the distances travelled in light-duty vehicles by 25% by 2030, compared to 2020. This can be achieved in part by supporting more compact urban planning in partnership with municipalities to increase active transportation and public transit. We will also provide continued support for digital access and remote work where feasible, building on the lessons learned during the COVID-19 pandemic. In addition, we will work with ICBC to monitor vehicle kilometres travelled and develop additional ways to bring them down, helping to reduce emissions, transportation costs, collision risk, and wear and tear on our roads.

To help inform future decisions, we'll continue to collect and share transportation data, supporting both provincial goals and planning and analysis by partners, such as local governments and Indigenous communities.

Encouraging "mode shifting" to more energy efficient forms of transport

One of the surest ways to reduce our GHG emissions from transport is to choose the least energy-intensive and polluting ways to get around. For personal travel that generally means walking, cycling or taking transit. For commercial travel, it means moving more goods by rail, water or cargo bike where possible instead of using heavy-duty, on-road vehicles.

To encourage these shifts, we will establish energy intensity targets for personal and commercial transportation and work with key partners to:

- Increase the share of trips (e.g., commuting for work and personal activities) made by walking, cycling, transit to 30% by 2030, 40% by 2040 and 50% by 2050. In a 2019 survey, 24% of people in B.C. said they primarily used sustainable transportation (walking, cycling or public transit) to get to work.
- Reduce the energy intensity of goods movement (tonne-kilometres) by at least 10% by 2030, 30% by 2040, and 50% by 2050, relative to 2020.

Accelerating the switch to ZEVs

B.C.'s Zero-Emission Vehicles Act, passed in 2019, has already helped to transform the marketplace. Thanks in part to government rebates, we're close to achieving our 2025 target, with ZEVs accounting for 9.4% of all new light-duty vehicle sales in 2020. To build on that momentum, we're accelerating our targets in alignment with automakers' published deployment plans. Our new light-duty ZEV sales targets are 26% by 2026, 90% by 2030 and 100% by 2035.

To support these targets, we will bring in "right-to-charge" legislation, allowing more people to install EV charging infrastructure in strata and apartment buildings. We will also introduce new ZEV targets for medium- and heavy-duty vehicles, in consultation with automakers, businesses and industry in alignment with the state of California.

Heavy-duty vehicles account for a large part of transportation emissions and modelling suggests the new targets will have a significant impact. Given the time required for research and engagement, we expect these targets will be in place by 2023.

Making cleaner models more affordable will help get more of them on our roads. And rising demand for cleaner vehicles will act as a further incentive for automakers, driving further improvements in efficiency and generating high-value jobs in ZEV research and development. We will explore other fiscal measures to broaden consumer access to ZEVs, accelerate market transformation and create a more sustainable fiscal framework for the ZEV transition.

Expanding B.C.'s public charging network

We will also ensure it's easy to charge your ZEV, wherever you are in the province. We will work with the private sector, utilities, Indigenous communities, the federal and local governments and others to achieve an overall target of B.C. having 10,000 public EV charging stations by 2030. This will include completing B.C.'s Electric Highway by ensuring broad geographic coverage across the Province for fast-charger EV sites by Summer 2024. BC Transit, TransLink and BC Ferries are also moving increasingly to zero-emission vehicles.

Making commercial transportation more energy efficient

Delivery trucks are getting cleaner – and bikes are sharing the load

Learn more at: **CleanBC.gov.bc.ca/success-stories**

In partnership with industry and other key stakeholders, we will work to make our commercial transportation systems more competitive while accelerating innovation and driving the adoption of clean B.C. technologies to support and advance climate change goals. As noted above, we're committed to reducing the energy intensity of goods movements by 10% in 2030, 30% by 2040 and 50% by 2050. We'll also use better data technology to make our transportation systems more efficient, intelligent and competitive.

Having one of the cleanest, greenest transportation networks in the world will add to our competitive advantages, supporting economic growth along with GHG reductions.

Improving vehicle efficiency

When you need to use a vehicle, it makes sense to choose the most efficient one. And this is another place where government can help move the market through regulations, standards and incentives.

To help drive improvements in vehicle efficiency, we'll work with business and industry to encourage faster fleet turnover for the oldest vehicles, work with the federal government to strengthen emissions standards, and develop new equipment regulations for air, rail, marine and off-road vehicles. We'll also identify how the CleanBC Heavy Duty Vehicle Efficiency Program can drive further improvements. For example, the Province could offer higher incentives for tires that reduce fuel consumption on specific types of commercial heavy-duty vehicles and encourage the use of speed-limiting technology and electronic tracking to improve safety while continuing to reduce GHG emissions.

Expanding the Low Carbon Fuel Standard (LCFS)

As noted in the Low Carbon Energy pathway, the Low Carbon Fuel Standard is one of our most successful approaches to reducing GHGs from transportation. It requires fuel suppliers to progressively decrease the average carbon intensity of the fuels they supply to users in B.C.

As part of this Roadmap, we will increase its stringency, consider expanding it to apply to marine and aviation fuels, and consider allowing new compliance options such as negative emissions technologies.

Completing the Clean Transportation Action Plan

In addition to the specific actions in this Roadmap, we will develop a comprehensive Clean Transportation Action Plan in 2023. The Plan will highlight additional steps government will take to reduce emissions in the transportation sector, including ports and airports, to meet our 2030 targets and align with the development of complete, compact, connected communities to reduce vehicle travel.

Electric ferries are the wave of the future

Learn more at: **CleanBC.gov.bc.ca/success-stories**

2.3 Buildings

Buildings – the places where we live, work, learn and play, and a vital component of B.C.'s economy – account for about 10% of the province's GHG emissions, mainly from the energy we use to heat them and provide hot water.

Our building sector has been getting steadily cleaner and greener in recent years, but current emissions reductions are not at the scale needed to meet our 2030 targets.

INVESTING IN AFFORDABLE HOUSING ACROSS B.C.

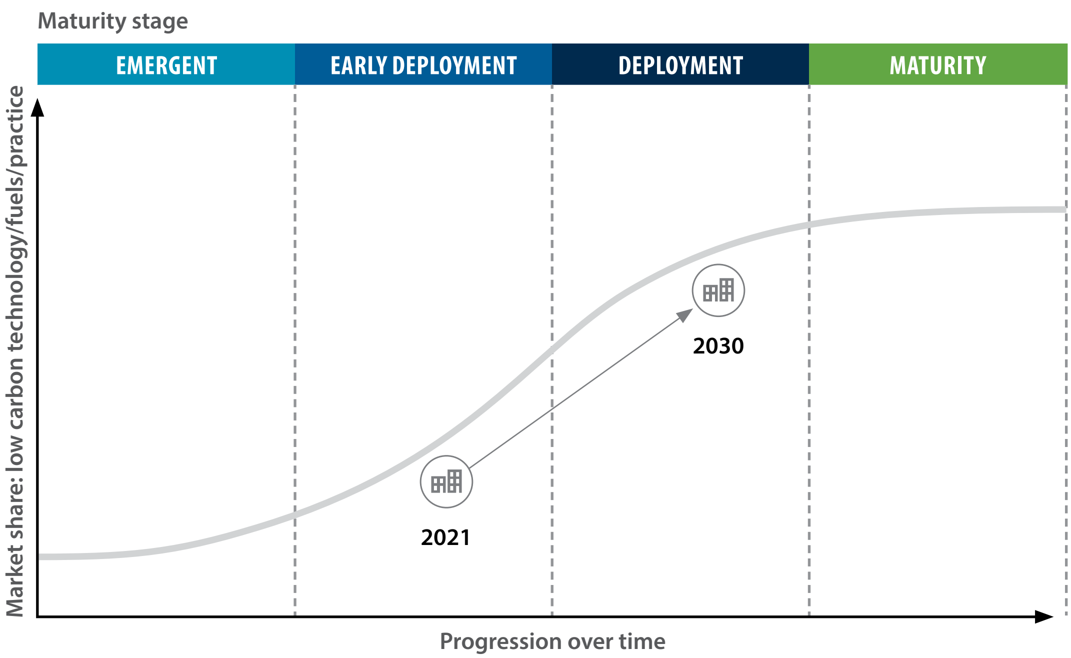
The Province is working to make housing more affordable for everyone in B.C. With $7 billion dedicated over 10 years, we're making the largest investment in housing in B.C.'s history. By working with partners, including local governments, we're delivering 114,000 affordable homes over this time period. In just over three years, more than 30,000 new affordable homes are already complete or underway in more than 100 communities across the province. And we continue to make progress on our plan to retrofit 51,000 units of publicly owned social housing over ten years, making them more energy efficient, less polluting and safer, while significantly reducing heating costs for residents.

Where we're starting from

The decarbonization of buildings is at an early deployment phase. Households and businesses can choose from a range of low carbon solutions and B.C. is already a leader in this space. New construction is steadily moving towards the highest efficiency levels and builders are growing their capacity to make new buildings cleaner, supported by increasing adoption of the Energy Step Code, which sets higher energy-efficiency standards than the base BC Building Code. However, we still rely on fossil fuels to meet more than half our energy needs in buildings.

Low carbon electric technologies like baseboard heaters are commonplace, but not the most efficient options available. Heat pump technologies are more than twice as efficient and cost less to operate. Plus, they double as air conditioners in increasingly hotter summers and can include air filtration, protecting people from wildfire smoke, pollen and pollution. Heat pumps are gaining in market share, with options available for all major building types and climates. However, costs are still a barrier for many households and businesses.

Buildings



KEY ACTIONS

- Zero-carbon new construction by 2030
- Highest efficiency standards for new space and water heating equipment
- Enhancing energy efficiency programs
- Introducing home energy labelling
- More low carbon building materials

What we heard

In the consultations that informed this Roadmap, a wide range of groups including local governments, utilities, Indigenous peoples, professionals and organizations, shared their views on decarbonizing buildings, such as:

- *Regulating carbon as well as energy efficiency in the BC Building Code for new buildings*
- *Accelerating highest efficiency heating equipment standards for existing buildings*
- *Addressing affordability impacts especially for those who need it most*
- *Integrating climate resilience, for example, to address heat waves and air quality issues*
- *Considering unique Indigenous geographic and cultural needs*
- *Ensuring program incentives support and align with future building codes and standards.*

THE PATH TO TRANSFORMATION – 2030 AND BEYOND

Zero-carbon new construction by 2030

Current requirements for new construction focus on energy efficiency without directly addressing the issue of GHG emissions. Since natural gas is still a dominant, low-cost energy source for buildings, efficiency requirements alone are not enough to meet our climate targets.

That's why we're adding a new carbon pollution standard to the BC Building Code, supporting a transition to zero-carbon new buildings by 2030. We're already working with local governments to develop voluntary carbon pollution standards. Those communities will serve as pilots for future province-wide requirements. The standard will be performance-based, allowing for a variety of options including electrification, low carbon fuels like renewable natural gas, and low carbon district energy.

In 2023, we'll review our progress and, based on what we've learned, we'll start phasing in provincial regulations over time (2024, 2027, 2030). We'll also incorporate energy-efficiency standards for existing buildings into the BC Building Code starting in 2024.

Highest efficiency standards for new space and water heating equipment

Space and water heating are the primary drivers of GHG emissions from buildings. To meet our targets, we need to ensure these functions are super-efficient, improve resilience and, wherever possible, run on clean electricity or other renewable fuels. To help accelerate this transition, we're committing to highest-efficiency standards for new space and water heating equipment by 2030, and earlier where feasible.

After 2030, all new space and water heating equipment sold and installed in B.C. will be at least 100% efficient, significantly reducing emissions compared to current combustion technology. Electric resistance technologies like baseboard and electric water heaters are 100% efficient: they convert all the energy they use into heat. But heat pump technologies exceed 100% efficiency by capturing and moving ambient heat, without having to produce it. The new requirements will encourage more people to install electric heat pumps while continuing to allow the use of electric resistance technologies. They will also allow hybrid electric heat pump gas systems and high-efficiency gas heat pumps.

As building owners, professionals, tradespeople and supply chains prepare for these significant shifts in how we build in B.C., the Province will continue to support market readiness and affordability through CleanBC Better Homes and Better Buildings rebates and financing, innovation funding, technical guidance and ongoing industry training.

CLEANBC BETTER HOMES INCOME QUALIFIED PROGRAM

CleanBC Better Homes is B.C.'s online hub for homeowners to access information, rebates and support to reduce energy use and greenhouse gas emissions in their homes.

The CleanBC Better Homes Income Qualified Program is a new, time limited, efficiency and electrification offer that provides high-value incentives to low- and moderate-income households. It complements existing residential energy efficiency programs to help make life more affordable while improving the quality, comfort and resiliency of homes, saving energy, and reducing GHG emissions.

Enhancing energy efficiency programs

Energy companies like BC Hydro and FortisBC have been working for years to encourage efficiency, offering information, tools and support and partnering with the Province to provide incentives and rebates. Utility-funded programs have been effective in reducing emissions, but like so many aspects of our climate-change response, they need to go further, building on initiatives in CleanBC to support the deep reductions needed to meet our long-term targets.

We'll achieve that, in part, with updated regulations to shift the focus of utility-funded efficiency programs to support market readiness for future standards and codes, place more emphasis on electrification, and to ensure affordability for households and businesses. Instead of seeing incentives for conventional gas-fired heating equipment such as furnaces and boilers, consumers will see more support for building-envelope improvements such as insulation and better windows, and all kinds of high efficiency heat pumps – electric, gas and hybrid. We'll also look for ways to further coordinate and integrate energy efficiency programs to make them more effective and easier to access.

We will proceed with the next steps on a Property Assessed Clean Energy (PACE) program, which is a form of financing for energy retrofits designed to help building owners save on energy costs and reduce greenhouse gas emissions. PACE programs link an energy improvement loan to a specific property through a municipal tax lien. The annual payments for the improvements are tied to the property, not an individual, and paid through local government property taxes. This allows for longer terms, helping to reduce upfront loan repayment costs for building improvements. If the property changes hands to a new owner, the outstanding balance of the PACE loan is also transferred over to the new owner.

Introducing home energy labelling

We've done it for years with appliances and vehicles. Now we're putting tools in place to show people how energy efficient their next home could be. B.C. home sale listings will include an energy efficiency rating or label, letting buyers know what their energy costs and carbon footprint will be. Along with raising public awareness, home energy labelling can motivate owners to invest in retrofits that save energy and cut GHG emissions, knowing it will impact future salability.

As a first step, we will introduce a user-friendly, web-based, virtual home-energy rating tool to let people see how efficient their homes are. The tool will be linked to the Better Homes web hub, helping to make CleanBC and utility program offers more accessible. In-home EnerGuide assessments will continue to play a role where homeowners want a more in-depth evaluation, or where homes are too unique for virtual energy ratings to be accurate.

Hartley Bay heats up (and cools down) with energy saving heat pumps

Learn more at: **CleanBC.gov.bc.ca/success-stories**

More low carbon building materials

Much of our work to date around cleaner buildings has focused on the amount and types of energy they use. The next bold step is to reduce embodied carbon, which refers to the total GHG emissions created through a building's lifecycle – from material extraction through manufacturing, transportation, construction, maintenance, and end-of-life disposal or reuse.

One approach is to use low carbon building materials, such as mass timber, wood-based insulation, carbon-absorbing concrete, and concrete made with lignin fibres from trees and other plants. Along with reducing embodied carbon, choosing cleaner materials can support a waste-free, circular economy while creating new opportunities in sectors such as forestry where the emphasis is shifting from high-volume to high-value products.

To help build the market for these cleaner materials, we will develop a Low Carbon Building Materials Strategy by 2023 that includes a holistic approach to decarbonizing buildings, initially emphasizing public sector buildings, supporting the development and implementation of embodied carbon targets for public sector buildings by 2030. We're also developing methods for quantifying and analyzing the total embodied carbon of our built environment and identifying pathways to reduce it.

2.4 Communities

B.C.'s local governments play a vital role in meeting provincial climate targets. Along with directly controlling emissions from their own facilities, operations and vehicle fleets, municipalities and regional districts have the capacity to influence about 50% of our GHG emissions through decisions on land use, transportation and infrastructure that affect where people live and work, how they get around, and how their communities grow and change with time.

This puts local governments on the front lines of climate action, where all these policies converge.

Local Government Relative Influence over GHG Emissions

High ← → **Low**

Municipal infrastructure, buildings and fleet	Transportation network Land use patterns Solid waste Building efficiency standards	Transportation mode share Residential and business energy efficiency Food security	Air travel Industrial energy efficiency Vehicle standards Energy utilities

Adapted from: Options to Accelerate Climate Action. Available online: https://kelownapublishing.escribemeetings.com/filestream.ashx?DocumentId=29429

What we heard

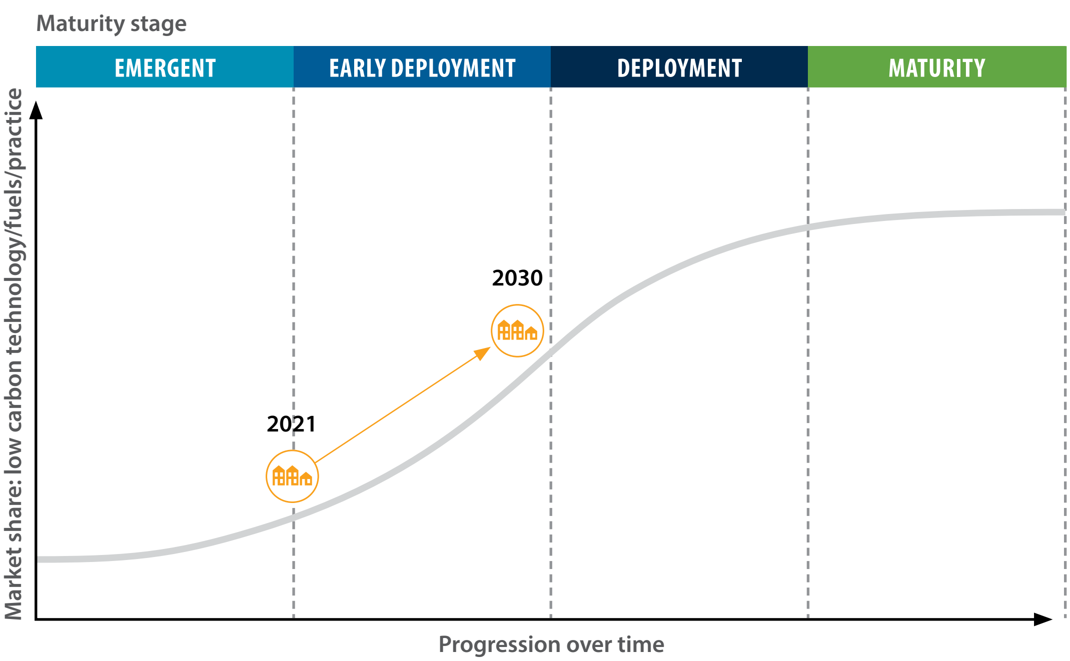
In the consultations that informed this Roadmap, many local governments shared their views regarding the need to:

- *Provide sufficient, flexible and guaranteed climate action funding*
- *Enable local governments to regulate via opt-in legislation and expanded authority*
- *Target capacity constraints through coordination, funding and tailored support*
- *Consider legislative changes to better integrate climate action into Official Community Plans and take a more holistic approach to integrate climate resilience*
- *Increase ZEV targets, carbon tax and the Low Carbon Fuel Standard.*

Where we're starting from

Since 2008, virtually all of B.C.'s local governments have signed the B.C. Climate Action Charter, a voluntary agreement to work toward corporate carbon neutrality, measure community-wide emissions and create complete, compact, more energy-efficient rural and urban communities. Many have ambitious targets and much has been achieved. However, within communities – especially in smaller and rural areas – capacity, environment, geography and size can add to the challenges of taking climate action.

Communities



KEY ACTIONS

- Supporting better land-use planning
- Supporting local climate action
- Improving local governance
- Supporting natural asset infrastructure

THE PATH TO TRANSFORMATION – 2030 AND BEYOND

Transformation for this sector is closely tied to actions in the other Roadmap pathways, including transportation, buildings and low carbon energy, all of which have significant impacts on communities' GHG emissions and will require local government leadership to implement. In this pathway, our work addresses land-use planning, infrastructure and governance – key elements contributing to the larger climate action picture.

Supporting better land-use planning

Land-use planning links communities to the environment and the economy. It's multi-faceted, complex work that affects people's daily lives and plays a large role in shaping how communities will look, feel and function in the future. As part of this Roadmap, we'll work with municipalities and regional districts to enhance their work on land-use planning by:

- Providing better supports, tools and guidance
- Making data available to help inform decisions and assess progress
- Using a climate lens to review provisions in areas such as Regional Growth Strategies, Official Community Plans and zoning.

INTEGRATING TRANSPORTATION AND LAND-USE PLANNING

The Province is developing an integrated planning approach to better align transportation and land-use planning. The goal is to integrate future transportation investments with local and regional development plans, supporting the seamless movement of people and goods, enabling trade, preparing for future growth, and encouraging the development of diverse, affordable, resilient connected communities that provide the amenities, housing and quality of life people value.

As communities grow, we will support them to better align land-use and transportation planning to build connected, mixed-use communities where more people can live closer to jobs, services and transportation choices, helping to reduce commute times and greenhouse gas emissions. Climate sensitive land-use planning can also reduce emissions from deforestation by reducing urban sprawl.

Supporting local climate action

Local governments are climate action leaders and we want to make sure they maintain their momentum. The Province will partner with local governments to find new ways to support their work. This will include establishing a new program in 2022 to support local government climate actions through flexible, predictable funding. And we will continue to work with federal partners to enable local governments, Indigenous communities and stakeholders to apply a climate and resilience lens for all major infrastructure funding applications. This will help ensure that B.C.'s future infrastructure is clean, low carbon and able to withstand the impacts of a changing climate.

Improving local governance

B.C.'s *Community Charter*, the *Local Government Act* (LGA) and the *Vancouver Charter* define the core authorities of local governments and guide their decision making across a range of areas including land-use planning. Because better land use is essential to climate action, we will evaluate opportunities to strengthen the local government legislative framework – working with municipalities, regional districts, Indigenous communities and other key partners to identify where improvements may be needed.

We're also taking steps to re-invigorate and refresh the Province's partnership with local governments and the Union of BC Municipalities (UBCM) through the Green Communities Committee, established under the Climate Action Charter. Committee members support the development of strategies, actions, supports and incentives to advance climate action in all of our communities. They also work with local governments to build their capacity to plan and implement climate change initiatives.

Other actions in this pathway will include:

- Supporting access to GHG emissions data related to buildings, transportation and waste
- Enhancing the existing Community Energy Emissions Database for local governments and Indigenous communities
- Working to develop regionally specific adaptation and resilience strategies as part of B.C.'s Climate Preparedness and Adaptation Strategy; this includes supporting access to data needed for hazard and land-use risk reduction.

Supporting natural asset infrastructure

Natural assets such as aquifers, forests, streams, wetlands and foreshores provide important environmental services equivalent to those from many engineered assets. When we keep them healthy, they're also inherently resilient and adaptable to climate change. With effective monitoring, maintenance and rehabilitation, natural assets can provide services and add value for decades in ways that many engineered assets cannot match. Supporting natural assets can also reduce deforestation, leading to lower emissions.

As part of this Roadmap, we will support the development of natural asset infrastructure for local governments and Indigenous communities, aligned with local government climate initiatives.

2.5 Industry, Including Oil and Gas

B.C.'s industries are making great strides in low carbon innovation, delivering some of the cleanest industrial products of their kind in the world. Keeping them competitive is both an economic and environmental imperative. We produce resources the world needs, and we can make them with a smaller carbon footprint than most of our competitors, helping to address the impacts of climate change worldwide. If production moves to places with less environmentally friendly practices, the planet will be worse off and so will our economy.

To meet our climate targets, B.C. companies will need to continue investing in low carbon technologies and practices. In some cases, they will need support to further reduce emissions so they can stay competitive, attract new investment and showcase their successes to the world.

Where we're starting from

The market for fully decarbonizing large industry in B.C. is at the emergent stage, with a number of solutions and technologies being piloted or demonstrated. Because each industrial facility is different, there is no one-size-fits-all solution, and some operators are farther along the low carbon continuum.

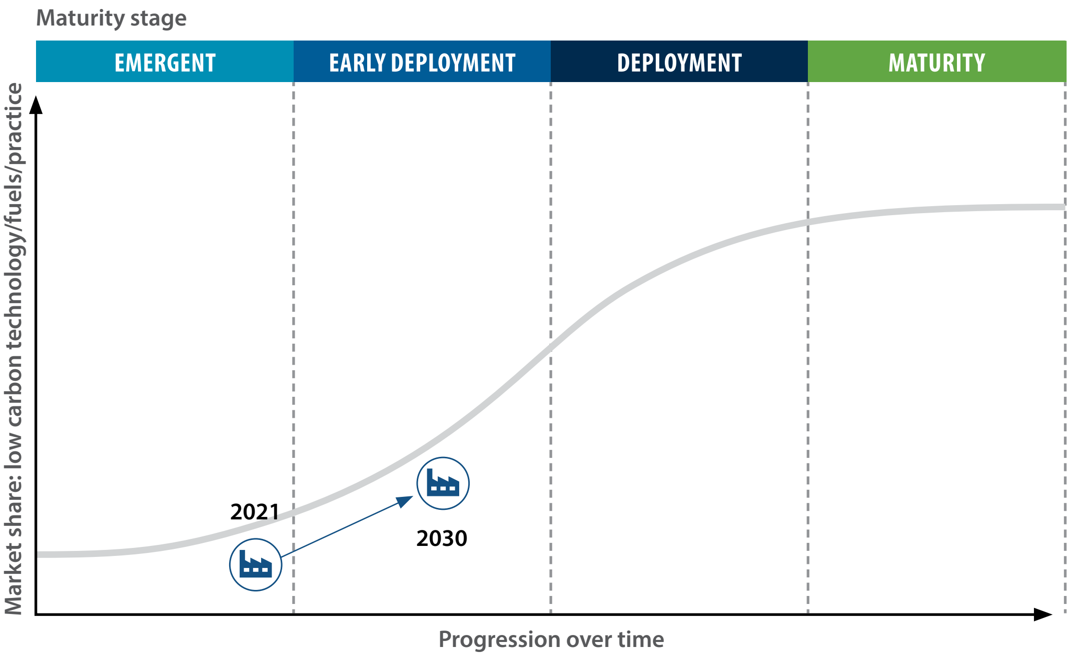
Commercial deployments are also at different stages, largely due to economic factors including cost, scale and regulatory considerations. Promising technologies such as carbon capture and storage are still in early development. And, while we're making progress towards reducing methane emissions in some sectors, we still have work to do on measuring and managing them in others.

What we heard

In the consultations that informed this Roadmap, industry leaders stressed the need to leverage their low carbon advantage while building on our natural resources to create opportunities for low carbon growth, including:

- *Providing a predictable and forward-looking policy landscape that allows for long-term emissions reduction planning and investment*
- *Increasing protection for emissions-intensive trade-exposed industry and considering flexible options, such as offsets or credit generating systems, to help address competitiveness concerns*
- *Providing clarity on how to advance carbon capture, utilization and storage projects, including through regulatory certainty and fiscal measures*
- *Tackling major barriers to electrification such as high initial investment and operating costs and timing uncertainty*
- *Advancing low carbon fuel production and use to fill specific niches within industry.*

Industry, Including Oil and Gas



KEY ACTIONS

- Enhancing the CleanBC Program for Industry
- Making new industrial operations 'net-zero ready'
- Aiming to eliminate industrial methane emissions by 2035
- Reducing emissions from the oil and gas sector
- Integrating emissions goals into the oil and gas royalty system
- Advancing a provincial approach to carbon capture, utilization and storage (CCUS) and negative emissions technologies

THE PATH TO TRANSFORMATION – 2030 AND BEYOND

To help meet our climate targets and keep B.C. industry at the forefront of low carbon innovation and production, we need to work together to reduce industrial emissions as quickly as possible, including continuing to invest in low carbon technologies and practices and implementing more circular processes.

As part of this Roadmap, we'll encourage more facilities to connect to clean electricity, use more low carbon fuels such as hydrogen, explore how best to capture and safely store or use carbon, and reduce industrial methane emissions. We're also moving forward with a suite of new initiatives to help keep our industries competitive as we move to a net-zero future.

Enhancing the CleanBC Program for Industry

The CleanBC Program for Industry supports GHG reductions and competitiveness by investing carbon tax revenue in projects that reduce emissions and costs across B.C. In 2022, we will work with industry, the Government of Canada and Indigenous peoples to redesign the program to align with new federal carbon pricing rules while continuing to promote a competitive business environment and significant GHG reductions.

Our work will include determining how best to support common infrastructure needs through projects such as transmission grids and access to low carbon fuels. We will also explore ways of structuring projects to include and further benefit Indigenous communities.

Making new industrial operations 'net-zero ready'

Electric fleet reduces costs and improves productivity at this B.C. mine

Learn more at: CleanBC.gov.bc.ca/success-stories

Some of B.C.'s largest industrial operators – accounting for almost 50% of industrial GHG emissions – have already committed to reaching net-zero emissions by 2050. Building on that progress, we're introducing a new requirement: all new large industrial facilities must have a plan to achieve net-zero emissions by 2050. New facilities will also have to show how they align with B.C.'s interim 2030 and 2040 targets.

This means facilities will have to be designed to minimize emissions as much as possible. Where emissions can't be reduced, companies will have to assess the use of new technologies such as carbon capture or consider the purchase of high-quality offsets from projects offering long-term carbon sequestration, such as through the use of negative emissions technologies. New net-zero plans will be required and assessed at different stages of development, subject to review, revision and enforcement over time. Government will work with facility proponents to align new policies and compliance mechanisms to support net-zero-emission plans.

This type of planning will future proof our newest industrial facilities, ensuring they can meet the needs of investors and purchasers adhering to a stringent definition of net zero. This approach will also help to drive investments in new, clean B.C. technologies while providing the certainty industry needs to thrive in a global net-zero economy. Government will work with stakeholders and First Nations as these requirements are further developed.

Aiming to eliminate industrial methane emissions by 2035

Methane is a powerful greenhouse gas, with more than 80 times the warming power of carbon dioxide during its first 20 years in the atmosphere. Clearly, we need to reduce its emissions – but measuring them and identifying where they're from has long been a major challenge.

New solutions are becoming available and we're learning more about them, thanks to the work we've been doing with research organizations, the oil and gas sector, the federal government and non-profits. Through the BC Methane Emissions Research Collaborative, we've demonstrated that methane emissions from oil and gas can be detected, attributed and quantified at specific sites, likely in a more cost-effective way than traditional methods.

With this Roadmap, we are committed to building on that research and applying it across the industrial sector to achieve our goal of zero emissions from methane – or as close to zero as possible – by 2035, and to reduce methane emissions in the oil and gas sector by 75% (compared to 2014) by 2030, consistent with the federal commitment. Methane from industrial wood waste landfills can be converted to less-harmful greenhouse gases through landfill management.

Reducing emissions from the oil and gas sector

Currently responsible for 20% of B.C.'s emissions and 50% of industrial emissions, the oil and gas sector will be required to make a meaningful contribution to BC's climate targets. B.C. is the first jurisdiction in Canada to set a specific sectoral target for reducing emissions from the oil and gas industry.

The Province will work to implement policies and programs to reduce emissions in line with its sectoral target of a 33-38% reduction below 2007 levels. In addition to strengthening B.C.'s methane regulations and modernizing B.C.'s royalty system, our new industrial climate program, to be released in 2023, will be designed to ensure the oil and gas sectoral target is met.

We will also commit to cleaning up 100% of current orphan wells in B.C. before 2030 through the industry-funded Orphan Site Reclamation Fund.

Integrating emissions goals into the oil and gas royalty system

B.C.'s royalty system was set up nearly 30 years ago in the 1992 Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation. The way natural gas is produced has changed significantly since then, as have market conditions, drilling technology and costs, and global concerns on the need to address climate change.

As part of this Roadmap, the Province will review the rules for oil and gas royalties to ensure they support our goals for economic development, environmental protection and a fair return on the resource for the people of B.C. It's part of our commitment to reduce emissions from oil and gas by 33-38% by 2030, compared to 2007 levels.

The review will examine ways to adjust the royalty system to help meet provincial emission reduction targets and will consider recommendations from the independent panel currently reviewing B.C.'s royalty system. Policy tools will be considered to encourage further emissions reductions from the sector, and to support the other pathways in this Roadmap.

Advancing a provincial approach to carbon capture, utilization and storage and negative emissions technologies

The full decarbonization of B.C. industry will require widespread electrification; the use of low carbon fuels like lignin, renewable gas and hydrogen; and the use of carbon capture, utilization and storage (CCUS) and other negative emissions technologies across different sectors.

The cleanest cement plant in Canada might be right here in B.C.

Learn more at: **CleanBC.gov.bc.ca/success-stories**

CCUS technologies can reduce emissions in hard-to-abate industrial sectors such as oil and gas, pulp and paper, and cement, where emissions associated with chemical processes cannot be eliminated in any other way. Since they are still in the emergent phase, we will develop a coordinated, comprehensive provincial approach to guide their deployment.

2.6 Forest Bioeconomy

B.C.'s expansive forests are central to our bioeconomy – the part of our economy that uses renewable resources to produce things we use every day like textiles and packaging. By using the residuals from conventional forestry, our forest bioeconomy supports the sector's shift from high volume to high value and contributes to a waste-free, circular economy while helping in the fight against climate change.

INDIGENOUS PEOPLES AND FOREST MANAGEMENT

Forests are, and have been, central to many Indigenous communities whose inherent rights are connected to their respective territories. They provide food, shelter, economic opportunities, tools and medicine along with materials for arts, culture and spiritual activities. For example, some Indigenous peoples see cedar as the tree of life, using it for homes, clothing, canoes, baskets and traditional ceremonies.[6] As the original stewards of the land we now call British Columbia, Indigenous peoples are essential partners in transforming our forest sector from high-volume to high-value, and keeping it sustainable.

What we heard

The Province engages regularly with industry, academia, Indigenous peoples and governments to advance forest sector innovation and build a broader bioeconomy in support of sustainable forest use. Key themes discussed in the consultations informing this Roadmap were:

- *Need for a competitive carbon policy that incentivizes GHG reduction practices and investments in the forest sector*
- *Investments and further engagement to support commercialization of new bioproducts that can replace more GHG intensive products; this includes using lignin in asphalt instead of bitumen and cellulose foams instead of Styrofoam.*

Indigenous peoples we engaged with emphasized the need to balance environmental and economic benefits, noting the alignment between bioeconomy opportunities and their traditional knowledge principles. Some also expressed interest in pursuing carbon offset projects.

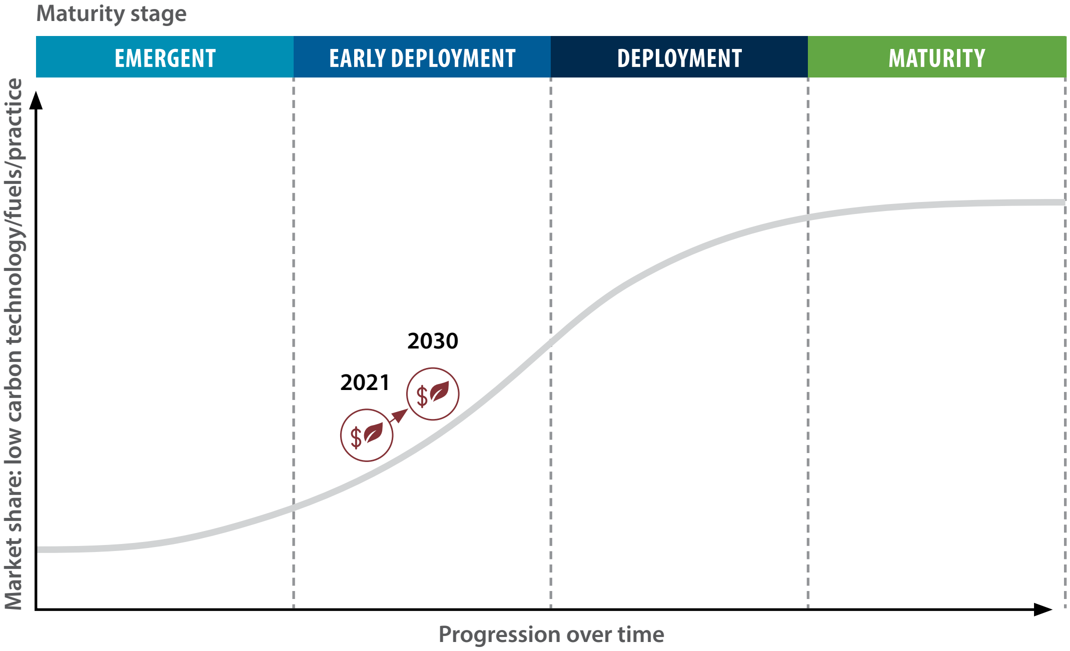
Where we're starting from

The B.C. bioeconomy is currently in early deployment, supported by partnerships with Indigenous peoples and private companies throughout the province. For example, the Indigenous Forest Bioeconomy Program has supported the production of a wide range of innovative high-value bioproducts – from essential oils extracted from conifer needles, to new health beverages from trees, to biochemicals extracted from bark.

There's also a growing market for forest carbon offsets – tradable credits used to offset or counterbalance greenhouse gas emissions. They provide a pathway to meeting climate targets for sectors whose emissions are particularly tough to abate.

6 "The Tree of Life". https://umistapotlatch.ca/enseignants-education/cours_4_partie_2-lesson_4_part_2-eng.php

Forest Bioeconomy



KEY ACTIONS

- Growing and caring for B.C.'s carbon sinks
- Supporting investment in bioproduct development
- Supporting integrated bioproduct manufacturing
- Minimizing slash pile burning/ encouraging fibre utilization

THE PATH TO TRANSFORMATION – 2030 AND BEYOND

The global market for bioproducts is expected to undergo a major transition over the next 10 years, with advanced biomaterials and biochemicals making up the largest market segments.

By 2030, the province should be producing bioproducts at scale and providing high-quality jobs in the bioproducts sector. We'll reach these goals through the following actions.

Old Growth Strategy

Old growth forests – those containing trees that are more than 250 years old – make up nearly one quarter of B.C.'s total forested area. Old growth has a range of benefits, on top of protecting biodiversity, watershed protection and helping the Province adapt to the effects of climate change, they also store large amounts of carbon. Because trees store carbon as they grow, old growth seems like a natural ally in the fight against climate change.

Consistent with the recommendations from the Old Growth Strategic Review, we're integrating climate mitigation into forest management and undertaking research to improve our understanding of old growth forests and their impacts on greenhouse gases. B.C. uses many mitigation options in our forests, including reforestation, fertilization, managing forest health, reducing slash pile burning and using more fibre in longer lived products. Conserving old growth forests as carbon sinks is one of those strategies.

Growing and caring for B.C.'s carbon sinks

B.C. will explore opportunities to partner with the federal government to plant more trees, creating larger carbon sinks and rehabilitating wildfire impacted lands – areas that absorb more carbon than they emit into the atmosphere. We'll also evaluate additional reforestation and forest management activities that sequester carbon and foster climate resilience – including through fertilization, forest health improvements and wildfire mitigation – ensuring opportunities for Indigenous businesses.

A new B.C. Forest Carbon Offset Protocol will expand access to the carbon-offset market for Indigenous communities and forest companies, supporting them to generate revenue while helping others meet their climate commitments. The Protocol will also help to focus attention on the value of non-timber forest benefits, including biodiversity protection and carbon sequestration.

Offset projects will include afforestation (planting trees in areas where there is no forest), reforestation, and improved forest management through practices such as letting trees grow longer before they're harvested. The Province will also explore updating policy and laws to allow the use of Crown land for offset purposes.

Supporting investment in bioproduct development

The Province will partner with Indigenous peoples and industry to build the market for high-value wood products that store carbon or displace products made with fossil fuels. This will include:

- Exploring policy actions, such as biomass content requirements, to increase the use of biomaterials in carbon-intensive products such as concrete, asphalt and plastic components used in finishing cabinets, flooring and other materials
- Encouraging the use of biomaterials in the packaging, consumer goods and biochemical sectors; this could include replacing single-use plastic packaging with biobased materials
- Exploring opportunities to support sector growth through measures such as market and supply chain studies, capacity building, technology assessments and pilot projects for scale-up opportunities
- Advancing mass timber production and use through a Mass Timber Action Plan; work to develop the plan is being guided by a steering committee representing Indigenous communities, industry and government
- Exploring the potential for regional bio-hubs to help ensure communities have access to fibre for diversified manufacturing, and to enhance the number of well-paying forest sector jobs across the province.

Supporting integrated bioproduct manufacturing

One of the potential downsides of forest-based bioproduct manufacturing is having to move material from one site to another. Integrating manufacturing with existing pulp and paper facilities and pellet mills eliminates that issue, creating significant logistical and cost advantages. As part of this Roadmap, we will explore ways to streamline regulations and generate investment for bioproducts facilities at pulp mill sites, allowing producers to make full use of B.C.'s forest resources.

Minimizing slash pile burning and encouraging fibre utilization

Slash piles – the residue from conventional forest harvesting– have long been burned as a way to help reduce the risk of wildfires, and to enhance habitat for wildlife and replanting. The Province will work towards near elimination of slash pile burning by 2030 and will increasingly divert materials away from slash piles and into bioproduct development, reducing both air pollution and GHG emissions while creating new economic opportunities.

In the months ahead, we will partner with forest licensees and Indigenous communities to explore ways to make this feasible, taking into account any impact on wildfire risks. We'll also continue to invest in projects that encourage greater use of forest fibre that would otherwise be burned.

2.7 Agriculture, Aquaculture and Fisheries

The agriculture sector directly accounts for just under 4% of B.C.'s GHG emissions. The largest source is from enteric fermentation, a digestive process of cattle and other ruminants that produces methane, a powerful greenhouse gas. The next largest sources of agricultural emissions are on-farm energy, agricultural soils and manure management.

AGRICULTURE, FISHERIES AND ADAPTATION

Adaptation to climate change has been, and continues to be, a key focus of climate action for agriculture, fisheries and aquaculture. These industries are extremely vulnerable to the impacts of changing weather patterns and severe weather events, including high intensity rainfall, heat waves, drought, wildfire and changing marine conditions. Industry and Indigenous partners are acutely aware that the changing climate affects their productivity and livelihoods, and that building resilience is critical. New measures to support the sector's adaptation will be included in the Climate Preparedness and Adaptation Strategy, due for release in 2022.

What we heard

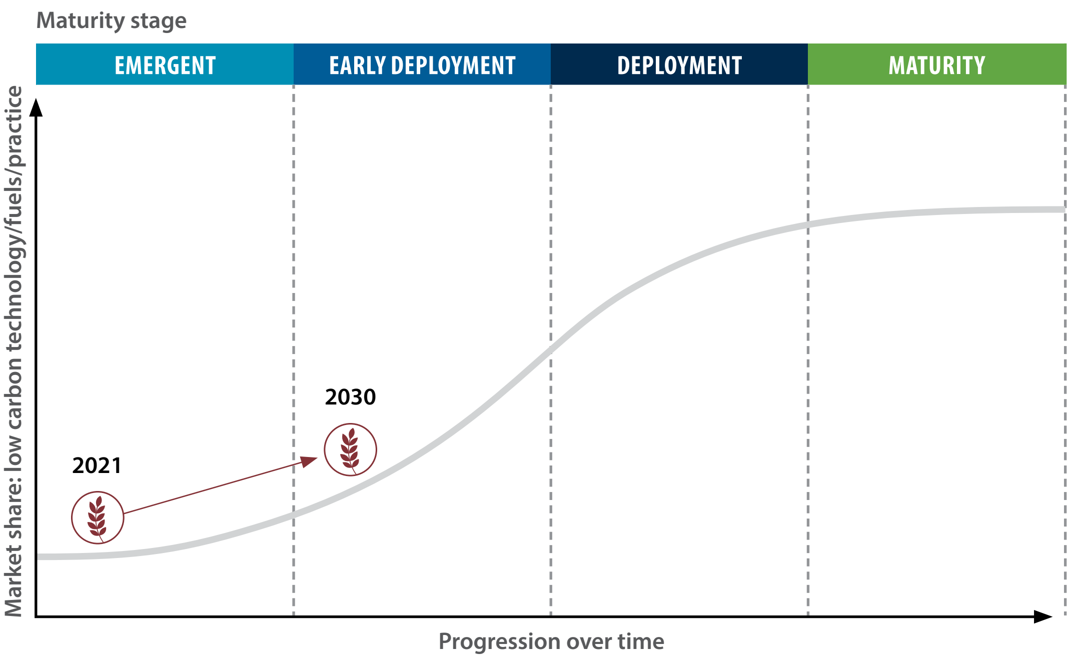
In the consultations that informed this Roadmap, people in the agriculture and aquaculture sectors said they want to continue being informed and consulted as programs and policies are developed and implemented, and want to see their roles and expected contributions more clearly defined. They also highlighted the importance of:

- *Providing financial support to help sectors transition practices and technology*
- *A high-level of buy-in from producers who will readily take up practices that are economically viable*
- *Undertaking research and development and developing monitoring and measurement frameworks to establish benchmarks and track GHG reductions.*

Where we're starting from

The market for decarbonizing agriculture, aquaculture and fisheries is in the emergent phase. Stakeholders have emphasized the need to be realistic about what can be achieved by 2030, noting that cost and economic viability present significant barriers to adopting new solutions.

Agriculture, Aquaculture and Fisheries



KEY ACTIONS

- Supporting GHG efficient practices
- Enhancing agricultural carbon sequestration
- Seizing the potential of regenerative agriculture
- Exploring the potential for seaweed aquaculture to sequester carbon
- Supporting increased on-farm efficiencies and fuel switching, and anaerobic digesters for biogas production

THE PATH TO TRANSFORMATION – 2030 AND BEYOND

To help move the market to early deployment by 2030, we're supporting producers to increase GHG efficient practices and exploring several measures to enhance carbon sequestration.

Supporting GHG efficient practices

As part of this Roadmap, the Province will continue to support the transition to technologies and practices that reduce both net GHG emissions and operating costs for producers. This includes encouraging fuel switching and electrification to reduce emissions from equipment in agriculture, aquaculture and fisheries, along with increased efficiency in manure and nutrient management. We'll encourage the development and piloting of new clean solutions such as electric tractors and technologies to further improve energy efficiency in greenhouses. And, we'll encourage more local, sustainable food production, which has the potential to reduce greenhouse gas emissions in B.C.

Waste management will be supported by growing opportunities to capture biogas, turning farm waste into a valuable resource. Pathway strategies related to biogas will contribute to our goal for renewable energy to make up at least 15% of the content of B.C.'s natural gas by 2030.

Enhancing agricultural carbon sequestration

We will work with the agriculture sector to determine beneficial management practices to maximize carbon sequestration and its benefits to biodiversity, soil and water quality, and farm profitability. Our primary focus in this area is supporting research and monitoring to fill in critical knowledge gaps. We will support applied research, explore piloting promising ideas, monitor results and work to improve local technical knowledge of climate adaptation.

Seaweed aquaculture reduces climate pollution

Learn more at: CleanBC.gov.bc.ca/success-stories

We will also encourage producers to implement regenerative agricultural practices and technologies that improve soil health and biodiversity, allowing farmland to store more carbon. And we'll work with Indigenous communities and the aquaculture sector to explore the carbon-storage potential of seaweed cultivation.

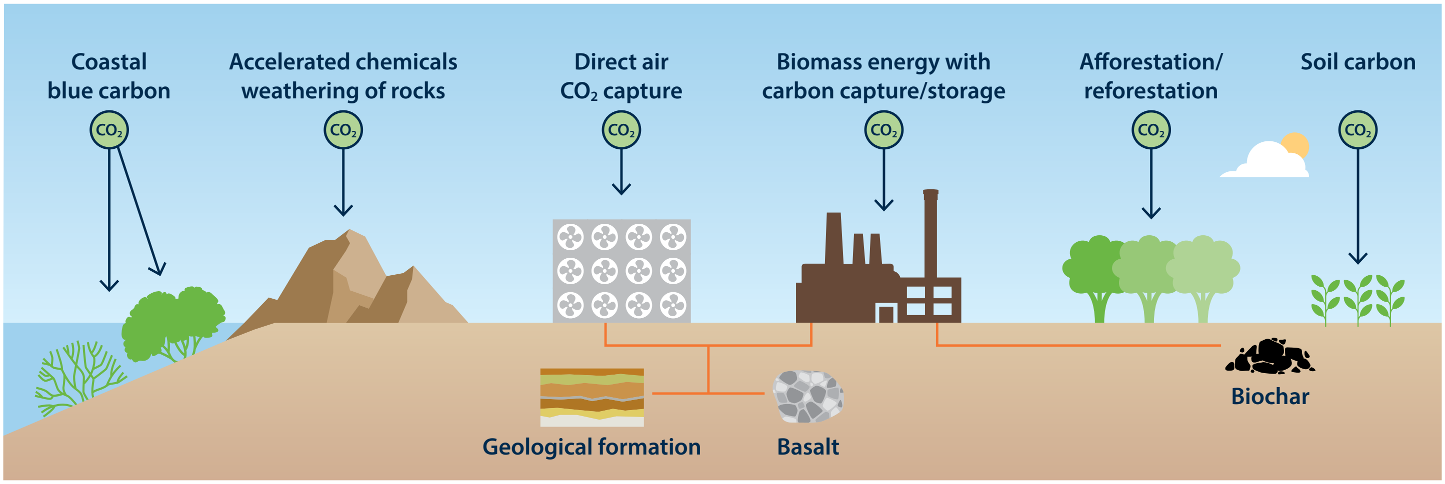
2.8 Negative Emissions Technologies

THE NEED FOR NEGATIVE EMISSIONS TECHNOLOGIES

According to the International Energy Agency, almost half the GHG reductions targeted worldwide for 2050 will come from technologies currently in the demonstration phase. Expert groups like the Canadian Institute for Climate Choices agree on the need for high-risk, high-reward technologies, projecting that solutions such as negative emissions technologies (NETs) could deliver two thirds of the reductions needed to meet our 2050 targets.

Negative emissions technologies can play an important role in meeting our climate targets, especially the long-range commitment to reach net-zero by 2050. They remove CO_2 from the atmosphere, offsetting emissions that have already occurred. NETs range from biological options, such as forest and soil ecosystems, to novel engineered technologies. This pathway is focused on the latter.

Negative Emissions Technologies



Adapted from: National Academies of Sciences, Engineering, and Medicine. 2019. Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. Available online: www.nap.edu/download/25259

What we heard

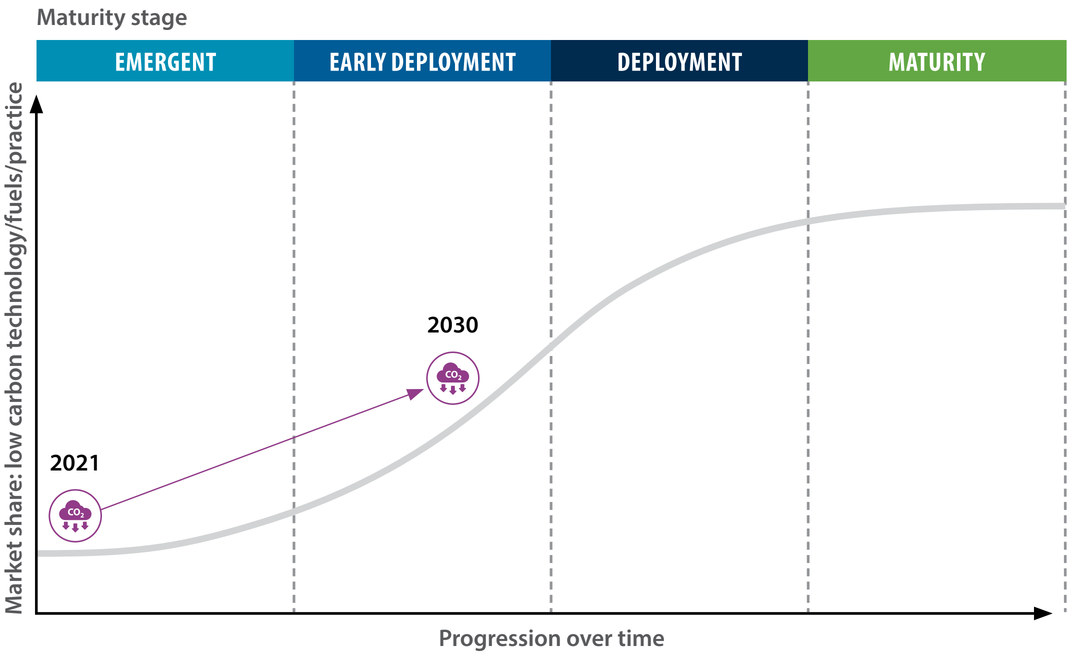
In the consultations that informed this Roadmap, industry, Indigenous peoples, businesses, clean tech companies and others encouraged the Province to explore the potential of NETs. Key themes discussed were:

- *Continuing engagement to develop a policy framework including a clear definition of NETs, especially as many technologies are in development or in early stages*
- *Encouraging NETs as part of a global solution, and considering equity and affordability implications*
- *Targeting NETs to offset emissions in hard-to-decarbonize industries, not as a replacement for decarbonization*
- *Providing adequate funding supports for technology development and to scale technologies for adoption*

Where we're starting from

The market for NETs is still in the emergent stage but B.C. has the capacity and potential advantage to play a lead role in moving it forward. We're home to a rich ecosystem of innovation and clean tech companies with NET solutions at various stages of development. Because of their novelty and complexity, it will take significant time and investment to determine whether their large-scale deployment is cost-effective and functional.

Negative Emissions Technologies



KEY ACTIONS

- Considering NETs as compliance pathways for the Low Carbon Fuel Standard (LCFS)
- Building an accounting framework for NETs
- Investing in research, development and deployment

THE PATH TO TRANSFORMATION – 2030 AND BEYOND

To support the scale-up of NETs by 2030, B.C. needs an enabling environment that supports innovation, incentivizes public-private involvement and is flexible enough to adapt to change. That could include a supportive regulatory and policy climate, economic incentives, measures to reduce costs or new business models to achieve economies of scale.

To achieve these goals and move the market, we will provide investments through InBC to help small- and medium-sized B.C. companies scale up and reach their highest potential. InBC investments will help foster a low carbon economy by anchoring talent, innovation, intellectual property and high-quality, family-supporting jobs throughout the province. We'll also take the following actions.

Considering NETs as compliance pathways for the Low Carbon Fuel Standard (LCFS)

The LCFS requires fuel suppliers to progressively decrease the average carbon intensity of the fuels they supply to users in B.C. By 2030, they'll have to deliver a reduction of more than 20%, with the target continuing to rise in the coming years.

Recognizing the challenges inherent in reducing carbon intensity, we will consider allowing NETs as an option for compliance. This could attract significant new investment to B.C., along with new jobs in clean technology. A final decision on the LCFS will be based on consultations and assessments of recent program changes affecting costs and emissions.

Building an accounting framework for NETs

Currently, our GHG accounting used to measure progress to targets only captures emission reductions from forest-offset projects, since they are the only NET that currently meets our rigorous standards for planning, implementation and monitoring. As more engineered solutions come online, B.C. will build an accounting framework by 2025 to define how other types of NET projects may impact emissions reductions, and how they can be brought into the inventory's scope. This will ensure they're evaluated on a lifecycle basis so we don't adopt technologies that ultimately require more materials and energy, and produce more GHGs, than what they're capturing and storing.

Once we're able to reliably quantify the impacts of NETs, we will clarify their role in carbon offsets. We will also advocate for international collaboration to ensure national inventories can account for NETs consistently.

Investing in research, development and deployment

As noted in the industry pathway, B.C. will develop a comprehensive provincial approach to carbon capture, utilization and storage (CCUS) technologies, leveraging supports such as the federal investment tax credit for CCUS. We'll also consider additional grants and incentives for research and development, pilot projects and commercial scale deployment.

Negative emissions technologies are breathing fresh air into emissions reductions

Learn more at: CleanBC.gov.bc.ca/success-stories

Some of this support will be delivered through the new B.C. Centre for Innovation and Clean Energy. Its mandate is to bring together innovators, industry, academics and government to accelerate the commercialization and scale-up of B.C. based, clean energy technologies. We will also assess the need for new provincial tools to encourage private-sector investment in NETs. And we will assess the potential of research developed through the University of British Columbia and University of Victoria to mineralize CO_2 from the atmosphere to store it in rock and in other materials.

CHAPTER 3: NEXT STEPS AND IMPLEMENTATION

The CleanBC Roadmap to 2030 is designed to be a living document, to be revisited and updated as we move forward to ensure we stay on track to meet our targets. In the months ahead, we will engage with partners and stakeholders to work out the details of major new measures and find the best ways to put them into practice.

Many of the actions in this Roadmap will expand and accelerate CleanBC policies and programs already in place. Others will require close monitoring and adjustments as we learn from experience. Where policies are working, we'll act quickly to ramp up our efforts. Where they're not as effective, we'll change course, in close collaboration with affected sectors.

As we chart our progress, we will continue to provide detailed reporting to the public through the annual Climate Change Accountability Report, which includes progress indicators for CleanBC programs. In future years, we will also report on the following indicators specific to the Roadmap:

- Market share of technologies, reflecting the extent to which low-emission solutions are being adopted
- Cost of transformation for each sector
- Workforce and skills readiness, reflecting our capacity to adopt new approaches
- Economic and social opportunities, pointing to important co-benefits such as reducing inequality and advancing reconciliation with Indigenous peoples.

The work ahead will be challenging. Transforming British Columbia's economy will require determination, particularly as many of these changes will be made in less than a decade. Achieving our targets will demand an unprecedented level of commitment. It will also offer unprecedented opportunities for the future as we work towards net zero by 2050.

Successful implementation of this plan will require a focused, all of government approach. To support this, the Premier has instructed all Ministers, via mandate letters, to ensure their work continues to achieve CleanBC's goals.

Business and industry will have new opportunities to innovate and build on the CleanBC actions and supports, as well as our global reputation as a place for environmental, social and governance investments and net-zero focused business. Local governments will have new opportunities to build more liveable, compact and energy-efficient communities. Indigenous peoples will have new opportunities to advance their self-determination and participate more fully in every sector of our economy. And everyone in B.C. will have the opportunity to look forward to a cleaner, better future.

We're building a British Columbia where no one's left behind; where innovation drives new advances and keeps us competitive; where we all enjoy improvements in our quality of life and prosper along with – not at the expense of – our natural environment. Meeting our climate targets and building a cleaner economy is fundamental to making this future a reality.

APPENDICES

Roadmap to 2030 Greenhouse Gas Reductions by Initiative

Economy-Wide Initiatives		
Increase the price of carbon pollution	Meet or exceed the federal benchmark of $170 by 2030	
	Revise industrial carbon pricing in 2023	
Reduction of GHGs in 2030 for Economy-Wide Initiatives		**Subtotal 2.4**
Low Carbon Energy		
Enhance the Low Carbon Fuel Standard	Increase the carbon intensity reduction requirement	
	Expand to include marine and aviation fuel	
	Double production capacity for made-in-B.C. renewable fuels to 1.3bn litres	
Increase benefits of electrification	Implement 100% Clean Electricity Delivery Standard	
Reduce emissions from natural gas	New GHG cap for natural gas utilities with a variety of compliance options	
Reduction of GHGs in 2030 for Low Carbon Energy		**Subtotal 5.0**
Transportation		
Accelerate zero-emission vehicle (ZEV) law	By 2030, ZEVs will account for 90% of all new light-duty vehicle sales in the province	
	New ZEV targets for medium- and heavy-duty vehicles to be developed in alignment with California	
Reduce light-duty vehicle travel	Reduce distances travelled by vehicle by 25% relative to 2020	
	Encourage increase in mode shift to walking, cycling and transit to 30% by 2030	
Reduce goods movement emissions	Reduce the energy intensity of goods movement by 10% relative to 2020	
Reduction of GHGs in 2030 for Transportation		**Subtotal 4.9**
Buildings		
New carbon pollution standard in BC Building Code	Carbon pollution standards introduced for new buildings in 2024, with zero-carbon new construction by 2030	
Highest efficiency standards	After 2030, all new space and water heating equipment sold and installed in B.C. will be at least 100% efficient (i.e. electric resistance heating, heat pumps, and hybrid electric heat pump-gas systems)	
Reduction of GHGs in 2030 for Buildings		**Subtotal 1.3**
Industry		
Enhance CleanBC Program for Industry	Enhance industry program to reduce GHGs and support a strong economy	
Reduce methane emissions	Near elimination of methane emissions by 2035 in oil and gas, mining, industrial wood waste and other sectors	
Make new industrial operations 'net-zero ready'	New large industrial development to submit plans to achieve net-zero emissions by 2050 and show how they align with interim 2030 and 2040 targets	
Reduce oil and gas sector emissions	Implement programs and policies so that oil and gas emissions are reduced in line with sectoral targets (reduction of 33-38% by 2030)	
Reduction of GHGs in 2030 for Industry		**Subtotal 2.6**
Other Measures Including: reducing agricultural emissions, supporting compact and resilient communities, and aligning with federal, municipal and Crown Corporation plans.		
Reduction of GHGs in 2030 for Other Measures		**Subtotal 0.9**
Note: Individual pathway reductions do not add up to the totals because of interaction effects between policies that target the same emissions		
Roadmap to 2030		16.2 $MtCO_2e$
CleanBC Phase 1		10.5 $MtCO_2e$
Total GHG $MtCO_2e$ reduced by 2030		**26.7 $MtCO_2e$**
The legislated target for 2030 is 39.4 $MtCO_2e$ (or a reduction of 26.3 $MtCO_2e$ from a 2007 baseline), which we are exceeding by 0.4 $MtCO_2e$.		

Roadmap Portfolio of Measures

Near-term

- Evaluate additional reforestation and forest management activities
- Support carbon sequestration, on-farm efficiencies, fuel switching and anaerobic digesters for biogas production
  Support investment in bioproduct development
- Phase out utility gas equipment incentives
- Implementation of BC Hydro Electrification Plan
- Local government climate action program
- Enhanced CleanBC Program for Industry
- Develop province-wide Circular Economy Strategy
- Establish energy intensity targets
  Implement Clean Transportation Action Plan
  ZEV targets for medium- and heavy-duty vehicles in place
- BC Hydro 100% Clean Electricity Delivery Standard
- Establish requirement for net-zero 2050 plans for industry
  Decision on industrial (including oil and gas) methane approach
  Advance provincial approach to CCUS
- Establish emissions cap for natural gas utilities (GHG Reduction Standard) for 2030
  Enhance LCFS including increasing stringency for 2030 and expanding to aviation/marine fuels
- Public sector new building and light-duty, ZEV-first requirements
  Revised carbon pricing system, including for Industry, that meets or exceeds federal benchmark and protects affordability

Mid-term

- Ensure broad geographic coverage of fast-charger sites
- Introduce carbon pollution standards in the BC Building Code for new buildings
  Energy-efficiency standards for existing buildings in the BC Building Code
- Requirement for low-carbon and resiliency standards for existing public sector buildings
- Implement energy intensity targets/policies for movement of goods
- Develop accounting framework for NETs
- Evaluate opportunities to strengthen local government legislative framework
- Public sector medium- and heavy-duty ZEV-first requirement
- ZEV targets to 26% for new light-duty vehicles
- Public sector 100% light-duty ZEV fleet acquisitions
  Zero-carbon new public sector buildings
- Near elimination of slash pile burning

2030

- ZEV targets to 90% for new light-duty vehicles
  10,000 public EV charging stations
- Highest efficiency standards for new space and water heating equipment and zero-carbon new construction
- Oil and gas sector achieves sectoral target and 75% reduction in methane
  Clean up 100% of current orphan wells
- Increase stringency of LCFS and double production of renewable fuels produced in B.C.
  Phase out gas-fired facilities
- Embodied carbon targets for public sector buildings

Agriculture, Aquaculture and Fisheries
Forest Bioeconomy
Personal Travel
Commercial Transportation
Circular Economy
Buildings
Negative Emissions Technologies
Low Carbon Energy
Electricity
Communities
Industry/Oil and Gas

The Roadmap is an iterative document subject to change on the basis of emerging technologies and changing social, economic and business environments.

BRITISH COLUMBIA

cleanBC

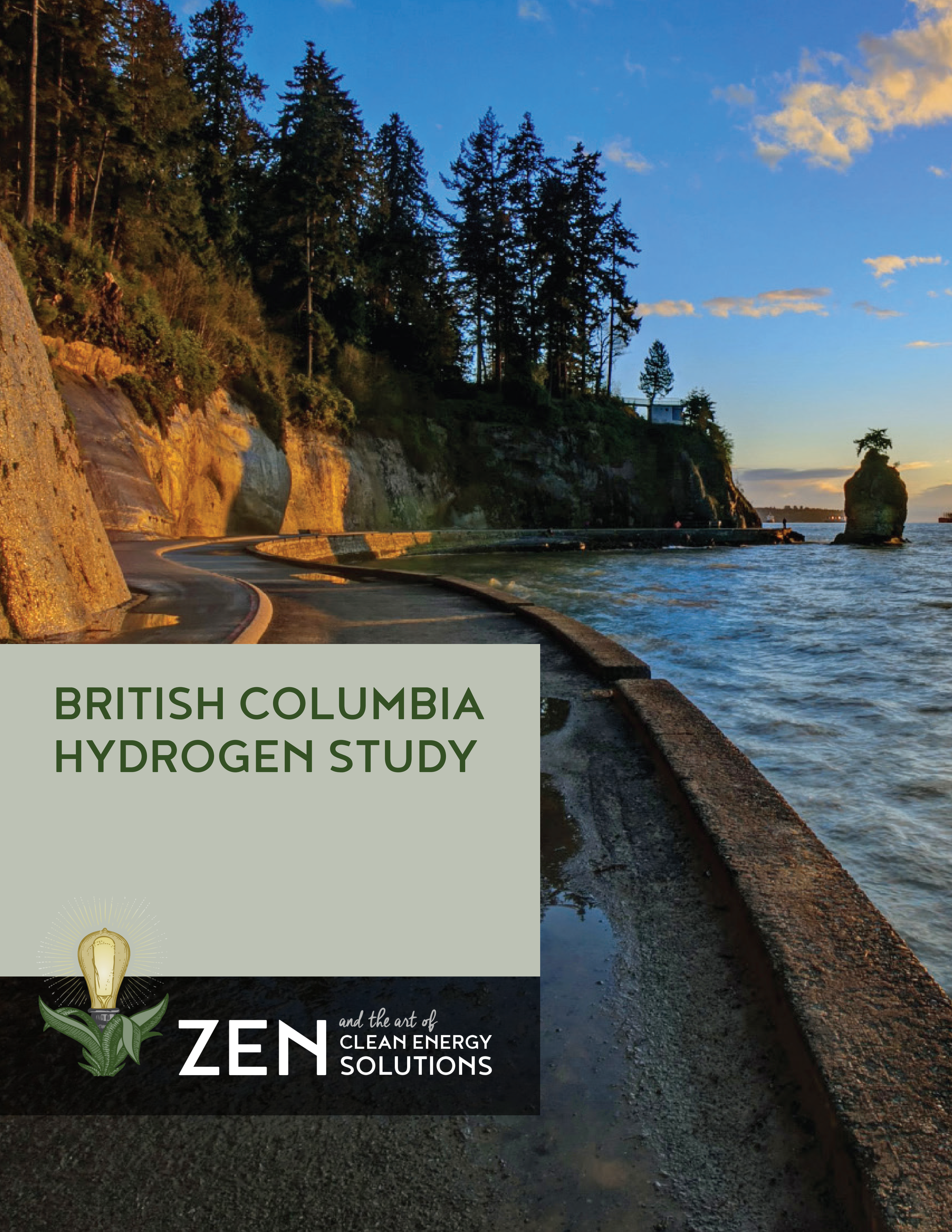
our nature. our power. our future.

Roadmap to 2030

CleanBC.gov.bc.ca

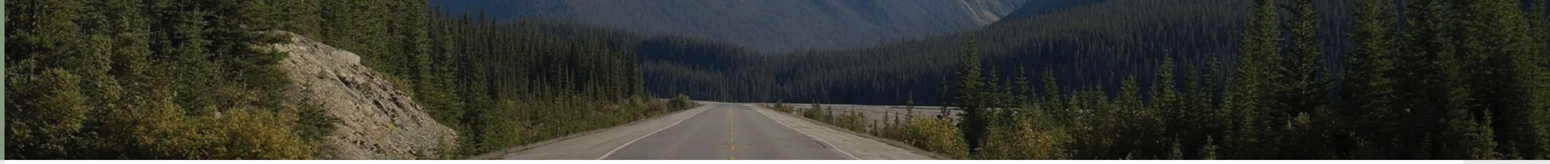
Appendix A-6

BRITISH COLUMBIA HYDROGEN STUDY – BC BIOENERGY NETWORK



BRITISH COLUMBIA HYDROGEN STUDY

ZEN and the art of CLEAN ENERGY SOLUTIONS



ACKNOWLEDGEMENTS

The BC Hydrogen Study was conducted by Zen and the Art of Clean Energy Solutions and project partners the Institute for Breakthrough Energy and Emission Technologies and G&S Budd Consulting Services. Work on the study ran from February 2019 to June 2019.

The project team would like to thank the many individuals and organizations that provided input to the study through participation in workshops, surveys, and individual interviews. The team would also like to thank the BC Ministry of Energy, Mines and Petroleum Resources, BC Bioenergy Network, and FortisBC for support and guidance throughout the study.

Project Team

IBET

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Project Sponsors

BC Bioenergy Network

BRITISH COLUMBIA
Ministry of Energy, Mines and Petroleum Resources

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EXECUTIVE SUMMARY

Why Hydrogen in BC?

Deployment of hydrogen in British Columbia (BC) will be required for the Province to meet 2030 and 2050 decarbonization goals and emissions reduction commitments. End use energy demand in BC was 1,165 petajoules (PJ) in 2016, with 68% of demand met through refined petroleum products and natural gas. Direct electrification and increased supply of renewable natural gas will not be able to displace all this energy to transition the Province to lower carbon and ultimately renewable energy sources. Hydrogen will play a critical role, particularly in energy intensive applications that are most reliant on fossil fuels today such as long-range transportation and heating.

Hydrogen is a versatile energy carrier that can be made from a range of feedstocks that are abundant in our Province, and it has the advantage of being carbon free at the point of use. BC has a distinct comparative advantage because of its clean electricity and low-cost natural gas resources, both of which can be leveraged to produce hydrogen. Hydrogen can be:

- *Blended with BC's rich natural gas reserves to create a cleaner burning fuel and increase the renewable content of the gas delivered through our extensive natural gas infrastructure;*
- *Used directly in fuel cells to produce zero emission electricity in electric vehicles, stationary power systems, and off-road industrial vehicles; and*
- *Utilized as a feedstock in industrial applications, including to produce renewable synthetic liquid fuels that allow existing combustion engines to be used in a cleaner and more sustainable way.*

Use of hydrogen in BC is in the nascent stages, while the pace of worldwide deployment is clearly accelerating. For BC to realize 2030 emissions reductions goals as set out in the CleanBC plan, it is important for government to work with industry now to establish supply and infrastructure necessary to stimulate adoption in the Province. Export opportunities can help to bring international investment to the development of our hydrogen energy systems and provide strong revenue generation potential.

Building of a vibrant and robust hydrogen economy in the Province will result in:

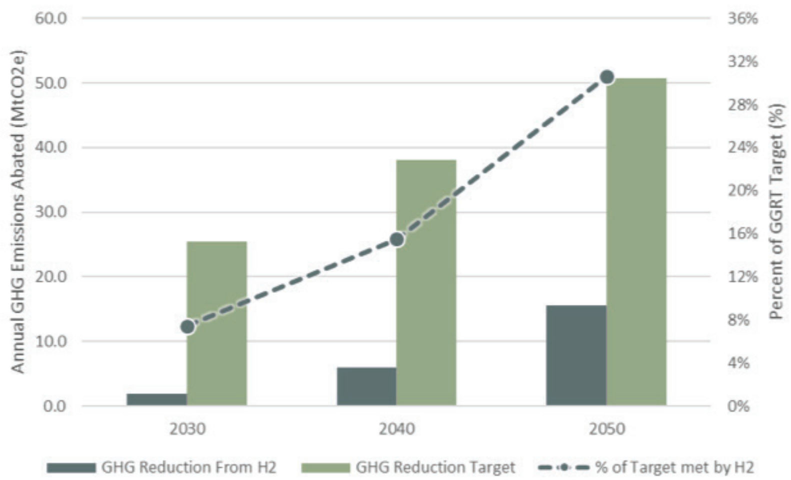
- *Decarbonization of hard-to-abate sectors of the economy such as heating and cooling, long-range transportation applications, and energy intensive industries;*
- *Economic growth and job creation through the development of BC's hydrogen supply chain and infrastructure, and supply to emerging export markets; and*
- *Leveraging BC's natural gas reserves and infrastructure to meet emissions reductions goals in the mid-term while transitioning to renewable energy sources in the long-term.*

Large-scale deployment of hydrogen in BC can close the gap in current plans to balance both emissions reduction and optimal utilization of BC's natural resources and infrastructure assets. It will also benefit the Province's world-class hydrogen and fuel cell sector which is increasingly facing pressures to develop new intellectual property (IP) abroad, in regions where governments support both deployment and development of hydrogen and fuel cell technologies.

Decarbonization of Economic Sectors

CleanBC is the Government of British Columbia's plan for achieving its greenhouse gas (GHG) emissions reductions commitments from the May 2018 Climate Change Accountability Act, formerly titled Greenhouse Gas Reduction Targets (GGRT) Act.

To meet its commitments, provincial emissions will have to fall 40% from the 2007 baseline by 2030 and 80% by 2050. Hydrogen is needed to meet those decarbonization objectives, with study findings demonstrating that hydrogen can contribute up to 31% of the 2050 carbon reduction target, at 15.6 Mt CO_2e/year reductions. The benefits of hydrogen will be strongest in the 2030 – 2050 timeframe, after other high-yield opportunities outlined in the CleanBC plan have been implemented and exhausted. In this period, hydrogen can reduce emissions by 13.7 Mt CO_2e, which represents 54% of the Province's goal during that timeframe.

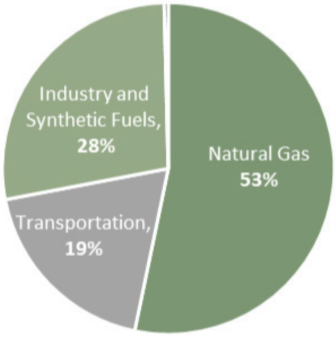


The opportunities where the greatest decarbonization impacts can be realized are: 1) through injection of low carbon hydrogen into the natural gas grid, which will have benefits in the built environment, transportation, and industry economic sectors in the Province; 2) through using low carbon hydrogen directly as a transportation fuel; and 3) through the production of low carbon synthetic fuels that can be used as drop in replacement for current combustion engines and are an important enabler in meeting the Renewable and Low Carbon Fuel Requirements Regulation in BC.

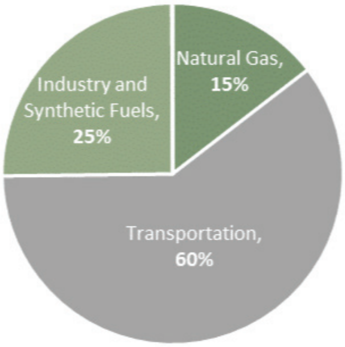
The relative benefits in these applications will shift over time. In the near-term, the easiest and lowest cost way to use hydrogen which will have the highest emission reduction potential in the Province is to inject it into the natural gas grid, and directly reduce emissions by utilizing the lower carbon hydrogen/natural gas blend. Ultimately directly using hydrogen as a transportation fuel will dominate in emissions reduction potential.

The deployment of both battery electric and fuel cell electric vehicles (FCEVs) is critical to reducing emissions in BC. The higher range and faster refueling times of FCEVs will lead to meaningful market share in the Province, particularly in larger passenger vehicles and in medium and heavy-duty vans, buses, and trucks. Utilizing hydrogen directly as a transportation fuel offers the greatest advantages for emissions reduction, as electrochemical conversion of hydrogen in fuel cells is twice as efficient as combustion. Regulation and financial support for infrastructure build out will be critical to achieving the adoption potential of FCEVs. As the transition to FCEVs is evolving, hydrogen can offer emissions reduction benefits in transportation applications through enabling higher use of renewable natural gas (RNG), in co-combustion retrofit engines, and as a low carbon feedstock for synthetic fuels.

2030 GHG Reduction Opportunities
1.9 Mt CO_2e/year



2050 GHG Reduction Opportunities
15.6 Mt CO_2e/year



In these graphs, 'Natural Gas' includes all end use applications that would benefit from the lower carbon H_2/NG blend, including heating in the built environment and industry, and transportation applications running on compressed natural gas (CNG). 'Transportation' refers to applications where pure hydrogen is used as a transportation fuel, either in fuel cell electric vehicles or hydrogen/diesel co-combustion engines.

Economic Growth and Job Creation

Since Geoffrey Ballard first set up shop in North Vancouver in 1979, Canada's hydrogen and fuel cell sector has been recognized as a global leader, with BC hosting Canada's largest industry cluster. BC has pioneered new technologies and industry expertise in areas such as hydrogen production and processing, fuel cell stack and system development, components and systems testing and test infrastructure development, technology research and development (R&D) and commercialization, and standards development. BC is also home to world class academic institutions with specialized programs and R&D supporting the clean tech sector. Local deployment of hydrogen technology will help to maintain a healthy economic cluster in the Province, and will help to develop technical expertise, job opportunities and IP, and will also contribute to continued growth of the sector by ensuring BC maintains a strong competitive advantage.

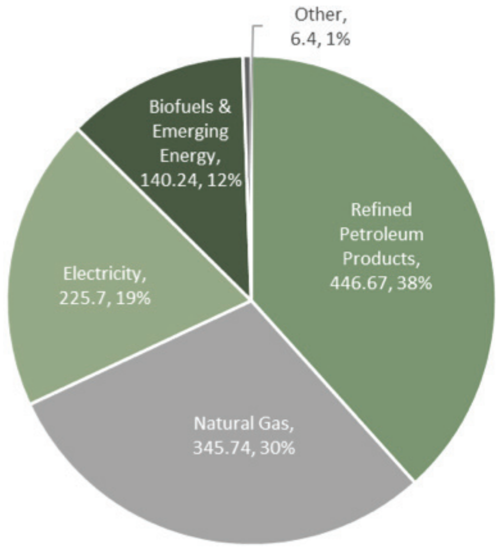
BC's economy is heavily dependent on the extraction, consumption, and export of natural resources, and hydrogen fits as a value-added future export resource that can support both local and international decarbonization efforts. Hydrogen is expected to become increasingly important in the world's energy systems as countries around the world develop roadmaps to achieve decarbonization goals and to improve local air quality. BC's coastal access and relative proximity to leading markets such as California, Japan, China and South Korea position BC to become an exporter of clean hydrogen. By 2050, demand in those target regions is projected to reach 100 million tonnes/year under moderate forecast assumptions, with significant upside potential. If BC were to capture 5% market share in those regions, the export market could be $15 billion annually. International investment for large-scale hydrogen production would benefit local markets while generating significant revenue and should be considered as a significant opportunity for the Province.

The Intergovernmental Panel on Climate Change (IPCC) estimates that USD $2.4 trillion will need to be invested through 2035 in clean technology deployments.[1] A portion of that investment will be made in the hydrogen sector, and BC can benefit from that through its leadership in the development and deployment of hydrogen technologies. BC is well positioned to reinvigorate its leadership position in innovation and venture creation. Build-out in the Province will benefit professional, trades, and manufacturing employment.

1 *IPCC. (2018). Special Report: Global Warming of 1.5°C. Retrieved from https://www.ipcc.ch/sr15/*

Low Carbon Use of Natural Gas Reserves and Infrastructure

BC is fortunate to have an abundance of clean, renewable hydroelectric power. In 2016 electricity supplied 19% of the Province's end use energy requirements. Electrification is a major theme in CleanBC to meet the Province's emissions reductions goals. While electrification will play an important role, it has limitations in generation capacity and transmission and distribution. Some applications are better served by gas as an energy carrier, such as high-grade heat production and long-range transportation. BC has abundant low-cost natural gas reserves that will play a role in meeting energy needs of the Province far out into the future. The National Energy Board (NEB) forecast shows increasing demand for both natural gas and refined petroleum products in BC out to 2040. This is at odds with the Province's emissions reduction goals unless we can find ways to decarbonize those energy sources. Hydrogen can play a key role in this through the decarbonization of natural gas at the source of extraction, and as a renewable feedstock for refined petroleum products and lower carbon intensity synthetic fuels to replace conventional refined petroleum products.



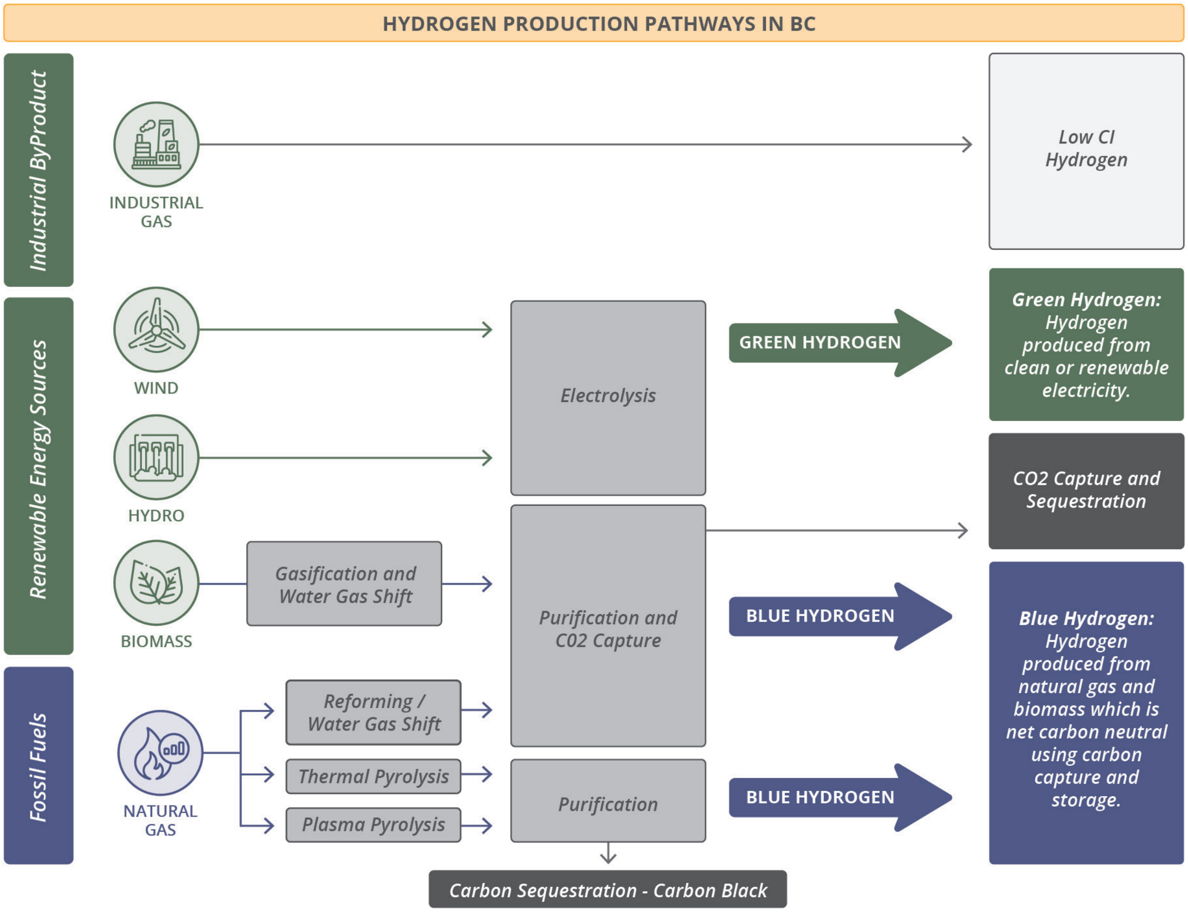
2016 BC End Use Energy Demand[2]

The natural gas infrastructure is a strategic asset for BC. Repurposing that asset for both the transportation and storage of hydrogen presents a cost-effective pathway for the large-scale deployment of hydrogen in the Province. The existing natural gas infrastructure can act as storage for low carbon hydrogen, initially as a hydrogen/natural gas blend and transitioning to 100% hydrogen in some regions of the Province over the longer-term. Hydrogen produced via electrolysis can also foster greater integration of our electricity and gas energy system, optimizing the Province's overall energy systems to achieve optimal efficiency and economic return on critical infrastructure assets.

Hydrogen Production Pathways in BC

Hydrogen can be produced via different pathways using a range of feedstocks. Hydrogen can be made via renewable and fossil fuel resources and is a by-product of some industrial processes. In this study, only 'Green Hydrogen' produced from clean and renewable electricity, 'Blue Hydrogen' produced from natural gas or biomass coupled with carbon capture and storage (CCS), and low carbon intensity (CI) industrial by-product hydrogen are considered.

2 *Canada National Energy Board (2017). Canada's Energy Future 2018: Energy Supply and Demand Projections to 2040. Retrieved from https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA*

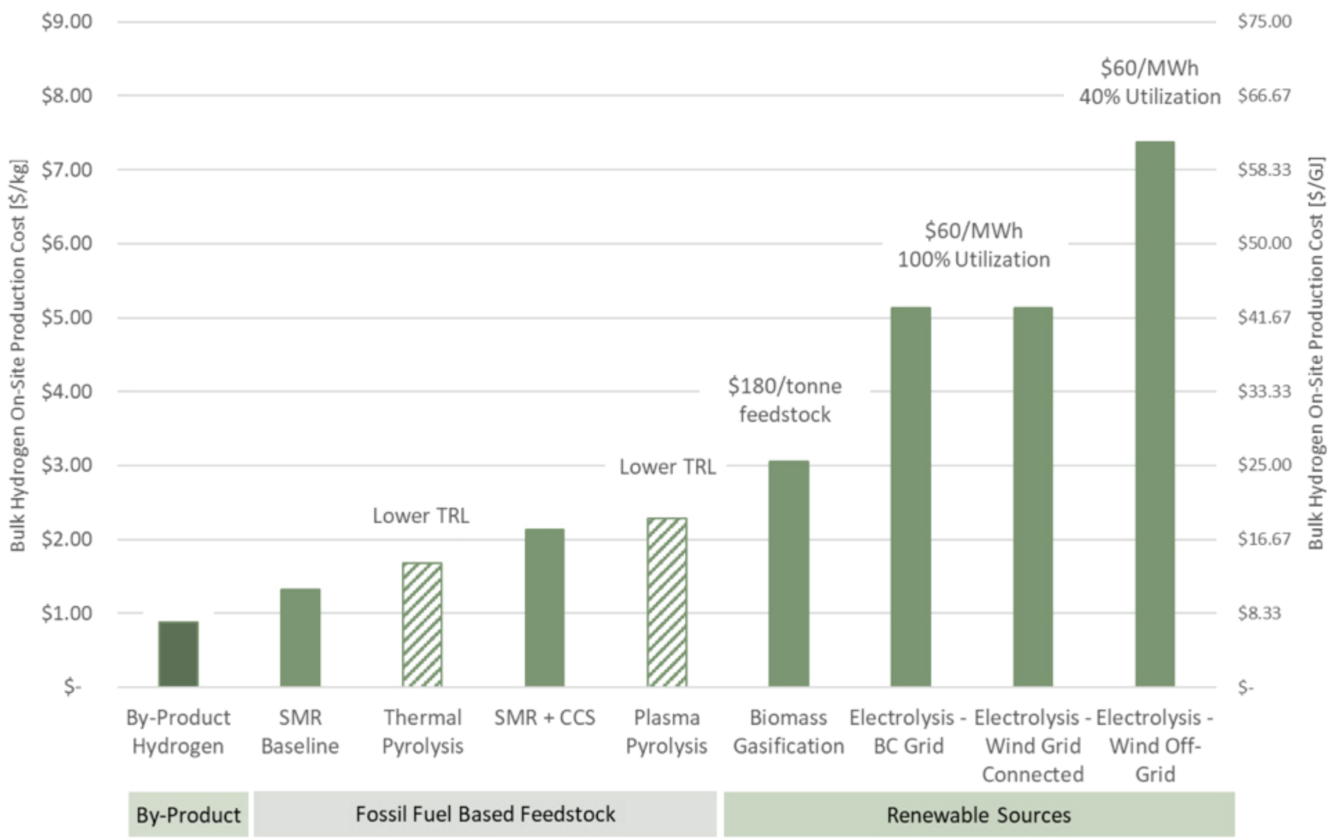


Hydrogen produced at scale from natural gas offers the lowest cost source of low carbon intensity hydrogen when coupled with carbon capture and storage technology. BC has substantial natural gas reserves in the Northeast of the Province, estimated at 525 trillion cubic feet and sufficient to meet 315 years of BC natural gas demand at current levels. The Province also has depleted gas reservoirs and saline aquifers that enable large volumes of CO_2 sequestration. Steam methane reforming (SMR) coupled with carbon capture and storage at the point of extraction is a mature commercial process, whereas pyrolysis with carbon black as a byproduct shows strong potential but is at lower technology readiness level (TRL).

Renewable sources of hydrogen in the Province are currently more expensive than fossil pathways. Production of hydrogen via electrolysis enables a distributed model of hydrogen production that is inherently scalable. While offering many advantages, the electrolysis pathway is currently the most expensive for at-scale hydrogen production in the Province. Flexible, low-cost electricity rates are essential to promoting the growth and adoption of Green Hydrogen.

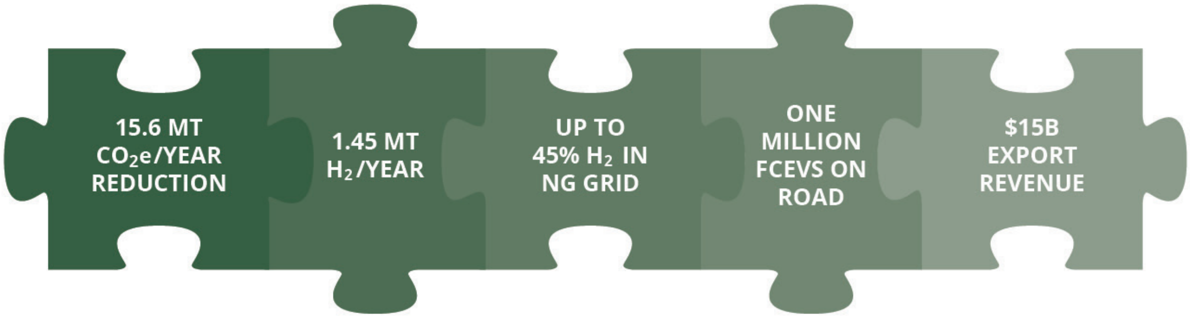
There is an immediate urgency to decarbonize BC's energy supply across all industry sectors, and low carbon intensity hydrogen from fossil fuels is seen as a key enabler to cost effective deployment of hydrogen in the intermediate period. The Province needs policy to drive adoption of multiple energy pathways to ensure both decarbonization and sustainability goals are met. Our policies should set BC as the global leader in hydrogen production with a clear understanding of how their inherent cost structure will drive market adoption of the lower cost natural gas sourced hydrogen to the more expensive fully renewable hydrogen as the finite hydrocarbon sources are depleted over time.

A key pillar to the successful introduction of hydrogen in BC is government support for infrastructure development for the production, distribution, and dispensing of hydrogen. Establishment of low-cost supply channels must lead large-scale adoption in the Province. Development of a robust hydrogen supply chain is also expected to attract new industry to the Province that relies on hydrogen as a feedstock.



Vision for 2050

BC can be a global leader by adopting policies that promote and support all sides of an emerging hydrogen economy including demand, supply and technology development. Through a combination of policy and investment, hydrogen can play a major role in the Province by 2050.



Recommendations

The report outlines a comprehensive list of 38 instrument and policy recommendations to support development of a vibrant hydrogen economy in BC.

The top ten recommendation themes for the 2020 – 2025 timeframe are to:

1. *Identify and communicate hydrogen as priority sector for the Province.*
2. *Prioritize development of large-scale, low carbon intensity hydrogen supply infrastructure and strategic hydrogen liquefaction and distribution assets in the Province.*
3. *Adopt policy that specifies the carbon intensity of hydrogen, rather than limiting to renewable only. This includes updating the definition of renewable natural gas in BC's Greenhouse Gas Reduction Regulation to include low carbon intensity hydrogen.*
4. *Set longer-term objectives for transition to renewable hydrogen supplies through establishing tiered thresholds of required renewable content over time.*
5. *Develop flexible, lower cost electricity rate schedule to encourage production of Green Hydrogen.*
6. *Support lighthouse projects that will demonstrate the potential of hydrogen in critical end use applications.*
7. *Adopt recommended policies and regulatory framework for light and heavy-duty FCEVs and support the build out of hydrogen refueling infrastructure.*
8. *Support research, development and deployment in the Province to ensure the local hydrogen cluster maintains competitive global advantages and remains an important economic sector within the Province.*
9. *Support initiatives related to developing an export market for hydrogen, particularly those that can leverage international investment to develop local supply of hydrogen.*
10. *Prioritize a strategic investment fund to support the above recommendations.*

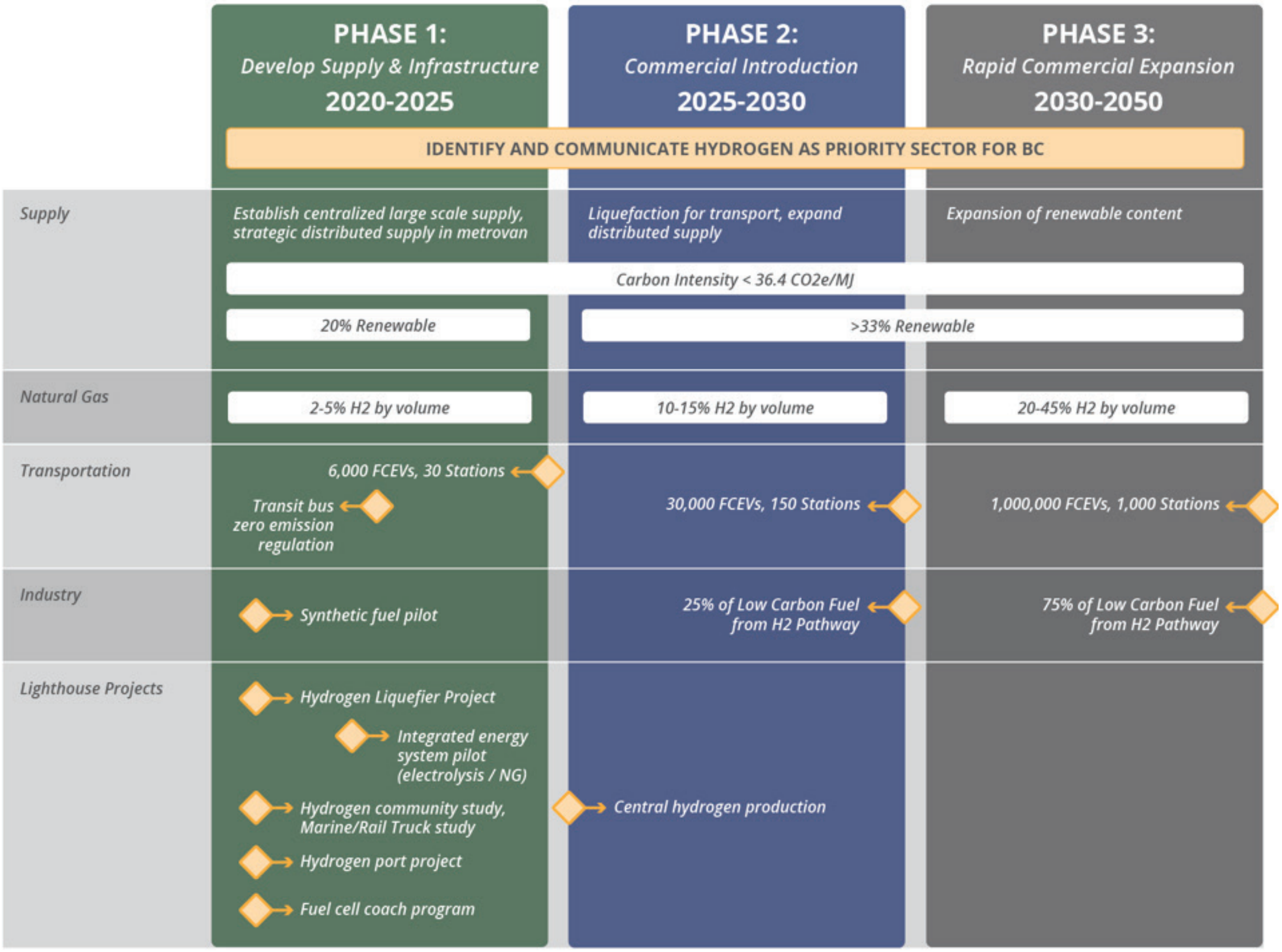
Recommended Investment, 2020-2025

Government investment is needed to establish a robust hydrogen economy in BC. That investment will provide the necessary infrastructure and sector support to allow industry to establish a foundation from which to grow commercial deployments. Government investment will yield necessary decarbonization benefits for the Province, economic growth potential, and long-term diversity and security of our energy systems.

Our analysis recommends a total spend from the Province in the order of $176,000,000 over the next five years, which is approximately $35,200,000 per year. This funding would be focused primarily on supporting lighthouse projects and studies, funding critical infrastructure development, providing subsidies for the rollout of light-duty FCEVs, and supporting the sector through establishing dedicated R&D funding. It is anticipated that this Provincial funding would be leveraged with Federal and Industry match funding, thereby amplifying the benefits of this investment in the Province.

Hydrogen in BC – A Phased Approach

For hydrogen to play a critical role in BC's energy systems in the mid and long-term, it is important to set goals and start developing supporting infrastructure and policies now. Over the next 5 years, the focus needs to be on establishing supply and distribution infrastructure for hydrogen, with lighthouse projects supported to initiate the rollout of end use applications in the Province. The following schematic summarizes the phases of hydrogen rollout and opportunities in the various applications over time.



GLOSSARY

TERM	DEFINITION
AANDC	*Aboriginal Affairs and Northern Development Canada.*
AZETEC	*Alberta Zero-Emissions Truck Electrification Collaboration.*
BC	*British Columbia.*
Ballard	*Ballard Power Systems.*
Bbl/d	*Barrels per day. Measure of production capacity for fuel.*
BCBN	*BC Bioenergy Network.*
Bcf	*Billion cubic feet. A measure of the energy content of one billion cubic feet of natural gas.*
Bcfd	*Billion cubic feet per day. A measure of natural gas production.*
BEB	*Battery Electric Bus.*
BECCS	*Bioenergy with Carbon Capture and Storage.*
BEV	*Battery Electric Vehicle.*
Blue hydrogen	*Hydrogen produced from natural gas or biomass which is net carbon neutral through carbon capture and storage.*
C	*Carbon.*
CAPEX	*Capital Expenditure.*
CCS	*Carbon Capture and Sequestration (or Storage). A process by which carbon dioxide is separated from a gas stream ("captured") and buried underground ("sequestered").* *Though industry prefers the term Carbon Capture and Utilization or Storage (CCU/S) this is less commonly used in a hydrogen context, so the convention of CCS will be maintained.*
CEV	*Clean Energy Vehicles. BC's incentive program designed to make clean energy vehicles more affordable for British Columbians.*
CHP	*Combined Heat and Power. Also called cogeneration (or cogen); it is the simultaneous production of electricity with the recovery and utilisation heat.*
CH_4	*Methane.*

TERM	DEFINITION
CI	*Carbon intensity.*
CNG	*Compressed Natural Gas.*
CO	*Carbon monoxide.*
CO_2	*Carbon dioxide.*
CO_2e	*Carbon dioxide equivalent. A measure of greenhouse gas warming potential expressed in terms of the equivalent amount of carbon dioxide.*
DAC	*Direct Air Capture.*
DCFC	*DC Fast Charger.*
DNV GL	*DNV GL is an international accredited registrar and classification society headquartered in Høvik, Norway. It provides services for several industries including maritime, renewable energy, oil & gas, electrification, food & beverage and healthcare.*
EER	*Energy efficiency ratio.*
EJ	*ExaJoule; a unit of energy equivalent to 10^{18} Joules.*
FCEB	*Fuel Cell Electric Bus.*
FCEV	*Fuel Cell Electric Vehicle.*
FCH JU	*Fuel Cells and Hydrogen Joint Undertaking. A public private partnership supporting research, technological development and demonstration activities in fuel cell and hydrogen energy technologies in Europe.*
FF	*Fossil Fuel.*
FF Gen	*Fossil Fuel Generation.*
g CO_2e	*Grams of CO_2 equivalent. A measure of GHG emissions intensity.*
Green hydrogen	*Hydrogen produced from clean or renewable electricity.*
GGRT	*Greenhouse Gas Reductions Target.*
GHG	*Greenhouse gas.*
GJ	*GigaJoule. One billion joules of energy.*
GWh	*Gigawatt-hour. One billion watt-hours, or one million kilowatt-hours.*
H_2	*Hydrogen.*
HARP	*Hydrogen Assisted Renewable Power.*

TERM	DEFINITION
HCl	*Hydrochloric acid.*
HDV	*Heavy-duty Vehicle, encompassing commercial trucks and buses.*
HOV	*High-Occupancy Vehicle.*
Hydrail	*Hydrogen fuel cell powered train.*
ICE	*Internal Combustion Engine.*
ICT	*Innovative Clean Transit.*
IEA	*International Energy Agency.*
IESO	*Independent Electricity System Operator*
IP	*Intellectual Property.*
IPCC	*Intergovernmental Panel on Climate Change.*
IPP	*Independent Power Producers.*
IRAP	*Industrial Research Assistance Program.*
IWHUP	*Integrated Waste Hydrogen Utilization Project.*
JIVE	*Joint Initiative for hydrogen Vehicles across Europe.*
JIVE 2	*Joint Initiative for hydrogen Vehicles across Europe (second project).*
JV	*Joint Venture.*
kWh	*Kilowatt-hour. One thousand watt-hours. A watt-hour is the amount of energy generated if one watt of power is sustained for one hour.*
LCFR	*Low Carbon Fuel Regulation.*
LCFS	*Low Carbon Fuel Standard, a market-based regulation designed to reduce the carbon intensity of the fuel mix.*
LDV	*Light-Duty Vehicle, encompassing the category known colloquially as passenger vehicles, from sedans to pickup trucks.*
LH_2	*Liquid hydrogen.*
LNG	*Liquefied Natural Gas.*
LPG	*Liquefied Petroleum Gas or Liquid Petroleum Gas.*
MCH	*Methylcyclohexane.*

TERM	DEFINITION
MDV	*Medium-duty Vehicle.*
METI	*Ministry of Economy, Trade and Industry from Japanese Government.*
MJ	*MegaJoule. One million joules of energy.*
Mt	*Megatonne; one million metric tonnes.*
MVRD	*Metro Vancouver Regional District.*
MW	*Megawatt.*
MWh	*Megawatt-hour. One million watt-hours, or one thousand kilowatt-hours. A price of $60/MWh is equivalent to a price of $0.06/kWh.*
NEB	*National Energy Board.*
NG	*Natural Gas.*
NGO	*Non-Governmental Organization.*
NGTL	*Nova Gas Transmission Limited.*
NRCan	*Natural Resources Canada.*
OCH	*Organic Chemical Hydride.*
OEM	*Original Equipment Manufacturer. An abbreviation generally used in reference to auto manufacturers.*
OGC	*Oil and Gas Commission.*
OPEX	*Operational Expenditure.*
P2G	*Power to Gas. Process of converting surplus renewable electricity into hydrogen gas through electrolysis.*
PE	*Polyethylene.*
PEM	*Proton Exchange Membrane.*
pH	*A figure expressing the acidity or alkalinity of a solution on a logarithmic scale on which 7 is neutral, lower values are more acid and higher values more alkaline.*
PJ	*PetaJoule; a unit of energy equivalent to 10^{15} Joules.*
PNG	*Pacific Natural Gas.*
PSA	*Pressure swing absorption.*
PUD	*Public Utility District.*

TERM	DEFINITION
PVC	*Polyvinylchloride.*
R&D	*Research & Development.*
RFP	*Request for Proposal.*
RG	*Renewable Gas*
RNG	*Renewable Natural Gas.*
SME	*Small to Medium-sized Enterprise. Industry Canada defines SMEs as enterprises with fewer than 500 employees.*
SMR	*Steam Methane Reforming. A process by which natural gas (chemical formula CH_4) is reacted at high temperature with water vapour (H_2O) resulting in the production of hydrogen (H_2) and carbon dioxide (CO_2).*
SNG	*Synthetic Natural Gas.*
SWOT	*Strengths, Weaknesses, Opportunities and Threats. A SWOT analysis is a strategic planning technique used to help a person or organization identify strengths, weaknesses, opportunities, and threats related to business competition or project planning.*
Syngas	*Syngas, or synthesis gas, is a fuel gas mixture consisting primarily of hydrogen, carbon monoxide, and very often some carbon dioxide.*
tcf	*Trillion cubic feet of gas. A measure of the energy content of one trillion cubic feet of natural gas.*
TPD	*Tonnes per day.*
TRL	*Technology Readiness Level.*
TWh	*Terawatt-hour. One-thousand Gigawatt-hours. 10^{12} watt-hours.*
VRE	*Variable Renewable Electricity.*
WCBS	*Western Canadian Sedimentary Basin.*
ZEV	*Zero Emission Vehicle.*

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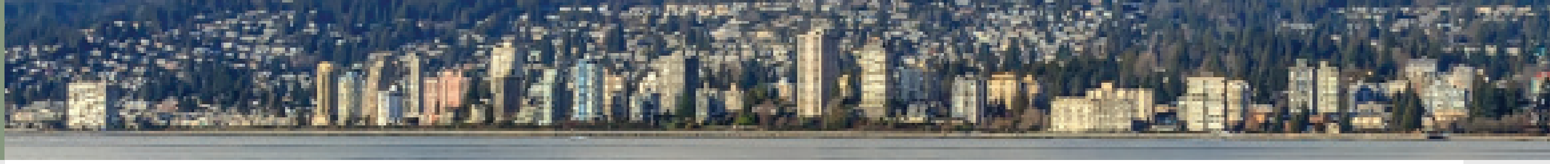

FIGURES

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1.0 : INTRODUCTION

1.1 : Objectives and Scope

The British Columbia Hydrogen Study was commissioned by the British Columbia Ministry of Energy, Mines and Petroleum Resources, the BC Bioenergy Network, and FortisBC with the aim of building a vibrant and robust hydrogen economy in the province.

At a high level the goals of the Hydrogen Study are to identify roles hydrogen can play in BC in the mid-term (2030) and long-term (2050) and to provide recommendations for instruments and policies to enable hydrogen to play an important role in the decarbonization of BC's economy.

Specific questions to be answered in the study are:

Q1	What role(s) should hydrogen play in decarbonizing the energy system and sectors of the economy in BC? Including, but not limited to, explicit consideration of the following: natural gas (NG), transportation, industry, the built environment, feedstock for low carbon energy and fuel production, and remote and off-grid communities.
Q2	What is the anticipated global demand and market potential for hydrogen and what is the export opportunity for BC to meet a portion of that demand?
Q3	What are BC's existing and potential competitive advantages in the hydrogen and fuel cell sector? How can BC maintain and improve its advantages?
Q4	What are BC's competitive disadvantages in the hydrogen and fuel cell sector? How can BC address them?
Q5	What are the instruments and policies necessary to develop hydrogen supply chains in BC?
Q6	What are the existing and potential competitive advantages and disadvantages specific to using hydrogen in the BC natural gas grid as a drop-in fuel, or as a replacement for natural gas?
Q7	What are the opportunities, challenges and costs specific to incorporating hydrogen as storage for intermittent renewable energy in BC?

The specific desired outputs of the study are:

R1	A mid-term (to 2030) and long-term (to 2050) cost curve of potential hydrogen supply in BC by quantifying the amount available at progressively higher price points.
R2	A jurisdictional scan of international commitments, financial incentives and regulatory instruments for green and blue hydrogen development/deployment.
R3	Recommendations for policies, regulations and legislation to facilitate the development of the hydrogen sector in BC.

The scope specifically excluded:

- *Technology Readiness Level (TRL) and Commercial Readiness Index analysis for hydrogen and fuel cell technologies;*
- *Hydrogen pathways that would result in increased greenhouse gas (GHG) emissions.*

1.2 : Project Methodology

The project team used a collaborative, integrative approach in conducting this study.

Data underpinning the study were collected through a combination of stakeholder engagement, online surveys, market and technology reports, internet research, and through leveraging the project team's expertise in the field.

A broad base of stakeholders was consulted throughout the project to ensure a balanced view of the hydrogen sector and to develop aggressive but achievable recommendations supporting the goals of the Province's CleanBC plan. Participants in stakeholder engagement spanned the private sector, non-governmental organizations (NGOs), public utilities, academia and government. Follow-up interviews were also conducted with selected participants.

The project team conducted three workshops, with the following themes:

- *Large Centralized Production of Hydrogen in BC for Decarbonization of BC's NG Industry, Synthetic & Low Carbon Fuel Production, and Export (Workshop 1, March 14, 2019, hosted by FortisBC);*
- *Opportunities for Hydrogen in Transportation Applications in BC (Workshop 2, April 5, 2019, hosted by LGM Financial Services); and*
- *BC's Competitive Advantages in Hydrogen and Fuel Cells (Workshop 3, April 11, 2018, hosted by Ballard Power Systems).*

In advance of each workshop, an online survey was developed and sent to workshop invitees. The project sponsors provided input to the survey questions. Survey responses were used to help guide discussion at the workshop, and to provide input to the study.

A complete list of stakeholders that provided input to the study, along with a summary of select survey responses, and notes from the workshops are included in APPENDIX A: Summary of Stakeholder Engagements.

To assess where hydrogen could decarbonize BC's economic sectors, the team first developed a baseline of provincial energy use and emissions. Baseline data were drawn from reputable public references such as Canada's National Inventory Report and the National Energy Board (NEB). Industry sectors were broken down as: Natural Gas, Transportation, Industry, Built Environment, and Remote Communities. For natural gas, opportunities for injecting hydrogen into natural gas infrastructure and its use to reduce the carbon intensity of the Liquefied Natural Gas (LNG) export market were both evaluated. Hydrogen injection into the natural gas grid impacts both the industry and built environment sectors.

Opportunities for hydrogen to reduce GHG emissions in each sector were identified through an analysis of activities in leading jurisdictions, input from stakeholders, a review of technology options and technology readiness levels, and modeling to understand specific opportunities and constraints related to British Columbia.

For each economic sector, two scenarios were modeled:

- *A conservative scenario incorporating the lowest cost, lowest risk opportunities for hydrogen deployment, generally aligned with existing policy goals and/or regulation;*
- *An aggressive scenario incorporating ambitious targets to realize greater emissions reductions through hydrogen, reliant on increased investment for the development of supply and distribution infrastructure, new policies, and in some cases more ambitious assumptions for technology development.*

The team also met with representatives from the local hydrogen and fuel cell sector to understand BC's competitive advantages and disadvantages, to understand how the Province can benefit from cost-effectively supporting and growing the sector, and to provide reference cases to help support the development of provincial exports.

The global market for hydrogen was assessed by referencing previously published studies forecasting hydrogen demand. Where available, goals for hydrogen use by region announced by local governments were also assessed and rolled into the overall global forecast for hydrogen out to 2050. The BC target markets and opportunity size for export of hydrogen were projected based on market penetration rates in order to size the potential opportunity for export of hydrogen.

Notable initiatives in other jurisdictions are highlighted in the report in sidebars. The team has also identified several "Big Bold Goals" with which to take a leadership position in hydrogen deployment, over and above the aggressive scenarios. These goals are the construction of a hydrogen "backbone" pipeline, decarbonizing of LNG Canada, and the planning of a hydrogen community. If these seem ambitious, or even unreasonable, the climate commitments and climate action of recent years have demonstrated that the ambitious is attainable.

The study findings were synthesized to create hydrogen demand curves based on the opportunities in the examined economic sectors. Policy recommendations were also made to support the development of a vibrant, profitable, emissions reducing hydrogen economy in the Province in the coming decades.

1.3 : Alignment with CleanBC goals

CleanBC is the Government of British Columbia's plan for achieving the GHG emissions reductions commitments from the May 2018 Climate Change Accountability Act of:

- *40% GHG emissions reductions by 2030 (from 2007 levels);*
- *60% reductions by 2040;*
- *80% reductions by 2050.*

For British Columbia to meet its 2030 commitment, provincial emissions will have to fall 40% from 63.6 million tonnes of CO_2 equivalent (Mt CO_2e) in the baseline year of 2007, to 38.2 Mt CO_2e in 2030. Consequently, the province is targeting GHG reductions of 25.4 Mt CO_2e from the 2007 baseline provincial emissions profile, by 2030.

The province's gross GHG emissions in 2016, the most recent year for which data are available, were 62.3 Mt CO_2e, but economic development is expected to increase provincial emissions in the interim.

The CleanBC plan identifies 18.9 Mt CO_2e of emissions reductions; additional opportunities are being evaluated to meet the Climate Change Accountability Act commitments.

Hydrogen's versatility allows it to contribute to CleanBC's GHG emissions reductions goals in several capacities:

1. *For **cleaner transportation**, hydrogen is expected to play a supporting role in helping BC achieve its light-duty vehicle Zero Emission Vehicle (ZEV) mandate targets, and a stronger role reducing emissions from larger vehicles, through fuel cell and co-combustion technologies. Renewable or low carbon hydrogen will also be required for fuel suppliers to meet the low carbon fuel standard. Hydrogen can also enable larger quantities of renewable natural gas to be available to fuel Compressed Natural Gas (CNG) vehicles.*
2. *To **improve where British Columbians live and work**, hydrogen can help achieve the goal of renewable gas comprising 15% of the Province's natural gas consumption. Hydrogen technologies can also help BC's many remote communities reduce their dependence on diesel.*
3. *For **cleaner industry**, renewable and low carbon hydrogen can serve as emissions-free alternatives to natural gas for heat.*
4. *To **reduce waste**, the production of hydrogen-rich synthetic gas (syngas) could up-cycle wood and crop residues and agricultural wastes. Such efforts would also align with the BC Bioenergy Strategy.*

Hydrogen can also play an important role connecting BC's electric and natural gas energy systems together via power-to-gas systems where hydrogen can be used for bulk energy storage. Hydrogen's versatility enables it to provide benefits greater than the sum of each discrete opportunity.

This report evaluates how hydrogen can be harnessed, as a clean energy fuel and feedstock, to grow British Columbia's economy while reducing its GHG emissions, in line with the CleanBC plan.

1.4 : Energy Consumption and GHG Emissions in BC

1.4.1 : Energy Consumption in BC

To understand how hydrogen can reduce the Province's GHG emissions and build its energy economy, an understanding of BC's energy sources and consumption is necessary. Figure 1 shows the NEB's assessment of the Province's primary energy demand by end use in 2016 and 2040.[3]

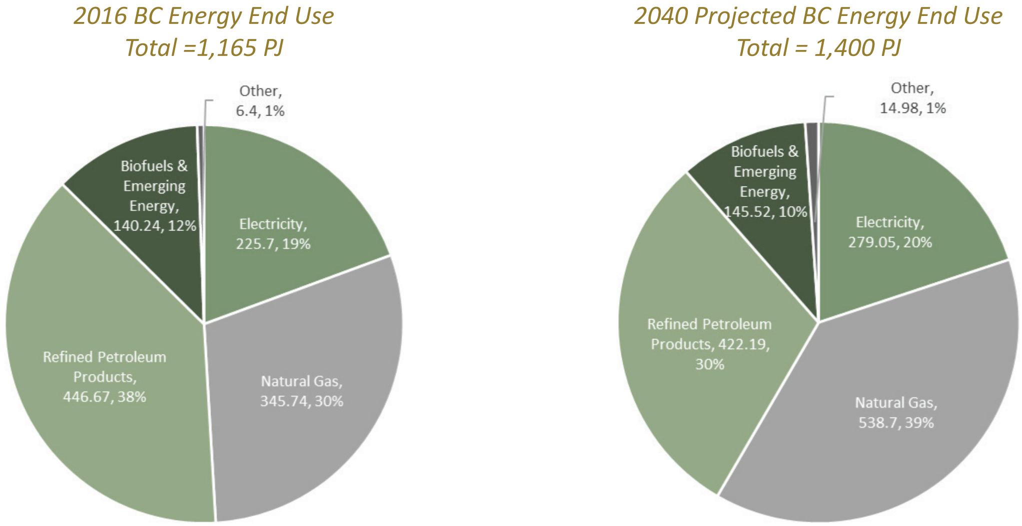


Figure 1. BC Historical and Projected Energy End Use by Energy Currency (2016 and 2040) [3]

The majority of primary energy consumption in the Province derives from fossil fuels: 68% in 2016 and a projected 69% in 2040.

Each energy source has a different GHG intensity, and the Province has provided guidance for quantifying GHG emissions from different energy sources.[4]

Electrification can improve energy efficiency and reduce primary energy demand – for example through the replacement of furnaces and boilers with heat pumps – but can only meet some of the Province's energy needs. A complementary strategy of using hydrogen to replace fossil fuels in other applications will be necessary for the Province to meet its longer-term climate goals. This includes contributing to increased use of renewable gas, which accounts for 75% of the GHG reductions attributed to the built environment in the CleanBC plan. Hydrogen blending in the NG pipeline will be required to meet the 15% renewable gas goal by 2030, which is needed to achieve the associated GHG reductions outlined in CleanBC.

3 *Canada National Energy Board (2017). Canada's Energy Future 2018: Energy Supply and Demand Projections to 2040. Retrieved from* https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

4 *(S&T) Squared Consultants Inc. (2018). GHGenius 5.0d. Calculations conducted by BC Ministry of Energy, Mines and Petroleum Resources Low Carbon Fuels Branch. Retrieved from* https://ghgenius.ca/index.php/downloads

1.4.2 : GHG Emissions in BC

BC's Climate Change Accountability Act sets GHG emission reduction targets of 40% by 2030, 60% by 2040, and 80% by 2050 compared to a 2007 baseline.[5] Figure 2 shows BC's GHG emissions from 1990 to 2016 and a linear path from 2007 GHG emissions levels to the 2030, 2040, and 2050 targets.

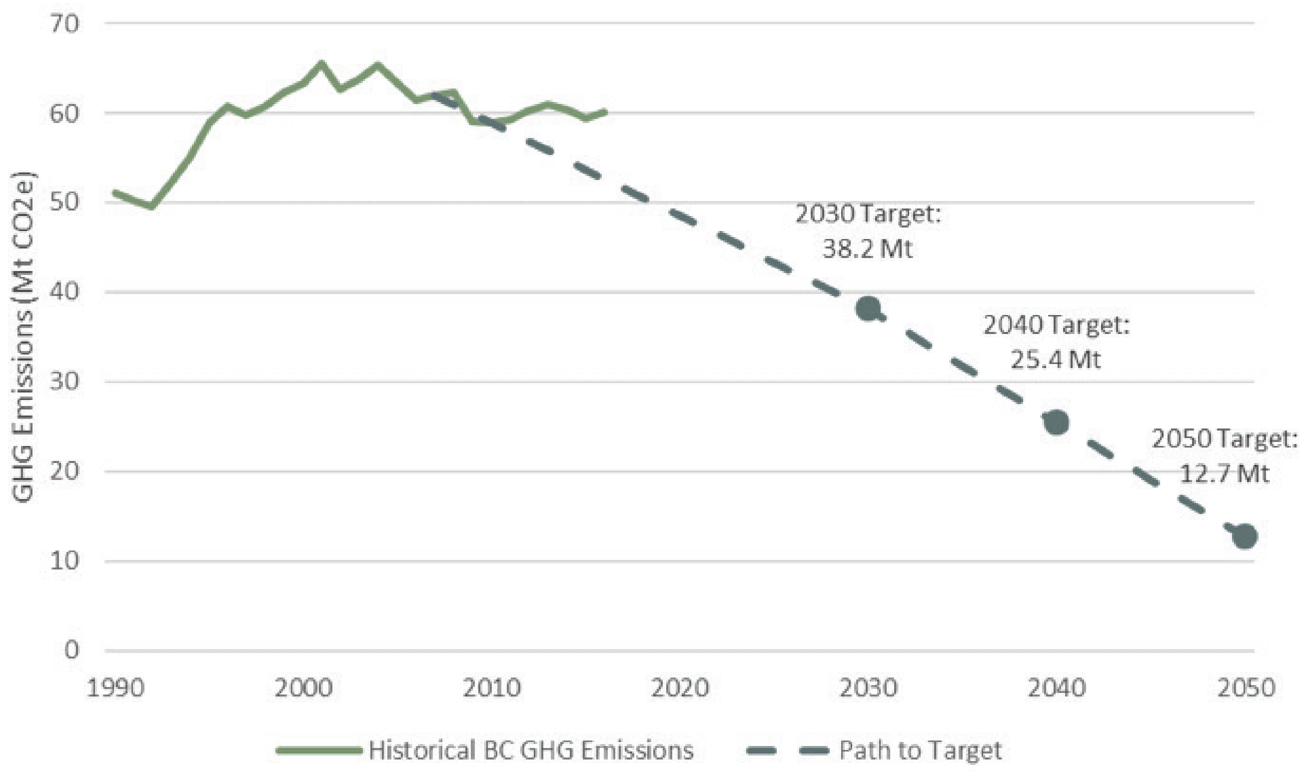


Figure 2. BC's Historical GHG Emissions and Path to Targets[5, 6]

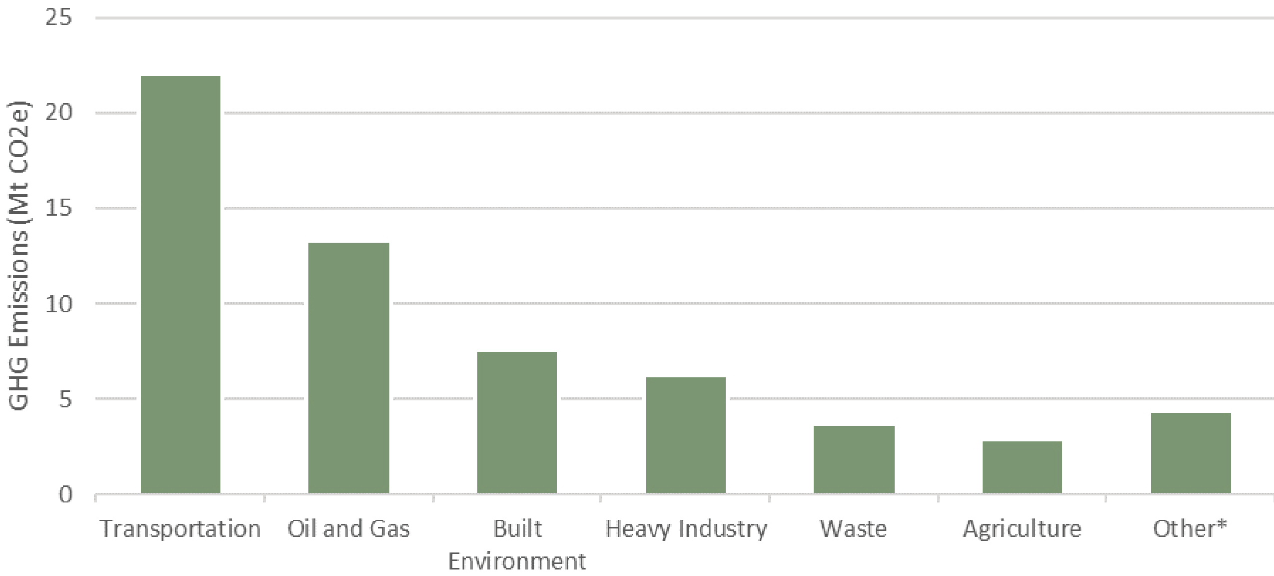
From 2007 to 2016, the Province experienced a moderate reduction in emissions of 3%.[6] To meet its GHG emissions targets, the Province needs to rapidly accelerate its decarbonization efforts. Over the same period, the GDP rose by 19%, demonstrating that economic growth can be decoupled from emissions growth.[7]

Figure 3 shows BC's 2016 GHG emissions by economic sector. Transportation made up the greatest share of total GHG emissions, followed by the oil and gas sector and the built environment.[6]

5 *BC Provincial Government. (2019). Climate Change Accountability Act. [SBC 2007] Chapter 42. Retrieved from http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_07042_01*

6 *Environment and Climate Change Canada. (2018). National Inventory Report 1990-2016: Greenhouse Gas Sources and Sinks in Canada, Annex 10. Retrieved from https://open.canada.ca/data/en/dataset/779c7bcf-4982-47eb-af1b-a33618a05e5b*

7 *British Columbia Provincial Government. (2018). Climate Action in BC: 2018 Progress to Targets. Retrieved from https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/progress-to-targets/2018-progress-to-targets.pdf*



**Other includes light manufacturing, construction, forest resources, coal production, and electricity.*

Figure 3. BC GHG Emissions by Economic Sector (2016)[6]

Inexpensive, energy-dense fossil fuels lend themselves well to transportation and the built environment, which is a reason for these two sectors' large share of the Province's GHG emissions profile. Hydrogen is well-suited to decarbonize these hard-to-abate sectors.

1.5 : Current Uses and Applications of Hydrogen in BC

BC has a strong history of developing hydrogen and fuel cell technologies and is known as the "cradle" of the modern fuel cell industry. Paradoxically, there are relatively few ongoing hydrogen or fuel cell deployments in the Province, forcing the sector to export technology with limited home-province or home-country reference cases. The sector is instead supported by exports to regions such as China, Europe and California, where governments recognize the benefits of hydrogen and fuel cell technologies for their GHG emissions reduction, air quality improvement and energy security objectives.

Without local deployments of hydrogen and fuel cell technology, these regions stand to become the true "centre of gravity" for the sector, eclipsing the Province's early leadership in deploying hydrogen technology. Some notable projects in BC related to hydrogen, starting with the most recent, include:

- *Shell opening Canada's first retail hydrogen filling station in 2018 in Vancouver.*
- *Demonstration of a hydrogen-diesel co-combustion class 8 truck by Hydra Energy in 2017.*
- *BC being selected as Hyundai's first market for its Fuel Cell Electric Vehicles (FCEVs) in Canada in 2015, leasing 10 Tucson FCEVs.*
- *The deployment of 20 fuel cell electric buses (FCEBs) with Ballard Power Systems fuel cells in Whistler from 2009 to 2014. The FCEBs made up almost the entire Whistler bus fleet, which comprised 23 buses (26 buses during peak season).*
- *The Integrated Waste Hydrogen Utilization Project (IWHUP), a six-year project led by Hydrogen Technology & Energy Corporation (HTEC) that included the processing of by-product hydrogen from a sodium chlorate plant, distribution to end users, hydrogen station development, and transportation and stationary fuel cell power system deployment. The Project ran from 2006-2011.*

- *The world's first deployment of fuel cells in a material handling application by Cellex Power at London Drugs in Richmond in 2003.*
- *The world's first 700 bar (10,000 psi) hydrogen refueling station at Powertech Labs in Surrey in 2002.*

There are currently a small number of light-duty FCEVs on-the-road in BC, with growing numbers expected in 2019. No hydrogen powered heavy-duty vehicles, marine vessels, railway locomotives, or aircraft are currently deployed in the Province.

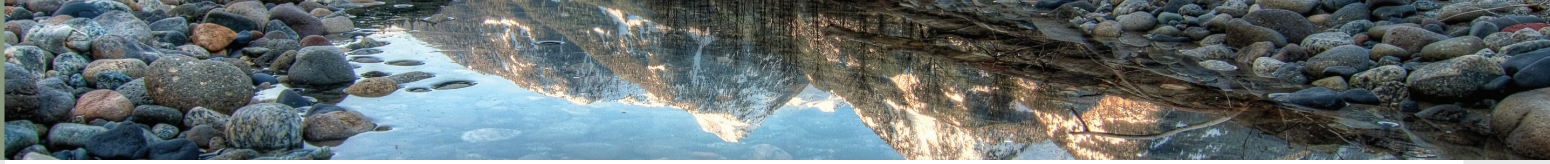
To support the rollout of vehicles, the Provincial and Federal governments have supported early development of hydrogen infrastructure. In addition to the first retail hydrogen fueling station that opened in Vancouver in June 2018, five more stations are in development as of May 2019.

BC industries using hydrogen include the hydrocarbon fuel refining, sodium chlorate, and chlor-alkali industries. The two refineries in BC, located in Burnaby (Parkland) and Prince George (Husky), use hydrogen as part of the refining process. Both produce hydrogen on site through naphtha as an internal part of the refining process and steam methane reformation respectively. There are also sodium chlorate plants in North Vancouver and Prince George and a chlor-alkali plant in North Vancouver. These plants produce hydrogen as a by-product. Some is currently captured for use in refineries, some is used to produce hydrochloric acid (HCl), some is used for process heat, and some is vented to the atmosphere. Vented hydrogen presents a potential hydrogen supply opportunity in the Province, discussed further in Section 3.0.

BC's Renewable and Low Carbon Fuel Requirements Regulation (LCFR), a form of Low Carbon Fuel Standard (LCFS), is driving demand for hydrogen in BC. The LCFR is made up of two components - the renewable content requirement for diesel and gasoline, and the decreasing carbon intensity of fossil fuels. Both of these are driving renewed interest in hydrogen.

Finally, there is strong hydrogen demand emerging from the Province and FortisBC as a means of meeting the CleanBC requirement that 15% of natural gas consumed in the Province comes from a renewable source, but at time of writing no Provincial regulation exists to enable the injection of hydrogen into the natural gas system and account for it as a feedstock for renewable gas.

Deployment of hydrogen within the Province has strong potential in the coming years, and early projects have helped to demonstrate the viability and benefits in various applications. The goal of this report is to recommend opportunities that will significantly assist the Province's decarbonization objectives, will support the goals for economic development in the province, and show the most promise for commercial and technical viability to ensure they can be sustained over the long-term.



2.0 : HYDROGEN PRODUCTION, STORAGE AND USE

2.1 : Hydrogen Production Technologies

Worldwide annual hydrogen production is approximately 55 million tonnes (Mt) or 6.6 ExaJoules (EJ) of energy.[8] The Hydrogen Council proposes that production could increase tenfold through 2050. The Council is a global initiative of leading energy, transportation and industry companies with a shared vision for hydrogen's role in the energy transition; at time of writing it comprised a 33-member Steering Group and 20 Supporting Members.[9]

Hydrogen can be produced via a number of different pathways using a range of feedstocks. Hydrogen can be made via renewable and fossil fuel resources and is a by-product of some industrial processes. Most hydrogen is made today from fossil fuels without carbon capture and sequestration. The majority is used in industrial processes and is produced at the site where it is used.

BC is focused on low carbon intensity hydrogen pathways, sometimes classified as "Green Hydrogen" or "Blue Hydrogen". Definitions for the two terms vary internationally. In this study Green Hydrogen is defined as hydrogen produced from clean or renewable electricity, and Blue Hydrogen as hydrogen produced from natural gas and biomass which is net carbon neutral using carbon capture and storage. The pathways that relate to BC are described in Section 3.1.

2.2 : Hydrogen Storage and Transport

There are several methods for storing and transporting hydrogen, illustrated in Figure 4 below. These include physical-based storage such as compressing or cryogenically liquefying the hydrogen. Hydrogen can also be stored in a range of material-based solid and liquid compounds. Storage methods are typically chosen based on end use requirements such as weight and volume available for energy storage. The natural gas pipeline can also be used to store and transport hydrogen using existing infrastructure. When the NG pipeline is used, a blend of H_2/NG is the result. In most cases this blend will be used directly, although it is possible to separate the H_2 and NG at the point of use once concentrations of hydrogen are high enough to cost effectively separate the gases.

8 The Hydrogen Council. (2017). Hydrogen Scaling Up: A Sustainable Pathway for the Global Energy Transition. Retrieved from http://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf

9 The Hydrogen Council. (2019). Frequently Asked Questions. Retrieved from http://hydrogencouncil.com/faq/

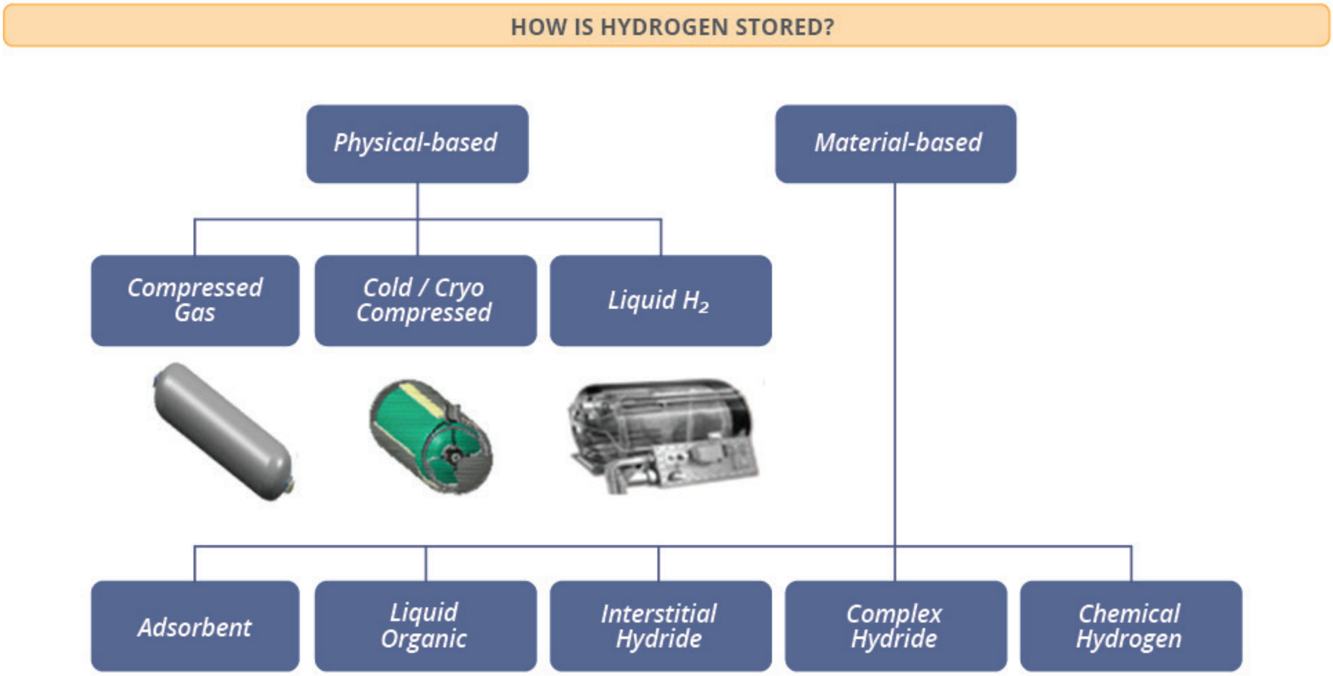


Figure 4. Methods of Hydrogen Storage. Source: US Department of Energy.[10]

2.2.1 : Compression

As a gas under atmospheric conditions, hydrogen must often be compressed, liquefied, or stored in an otherwise dense manner prior to use.

Hydrogen tanks for forklift and public transit applications often use hydrogen compressed to a pressure of 350 bar (5,000 psi) or 345 times as dense as it would be under atmospheric conditions. (Standard atmospheric pressure is 1.01 bar.)

This is somewhat higher than the 250 bar (3,600 psi) pressure in compressed natural gas, or CNG cylinders. The energy loss from having to compress the hydrogen to 350 bar was estimated by UC Davis to be on the order of 8.5 percent.[11] The results are consistent with a recent International Energy Agency (IEA) report.[12]

10 United States Department of Energy, Fuel Cell Technologies Office. Hydrogen Storage. Retrieved from https://www.energy.gov/eere/fuelcells/hydrogen-storage

11 Burke, A., and Gardiner, M., Hydrogen Storage Options: Technologies and Comparisons for Light-Duty Vehicle Applications, UC Davis Institute for Transport Studies, Jan 2005. Document reference UCD-ITS-RR-05-01. Retrieved from https://escholarship.org/uc/item/7425173j

12 Gielen, D. and Simbolotti, G., IEA Energy Technology Analysis: Prospects for Hydrogen & Fuel Cells, International Energy Agency, 2005. Retrieved from https://web.archive.org/web/20080307082839/http://www.iea.org/textbase/nppdf/free/2005/hydrogen2005.pdf

2.2.2 : Liquefaction

Where hydrogen must be made denser – such as for rail, marine, power plant or space applications -- it is likely to be liquefied, providing an 800-fold increase in density. Hydrogen liquefaction is performed in a series of compression and cooling steps, much as is done when producing liquefied natural gas. Liquid hydrogen (LH_2) is considerably more energy intensive to produce; natural gas liquefies at -160°C while hydrogen liquefies at -253°C. As a result, while the energy loss to liquefy natural gas is on the order of 10 percent, the energy loss to liquefy hydrogen is generally estimated to be on the order of 20 to 30 percent, though an energy loss of as little as 13 percent may be possible. [13, 14]

Organizations evaluating hydrogen export options such as Japan's Kawasaki Heavy Industries and Norway SINTEF favour liquid hydrogen for long-distance transport.

2.2.3 : Chemical Storage

Another means of storing hydrogen is in the form of compounds called chemical carriers. Liquid chemical carriers are relatively easily handled and can contain large quantities of hydrogen by volume: there is more hydrogen in a litre of gasoline (116 g H_2) than in a litre of liquid hydrogen (71 g H_2).

The two chemical carriers currently receiving the most development are methylcyclohexane (MCH) and ammonia. MCH is a liquid at atmospheric pressure with the chemical formula C_7H1_4 and can be handled by oceanic chemical tankers. Three hydrogen molecules (H_2) can be liberated from the MCH, transforming it into toluene, also a liquid. When hydrogen is added to toluene, it is transformed back into MCH. The business model consists of bonding hydrogen into toluene, forming MCH at the point of hydrogen supply, and then releasing the hydrogen from the MCH, forming toluene, at the point of hydrogen demand.

An illustrative diagram from Chiyoda Corporation is shown in Figure 5. A consortium is currently evaluating the export of hydrogen from the coast of British Columbia to Japan in the form of MCH.[15]

13 *Hydrogen Strategy Group. (2018). Hydrogen for Australia's Future: A Briefing Paper for the COAG Council. Retrieved from https://www.chiefscientist.gov.au/wp-content/uploads/HydrogenCOAGWhitePaper_WEB.pdf*

14 *Sadaghiani, M.S. and Mehrpooya, M., Introducing and energy analysis of a novel cryogenic hydrogen liquefaction process configuration, International Journal of Hydrogen Energy, Volume 42 (9), pp 6033-6050. Retrieved from https://doi.org/10.1016/j.ijhydene.2017.01.136*

15 *ITM Power. (2018). British Columbia Renewable Hydrogen Study. Retrieved from https://www.itm-power.com/news-item/british-columbia-renewable-hydrogen-study*

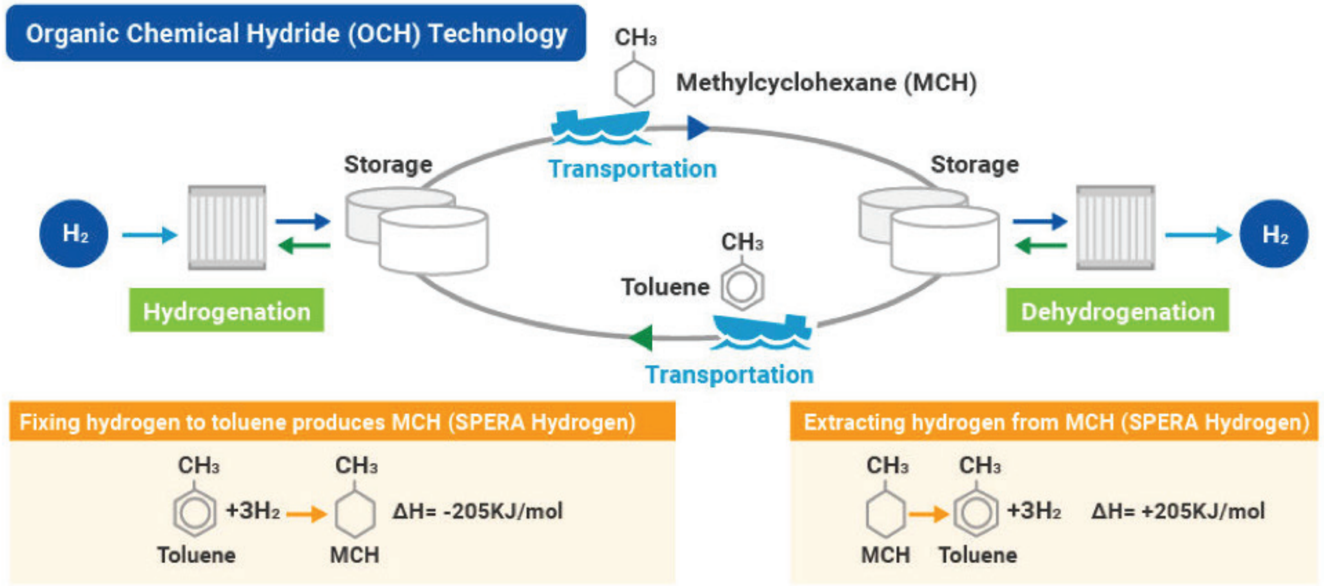


Figure 5. Methylcyclohexane as Hydrogen Carrier. Source: Chiyoda Corporation.[15]

Ammonia (NH_3) is also being evaluated as a chemical carrier for hydrogen, particularly for jurisdictions wishing to export electrolyzed hydrogen in the form of ammonia for fertilizer production. Ammonia is a common industrial chemical already produced and transported on a global scale; it is also the largest global consumer of steam methane reformed hydrogen. Once transported to the point of demand, the ammonia can be dehydrogenated, yielding 0.176 tonnes of hydrogen per tonne of ammonia.

2.2.4 : Adsorbent Storage

Hydrogen can also be stored by adsorbing the gas on powders. One advantage of this method is that the amounts of energy required to adsorb (bind) the hydrogen to the powder should be less than required to form chemical bonds, as per the chemical storage methods above. Adsorbent storage may make it possible to store relatively high densities of hydrogen – comparable to compressed gases – at lower pressures. BC's Hydrogen In Motion is developing a hydrogen storage technology by engineering a powder for this purpose.

2.2.5 : Transport

In gaseous form, hydrogen can be transported in existing natural gas pipeline networks. Small percentages of hydrogen could be blended into existing natural gas streams without requiring infrastructure retrofits. The blending of larger quantities, or of 100% hydrogen, could necessitate retrofits to pipeline equipment, though the pipe segments themselves are not expected to require replacement. This concept is discussed further in Section 4.1.

Smaller volumes of compressed hydrogen are also transported by truck in tube trailers, in much the manner done for other industrial gases.

Hydrogen can also be transported by truck in liquefied form, again in the manner of industrial gases. Kawasaki Heavy Industries, which built Japan's first LNG carrier vessel, plans to build the world's first liquid hydrogen (LH_2) carrier as part of its Hydrogen Energy Supply Chain project in Australia.

When stored in the form of a chemical carrier, hydrogen transportation would follow chemical industry practice for transporting the carrier.

2.3 : Hydrogen Applications

Demonstrating hydrogen's versatility, the Hydrogen Council enumerated seven separate supportive roles it could play in global decarbonization efforts, as shown in Figure 6 below.[16]

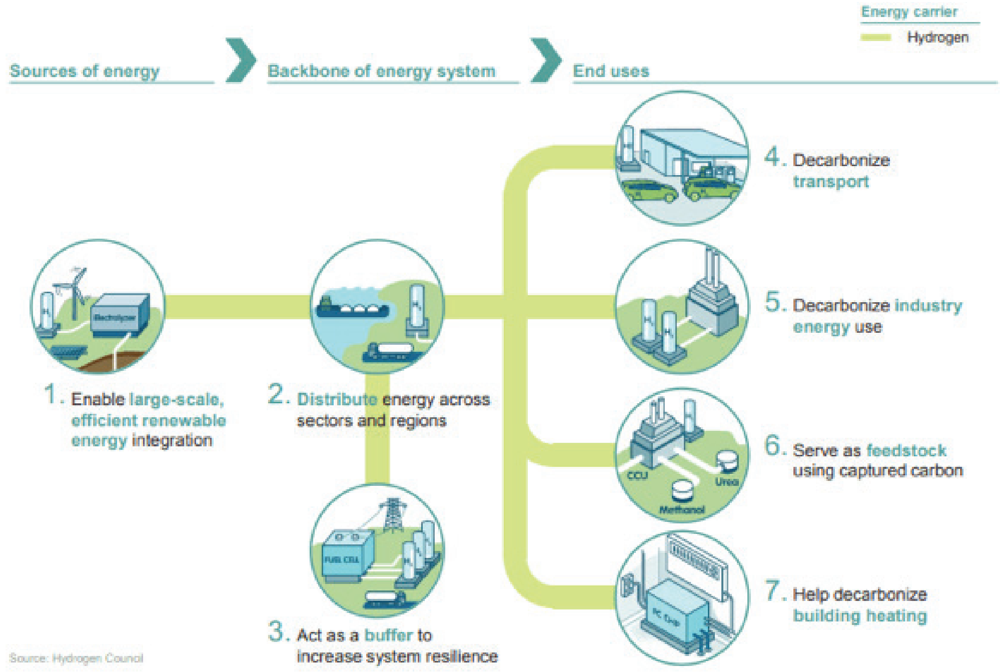


Figure 6. Roles for Hydrogen in Decarbonization. Source: Hydrogen Council.[16]

This report focuses how hydrogen can be deployed in support of the Province's CleanBC plan and broader climate targets. Consideration is given to hydrogen's potential in BC related to:

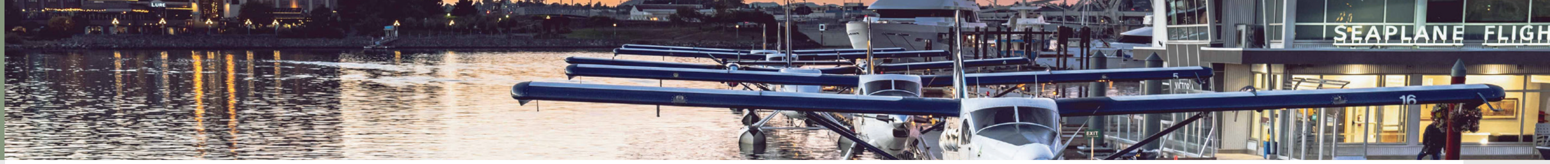
- *BC's Natural Gas sector (section 4.1)*
- *BC's Transportation sector (section 4.2)*
- *BC's Industrial sector (section 4.3)*
- *BC's Built Environment (section 4.4)*
- *BC's Remote and Off-Grid Communities (section 4.5)*
- *Energy Storage through Power to Gas opportunities (section 5.2)*

Hydrogen can be combusted as a cleaner burning substitute for fossil fuels such as natural gas or oil. This is one use case for end users of natural gas in the industrial and built environment sectors. Hydrogen combustion equipment and technology are also being pursued in jurisdictions where natural gas is combusted for power generation. In the transportation sector, BC company Hydra Energy has developed technology allowing for hydrogen-diesel co-combustion.

16 *The Hydrogen Council. (2017). How Hydrogen Empowers the Energy Transition. Retrieved from http://hydrogencouncil.com/wp-content/uploads/2017/06/Hydrogen-Council-Vision-Document.pdf*

Hydrogen can also be reacted electrochemically -- without combustion – in fuel cells, generating an electric current. Fuel cell technology is being developed across the transportation sector, from light-duty and heavy-duty vehicles up to rail and marine vessels. Fuel cells are increasingly being deployed for utility-scale power generation (South Korea) and to provide guaranteed on-site power, and sometimes hot water, at commercial facilities (California) or in residential homes (Japan, Europe). Proton Exchange Membrane (PEM) stationary fuel cell systems can run on both natural gas (with a reformer) or on pure hydrogen fuel.

During times of overproduction of renewable electricity, hydrogen can also be generated via electrolysis and used for long-term energy storage, a highly valuable characteristic for BC's remote and off-grid communities.



3.0 : HYDROGEN PRODUCTION IN BRITISH COLUMBIA

3.1 : BC Production Pathways

Hydrogen molecules do not generally exist on their own in a free state in nature but are found in many abundant compounds. Hydrogen must be produced from feedstocks using energy inputs. When investigating viable local hydrogen pathways, the availability of both feedstocks and energy sources must be considered. For energy sources, point source emissions and upstream emissions must both be considered; a fuller treatment is provided in APPENDIX B: Upstream GHG emissions In BC.

Feedstocks are the chemical sources of the hydrogen. BC is fortunate to have an abundance of three hydrogen feedstocks: water, biomass (predominantly carbon, hydrogen and oxygen) and natural gas (primarily methane). Crude oil and coal could also be used as hydrogen feedstocks, but they have a lower ratio of hydrogen to carbon, making them less attractive than natural gas. BC is a minor producer of crude oil and produces significant quantities of coal. The vast majority (80-90%) of this coal however is low hydrogen-content metallurgical grade coal used for high-value steel manufacture.

This report considers the three most likely energy inputs for large-scale hydrogen production in British Columbia: electricity, biomass, and natural gas. In the case of electricity, electricity generated from hydroelectricity and wind are considered, since these are the most abundant sources of electricity in the Province.

BC generates by-product hydrogen from two sodium chlorate plants operating in the Province, located in North Vancouver and Prince George, and one chlor-alkali plant in North Vancouver. Chemtrade operates the chlor-alkali plant in North Vancouver and the sodium chlorate plant in Prince George. While some of the by-product hydrogen is currently used as feedstock in chemical production, approximately 18,500 kg/day of hydrogen is vented. This represents an important near-term hydrogen source for the Province.

Considering feedstock and energy sources in tandem, the following pathways have been identified as primary options for producing large quantities of hydrogen in the Province:

- *Industrial by-product hydrogen;*
- *Electrolysis via hydroelectric or wind (grid connected or non-grid connected);*
- *Biomass gasification with water gas shift and reforming;*
- *Steam methane reforming with carbon capture and storage; and*
- *Methane pyrolysis (thermal and plasma) with carbon capture and storage.*

With hydroelectricity representing 86% of the electricity generated in BC the assumption has been made that grid connected electrolysis is primarily powered by hydroelectricity. Hydroelectricity, wind and biomass together account for approximately 95% of the province's electricity production.[17]

17 *National Energy Board. (2018). Canada's Renewable Power Landscape 2016 – Energy Market Analysis. Retrieved from* https://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2016cndrnwblpwr/prvnc/bc-eng.html

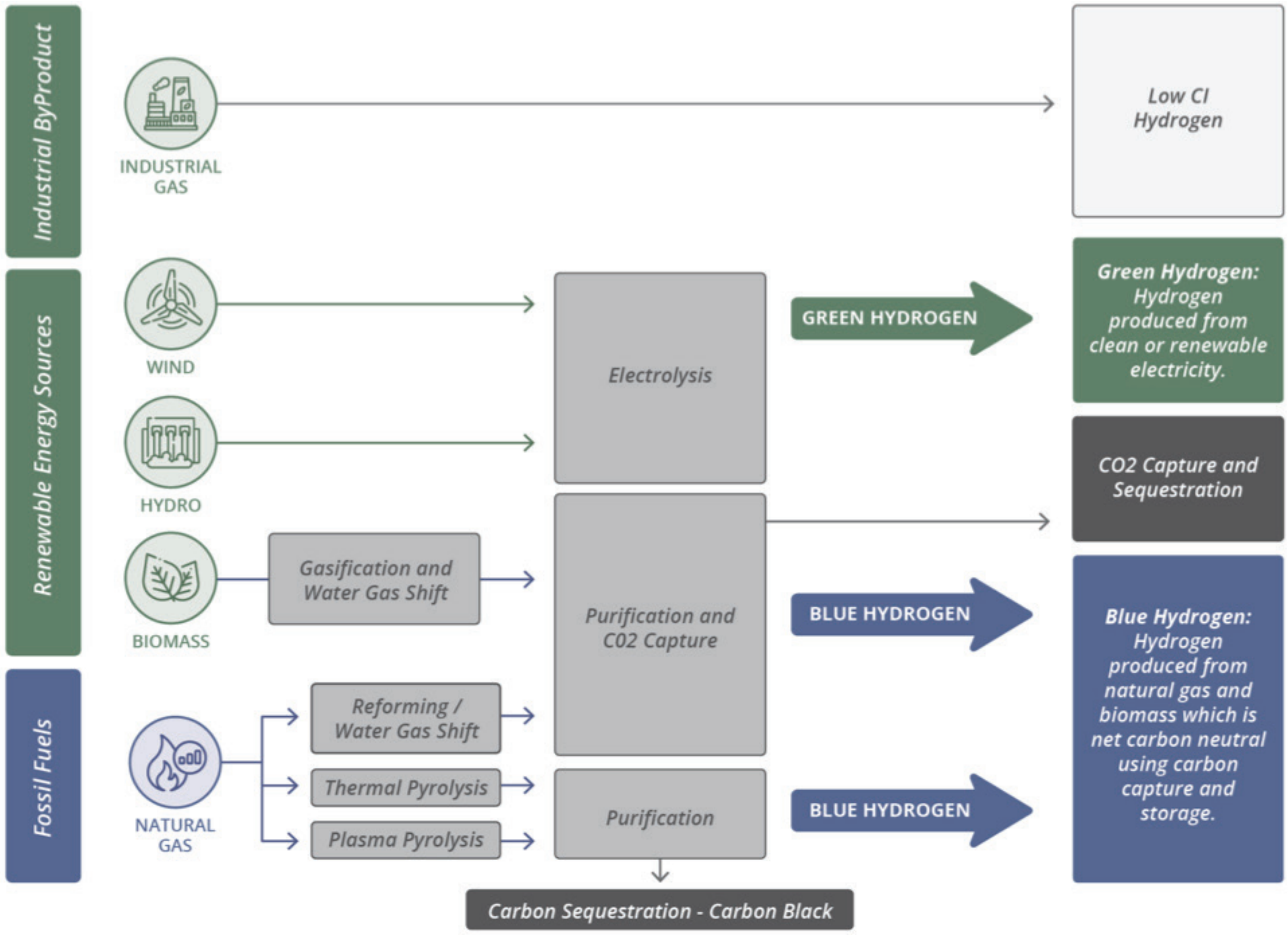


Figure 7. Hydrogen Production Pathways in BC

BC is focused on low carbon intensity hydrogen pathways, or Green and Blue Hydrogen as it is commonly called. The report focuses on low carbon intensity hydrogen, without the use of Green and Blue terminology. It is recommended that all pathways shown in Figure 7 above be evaluated based on production cost, carbon intensity, and availability in the Province.

Given the Province's interest in transitioning to sustainable energy in the longer-term, it is recommended that hydrogen produced from renewable resources including hydroelectric, wind, and biomass resources be given special consideration as identified in the policy recommendations of this report. By-product hydrogen currently produced in BC can also be considered renewable, as the primary energy source used in the brine electrolysis in the sodium chlorate and chlor-alkali plants comes from the electric grid.

The technology fundamentals for each production pathway is described in the following sections. A large production scale of 100 tonnes of hydrogen per day is assumed given that some technologies, such as steam methane reforming (SMR) followed by carbon capture and sequestration (CCS) are only expected to be feasible at large scale. Cost sensitivities have also been provided, where estimates could be made. Cost figures refer to bulk centralized production and do not include transportation costs, which can vary significantly by location. Costs also do not include any profit.

GHG intensities are also presented for each pathway. The analysis looks at both upstream and direct emissions, projected for 2030 which account for potential changes in upstream emissions per year. The assumptions and analysis for calculating carbon intensity are described in Appendix B.

3.1.1 : Industrial By-product Hydrogen

Approximately 18.5 tonnes of relatively pure hydrogen is currently vented to atmosphere every day in the Province. The by-product hydrogen requires minimal cleanup to remove traces of chlorine gas, and represents a low-cost, low carbon intensity hydrogen supply. It would have to be pressurized prior to purification and transportation to distributors (in the case of fuel stations) or end users. The cost of recovering this industrial by-product hydrogen is based on hydrogen's heating value, as it is often burned for process heat, and the amortized capital costs. These costs are estimated to be $0.88/kg as shown in Figure 8.

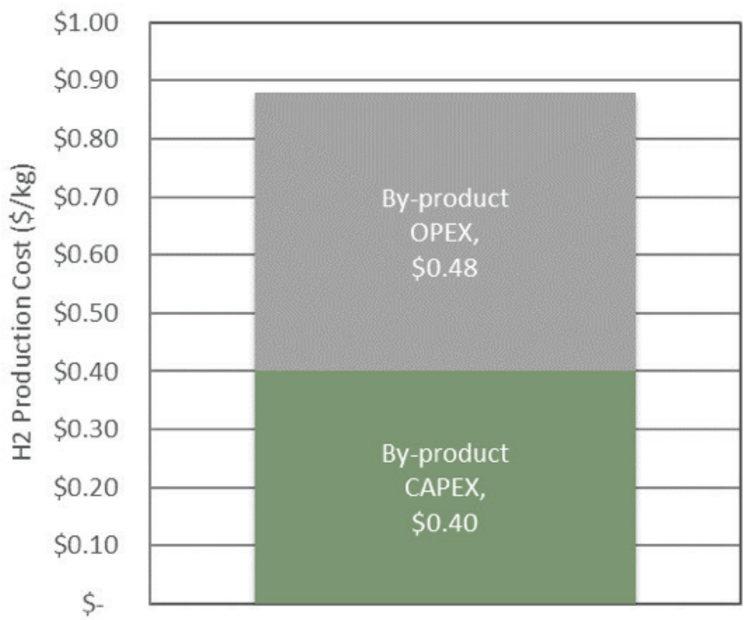


Figure 8. Cost breakdown for by-product hydrogen

Hydra Energy is looking to secure by-product hydrogen supply in the Province to operate trucks retrofitted with their hydrogen co-combustion technology. They have recently evaluated the carbon intensity from this pathway and have determined it to be 1.43 g CO_2e/MJ at the point of dispensing. This has been used in the pathway comparison in this report.

3.1.2 : Electrolysis

Water electrolysis is a hydrogen production pathway attractive in BC given the relatively low cost of electricity from the Province's low carbon intensity electric grid. In addition to existing hydroelectric dams, the Province also possesses significant wind energy resources.

Electrolysis is the process by which electricity is used to split water into hydrogen and oxygen. The chemical transformations are described in reaction (1).

(1) $H_2O + \text{electricity} \rightarrow H_2 + \frac{1}{2}O_2$

The ideal or minimum amount of electricity required to produce 1 kg of hydrogen is 39 kWh.

The equipment in which this reaction takes place is called an electrolyzer. Electrolyzers are modular, and their sizes vary widely depending on the chosen technology and required production capacity. They can range from appliance-sized equipment for small-scale hydrogen production to large-scale, central production facilities. Their modular nature makes electrolyzers attractive when relatively small quantities of hydrogen are required; higher per-kg production costs may be offset by reduced transportation costs.

Electrolyzers consist of an anode and a cathode separated by an electrolyte, as in Figure 9. The two major types of electrolyzers in current use are Proton Exchange Membrane (PEM) electrolyzers, and Alkaline electrolyzers.

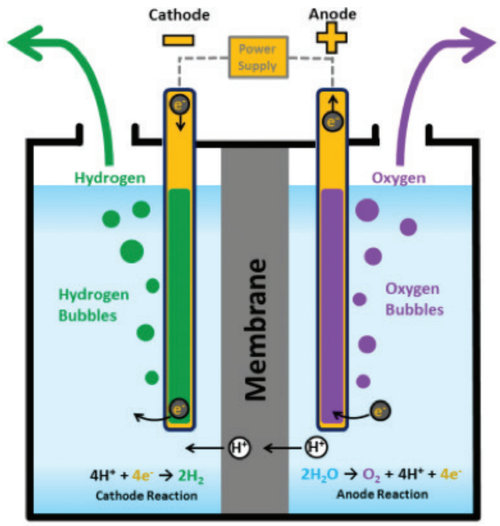


Figure 9. Electrolysis in a PEM Electrolyzer. Source: US Department of Energy.[18]

3.1.2.1 : PEM Electrolyzers

In a PEM electrolyzer, the electrolyte is a solid polymer, or plastic. At the anode, water is split into oxygen, positively charged hydrogen ions (protons) and negatively charged electrons. The protons migrate across the proton exchange membrane while the electrons flow through an external circuit. The protons and electrons recombine on the cathode to form hydrogen gas.

PEM electrolyzers have received heightened attention in recent years. This is due in part to breakthroughs allowing for significantly higher hydrogen production density. It is also due to PEM electrolyzers' flexibility; they can operate when the incoming current fluctuates, producing variable rates of hydrogen from second to second, depending on the power supplied. This "load-following" capability makes them a highly complementary technology to variable solar photovoltaic and intermittent wind energy. Curtailment of renewable electricity currently occurs during periods of excess production; more curtailment is expected to occur as renewable electricity is added to electrical grids. PEM electrolyzers provide a responsive electrical load, which can reduce the amount of curtailment while producing valuable hydrogen. Some PEM electrolyzer deployments have also generated additional revenue by providing grid services, being compensated for helping to buffer and stabilize the grid when solar or wind power suddenly ramps up or down.

3.1.2.2 : Alkaline and Solid Oxide Electrolyzers

While PEM electrolyzers transport protons (H^+) through a membrane, Alkaline electrolyzers transport hydroxide ions (OH-) through their electrolyte, which is generally sodium or potassium hydroxide. Both compounds are alkaline – in chemical terms they have a high pH – hence the term Alkaline electrolyzer.

A third electrolyzer technology, the Solid Oxide electrolyzer, is under development but has not yet been commercially deployed. These electrolyzers operate at high temperatures and hold the promise of being more efficient than PEM or Alkaline electrolyzers.

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18 U.S. Department of Energy Office of Energy Efficiency & Renewable Energy. Hydrogen Production: Electrolysis. Retrieved from https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

3.1.2.3 : Hydrogen Production Cost

The price of electricity is the dominant factor determining the cost of hydrogen produced via electrolysis. Whereas ideal specific efficiencies for water electrolysis is 39 kWh/kg H_2, actual demonstrated specific efficiencies are between 50-60 kWh/kg H_2. Where an electrolyzer is run 24/7, operating costs account for approximately 80% of the cost of hydrogen, and the bulk of operating costs consist of the sourced electricity.

As shown in Figure 10 below, hydrogen production in BC via electrolysis is expected to be $5-7/kg H_2 based on an industrial electricity rate of $60/MWh (Megawatt-hour), representative of current industrial rate tariffs.[19]

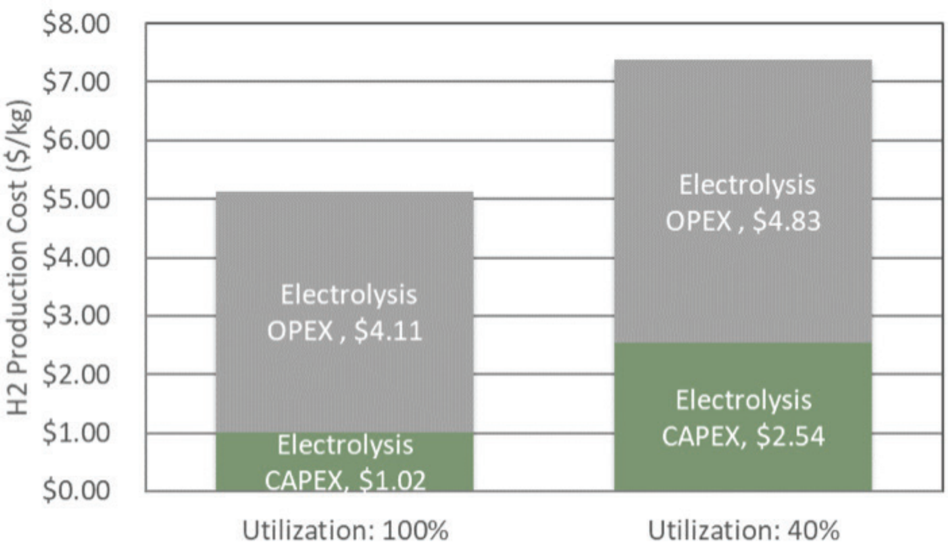


Figure 10. Cost breakdown for hydrogen produced via Electrolyzer

Figure 11 shows a sensitivity analysis of hydrogen production costs based on the cost of electricity and the size of the electrolyzer. As would be expected, larger electrolyzers drive economies of scale in capital equipment and installation cost.

For hydrogen to be produced at scale in BC using electrolysis, it is estimated that the cost of electricity must be <$40/MWh. If the cost of electricity is higher, other hydrogen production processes will have a cost advantage. This report provides recommendations by which to decrease the cost of this production pathway, which has potential to be strategic for the Province.

19 *$0.0606/kWh equates to $60.60/MWh. Source: BC Hydro. (2019). General Service Business Rates. Retrieved from* https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/business-rates.html

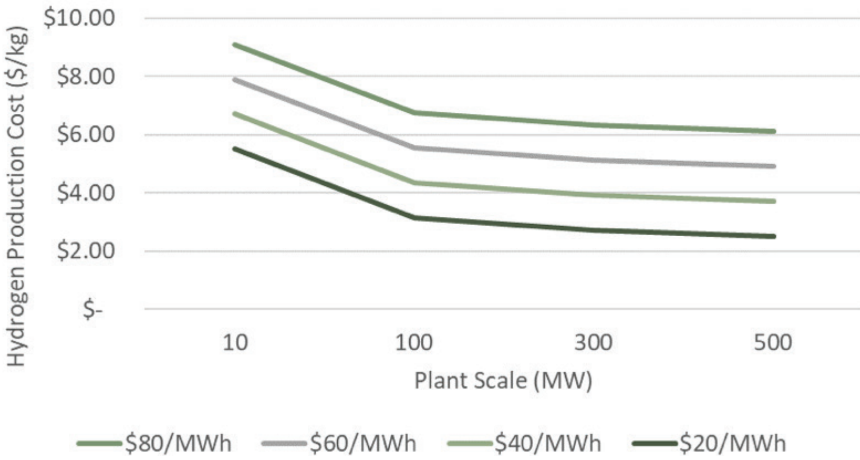


Figure 11. Impact of Scale and Electricity Feedstock Price for Electrolysis Pathway

In addition to rich hydroelectric resources in the Province, BC has significant wind reserves that can be leveraged to produce hydrogen. It is estimated that there are >5.4 GW of high-quality wind reserves with high utilization potential (40-70%) in areas that can be readily developed.

BC's Renewable Hydrogen Canada (RH_2C) is developing large-scale projects to produce hydrogen from renewable power, primarily wind augmented by hydroelectric power. They are in the stages of developing a project in Northeastern BC in the heart of the Montney gas formation. In the first phase of the project, a 120 MW electrolyzer farm will produce pure hydrogen and inject in into the natural gas grid. Longer-term, additional projects will be developed to use the hydrogen to produce methanol (Canadian Methanol) and low carbon gasoline (Blue Fuel Energy).

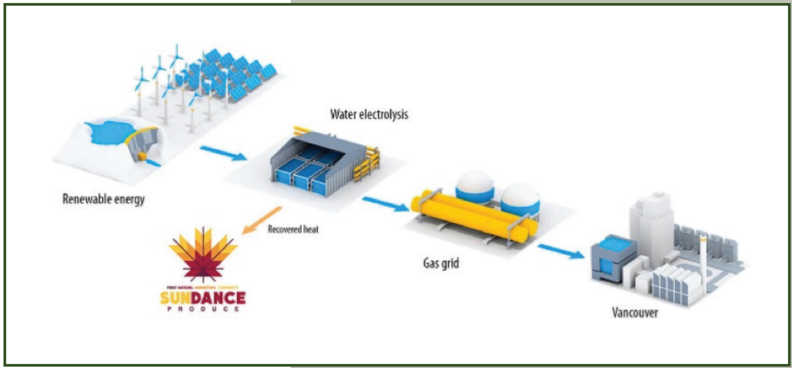
3.1.3 : Biomass Gasification and Purification

Biomass is a renewable organic resource predominantly comprised of carbon, hydrogen and oxygen, encompassing crop and forest residues, specialty crops, and even waste streams. Biomass gasification is a mature technology that uses the controlled application of heat (generally >700°C), steam, and oxygen (from air) to convert biomass to hydrogen and other products without combustion. Biomass gasification is generally undertaken in two stages, with an initial gasification stage (reaction 1) followed by a water-gas shift reaction (reaction 2) in which carbon monoxide (CO) is converted to carbon dioxide (CO_2), generating additional H_2.

(1) $C_6H_{12}O_6 + O_2 + H_2O + \text{heat} \rightarrow CO + CO_2 + H_2$ + other species

(2) $CO + H_2O \rightarrow CO_2 + H_2 + \text{heat}$

The products of gasification are H_2 and CO_2, along with other species; pressure swing absorption is then used to purify the hydrogen. Though carbon dioxide is produced, biomass is considered a GHG-neutral fuel because biomass sequesters carbon dioxide during its life. Some biomass facilities may sequester the resulting CO_2, effectively making this pathway carbon negative. Such technology pathways are sometimes referred to in climate science literature as Bioenergy with Carbon Capture and Storage (BECCS).



The cost of hydrogen from biomass gasification for this study was modeled without CCS. Feedstock costs of $80/dry tonne of biomass were assumed, with $100/tonne of processing costs. For a facility producing 100 tonnes of hydrogen per day the cost of hydrogen is modelled to be approximately $3/kg H_2 as shown in Figure 12.

A facility producing 100 tonnes of hydrogen per day would be very large, requiring 1,350 dry tonnes of biomass feedstock per day, and thus may or may not be feasible based on constraints for regional supplies. Smaller facilities would be more feasible from a feedstock availability perspective but would drive up the capex portion of the cost.

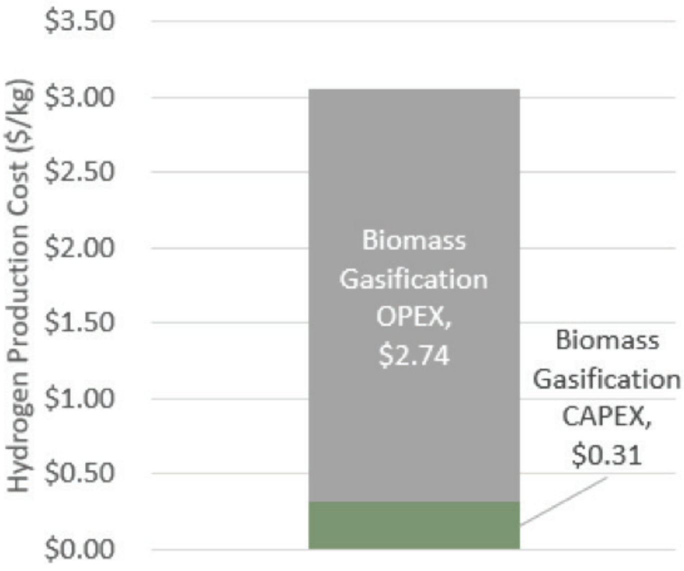


Figure 12. Cost breakdown for hydrogen produced via biomass gasification

3.1.4 : Steam Methane Reforming with CCS

Steam methane reforming (SMR) is the most common bulk hydrogen production pathway; fossil fuel reforming accounted for approximately 95% of worldwide hydrogen production in the year 2000 timeframe with natural gas representing about one-half the total.[20]

SMR involves reacting natural gas (primarily methane, CH_4) with steam (H_2O) to produce H_2 and CO_2. The efficiency of SMR is greater than 80% as measured by the higher heating value of the energy content of the hydrogen produced, compared to that of the natural gas consumed.[21] Higher heating value is a measure of the energy liberated from a compound if, after being combusted, all the combustion products are brought back to pre-reaction temperatures.

The overall chemical reaction for steam methane reforming process is shown in reaction (1) below. Reaction (2) describes the water gas shift reaction, which is used in SMR as well as in biomass gasification.

(1) $CH_4 + H_2O + \text{heat} \rightarrow CO + 3H_2$

(2) $CO + H_2O \rightarrow CO_2 + H_2 + \text{heat}$

20 *Ogden, J. M. (1999). Prospects for building a hydrogen energy infrastructure. Annual Review of Energy and the Environment. 24: 227–279. Retrieved from https://www.annualreviews.org/doi/10.1146/annurev.energy.24.1.227*

21 *Peng, X. D. (2012). Analysis of the Thermal Efficiency Limit of the Steam Methane Reforming Process. Ind. Eng. Chem. Res., 51 (50), pp 16385–16392. Retrieved from http://www.airproducts.com/~/media/Files/PDF/industries/en-analysis-of-thermal-efficiency-limit-of-steam-methane-reforming-process.pdf*

A process diagram for steam methane reforming is provided in Figure 13 below.

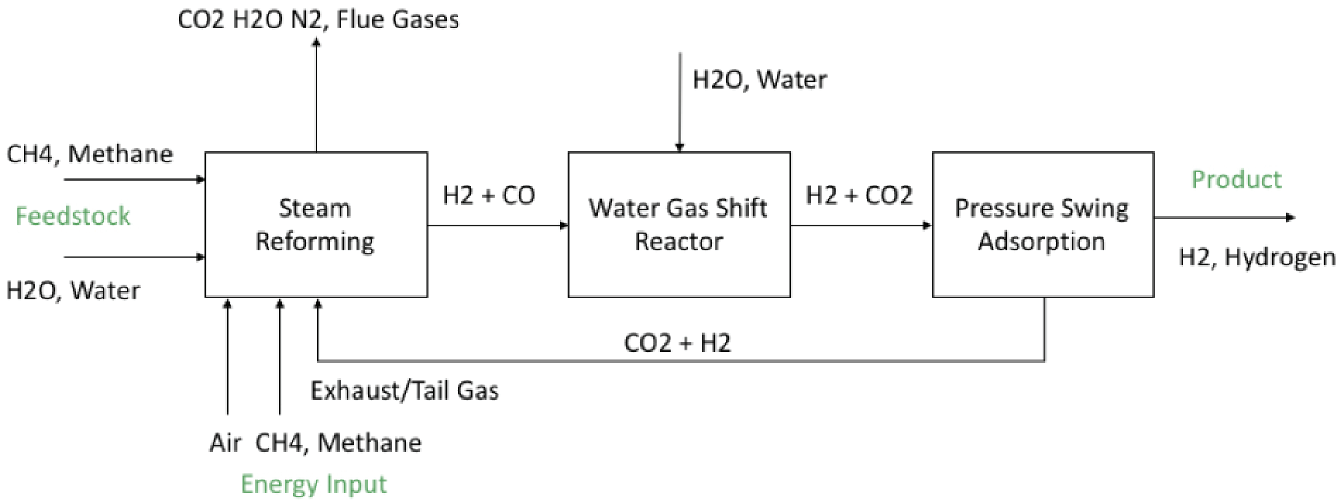


Figure 13. Steam Methane Reforming Process

Using a conservative 75% efficiency, applying SMR to 1 GigaJoule (GJ) of natural gas would result in 0.75 GJ of hydrogen, or approximately 5.3 kg.[22] SMR plants can produce hydrogen at very large scale; a recent plant announcement exceeded 300 tonnes H_2/day.[23]

SMR generates approximately 8-10 kg CO_2e per kg of H_2 produced (CO_2e/kg H_2). The report will use 10 kg CO_2e/kg H_2. Existing technology such as amine scrubbers and vacuum swing adsorption can be deployed within the SMR process to capture up to 56-90% of the generated CO_2 resulting in net emissions of 2 kg CO_2e/kg H_2.[24]

Factoring in upstream natural gas GHG emissions, total GHG emissions from SMR with CO_2 capture and storage comprise 2.7 t CO_2e/t H_2.[25, 26]

In SMR processes, hydrogen production costs are driven by feedstock costs and amount to 2 to 3 times the cost of natural gas on a $/GJ basis. For example, for a natural gas price of $4/GJ (approximately $4.20/MMBTU) hydrogen production costs can be expected to range from $8-12/GJ H_2. Our analysis of SMR production costs yielded a per-kilogram cost of $1.32/kg H_2.

CCS is estimated to add approximately $0.82/kg H_2 to base SMR costs. The hydrogen production cost of SMR + CCS is then estimated to be approximately $2.14/kg H_2. The cost breakdown is shown in Figure 14, with the sensitivity to natural gas feedstock price shown in Figure 15.

22 *Based on higher heating value of hydrogen at 0.142 GJ/kg*

23 *Bailey, M.P. (2018). Air Products Inaugurates Steam-Methane Reformer at Covestro's Baytown Site. Chemical Engineering. Retrieved from https://www.chemengonline.com/air-products-inaugurates-steam-methane-reformer-at-covestros-baytown-site/*

24 *ieaghg. (2017). SMR Based H_2 Plant with CCS. Retrieved from https://ieaghg.org/terms-of-use/49-publications/technical-reports/784-2017-02-smr-based-h2-plant-with-ccs*

25 *Upstream emissions = 3.3 kg CO_2/GJ NG ÷ 5.3 kg H_2/GJ NG = 0.62 kg CO_2e/kg H_2*

26 *This analysis assumes the 2030 upstream natural gas business as usual emissions in 2030 are equal to 2016/2017 emissions. This is supported by the figure on page 10 of the CleanBC plan. Retrieved from https://blog.gov.bc.ca/app/uploads/sites/436/2019/02/CleanBC_Full_Report_Updated_Mar2019.pdf See APPENDIX B: Upstream GHG emissions In BC for full details.*

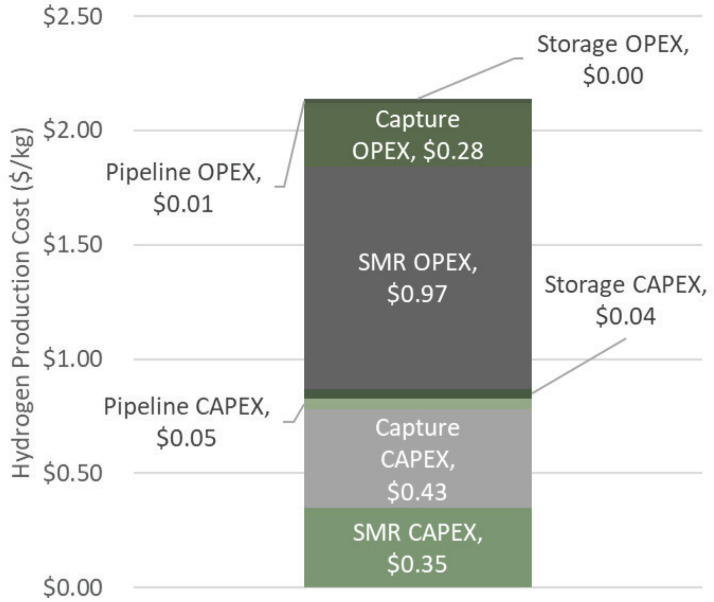


Figure 14. Cost breakdown for hydrogen produced via SMR + CCS

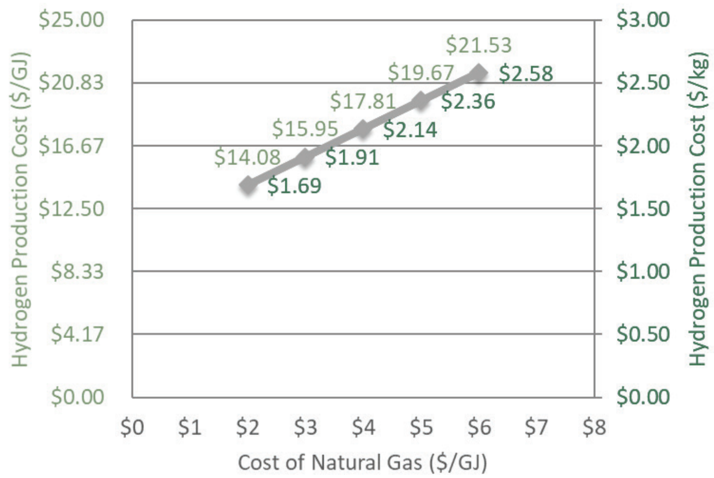


Figure 15. Impact of natural gas feedstock cost on hydrogen cost from SMR + CCS

Assuming that CCS processes cost approximately \$0.82/kg H_2 and remove 8 kg of the 10 kg CO_2e produced per kg H_2 in the SMR process, the equivalent cost of carbon capture and storage can be calculated as \$0.82/8 kg CO_2e, or \$0.102/kg CO_2e. This is equivalent to \$102/tonne CO_2e.

3.1.5 : Methane Pyrolysis

Methane pyrolysis is the decomposition of natural gas without oxygen into its two main elements; gaseous H_2 and solid carbon (C). CO_2 is not produced, as the reaction takes place in the absence of oxygen. Thermal pyrolysis of natural gas has been commercially operated at scale by Cancarb of Alberta since the early 1900s.

The pyrolysis process is described in reaction (1) and a process diagram is shown in Figure 16 below.

(1) $CH4 + \text{energy} \rightarrow C + 2H_2$

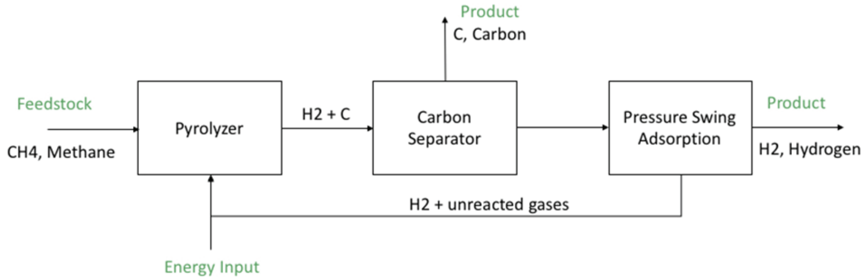


Figure 16. Methane Pyrolysis Process

Thermal pyrolysis and plasma pyrolysis are two technologies under development.

Carbon powder, sometimes called carbon black, commands a price of \$50 to \$500/tonne in a market of approximately 12 million tonnes per year.[28] Methane pyrolysis will generate approximately 3.75 kg of carbon black per kg of hydrogen, so large-scale pyrolysis could saturate BC carbon black markets and reduce the powder's market price.

3.1.5.1 : Thermal Pyrolysis

In thermal pyrolysis, complete conversion of methane to hydrogen and carbon is difficult to achieve; hydrogen leaving the reactor will contain unreacted methane. Pressure swing absorption is likely to be used to separate the hydrogen from the methane, with the latter recirculated and combusted to provide the heat for the reaction. A novel type of thermal pyrolysis, using a liquid or molten metal to separate the gases, may circumvent this requirement.

Energy inputs were estimated assuming a 90% conversion of methane to hydrogen and carbon and an 80% yield in the pressure swing absorption process, resulting in an estimated 0.32 GJ/kg H_2 of which 0.028 GJ/kg H_2 is required to provide heat for the reaction.

Based on natural gas feedstock costs of \$4/GJ, no value being assigned to the carbon black, and building on a recent analysis[29] for a liquid metal thermal pyrolysis technology, the study calculated the hydrogen production costs at \$1.68/kg H_2 comprising approximately \$1.26/kg for operating costs and \$0.43/kg for capital cost amortization. This is shown in Figure 17.

BC's Ekona Power proposes to use unsteady gas dynamics and multiple reactors to create a continuous output of decarbonized hydrogen at a cost similar to SMR. The startup has attracted funding from Evok Innovations[27] and BC's ICE Fund, has completed modelling of the process and is designing a proof-of-concept reactor to test the process

27 Evok Innovations. (2019). Fueling Industrial Innovation. Retrieved from http://www.evokinnovations.com

28 Jung CG, Bouysset JP. (2015). Recovered Carbon Black from Tyre Pyrolysis. Université Libre de Bruxelles. Retrieved from https://docplayer.net/60487355-Recovered-carbon-black-from-tyre-pyrolysis.html

29 Parkinson, B., Matthews, J. W., McConnaughy, T. B., Upham, D. C., and McFarland, E. W., (2017). Techno-Economic Analysis of Methane Pyrolysis in Molten Metals: Decarbonizing Natural Gas, Chem. Eng. Technol. 40, pp 1022–1030. Retrieved from https://doi.org/10.1002/ceat.201600414

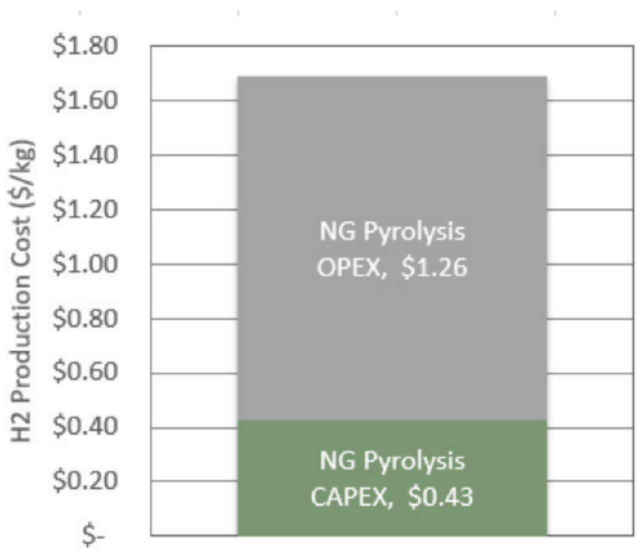


Figure 17. Cost breakdown for hydrogen produced via Liquid Metal Thermal Pyrolysis

The sensitivity of hydrogen costs to natural gas feedstock costs is provided in Figure 18 below:

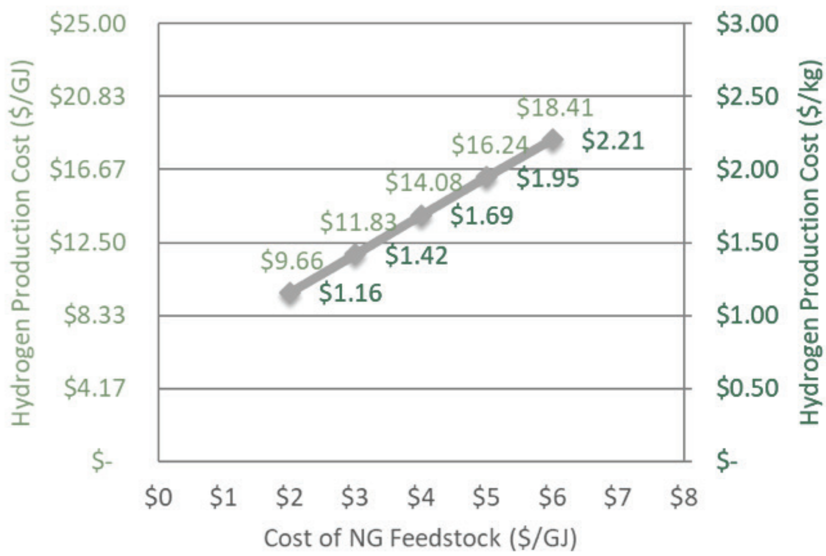


Figure 18. Impact of natural gas feedstock cost on hydrogen cost from liquid metal thermal pyrolysis

The Province estimates emissions associated with natural gas combustion as 57.94 kg CO_2e/GJ.[30] Combined with the above information this provides an emissions intensity of 0.66 kg CO_2e/kg H_2 for the hydrogen produced from thermal pyrolysis, owing to the combustion of natural gas in the process for heat. Factoring in upstream emissions, the GHG emission intensity from thermal methane pyrolysis would be 1.77 kg CO_2e/kg H_2 or 14.7 g CO_2e/MJ.[31]

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30 *(S&T) Squared Consultants Inc. (2018). GHGenius 5.0d. Calculations conducted by BC Ministry of Energy, Mines and Petroleum Resources Low Carbon Fuels Branch. Retrieved from https://ghgenius.ca/index.php/downloads*

31 *This analysis assumes the 2030 upstream natural gas business as usual emissions in 2030 are equal to 2016/2017 emissions. This is supported by the figure on page 10 of the CleanBC plan. (https://blog.gov.bc.ca/app/uploads/sites/436/2019/02/CleanBC_Full_Report_Updated_Mar2019.pdf) See APPENDIX B: Upstream GHG emissions In BC for full details.*

The cost of carbon capture and storage was calculated (on a \$/tonne CO_2e basis) in section 3.1.4, and an equivalent calculation can be made for pyrolysis processes. Pyrolysis is more expensive than steam methane reforming but produces significantly less GHG emissions, so the cost of the avoided CO_2 emissions can be calculated.

- *The cost of hydrogen from thermal pyrolysis has been calculated as \$1.68/kg H_2, higher than the \$1.32/kg H_2 to produce hydrogen through SMR; a cost premium of \$0.36/kg H_2.*
- *The CO_2e emissions from thermal pyrolysis have been estimated at 1.77 kg CO_2e/kg H_2, significantly less than the 10.7 kg CO_2e/kg H_2 for SMR; a reduction of 8.9 kg CO_2e/kg H_2.*
- *For each kg of H_2 produced, it costs \$0.36 to avoid 8.9 kg CO_2e emissions, for a mitigation cost of \$0.041/kg CO_2e or \$41/tonne CO_2e emissions.*

Put differently, using thermal pyrolysis in place of SMR reduces CO_2e emissions from hydrogen production at an equivalent cost of \$40/tonne CO_2e.

3.1.5.2 : Plasma Pyrolysis

In plasma pyrolysis, electricity is used to generate a plasma arc in a reactor chamber, which decomposes methane into hydrogen and carbon. Process costs relate to the amount of electricity required per kg H_2. Thermal processes use high temperatures to decompose methane, with process costs largely driven by the amount of fuel used to bring reactors to high temperature.

Plasma pyrolysis requires electricity inputs of 10-12 kWh/kg H_2 [32], approximately one-fifth of the amount currently required for PEM electrolysis.[33]

Based on 10 kWh/kg H_2 and \$0.06/kWh industrial electricity costs, electricity inputs for plasma pyrolysis amount to \$0.60/kg H_2. Assuming the cost structure is otherwise similar to that of thermal pyrolysis the total hydrogen production cost for plasma methane pyrolysis is estimated to be \$2.28/kg H_2. This is depicted in Figure 19.

The Cancarb plant in Medicine Hat, AB produces approximately 45,000 tonnes/year of carbon black through thermal pyrolysis; it is currently the only plant in North America producing carbon black from natural gas. Pre-heated natural gas feedstock is decomposed at approximately 1400°C in the absence of air or flame to produce carbon black and hydrogen.

32 Personal communication, Pete Johnson, Monolith Materials

33 Stakeholder input.

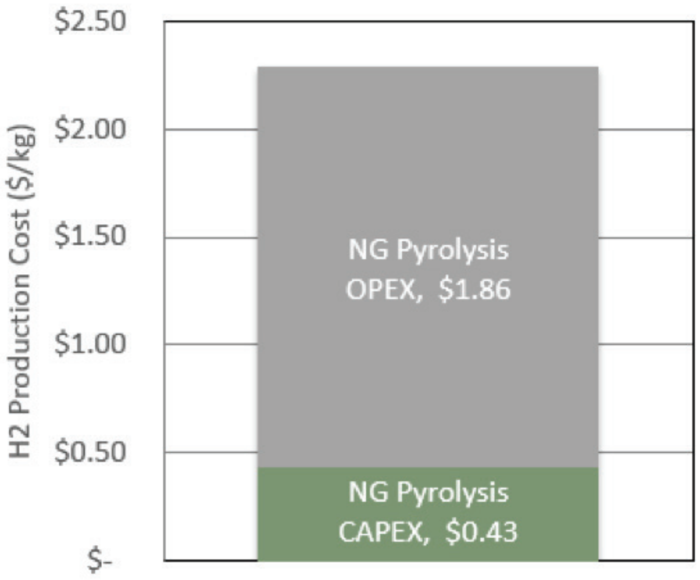

Figure 19. Cost breakdown for hydrogen produced via Plasma Pyrolysis

The sensitivity of plasma pyrolysis to natural gas feedstock costs is shown in Figure 20.

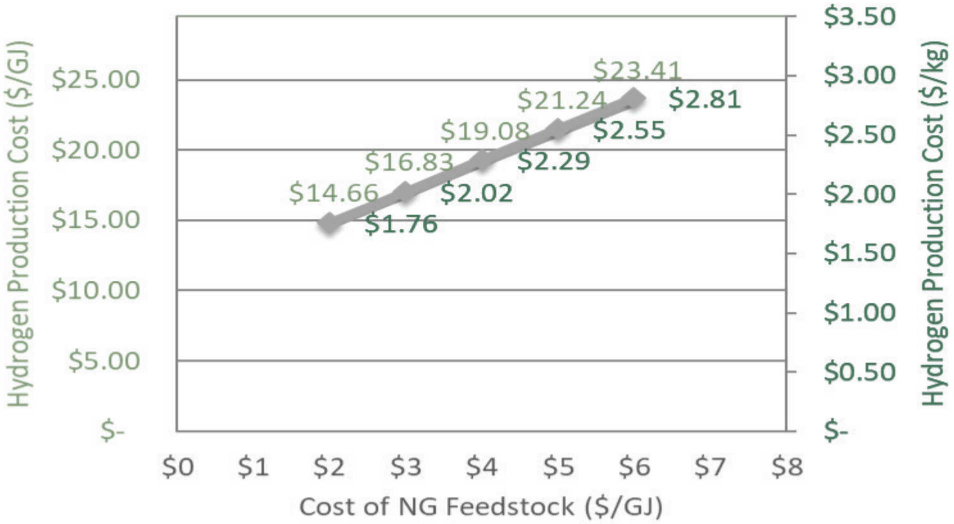

Figure 20. Impact of natural gas feedstock cost on hydrogen cost from plasma pyrolysis

Given the GHG emissions intensity of electricity from BC Hydro (54.72 g CO_2e/kWh)[34] the emissions intensity of hydrogen production from plasma pyrolysis would be on the order of 150 g CO_2e/kg H_2, or 0.150 kg CO_2e/kg H_2.

34 (S&T) Squared Consultants Inc. (2018). GHGenius 5.0d. Calculations conducted by BC Ministry of Energy, Mines and Petroleum Resources Low Carbon Fuels Branch. Retrieved from https://ghgenius.ca/index.php/downloads

Knowing these figures, the equivalent cost of mitigating GHG emissions using plasma pyrolysis in place of SMR can also be calculated.

- *The cost of hydrogen from plasma pyrolysis has been calculated as \$2.28/kg H_2, higher than the \$1.32/kg H_2 to produce hydrogen through SMR; a cost premium of \$0.96/kg H_2.*
- *The CO_2e emissions from thermal pyrolysis have been estimated at 0.150 kg CO_2e/kg H_2, significantly less than the 10.69 kg CO_2e/kg H_2 for SMR; a reduction of 9.18 kg CO_2e/kg H_2.*
- *For each kg of H_2 produced, it costs \$0.96 to avoid 9.18 kg CO_2e emissions, for a mitigation cost of \$0.105/kg CO_2e or \$105/tonne CO_2e emissions.*

Put differently, using plasma pyrolysis in place of SMR reduces CO_2e emissions from hydrogen production at an equivalent cost of \$105/tonne CO_2e.

3.1.6 : CO_2 sequestration

Effective CCS will be necessary for BC to capitalize on its abundant supply of natural gas to produce hydrogen without sacrificing GHG emissions goals. This section describes the state of CCS technology and storage capacity in BC.

3.1.6.1 : Overview

The Intergovernmental Panel on Climate Change (IPCC) defines carbon dioxide capture and storage as:

> "…a process consisting of the separation of CO_2 from industrial and energy-related sources, transport to a storage location and long-term isolation from the atmosphere."[35]

Subterranean geological formations are currently used for CO_2 storage, and are expected to continue being so in the future. The technologies in use are similar to long-established processes in the oil & gas sector. An overview of the storage options is given in Figure 21.

35 *Metz B, et al. (2005). IPCC Special Report on Carbon Dioxide Capture and Storage. IPCC. Retrieved from https://www.ipcc.ch/site/assets/uploads/2018/03/srccs_wholereport-1.pdf*

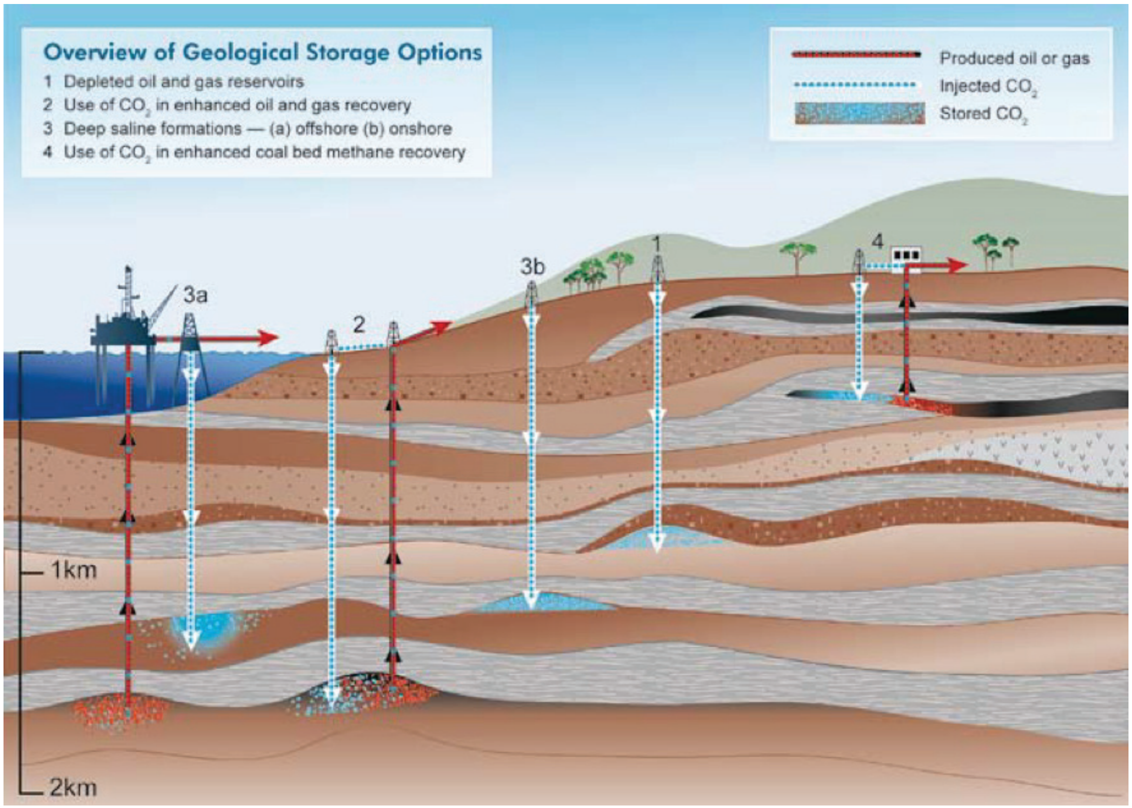

Figure 21. CO_2 Storage Options. Source: IPCC.[35]

A common feature in CO_2 storage options is the presence of a caprock which prevents the CO_2 from migrating back to the surface. Reservoir depths are recommended to be at least 800 m below ground, so the CO_2 can be stored as a supercritical fluid. This is desirable, as CO_2 is about 200x denser as a supercritical fluid than a gas, allowing considerably more CO_2 to be stored in each reservoir.

Shallower coalbeds can also be used for storage, as the CO_2 adsorbs onto the coal.

Over 200 million tonnes of CO_2 have been stored underground to date.[36] The Sleipner Gas Field off the coast of Norway is one the largest CO_2 storage sites; it has been used to sequester approximately 1 million tonnes of CO_2 per year since 1996.[37]

The IPCC conservatively estimates worldwide CO_2 storage capacity in depleted oil and gas reservoirs and saline aquifers to be approximately 3 trillion tonnes[35] representing sufficient capacity to store 80 years' worth of CO_2 from fossil fuel combustion at 2018 consumption rates.[38]

Promising sequestration sites can be found around the globe, including in Canada's Western Canadian Sedimentary Basin (WCSB), which extends from Alberta into BC.[39]

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36 Global CCS Institute. (2018). The Global Status of CCS: 2017. Retrieved from https://www.globalccsinstitute.com/wp-content/uploads/2018/12/2017-Global-Status-Report.pdf

37 Wikipedia. (2019). Sleipner gas field. Retrieved from https://en.wikipedia.org/wiki/Sleipner_gas_field

38 2018 CO_2 emissions from fossil fuel energy sources – 37 Gt.

39 Wikipedia. (2019). Sleipner gas field. Retrieved from https://en.wikipedia.org/wiki/Sleipner_gas_field

3.1.6.2 : CO_2 storage in BC

CO_2 storage options in BC include depleted gas reservoirs and saline aquifers. Gas reservoirs exist in the Northeast of the Province, in the Western Canadian Sedimentary Basin. Storage potential in these gas reservoirs – shown in Figure 22 – is estimated at approximately 2,000 Mt CO_2 per year.

Carbon dioxide can also be stored in saline aquifers, which exist throughout the province, as shown in Figure 23. The aquifers' potential for CO_2 storage has only been assessed in the Northeast of the province, so there remains considerable uncertainty about the aquifers' storage capacity. Estimates vary from 880 to 3580 Mt CO_2 per year.[40]

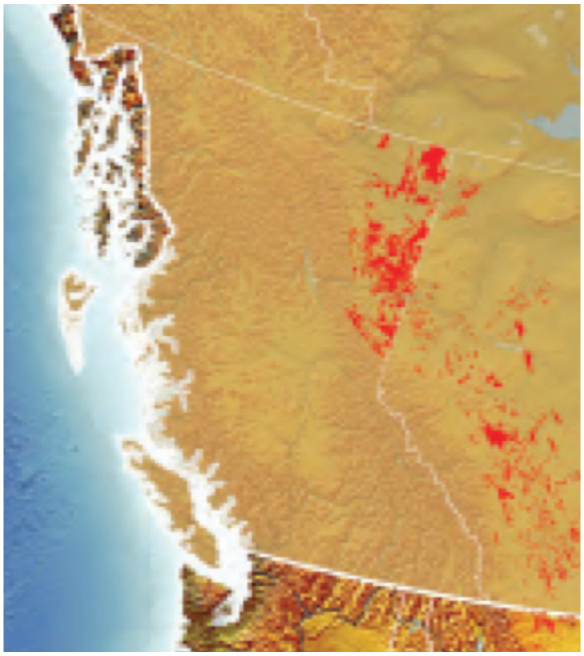


Figure 22. Natural Gas Fields in BC[41]

Figure 23. Location of Saline Aquifers in BC (light blue=non-assessed, dark blue=assessed)[40]

Drawing these together, Table 1 compiles the estimated CO_2 storage capacities for geological formations in the Province.

40 U.S. Department of Energy. (2015). Carbon Storage Atlas, Fifth Edition. National Energy Technology Laboratory. Retrieved from https://edx.netl.doe.gov/dataset/netl-carbon-storage-atlas-fifth-edition

41 Bachu, S. (2006a): The potential for geological storage of carbon dioxide in Northeast British Columbia; Report to the BC Ministry of Energy, Mines and Petroleum Resources, 71 pages.

CO_2 STORAGE OPTION	ESTIMATED CAPACITY (MT CO_2e)
Gas Reservoir	2,000
Saline Aquifer	1,000
Total	3,000

Table 1. CO_2 storage capacity in BC

In our hydrogen supply analysis, the study determined the annual capacity based on the assumption the CO_2 storage capacity would last 160 years. Further assuming that half of the storage capacity would be allocated to hydrogen, the maximum production through SMR+CCS processes would be 1.1 million tonnes hydrogen per year.

3.2 : Cost of Hydrogen Production in Province

The levelized cost of production for each pathway was calculated based on a 100 tonne per day (TPD) hydrogen plant, to evaluate the viability of large-scale centralized hydrogen production in the province. Figure 24 compares the hydrogen production cost of the various pathways relevant to BC's strategic resources. The cost to produce hydrogen via steam methane reformation is shown in the graph as a comparative baseline. It is recommended that the province focus only on low carbon hydrogen pathways, as described in 3.1.

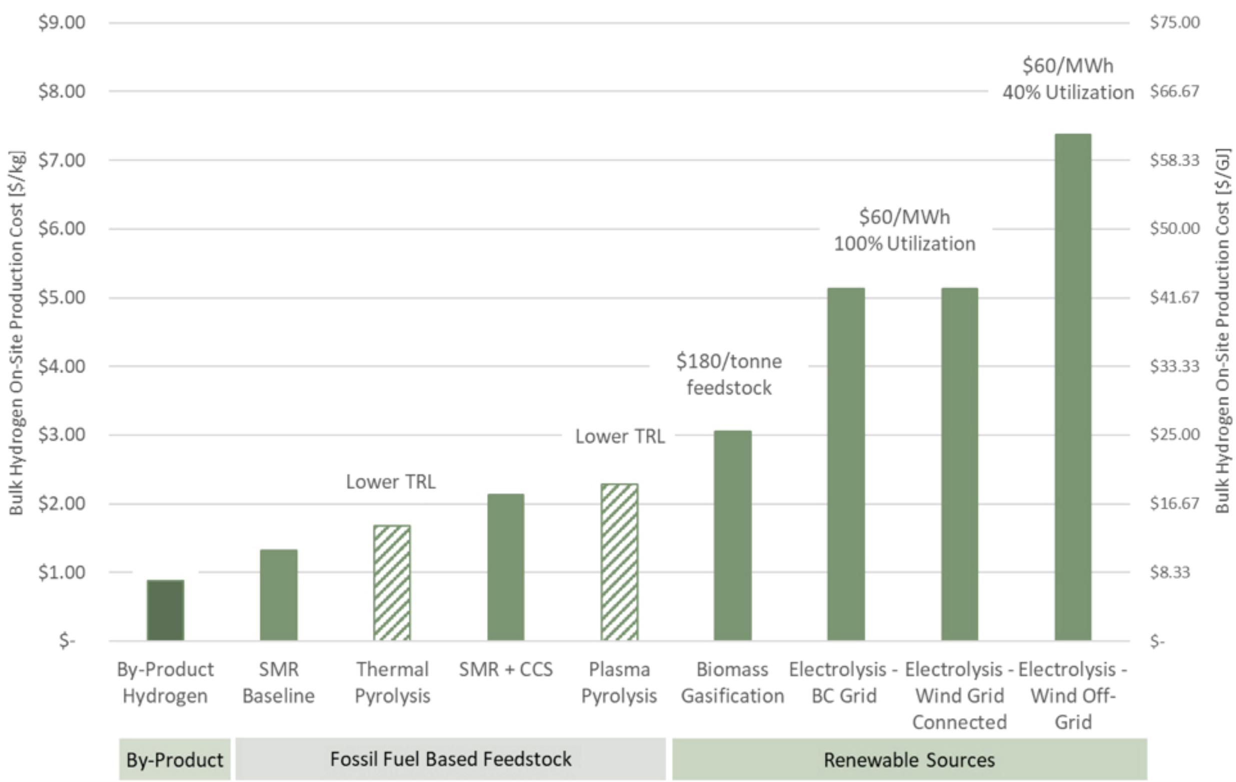


Figure 24. Cost of Bulk On-site Hydrogen Production by Pathway in BC (2030). Production costs are normalized to production scale of 100 TPD

Additional costs will be incurred during transportation, for which three pathways are likely:

1. *Injection into the natural gas grid, leveraging BC's natural gas pipeline infrastructure to store and deliver the hydrogen. In the near-term, hydrogen would be blended at low enough levels into the natural gas that the mixture could be consumed by existing end users without necessitating changes to their equipment. In the longer-term, hydrogen could be blended into natural gas at higher levels and then separated out for hydrogen-specific end users.*
2. *Delivery as a compressed gas, generally done through tube trailer trucks common to the chemical industry.*
3. *Delivery as a cryogenic liquid, also by delivery truck.*

The cost of delivering hydrogen as a compressed gas or a cryogenic liquid are a function of distance; estimated costs are shown in Figure 25.

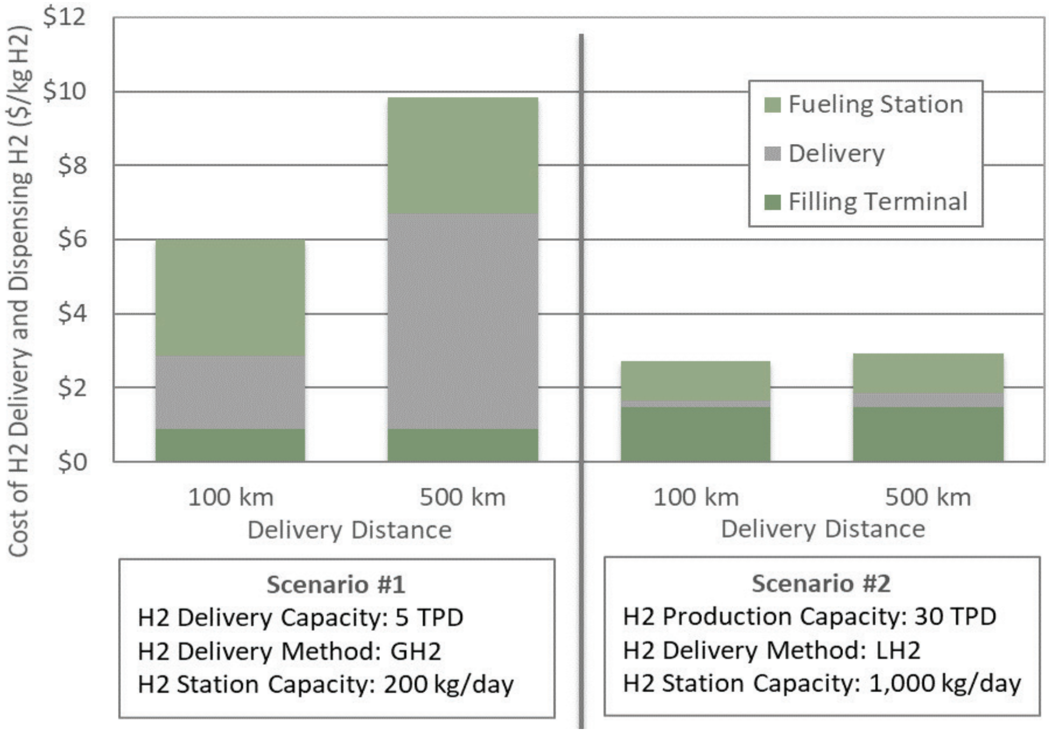


Figure 25. Truck-based delivery cost for hydrogen as a compressed gas and cryogenic liquid

On a per-kg basis, it is more economic to deliver hydrogen as a cryogenic liquid, but not all customers consume enough hydrogen to justify the higher capital expenditures liquid hydrogen deliveries require.

A hydrogen production plant might need to produce at least 10 tonnes H_2 per day to warrant investment in a liquefaction plant by the producer. Most end users are likely to use hydrogen in gas form, so would need to install a cryogenic tank on-site and vaporize it prior to use. Ballard Power Systems has such an installation at their Burnaby facility.

3.3 : Carbon Intensity of Hydrogen Production Pathways in BC

The GHG emissions intensity of the hydrogen pathways considered in this report is given in Figure 26 below. For context, it is noted that 1 kg H_2 contains 120 MegaJoules (MJ) of chemical energy. Thus, SMR baseline emissions of 89.1 g CO_2e/MJ is equivalent to 10.69 kg CO_2e/kg H_2.

All the pathways under consideration provide at least a 69% GHG emissions reduction relative to SMR. It is recommended that the Province set a threshold for hydrogen production carbon intensity of 36.4 g CO_2e/MJ going forward. This is consistent with the European CertiHy threshold.[42]

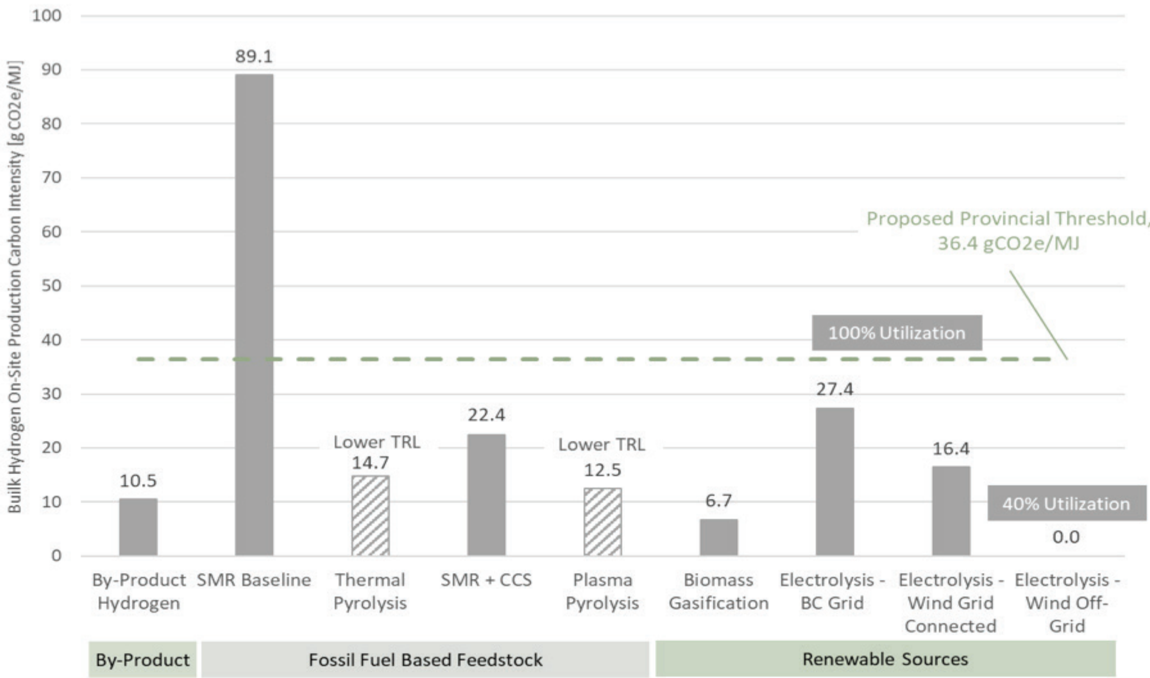


Figure 26. Carbon Intensity of BC's Hydrogen Production Pathways

An important metric for each pathway is the relative cost of carbon mitigation: the hydrogen production cost premium measured in terms of avoided CO_2e emissions. This metric measures the cost effectiveness of each hydrogen production pathway, relative to the emissions reductions it offers over SMR. Figure 27 shows this cost of carbon mitigation for each pathway.

42 *Fuel Cells and Hydrogen 2 Joint Undertaking (2019). Hydrogen Roadmap Europe: A Sustainable Pathway for the European Energy Transition. Retrieved from* *https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf*

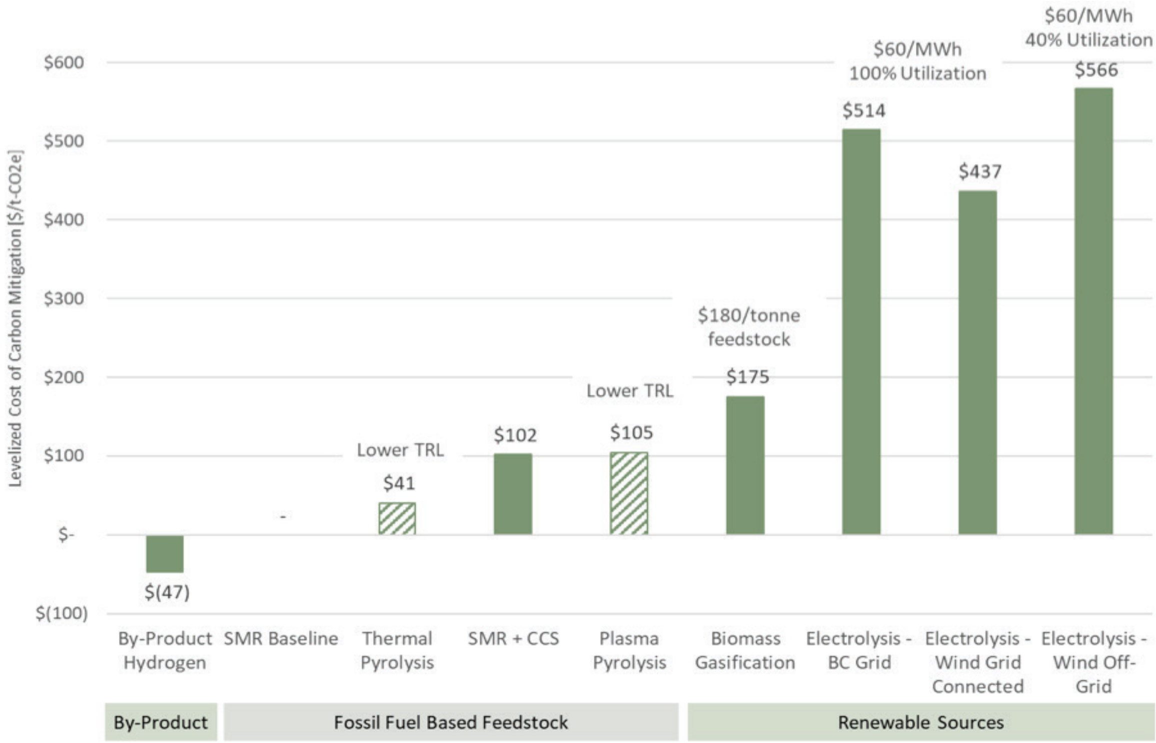


Figure 27. Cost of Carbon Mitigation by Hydrogen Production Pathway in BC (2030)

This chart shows by-product hydrogen to be the most cost-effective means of procuring hydrogen, relative to the avoided GHG emissions. Hydrogen supply from this pathway should be prioritized.

While Figure 24 showed that natural gas-based hydrogen pathways offer the lowest-cost hydrogen supply and Figure 26 showed that renewable hydrogen pathways offered the greatest emissions reductions potential, Figure 27 shows that the natural gas pathways have a lower cost of carbon mitigation.

The inference is that with prevailing price structures, natural gas-based hydrogen production pathways will be critical for cost-effective hydrogen production in the Province. If prevailing natural gas prices rise, perhaps through access to export markets, or if biomass or renewable electricity costs fall, perhaps through public policy measures, preferred rate tariffs or technology development, the cost comparisons would need to be revisited.

3.4 : Hydrogen Availability in BC

Each production pathway can supply different amounts of hydrogen based on the Province's natural resources. Figure 28 and Figure 29 show hydrogen supply curves against production cost; Figure 28 does so for all evaluated sources of hydrogen, while Figure 29 does so only for renewable pathways.

Industrial by-product hydrogen is the lowest-cost source of supply, and it can currently supply approximately 18.5 tonnes per day or 6, 800 tonnes per year.

BC's production capacity is estimated to be in excess of 2.2 million tonnes per year, positioning it to satisfy not just provincial demand but also proving excess capacity that could be exported.

Appendix C outlines the key assumptions underpinning the calculations for both hydrogen cost and availability above.

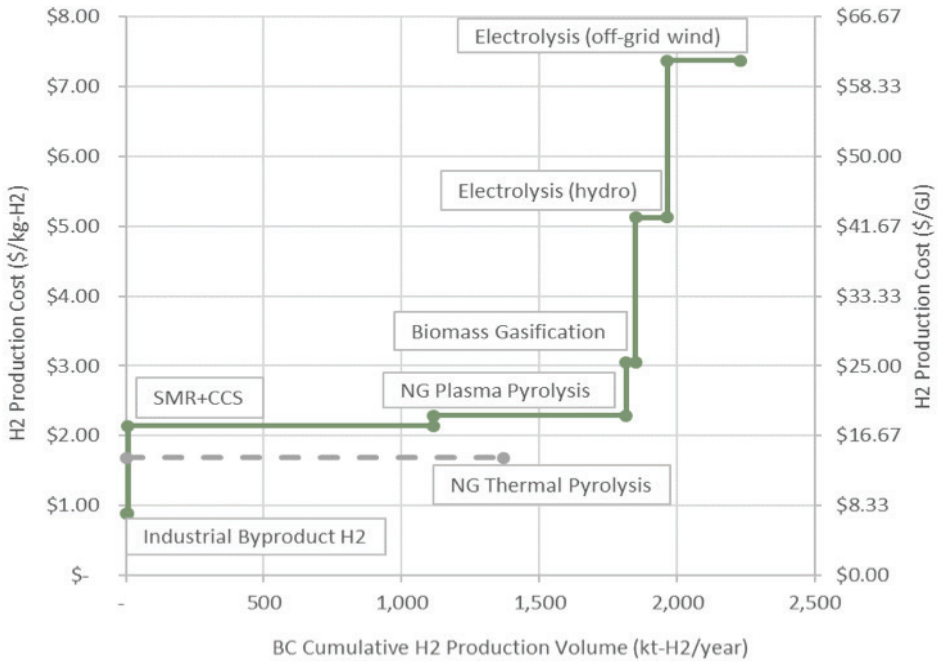


Figure 28. Estimated Hydrogen Production Price and Maximum Annual Volume by Pathway in BC (2030)

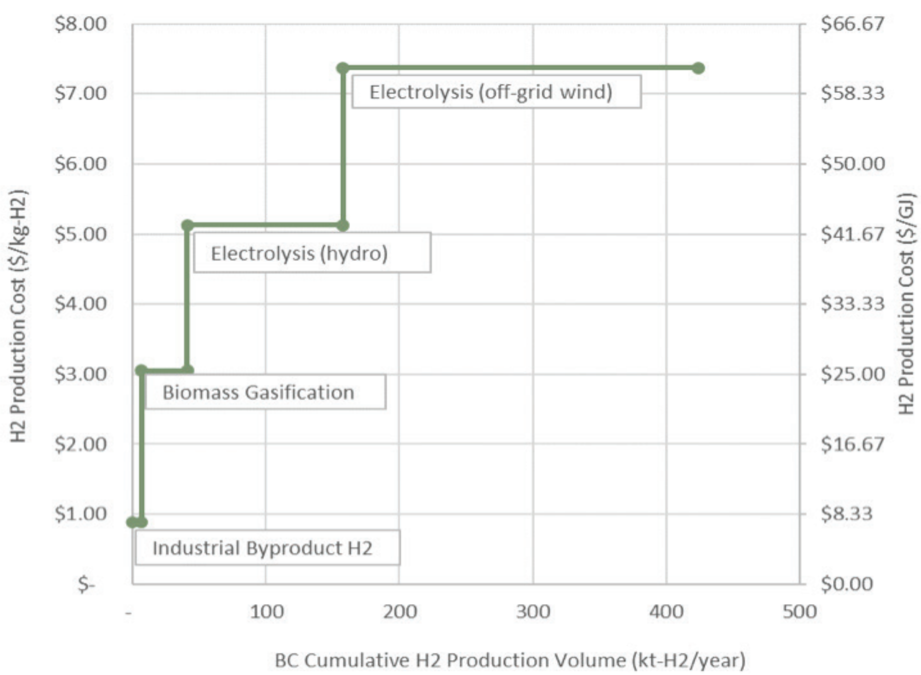


Figure 29. Estimated Hydrogen Production Price and Maximum Annual Volume by non-Fossil Fuel Pathway in BC (2030)

While there are uncertainties in potential production volume for each pathway, uncertainty in hydroelectric capacity warrants elaboration. The Province's CleanBC plan and the more recent City of Vancouver's Climate Change Emergency Response[43] focus on the electrification of transportation and the built environment will tend to increase hydroelectricity consumption; falling electric demand in BC's industrial sector[44] and the deployment of other renewable energy will tend to decrease it.

BC Hydro's peak capacity forecast does not show excess capacity after 2031[45], but the forecast load factor was not provided as input to the study. Both total electricity production and the shape of the load curve are important to accurately model the economics and capacity of electrolyzer development. BC Hydro has indicated that they build capacity to match demand. The values forecasted above for 2030 and 2050 for hydroelectric capacity were deemed to be reasonable by BC Hydro, provided adequate advance forecasting is given.

3.5 : Supply Development Approach

In the near-term, the lowest-cost, low-emissions sources of hydrogen will be necessary to maximize hydrogen's potential for decarbonizing BC's economy, complementing other efforts throughout the Province. Higher-cost hydrogen supplies will have greater challenges displacing GHG emissions in the public and private sector, and winning contracts for hydrogen exports.

In the longer-term it will be necessary for the Province to transition to renewable hydrogen sources rather than risk depleting fossil resources.

To that end, it is recommended that the Province support the development of a provincial industry for the production of clean hydrogen, while mandating that an increasing proportion of hydrogen be sourced from renewable feedstocks. This would allow the Province to capitalize on its natural gas resources in the mid-term while establishing a framework for a transition to renewable hydrogen.

Given the availability of low-cost, low-emissions by-product hydrogen from chemical facilities in Metro Vancouver and Prince George, it is recommended that one or more lighthouse projects be developed in the region to capitalize on the resource. When hydrogen demand exceeds by-product hydrogen supply, if large-scale hydrogen production has not begun, supplemental hydrogen could be generated from modular electrolyzers. These could be placed near end user facilities to minimize transportation costs.

Hydrogen liquefaction facilities will be necessary to move hydrogen economically around the Province. To that end, it is recommended that liquefaction facilities be seen as strategic assets to facilitate the decarbonization of the BC economy through hydrogen. Given the proposed lighthouse projects in Metro Vancouver, a nearby liquefaction facility will be critical to lower the delivered costs of hydrogen in the region.

The Peace Region, with ample natural gas, hydroelectric generation capacity, carbon sequestration and wind resources along with existing gas and electric transmission infrastructure could be suitable for large-scale clean hydrogen production, whether from natural gas or electrolysis or both. Hydrogen could be blended into existing natural gas pipelines in the near-term, as plans develop for larger hydrogen-specific deployments.

43 City of Vancouver, Climate Emergency Response. (2019). Retrieved from https://vancouver.ca/green-vancouver/climate-emergency-response.aspx

44 BC Hydro, Transmission Service Rate Design Workshop. (11 October 2018.)

45 BC Hydro, forecast data provided for study.

3.5.1 : Recommendations

Adopt policy that specifies the GHG intensity of hydrogen, rather than limiting to renewable only

- *Set longer-term objectives for transition to renewable hydrogen supplies through establishing tiered thresholds of required renewable content over time*

Prioritize development of large-scale, low carbon hydrogen supply infrastructure and strategic hydrogen liquefaction and distribution assets in the Province

- *Set a threshold for the GHG intensity of the hydrogen for all provincially funded projects and stipulate that there must be a transition plan for hydrogen to be produced within the province during the project*

Develop flexible, lower cost electricity rate schedule to encourage production of green hydrogen

- *In near term, small, distributed electrolyzers will require lower electric rates*

Lighthouse project: Support a study to look at the potential for centralized hydrogen production and transport from the Peace region, both through the NG pipeline and as liquid through liquefaction plant

BC HYDROGEN PIPELINE

The Peace Region of BC, with extensive gas reserves, CO_2 sequestration potential, hydroelectric generation capacity and wind resources, coupled with an abundant fresh water supply, could become a centralized large-scale producer of clean hydrogen supplying not only BC, but also the US Pacific Northwest and California.

There is potential to use the existing NG grid and inject large amounts of hydrogen and create a blended NG/ H_2 gas stream. Liquefaction coupled with rail or road transport would enable delivery of pure hydrogen. A 'big bold goal' would be to construct a dedicated hydrogen pipeline that runs from the Peace Region right down to California. This would be built with a view to future energy systems, rather than one retrofitted to the hydrocarbon energy systems of the past. There could also be potential to run the pipeline east into Alberta. This carbon-free energy pipeline could provide a means for both provinces to transmit carbon-free energy derived either from renewable resources or fossil resources where the carbon is sequestered directly at the source of extraction, thereby alleviating many of the environmental concerns connected to existing pipeline projects under development.

4.0 : Hydrogen's Role in Decarbonizing BC's Energy System and Economic Sectors

Given the Study goal of identifying roles hydrogen can play in BC's decarbonization efforts, an evaluation of economic sectors in the Province was made, with the following analysis for each sector:

- *Baseline for energy use and emissions;*
- *Opportunities for hydrogen based on technical and commercial factors;*
- *Sector-specific challenges or barriers, and policy recommendations to overcome these;*
- *Adoption scenarios based on factors such as technology maturity, cost, and pertinent and potential policies and regulations.*

4.1 : Natural Gas

4.1.1 : Baseline

As per Figure 30 below, natural gas represents 30% of BC energy consumption and 80% of the Province's energy production.[46] As such, it is an important energy source and a vector for economic development. The upstream oil and gas sector contributes approximately 10,000 jobs and almost $1 billion per year in provincial revenues.[47] Extracting hydrogen from oil and gas, and capturing and sequestering the carbon dioxide produced, could provide a path for BC's oil and gas sector to continue supplying energy in a carbon-constrained future.

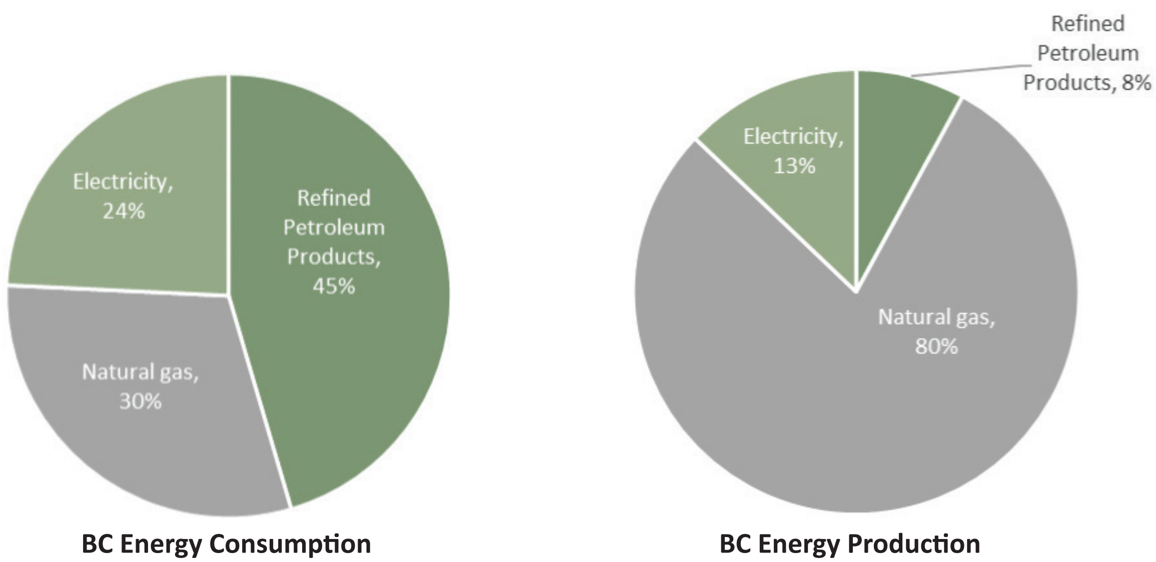


Figure 30. BC Energy Consumption and Production by Energy Type.[46]

46 *Canada's Oil and Natural Gas Producers. (2018). British Columbia's Oil and Natural Gas Industry. Retrieved from* https://www.capp.ca/publications-and-statistics/publications/335337

47 *Ibid 46*

The Province has extensive low-cost natural gas resources which technology innovations have made feasible for extraction. BC's natural gas fields are located in the Northeast of the Province, which overlaps the Western Canadian Sedimentary Basin; the largest are the Montney Formation, the Horn River Basin, the Cordova Embayment and the Liard Basin.

BC's natural gas reserves are estimated at more than 525 trillion cubic feet (tcf), sufficient to meet more than 100 years of natural gas demand at current levels. The Province's approximately 10,000 producing wells produce about 1.5 tcf of natural gas per year, representing about 28% of Canadian natural gas production, only 10% of which is consumed in-province.[48]

Natural gas is distributed around the Province and to neighbouring jurisdictions through networks of pipelines, shown in Figure 31 below. Pipeline operators include Enbridge, FortisBC and Pacific Northern Gas (PNG). BC's extensive natural gas pipeline network represents a significant capital investment and infrastructure for energy supply that presently serves all major population centres in the province.

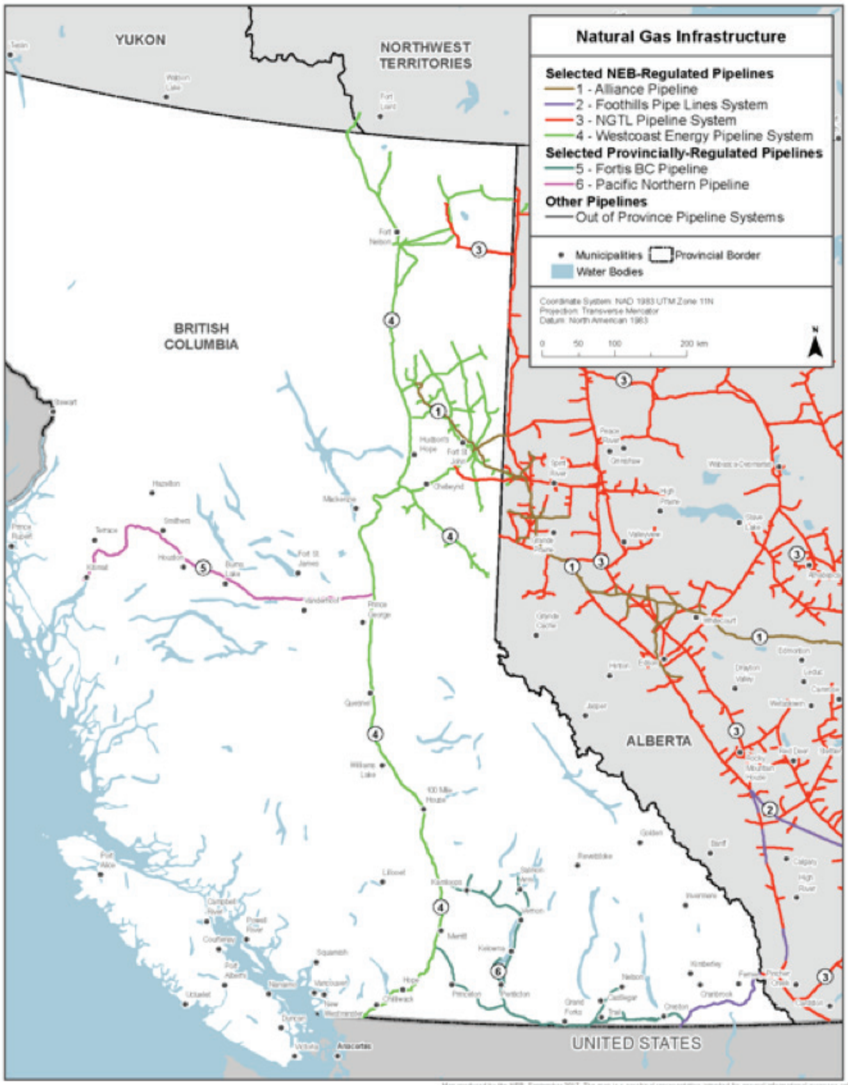


Figure 31. Map of BC Natural Gas Infrastructure [49]

48 *Ibid 46.*

49 *National Energy Board. (2017). Electricity Capacity and Primary Fuel Sources. Retrieved from* [*https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/nrgsstmprfls/mg/bc-fg03-lg-eng.png*](https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/nrgsstmprfls/mg/bc-fg03-lg-eng.png)

The Westcoast Energy Pipeline, operated by Enbridge and sometimes called the Westcoast Transmission System or the BC Pipeline, was built in 1957. It is shown in green in the Figure above. The Enbridge-owned and operated pipeline delivers natural gas from the Western Canadian Sedimentary Basin to Metro Vancouver. It transports about 60% of the natural gas produced in BC and supplies about 50% of natural gas demand in Washington, Oregon and Idaho. The pipeline consists of two systems, Transmission North and Transmission South, both of which are being upgraded to increase capacity beyond the current 2.9 billion cubic feet (Bcf) per day. (This figure is equivalent to approximately 1.0 tcf/year of transmission capacity, as compared to the province's current 1.5 tcf/year of production.)

BC's eastbound natural gas flows through TransCanada's Nova Gas Transmission Limited (NGTL) system, which is also expanding to accommodate new supply from the Montney Formation. The Province's natural gas is also exported to the U.S. Pacific Northwest at the Huntingdon export point, via the Westcoast Pipeline (Enbridge), or exported to the U.S. Midwest via the Alliance Pipeline (Enbridge) and through the Alameda, Saskatchewan export point.

The BC Oil and Gas Commission (OGC) provides oversight for industrial activities, licensing, regulations, growth and associated economic development. Natural gas prices are regulated in the Province through the BC Utilities Commission. Rates vary between customer type – residential, commercial or industrial – and from region to region. Medium-sized commercial operations in BC pay a rate structure for NG supply broadly in line with that outlined in Table 2.

COST ELEMENT	COST ($/GJ)
Cost of Natural Gas	$1.50
Delivery Charge	$3.00
Storage and Transport Charge	$1.20
Total	$5.70

Table 2. Typical Natural Gas Rate Structure, Medium-Sized Commercial Operation[50]

50 Fortis BC. (2019). Business Natural Gas Rates. Retrieved from https://www.fortisbc.com/accounts-billing/billing-rates/natural-gas-rates/business-rates

4.1.1.1 : BC Energy Demand and GHG Emissions

In 2016 BC end use energy demand was 1,165 petajoules (PJ) of which natural gas accounted for 346 PJ, supplying approximately 30% of total energy demand for the province.

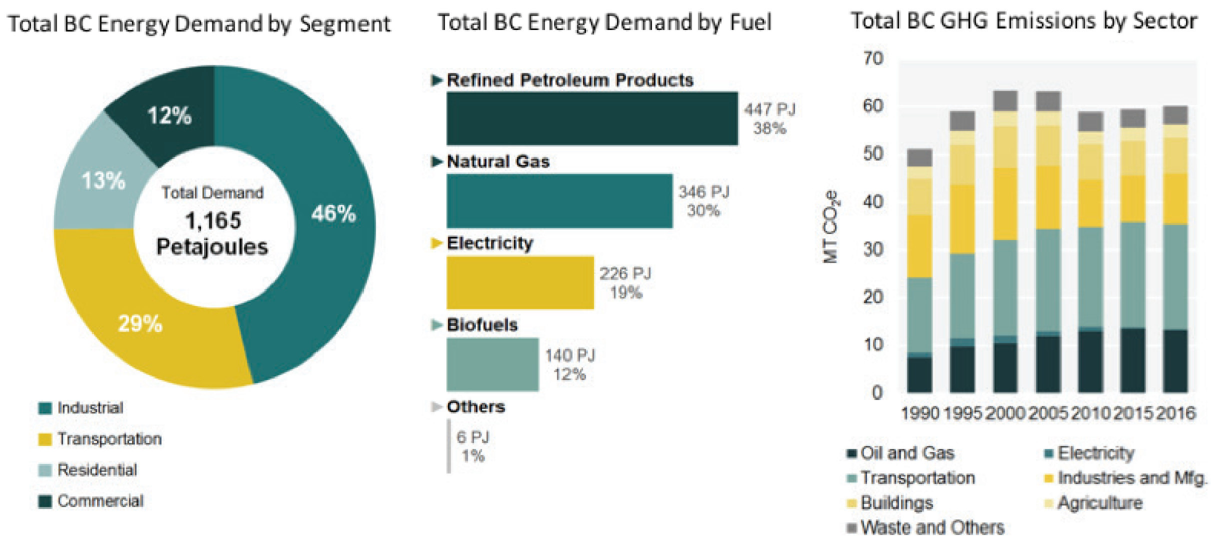


Figure 32. Energy Demand and GHG Emissions in BC[51]

BC's GHG emissions in 2016 were 62.3 Mt of CO_2e.[52] Natural gas plays a role in the largest emitting sectors of the Province's economy: transportation, oil and gas, and the built environment.

4.1.1.2 : Renewable Natural Gas

Biogas is a renewable form of methane gas, generally produced from biomass feedstocks. Renewable Natural Gas, or RNG, is biogas that is cleaned to pipeline-quality standards. It is typically blended with fossil natural gas. Sometimes called bio-methane, it is carbon-neutral and chemically similar to fossil natural gas.

RNG is produced from a variety of resources, including landfill gas (from anaerobic decomposition of organic matter), sewage, farm waste and food waste. Forestry residues and dedicated energy crops can also be cultivated for RNG production, although these have more often been considered for liquid fuels production. The major benefit of RNG production is that the methane that is already naturally produced from waste is captured and utilized before it can escape to the atmosphere.

Given its feedstocks, RNG is a carbon-neutral fuel that can displace fossil natural gas and the upstream GHG emissions associated with its production and supply. Recent studies have suggested that anywhere from 5% to 20% of current natural gas demand could be met with RNG.[53] That said, at present only 0.3% of natural gas consumption in the Province consists of RNG.[54]

51 *National Energy Board. (2019). Provincial and Territorial Energy Profiles – British Columbia. Retrieved from https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/nrgsstmprfls/bc-eng.html*

52 *British Columbia Provincial Government. (2018). Provincial Greenhouse Gas Emissions Inventory: 2016 Provincial Inventory. Retrieved from https://www2.gov.bc.ca/gov/content/environment/climate-change/data/provincial-inventory*

53 *Alberta Research Council - Potential Production of Methane from Canadian Wastes*

54 *Provided by FortisBC during Stakeholder workshop #1.*

One barrier for RNG is its cost of production, which ranges from $6 to $45/GJ depending on plant size, feedstock, and location, and in most cases is significantly higher than fossil-derived natural gas. Other barriers to RNG adoption include lack of standards, dispersed feedstock supply and geographical constraints for pipeline delivery. Nevertheless, the most attractive sources of renewable biogas, such as landfill gas, can yield energy supply in the form of RNG at half the cost of electricity in British Columbia, and these sources of renewable and carbon-neutral energy are being rightly exploited in BC and elsewhere.

4.1.2 : Opportunities for Hydrogen

4.1.2.1 : Hydrogen's Role in Decarbonizing the Natural Gas Grid

Hydrogen can be blended into the natural gas grid; if cleanly generated it can reduce the GHG emissions intensity of the delivered blend. Large-scale demonstration and lighthouse projects have been undertaken in the past decade. At relatively low concentrations of 5-15% hydrogen by volume, this approach does not appear to increase risks associated with utilization of the gas blend in end use devices such as household appliances, for overall public safety, or the durability and integrity of the existing natural gas pipeline network.[55]

The blending of hydrogen into natural gas pipelines has also been proposed as a means of delivering pure hydrogen to markets; separation and purification technologies could separate hydrogen downstream of the injection points and closer to end users. Blending can delay costs associated with building dedicated hydrogen pipelines or other costly infrastructure during early market development.

4.1.2.2 : Hydrogen's Role in the CleanBC 15% Renewable Gas Target

The CleanBC plan establishes a target of 15% renewable content for natural gas consumption in industrial, commercial and residential sectors in BC by 2030. The Province, FortisBC and PNG are evaluating the expanded use of RNG from wastewater treatment plants, landfills and the anaerobic digestion of agricultural waste. While these sources of renewable biogas supply are an excellent resource for scaling RNG production in the province, challenges remain in terms of meeting the 15% RNG target by 2030 at a cost structure that competes with incumbent fossil-based natural gas. This report recommends adopting low-cost, low carbon hydrogen production for natural gas grid injection as a means to complement more traditional RNG supply methods and meet the Province's renewable gas targets.

It is recommended that all sources of low carbon hydrogen qualify towards the CleanBC target given the primary objective of decarbonization. Defining the CleanBC target as "Renewable Gas" could restrict the Province's ability to cost-effectively decarbonize natural gas energy services.

55 *Melaina MW., et al. (2013). Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues. National Renewable Energy Labs Technical Report 5600-51995. Retrieved from https://www.nrel.gov/docs/fy13osti/51995.pdf*

THE ORKNEY ISLANDS HYDROGEN COMMUNITY

Orkney is a group of islands off the north coast of Scotland with abundant wind, tidal, and wave energy resources. Orkney aims to establish a sustainable hydrogen supply chain to replace fossil fuels with clean, locally-sourced energy. To minimize curtailment, excess electricity powers a 500 kW electrolyzer on Eday Island and a 1 MW electroyzer on Shapinsay Island to produce hydrogen. The compressed hydrogen is transported on a storage trailer via truck and ship to Kirkwall where it is either run through a 75 kW fuel cell to power the local electricity grid when there is not enough renewable electricity being generated or fuels FCEVs. Waste heat produced from the fuel cell is piped into nearby buildings. Eventually, the hydrogen will also be used to power passenger and vehicle ferries between the islands and the mainland.

Hydrogen can contribute to meeting the 15% Renewable Gas target through two principal pathways: (1) direct injection, or (2) methanation/biomethanation through the Sabatier reaction. Methanation combines CO_2 with hydrogen to produce synthetic methane and steam, according to the reaction below:

$$CO_2 + 4\ H_2 \rightarrow CH_4 + 2\ H_2O + \text{energy}$$

Synthetic methane production has the advantage of providing a gas supply that is chemically similar to fossil-based natural gas and can be added to the pipeline network with virtually no restriction. However, the methanation process adds cost, which makes it less favoured to direct grid injection of low carbon hydrogen.

- *Prevailing natural gas costs are on the order of $4/GJ.*
- *Low carbon hydrogen pathways range from $2 to $5/kg H_2, equivalent to $17 to $42/GJ.*
- *Approximately 10 kg of H_2 are required to produce 1 GJ of synthetic methane, in addition to capital and operating expenditures for the Sabatier process, meaning synthetic methane would be the most expensive option.*

Therefore, strategies for injecting low carbon and/or renewable gas into the natural gas pipeline network will always favour direct hydrogen injection over synthetic methane production, provided hydrogen injection levels are acceptable to prevailing pipeline networks and end use technologies. As such, synthetic natural gas production is expected to play only a minor role in meeting the CleanBC 15% Renewable Gas target.

As hydrogen has a lower heating value than natural gas, its injection into natural gas networks will result in a mixture with a lower heating value on a volume basis. Delivering the same amounts of energy to end users would therefore necessitate increased volumetric flows. For example, injecting 10% H_2 by volume will require the total volumetric flow rate in the pipeline to increase by ~ 8% compared to pure natural gas. At 40% hydrogen, the total volumetric flow rate must increase by 40% indicating a slightly non-linear trend.

To accommodate higher flows, pipelines and distribution networks will need to increase system pressure and increase the density of the gas mixture flowing through the pipeline. Pipelines' pressure ratings may therefore constrain the amount of hydrogen injection into natural gas infrastructure, along with the compatibility of end users' appliances as hydrogen concentrations increase.

Hydrogen injection limit concerns could be circumvented by localizing portions of the natural gas infrastructure or end customers who can tolerate higher hydrogen concentrations. The 15% Renewable Gas target is a provincial annual average, and so could be met if selected pipelines and end users converted to renewable or low carbon hydrogen, even if the rest of the province remained on fossil-based natural gas. For example, if the PNG pipeline system terminating at Kitimat was converted to 100% hydrogen, it would fulfill 2.3% of the 15% Renewable Gas requirement.

DECARBONIZING THE LNG SECTOR

In October 2018, the Government of British Columbia approved the construction of LNG Canada's export terminal in Kitimat; an export license has been awarded for 40 years. The capacity of the project is 26 Mt per year of LNG exports, expected to be deployed in two stages, the first of which will build two LNG trains with a total capacity of 13 Mt/year.

At full capacity, total emissions for the LNG Canada project are expected to be 6.9 Mt CO_2e/year. Of these emissions, about one half are due to upstream and pipeline emissions – mostly caused by leaks, or "fugitive" methane -- and the balance relates to LNG Canada's liquefaction plant. Currently, power for the facility is expected to come from natural gas.

The cost of natural gas for the Kitimat terminal is estimated to be about $3/GJ. This is equivalent to an electricity cost of $11/MWh, much lower than BC Hydro's $60/MWh industrial rate. If the terminal's power consumption were fully electrified with hydroelectricity, there would be a decrease of approximately 3.0 Mt CO_2e/year, representing about 42% of the project's overall emissions.

Clean hydrogen could be used in place of natural gas to power the LNG terminal and reduce its environmental footprint. The hydrogen could be run through the turbine to generate clean power and significantly reduce the emissions associated with producing LNG in the Province.

If electrolysis was used to generate renewable hydrogen for the 15% Renewable Gas requirement, it would represent a significant new electrical load for the Province. Meeting just a third of the CleanBC target in this manner would require approximately 100,000 tonnes per year of hydrogen, representing an average load of approximately 700 MW. As this exceeds BC Hydro's surplus capacity, and the Province has committed to self-sufficiency in electricity, it would be necessary for some renewable hydrogen to be derived from biomass or for new renewable electricity projects to come online.

4.1.3 : Challenges and Barriers

Blending hydrogen into natural gas networks can significantly reduce GHG emissions if low-emission hydrogen is used. Implementing hydrogen blends into the natural gas pipeline network however introduces considerations of composition, pressure, material compatibility and appliance operation, and in some cases hydrogen extraction, to ensure a robust gas delivery system is achieved.

Embrittlement

Some metal pipes can degrade when exposed to hydrogen over long periods, particularly for the higher hydrogen concentrations and pressures that may occur when it is injected into high-pressure natural gas transmission systems. Embrittlement effects depend on the type of steel and on operating conditions and must be assessed on a case-by-case basis.

Natural gas transmission pipelines are typically made of high-strength steels, with diameters of 4–48 inches, operate at high pressures of 600–2,000 psi_g (42–139 bar) and are usually wrapped/coated and cathodically protected against corrosion. Because of the high strength steels employed and the high pressure of operation, transmission pipelines can be susceptible to hydrogen embrittlement. Therefore hydrogen concentrations are more limited in transmission networks. Nevertheless, the high pressure and large throughput of gas in transmission networks can translate into significant hydrogen volumes, even if conservative grid injection levels of 5-10% by volume are employed.

Steel and polyethylene (PE) are the dominant materials for natural gas distribution systems. The metallic pipes used in the lower-pressure natural gas distribution systems are usually made of low-strength steels, and these materials are not generally susceptible to hydrogen-induced embrittlement under normal operation. Other metallic pipes including iron (ductile, cast and wrought) and copper that are sometimes used in natural gas distribution are also free from embrittlement concerns. Town gas, containing approximately 50% H_2, was in common use in Europe prior to the switch to natural gas, and continues to be used in some jurisdictions, including Hong Kong.[56]

There are no major concerns about hydrogen aging the polyethylene (PE), polyvinylchloride (PVC) or elastomeric materials more common in recent natural gas distribution networks.

While the allowable concentrations of hydrogen in natural gas pipeline networks remains an area of active research and evaluation, recent studies have concluded that transmission pipelines can accept hydrogen concentrations of 5% (by volume) with minimal risk.[57] Distribution networks have been judged able to accept hydrogen concentrations of up to 25% with minimal risk and as high as 50% with additional validation. The majority of stakeholders consulted in this study concluded that a hydrogen concentration target of 10% represents a conservative near-term target for hydrogen grid injection into the natural gas network.

56 *Towngas, Gas Production. The Hong Kong and China Gas Company. Retrieved from https://www.towngas.com/en/About-Us/Hong-Kong-Gas-Business/Gas-Production*

Pipeline Standards and Policy

The amount of hydrogen presently allowed in natural gas infrastructure is limited by country-specific standards and regulations. In certain countries, hydrogen injection limits have been established, ranging from less than 1% to as high as 12% H_2 by volume (see sidebar).

Hydrogen injection standards have yet to be established in British Columbia and elsewhere in North America. The Canadian Gas Association was interviewed for this study and anticipates the release of a report advising that hydrogen blending of up to 5% by volume is acceptable in the near-term.

Technical specifications and interface requirements for hydrogen blending will need to be established and standardized across affected regions. These steps should be considered for near-term policy development.

The amount of H_2 presently allowed in the NG grid is limited by country-specific standards and regulations

- *UK: 0.1% (vol.)*
- *Belgium: 0.1% (vol.)*
- *Sweden: 0.5% (vol.)*
- *Austria: 4% (vol.)*
- *Switzerland: 4% (vol.)*
- *France: 6% (vol.)*
- *Germany: 10% (vol.)*
- *Holland: 12% (vol.)*

Reference: Review of hydrogen tolerance of key Power-to-Gas (P2G) components and systems in Canada, NRC, July 2017

Pipeline Capacity

For hydrogen blending to occur, hydrogen production capacity must be matched to existing natural gas pipeline capacity. A detailed study of pipeline capacity and injection location must be conducted to optimize hydrogen injection efforts.

Appliances

Natural gas-consuming appliances must be able to operate without impediment on hydrogen-blended natural gas. While most appliances are compatible with hydrogen concentrations of up to 10% H_2 by volume and lower, this is unlikely to be the case for combustion turbines, compressors (which may contain natural gas but leak hydrogen) and CNG tanks.

For higher hydrogen concentrations – in the range of 30% and higher – performance issues may arise with engines, burners, boilers and stoves. Appliance testing and validation for all product models and makes would be necessary to move to these higher hydrogen levels.

Hydrogen Separation

A low-cost method for separating hydrogen from a natural gas stream would be an enabling technology for hydrogen blending, and reduce concerns relating to downstream appliance compatibility. Pressure swing absorption (PSA) technology is mature and could be used to remove hydrogen from a natural gas pipeline. Leveraging the pressure difference between (high-pressure) transmission and (low-pressure) distribution networks could facilitate a low-cost PSA solution for hydrogen separation, and it is recommended that research to this end be supported.

Hydrogen separation technology would be particularly important where downstream natural gas might be used by CNG vehicles, as some Type 3 CNG tanks can only tolerate hydrogen concentrations of less than 2%. An alternative would be to require the replacement of the affected tanks.

Gas Metering

Hydrogen blends can influence the accuracy of existing gas meters. Studies have shown that gas meters would not need to be tuned for low hydrogen blend levels (less than 50% volume).[58]

57 *Yoo Y., et al., (2017). Review of Hydrogen Tolerance of Key Power-to-Gas (P2G) Components and Systems in Canada. NRC-EME-55882. Retrieved from* https://nrc-publications.canada.ca/eng/view/fulltext/?id=94a036f4-0e60-4433-add5-9479350f74de

Contaminants

The potential impact of contaminants associated with hydrogen injection into the natural gas network deserves examination, though this would be less urgent for hydrogen production methods producing relatively pure hydrogen, such as electrolysis methods.

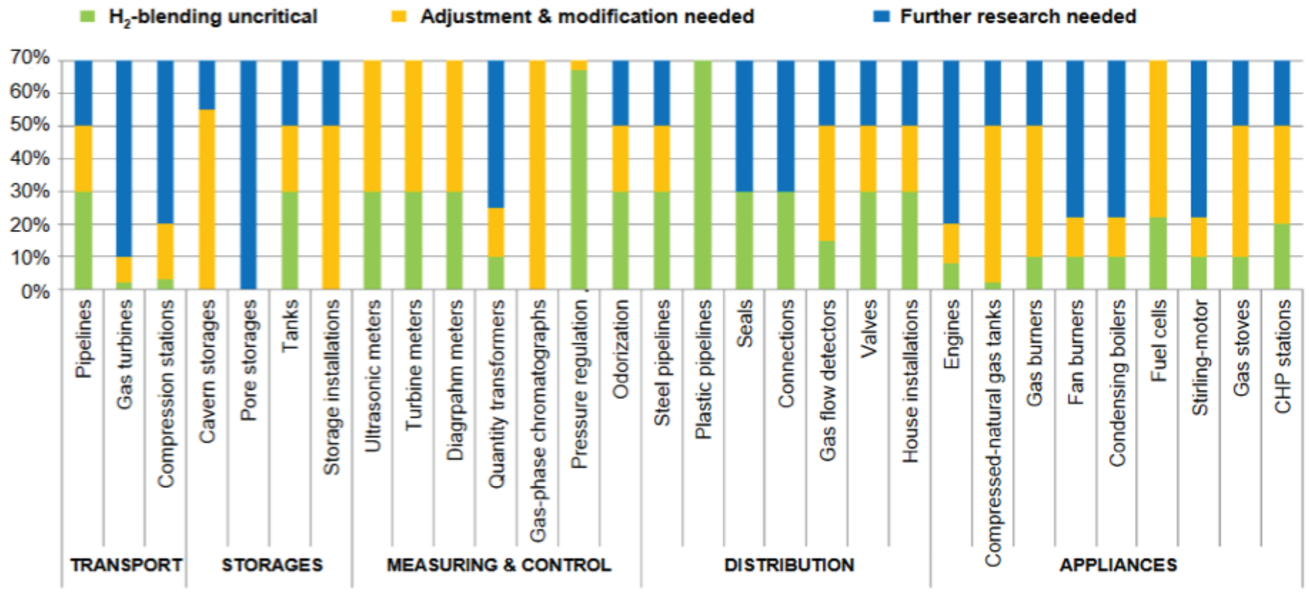


Figure 33. Limit of Hydrogen Blending along the Natural Gas Infrastructure[59]

4.1.4 : Adoption Scenarios

Adoption scenarios that project hydrogen demand through 2050 have been developed on conservative and aggressive cases. The amount of hydrogen introduced into the grid has been defined as a percentage of natural gas volume consumed by the Province's industrial, commercial and residential sectors. Natural gas demand in

58 *Melaina MW, Antonia O, Penev M. (2013). Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues. NREL Technical Report 5600-51995. Retrieved from https://www.nrel.gov/docs/fy13osti/51995.pdf*

59 *SBC Energy Institute. (2014). Hydrogen-Based Energy Conversion. Retrieved from http://www.4is-cnmi.com/feasability/doc-added-4-2014/SBC-Energy-Institute_Hydrogen-based-energy-conversion_Presentation.pdf*

BC was forecasted based on FortisBC's long-term planning report [60] and assuming FortisBC continues to provide 95% of natural gas delivered in the Province.[61] Beyond 2036, which is the last year forecasted in FortisBC's long term planning report, natural gas demand was assumed to remain constant through 2050.

YEAR	BC FORECASTED NATURAL GAS DEMAND (PJ)		
	Non-Transportation	Transportation	Total
2015	202	1	204
2020	203	8	211
2025	205	40	245
2030	208	58	266
2035	212	75	287
2040	212	78	291
2045	212	78	291
2050	212	78	291

Table 3. BC Natural Gas Demand Forecast 2020-2050

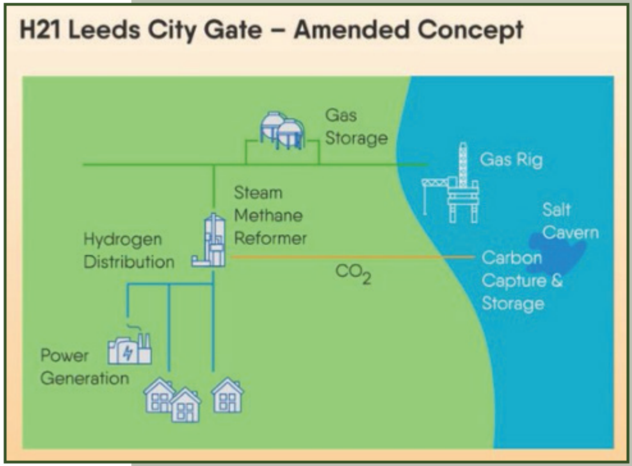
The conservative scenario assumes that hydrogen content reaches 10% by volume by 2030 and increases to 20% by volume 2050. The aggressive scenario assumes hydrogen represents 15% by volume by 2030 and increases to 45% by volume by 2050. The scenarios represent plausible pathways to help meet CleanBC renewable gas targets.

The resulting hydrogen demand curves for natural gas grid injection are given in Figure 34 below.

BC HYDROGEN COMMUNITY

Some regions are exploring the conversion of entire communities and regions to run on 100% hydrogen to decarbonize their energy system. The City of Leeds is one such example and the United Kingdom has developed long-term plans to convert Northern England to hydrogen. The H21 North of England is a detailed engineering solution for converting 3.7 million UK homes and businesses from natural gas to hydrogen, in order to reduce carbon emissions. H21 North of England finds that converting the UK gas grid to hydrogen has the ability to provide "deep decarbonisation" of heat, as well as transport and power generation, with minimal disruption to customers.

In that spirit, BC could adopt a "Big Bold Goal" to convert one of its communities to hydrogen. This could include local hydrogen production, distribution through a pipeline, zero carbon energy delivery to houses running fuel cell cogeneration systems, and a fully zero emission transportation system consisting of light duty FCEVs and transit buses. A smaller community such as Revelstoke, which has an isolated LPG grid, is one such option. A bolder option would be to convert Vancouver Island -- which is at the end of the BC's natural gas pipelines – to 100% hydrogen by 2050.



60 FortisBC. (2017). FortisBC 2017 Long Term Gas Resources Plan. Retrieved from https://www.bcuc.com/Documents/Proceedings/2018/DOC_50742_B-1_FEI-2017-Long-Term-Gas-Resource-Plan.pdf

61 BC Provincial Government. (2018). Production and Distribution of Natural Gas in BC. Retrieved from https://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/statistics

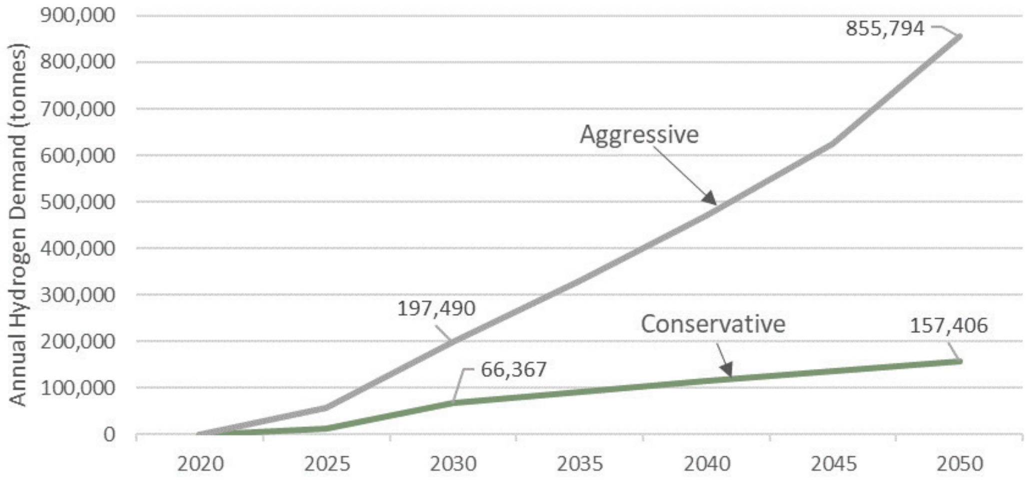


Figure 34. Hydrogen Demand for Natural Gas Grid Injection in BC

These adoption rates of hydrogen into the natural gas grid will result in significant GHG emissions reductions. In 2030, the projected emissions reduction ranges from 0.3 to 0.5 Mt CO_2e/year while in 2050 the projected emissions reductions would range from 0.8 to 2.3 Mt CO_2e/year. The GHG emissions were calculated assuming the hydrogen displaces natural gas based on lower heating values of natural gas of 38.9 MJ/m^3 and hydrogen of 10.8 MJ/m^3. The natural gas carbon intensity was assumed to be 57.9 g CO_2e/MJ[62] and the hydrogen carbon intensity was estimated to be 15.9 g CO_2e/MJ (1.91 kg CO_2e/kg H_2) based on the weighted average of carbon intensity for the different low carbon pathways studied in this report based on capacity in BC. It was assumed that all the hydrogen injected into the grid is burned. If the hydrogen was separated from the natural gas before consumption and run through a fuel cell to generate electricity and heat, the improved efficiency would increase the abated emissions by a factor of at least 2 depending on the energy efficiency ratio (EER) of the equipment.

4.1.5 : Recommendations

Allow all sources of clean hydrogen to qualify as "Renewable Gas"

- *Specify fraction of green hydrogen content to support transition to renewable pathway*

Develop provincial codes and standards for hydrogen blending into the natural gas grid

Change provincial codes to mandate all new gaseous pipelines are compatible with 100% hydrogen

Investigate integration of electricity grid and natural gas grid through low cost hydrogen production

Lighthouse Project: Hydrogen Community Feasibility Study

62 (S&T) Squared Consultants Inc. (2018). GHGenius 5.0d. Calculations conducted by BC Ministry of Energy, Mines and Petroleum Resources Low Carbon Fuels Branch. Retrieved from https://ghgenius.ca/index.php/downloads

4.2 : Transportation

4.2.1 : Baseline

Transportation makes up approximately 37% of total GHG emissions in BC.[63] This sector can be divided into the several broad categories shown in Table 4.

CATEGORY	DESCRIPTION
Light-Duty Vehicles	Light-duty vehicles registered in BC and licensed to operate on roads
Heavy-Duty Vehicles	Heavy-duty vehicles registered in BC and licensed to operate on roads
Off-Road Vehicles	Vehicles not licensed to operate on roads excluding oil & gas, heavy industry, agricultural, manufacturing, construction, and forest resource services.
Domestic Railway and Marine	Locomotives operating in BC and marine vessels registered and fueled in BC
Pipeline Transport	Transportation and distribution of crude oil, natural gas and other products
Domestic Aviation	Canadian registered aircrafts flying domestically within Canada and originating in BC, including commercial, private, and agricultural flights

Table 4. Definition of Transportation GHG Emissions Categories[63]

Figure 35 shows the GHG emissions of each category in BC from 1990 to 2016.

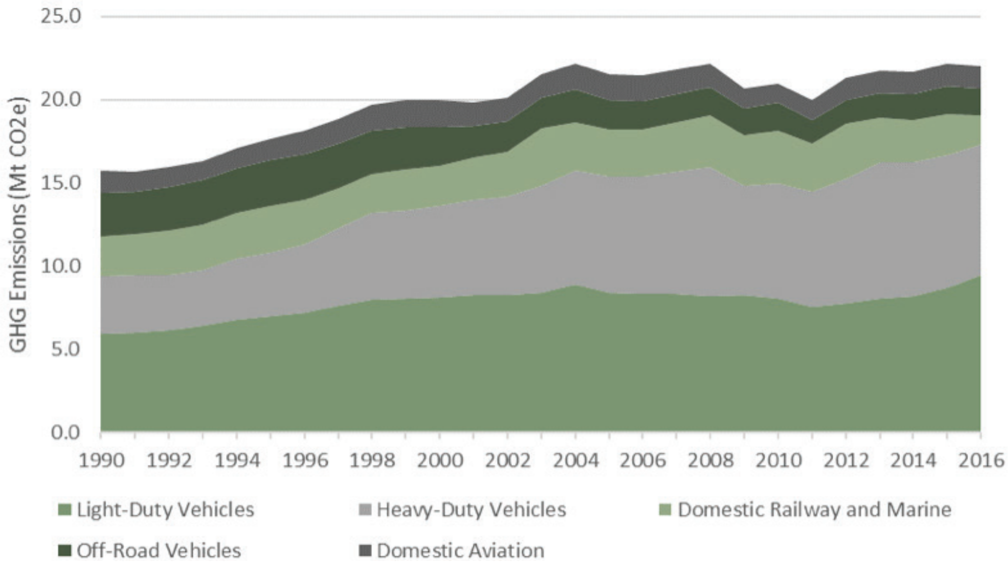


Figure 35. BC Transportation GHG Emissions by Category (1990-2016)[63]

63 *Environment and Climate Change Canada. (2018). National Inventory Report 1990-2016: Greenhouse Gas Sources and Sinks in Canada, Annex 10. Retrieved from https://open.canada.ca/data/en/dataset/779c7bcf-4982-47eb-af1b-a33618a05e5b*

Total transportation GHG emissions peaked in 2004, but following a dip to 2011, have trended upward through 2016. Figure 36 shows the percent of total transportation GHG emissions attributable to each category in 2016.

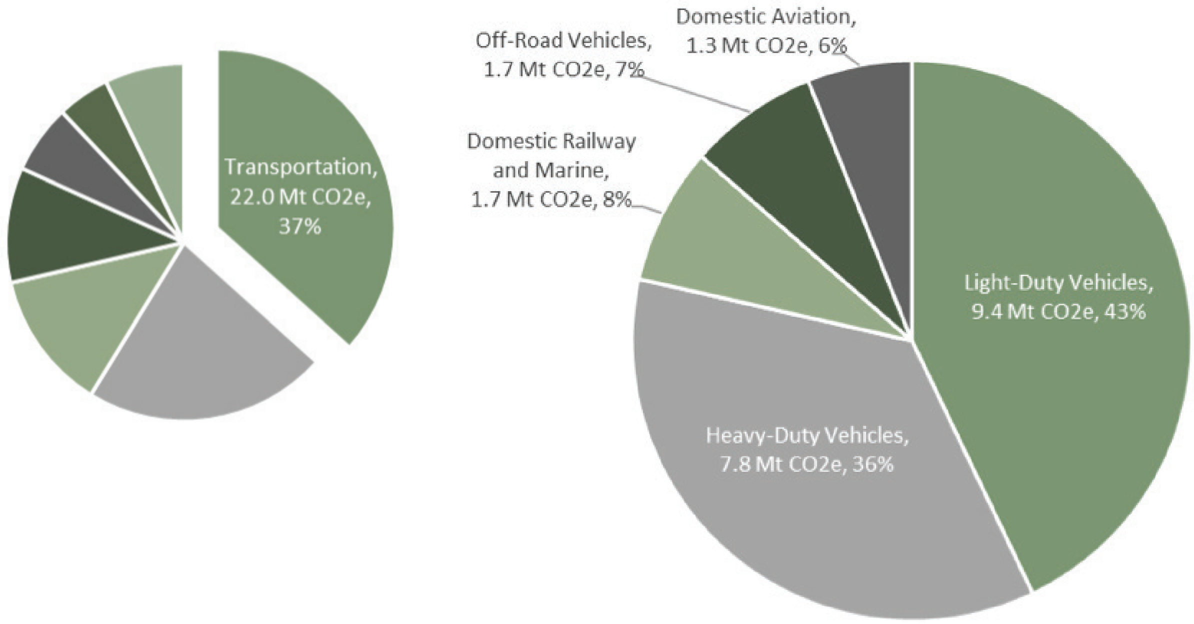


Figure 36. BC Transportation GHG Emissions by Category (2016)[63]

Combined, light and heavy-duty vehicles make up almost four-fifths of BC's total transportation GHG emissions (79%). Domestic railway, marine and aviation comprise 14% of GHG emissions and off-road vehicles make up the remaining 7%.

4.2.1.1 : Light- and Heavy-Duty Vehicle Baseline

Since light-duty vehicles (LDVs) and heavy-duty vehicles (HDVs) are the primary sources of BC's GHG emissions, they are the predominant categories of interest in this study within the Transportation sector.

VEHICLE TYPE	NEW VEHICLE REGISTRATIONS (2018)[64]	REGISTERED VEHICLES (2017)[65]	PER-VEHICLE GHG/YEAR (2016) (TONNES CO_2E)[63, 65]	EST GHG/ YEAR (2016) (MT CO_2E)[63]
Light-Duty Vehicles	219,387	3,082,813	3.2	9.4
Heavy-Duty Vehicles (excluding buses)	5,788	165,675	47.4	7.8
Buses	364	10,211		

Table 5. BC New Vehicle Registrations, Registered Vehicles, and Related GHG Emissions

Light-duty vehicles far outnumber heavy-duty vehicles, but because of the latter's greater size and annual driving distances, each heavy-duty vehicle generates almost fifteen times as many GHG emissions per year: an average of 47.4 tonnes CO_2e per HDVs compared to 3.2 tonnes per LDV.[63, 65]

Public transit accounts for approximately 30% of buses in BC.[65] Public transit fleets are operated by two large agencies: TransLink in Metro Vancouver, and BC Transit in the rest of the province. Table 6 shows the makeup of both agencies' fleets.

TRANSIT VEHICLE TYPE	TRANSLINK[66]	BC TRANSIT[67]
Electric Trolley Bus	262	0
Compressed Natural Gas (CNG) Bus	116	120
Diesel-Electric Hybrid Bus	226	6
Non-Hybrid Diesel Bus	697	683
Gasoline Community Shuttle Bus	147	0
Diesel Community Shuttle Bus	47	0
Marine Vessels	3	0
Conventional Diesel or Hybrid Bus (Unspecified)	48	0
HandyDART (Accessible Transit) Vehicle	307	347
TOTAL	**1,853**	**1,156**

Table 6. Transit Vehicle Fleet Inventory in BC

64 *Statistics Canada. Table 20-10-0002-01 New motor vehicle sales, by type of vehicle. Retrieved from https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2010000201*

65 *Statistics Canada. Table 23-10-0067-01 Road motor vehicle registrations, by type of vehicle. Retrieved from https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310006701*

66 *TransLink. (2016). Fleet and Technologies. Retrieved from https://www.translink.ca/About-Us/Corporate-Overview/Operating-Companies/CMBC/Fleet-and-Technologies.aspx*

67 *BC Transit. Our Fleet. Retrieved from https://www.bctransit.com/about/fleet*

Translink has been incorporating CNG vehicles into their fleet as a way to reduce emissions. Hydrogen can play a role in CNG vehicles by enabling a greater availability of renewable gas (RG) in the network for operators, like Translink, willing to pay a premium to further reduce emissions. Both Translink and FortisBC are working together to increase the use of RG in BC's transit system.

Although buses are a small percentage of vehicles on the road, they provide an early opportunity for hydrogen adoption as a direct transportation fuel with higher efficiencies because of the high commercial readiness of FCEBs. There are currently 30 FCEBs on roads in California and 22 more in development.[68] The 22 buses to be deployed in the near-term are all manufactured by Canada's New Flyer Industries and incorporate heavy-duty fuel cell modules designed and manufactured by BC's Ballard Power Systems.

Europe is projected to deploy 300 FCEBs by the early 2020's and Japan plans to operate 100 FCEBs for the 2020 Tokyo Olympics.[69]

Jurisdictions around the world are setting aggressive targets to reduce emissions from public transit vehicles, and in some cases are mandating a transition to zero emission fleets. For example, California's Innovative Clean Transit (ICT) ruling in December 2018 legislated that all public transit vehicles in California must be zero emission vehicles by 2040. This has driven transit agencies to consider the challenges of scale deployments of Battery Electric Buses and FCEBs. Several agencies including SunLine Transit, Orange County Transit and Alameda-Contra Costa Transit District are scaling their fleets of FCEBs. They cite FCEBs' longer range, flexibility for route deployment, faster fueling times and improved refueling logistics as advantages over Battery Electric Buses.

4.2.1.2 : Deployments to Date

EV-Volumes.com estimates that 550,000 plug-in electric heavy-duty vehicles (encompassing trucks and buses, plug-in hybrid and battery electric vehicles) had been deployed around the world through 2018. Virtually all these deployments came in China due to strong policy support. EV-Volumes.com tracked 5,800 plug-in electric heavy-duty vehicle deployments in the rest of the world, or one percent of the Chinese total.[70]

Significantly, China's industrial policy has shifted to favour fuel cell vehicles, with a focus on taxis, long- distance buses, urban logistics and long-haul trucks, the latter three being heavy-duty applications.[71] Chinese automotive conglomerate Weichai recently reaffirmed its plans to deploy a minimum of 2,000 commercial fuel cell vehicles containing stacks from BC's Ballard Power Systems.[72]

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68 *California Fuel Cell Partnership. (2019). By the Numbers: FCEV Sales, FCEB, & Hydrogen Station Data. Retrieved from https://cafcp.org/by_the_numbers*

69 *California Fuel Cell Partnership. (2018). Largest Bus Manufacturer Markets Fuel Cell Buses. Retrieved from https://cafcp.org/blog/largest-bus-manufacturer-markets-fuel-cell-buses*

70 *EV-Volumes.com, personal correspondence.*

71 *Bloomberg News. (2018). Senior China Official Urges Shift Towards Fuel-Cell Vehicles. Retrieved from https://www.bloomberg.com/news/articles/2018-12-17/senior-china-official-urges-shift-toward-fuel-cell-vehicles*

72 *Ballard Power Systems. (2019). Ballard Reaches Agreement for $44M Order With Weichai-Ballard JV to Support Initial Fuel Cell Vehicle Deployments in China. Retrieved from http://www.ballard.com/about-ballard/newsroom/news-releases/2019/05/01/ballard-reaches-agreement-for-$44m-order-with-weichai-ballard-jv-to-support-initial-fuel-cell-vehicle-deployments-in-china*

4.2.1.3 : Other Transportation Baseline

Rail

Railway operations in BC are dominated by two large freight operators: Canadian National Railway and Canadian Pacific Railway. Several other rail companies operate short line routes in BC, including BNSF Railway, which travels from the U.S. border to Vancouver, and the Southern Railway of British Columbia, which travels from Vancouver to Chilliwack.

Several passenger railway companies also operate in BC, including VIA Rail, Rocky Mountaineer, Amtrak *Cascades*. TransLink also provides a commuter rail service called the West Coast Express between Metro Vancouver and the Fraser Valley Regional District.

Transport Canada has a Memorandum of Understanding with the Railway Association of Canada to reduce GHG emissions from the rail industry. In 2017, Locomotive Emissions Regulations came into effect, which enforces mandatory emissions standards and reduced idling.

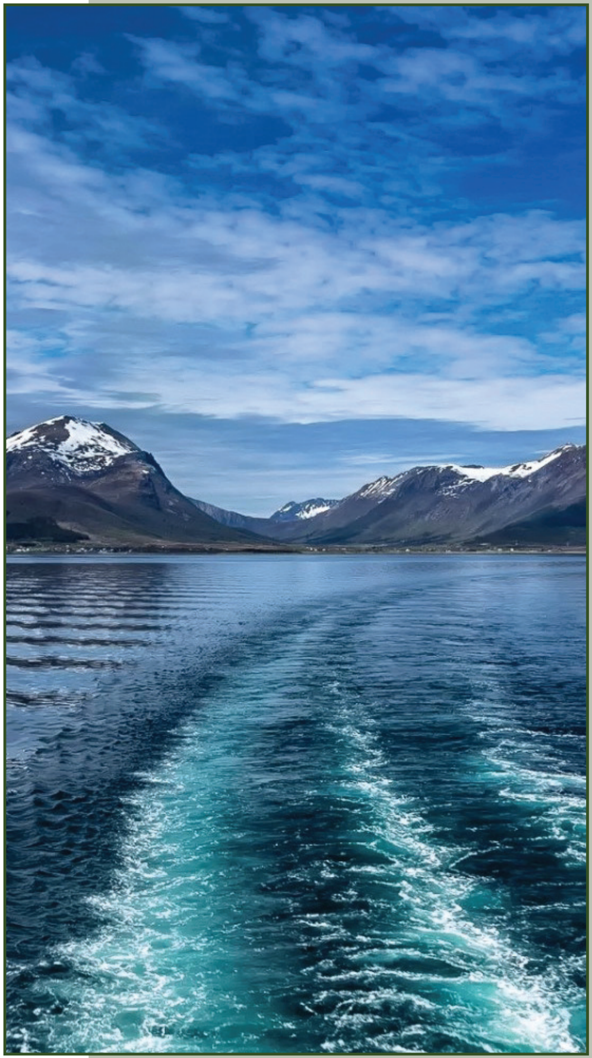
Marine

BC Ferries is one of the world's largest ferry operators, providing vehicle and passenger service on 25 routes between 47 terminals. Their fleet comprises 35 vessels powered by a mix of diesel and liquid natural gas (LNG). In fiscal 2018, the company consumed 118.2 million litres of diesel and 2.0 million diesel litres-equivalent at a cost of $102.5 million, representing its second-largest operating expense.[74]

BC Ferries is a leader in transitioning to lower carbon and more efficient fuel sources. They were the first passenger ferry system in North America to adopt LNG, and by 2020 project LNG will make up 22% of their fuel consumption.Their diesel vessels currently consume an average of 5% biodiesel, making them one of the largest biodiesel consumers in the Province. They have also been using ultra-low sulfur diesel in all diesel applications since 2007.[74]

HYDROGEN FERRIES

Norway plans to deploy the world's first hydrogen-electric ferry in 2021. Norled is leading the development of the ferry, which will carry 299 passengers and 80 vehicles. According to the development contract, at least 50% of the energy requirement must come from hydrogen.[73] Norway is aggressively focused on marine vessel emissions, as the marine fleet accounts for approximately 30% of the country's total NOx emissions.



73 *World Maritime News. (2019). Norled to Build World's 1st Hydrogen-Electric Ferry. Retrieved from https://worldmaritimenews.com/archives/268356/norled-to-build-worlds-1st-hydrogen-electric-ferry/*

74 *British Columbia Ferry Services Inc. (2018). Fuel Management Plan Outcomes in Performance Term Four. Retrieved from https://www.bcferries.com/files/AboutBCF/2018_09_28_PT4_fuel_management_outcomes_report.pdf*

Aviation

There are 5,198 aircraft registered in BC. The majority are airplanes (82%) and helicopters (16%); a small number of gliders, gyroplanes, and balloons are also registered. Nearly three quarters of aircraft are privately owned (74%) and almost the entire balance (26%) is used for commercial purposes. The exceptions are a small number of airplanes (5) and helicopters (11) owned by the Provincial government.[75]

In 2012, the Federal Government published Canada's Action Plan to Reduce GHG Emissions from Aviation, which sets target to improve fuel efficiency by 1.5%, measured in litres of fuel per 100 revenue tonne-kilometers, by 2020 compared to a 2008 baseline.[76] In 2019, BC airline Harbour Air announced plans to electrify its fleet of airplanes. While an excellent solution for the airline's typical flights, batteries are not expected to be practical for larger flights.

4.2.1.4 : Transportation Hydrogen Baseline

From 2009 to 2014, BC Transit deployed 20 fuel cell electric buses in Whistler. These comprised almost the entire Whistler bus fleet, which totaled 23 buses (26 during peak season). During this period, it was the largest single deployment of fuel cell electric buses in the world. The buses drove over 4 million kilometers and avoided more than 5,835 tonnes of CO_2e emissions.[77]

While this was an important flagship deployment for the Province timed with the 2010 Winter Olympics, the buses suffered reliability and operating cost challenges. Not being able to secure a local supply of hydrogen in BC, liquid hydrogen was trucked in from Quebec, adding to operating costs, and leading to negative public perception. As a result, BC Transit decided to retire the fleet in 2014.

In 2015, Hyundai selected BC as its first market for FCEVs in Canada, leasing up to 10 Tucson FCEVs.

At time of writing there are nine light-duty FCEVs on-the-road in BC: three Hyundai Tucsons, five Hyundai Nexo, and one Toyota Mirai. Since 2016, BC-based Hydra has run a pilot project demonstrating a heavy-duty hydrogen/diesel co-combustion engine on a semi-trailer, logging approximately 250,000 km of operation.

Hydrogen has yet to be deployed to power marine vessels, railway locomotives, off-road vehicles or aircraft in BC.

4.2.2 : Opportunities and Challenges

Hydrogen technologies can significantly reduce GHG emissions from the transportation sector.

Battery electric vehicles (BEVs) and FCEVs are complementary types of Zero Emission Vehicle; both will play roles in decarbonizing transportation in the Province.

Batteries provide greater "well-to-wheel" efficiency for transportation than fuel cells but offer lower energy storage density than compressed or liquid hydrogen tanks. That said, batteries remain very well-suited for many light-duty vehicle applications, and for heavy-duty vehicles with shorter routes.

Though battery fast charging speeds have increased with ever-more powerful DC Fast Chargers (DCFCs) hydrogen refueling remains faster, and the infrastructure has potential to be more scalable and economic at mass scale. This is because fuel cell vehicles can be expected to refuel at regular intervals. Because BEVs can be charged more slowly but more cheaply at home, at work, or at publicly available "Level 2" stations, drivers can be expected to use DCFCs sparingly – except on weekends and long weekends, when overcrowding is likely to occur. In short, regular fueling from FCEV owners provides a path to return-on-investment for owners of hydrogen stations.

75 *Transport Canada. (2018). Canadian Civil Aircraft Registrar. Retrieved from http://wwwapps.tc.gc.ca/Saf-Sec-Sur/2/CCARCS-RIACC/DDZip.aspx*

76 *Federal Government of Canada. (2018). Summary: 2017 Annual Report – Canada's Action Plan to Reduce Greenhouse Gas Emissions from Aviation. Retrieved from http://www.tc.gc.ca/eng/policy/2017-greenhouse-gas-emmissions-aviation-annual-report-summary.html*

77 *Eudy L., Post M. (2014). BC Transit Fuel Cell Bus Project Evaluation Results: Second Report. National Renewable Energy Laboratory. Retrieved from https://www.nrel.gov/docs/fy14osti/62317.pdf*

For these reasons and others, a variety of studies have concluded that hydrogen infrastructure can be less expensive, on balance, as vehicle penetration increases.[81]

Fuel-related GHG emissions per km were calculated using provincially-established carbon intensities for gasoline and electricity as a transportation fuel, as well as efficiency equivalent ratios. The carbon intensity used for gasoline was 3.2 kg CO_2e/L[82] with an efficiency of 10 L/100km. The carbon intensity for electricity used was 0.05 kg CO_2e/kWh[83] with an efficiency equivalent ratio (EER) of 3.4.[84] The carbon intensity for hydrogen was established to be 15.9 g CO_2e/MJ (1.91 kg $CO_2e/kg\ H_2$) based on the weighted average of carbon intensity for the different low carbon pathways studied in this report based on capacity in BC.

Figure 37 shows the calculated per kilometer GHG emissions from a gasoline, fuel cell electric, and battery electric vehicles.

IS ELECTRIFICATION THE ANSWER?

While the Province should do everything it can to leverage its renewable electricity infrastructure to reduce GHG emissions, electrification has limitations.

Consider the light-duty vehicle transportation sector. In 2017, there were 3 million light-duty vehicles registered in BC [78]. Assuming an average annual distance traveled of 15,000 km, fuel efficiency of 10 L/100-km, and an energy effectiveness ratio of 3.4, the resulting electricity demand would be 46 PJ per year if all of these vehicles were electric.

This would require an increase in annual electricity generation of 21% [79], equivalent to 2.5 Site C projects.[80] Electrification of the medium- and heavy-duty transportation sectors would roughly double this effect. Hydrogen powered vehicles will allow BC to leverage its abundant natural gas supplies while reducing emissions if the hydrogen is produced via SMR or Pyrolysis with carbon capture and sequestration.

78 *Statistics Canada. Table 23-10-0067-01 Road motor vehicle registrations, by type of vehicle. Retrieved from https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310006701*

79 *Canada National Energy Board (2017). Canada's Energy Future 2018: Energy Supply and Demand Projections to 2040. Retrieved from https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA*

80 *BC Hydro. (2019). Site C Clean Energy Project: Site C At a Glance. Retrieved from http://sitecproject.com/sites/default/files/fact-sheet-sitec-project-201905_0.pdf*

81 *Robinius M, et al., (2018). Comparative Analysis of Infrastructures: Hydrogen Fueling and Electric Charging of Vehicles. Forschungszentrum Jülich GmbH Zentralbibliothek. 1866-1793. Retrieved from https://www.researchgate.net/publication/322698780_Comparative_Analysis_of_Infrastructures_Hydrogen_Fueling_and_Electric_Charging_of_Vehicles*

82 *(S&T) Squared Consultants Inc. (2018). GHGenius 5.0d. Calculations conducted by BC Ministry of Energy, Mines and Petroleum Resources Low Carbon Fuels Branch. Retrieved from https://ghgenius.ca/index.php/downloads*

83 *Ibid.*

84 *British Columbia Provincial Government. (2017). Regulation 394/2008 O.C. 907.2008. Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act. Retrieved from http://www.bclaws.ca/civix/document/id/lc/statreg/394_2008*

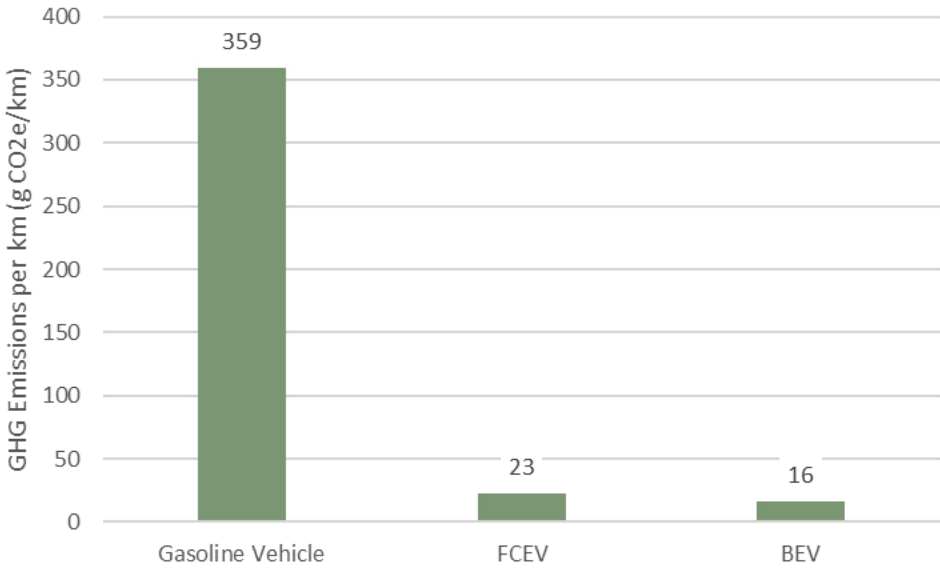


Figure 37. Calculated Light-duty Passenger Vehicle GHG Emissions per Kilometer

Figure 38 shows the European Fuel Cells and Hydrogen Joint Undertaking's enumeration of major segments in the transportation sector, and evaluation of the relative strengths of battery electric and fuel cell electric technology in each.

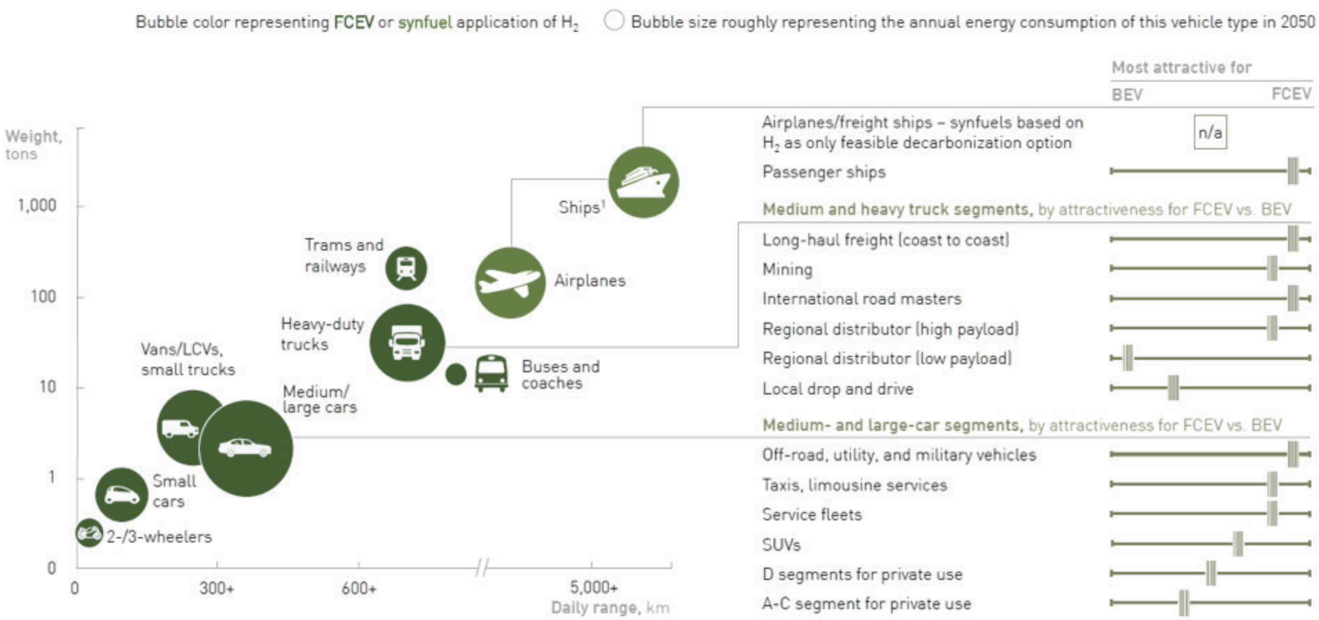


Figure 38. Comparison of Range, Payload, and Technology Preference[85]

85 Fuel Cells and Hydrogen Joint Undertaking. (2019). Hydrogen Roadmap Europe. Retrieved from https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf

4.2.2.1 : Light-Duty Vehicles

The future light-duty vehicle market will comprise a mix of BEVs and FCEVs. Compared to BEVs, FCEVs offer greater range and faster refueling, which allows for a driver experience closer to a conventional internal combustion engine (ICE) vehicle. However, BEVs are expected to dominate the light-duty vehicle market, having already achieved widespread commercialization and benefiting from electricity's relative ubiquity. FCEV commercialization is lagging by approximately one decade, and hydrogen fueling infrastructure remains limited.

Fuel cell vehicles are likely to be more attractive for drivers in multi-unit residential buildings (condominiums, apartments, townhouses with shared garages, etc.) where cost and strata law barriers can make retrofits of home charging stations expensive and difficult: a comprehensive literature review from UC Davis found that the availability of a home charging station was the most important piece of infrastructure in convincing consumers to purchase a BEV, followed by workplace charging, and lastly public charging stations.[86]

This is particularly pertinent for the Province, where 33% percent of households live in multi-unit residential buildings.[87] Households who cannot recharge their vehicles from their parking stalls may opt for fuel cell electric vehicles – providing they feel well-served by hydrogen fueling infrastructure.

Three-shift (24/7) fleet vehicles such as taxis will find fast refueling times attractive, again providing hydrogen fueling infrastructure is adequate. The cost premium for hydrogen over electricity will have to be modest enough that fleet operators value increased uptime higher than the potential cost savings from battery electric vehicle options.

Although FCEVs are currently available on the market, they are still produced at a relatively small scale. The greatest impediment to deployment of light-duty fuel cell vehicles in the Province in the near-term is supply. The Province could incentivize auto manufacturers (generally referred to as original equipment manufacturers, or OEMs) to bring their vehicles to BC by recognizing the benefits of long range and fast fueling in the credit system adopted by the ZEV mandate.

Since FCEVs are currently produced in small volumes, they remain more expensive than comparable ICE or BEVs. Until production scale reduces costs, the Province is advised to incentivize the purchase of light-duty fuel cell vehicles. The $6,000 Provincial incentive available as of the initial issue of this study in June 2019[88] (comprising the $5,000 CEV for BC purchase rebate and $1,000 in fuel) can be applied to fuel cell vehicles, however the base model price cap of $45,000 on the $5,000 federal incentive excludes FCEVs at this time. The Province could also set up a support mechanism to incentivize the purchase of used fuel cell and battery electric vehicles. This would increase the overall demand for ZEVs and reduce the number of older, higher-polluting fossil fuel vehicles on the road. The availability of used ZEV purchase incentives could also make it easier for lower income households to purchase zero emission vehicles.

Other jurisdictions have had success driving adoption of ZEVs using non-financial incentives. In addition to incentives on the initial purchase price, Norway, offers discounted or free ferry travel, toll road access, and municipal parking to ZEV drivers as well as access to bus lanes. California has increased demand for ZEVs by allowing them access to HOV lanes with only a single occupant. China has expedited the vehicle registration process for ZEVs, reducing the wait time from as long as two years to as short as a single day. BC already allows ZEV drivers to register their vehicles for High-Occupancy Vehicle (HOV) lane access. It is recommended that the Province consider additional cost-effective measures to drive their adoption. Local governments can also play a role, through incentivizing in areas they control such as preferred parking.

86 *Hardman S, et al. (2018). A Review of Consumer Preferences of and Interactions with Electric Vehicle Charging Infrastructure. Transportation Research Part D 62: 508-523. Retrieved from https://phev.ucdavis.edu/wp-content/uploads/a-review-of-consumer-preferences-and-interactions-with-electric-vehicle-charging-infrastructure.pdf*

87 *Natural Resources Canada. Comprehensive Energy Use Database: Residential Sector – British Columbia. Retrieved from http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_res_bc.cfm*

88 *On June 22, 2019 the Province's CEV incentive was reduced to $3,000 for battery, fuel-cell, and longer-range plug-in hybrid electric vehicles and to $1,500 for shorter-range plug-in hybrid electric vehicles.*

4.2.2.2 : Hydrogen Infrastructure

Lack of hydrogen fueling infrastructure in BC is a key barrier to the near-term adoption of FCEVs. California has had success stimulating fuel cell vehicle adoption by carefully and consistently expanding their network of stations and have determined that infrastructure expansion precedes vehicle adoption. In that state the process is overseen by the California Fuel Cell Partnership, who aggregate data from OEMs to determine how many vehicles will be on the road and plan the optimal location for new fueling stations. A similar body could help encourage growth in BC; significant infrastructure investment will be required to ensure FCEVs can be deployed as successfully in the Province as in California. Section 4.2.4 provides more detail related to infrastructure.

4.2.2.3 : Medium- and Heavy-Duty Vehicles

In most instances, medium- and heavy-duty trucks are better suited to hydrogen technology than batteries. There will be opportunities for battery powered trucks for applications with a limited daily range, like parcel distribution, but the heavy loads and long distances required of most applications are better suited to hydrogen fuel cells. A fuel cell truck would end up roughly the same weight as a conventional diesel truck, whereas a battery for a 40-ton truck would add about 3 tonnes of payload.[89] Fuel cell vehicles also require less raw materials, are cobalt free, and research targets are to use less platinum than a comparable diesel vehicle.[90]

Medium- and heavy-duty vehicle hydrogen fuel cell trucks have been demonstrated around the world but have not yet been widely deployed. It is recommended that the Province encourage near-term zero emission medium- and heavy-duty vehicle adoption in applications that have central fueling locations as an early means of deploying hydrogen in these segments.

DIESEL/HYDROGEN CO-COMBUSTION

Diesel/hydrogen co-combustion is a near-term path by which hydrogen could reduce emissions from medium and heavy-duty vehicles. BC-based Hydra Energy retrofits heavy-duty trucks with a co-combustion system that reduces diesel fuel consumption by 30%, and aims to scale up to 120 trucks by 2022.

Hydra plans to build out 350 bar hydrogen fuelling infrastructure that will be compatible with FCEVs in the long-term.

BC could seek to leverage work in other jurisdictions. China has experienced a rapid increase in the deployment of medium-duty hydrogen fuel cell trucks. Homologation efforts could speed technical readiness for deployment in the Province.

89 *Fuel Cells and Hydrogen Joint Undertaking. (2019). Hydrogen Roadmap Europe. Retrieved from https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf*

90 *Ibid.*

4.2.2.4 : Public Transit

Public transit agencies around the world are shifting towards low and zero emission vehicles. Low emission technology includes CNG and RNG as a transit fuel. Zero emission transit options include BEBs and FCEBs. As is the case with light-duty vehicles, battery electric buses are most cost effective on relatively short routes. Fuel cell electric buses are advantageous on long routes with higher power requirements. Provincial support for a fuel cell electric coach bus program would provide an opportunity for BC's hydrogen and fuel cell cluster to lead that market segment in the near- to mid-term.

Hydrogen powered buses are more easily scaled than battery electric buses. Fuel cell buses can be refueled at comparable speeds and in a similar way as conventional diesel buses, whereas battery electric buses require much longer charging times. Battery electric buses are either charged over several hours, typically overnight in a depot, or through opportunity charging en-route. Opportunity charging typically requires a bus to be recharged over a shorter period several times a day. It allows for less onboard battery power, and therefore less weight, but increases the operational complexity and constraints. Feedback from transit authorities has been that while longer bus charging times are not an issue at demonstration scale, challenges of cost and complexity increase significantly at fleetwide scale.

California has adopted the ICT rule, which requires 25% of new bus purchases by large transit agencies to be zero emission by 2023, 50% by 2026, and 100% by 2029. By 2040 it requires all buses in operation to be zero emission. It is recommended that BC develop a similar policy. A support mechanism such as the province's Specialty-Use Vehicle Incentive Program[91] or a voucher system could mitigate the higher purchase prices for zero emissions buses. As in the ICT, policies should require transit agencies to develop plans for reaching 100% zero emission vehicle fleets. This will ensure fleet infrastructure needs, whether for electricity or hydrogen, are considered in a holistic, fleetwide manner, and ensure the most cost-effective technology mix is deployed.

91 BC's Special Use Vehicle Incentives are described at: https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/clean-transportation-policies-programs/clean-energy-vehicle-program/suvi

RENEWABLE NATURAL GAS FOR TRANSPORTATION

In April 2019, TransLink and FortisBC announced a partnership whereby FortisBC will supply Renewable Natural Gas (RNG) for TransLink's natural gas powered buses, which make up roughly a fifth of TransLink's bus fleet. The parties have signed an RNG-supply contract for up to 500,000 GJs annually within five years. This is expected to provide enough to fuel the existing natural gas bus fleet with 100 per cent RNG. Over the five-year period, the transition to RNG will reduce TransLink's greenhouse gas (GHG) emissions by 50,000 tonnes.

How does hydrogen fit?

By updating the B.C. Greenhouse Gas Reduction Regulation definition of RNG to include hydrogen, the Province can accelerate the decarbonization of the transportation sector for near-term opportunities such as Translink. While TransLink will purchase 100% RG, any hydrogen blended into the natural gas would be separated before filling the vehicles. There can be technical challenges in using a H_2/CNG blend in the vehicles related to tank embrittlement and NOx emissions. Separation of hydrogen at the point of use could lead to fueling stations with dual fuel sources – CNG and hydrogen. Pure hydrogen can be used in fuel cell vehicles or other applications that required pure hydrogen, and the buses will run on CNG. This is in essence a credit trading mechanism that will lead to real benefits in overall decarbonization of the transportation network.

4.2.2.5 : Long Haul Trucking

The past few years have seen heightened interest in fuel cells for class 8 long haul trucks, known colloquially as freight trucks, semi-trucks or tractor-trailers. Nikola Motor, Toyota and Hyundai are all developing fuel cell powertrains for this market segment. Cummins Inc. recently announced that it has entered into a definitive agreement to acquire Hydrogenics Corporation, which is a major move into the fuel cell space for this major diesel and natural gas engine OEM. A number of demonstration projects have been piloted, including the Alberta Zero-Emissions Truck Electrification Collaboration (AZETEC) project, which will trial class 8 fuel cell trucks on the corridor between Edmonton and Calgary.[93]

It is recommended that BC develop similar projects for this market, and it is noted that the CleanBC plan references a pilot project to switch 1,700 freight trucks to cleaner or zero-emission fuel. The larger quantities of hydrogen fuel consumed by these heavy-duty vehicles would have the additional benefit of increasing hydrogen demand within the Province; the increased hydrogen consumption should also help bring down retail hydrogen prices.

AZETEC PROJECT

The Alberta Zero-Emissions Truck Electrification Collaboration (AZETEC) project will include the design, manufacture, and deployment of two heavy-duty extended range hydrogen fuel cell electric trucks that will move freight between Edmonton and Calgary year round. The $15 million project is led by the Alberta Motor Transport Association and will receive more than $7.3 million from Emissions Reduction Alberta. Over the three-year lifespan of the project, the trucks will have travelled more than 500,000 km and carried about 20 million tonne-km of freight.[92]

92 *Lowey, M. JWN. (2019). $15-million Project to test Hydrogen Fuel in Alberta's Freight Transportation Sector. Retrieved from https://www.jwnenergy.com/article/2019/3/15-million-project-test-hydrogen-fuel-albertas-freight-transportation-sector/*

93 *Ibid 92*

4.2.2.6 : Rail and Marine

Given the range and power required, hydrogen fuel cells may have the potential to displace fossil fuels as a major energy source in rail and marine applications. Pilot projects are currently underway in Europe and Asia, but the technology and the infrastructure required to enable it is still at an early stage. In this report, only BC Ferries were considered as a possible use for hydrogen technology. It was assumed that other marine or rail projects will be undertaken in the Province before 2050. However, given the activity in other jurisdictions, the Province should support development through feasibility studies and pilot projects if suitable opportunities become available. The aforementioned South Fraser Community Rail proposal to revive commuter rail in the Fraser Valley through hydrogen rail could be a suitable lighthouse project.

HYDROGEN RAIL (HYDRAIL)

In 2018, the world's first commercial hydrogen powered trains entered service in Germany. There are currently two trains in operation and plans in place to deliver another 14 trains by 2021. The trains are capable of travelling 1,000 km without refueling, which is comparable to a diesel alternative.[94] The trains are being built by French train manufacturer Alstom and the fuel cells are being provided by Ontario-based Hydrogenics.[95]

While no hydrogen powered rail deployments currently exist in BC, an organization called South Fraser Community Rail is actively campaigning for a hydrogen powered commuter train project to connect Surrey to Chilliwack along the Fraser Valley corridor.[96]

94 *Agence France-Presse. (2018). Germany Launches World's First Hydrogen-Powered Train. Retrieved from https://www.theguardian.com/environment/2018/sep/17/germany-launches-worlds-first-hydrogen-powered-train*

95 *Hydrogenics. (2015). Hydrogenics and Alstom Transport Sign Agreement to Develop and Commercialize Hydrogen-Powered Commuter Trains in Europe. Retrieved from https://www.hydrogenics.com/2015/05/27/hydrogenics-and-alstom-transport-sign-agreement-to-develop-and-commercialize-hydrogen-powered-commuter-trains-in-europe/*

96 *Hernandez, J. CBC News. (2019). Transit Advocates Call for Hydrogen Trains on Century-Old Fraser Valley Rail Corridor. Retrieved from https://www.cbc.ca/news/canada/british-columbia/transit-advocates-call-for-hydrogen-trains-on-century-old-fraser-valley-rail-corridor-1.5065117*

4.2.3 : Adoption Scenarios

Projecting hydrogen technology adoption in the transportation sector is dependent on a wide range of economic, social, and technical factors, and inherently contains a high degree of uncertainty. As such, the approach used in this study sought to provide a realistic range of adoption that is bound by conservative and aggressive scenarios of technology development and policy implementation. Within the transportation sector, adoption was estimated for light-duty passenger vehicles, medium- and heavy-duty trucks, public transit and private coach buses, and ferries. Although hydrogen could also be used in rail and aviation applications, this analysis assumed hydrogen does not play a role in either category by 2050.

Hydrogen demand was modelled for each segment of the transportation sector based on the projected number of vehicles in operation, assumed kilometers driven per year, fuel economy of the gasoline/diesel baseline and hydrogen alternative. Figure 39, Figure 40, and Figure 41 show the modelled hydrogen demand in the conservative and aggressive scenarios for transportation from 2020 to 2050.

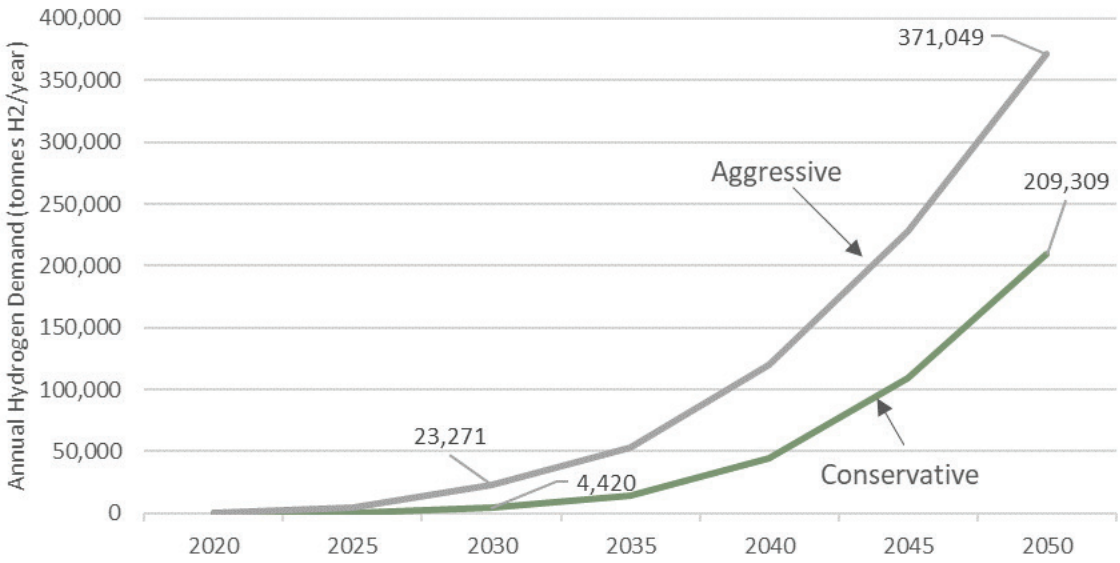


Figure 39. Transportation Conservative and Aggressive Hydrogen Demand (2020-2050)

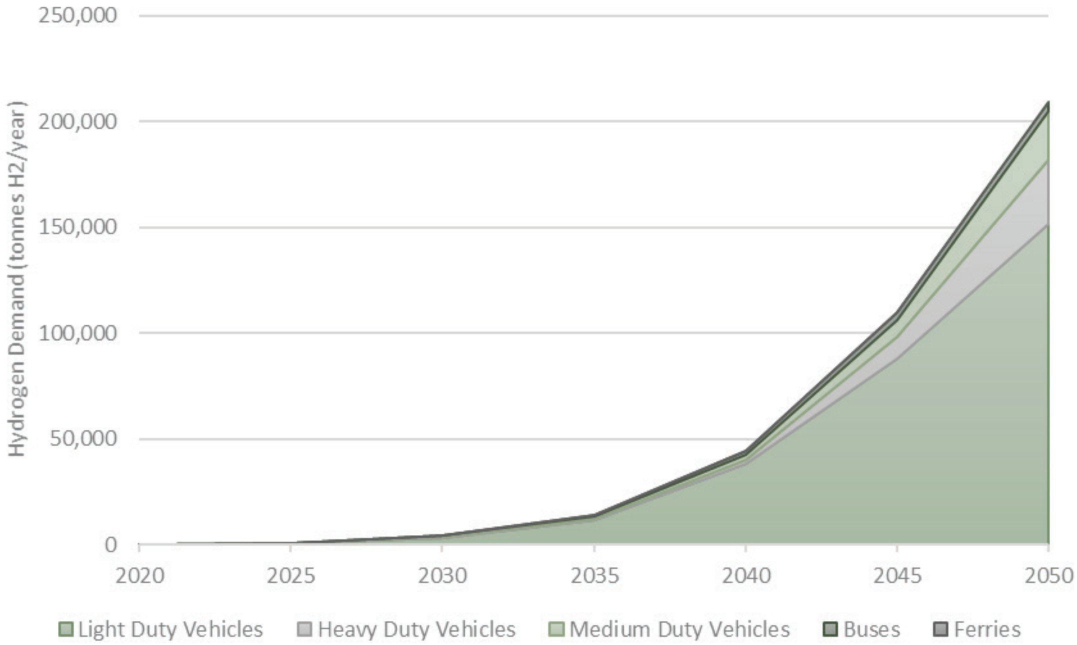


Figure 40. Transportation Conservative Hydrogen Demand by Vehicle Type (2020-2050)

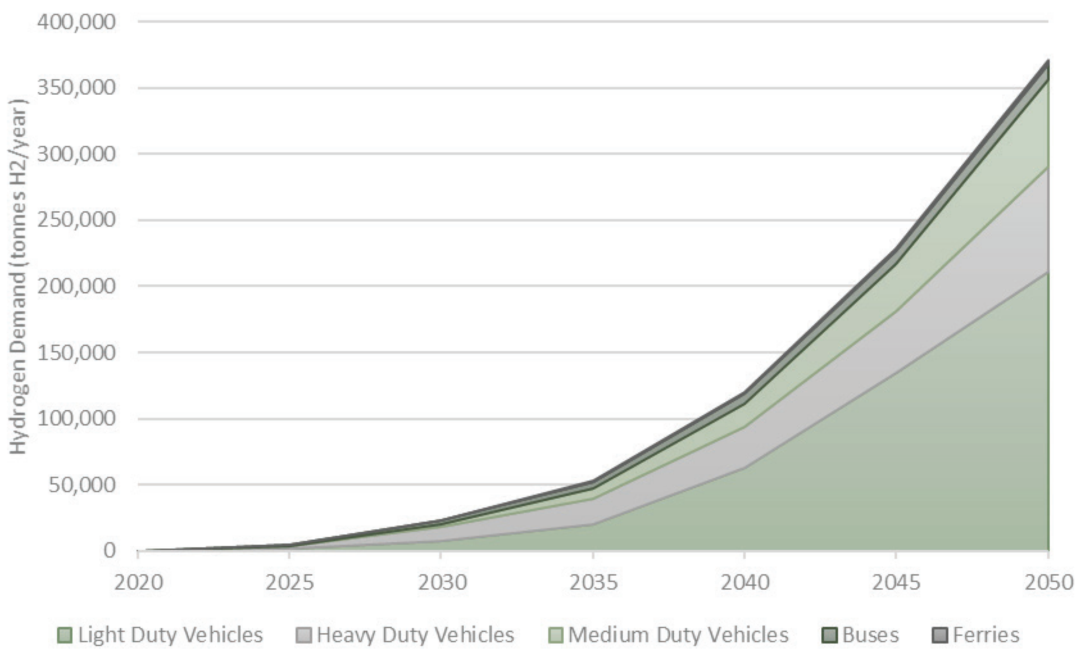


Figure 41. Transportation Aggressive Hydrogen Demand by Vehicle Type (2020-2050)

Figure 42 shows the modelled share of hydrogen demand for each vehicle type in 2030 and 2050 in the conservative and aggressive scenarios.

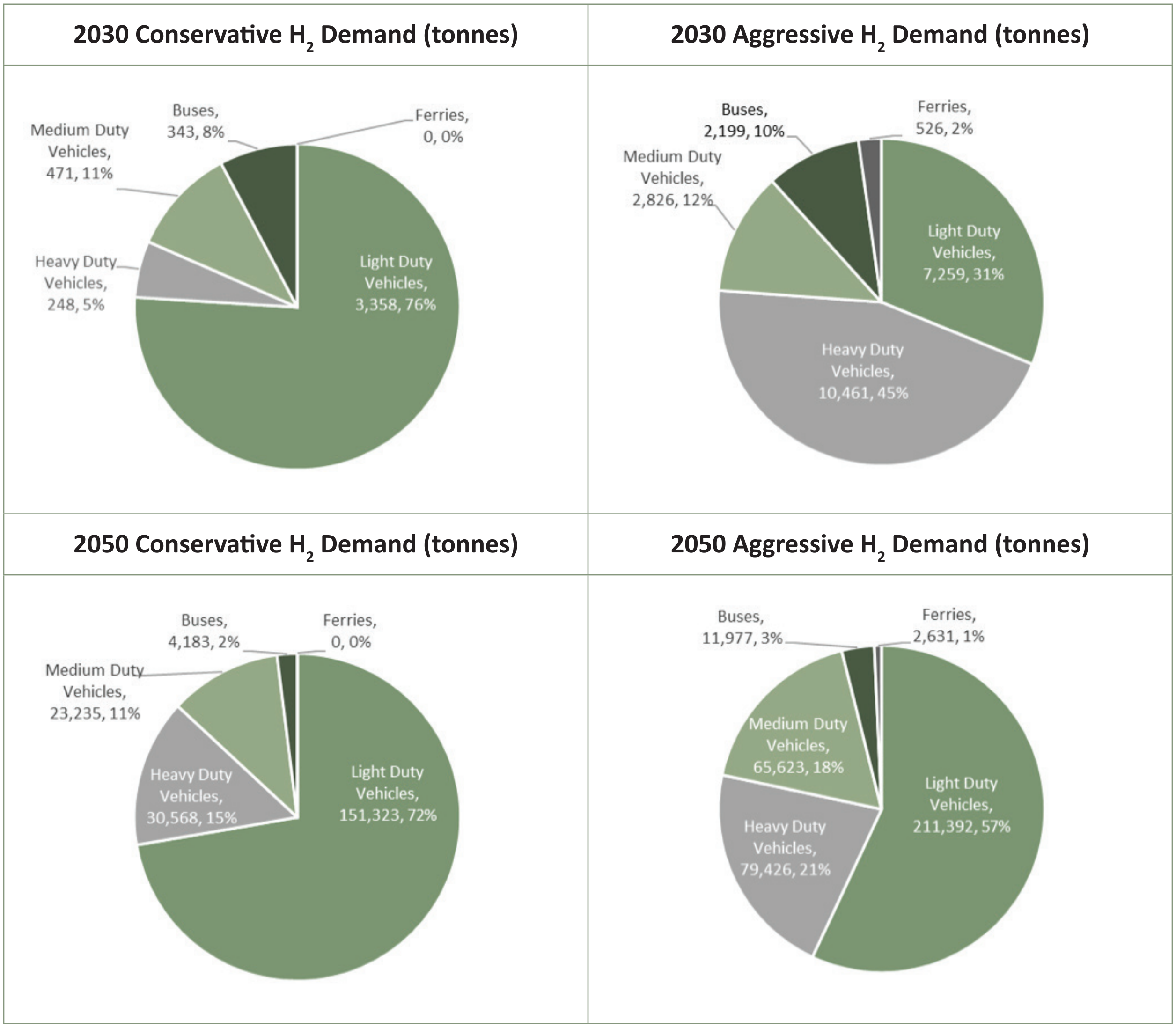


Figure 42. Conservative and Aggressive Transportation Hydrogen Demand in tonnes by Vehicle Type (2030 & 2050)

4.2.3.1 : Light-duty Vehicles

The upcoming ZEV mandate will drive the adoption of fuel cell light-duty vehicles in BC. The analysis considered both how the ZEV standard will impact the sales of vehicles across the industry and how it could impact OEMs individually based on their current offerings assuming a credit scheme similar to Quebec's ZEV standard is put in place.

From 2020 to 2030, FCEV sales are highly dependent on how the ZEV mandate is legislated. The aggressive scenario assumes that credits will be allocated per vehicle using the formulas currently in place in Quebec[97] and that each OEM will have to meet the sales targets outlined in the Zero-emission Vehicles Act (10% by 2025, 30% by 2030, 100% by 2040).[98] Under this scenario, FCEV adoption will be driven largely by each OEM's need to meet their credit requirement. The analysis considered annual new vehicle sales across the province,[99, 100] the approximate market share of OEMs offering FCEVs,[101] how many credits each FCEV would receive, and how many FCEVs would need to be sold to satisfy the ZEV mandate taking into account sales of BEVs and PHEVs. Toyota is expected to drive sales more than other OEMs because, unlike other major car brands that offer a BEV, they currently only offer the Mirai (FCEV, 3.6 credits) and the Prius plug-in hybrid (0.6 credits). The conservative scenario assumes the OEMs will not be required to meet targets through their own direct sales, but the ZEV legislation will drive adoption across the entire industry. This could occur if it is easy for OEMs to purchase credits from others that achieve greater ZEV sales than the target. In this conservative scenario, it is assumed that the Province falls short of its ZEV targets, reaching 8% of sales in 2025 and 20% in 2030. It was assumed that FCEV sales make up 8% of ZEV sales by 2030, which is 20% less than a model developed for ZEV deployment in Europe.[102, 103]

From 2030 to 2050, the estimates are not based on how a credit system could impact specific OEMs, since many of the OEMs will likely be offering different vehicle models by that time. The aggressive scenario assumes that the Province meets its ZEV targets of 100% sales by 2040, and that FCEVs make up 19% of ZEV sales in 2040 and 26% in 2050, which matches the model developed for Europe.[102] The conservative scenario assumes the Province falls short of its ZEV targets, reaching 80% of sales in 2040 and 100% in 2050, and that FCEV sales as a percent of ZEV sales are 80% lower than the penetration in the aggressive scenario (15% in 2040 and 21% in 2050).

In all scenarios it was assumed that total new vehicle registrations increase linearly based on the past five years of data at 7,711 new vehicles per year[104] and that vehicles remain on the road for an average of 13 years. There is considerable uncertainty in projecting vehicle sales growth through 2050 based on historical sales trends, given potentially disruptive changes to car ownership such as car-sharing, ride-hailing and autonomous vehicle technology. These could each result in a decrease in the number of registered vehicles on provincial roads in the future, though total vehicle km travelled might remain largely unaffected.

97 *Government du Quebec. (2019). The ZEV Standard in a Nutshell: Explanatory Leaflet. Retrieved from http://www.environnement.gouv.qc.ca/changementsclimatiques/vze/feuillet-vze-reglement-en.pdf*

98 *BC Ministry of Energy, Mines, and Petroleum Resources. (2019). Legislation to Guide Move to Electric Vehicles, Reduce Pollution. Retrieved from https://news.gov.bc.ca/releases/2019EMPR0011-000608*

99 *The number of new passenger vehicle registrations in BC were projected linearly based on new registrations over the past five years.*

100 *Statistics Canada. Table 20-10-0002-01 New motor vehicle sales, by type of vehicle. Retrieved from https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2010000201*

101 *Scotiabank. (2019). Global Auto Report. Retrieved from https://www.scotiabank.com/content/dam/scotiabank/sub-brands/scotiabank-economics/english/documents/global-auto-report/GAR_2019-01-30.pdf*

102 *Cambridge Econometrics. (2018). Fueling Europe's Future: How the Transition from Oil Strengthens the Economy. Retrieved from https://europeanclimate.org/wp-content/uploads/2018/02/FEF_transition.pdf*

103 *The analysis in this report is based on historical data through 2018. In 2019, ZEV sales have accelerated in BC, largely driven by the newly available federal incentive and record high gas prices. The analysis was not revised to account for this increase in sales. At this time, FCEV sales are limited by supply and it is unclear if the uptick in sales will translate to FCEVs as they are not currently eligible for the federal incentive because of the cap on vehicle retail price.*

104 *Statistics Canada. Table 23-10-0067-01 Road motor vehicle registrations, by type of vehicle. Retrieved from https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310006701*

The adoption scenarios were compared to past and projected adoption in California, the world leader in light-duty fuel cell passenger vehicle adoption. Since the passenger vehicle market in California is significantly greater than BC, the data was scaled to be proportional to the BC passenger vehicle market. Additionally, the California reference data was shifted by four years because the number of light-duty fuel cell vehicles on the road in California has been growing since 2015. Thus, the California reference value for 2019 is the number of light-duty fuel cell vehicles on the road in California in 2015 scaled by the passenger vehicle market, the value in 2020 is related to California in 2016, etc. From 2019 to 2022, the California reference values are based on the number of fuel cell vehicles on the road from 2015 to 2018.[105] From 2022 to 2028, the California reference values are based on California Air Resource Board projections of vehicles on the road in California from 2019 to 2024.[106] From 2028 to 2034, the California reference values are based on achieving the aspirational goal of 1,000,000 fuel cell vehicles on the road in California by 2030. The California reference case was not extended beyond 2034 (i.e., beyond the 1,000,000 vehicles in 2030 target).

Figure 43 shows the range of annual light-duty fuel cell vehicle new sales per year and Figure 44 shows total projected fuel cell vehicles on the road as well as hydrogen demand from 2019 to 2050. Hydrogen demand was estimated as 0.5 kg/vehicle/day, which is corresponds to a driving range of approximately 15,000 km/year.

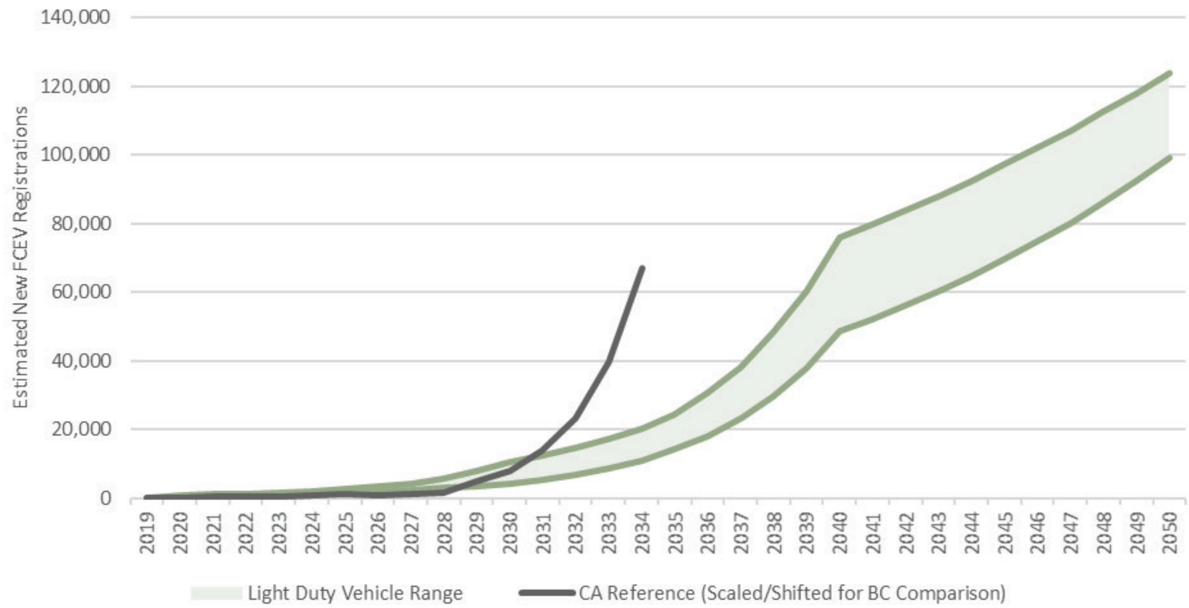


Figure 43. Light-duty Fuel Cell Passenger Vehicles Sales per Year (2019-2050)

105 *California Fuel Cell Partnership (2018). By the Numbers: FCEV Sales, FCEB, & Hydrogen Station Data. Retrieved from https://cafcp.org/by_the_numbers*

106 *California Air Resources Board. (2018). 2018 Annual Evaluation of Fuel Cell Electric Vehicle Deployment & Hydrogen Fuel Station Network Development. Retrieved from https://www.arb.ca.gov/msprog/zevprog/ab8/ab8_report_2018_print.pdf*

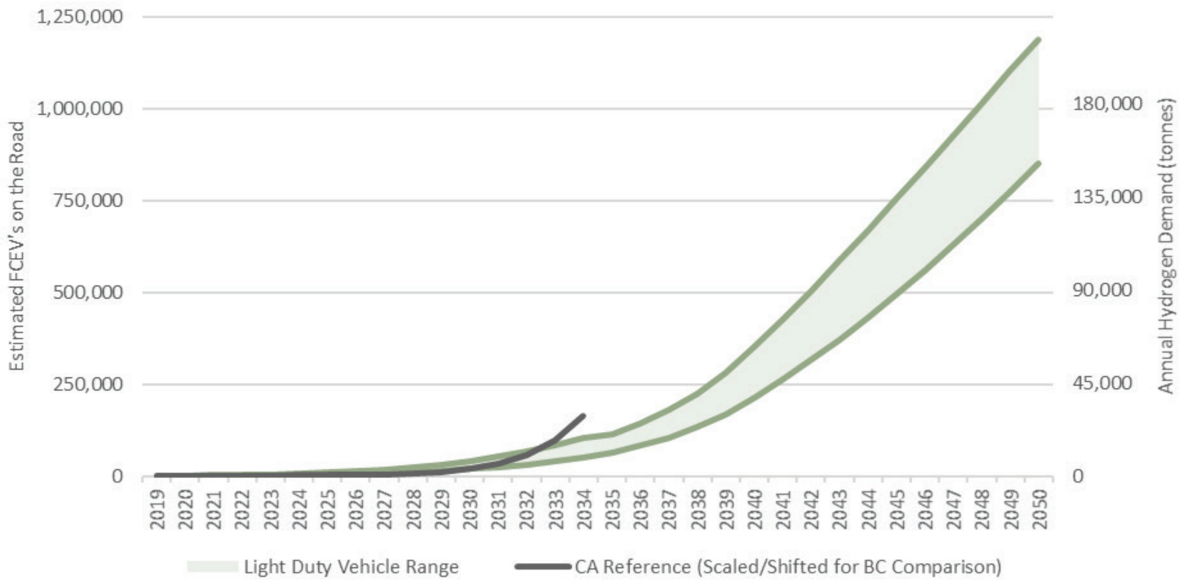


Figure 44. Light-duty Fuel Cell Passenger Vehicles on the Road per Year (2019-2050)

The number of fuel cell vehicles sold is expected to increase exponentially from 2019 to 2040. After 2040, the ZEV mandate will require all new vehicles sold to be ZEVs, so the growth continues linearly assuming the total number of vehicles sold continues to grow.

The sales targets of the BC ZEV mandate are more aggressive than the mandate currently in place in California, which is only defined through 2025. As a result, the projected fuel cell vehicles in BC exceed the California reference case in the near-term. However, for California to meet its 2030 target of 1,000,000 vehicles, sales will need to ramp up rapidly, which causes the California reference case to exceed the projected range for BC adoption.

Table 7 shows the estimated number of new vehicle registrations, FCEV new registrations, and FCEVs on the road per year from 2019 to 2050.

YEAR	VEHICLE REGISTRATIONS	FCEV NEW REGISTRATIONS		FCEV % OF NEW VEHICLE REGISTRATIONS		FCEV'S ON ROAD	
		Low	High	Low	High	Low	High
2019	237,251	30	50	0.0%	0.0%	33	53
2020	244,962	60	816	0.0%	0.3%	93	869
2021	252,672	118	1,084	0.0%	0.4%	211	1,953
2022	260,383	234	1,364	0.1%	0.5%	445	3,317
2023	268,093	464	1,656	0.2%	0.6%	909	4,973
2024	275,804	918	1,961	0.3%	0.7%	1,827	6,934
2025	283,514	1,581	2,835	0.6%	1.0%	3,641	9,210
2026	291,225	2,141	3,470	0.7%	1.2%	5,782	12,328
2027	298,935	2,524	4,254	0.8%	1.4%	8,306	16,582
2028	306,646	2,975	5,789	1.0%	1.9%	11,281	22,371
2029	314,356	3,503	7,856	1.1%	2.5%	14,784	30,227
2030	322,067	4,122	10,638	1.3%	3.3%	18,906	40,865
2031	329,777	5,287	12,506	1.6%	3.8%	24,190	53,368
2032	337,488	6,777	14,689	2.0%	4.4%	30,937	68,006
2033	345,198	8,681	17,238	2.5%	5.0%	39,558	84,428
2034	352,909	11,116	20,214	3.1%	5.7%	50,556	103,558
2035	360,619	14,227	24,352	3.9%	6.8%	64,549	113,112
2036	368,330	18,200	30,590	4.9%	8.3%	82,285	142,961
2037	376,040	23,273	38,408	6.2%	10.2%	104,640	179,919
2038	383,751	29,747	48,205	7.8%	12.6%	132,573	225,289
2039	391,461	38,006	60,477	9.7%	15.4%	168,438	282,296
2040	399,172	48,539	75,843	12.2%	19.0%	214,453	353,896
2041	406,882	52,205	79,771	12.8%	19.6%	263,683	428,482
2042	414,593	56,128	83,872	13.5%	20.2%	316,308	506,021
2043	422,303	60,325	88,154	14.3%	20.9%	372,511	586,445
2044	430,014	64,814	92,624	15.1%	21.5%	432,038	669,335
2045	437,724	69,614	97,289	15.9%	22.2%	494,875	754,373
2046	445,435	74,747	102,157	16.8%	22.9%	560,941	841,119
2047	453,145	80,235	107,237	17.7%	23.7%	630,060	928,979
2048	460,856	86,100	112,537	18.7%	24.4%	701,933	1,017,164
2049	468,566	92,368	118,065	19.7%	25.2%	776,101	1,104,639
2050	476,277	99,066	123,832	20.8%	26.0%	851,894	1,190,063

Table 7. LDV FCEV Registrations and Vehicles on the Road (2019-2050)

4.2.3.2 : Medium- and Heavy-Duty Trucks

Due to the required range and power, medium-duty vehicles (MDVs) and HDVs present one of the best opportunities for hydrogen technology. Outside of China, which is rapidly deploying MDV fuel cell vehicles, few hydrogen-powered MDVs and HDVs are currently in operation. Given the Province's technical expertise and commitment to reducing emissions, BC is well positioned to become a world leader in the deployment of hydrogen-powered MDV and HDV trucks. Crucially, leadership in this market segment would allow the Province's hydrogen and fuel cell cluster to gain insights from early local deployments. BC companies would then enjoy a competitive advantage over competitors from other jurisdictions, when slower-moving jurisdictions prepare their own deployments of zero emission medium- and heavy-duty trucks.

The aggressive scenario for medium- and heavy-duty hydrogen powered trucks assumes the Province supports multiple lighthouse projects to demonstrate the effectiveness of the technology by 2030 and wide scale adoption by 2050. In the near- to mid-term, it was assumed that diesel-hydrogen co-combustion proves effective for heavy-duty vehicle retrofits, leading to up to 1,700 retrofit heavy-duty hydrogen diesel co-combustion vehicles on the road. Under this scenario, we expect the deployments of hydrogen co-combustion vehicles will peak in 2040, after which fuel cell vehicles will dominate. The conservative scenario assumes small demonstration projects with medium- and heavy-duty fuel cell vehicles through 2030 leading to moderate adoption through 2050 and no diesel co-combustion vehicles.

HYUNDAI AND H_2E: 1600 TRUCK PROJECT – SWITZERLAND

Hyundai and H_2 Energy (H_2E) have established the Hyundai Hydrogen Mobility joint venture (JV) in Europe, focused on heavy-duty commercial hydrogen fuel cell vehicles. The goal of the JV is to deliver 1600 fuel cell heavy-duty trucks and supporting fueling stations in Switzerland between 2019 -2025.[107]

Hyundai Motor will deliver the trucks, and H_2E will be responsible for marketing the fleet as well as developing the infrastructure. A stringent road tax on diesel trucks imposed by Switzerland is incentivizing fleet operators to switch to zero emission vehicles. The road tax on commercial vehicles is meant to prevent diesel trucks from crossing through Switzerland as they traverse Europe, and depending on weight and distance the annual road tax can cost up to $50,000 per vehicle.[108]

After scaling up to meet the demand in Europe, Hyundai then plans to launch its fuel cell commercial vehicle businesses in other regions around the world, including the U.S. and domestic market in Korea.

107 Electrive.com. (2019). Hyundai & H_2E: 1,6000 Fuel Cell Trucks for Europe. Retrieved from https://www.electrive.com/2019/04/15/hyundai-h2e-1600-fuel-cell-trucks-for-european-market/

108 ZunMallen R. (2018). 1,000 Hyundai Fuel Cell Electric Trucks Headed for Switzerland. Trucks.com. Retrieved from https://www.trucks.com/2018/09/21/hyundai-fuel-cell-electric-trucks-switzerland/

Table 8 shows the estimated adoption schedule for MDV and HDV trucks from 2020 to 2050.

YEAR	NUMBER OF HYDROGEN POWERED VEHICLES ON THE ROAD					
	HDV FUEL CELL		HDV CO-COMBUSTION		MDV FUEL CELL	
	Conservative	Aggressive	Conservative	Aggressive	Conservative	Aggressive
2020	0	0	0	0	0	0
2025	10	125	0	125	25	100
2030	30	625	0	1,125	75	450
2035	70	1,375	0	1,625	175	1,275
2040	260	2,750	0	1,700	350	2,825
2045	1,240	5,250	0	700	1,300	5,775
2050	3,700	9,500	0	200	3,700	10,450

Table 8. Medium- and heavy-duty Vehicle Adoption Projections (2020-2050)

Figure 45 and Figure 46 show the projected hydrogen demand from medium- and heavy-duty hydrogen trucks in the conservative and aggressive scenarios from 2020 to 2050.

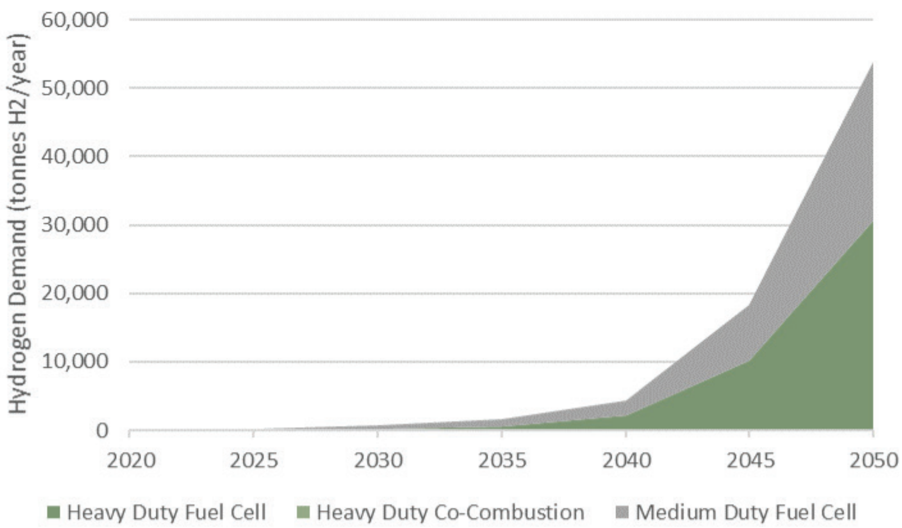


Figure 45. Conservative Projected Medium- and heavy-duty Truck Hydrogen Demand (2020-2050)

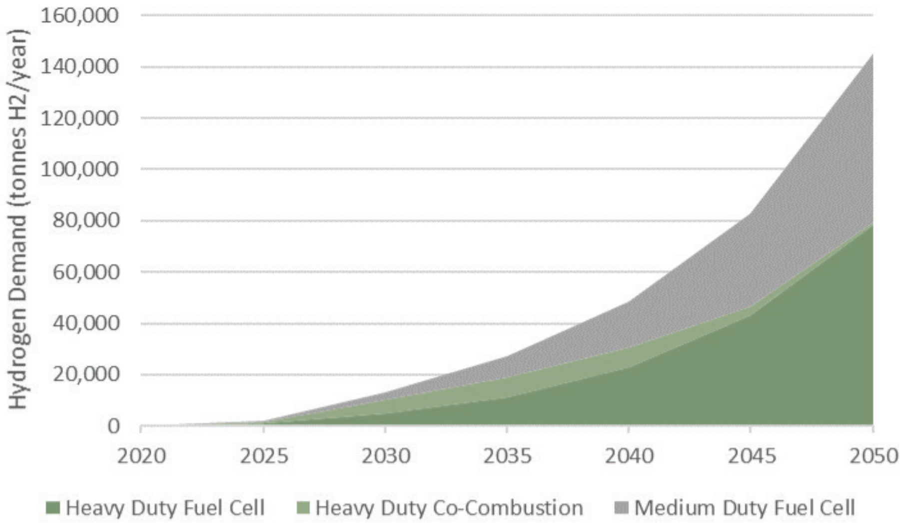


Figure 46. Aggressive Projected Medium- and heavy-duty Truck Hydrogen Demand (2020-2050)

4.2.3.3 : Buses

Transit agencies around the world are looking at reducing emissions through deployment of hydrogen fuel cell and battery electric buses. Though more expensive than conventional diesel buses, hydrogen fuel cell public transit buses are currently available on the market from several suppliers. The modelled scenarios are based on feedback from TransLink and BC Transit. The aggressive scenario assumes the Province institutes a zero-emission bus mandate similar to the Innovative Clean Transit regulation in California, leading to 25% of the Province's public transit fleet comprising fuel cell electric buses by 2035. The conservative scenario assumes slow adoption of fuel cell public transit buses, peaking at 12% of the fleet in 2050.

Hydrogen powered inter-city buses (also called "coaches" or "coach buses") are at an earlier stage of development than public transit buses, primarily due to technical challenges with current vehicle configurations that constrict hydrogen storage on the rooftops due to centre of gravity restrictions. This fuel storage technical challenge can be overcome with emerging technologies, and as with medium- and heavy-duty trucks, coach buses are well suited to hydrogen fuel cell technology because of the long ranges and short refueling times required for existing duty cycles.

It is assumed that there will be zero and low emissions regulations applied to these buses in the post-2025 period building on the regulation of transit buses. The aggressive scenario assumes a successful technology development program in BC leading to adoption of 15% of new sales by 2035 and 75% of new sales in 2050. The conservative scenario assumes moderate adoption of fuel cell coach buses beginning in 2030 and peaking at 25% of new sales in 2050.

Table 9 shows the estimated adoption schedule for public transit and coach buses from 2020 to 2050.

YEAR	NUMBER OF HYDROGEN POWERED VEHICLES ON THE ROAD			
	PUBLIC TRANSIT BUSES		COACH BUSES	
	Conservative	Aggressive	Conservative	Aggressive
2020	0	0	0	0
2025	0	20	0	65
2030	20	209	64	257
2035	62	522	192	577
2040	125	522	384	1,153
2045	188	522	576	1,923
2050	250	522	768	2,565

Table 9. Public Transit and Coach Bus Adoption Projections (2020-2050)

Figure 47 and Figure 48 show the projected hydrogen demand from public transit and coach buses in the conservative and aggressive scenarios from 2020 to 2050.

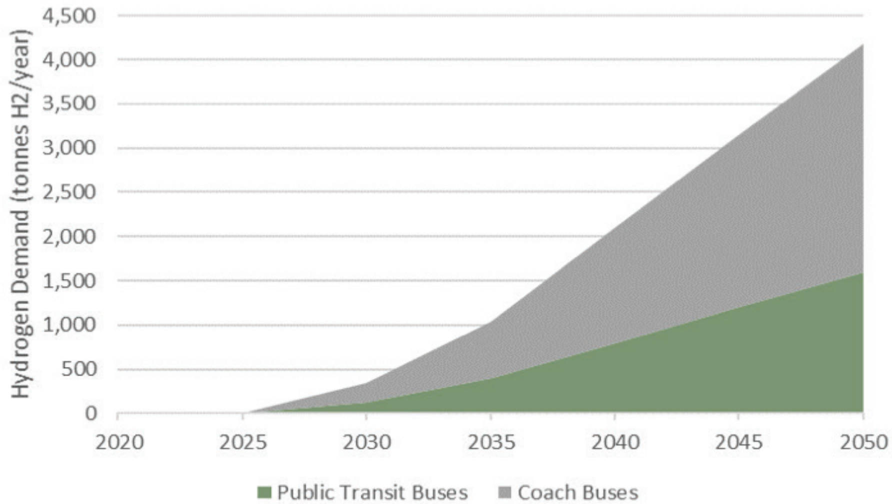


Figure 47. Conservative Projected Public Transit and Coach Bus Hydrogen Demand (2020-2050)

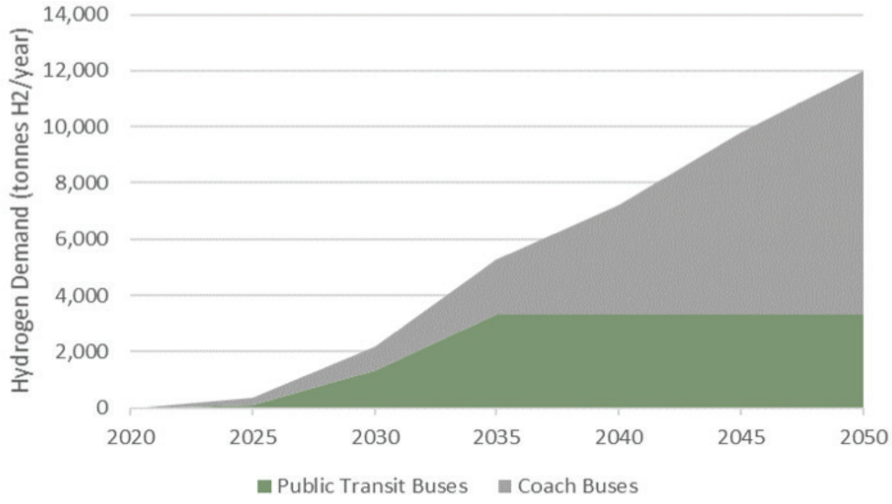


Figure 48. Aggressive Projected Public Transit and Coach Bus Hydrogen Demand (2020-2050)

4.2.3.4 : Ferries

BC Ferries is committed to reducing emissions and, though is at an early stage relative to road transportation applications, hydrogen fuel cell technology shows promise in marine applications. The aggressive scenario assumes a successful pilot project of a single ferry in 2030 leading to 3 vessels in the fleet by 2040 and 5 by 2050. The conservative scenario assumes no hydrogen powered ferries by 2050.

Table 10 shows the estimated adoption schedule for ferries from 2020 to 2050.

YEAR	NUMBER OF HYDROGEN POWERED VESSELS IN FLEET	
	Conservative	Aggressive
2020	0	0
2025	0	0
2030	0	1
2035	0	1
2040	0	3
2045	0	3
2050	0	5

Table 10. Ferry Adoption Projections (2020-2050)

Figure 49 shows the projected hydrogen demand from ferries from 2020 to 2050 in the aggressive scenario (the conservative scenario is not shown because there are no hydrogen powered vessels in the fleet).

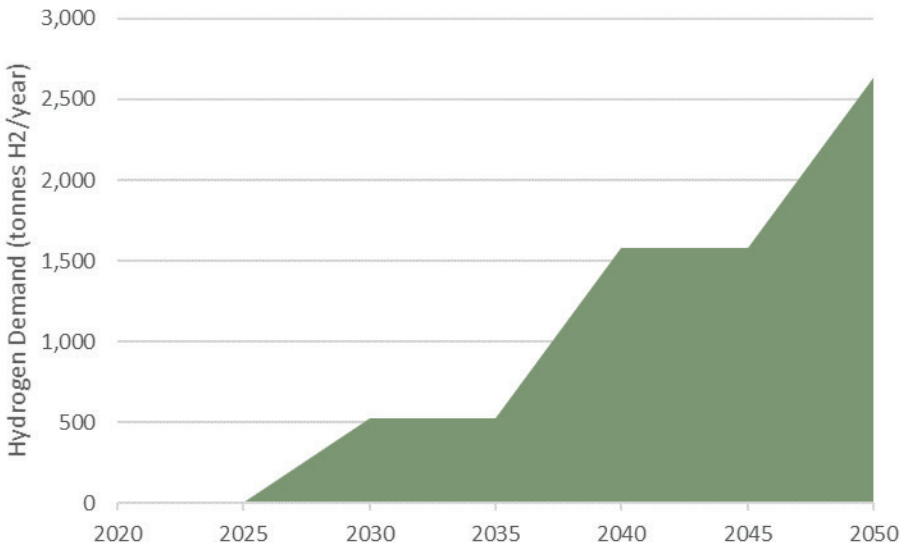


Figure 49. Aggressive Projected Ferry Hydrogen Demand (2020-2050)

Although there is potential for marine applications of hydrogen technology in BC other than ferries, the technology is still at a relatively early stage of development. For the purposes of this report, it was assumed that there will not be significant adoption of hydrogen for non-ferry marine applications before 2050

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4.2.3.5 : GHG Emissions

The GHG emissions reduction for each vehicle type based on the average annual distance travelled, fuel economy, and diesel and gasoline emissions factors were modeled.[109] The assumed carbon intensities was 3.59 kg CO_2e/L for diesel in medium- and heavy-duty vehicles, 3.20 kg CO_2e/L for gasoline light-duty vehicles, 3.49 kgCO_2e/L for diesel in marine vessels.[110] Hydrogen as a transportation fuel was estimated to have an emissions factor of 15.9 g CO_2e/MJ (equivalent to 1.91 kg CO_2e/kg H_2) based on the weighted average carbon intensity of the pathways studied in this report based on their capacity in BC.

Fuel cell vehicles were assumed to have an energy effectiveness ratio (EER) of 1.9 compared to diesel engines and 2.5 compared to gasoline engines.[111]

Figure 50, Figure 51, and Figure 52 show the estimated GHG abated in the conservative and aggressive scenarios for transportation from 2020 to 2050.

109 *(S&T) Squared Consultants Inc. (2018). GHGenius 5.0d. Calculations conducted by BC Ministry of Energy, Mines and Petroleum Resources Low Carbon Fuels Branch. Retrieved from https://ghgenius.ca/index.php/downloads*

110 *Ibid.*

111 *British Columbia Provincial Government. (2017). Regulation 394/2008 O.C. 907.2008. Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act. Retrieved from http://www.bclaws.ca/civix/document/id/lc/statreg/394_2008*

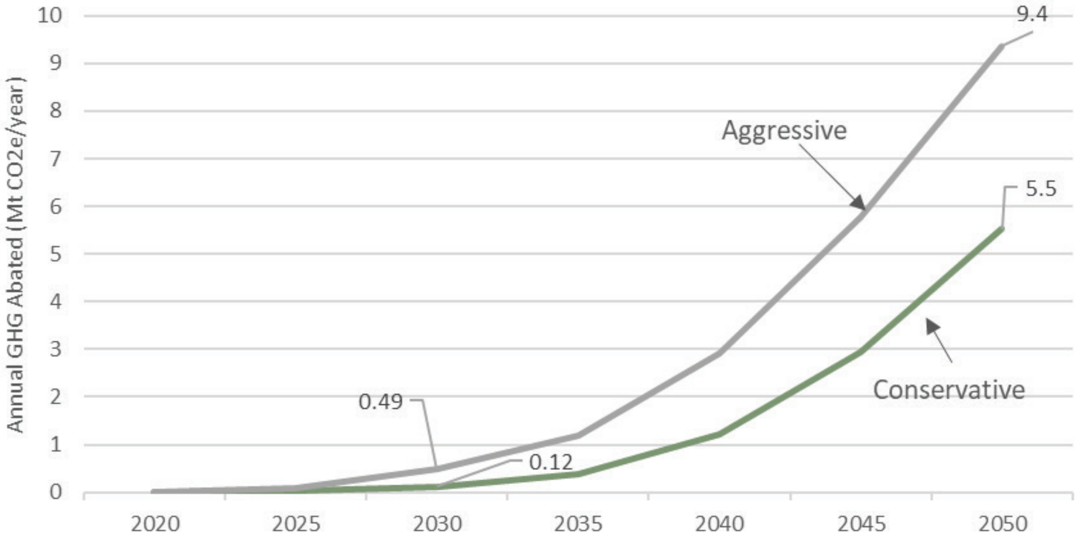


Figure 50. Transportation Conservative and Aggressive GHG Abated (2020-2050)

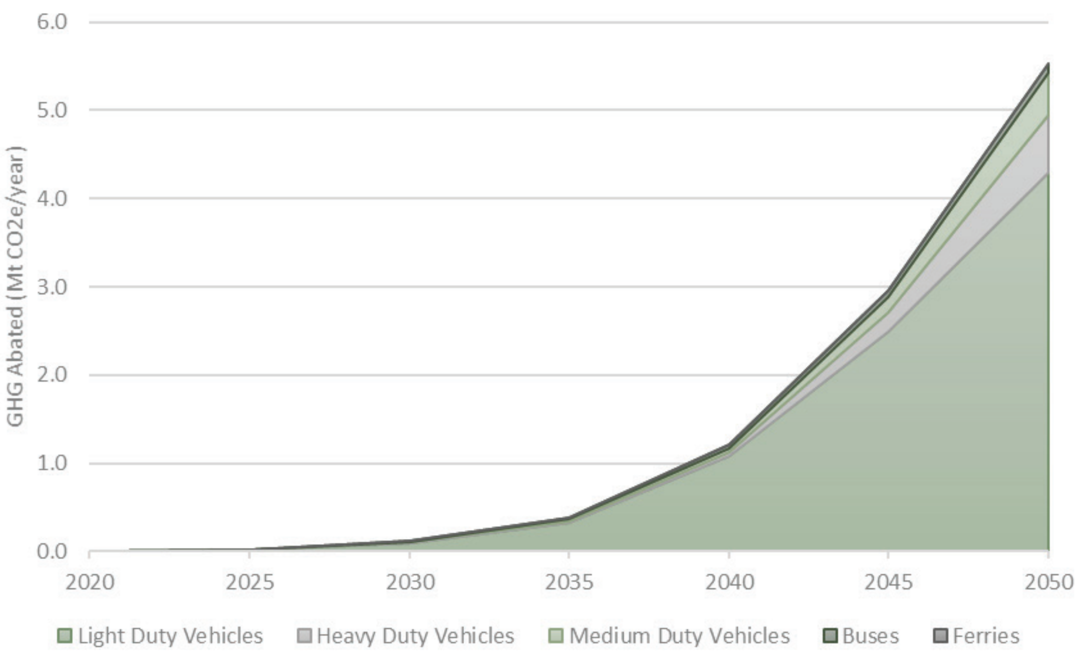


Figure 51. Transportation Conservative GHG Abated by Vehicle Type (2020-2050)

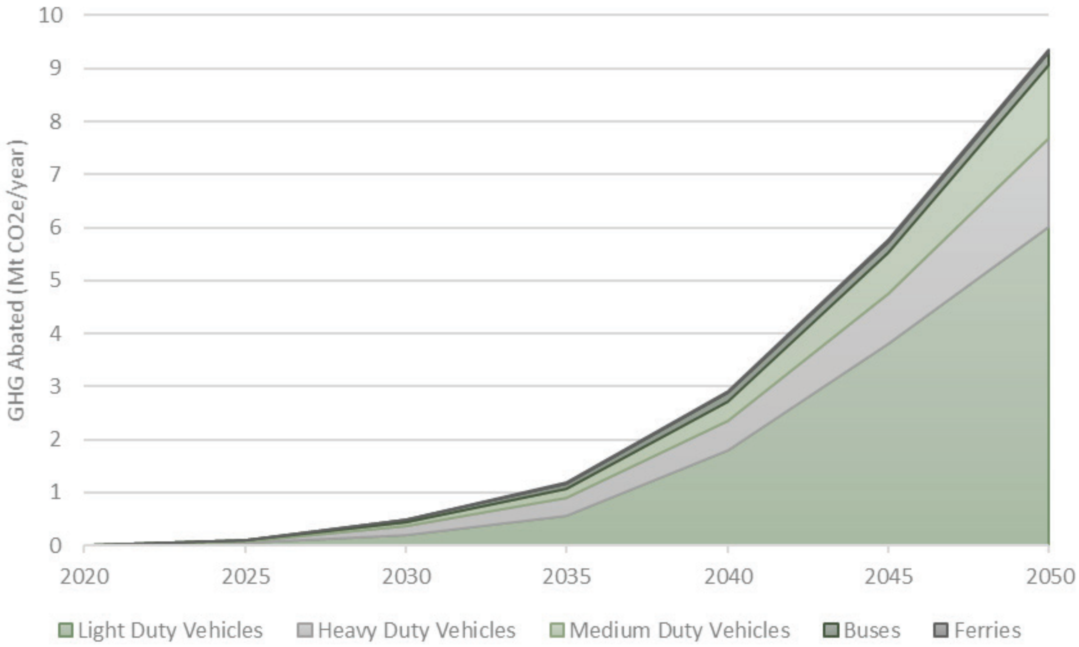


Figure 52. Transportation Aggressive GHG Abated by Vehicle Type (2020-2050)

Figure 53 shows the estimated share of GHG abated for each vehicle type in 2030 and 2050 in the conservative and aggressive scenarios.

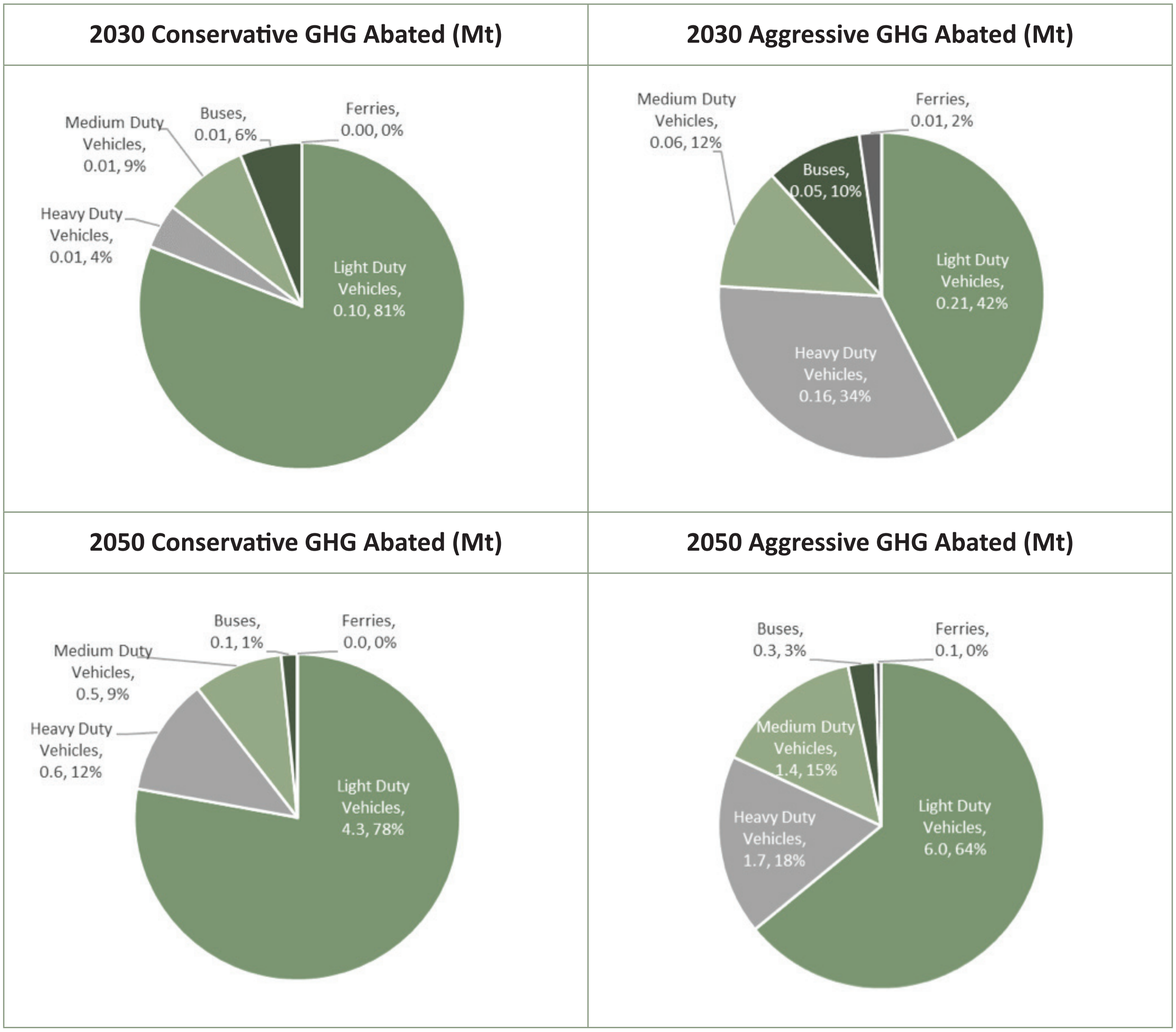


Figure 53. Conservative and Aggressive Transportation GHG Abated in Mt CO_2e by Vehicle Type (2030 & 2050)

In all cases, the deployment of light-duty FCEVs will have the greatest emissions reduction impact, driven primarily by the far larger vehicle populations under consideration. It is therefore recommended that in the near-term a strong credit system favouring FCEVs (to incentivize OEMs to preferentially supply FCEVs to the province) be implemented, and that the continued roll-out of light-duty vehicle hydrogen fuel infrastructure be strongly supported.

4.2.4 : Infrastructure to Support Adoption

4.2.4.1 : 2019 Current Status

BC has been a leader in developing and deploying hydrogen fuel cell technologies. In 2002, Powertech Labs installed the world's first 700 bar hydrogen refueling station in Surrey and in 2018, Hydrogen Technology & Energy Corporation (HTEC) opened Canada's first retail hydrogen fueling station at a Shell site in Vancouver. This is the first of 5 stations that HTEC intends to deploy over the next 18 months to support anticipated fuel cell electric vehicle operations in the Province. An additional station is being developed by the University of British Columbia, scheduled to open in the second half of 2020.

Figure 54. Hydrogen Infrastructure Map of Active and Planned Stations

Turning to heavy-duty vehicle infrastructure, since the Whistler Transit fueling station was decommissioned in 2014, the only operational fueling equipment for heavy-duty transportation equipment in the Province is a 250-bar Praxair dispenser used by Ballard Power Systems for testing buses and trucks out of their Burnaby facility.

4.2.4.2 : 2020 -2025 Lighthouse Project Adoption, Light-Duty Vehicle Growth

To support the vehicle adoption numbers outlined in section 4.2.3 under both the conservative and aggressive scenarios, the Province will need substantial infrastructure investment.

For light-duty vehicles, it is estimated that the currently planned and funded network will support approximately 1,000 vehicles based on 6 stations supporting an average of 150-200 vehicles per dispenser by mid-2020.

Based on the vehicle adoption modeling, the Province will need to begin adding retail fueling station capacity between 2021 and 2024, growing to 19 - 47 dispensers by 2025. During this period, stations with higher throughput capacity (larger storage tanks and compression sub-systems, and multiple dispensers) will be necessary. It is anticipated that geographic coverage will extend outside of Metro Vancouver and the Capital Region District to include clusters in other parts of the Province such as Kelowna and Whistler.

It must be noted that the current development cycle for deploying fueling station equipment in BC and elsewhere is approximately 18 -24 months from issuing the RFP, to the first vehicle fueling event. Solicitations would therefore need to be released in Q4 2019 to support the infrastructure requirements for the aggressive adoption scenario.

For medium- and heavy-duty vehicles, multiple lighthouse projects are recommended during this period, requiring both 350 and 700-bar infrastructure:

- *1x Port of Vancouver heavy-duty fueling station capable of supporting up to 50 vehicles including drayage and terminal tractors.*
- *2x heavy-duty fueling station (with multiple dispensers) capable of supporting up to 75 class 8 long-haul trucks within the Metro Vancouver Regional District (MVRD).*
- *1x heavy-duty fueling station (with multiple dispensers) capable of supporting up to 125 co-combustion, class 8 long-haul trucks in the Prince George region, to leverage the availability of by-product hydrogen from the Chemtrade plant.*
- *2x medium-duty fueling stations capable of supporting up to 100 class 6 delivery trucks within the GVRD.*
- *2x heavy-duty fueling stations to support 65 fuel cell electric coaches, one to be located in Metro Vancouver and the other to be located in a community outside of Metro Vancouver.*

BEV CHARGING FACILITIES

BEV charging facilities take far less time to plan and install than FCEV hydrogen fueling stations. The situation has an unexpected parallel in the renewable energy sector. There, utility-scale solar arrays can be planned and installed over a matter of months.

In contrast, wind farms of any scale frequently require two or more years, including a minimum of one year of data collection, owing to the unique complexities of each wind farm site.

Figure 55 below outlines an example of the network in BC that would be required to support the roll-out of fuel cell electric vehicles (conservative to aggressive range) and lighthouse projects (aggressive) for medium- and heavy-duty applications in the 2020-2025 timeframe.

Figure 55. Potential Hydrogen Infrastructure Map (2025)

4.2.4.3 : 2025 -2030 Light-Duty Vehicle Adoption, Medium- and Heavy-Duty Growth in Niche Applications

This five-year period will be characterized by an acceleration in the adoption rate of light-duty vehicles and an evolution in the market for medium- and heavy-duty vehicles from lighthouse projects to early market growth in specialized applications where fuel cell technology offers a positive value proposition relative to competing technologies.

For light-duty vehicles, it is assumed that dispenser capacity per station will dramatically increase to 2-3 dispensers per station to satisfy fuel demand. Based on the light-duty vehicle projections, 96 to 206 dispensers will be required by 2030, expanding into rural communities beyond the targeted clusters that will be the focus of the previous phase, and strategically intersecting major highways to facilitate travel.

It is anticipated that a number of these fueling stations will be containerized or "connector" stations that will be replaced and re-deployed as the demand for full-scale retail fueling stations is realized in different regions. Also, as car sharing businesses begin to incorporate fuel cell electric vehicles into their fleets, mobile fueling systems will be deployed to fuel vehicles in-situ as is currently happening with gasoline refueling. Based on BC Hydro capacity projections, this phase of deployment is where electrical generation and transmission will be significantly constrained in supporting battery electrical vehicle infrastructure, driving a higher percentage (6.4% - 8.0%) of new fuel cell vehicles relative to all new zero-emission vehicles deployed. As presented in 4.2.2.1, this range of dispensers is heavily influenced by the relative strength of the BC ZEV mandate, and the OEM's ability to deploy vehicles.

Medium- and heavy-duty vehicles, during this period, will transition from the testing and demonstration phase into early commercial adoption. Deployment will be focused on applications where the duty cycle for the vehicles offer a comparative advantage compared to other zero-emission technologies. Examples include Class 8 trucks with heavy payloads, inter-city buses for both transit and commercial operations, and goods movement equipment requiring short fueling times. Based on the medium- and heavy-duty projections, assuming 50 fleet vehicles per dispenser, it is expected that up to 48 medium- and heavy-duty dispensers will be required by 2030, each capable of supplying a minimum of 25 kg per fill.

QUEBEC CONTAINERIZED STATION

In 2019, the first 700 bar retail hydrogen station opened in Quebec. The station is fully enclosed in a 28-foot containerized package. It is capable of fueling four vehicles consecutively and is sized to fill 20 vehicles per day. The station was constructed by Powertech, a subsidiary of BC Hydro, and installed by North Vancouver based HTEC. Powertech has designed and constructed 16 other turnkey compressed hydrogen fueling stations across North America.

4.2.4.4 : 2030 -2050 Light-Duty, Medium- and Heavy-Duty Commercial Operation

It is easier to predict the energy demand for hydrogen during this time period than to predict the corresponding fueling model for energy delivery, as car sharing, ride hailing, and autonomous operation of private and commercial vehicles proliferate. In addition to these changes to vehicle operation, it is anticipated that fueling technology will change as well, moving to more energy dense fuel storage mediums such as liquid or cryo-compressed hydrogen.

Based on the light-duty vehicle projections, it is estimated that between 3,330 to 4,260 dispensing points will be required by 2050, distributed across every community across the Province. The network of fueling stations will need to become ubiquitous enough to allow convenient travel anywhere/anytime in the Province for commercial and private drivers.

Medium- and heavy-duty vehicle infrastructure will continue to grow in commercial volumes. Based on the projections, up to 278 medium- and heavy-duty dispensers will be required to support the trucks, goods movement equipment, transit and inter-city buses, passenger ferries and rail applications by 2050. Note that many of these dispensers will be co-located at fleet fueling facilities as the scale of deployment expands.

4.2.4.5 : Low Carbon Fuel Regulation

BC's Low Carbon Fuel Regulation has provided a funding mechanism for developers, such as North Vancouver's HTEC, to deploy the hydrogen infrastructure planned in the Province to date. Under the LCFR, credits can be approved by the Province based on the projected station capacity and displacement of fossil fuel emissions by hydrogen, then sold to fuel suppliers bound by the LCFR.

While credit sales have assisted, other sources of funding have been required; examples include the Province's CEV program and federal funding through Natural Resources Canada (NRCan) funding. OEMs have also invested in infrastructure in limited cases.

At present, this approach is that project development takes significant time and effort, and lacks a cohesive strategic direction supported by government. It is recommended that the Province take a more active role in guiding infrastructure development, including through the release of special prescriptive call for hydrogen LCFR Part 3 agreements, likely required every 2-3 years, until hydrogen infrastructure in the province is well established.

4.2.5 Recommendations

Structure the light-duty ZEV mandate to encourage OEMs to make FCEVs available in BC

- *Make British Columbia the world leader in credit value for FCEVs.*

Implement a Zero Emission Bus Mandate for public transit vehicles and a Voucher Program to offset incremental costs.

Strengthen funding to support rollout of hydrogen infrastructure in the Province

Support feasibility study for the use of hydrogen in Marine, Rail and off-road applications in BC.

Support lighthouse projects to deploy medium- and heavy-duty fuel cell vehicles in the Province.

- *Support a fuel cell electric coach pilot program.*
- *Create a large-scale, zero-emission heavy-duty vehicle program focused on Vancouver ports*

4.3 : Industry

4.3.1 : Baseline

BC industries that currently use hydrogen include the production of liquid transportation fuels and sodium chlorate and chlor-alkali plants. The two remaining refineries in BC, located in Burnaby and Prince George, use hydrogen as part of the refining process. Sodium chlorate plants are located in North Vancouver and Prince George while the only chlor-alkali plant is in North Vancouver.

The Parkland refinery in Burnaby, has a production capacity of 55,000 barrels per day (bbl/d) of light crude into a range of products including gasoline, diesel, aviation fuel, LPG and industrial fuel supplying ~ 25% of the Province's transport fuel needs. Hydrogen is produced from naphtha as an internal part of the refining process at a rate of ~ 26 tonnes/day or 10,000 tonnes/year.[112]

The Husky refinery in Prince George has a production capacity of 12,000 bbl/day of light crude into a range of products including gasoline, diesel, LPG/butane and industrial fuel supplying ~ 5% of the Province's transport fuel needs. The facility produces hydrogen from a steam methane reformer at a rate of 3.3 tonnes/day or 1,200 tonnes/year.[113]

Chemtrade operates both the chlor-alkali plant in North Vancouver and the sodium chlorate plant in Prince George. The North Vancouver plant produces hydrogen as a by-product but uses this during the production of HCl. To supplement this hydrogen demand, Chemtrade buys by-product hydrogen from the neighbouring ERCO sodium Chlorate plant. ERCO dechlorinates, compresses and sends the hydrogen via a dedicated hydrogen pipeline to the Chemtrade plant. The total ERCO by-product hydrogen production is approximately 15 tonnes/day or 5,500 tonnes/year of which ~50% is sold to Chemtrade and 50% or 7.5 tonnes/day is vented to atmosphere. This is sufficient to meet the needs of approximately 7,500 light-duty FCEVs.

The Chemtrade sodium chlorate plant in Prince George produces approximately 11 tonnes/day or 4,000 tonnes/year of by-product hydrogen,[113] enough to provide fuel for about 22,000 light-duty FCEVs. This hydrogen is currently vented however a portion of this capacity may be contracted to a potential customer in the near future.

Combined, the Parkland, Husky, and Chemtrade facilities produce 20,700 tonnes of hydrogen annually. This is equivalent to approximately 2.5 million GJ of energy.

The industrial sector in BC accounted for approximately 38% of natural gas consumption in the province as of 2017.[114] Natural gas is primarily used in industry for high-grade process heat, for space and hot water heating in industrial complexes, and as a chemical feedstock. The natural gas use accounts for GHG emissions of approximately 4.2 Mt CO_2e/year.

112 *Personal correspondence – Parkland April 26, 2019*

113 *Dalcor Consultants, Ltd. (2005). Canadian Hydrogen Survey - 2004/2005. Retrieved from http://ieahydrogen.org/Activities/Subtask-A,-Hydrogen-Resouce-Study-2008,-Resource-S/Canadian-H2-survey-2005.aspx*

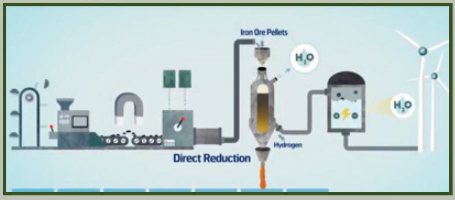
114 *BC Provincial Government. (2018). Production and Distribution of Natural Gas in BC Retrieved from https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/natural-gas-oil/production-statistics/gasnew.xls*

ATTRACTION OF NEW INDUSTRY TO BC

Hydrogen is used as a feedstock in several major industrial processes. Establishment of large scale, low carbon intensity, and cost competitive hydrogen supply in the Province has the potential to attract new industry and drive economic growth in the Province. By-products in the hydrogen production process, such as oxygen in the case of electrolysis, and waste heat can also attract new industry.

Hydrogen is used in the following industrial processes:

- *Ammonia production (NH3), through the Haber-Bosch process which combines hydrogen and nitrogen together. Approximately 90% of Ammonia produced goes into fertilizer production.*
- *Processing crude oil into refined fuels, such as gasoline and diesel, and also removing contaminants like sulfur form these fuels.*
- *Steel-making – SSAB, LKAB and Vattenfall joined forces to create HYBRIT – an initiative that endeavours to revolutionize steel-making. HYBRIT aims to replace coking coal, traditionally needed for ore-based steel making, with hydrogen.*



- *In the electronics industry, it is widely employed as a reducing agent and as a carrier gas.*
- *In margarine production, for the hydrogenation of fats. It consists of adding hydrogen to compounds that contain multiple bonds.*
- *In methanol production or methyl alcohol production.*
- *In synthetic liquid fuel production.*

The greatest opportunity for hydrogen is in the production of low carbon or renewable liquid fuels. BC's renewable and low carbon fuel standard (LCFS) is a performance-based standard which specifies the GHG intensity and renewable content of fuels used for transportation. Part 3 of the LCFS calls for a 10% reduction in GHG intensity for transportation fuels sold in the province by 2020 relative to 2010. Part 2 of the Standard calls for a minimum of 5% renewable content for gasoline and 4% for diesel. Currently the renewable fractions are higher than the minimum which indicates that GHG intensity part of the standard is more stringent to meet.

The CleanBC plan further decreases the GHG intensity by another 10% by 2030 or a 20% reduction compared to 2010. This is projected to increase the production of renewable gasoline and diesel to 650 million litres per year by 2030 representing 8% of the total fuel demand.[115]

There are a number of ways to meet this projected fuel demand. Biomass based fuels such as corn ethanol, methanol and biodiesel can be produced. Ethanol and methanol can be mixed with gasoline and biodiesel can be mixed with or replace fossil produced diesel.

The pathways for biomass to produce renewable diesel are shown in Figure 56.

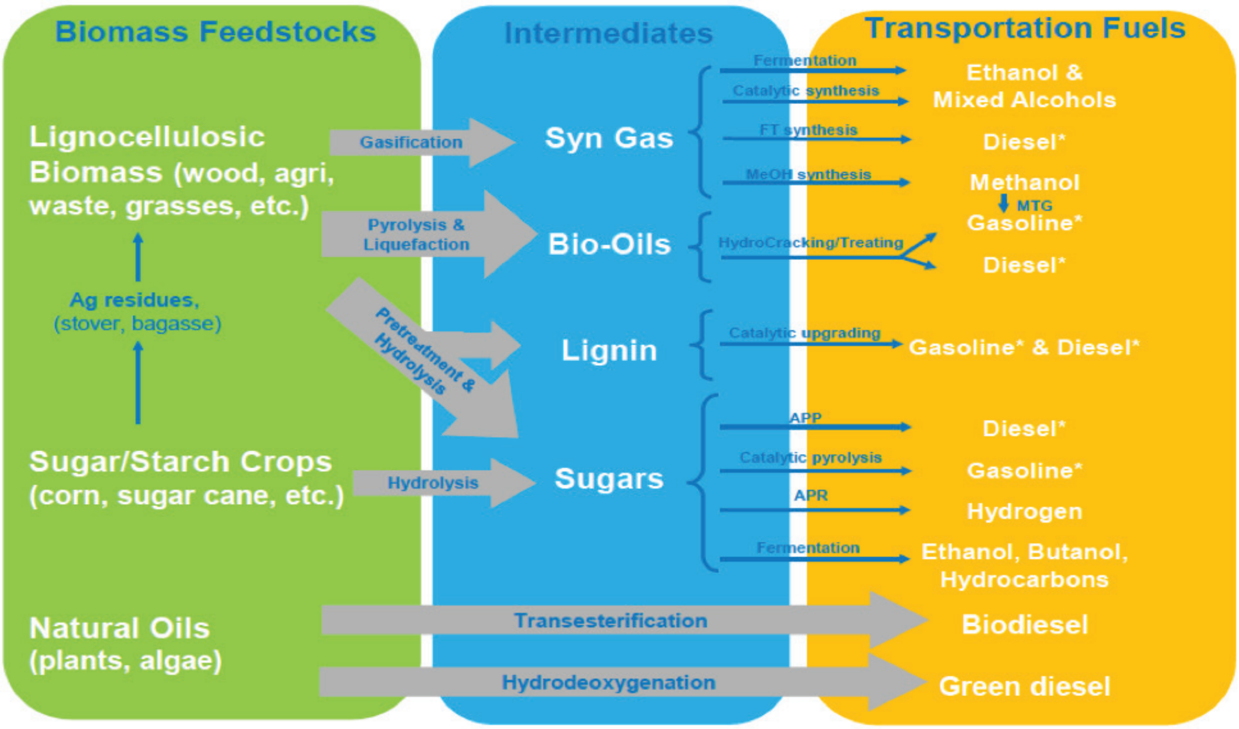


Figure 56. Biomass to Liquid Fuel Pathways

Current biomass feedstocks being investigated at the Parkland refinery include canola and tallow oil which are co-processed with fossil crude in the refinery. However, the available bio feedstocks will be insufficient to meet the projected demand.

115 *BC Provincial Government. (2018). CleanBC: Our Nature. Our Power. Our Future. Retrieved from https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_2018-bc-climate-strategy.pdf*

Forest residues are being considered as a biomass feedstock to meet the 2030 demand. This source of biomass contains a high proportion of oxygen and will require additional hydrogen during production. Parkland is currently investigating this pathway in their refinery but were unable to provide estimates of how much hydrogen would be required.

Another pathway to meet the LCFS proposed in BC is via the production of synthetic crude or fuels using low carbon or renewable hydrogen and CO_2 captured from the air. This pathway is shown in Figure 57.

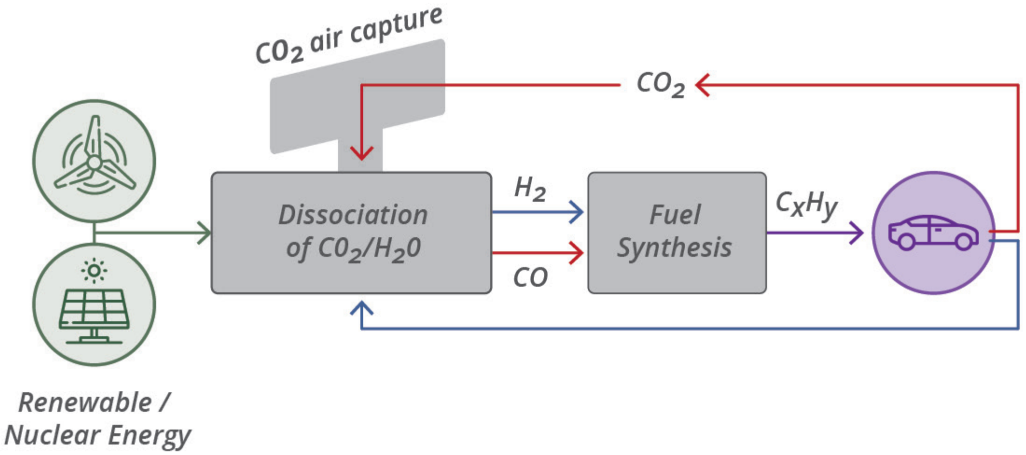


Figure 57. Synthetic Fuel Production Process

Carbon Engineering, based in Squamish, is developing an AIR to FUELS™ process whereby CO_2 from air and hydrogen are converted in conventional chemical processes to produce synthetic crude which can be processed in conventional refineries without any modifications. A commercial scale plant producing 100 million litres/year of synthetic crude would require 100 tonnes/day of clean hydrogen and 550 tonnes per day of CO_2 captured from the air. Depending on the GHG intensity of the hydrogen and the energy required in the direct air capture (DAC) process, the GHG intensity of the liquid fuels will be reduced by 70 – 90%.[116] If this hydrogen is produced by electrolysis, electrical input power would comprise approximately 250 MW[117] per plant for hydrogen production with another 8 MW for the DAC plant.[118] This is a significant electrical load, representing 23% of total Site C dam nameplate capacity.

By-product hydrogen produced by ERCO and Chemtrade provides a relatively small but low-cost hydrogen pathway of up to 18.5 tonnes per day. Due to their locations, the hydrogen must be either used on-site or transported to another location. Given the very high demand for low-cost hydrogen in the synthetic fuels production pathway, other sources of bulk, clean hydrogen and production will likely have to be constructed. Technology hurdles remain that will need to be overcome for synthetic fuel production to happen at scale in BC. In addition, as fuel cell electric vehicle adoption increases, the hydrogen market is likely to tip towards the more efficient pathway of directly using hydrogen for transportation, rather than using it to produce a synthetic fuel. That said, the synfuels pathway can immediately reduce the emissions of the existing vehicle fleet. Synfuels may also play a key role in helping to decarbonize emissions relating to marine and aviation transport.

An additional opportunity for hydrogen in the industrial sector is through the displacement of natural gas related to heating. This opportunity is discussed in Section 4.1 so is not treated further here.

116 Personal Correspondence – Carbon Engineering April 3, 2019

117 Assumes 60 kWh/kg H_2

118 Keith et al. (2018). A Process for Capturing CO_2 from the Atmosphere. Joule 2, 1573–1594. Retrieved from https://www.cell.com/joule/pdf/S2542-4351(18)30225-3.pdf

4.3.3 : Challenges and Barriers

Due to the quantity of low carbon fuels required by 2030, hydrogen production at large scale in the province will likely be required regardless of the method used to produce the low carbon fuel. These hydrogen plants may be located near existing refineries to support production of biofuels using lignocellulosic feedstocks such as forestry residue or located in other regions where hydrogen production is co-located with DAC plants to produce synthetic crude which is transported to the refineries by rail, truck or pipeline. The main challenges for installing these large-scale plants include long upfront delays to obtain the necessary permits required to build the plant, as well as the potential for protests if the hydrogen is produced from natural gas.

If the plants are located at the existing refineries, hydrogen production via SMR+CCS is not possible due to the lack of CO_2 storage at the refinery sites. Unless there is a local use for solid carbon, hydrogen production via pyrolysis may also not be feasible at refineries. Lastly, due to the large electrical demand for large-scale electrolysis, onsite multi-MW supply at these locations may not be available due to local electrical transmission constraints.

In either case, intermittent hydrogen production from wind – electrolysis is also not viable due to the likely requirement of continuous hydrogen supply. Therefore, it appears likely that large-scale hydrogen production to support low carbon fuels demand will be located remotely from the refinery.

Finally, in order for the cost of low carbon fuels to remain low, hydrogen must be supplied at a low cost. Hydrogen produced for a cost of $5/kg will likely be too expensive as the cost of hydrogen alone equates to almost $2/litre of fuel.

Policies that could help drive hydrogen demand in the province includes maintaining the performance basis of the LCFS. By creating lower GHG intensity fuels and not allowing producers to exceed the intensity by paying a fee, clean hydrogen demand will be increased significantly and result in GHG emissions reductions in the province. Also, Part 2 of the LCFS should be modified to increase the proportion of renewable content in the LCFS over the longer-term as costs for renewable feedstocks decrease. The province could also consider further decreases in the GHG intensity for transportation fuels beyond 2030.

The province should consider supporting an initial large-scale project to kickstart hydrogen production for LCFS production. This could be either an AIR to FUELS™ plant to produce synthetic crude or a forestry biomass fed plant to produce renewable diesel and/or gasoline.

4.3.4 : Adoption Scenarios

Adoption scenarios that project hydrogen demand to 2050 have been based on conservative and aggressive policies. Due to the unknown hydrogen requirements to produce liquid fuels from biomass feedstocks, hydrogen demand was estimated using Carbon Engineering's AIR to FUELS™ pathway for a 100 ML/year of synthetic crude oil facility. The GHG reduction potential for this pathway is assumed to be 90%.[119] Finally, the overall transport fuel demand in BC is assumed to stay constant based on actual 2017 demand.[120]

The conservative scenario assumes the CleanBC target of 20% reduction in GHG intensity for transportation fuels continues until 2050. In this scenario, synthetic fuels will only meet 5% of the low carbon fuel requirement by 2030 and produce approximately 76 million litres/year. By 2050, growth to 25% of the low carbon fuel requirement is projected, with production of 380 million litres/year.

In the aggressive scenario, the GHG intensity reduction continues past 2030 and reaches 30% below 2010 levels by 2050. In this case, it is projected that synthetic fuels meet 25% of the total low carbon fuel demand by 2030, the equivalent of 380 million litres/year. By 2050, synthetic fuels plants meet 75% of the total low carbon fuel demand with production of 1,710 million litres/year.

119 Personal Correspondence – Carbon Engineering April 3, 2019

120 The Ministry of Energy, Mines and Petroleum Resources has provided a forecast that liquid fuel demand (gasoline, diesel) in BC will remain flat.

The demand curves for Industry for these scenarios are given in the figure below.

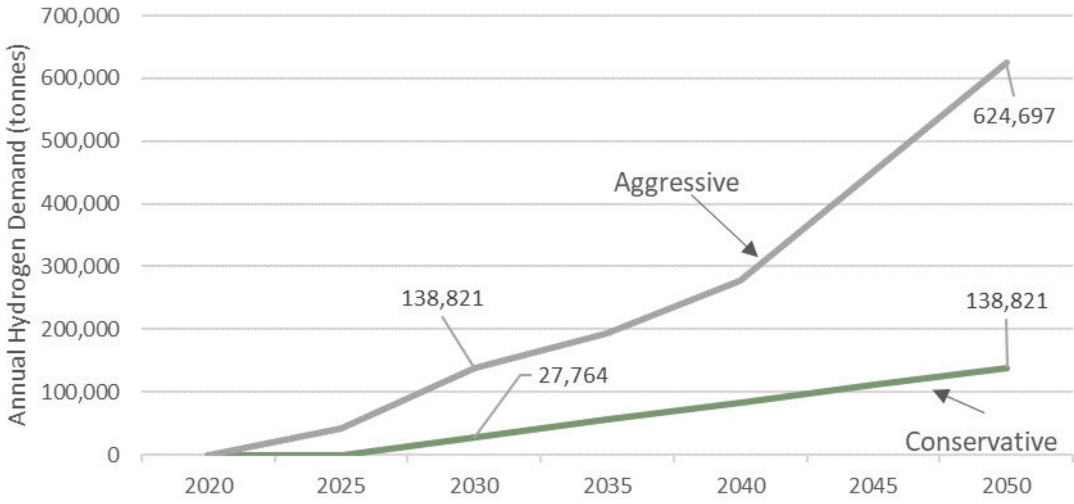


Figure 58. Hydrogen demand for Industry in BC

4.3.5 : Recommendations

Maintain the current performance base, GHG intensity reduction mandate of the LCFS

- *Include increasing proportion of renewable content over time*

Extend and Increase the proportion of low carbon fuels beyond 2030

- *Provides assurances to developers on a long-term market to justify large capital expenses*

Support a large-scale demonstration project in BC which uses clean hydrogen for the production of synthetic liquid fuels.

4.4 : Built Environment

4.4.1 : Baseline

The built environment makes up approximately 13% of total GHG emissions in BC. This sector can be divided into two broad categories as shown in Table 11.[121]

CATEGORY	DESCRIPTION
Residential	Personal residences (homes, apartment hotels, condominiums and farmhouses).
Commercial	Service industries related to mining, communication, wholesale and retail trade, finance and insurance, real estate, education, etc.; offices, health, arts, accommodation, food, information & cultural; Federal, provincial and municipal establishments; National Defense and Canadian Coast Guard; Train stations, airports and warehouses.

Table 11. Definition of Built Environment GHG Emissions Categories[121]

Figure 59 shows the GHG emissions from both built environment categories in BC from 1990 to 2016.

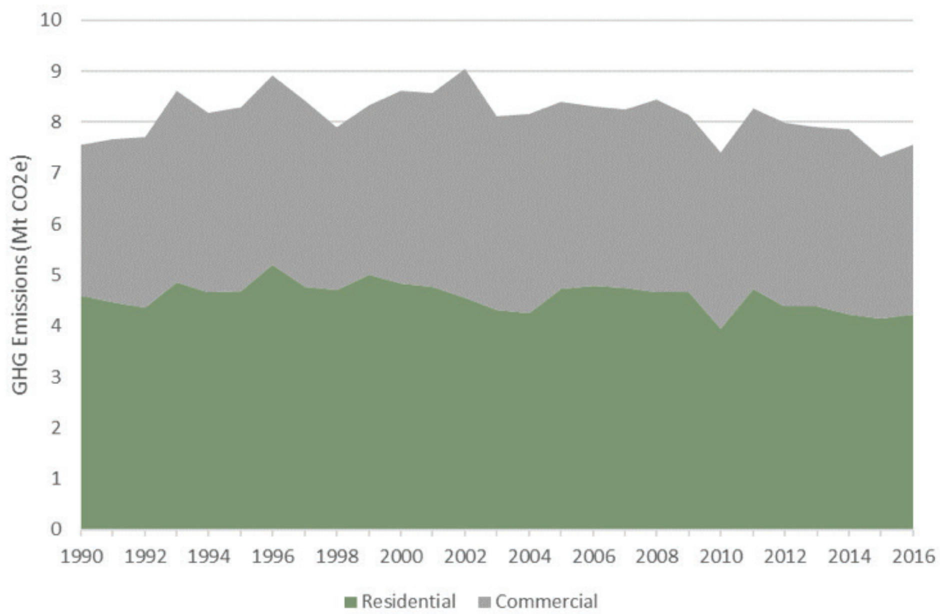


Figure 59. BC Built Environment GHG Emissions by Category (1990-2016)[121]

121 *Environment and Climate Change Canada. (2018). National Inventory Report 1990-2016: Greenhouse Gas Sources and Sinks in Canada, Annex 10. Retrieved from* https://open.canada.ca/data/en/dataset/779c7bcf-4982-47eb-af1b-a33618a05e5b

Total built environment GHG emissions trended slightly upward from 1990 to 2004 and have trended slightly downward since then. The split between residential and commercial/industrial has remained relatively consistent ranging from 61%/39% to 50%/50%. Figure 60 shows the percent of total built environment GHG emissions attributable to both categories in 2016.

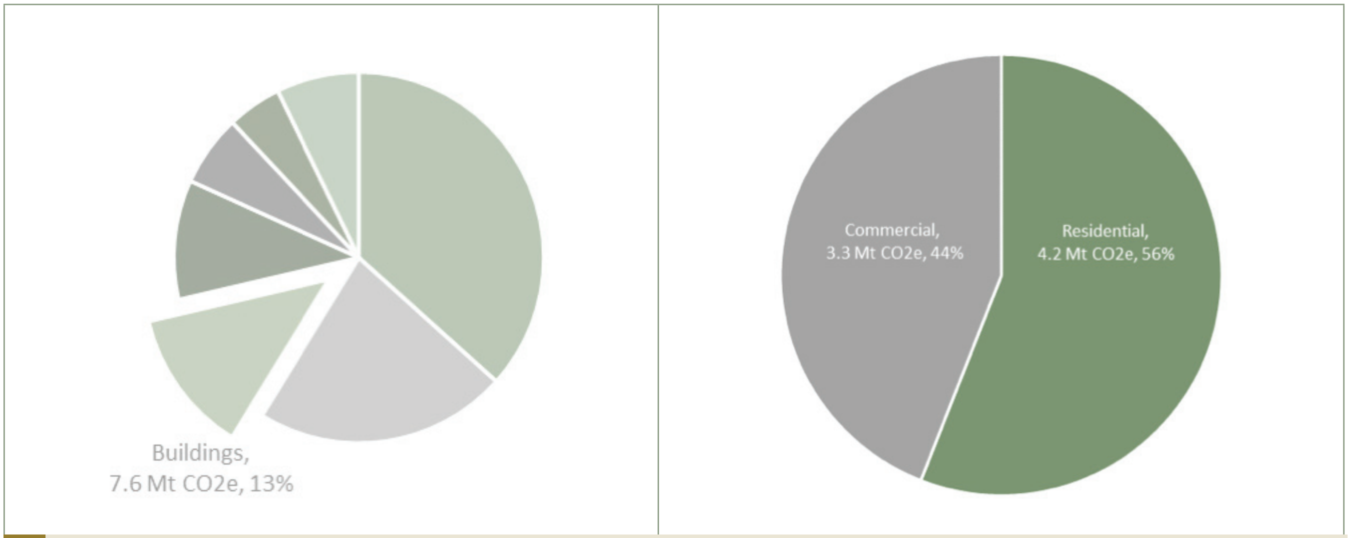


Figure 60. BC Built Environment GHG Emissions by Category (2016)[121]

4.4.1.1 : Residential Built Environment Baseline

Figure 61 shows residential building GHG emissions by source and end use (neglecting electricity).

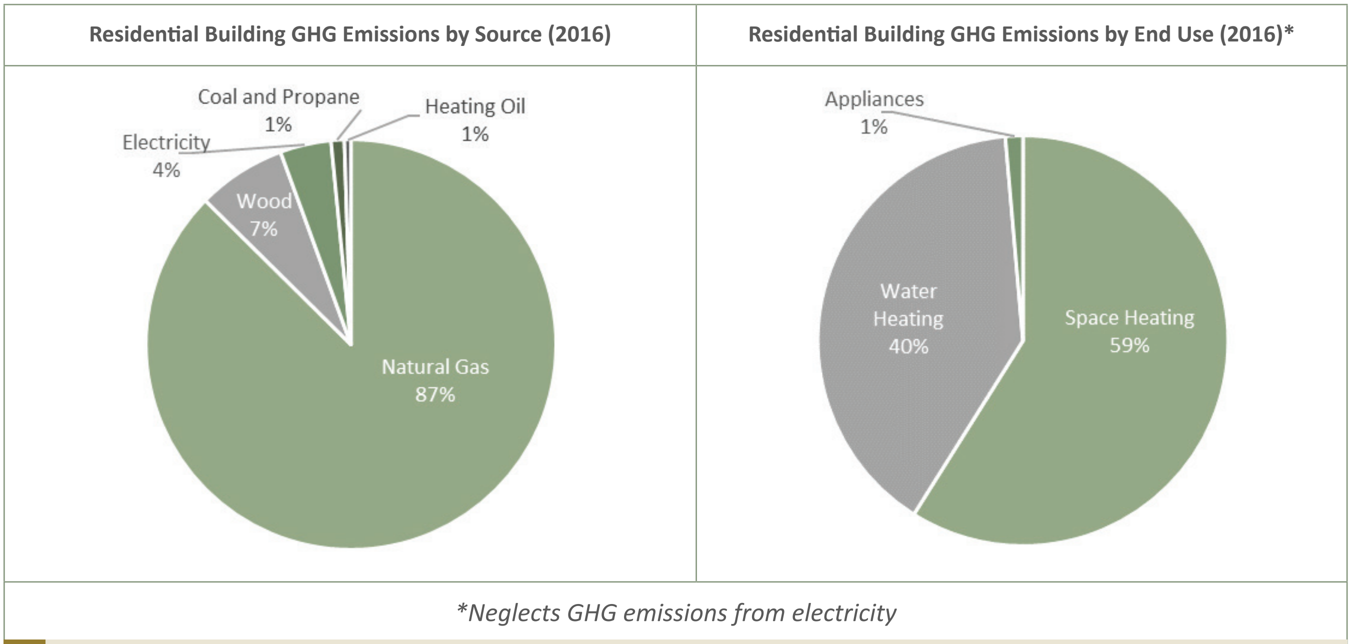


Figure 61. BC Residential Building GHG Emissions by Source and End Use (2016)[122]

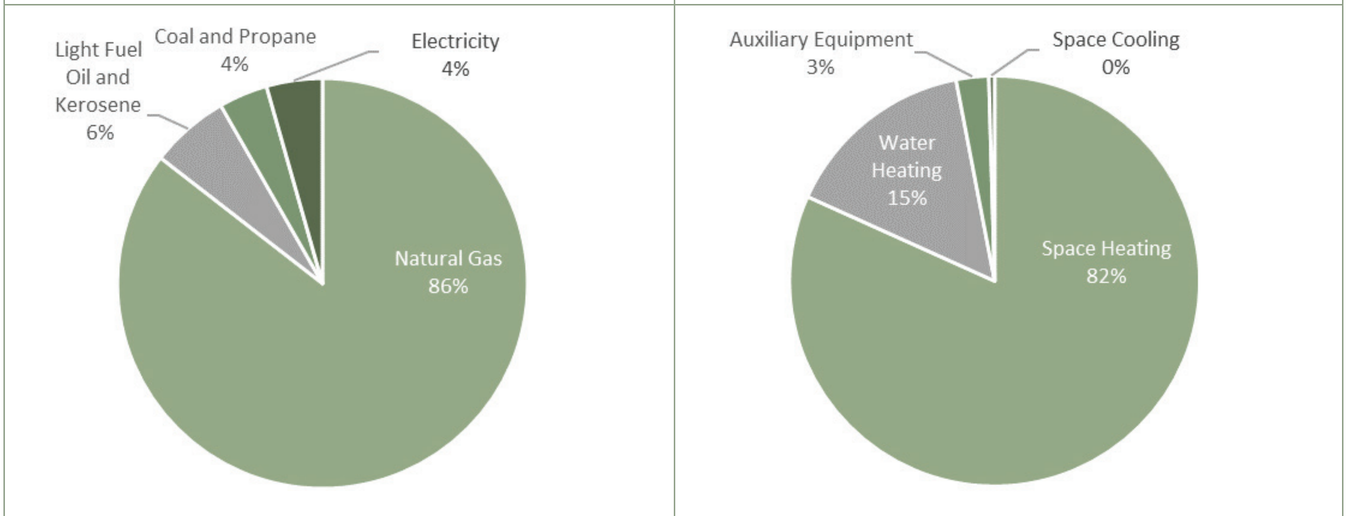
122 Natural Resources Canada. Comprehensive Energy Use Database: Residential Sector – British Columbia. Retrieved from http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_res_bc.cfm

The majority of residential GHG emissions results from natural gas consumed for space and water heating. The prevalence of heating oil has decreased significantly in BC, from 16.1% of GHG emissions in 1990 to less than 1% in 2016. Over the same period, emissions from water heating have increased while emissions from space heating decreased.[122]

4.4.1.2 : Commercial Built Environment Baseline

The majority of GHG emissions from the commercial and industrial built environment results from the burning of natural gas for space heating (Figure 62). The proportions shown have stayed relatively constant over time.

Commercial Building GHG Emissions by Source (2016)	Commercial Building GHG Emissions by End Use (2016)*



*Neglects GHG emissions from electricity

Figure 62. BC Commercial Building GHG Emissions by Source (2016)[122]

4.4.1.3 : Built Environment Hydrogen Baseline

Hydrogen is not currently in use to provide heating, cooling, or on-site electricity generation for the built environment in BC. The CleanBC plan primarily focuses on reducing emissions in the built environment by increasing the percent of natural gas that comes from renewable sources, improving the building code, investing in demand side management, and encouraging the installation of heat pumps.

4.4.2 : Opportunities and Challenges

The best opportunity for hydrogen to reduce GHG emissions in the built environment is through the displacement of natural gas in the grid. The built environment makes up approximately three quarters of the demand for natural gas across the Province. Achieving the CleanBC goal of 15% renewable gas by 2030 will result in significant emissions reductions, and hydrogen can play a pivotal role, as described in Section 4.1.

Off-setting natural gas consumption through the addition of hydrogen to the grid is particularly attractive for the built environment because at low concentrations it requires no action on behalf of the building occupants. Research suggests the natural gas stream feeding most domestic appliances could contain up to 20-30% hydrogen by volume without the need to separate the gases at their end use or making major changes to the grid or appliances.[123, 124, 125] Retrofitting buildings with improved insulation and weatherization, or installing energy efficient equipment like heat pumps or tankless water heaters requires effort and capital expenditure on the part of building owners. Adding hydrogen to the gas grid requires no action from the population at large, though it is likely to impact the rates paid.

Beyond the 20-30% range, the hydrogen/natural gas blend may become incompatible with domestic appliances like furnaces and stoves because of hydrogen's relatively low energy content, low density, and high burning velocity. To increase the hydrogen content beyond this level would require modifications to the pipe network as well as the appliances themselves. Though challenging, a major overhaul of this sort is not unprecedented. In 2009, Whistler underwent a transition from propane to natural gas, which involved similar retrofits of about 14,000 domestic appliances.[126]

Another opportunity for hydrogen in the built environment is stationary fuel cell systems that provide combined heat and power (CHP), sometimes called cogeneration, or cogen. These systems, which can run on natural gas, pure hydrogen, or a blend, have been successfully deployed at scale in Japan. However, they are not well suited to most regions in BC because of their relatively high capital cost and the availability of inexpensive renewable electricity in BC. Residential cogeneration systems might make sense if an entire community converted to 100% hydrogen, as described in Section 4.1 and Section 4.5.

4.4.3 : Adoption Scenarios

Hydrogen adoption in the built environment was not modeled independent of the natural gas pipeline (Section 4.1) and remote communities (Section 4.5). The hydrogen demand in both of those sectors will be largely consumed in the built environment. Figure 63 shows the natural gas demand by segment in 2017.

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123 *California Hydrogen Business Council. (2015). Power-to-Gas: The Case for Hydrogen White Paper. Retrieved from https://www.californiahydrogen.org/wp-content/uploads/2018/01/CHBC-Hydrogen-Energy-Storage-White-Paper-FINAL.pdf*

124 *Dentons. (2019). The Future of Gas: Transitioning to Hydrogen in the Gas Grid. Retrieved from https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=6&ved=2ahUKEwilmbvrio3iAhWLqZ4KHd8mBBwQFjAFegQIBRAC&url=https%3A%2F%2Fwww.dentons.com%2Fen%2Fpdf-pages%2F-%2Fmedia%2Fef787bcd303a459dbbfa60677a3e7df1.ashx&usg=AOvVaw3oY6CfCFtG6Z6YsVhnHf_y*

125 *Jones DR, Al-Masry WA, Dunnill CW. (2018). Hydrogen-enriched Natural Gas as a Domestic Fuel: An Analysis Based on Flash-back and Blow-off Limits for Domestic Natural Gas Appliances within the UK. Sustainable Energy Fuels, 2, 710-723. Retrieved from https://pubs.rsc.org/en/content/articlelanding/2018/se/c7se00598a/unauth#!divAbstract*

126 *Fortis BC. Whistler Natural Gas Conversion. Retrieved from https://talkingenergy.ca/node/80*

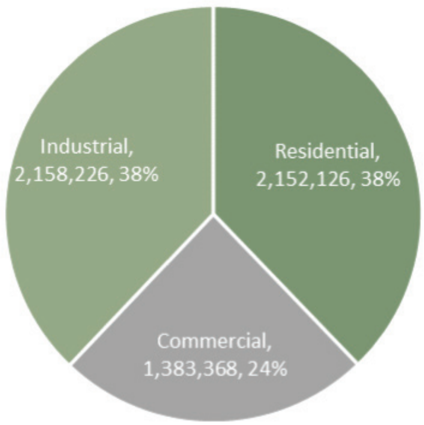


Figure 63. Natural Gas Demand in m^3 in BC by Segment (2017)[127]

The modeling assumed the percent share of each segment remained constant through 2050, so the built environment represents approximately three quarters of the hydrogen demand projected in Section 4.1. Effectively all the hydrogen demand modeled for remote communities are attributable to the built environment.

4.5 : Remote / Off-Grid Communities

4.5.1 : Baseline

4.5.1.1 : Overview

A remote community is defined as a permanent community not connected to North America's integrated electrical or natural gas grids. It must have been settled for longer than 5 years, with 10 or more dwellings. The NRCan Remote Communities Energy Database[128] (based on 2017 or most recently available data) identifies 75 remote communities in BC, illustrated in Figure 64.

Fourteen remote communities rely on hydro with backup diesel generation for their electricity. Fifty-two communities rely on diesel as their primary power source. Six communities have unknown power sources.

127 *BC Provincial Government. (2018). Production and Distribution of Natural Gas in BC. Retrieved from https://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/statistics*

128 *Natural Resources Canada. (2018). The Atlas of Canada – Remote Communities Energy Database. Retrieved from http://atlas.gc.ca/rced-bdece/en/index.html*

Figure 64. BC Remote Communities with Power Source

4.5.1.2 : Microgrids

A microgrid is a complete system (diesel generators or small-scale hydro, distribution wires/equipment, control systems) that provides electricity to a community; in some cases, they may provide power to surrounding communities as well. Fourteen of BC's remote communities are connected to one of four local microgrids owned by BC Hydro: Bella Bella, Bella Coola (Ah-Sin-Heek power plant) and Sandspit provide hydroelectric power with diesel as back-up, while Masset is 100% diesel generation.

NAME	#*	PRIMARY POWER	SECONDARY POWER	FOSSIL FUEL GENERATION (MWH/Y)	FOSSIL GENERATING CAPACITY (MW)	PEAK LOAD (MW) (2016)	NOTES ON POWER SOURCE
Bella Bella	4	Hydro	Diesel	983	4.90	4.30	93% hydro, diesel as backup
Bella Coola	3	Hydro	Diesel	7939	9.25	4.85	70% hydro, Clayton Falls Hydroelectric
Sandspit	4	Hydro	Diesel	5507	10.15	6.96	70-90% hydro, Moresby Lake Hydro Station
Masset	3	Diesel	n/a	26433	13.10	6.22	5 Generators, 10.455 MW capacity
**Number of communities supported*							

Table 12. BC Hydro Local Microgrids

Diesel generators and small-scale hydro can provide consistent 24/7 electricity, facilitating the balancing of supply and demand. Variable renewable electricity, or VRE, composed of intermittent wind and variable solar, can provide intermittent power which can help reduce costs and emissions, but which increase the complexity of a microgrid system. Hybrid systems of hydroelectricity with diesel back-up can supply the majority of a community's power needs, providing lower-cost, cleaner electrical supply most of the time, while using diesel generators as back-up to ensure uninterrupted electricity supply.

For a microgrid without storage (generally lithium-ion battery, though in some cases flow battery), intermittent renewables penetration is estimated at 20-30%. As integration of renewable sources increases (bringing down the overall cost of generating the electricity), combined with falling battery prices, investing in storage options could become an economically viable option.

4.5.1.3 : Single Off-Grid Communities

Sixty-one (61) off-grid communities in BC are powered primarily by diesel, but also by small hydroelectric projects as well as demonstration projects for LNG, Biomass and solar.

Fifty-two (52) communities rely on diesel generation as their primary source for electricity, three communities get electricity from small local hydroelectric projects (run of river with no storage) and three additional communities use hybrid systems of Diesel with LNG, biomass or solar. Service is provided by BC Hydro (diesel generation from 10 stations and two small hydroelectric projects), Independent Power Producers (IPP) provide diesel electricity to 31 communities and ATCO Electric Yukon to a single community.

SERVICE PROVIDER	COMMUNITIES	PRIMARY POWER	SECONDARY POWER	FF* DEMAND (MWH/Y)	FF GEN** CAPACITY (KW)	NOTES ON POWER SOURCE
BC Hydro-2 IPP-1	3	Hydro	Diesel	348		Minimal diesel as backup
BC Hydro-8 IPP-30 Unknown-10 ATCO Electric YT-1	49	Diesel		92,513	58,514	100% diesel
BC Hydro	1	Diesel	LNG	6,649	3,550	50% diesel, 50% LNG
BC Hydro	1	Diesel	Biomass	2,963	1,800	20-25% biomass
IPP	1	Diesel	Solar	1,400	78	250 kW solar + 1 MWh storage; target 80% solar
Unknown	6	Unknown		Unknown		Small amounts of diesel, Propane, Gasoline, Small solar
** Fossil Fuel* ***Fossil Fuel Generation*						

Table 13. Power Source(s) for 61 Single Off-grid Communities

4.5.1.4 : Diesel GHG Baseline

Remote communities in BC and across Canada rely primarily on diesel for electricity, and efforts continue to reduce this reliance. Data on diesel use and the resulting GHG emissions remains limited. The Pembina Institute estimated that more than 90 million litres of diesel[129] are consumed in Canada's remote communities with BC communities estimated to use 3 million litres per year.

To establish a GHG baseline for BC's remote communities, information was gathered on annual diesel demand at the community level. Data was unavailable for some of the smallest communities, but these likely use 3 (or fewer) installed gensets with capacity well below 1MW. Data was gathered from the NRCan Remote Community database and an earlier report (2011) on the Status of Remote/Off-Grid Communities in Canada[130] prepared by NRCan and Aboriginal Affairs and Northern Development Canada (AANDC).

129 *Pembina Institute. (2019). Diesel, Renewables, and the Future of Canada's Remote Communities: Introduction to Microgrids. Retrieved from https://www.pembina.org/blog/remote-microgrids-intro*

130 *Natural Resources Canada. (2011). Status of Remote/Off-Grid Communities in Canada. Retrieved from https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/canmetenergy/files/pubs/2013-118_en.pdf*

PROVIDER	FOSSIL FUEL GENERATION (MWH/Y)	FOSSIL GENERATING CAPACITY (MW)
BC Hydro	61,159	60.7[131]
IPP + Other	31,354	9.3
Total	92,513	70

BASELINE CO_2E EMISSIONS RESULTING FROM DIESEL ELECTRICITY GENERATION ANNUALLY IN BC REMOTE COMMUNITIES	
Annual FF electricity generation in BC Remote Communities (MWh/y)	92,513 MWh/year
Conversion Factors	
1 MWh = 3.6 GJ	
Diesel emission factor CO_2e = 100.5 kg/GJ[132]	
CO_2e emissions from FF generation in BC Remote Communities	**33.47 kt CO_2e/year**

Table 14. Annual Fossil Fuel Power Generation and Generating Capacity

4.5.1.5 : Diesel Issues – Economic, Environmental, Social

In Canada, the average cost of electricity is between $0.07-$0.17/kWh, while the unsubsidized cost of electricity from diesel generation is approximately $1.30/kWh[133]. BC has some of the lowest electricity costs in the country and under their Non-Integrated Area rate plan BC Hydro provides diesel energy to remote communities in BC at the following subsidized rates:[134]

- *$0.1028/kWh for the first 1,500 kWh per month,*
- *$0.1767/ kWh for remaining kWh per month;*

The initial rate is equivalent to the rate paid by grid-connected customers, while the second rate is higher, although much lower than remote communities pay in other parts of the country.

131 BC Hydro. (2018). BC Hydro Quick Facts. Retrieved from http://www.llbc.leg.bc.ca/public/PubDocs/bcdocs/358355/quick_facts_2018.pdf

132 (S&T) Squared Consultants Inc. (2018). GHGenius 5.0d. Calculations conducted by BC Ministry of Energy, Mines and Petroleum Resources Low Carbon Fuels Branch. Retrieved from https://ghgenius.ca/index.php/downloads

133 Wilt J. (2018). Canada's Commitment of @220 Million to Transition Remote Communities Off Diesel a Mere 'Drop in the Bucket.' The Narwhal. Retrieved from https://thenarwhal.ca/canada-s-commitment-220-million-transition-remote-communities-diesel-mere-drop-bucket/

134 Kennedy M. (2017). Energy Shift: Reducing Diesel Reliance in Remote Communities in BC. Simon Fraser University. Retrieved from http://summit.sfu.ca/item/17979

In general, the high cost of diesel is driven by the cost of transportation over long distances and often very challenging terrain. Without the highly subsidized rates from BC Hydro, the high cost of diesel would make it very difficult for any industry consuming even small amounts of electricity to operate economically in these remote communities. As well, residents of remote communities often live at a subsistence level with the high cost of electricity contributing heavily to this. Poor building energy efficiency and cold northern climate also increase overall electricity use in these communities.

In addition to the substantial GHG emissions from the diesel generation, transportation by truck, ship or plane creates additional GHG emissions, and long transport over rough terrain increases the risk of spills. Diesel generators are also noisy, disruptive, have unpleasant fumes and the emissions can contribute to health problems (asthma, bronchitis, allergies, lung function, heart problems)[135]. Finally, the unreliability of aging generators running at capacity increases the risk of power outages which negatively impacts services and businesses and can be dangerous in cold, remote locations.

4.5.1.6 : Other Power Sources

Micro Hydroelectric Projects

Run-of-river hydroelectric projects use the natural elevation, channeling water through a penstock to a downstream turbine. Water is diverted from the stream/river for a short distance and returned to the stream after the turbine. These projects have far less environmental footprint than a traditional dam, and there are many rivers and streams in BC, however these projects require over 50 permits, licenses, approvals and reviews by many Government agencies and consultation with First Nations and public groups. BC Hydro and one Independent Power Provider (IPP) operate 6 small hydro projects in the Province: 3 hydroelectric microgrids supporting 11 communities (See Table 12 above) and 3 single community micro hydro projects.

PROVIDER	ANNUAL GENERATION (MWH/Y)	CAPACITY (MW)
BC Hydro - Atlin	5,000	2.1
BC Hydro - Dease Lake	5,000	3.0
IPP - Klemtu/Kitsoo*	At capacity	1.7
** Klemtu/Kitsoo is installing small solar (23kW) to avoid using diesel as backup*		

Table 15. Single Community Micro Hydro Projects

LNG

BC Hydro is the power provider for the community of Anahim Lake and in the fall of 2016, began a 3-year pilot project, converting the largest of 5 diesel generators to operate with LNG, with the goal of reducing both GHG emissions and fuel costs. Cryopeak trucks LNG from FortisBC's Tilbury Island facility in Delta, stores it and regasifies it in Anahim Lake. Long-term expectations are that 60% of Anahim Lake's power could come from LNG. The NRCan remote community database estimates that 50% of the electricity is currently being generated by LNG.

135 *Huter, H.-P., Kundi, M., Moshammer, H., Shelton, J., Kruger, B., Schicker, I., & Wallner, P. (2015). Replacing Fossil Diesel by Biofuel: Expected Impact on Health. Environmental & Occupational Health, 4-9.Retrieved from* https://www.ncbi.nlm.nih.gov/pubmed/24965323

Biomass

The community of Kwadacha First Nation (Tsek'ene) is using biomass gasification-to-electricity to reduce reliance on diesel. In April of 2017, the biomass system, consisting of three CHP biomass generators and a dryer, began operation, producing electricity for the majority of the community and heat for the local school and greenhouses. Each generator produces 45kW of electricity and 108KW of heat in the form of hot water.[136] The project is projected to reduce reliance on diesel by 20-25% (reducing GHG emissions by ~400 tonnes/year[137]) as well as reduce the use of propane for heat. BC Hydro provides the diesel generation and under a 20-year electricity purchase agreement, purchases power resulting from the biomass project and reduces diesel generation by an equivalent amount.

Solar

Xeni Gwet'in First Nation, located in south-central BC, is reducing their reliance on diesel through a solar installation project. The system includes 250 kW PV with 1,000 kWh storage that provides a full day of backup under cloudy skies and is expected to reduce diesel consumption by an estimated 143,000 litres/year, reducing GHG emissions by 382 tonnes/year.[138] While the system clearly reduces electricity cost and GHG emissions, replacement of the lithium battery storage in 15-20 years will be a significant cost.

Previous Hydrogen Related Projects

Hydrogen Assisted Renewable Power (HARP) Project in Bella Coola[139, 140]

The HARP project was a small demonstration project that ran from 2009-2013 and combined hydrogen production via electrolysis, hydrogen storage, and Fuel Cells. Renewable energy from the Clayton Falls hydro station was used to power an electrolyzer to create hydrogen which was then compressed and stored at 200 bar (20 MPa). PEM fuel cells converted the hydrogen into 100 kW of electricity during peak demand periods, offsetting diesel generation. The demonstration project used a microgrid control system to balance the electrical load between the renewable energy source, diesel generation, and the power provided by the fuel cells.

The project reduced diesel consumption by an estimated 10%, however, it came with very high costs and reliability issues. Not only was the fuel cell and electrolyzer equipment very costly, the 3-step process for generating electricity, (hydroelectricity generation, electrolysis, fuel cell) was very expensive with a system efficiency of only ~35%.

As well, at the time, a 100 kW fuel cell was unavailable, so 100x 1 kW fuel cells were connected in series creating a system with 100 discrete modules each with its own compressor, controls, etc. With so many components in the overall system, the number of failure points increased, and reliability became a significant issue.

The project demonstrated that the system was not ready for full deployment in real-world situations where equipment reliability is critical.

136 *Fredericks T. (2018). Kwadacha Nation Installs Wood Gasification System. Canadian Biomass. Retrieved from https://www.canadianbiomassmagazine.ca/news/green-gas-kwadacha-nation-installs-wood-gasification-system-6699*

137 *BC Hydro. (2017). Wood Chips Help Power Kwadacha First Nation, Cutting Carbon Emissions. Retrieved from https://www.bchydro.com/news/conservation/2017/kwadacha-biomass-ipp.html*

138 *BC Provincial Government. (2017). Hybrid Solar Power Burns Cleaner for Zeni Gwet'in. Retrieved from https://news.gov.bc.ca/releases/2017IRR0057-002106*

139 *Powertech Labs. Energy Storage Systems. Retrieved from https://www.powertechlabs.com/services-all/energy-storage-systems*

140 *Thompson C. (2017). Wuikinuxv Nation Receives Funding for Run-of-River Hydro Project. Coast Mountain News. Retrieved from https://www.coastmountainnews.com/news/wuikinuxv-nation-receives-funding-for-run-of-river-hydro-project/*

4.5.2 : Opportunities for Hydrogen

As part of the CleanBC plan, the Province has set a target of reducing diesel electricity generation in remote communities by 80% by 2030. This is an ambitious target and will require many solutions. Every remote community in BC differs in size, weather, geography, skill base and power requirements and solutions for reducing diesel dependence will be community and site specific.

Most of the remote communities in BC rely solely on trucked or barged in diesel fuel for their electricity supply and there is an opportunity to replace the diesel fuel imports with hydrogen imports. The hydrogen could supply a microgrid system, either centralized, or distributed with co-generation of heat and power. Renewable energy sources can also be incorporated to produce hydrogen using electrolysis, reducing reliance on imported fuel.

A hydrogen supplied microgrid offers significant advantages over diesel generation:

- *Eliminates GHG emissions*
- *Eliminates spill pollution risk*
- *Lower transport weight (in the case of LH_2 supply) reducing transport cost*

If hydrogen is produced for export and shipped through Kitimat, it may be possible to divert some of the hydrogen for delivery to remote communities in the northern part of the Province. This could provide a reliable and reasonably priced hydrogen source.

Compressed natural gas (CNG) also offers the opportunity to transition away from diesel to a cleaner burning fossil fuel. Hydrogen can play a role here as well, as it can be injected into the natural gas prior to compression, reducing the gas's carbon intensity and its associated emissions.

Each of these opportunities is discussed in more detail below.

Hydrogen Microgrid with Distributed Heat and Power Generation

In a distributed hydrogen micro-grid system, imported hydrogen is stored centrally and distributed via pipeline to local houses and buildings which are each outfitted with a local combined heat and power (CHP) generation system. The ENE-FARM system, shown in Figure 65, is an example of a CHP system being used in Japan, where over 300,000 units have been installed.[141]

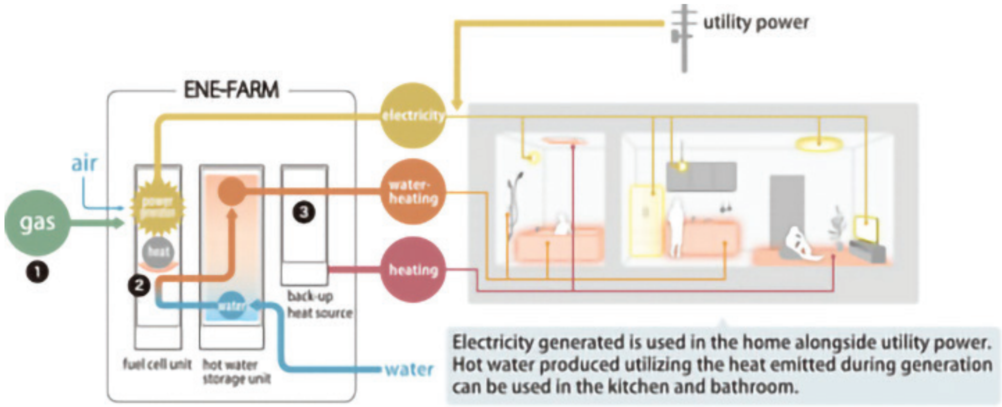


Figure 65. ENE-FARM System

141 FuelCellsWorks. (2019). FCW Exclusive: Tokyo Fuel Cell Expo 2019 – 300,000 Ene-Farms. Retrieved from https://fuelcellsworks.com/news/fcw-exclusive-tokyo-fuel-cell-expo-2019-300000-ene-farms/

The CHP system converts hydrogen into electricity as needed via a PEM fuel cell and heat produced during the process is captured and used to heat hot water for the building. By re-using the waste heat, CHP systems can be up to 95% efficient and significantly reduce overall electricity requirements. The up-front capital cost for a distributed micro-grid system is fairly high, but the higher efficiency would reduce overall hydrogen imports, lowering operating costs.

Hydrogen Microgrid with Centralized Power Production

Fuel cell generators running on pure hydrogen are becoming available and could offer a direct replacement for diesel gensets. In this scenario, hydrogen is imported and stored centrally, with hydrogen fuel cell generators creating power as needed and distributing it to homes and buildings. Hydrogen fuel cell generators are relatively new and higher cost than their diesel counterparts, but connection into the existing distribution lines, previously used by the diesel generators, would minimize the up-front capital costs of the system.

Electricity requirements, and hence hydrogen import requirements, are higher in this centralized microgrid scenario vs. a distributed system, as electricity must be generated for heat and hot water (via baseboard heaters and electric water heaters) as well as power. Efficiency of fuel cell generator systems is ~40% as heat generated by the fuel cells is not re-used.

Hydrogen Microgrid with Renewable Sources

A hydrogen microgrid, either centralized or distributed, can be combined with renewable energy sources, reducing both the amount of hydrogen imported and the GHG emissions due to transport.

Most remote communities are completely reliant on imported diesel for their power generation and transportation needs, and the transport costs make energy supply to these regions very expensive. As such, remote communities provide an attractive cost basis for new competing renewable electricity and hydrogen technologies that can offset imported fuel requirements.

Remote communities can take advantage of renewable energy sources such as wind, solar, and run-of-river hydro. The renewable energy source is connected to a microgrid controller to balance the supply and demand of electricity. In times of excess supply, hydrogen can act as an energy storage medium with surplus electricity fed into an electrolyzer to create hydrogen on-site, thereby reducing hydrogen import requirements.

The Raglan Nickel Mine in Northern Quebec is a successful example of wind energy and hydrogen storage reducing diesel consumption.

WIND POWER AND HYDROGEN STORAGE AT RAGLAN NICKEL MINE IN NORTHERN QUEBEC

At the Raglan Nickel Mine in Nunavik, hydrogen is used as an energy storage solution to reduce diesel consumption.

A 3MW wind turbine was installed and combined with a 3 tiered energy storage system. A flywheel and battery combination filters out large wind variations and transitions the system to diesel generator or 200kW fuel cell for back up power when needed.

A 315kW electrolyzer converts excess renewable supply into hydrogen for storage. A micro-grid controller manages the supply and demand, producing a smooth power output that has allowed wind to generate 50% of the mine's power requirements. The system has reduced diesel consumption at the mine by 2.4 million litres annually and the project can act as a flagship site for future wind development projects.

Source: https://www.nrcan.gc.ca/science-and-data/funding-partnerships/funding-opportunities/current-investments/glencore-raglan-mine-renewable-electricity-smart-grid-pilot-demonstration/16662

CNG with Injected Hydrogen as a Transition Step

CNG is the cleanest burning fossil fuel and can support communities as they transition away from diesel. It provides a cleaner, lower cost alternative and poses much less risk to the environment as it vaporizes, eliminating any contamination or cleanup, in the event of a spill.

CNG generators or Jenbacher engines running on CNG could be used as direct replacements for diesel gensets. They could tie into existing distribution lines in a community and be coupled with renewable energy sources to reduce overall fuel import requirements.

Hydrogen can also play a role with CNG as low carbon hydrogen can be injected into the natural gas grid, reducing the carbon intensity of the CNG produced and shipped to remote communities.

4.5.3 : Challenges and Barriers

Transitioning to clean energy in remote communities can be difficult due to logistical, technical, financial and human capacity challenges that larger communities take for granted.

Geography and Remoteness

Logistically, transporting equipment long distances over difficult terrain can be challenging and expensive. Delays are common, pushing out project schedules and further driving up costs. Construction can be more challenging as infrastructure and equipment taken for granted in larger centres is limited or unavailable. And once a project is up and running, the remote location can limit quick access to technical service people and spare parts which can leave a system down for weeks.

Human capacity is also a huge concern for these projects. Communities often do not have the local technical expertise to plan, develop and support clean energy projects. If outside expertise is brought in to implement the project, the community runs the risk of being left without critical technical knowledge should that person ultimately leave the community.

These factors increase the costs and risks of projects making it difficult to get project financing.

System Complexity and Economies of Scale

Renewable energy sources present an opportunity for remote communities, but also come with challenges. The imbalance between electricity supply and demand must be managed. This means enhanced control systems to manage the intermittent supply sources, adding cost and technical complexity to a new clean energy system. The added complexity increases the risk of downtime and delays in accessing necessary spare parts and expertise to fix the system.

Maturity of technology is of critical concern to remote communities in order to avoid the risk of interruptions and downtime typical of new technology deployments. As such, technology being considered for implementation in a remote community must have been tested for 3 years in 3 separate locations to ensure the reliability of the technology. This requirement will make it challenging to deploy new technologies in the near-term.

Renewable energy projects are becoming more common and can have reasonable project economics when sized at 200-300 MW for wind, 50-100MW for solar and 10MW for small-scale hydro.[142] For remote communities, the system requirements are often an order of magnitude smaller, but still require all the typical project costs, such as engineering, project management and permitting, and thus have higher relative costs. The high costs and small project size make it difficult to get funding or attract private financing.

142 *Pembia Institute. (2018). Renewables in Remote Communities: 2017 Conference Proceedings. Retrieved from https://www.pembina.org/pub/renewables-remote-communities*

4.5.4 : Adoption Scenarios

The opportunity for hydrogen use in remote communities is very small in comparison to other sectors, but can provide significant and meaningful improvement to local air quality. For adoption, these communities require technologies to be more mature (three years of proven deployment) to make the costs and risks more realistic for small-scale deployments. In the near-term, remote communities will focus on energy efficiency improvements in local homes and buildings to reduce overall energy demands and therefore it is assumed that there will be no increase in diesel consumption beyond current levels. Communities will be encouraged to investigate clean energy opportunities such that by 2025 some technologies supporting hydrogen use start to be deployed.

In developing scenarios for hydrogen use in remote communities, it is assumed that hydrogen microgrids will be adopted with centralized diesel gensets replaced by either centralized hydrogen fuel cell generation systems, or distributed small-scale (~ 1-3 kW) cogeneration systems fed through a hydrogen pipeline, similar to the long-term vision for the Japan ENE-FARM project.

Because the CleanBC plan is focused on the 22 largest diesel operations (12 BC Hydro operations and 10 Indigenous Services Canada stations which combined provide ~75% of all diesel generation for BC remote communities), diesel use for these operations was considered separately from the remaining communities. Conservative and aggressive scenarios were developed by estimating the diesel reduction percentage, and the percentage of this reduction that will be attributed to hydrogen.

Conservative Scenario

In the top 22 communities, diesel reduction is assumed to increase gradually from 20% in 2025 to 80% in 2050, with hydrogen responsible for 25% of the reduction. In the remaining communities, diesel reduction increases from 5% in 2025 to 30% in 2050 with no use of hydrogen technologies.

Table 16 summarizes the demand reduction and hydrogen use assumptions for the Conservative Scenario, and the resulting hydrogen demand and GHG reduction.

CONSERVATIVE SCENARIO						
	Top 22 Communities		Remaining Communities		Total	
Year	Diesel Demand Reduction	Energy Use Reduction from H_2	Total Diesel Demand Reduction	Energy Use Reduction from H_2	Total H_2 Demand (t)	GHG Abated (t CO_2e)
2020	0%	0%	0%	0%	0	0
2025	20%	25%	5%	0%	55	1,251
2030	40%	25%	10%	0%	110	2,502
2035	50%	25%	15%	0%	137	3,128
2040	60%	25%	20%	0%	165	3,753
2045	70%	25%	25%	0%	192	4,379
2050	80%	25%	30%	0%	220	5,004

Table 16. Conservative Scenario - Remote Community Hydrogen Demand (2020-2050)

Aggressive Scenario

In the top 22 communities, diesel reduction increases aggressively to 80% by 2030 to achieve the target reduction laid out in the CleanBC plan and then a much more gradual increase to 95% occurs between 2030 and 2050. Hydrogen is assumed to be responsible for 50% of the reduction. In the remaining communities, diesel reduction increases from 10% in 2025 to 60% in 2050 with 10% reduction attributed to hydrogen technologies.

Table 17 summarizes the demand reduction and hydrogen use assumptions for the Aggressive Scenario, and the resulting hydrogen demand and GHG reduction.

AGGRESSIVE SCENARIO						
	Top 22 Communities		Remaining Communities		Total	
Year	Total Diesel Demand Reduction	Energy Use Reduction from H_2	Total Diesel Demand Reduction	Energy Use Reduction from H_2	Total H_2 Demand (tonnes)	GHG Abated (tonnes CO_2e)
2020	0%	0%	0%	0%	0	0
2025	40%	50%	10%	10%	223	5,087
2030	80%	50%	20%	10%	446	10,174
2035	85%	50%	30%	10%	477	10,882
2040	90%	50%	40%	10%	508	11,590
2045	95%	50%	50%	10%	539	12,299
2050	95%	50%	60%	10%	543	12,381

Table 17. Aggressive Scenario - Remote Community Hydrogen Demand (2020-2050)

The results from both the Conservative and Aggressive Scenarios are shown in Figure 66. The potential for hydrogen demand in remote communities in 2050 is estimated to range from 220 to 540 tonnes annually, with GHG reductions in the range of by 5,000-12,400 tonnes CO_2e/year.

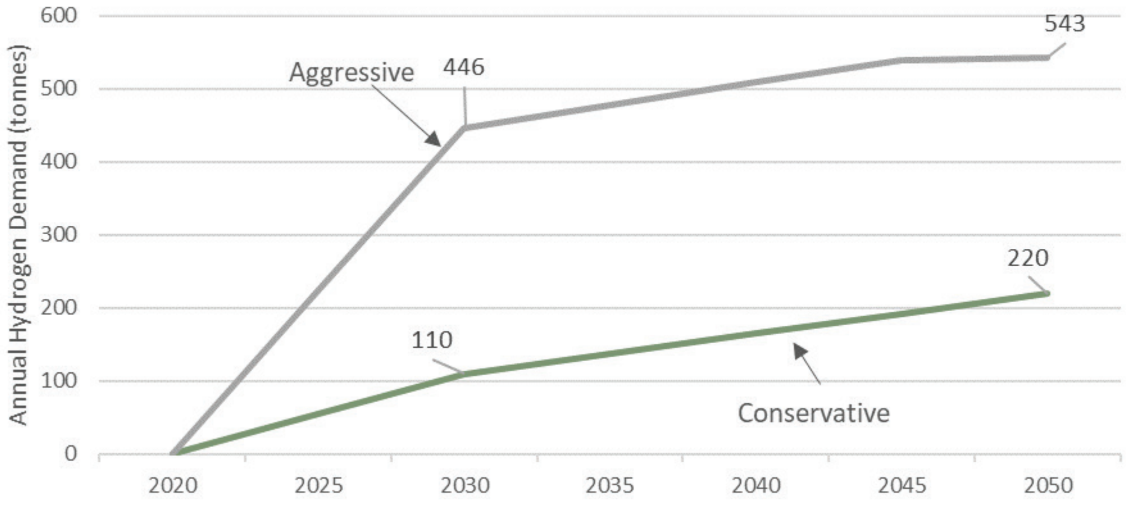


Figure 66. Remote Community Conservative and Aggressive Hydrogen Demand (2020-2050)

4.5.5 : Recommendations

Encourage development of hydrogen microgrids

- *For communities that rely entirely on trucked or barged in energy supply, encourage development of microgrids that utilize a 100% hydrogen distribution grid with local combined heat and power (CHP) generation such as the ENE-FARM program in Japan*

Work with remote communities to develop plans to implement hydrogen related projects and make it easier for communities to own and operate their own facilities

- *Provide a 'hydrogen toolkit' including: support to navigate funding opportunities; technical expertise for planning, implementation and operations; and database with technical and cost details of successful hydrogen projects*

Create access to financing for cleaner fossil fuel-based systems that utilize a CNG / hydrogen blend

5.0 Power to Gas and Energy Storage

5.1 : Power to Gas

Power to Gas (P2G) is the process of converting surplus renewable electricity into hydrogen gas through electrolysis. It is a use case for electrolysis technology discussed in section 3.1.2.

The hydrogen can then be injected into natural gas pipeline networks or for other applications such as a transportation fuel. As shown in Figure 67, hydrogen is versatile once generated, and can be converted into methane or even liquid fuels. (As noted in section 4.1.2, the economics for such transformations may be challenging.)

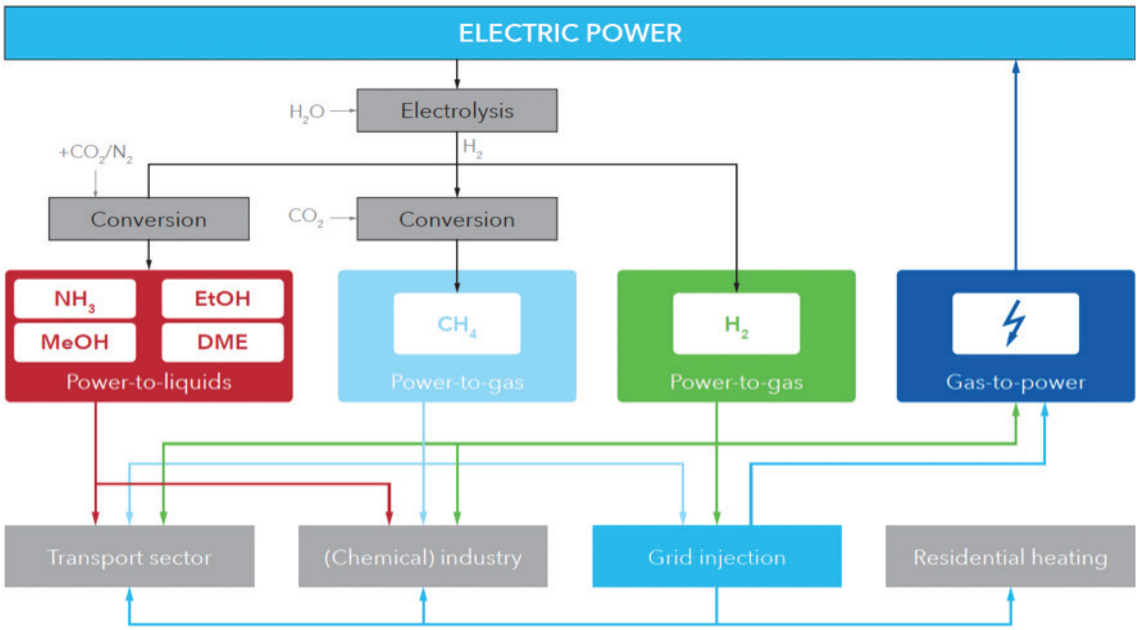


Figure 67. Options for Hydrogen Generated via Power to Gas. Source DNV GL.

Given that hydrogen can be injected into natural gas networks, P2G is sometimes described as a means of connecting the electric and natural gas energy systems; it can also be a key enabler of the transition from a fossil natural gas grid to a decarbonized one.

Rising P2G interest in Europe has been driven by aggressive GHG reduction targets and an increasing supply of variable renewable electricity (wind and solar). Figure 68 shows a DNV GL projection for power generation capacity in Europe. It should be noted that while capacity factors for solar and wind are known to be low, their proliferation has displaced thermal power generation ("combustibles" in the Figure) such that thermal power plants' own capacity factors have begun to decrease over time.

REGENSBURG UNIVERSITY

In 2008 the Regensburg University of Applied Sciences and the Centre for Solar Energy and Hydrogen Research in Ulm jointly developed the concept of power to gas for energy storage. The German government energy agency established a P2G strategy in 2011. There are currently more than 45 P2G projects in Europe.

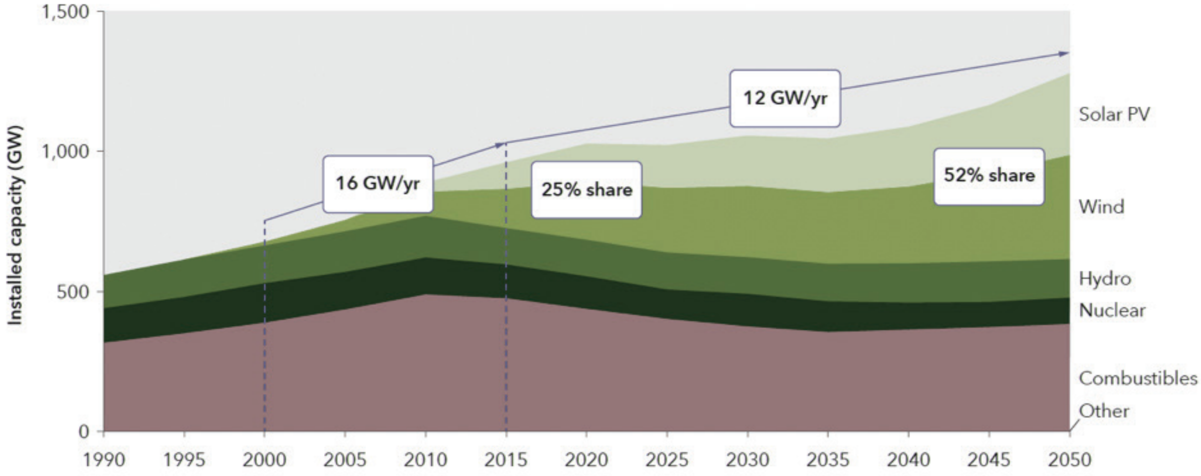
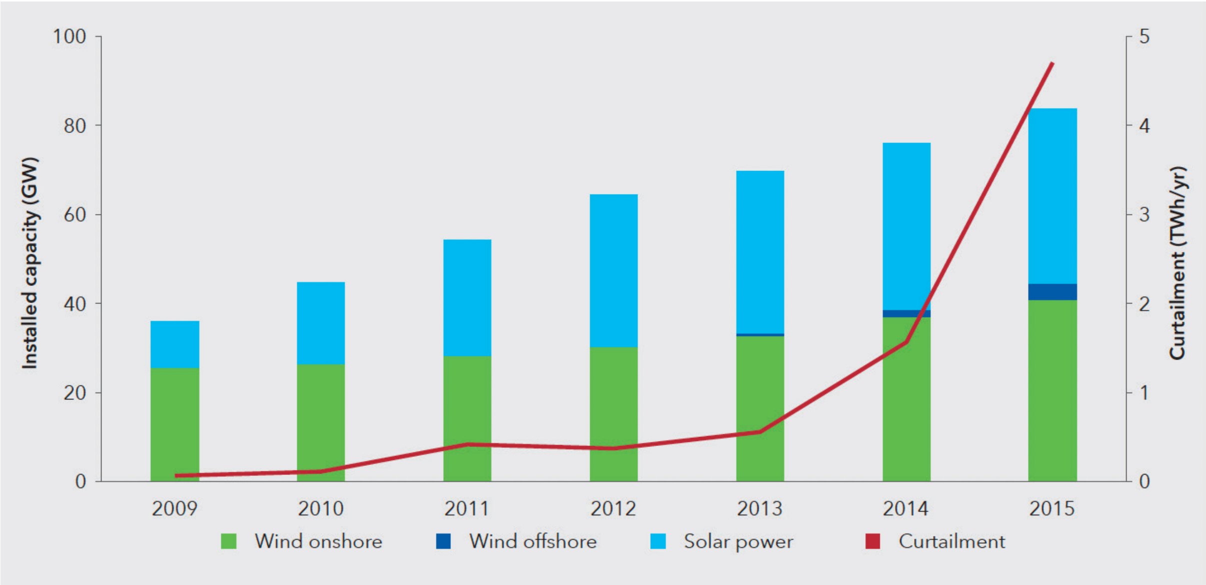


Figure 68. Historic & Future Installed Power Generation Capacity Projections for Europe. Source: DNV GL.

Figure 69 shows the case of Germany, where in 2015 a total of 4.7 TWh of electricity was curtailed, the overwhelming majority from renewables, impairing economic returns for the sector. (4.7 TWh is the amount of electricity that would be generated by a 540 MWh generator operating 24/7/365.)



Germany had an installed capacity of 44.5 GW of wind turbines and 39.3GW of solar power at the end of 2015. The average load profile in Germany fluctuates between 50 and 80GW on a work day and 40 and 60GW during weekends. When both renewable sources produce electricity at full capacity in periods of a lower load profile, there is surplus electricity generation. This situation occurred various times in 2015 resulting in 4.7 terawatthours (TWh) of electricity being curtailed (93% wind and solar power). The network operators had to pay compensations in total of €315 million (m). This amount is expected to increase in the coming years as grid extensions do not have the necessary velocity.

Figure 69. Wind and Solar Deployment and Annual Electricity Curtailment in Germany. Source: Bundesnetzagentur

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5.1.1 : Advantages of P2G Deployment

Advantages of P2G deployment include a reduced need to expand or upgrade electricity transmission networks, and the facilitation of electric grid balancing through demand response and ancillary services. P2G can also help reduce the carbon intensity of natural gas supply, as discussed in section 4.1, and can leverage natural gas infrastructure and storage facilities.

Finally, P2G – as an application of electrolysis – can also facilitate the production of low carbon hydrogen as a zero-emission transportation fuel. In this application hydrogen has a much higher value than when used in natural gas networks, where it is valued purely on heat content.

5.1.2 : Barriers to P2G Deployment

A variety of barriers to P2G have impeded their greater deployment. Barriers have included:

Technology: the PEM electrolyzers best suited to P2G applications remain an early-stage technology.

Economics: though capital costs are expected to fall significantly, they remain high, limiting business cases for deployment.

Carbon pricing: carbon tariffs generally remain too low to incentivize commercial P2G efforts.

Lack of collaboration: a lack of collaboration between the electricity and natural gas grids has impeded P2G's use as a bridge linking the two energy infrastructures.

5.1.3 : P2G in Europe

Figure 70 shows the locations of 45 P2G demonstration projects underway in Europe as of October 2018. Germany is home to more than 30 of the demonstration P2G projects, comprising an electrolysis load capacity of approximately 25 MW.

The main challenges have related not to the technology, but to achieving commercial cost targets. Equipment cost reductions, efficiency improvements and policies such as renewable energy tariff structures are believed necessary for P2G to be viable beyond demonstration projects. (The CleanBC target for 15% Renewable Gas is an example of such a policy.)

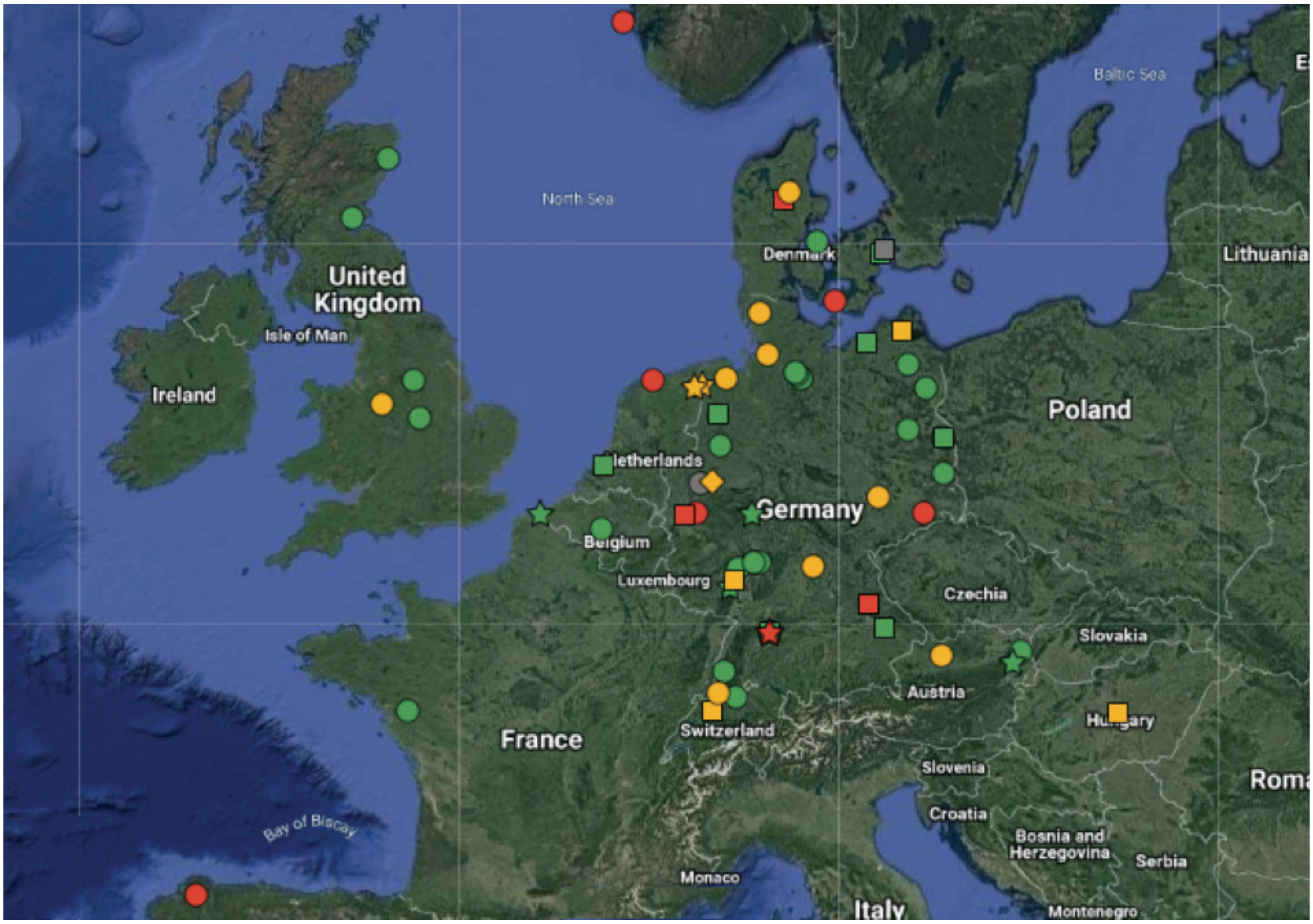


Figure 70. P2G Projects in Europe. Source: Europeanpowertogas.com

5.1.4 : P2G in North America

North America's first P2G facility began operations in Ontario in July 2018 when a 2.5 MW PEM electrolyzer from Hydrogenics was installed under contract to the Ontario Independent Electricity System Operator (IESO). The electrolyzer will provide grid energy demand response functions to the IESO and the hydrogen produced will be injected into the Enbridge gas distribution network.

In the United States, California utility SoCalGas has teamed with other organizations to run an electrolyzer powered by solar photovoltaics and inject renewable hydrogen into the campus power plant at UC Irvine. The utility has also established a partnership with the U.S. Department of Energy's National Renewable Energy Laboratory to install the United States' first biomethanation plant, located at the Energy Systems Integration Facility in Golden, Colorado.

5.2 : P2G Opportunities in BC

BC's geography provides an abundant supply of clean, renewable hydroelectricity, which with other renewables provides more than 90% of BC Hydro's annual production. Equally importantly, hydroelectric dams serve as a reservoir for storing and discharging energy. As variable renewables are added to the grid, hydroelectric dams alleviate the need for energy storage in the near-term.

There remain advantages to producing hydrogen via electrolysis in BC for use as a bridge linking the electric and natural gas energy systems. As an example, hydrogen produced via electrolysis could be used directly by utilities such as BC Hydro and FortisBC to optimize the use of their utility infrastructure.

5.3 : Recent P2G Developments

Hydroelectric utilities in the U.S. Pacific Northwest are developing plans to produce hydrogen to complement their energy offerings. The states of Washington and Oregon have conducted studies to determine opportunities for decarbonizing their energy systems, and the production of clean hydrogen from hydroelectricity for transportation fuels was found to be a strategic opportunity.

In April 2019, Substitute Senate Bill 5588 was signed in Washington State authorizing Public Utility Districts (PUDs) to produce, distribute and sell renewable hydrogen.[143] Douglas County PUD announced plans to be the first utility to do so; during periods of high river flows, solar and wind generation, it had resorted to spilling excess water. Hydrogen production would be a means of creating value.

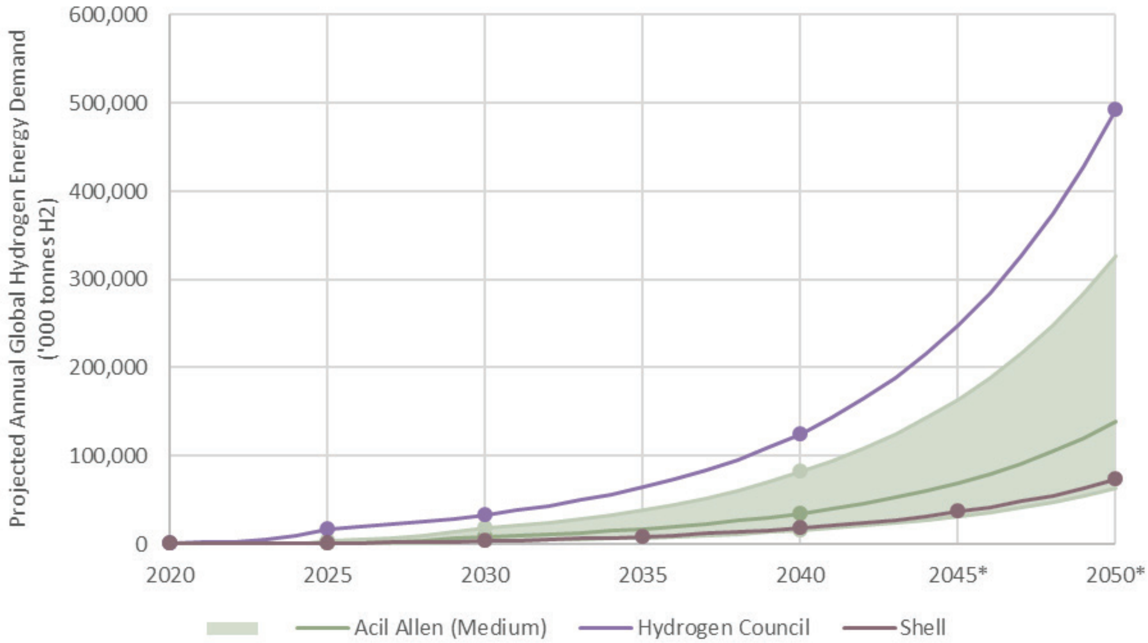
It is anticipated that similar benefits could be realized by BC's utilities, so it is recommended that energy storage/ hydrogen production opportunities be evaluated further through pilot demonstration projects. Expanding the mandate of utilities to include the production, distribution and sale of hydrogen could also be a key enabler for increasing hydrogen supply in the Province.

143 *Washington State Legislature. (2019). Authorizing the production, distribution, and sale of renewable hydrogen. SB 5588 – 2019/20. Retrieved from https://app.leg.wa.gov/billsummary?BillNumber=5588&Year=2019&Initiative=false*

6.0 : Global Demand and Market Potential for Hydrogen

6.1 : Global Hydrogen Demand Projections to 2050

Hydrogen is expected to become increasingly important in the world's energy economy, though projections vary significantly based on assumptions around technology development and policy adoption. Figure 71 compares recent global hydrogen energy demand estimates from Acil Allen, the Hydrogen Council, and Shell.[144, 145, 146] Note that it does not include hydrogen use in industry.



**Acil Allen projections only provided to 2040. The 2050 values were estimated based on the year over year growth from the Hydrogen Council and Shell reports.*

Figure 71. Estimated Annual Global Hydrogen Demand (2020-2050).[144, 145, 146] Hydrogen consumption in industrial processes is not included.

144 Acil Allen Consulting. (2018). Opportunities for Australia from Hydrogen Exports. Retrieved from https://arena.gov.au/assets/2018/08/opportunities-for-australia-from-hydrogen-exports.pdf

145 The Hydrogen Council. (2017). Hydrogen Scaling Up: A Sustainable Pathway for the Global Energy Transition. Retrieved from http://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf

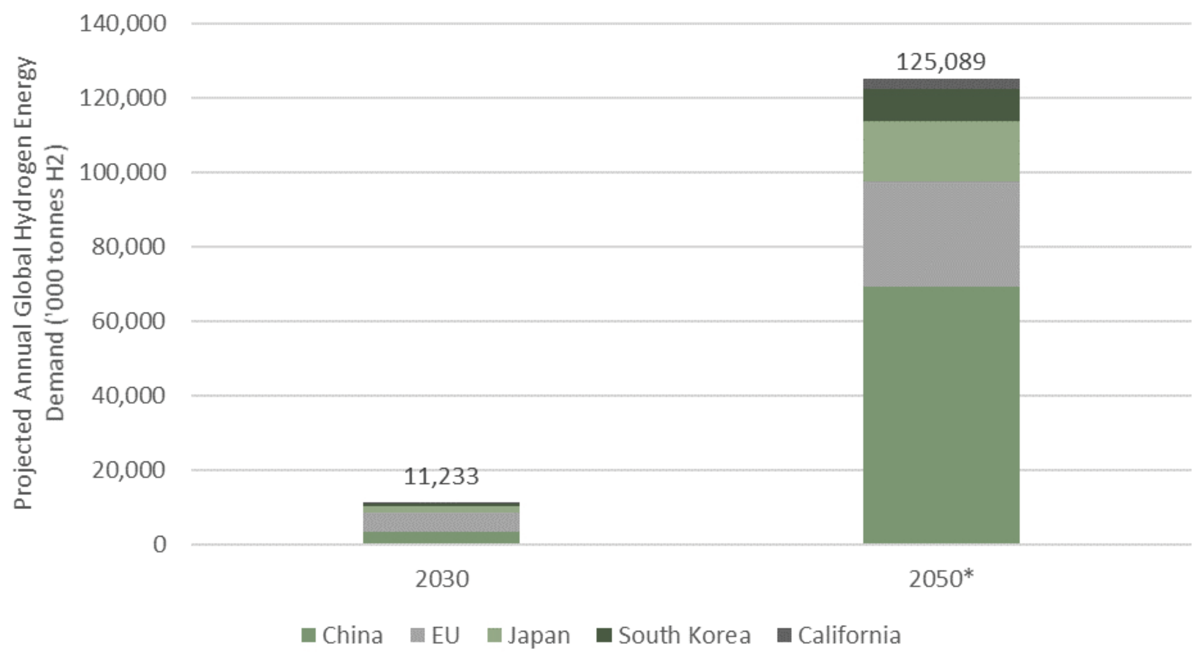
146 Shell. (2018). Shell Sky Scenario: Meeting the Goals of the Paris Agreement. Retrieved from https://www.shell.com/energy-and-innovation/the-energy-future/scenarios/shell-scenario-sky.html

Acil Allen provides low, medium, and high hydrogen uptake scenarios based on assumptions around the afore-mentioned technology development and policy adoption, as well as climate change and alternative fuel prices.[144] The Hydrogen Council projection is based on an ambitious vision in which hydrogen accounts for 18% of total energy demand in 2050.[145] Shell's Sky Scenario projects a slower uptake of hydrogen technologies, but still expects hydrogen to emerge as material energy carrier after 2040, resulting in 800 million tonnes of hydrogen demand for energy by 2070.[146]

Figure 72 shows the medium range estimate of hydrogen demand for regions which have placed the greatest emphasis on hydrogen technologies in 2030 and 2050. Figure 73 shows a range of estimates for each region individually. Demand projections for China, Japan and South Korea were based on Acil Allen.[144] EU projections were from FCH-JU[147] and California projections were from UC Irvine.[148]

Japan, China and South Korea – the world's three largest importers of liquefied natural gas (LNG) – have each embarked on ambitious hydrogen initiatives, which could explain the more aggressive projections. In California, the projections plateau around 2050 assuming hydrogen reaches its full market penetration potential.

Looking at these markets together, in 2030 and 2050 the total market size, based on the medium projection for each region, are 11.2 million tonnes per year and 125.1 million tonnes per year, respectively.



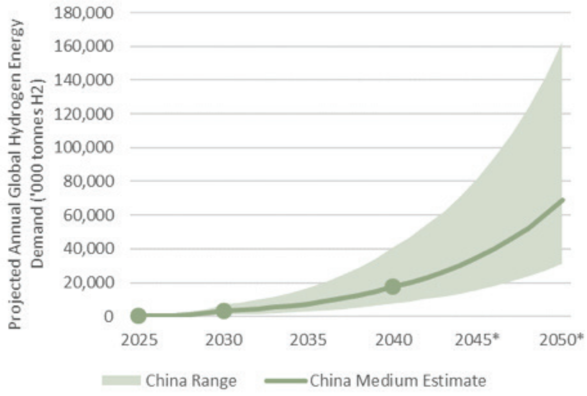
**Acil Allen projections only provided to 2040. The 2050 values were estimated based on the year over year growth from the Hydrogen Council and Shell reports.*

Figure 72. Medium Range Estimated Annual Hydrogen Energy Demand of Selected Countries (2025-2050)[144, 147, 148]

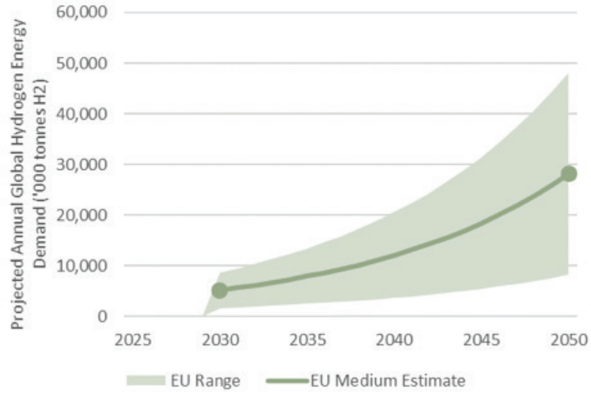
147 Fuel Cells and Hydrogen 2 Joint Undertaking (2019). Hydrogen Roadmap Europe: A Sustainable Pathway for the European Energy Transition. Retrieved from https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf

148 UC Irvine/Advanced Power and Energy Program. (2019). Renewable Hydrogen Transportation Fuel Production. Retrieved from https://efiling.energy.ca.gov/GetDocument.aspx?tn=227515&DocumentContentId=58764

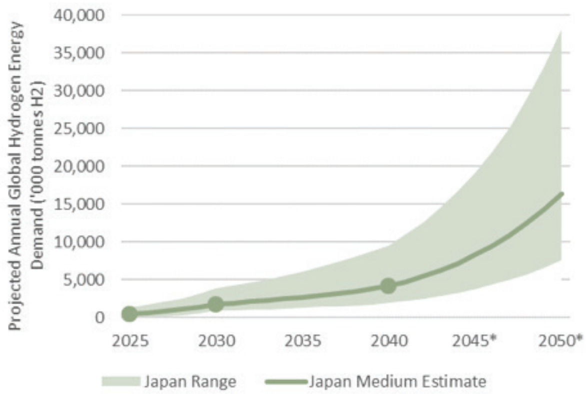
China[144]



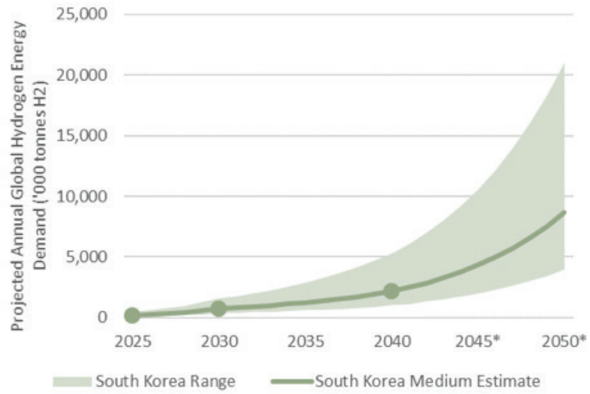
EU[147]



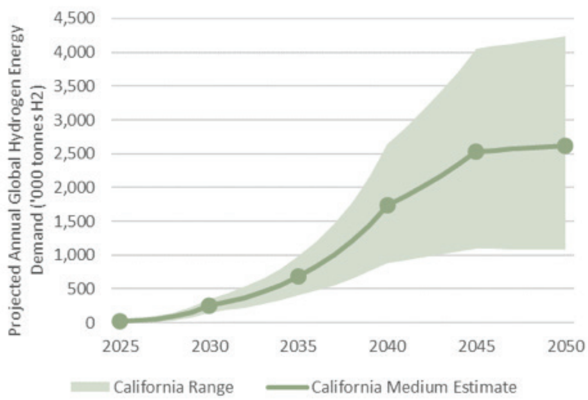
Japan[144]



South Korea[144]



California[148]



**Acil Allen projections only provided to 2040. The 2050 values were estimated based on the year over year growth from the Hydrogen Council and Shell reports.*

Figure 73. Estimated Annual Hydrogen Energy Demand of Selected Countries (2025-2050)

6.2 : Hydrogen Export Opportunity

As discussed in Section 3.0, BC has the potential to produce vast amounts of low-cost, low carbon hydrogen, leveraging the Province's abundant renewable electricity and natural gas resources.

BC's strategic advantages for producing hydrogen for export include:

- *Deepwater harbour accessible locations for the production and supply of large quantities of hydrogen to export markets, such as California, Japan, the Republic of Korea and China;*
- *An abundance of a very low carbon electricity with which to produce hydrogen through electrolysis;*
- *Large quantities of fresh water available for electrolysis; and*
- *An abundance of low-cost natural gas with which to produce hydrogen through SMR+CCS and pyrolysis.*

6.2.1 : Key Markets

Four key markets have been identified as viable export market for BC hydrogen: California, Japan, the Republic of Korea, and China. They are in closer proximity to BC than to other likely hydrogen exporters and have defined policies and programs to grow the development and use of clean hydrogen as an energy vector.

6.2.1.1 : California

California's projected hydrogen demand is expected to be as large as 1 to 4 million tonnes by 2050. The state is also a prime candidate to be an importer of renewable hydrogen in the future and has strong Governmental regulations and supportive funding for the initiation of a hydrogen supply infrastructure and deployment of fuel cell powered mobility.

6.2.1.2 : Japan

The Ministry of Economy, Trade and Industry (METI) from the Japanese Government developed the "Basic Hydrogen Strategy" (December 2017) for a plan of action until 2030, and, a future vision up to 2050. The prognosis for 2050 is for demand of between 5 to 35 million tonnes of hydrogen per year. The country is expected to be a very large importer of hydrogen and has already begun investigating supply options for importing large quantities of clean hydrogen in the future.

6.2.1.3 : The Republic of Korea

The Korean government has recently published its National Hydrogen Economy Roadmap. The prognosis for 2050 is for a demand of between 4 to 20 million tonnes per year.

6.2.1.4 : China

China is currently the leading region for the growth of renewable hydrogen and fuel cell market segments. The Chinese government is financially supporting these industries at the federal, provincial and municipal levels. The prognosis for 2050 is a demand of between 18 to 160 million tonnes per year.

6.2.2 : Storage and transport technologies

Hydrogen storage and transport from production hubs to users' sites will be one of the more challenging obstacles for the large-scale global adoption of hydrogen as a renewable energy vector. Liquefaction and chemical storage, in the form of chemical carriers, are treated in section 2.2.

6.2.3 : BC's Positioning

BC currently lacks a clear position on the importance of developing a hydrogen export market, in part because the demand for hydrogen is just starting to grow. In addition, BC has not currently developed any sources of hydrogen supply.

Australia would be a major competitor to BC in the Asian target markets identified above and has developed both a national roadmap and a strategy to guide development of a hydrogen export sector. It can also leverage decades of experience as an LNG exporter.

The size of the potential hydrogen export market for BC is significant. In 2030 and 2050, respectively, the total market size of the four combined target markets of China, Japan, Korea and California is expected to be $87 billion and $305 billion, respectively. If BC were to capture just 5% of these markets, this would represent export revenue potential of $4 billion in 2030 and $15 billion in 2050. Not only would this bring new export revenue to the Province, but it would stimulate local employment growth and would likely attract foreign capital investment.

The development of large-scale hydrogen export markets would create high enough production volumes that the cost of hydrogen in the Province would decrease. This would stimulate additional in-Province deployment, as lower cost hydrogen would improve the business case of switching from fossil fuels.

A SWOT (strengths / weaknesses / opportunities / threats) analysis is presented in Table 18 below.

STRENGTHS	WEAKNESSES
◆ *Abundance of renewable electricity for electrolytically produced hydrogen* ◆ *Relativley low-cost electricity for hydrogen production* ◆ *Abundance of water for electrolysis* ◆ *Close proximity to numerous large import markets via ocean freight* ◆ *Large source of natural gas supply for the production of clean hydrogen using SMR and CCS* ◆ *Export focused communities and sites along the BC West Coast* ◆ *Availability of deep water harbours to handle large ocean going vessels for export*	◆ *Clearly defined government policies, objectives and strategies to support and grow the clean hydrogen export markets* ◆ *The need to develop additional incentives to support the competitive production and supply of clean hydrogen to export markets* ◆ *Cost reductions in the production of clean hydrogen production technologies required to meet the various target prices for clean hydrogen in numerous global markets and related segments*
OPPORTUNITIES	**THREATS**
◆ *Business and job growth for local, remote communities and First Nations in BC* ◆ *Large future demand markets including California, Japan, Republic of Korea and China relatively close to BC* ◆ *The opportunity for multinationals involved in the clean energy economies to invest in BC* ◆ *Growth of the BC hydrogen related research and technology development* ◆ *The ability for BC to play a positive role in the reduction of GHG by producing and exporting large quantities of renewable hydrogen* ◆ *A large hydrogen export economy in BC will support low-cost domestic market needs*	◆ *Competition from Australia that has established a clear government-led strategy to produce and export large quantities of renewable hydrogen in the future* ◆ *Loss of the strong hydrogen and fuel cell resource base in BC to competitive regions around the globe*

Table 18. BC Hydrogen Export SWOT Analysis

7.0 : BC's Competitive Advantages and Disadvantages in Hydrogen and Fuel Cells

Canada's hydrogen and fuel cell sector is recognized as a global leader. In 2018, the industry generated revenue of $207 million and was responsible for 2,177 jobs. British Columbia, as the "cradle of the modern fuel cell industry", is home to Canada's largest hydrogen and fuel cell industry cluster as shown in Figure 74.

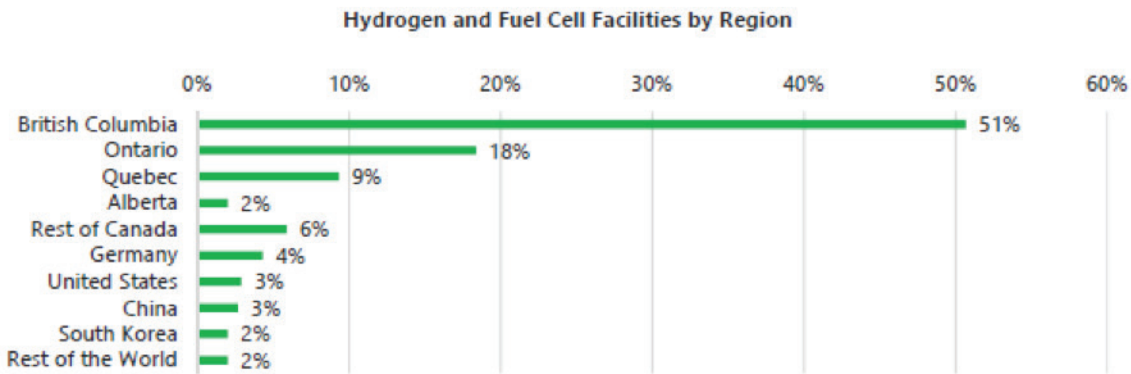


Figure 74. Hydrogen and Fuel Cell Facilities by Region[150]

BC's cluster has advanced technologies for hydrogen production and processing, equipment and systems testing, has undertaken world-leading research, development and commercialization, and has played a leading role in standards development. The Province is also home to world-class academic institutions supporting the clean tech sector. Centres of Excellence have been established at the University of British Columbia (UBC), the University of Victoria (UVic), Simon Fraser University (SFU) and the University of Northern British Columbia (UNBC).[149]

7.1 : Competitive Advantages and Recommendations

7.1.1 : Fuel Cells

BC is a global leader in the fuel cell sector, the industry cluster having been formed around Ballard Power Systems 40 years ago. Industry-academic collaborations and state of the art research and development facilities have created a recognized talent pool and recently led Austrian automotive consulting company AVL to establish its fuel cell research and development centre in Burnaby. Canadian companies such as Ballard Power Systems, Loop Energy, Hydrogen Technology and Energy Corporation (HTEC) and Powertech are also recognized as international leaders.

149 *UBC: Centre for Energy Systems Applications, Centre for Interactive Research on Sustainability and the Institute for Resources, Environment and Sustainability. SFU: School of Mechatronics. UVic: Institute for Integrated Energy Systems. The aforementioned and UNBC are all involved with the Pacific Institute for Climate Change Solutions.*

150 *CHFCA. (2018). Canadian Hydrogen and Fuel Cell Sector Profile. Retrieved from http://www.chfca.ca/media/CHFC%20Sector%20Profile%202018%20-%20Final%20Report.pdf*

7.1.2 : Potential Producer of Hydrogen – Natural Resources

BC is well positioned to become a bulk producer of hydrogen given its:

- *clean, renewable, low-cost hydroelectric resources;*
- *abundant, low-cost natural gas and supporting distribution network;*
- *proximity to major markets.*

The carbon intensity of BC Hydro's electricity generation is one of the lowest in North America, meaning hydrogen produced through electrolysis would have a very low carbon footprint.

As noted in prior sections, BC's low-cost natural gas can provide another path for supplying cost-competitive hydrogen, even when CCS costs are factored in.

Finally, BC's coastal access and relative proximity to leading markets such as California, Japan, South Korea and China put the Province in an excellent position to become an exporter of clean hydrogen. The Province's economy is heavily dependent on the export of natural resources, and hydrogen is a means by which BC can provide energy exports without emissions.

7.1.3 : Hydrogen Infrastructure

Vancouver is home to the first public hydrogen refueling station in Canada, part of a network of stations being built in the Metro Vancouver and Capital Region Districts. As demonstrated in California and elsewhere, fuel infrastructure leads the deployment of fuel cell electric vehicles, resolving the so-called "chicken-and-egg" dilemma. BC's investments in hydrogen fueling infrastructure provide a signal for auto manufacturers to make their FCEVs available for sale in this province.

7.1.4 : Recommendations

7.1.4.1 : Provincial Project Deployments

Products from BC's hydrogen and fuel cell industry cluster are deployed in the United States, Europe and Asia, but there are currently no deployments of BC hydrogen and fuel cell technology within the Province.

Local deployments of technology are key to maintaining employment, technical expertise and intellectual property in-province; ownership also tends to shift to where deployments occur. A recent case is that of BC's Corvus Energy, a pioneer in the use of battery energy storage systems for marine applications. Norway was home to many of its early product deployments, and by 2017 ownership stakes had been taken by Hydro and Statoil Technology Invest (both Norwegian) and BW Group (headquartered in both Norway and Singapore).[151]

It is strongly recommended that the Province deploy hydrogen and fuel cell technology from its own cluster, within-province. This would help root BC's sector expertise in British Columbia and would encourage international participants to locate themselves in-province as well. Deployments and pioneering lighthouse projects would strengthen the local cluster, provide additional opportunities for collaboration between industry and academia, and help BC businesses develop world-leading expertise they can export to slower-moving jurisdictions.

151 *Corvus Energy. (2017). Global Aluminum Supplier Makes Significant Investment in Corvus Energy. Retrieved from* https://corvusenergy.com/global-aluminum-supplier-makes-significant-investment-in-corvus-energy/

7.1.4.2 : Lead a Coordinated BC Cluster Strategy

Although BC is recognized as a centre of hydrogen and fuel cell expertise, companies involved in the sector operate very independently. At the federal level, the Canadian Hydrogen and Fuel Cell Association (CHFCA) provides a mechanism to pull companies in the sector together, but more is needed at the Provincial level to encourage and support stronger joint initiatives locally.

An organization similar to the California Fuel Cell Partnership (CaFCP) or Hydrogen Valley in Denmark could help coordinate industry and academia collaborations and work to ensure that companies are operating in step with each other as technology is brought to market. A provincial association could assist with initiatives to help Academia develop curriculum that will support talent development to grow the cluster. The association could also provide coordinated media efforts and outreach activities to educate the public about hydrogen and fuel cell initiatives occurring locally in our Province as well as abroad.

A Stream 5 Application through the Strategic Innovation Fund[152] could also be developed to support a coordinated cluster strategy for hydrogen and fuel cells.

7.2 : Competitive Disadvantages

7.2.1 : No Deployments in the Province

Despite being a leader in hydrogen and fuel cell R&D, there are no current technology deployments in the province. Local deployment of technology is key for BC companies to showcase their technology to attract investment, increase their scale of operations, improve their market readiness and support continued industry advancement.

Deployments of fuel cell buses, using world class fuel cell technology developed in BC, are well established in Europe, China and the US. Unfortunately, locally, there are no fuel cell bus deployments and no support from local transit authorities to consider fuel cell technology as a clean energy alternative. Support is needed to encourage technologies developed in BC to be demonstrated locally.

Without local project deployments, critical technical skill sets in manufacturing and operations, necessary for scaled up operations and commercialization, are not being developed. And although local academic institutions have supporting clean energy programs, relevant practical training, necessary for students to succeed in fuel cell sector jobs, is not being provided. An integrated project deployment with collaboration of industry and academia, could guide academia to develop appropriate curriculum to meet future skill set requirements in the sector. It would also ensure that knowledge and hands-on technical skills required to grow the sector beyond the R&D phase are created within the province.

The high cost of living in Vancouver also contributes to scarcity of technical personnel as it makes it difficult to both attract, and keep, skilled personnel.

152 *Innovation, Science and Economic Development Canada. (2019). Stream 5: National Ecosystems. Retrieved from https://www.ic.gc.ca/eic/site/125.nsf/eng/00017.html*

7.2.2 : Lack of Provincial R&D Funding

Investment is needed to maintain the province's leadership role in hydrogen and fuel cell R&D. Mid-TRL level projects are the most effective in developing technology and creating jobs, but currently in BC, there is no funding to support these types of projects.

Local organizations require access to funding that can be leveraged to access greater funds from outside entities. For example, a recent federally funded Ballard Power R&D project was moved from BC to Ontario because there was no provincial funding available in BC, which was required to access the federal funds.

NRCan no longer funds R&D and funding that is available, such as IRAP on a federal level, is spread thinly, with relatively modest sums. Funding can also be limited for larger companies or those with large parent companies. For example, AVL opened a fuel cell technology R&D centre in Vancouver because Vancouver has the largest cluster of fuel cell expertise in the world and can provide a solid base on which to further develop their fuel cell technology and commercialization plans. By locating in Vancouver, AVL creates additional jobs in the cluster and advances the technology, but because of its large parent company, is not eligible for funding.

Ballard has also hit the small to medium-sized enterprise (SME) limit on their eligibility to access local funding as their company size now exceeds 500 employees. As a result, Ballard is opening a Fuel Cell Centre of Excellence at their facility in Hobro, Denmark which will allow them to take advantage of $900 Million in funding available for European projects. Denmark will benefit from the jobs and technical skills developed at this CoE.

7.2.3 : Competitive Threat from China

China is investing heavily in hydrogen and fuel cell technologies and is preparing to deploy on a massive scale. It has aggressively pursued investment in foreign technology, and with its requirement for local content, foreign companies are establishing joint venture facilities in China.

Ultimately, China's large-scale development of fuel cell technology will drive down costs, benefitting the entire

BALLARD DEVELOPING NEXT-GEN FUEL CELL WITH ONTARIO UNIVERSITIES

The Canadian Urban Transit Research and Innovation Consortium (CUTRIC) is funding a collaborative project between industry, academia and government to develop low-cost, high performing durable fuel cells for next generation transit and automobile applications.

Project Partners: *University of Waterloo (Principal Investigator), Western University, Ballard Power Systems Inc.; and, StarPower ON Systems Inc.*

Funding: *CUTRIC, NSERC CRD, Industry Partners.*

BALLARD ESTABLISHING COE IN EUROPE

Ballard will establish a Marine Centre of Excellence (CoE) at its engineering, manufacturing and service facility in Hobro, Denmark.

The CoE will focus on development of next generation heavy-duty fuel cell module targeted for European marine applications with commercial launch planned for late 2019.

BALLARD-WEICHAI POWER COLLABORATION IN CHINA

Ballard has entered a strategic joint venture with Weichai which will see Ballard's next generation LCS fuel stack and fuel stack modules for buses and heavy-duty trucks manufactured in China.

industry, however, it comes at the expense of jobs and IP being created in China. As an example, Ballard is entering into a strategic joint venture with Weichai Power in China which will allow them to take advantage of the investment opportunities and enormous market size that China has to offer.

7.2.4 : Recommendations Moving Forward

(1) **Identify Hydrogen and Fuel Cells as a Priority Sector**

Despite its global leading status in fuel cell technology, this sector has not been explicitly identified as a priority by the Province. During discussions involving clean technology, such as zero emission vehicles, the focus is often entirely on BEVs, with FCEVs left out of the discussion altogether. As an example, the current Federal incentive cap of $45,000 for Zero Emission Vehicles eliminates fuel cell vehicles as an eligible option as the technology is still pre-commercial and no FCEVs fall within this threshold.

The Province needs to communicate strongly and consistently to the Federal Government that hydrogen and fuel cells are an important priority sector for BC.

(2) **Provincial R&D and Deployment Funding Support**

It is important for the Province to commit to research, development and deployment funding over the longer-term. Local organizations should have access to funding that can be combined with matching funds from the Federal government or leveraged to access greater funds from outside entities. Companies in the Province also struggle with reduced federal R&D funding, as NRCan has shifted its focus from R&D to infrastructure deployment.

The ARC program supports BC companies operating in the clean electric vehicle (CEV) sector and encourages international investment. The ARC fund could be expanded to support technologies beyond transportation and provide a base for matched federal funding.

(3) **Support for Maintaining Leadership**

It is recommended that the Province adopt an industrial policy of assisting BC companies in navigating the Chinese market. In the case of fuel cells, the BC sector would be advised to identify competitive advantages, such as the manufacturing of highly automated parts, that cannot be easily replicated by Chinese competition. Investment and policy support are necessary to keep the companies, jobs and technical knowledge in BC.

Canada has strong federal support organizations that may be able to assist in facilitating technology exchanges between China and BC. Establishing “sister province” initiatives with projects operating in parallel may provide a mechanism to overcome China’s strong preference to localize manufacturing.

7.3 : Opportunities for Innovation Leadership

The areas for BC innovation leadership can be divided into the categories of policy, investment and technology.

(1) **Policy**

BC can be a global leader by adopting policies that promote and support all sides of an emerging hydrogen economy including demand, supply and technology development. Any policy needs to maximize the GHG reduction impact, manage the cost issues associated with the change-over and allow the market to act in terms of technology selection. BC is rich in two key natural resources for the production of clean hydrogen: natural gas reserves and renewable hydroelectricity. Our policies should set BC as the global leader in hydrogen production from both of these assets with a clear understanding of how their inherent cost structure will drive market adoption. Specifically, decarbonized hydrogen from hydrocarbon sources will be cheaper and thereby adopted earlier, but at the same time, the policies should encourage the gradual transformation from the lower cost natural gas-sourced hydrogen to the more expensive fully renewable hydrogen as the finite hydrocarbon sources are depleted over time.

(2) **Investment**

BC can strongly drive innovation leadership by where and how it chooses to invest its capital. BC has had global innovation leadership over hydrogen and fuel cells in the past and there continues to be key innovation resources resident in BC to this day. However, because there has been only ad-hoc investment continuity, other areas in the world have largely taken over this innovation leadership position.

These competing regions include China – who have been actively hiring BC experts to bolster their own innovation leadership; Japan and Korea – countries who have declared their commitment to developing a hydrogen economy and are heavily investing in low-cost hydrogen production technologies, import systems, and hydrogen and fuel cell vehicles; the UK is conducting public trials of using hydrogen in NG networks; Germany is focussing on storing excess renewable energy using power-to-gas.

BC does well in the generation of large clean energy companies such as Ballard Power Systems, Carbon Engineering, InvenTys and General Fusion largely because of past investments in fuel cell and hydrogen through Ballard and other initiatives in the past. This had the effect of creating highly experienced, clean technology venture professionals who have spurred other innovation and venture creation. The Province can become a global leader in the development of hydrogen economy by investing in:

1) ***Revitalization of the Innovative Clean Energy (ICE) Fund***. The ICE fund plays an important role in the early stage infrastructure of BC's clean technology community and more funding will be essential to help foster the next generation of innovative clean energy companies.

2) ***Development of large H_2 infrastructure initiatives***. Large programs such as those being enacted in the UK and Japan will catalyze and concentrate the technology innovation required to execute these programs in sustainable techno-economic fashion. Examples of programs that could be enacted in BC are listed below. For each of these programs, there should be 'customer requirements' such as carbon intensity (CI) limits and cost targets established to which the sector must innovate.

    a. Build large decarbonized hydrogen production and CO_2 sequestration facilities in the Peace Region where BC can utilize its NG resources to provide decarbonized hydrogen into the NG grid for provincial or export use.

    b. Convert government fleets to fuel cells and hydrogen with stricter carbon intensity limits and cost criteria than the previous bus program in Whistler.

    c. Convert an entire community or area (such as UBC or a remote community) to hydrogen including production, storage, delivery and end use (vehicles, power, and heat) with a zero GHG emission target

    d. Build large LH_2 liquefier(s) in the province to help support low-cost transport of hydrogen fuel to market demand sites.

    e. Establish pilot facilities co-located at the Kitimat NG export terminal for the export of hydrogen produced in BC to the emerging global markets.

3) ***Tax incentives*** – Provide all investors in hydrogen and clean technologies with tax exempt status for their investments and create tax credits for business and individuals buying hydrogen and hydrogen related projects.

(3) **Technology Innovation**

a. ***Low-Cost Green and Blue Hydrogen Production***

Innovation is required to develop new production methods that can produce industrial quantities of hydrogen at a cost structure that is as low as current NG costs plus BC's CO_2 avoidance incentives. This means that the hydrogen will likely need to be under \$10/GJ (equivalent to \$1.20/kg H_2) to get industrial, commercial and residential consumers to take up the fuel without forcing regulations. In addition, if these costs can be achieved, the use of hydrogen as a vehicle fuel or as an input to the production of renewable synthetic fuels will become more widespread.

The specific areas of innovation include:

- *Low-cost NG pyrolysis technology to produce hydrogen and solid carbon from NG and other hydrocarbon feedstocks.*
- *Technologies and processes to utilize and monetize the emerging and plentiful carbon feedstocks to help offset costs of NG pyrolysis H_2 production methods.*
- *Lower cost and higher efficiency electrolysers including those that can operate at vehicle refueling pressures.*
- *Lower cost and less energy intensive technologies to convert renewable CO_2 and H_2O into H_2 and CO as feedstocks for renewable synthetic fuels.*

b. ***Hydrogen storage and delivery***

H_2 delivery and storage are key parts of any hydrogen economy. Hydrogen needs to be transported to the consumer as either a liquid or a gas. Areas of innovation include:

- ***Liquefaction*** *– Low-cost H_2 liquefaction will be essential for the delivery of H_2 to different customer sites, particularly refueling sites. Liquid hydrogen (LH_2) is transported and delivered at a much lower cost than compressed H_2 (CH_2). As BC develops a H_2 economy, it is possible that BC could become a net exporter of hydrogen to the world energy markets and would have further incentives to develop low-cost LH_2 liquefiers. Large baseload LNG plants are approaching ideal efficiencies but H_2 liquefaction costs are high and energy intensive – there is a long way to go. As well, technical innovation will be required on how to best recover LH_2 exergy since it is much higher than LNG due to lower liquefaction temperatures and ortho to para conversion. The Institute for Integrated Energy Systems at the University of Victoria (IESVic) has been researching novel hydrogen liquefaction and exergy recovery technologies since 1990 and is well suited to play a key role.*
- ***Pipelines*** *– A hydrogen economy will use as much of the sunk infrastructure as possible. In the case of the NG grid, BC already has a fully developed mature gaseous fuel distribution system. At present, BC can likely inject up to 10-15% of H_2 by volume in the NG grid without modification. To get to higher hydrogen utilization, the pipelines will either have to be replaced with pipelines made with hydrogen compatible materials or we will innovate a way to modify the existing pipelines in-situ in a cost-effective way.*
- ***Gas Separation*** *– The production and distribution of hydrogen requires separation of hydrogen with other gases. In typical cases, this can be accomplished with mature pressure swing absorption (PSA) technology. However, in certain production methods, H_2 will need to be separated from combusted gases and nitrogen which is not as straightforward. When H_2 is mixed with NG in the grid, there will likely be many instances where it will be advantageous to separate the H_2 at sites where demand is the highest and these sites are unlikely to correspond with pressure let down stations where PSA technology could be used. There needs to be innovation in low-cost hydrogen separation technologies such as membranes and electrochemical methods.*
- ***Other Hydrogen Storage*** *– LH_2 is an important way to store hydrogen but suffers from high capital costs. Other innovative storage technologies include cryo-compression, solid state storage, liquid organic storage, adsorbents, and non-carbon chemical carriers such as ammonia.*

c. ***Grid optimization using electrolysis hydrogen***

The electrolysis hydrogen production pathway offers unique opportunities to connect the electric grid and natural gas energy infrastructure in an optimized and efficient system. Innovative technology development includes grid monitoring and control systems, integration technologies that span the electrical and gas grid control systems, predictive Artificial Intelligence (AI) technologies that anticipate intermittent power production and storage variables.

d. ***Fuel cells***

BC still arguably holds an innovation edge in fuel cell technology. However, that hold is tenuous at best as other jurisdictions around the world ramp up their programs, particularly China. Increased R&D support for fuel cell materials, components, and systems is important for BC to maintain its position at the forefront of the industry.

e. ***Carbon and CO_2 sequestration***

The production of low-cost hydrogen from NG will produce either carbon or CO_2. Currently, CO_2 sequestration technology is mature. However, exploration of other sequestration sites in BC such as the off-coast sea beds will be important to create a network of sequestration sites that are closer to H_2 production sites. Innovation in carbon utilization methods will also be important. The amount of carbon created over the next decades will be substantial. Economic carbon use such as agriculture land applications, construction materials, and power production will require innovation. As well, further innovation for sequestration of solid carbon (Pyrogenic CCS[153]) without CO_2 production on land and in oceans is required.

f. ***Renewable synthetic gaseous and liquid fuels***

Renewable or decarbonized hydrogen and CO_2 from renewable resources are the most important feedstocks to renewable synthetic gaseous and liquid fuels. Currently, both of these feedstocks are too expensive. Opportunities for technology innovation leadership for these fuels are:

a. Low-cost decarbonized or renewable hydrogen (discussed above),

b. Low-cost environmental carbon dioxide capture from both the atmosphere and the oceans for CO synthesis,

c. Electrolysis, photo-electrolysis and other advanced methods for processing both water and renewable CO_2 together into H_2 and CO. Depending on the technology, the amount of hydrogen required for synthetic diesel for example could be reduced by up to 1/3 if the CO_2 reduction method can entirely avoid the reverse water-gas-shift reaction to produce the CO.

153 *Wikipedia. (2019). Pyrogenic Carbon Capture and Storage. Retrieved from https://en.wikipedia.org/wiki/Pyrogenic_carbon_capture_and_storage*

8.0 : Mid-term And Long-Term Hydrogen Cost Potential and Demand in BC

8.1 : Hydrogen Demand

As described in Section 4.0, hydrogen demand was estimated in the natural gas, transportation, industrial, and remote community sectors based on aggressive and conservative scenarios. Hydrogen used in the built environment was also considered, but the only significant use of hydrogen in the built environment is expected to be through injection in the natural gas grid. To avoid double counting, this hydrogen was attributed to the natural gas sector. The estimated demand in each sector should be considered a projection of what will occur in BC but represents what demand could be if certain policies are adopted and given certain rates of technology development.

Each sector was considered in isolation from the others, so the resulting demand is not necessarily additive. The most significant example of this is the interaction between industry and transportation. The estimated hydrogen demand in the industry sector is based on the production of synthetic fuel that will reduce the carbon intensity of liquid fuels to satisfy the Renewable & Low Carbon Fuels Program. In our analysis, the demand for liquid fuel remained constant from year to year. However, if hydrogen fuel cell and battery electric vehicles reach mass adoption, as predicted in the transportation sector in this analysis, liquid fuel demand in BC is likely to reduce significantly over time.

Figure 75 shows the estimated aggregate demand in the Province for the aggressive and conservative scenarios from 2020 to 2050. In the aggressive scenario in 2050, demand could reach as high as 1,445 kilotonnes/year annual demand. This number is less than half the estimated annual supply.

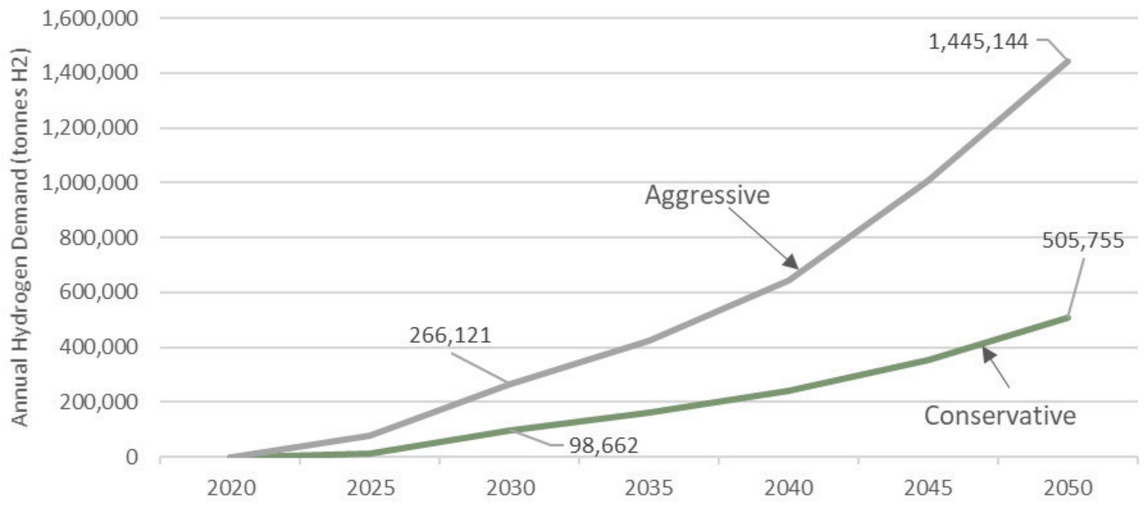


Figure 75. Aggregate Conservative and Aggressive Hydrogen Demand (2020-2050)

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Figure 76 and Figure 77 show the conservative and aggressive hydrogen demand scenarios from 2020 to 2050 by sector, and Figure 78 shows the detailed breakdown by sector in 2030 and 2050.

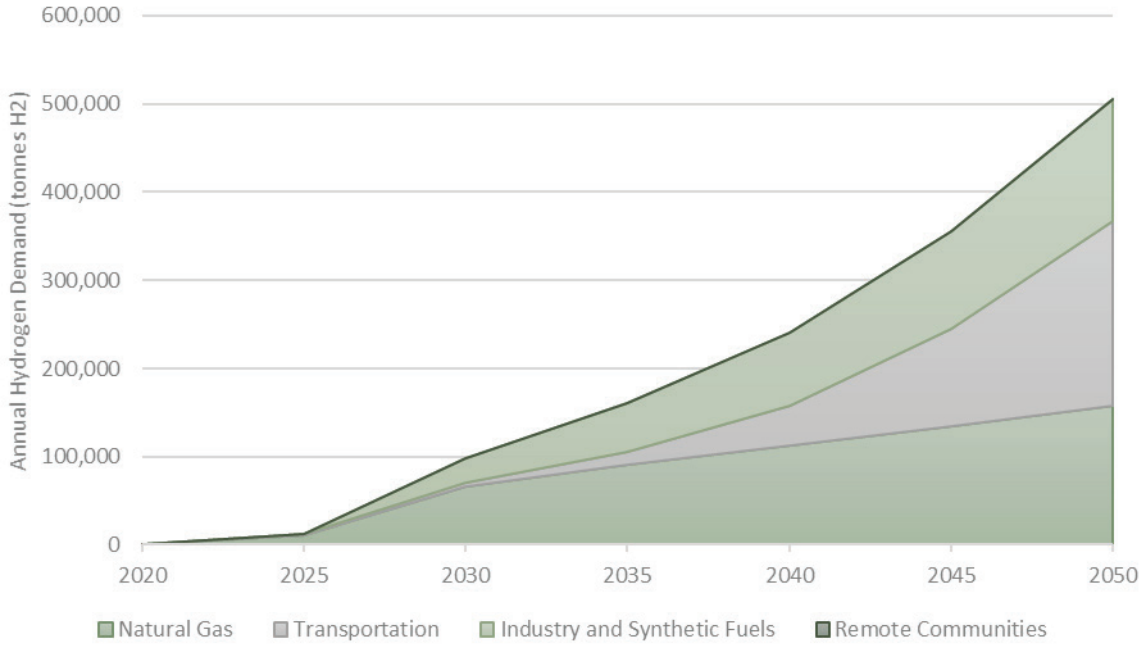


Figure 76. Conservative Aggregated Hydrogen Demand by Sector (2020-2050)

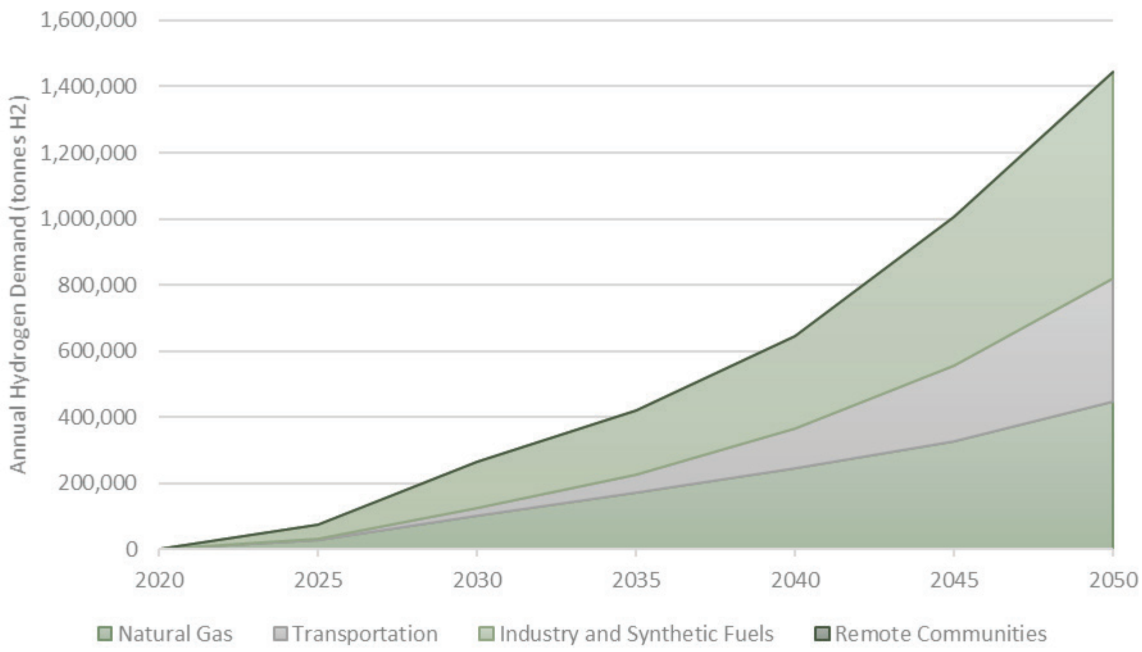


Figure 77. Aggregate Aggressive Hydrogen Demand by Sector (2020-2050)

Initially, the industry and natural gas sectors offer the greatest potential for hydrogen consumption, but by 2050, the transportation sector will play a significant role.

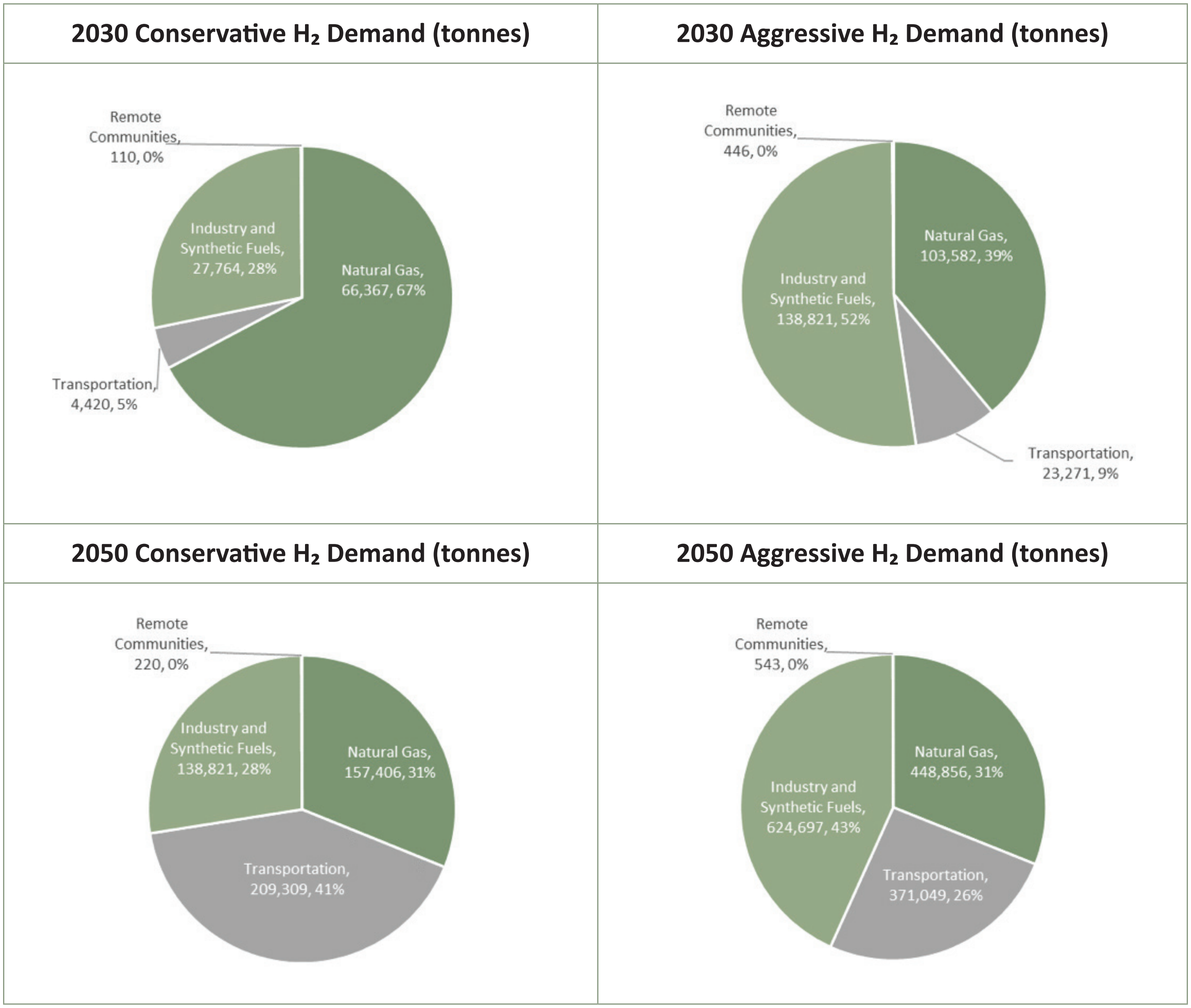


Figure 78. Conservative and Aggressive Aggregate Hydrogen Demand in tonnes by Sector (2030 & 2050)

8.2 : GHG Emissions Abatement

As described in detail in Section 4.0, hydrogen has the potential to reduce GHG emissions from each sector investigated in this study. Figure 79 shows the estimated aggregate GHG emissions that could be abated in the Province for the aggressive and conservative scenarios from 2020 to 2050. In the aggressive scenario in 2050, the reduction is 15.6 Mt CO_2e, which represents 31% of the Province's target to reduce emissions by 80% compared to a 2007 baseline. The conservative scenario estimates the reduction to be 7.2 Mt CO_2e, which represents 14% of the Province's target.

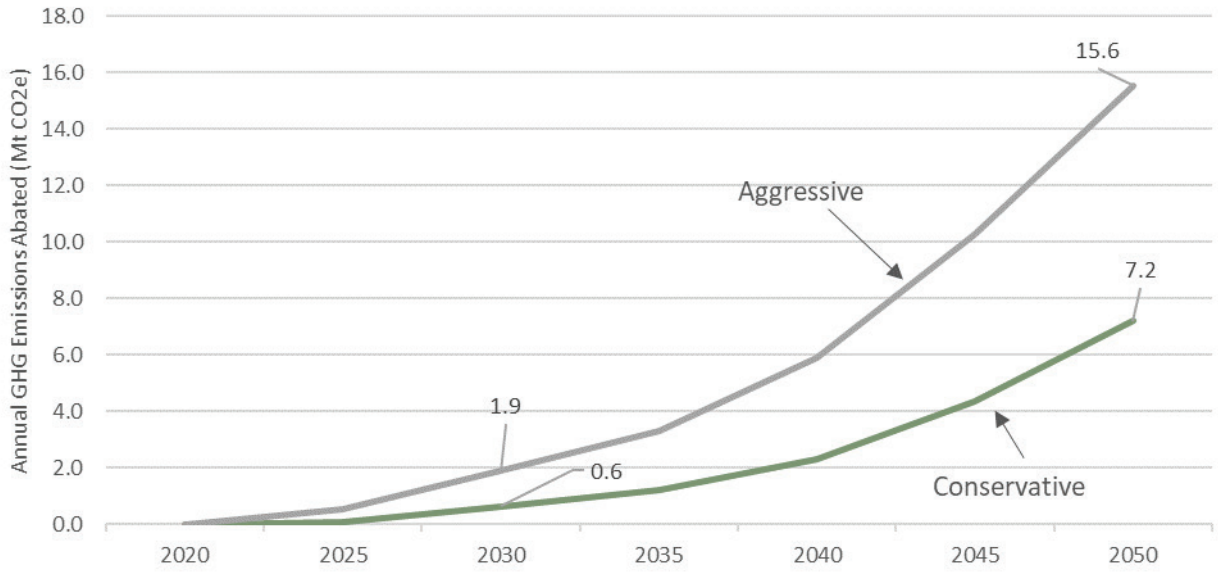


Figure 79. Aggregate Conservative and Aggressive GHG Emissions Reduction (2020-2050)

Figure 80 and Figure 81 show the conservative and aggressive GHG emissions reduction scenarios from 2020 to 2050 by sector, and Figure 82 shows the detailed breakdown by sector in 2030 and 2050.

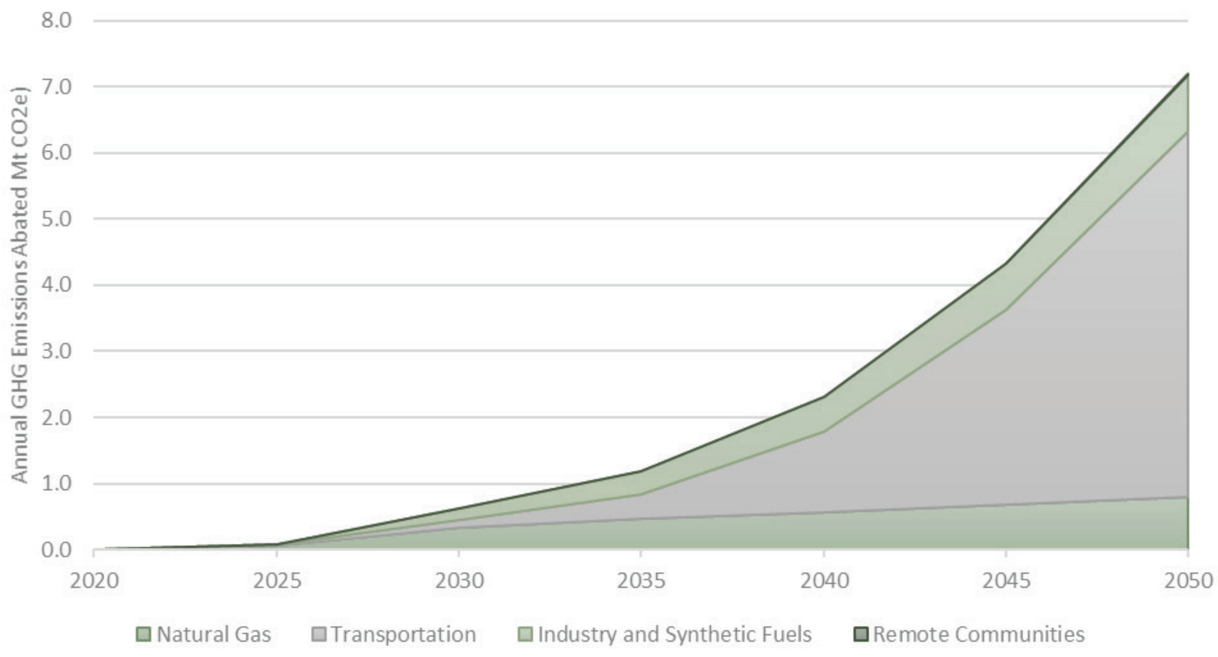


Figure 80. Conservative Aggregated GHG Emissions Reduction by Sector (2020-2050)

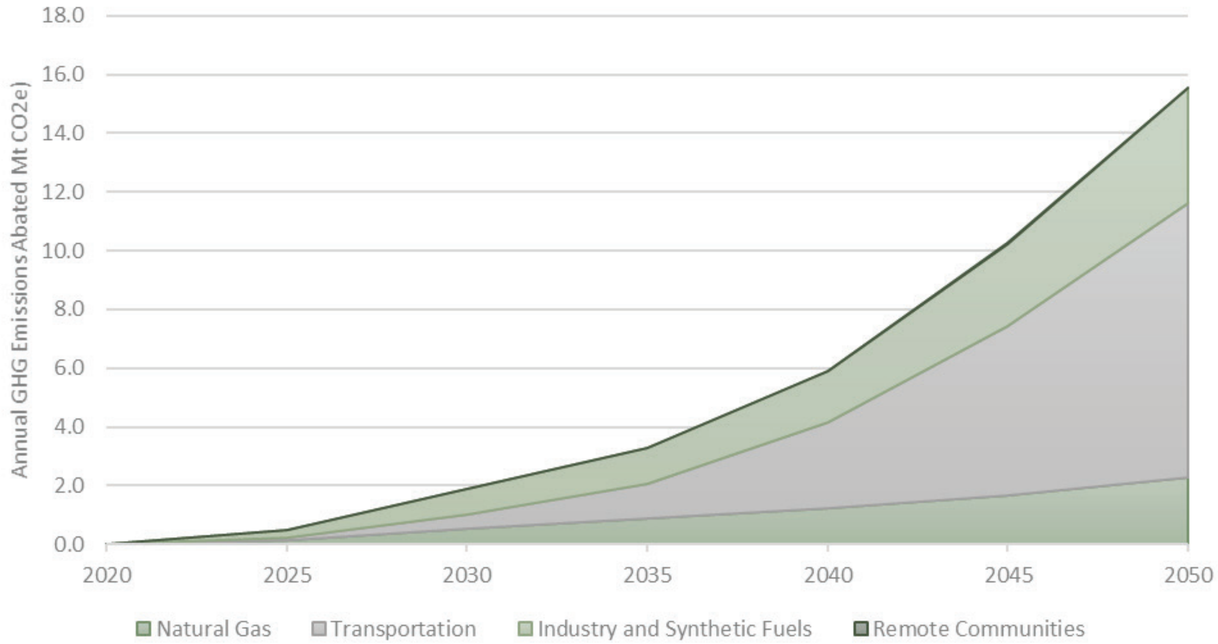


Figure 81. Aggressive Aggregated GHG Emissions Reduction by Sector (2020-2050)

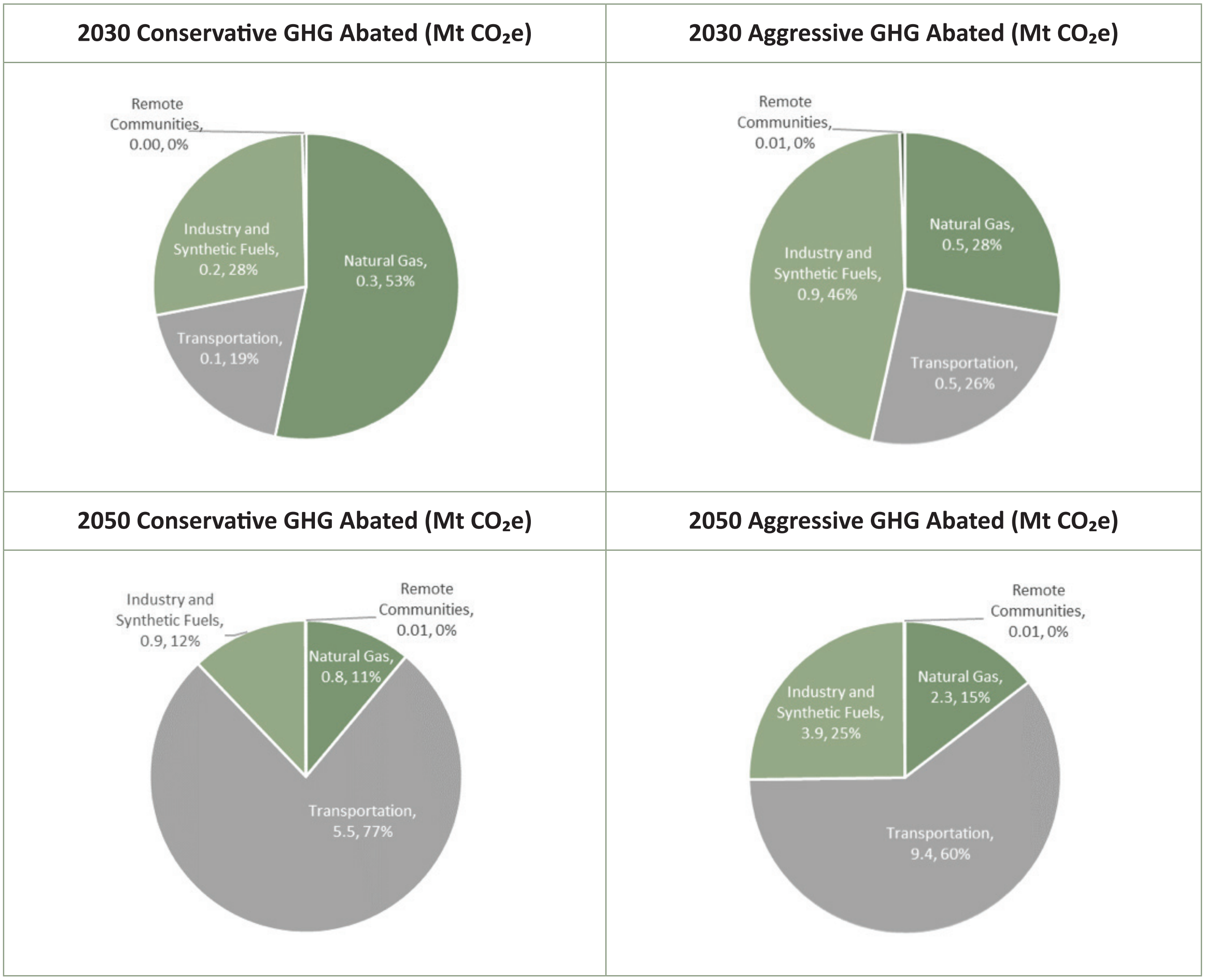


Figure 82. Conservative and Aggressive Aggregate Hydrogen Demand in tonnes by Sector (2030 & 2050)

Initially, natural gas offers the greatest potential for GHG emissions reduction, but by 2050 the transportation sector is expected to dominate savings. This occurs for two reasons. First, it will take time to build up the hydrogen transportation sector because of the large number of gasoline and diesel vehicles on the road and because of the time needed to develop the technology and scale up performance. In contrast, the natural gas grid can begin incorporating hydrogen immediately. Second, most transportation applications will be powered by fuel cells, which offer a significant efficiency improvement compared to burning the hydrogen. This analysis assumed the hydrogen injected into the natural gas grid will be burned directly, so the savings potential is greater in transportation applications.

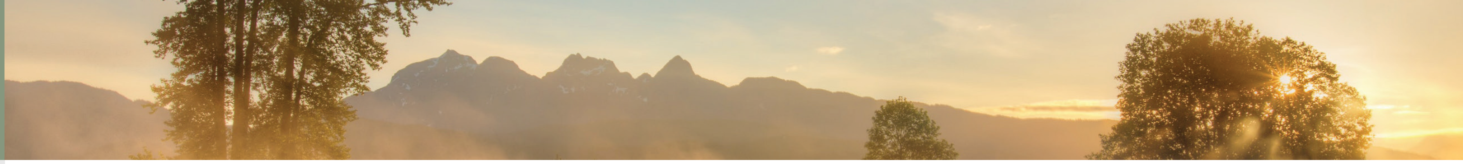
8.3 : Hydrogen Supply

In the near-term, the majority of hydrogen produced in the Province is expected to come from electrolysis. As described in Section 3.1.2, electrolysis can produce hydrogen at a cost of approximately $5 to $7 per kilogram. Facility design is highly scalable, allowing for distributed generation based on local demand. The capital expenditure to build an electrolysis facility is low relative to SMR, so it will be more palatable for investors while demand is low.

By-product hydrogen is expected to become available in the mid-term. This will be the lowest cost pathway for hydrogen production (less than $1 per kilogram as described in Section 3.1.1). However, the provincewide supply of by-product hydrogen is limited and localized to two regions: North Vancouver and Prince George. Industrial suppliers are also hesitant to provide the hydrogen at small scale, so it will not be available until sufficient demand exists.

In the mid-term, hydrogen can also be produced by decarbonizing natural gas through SMR with carbon capture and storage and pyrolysis. This approach leverages BC's abundant natural gas supply while reducing emissions and limiting the amount of new electrical generation capacity that would otherwise be needed to meet the Province's GHG emissions reduction targets. As described in Section 3.1.4, hydrogen produced in this way will be relatively low cost (approximately $2 per kilogram) and can be generated in large quantities. However, this hydrogen pathway is only viable at large scale. Building the infrastructure to produce and distribute the hydrogen will require significant investment and will take a minimum of three to five years to deploy, and therefore, a project would need to be initiated in the near-term to be available by 2025.

In the long-term, all three pathways are likely to continue. By-product hydrogen will reach its maximum capacity and continue at a consistent rate indefinitely. Hydrogen from natural gas will remain a major source as demand increases and new technologies, like pyrolysis, are commercialized. Electrolysis will likely continue to grow throughout the Province over this period as costs drop and regulation pushes towards renewable energy.



9.0 : Instruments and Policies to Develop Hydrogen Supply Chains in BC

9.1 : Jurisdictional Scan of Leading Markets

To inform the policy recommendations in this report, the project team conducted a review of jurisdictions leading the world in hydrogen technology development and deployment. Figure 83 summarizes hydrogen technology deployments in three key regions: North America, Europe, and Asia.[154]

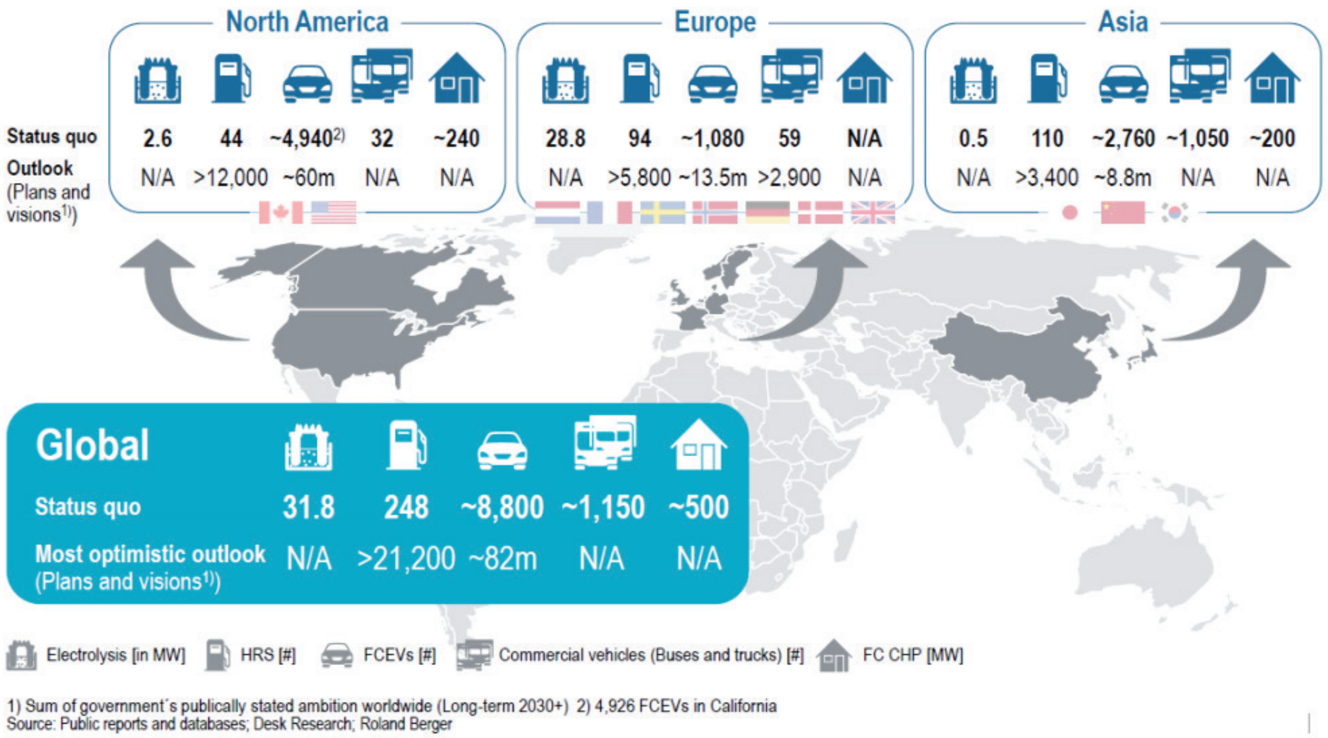


Figure 83. Status and Publicly Stated Plans of Hydrogen Technology Deployments by Continent. Source: Hydrogen Council.

Complementing the hydrogen deployment data, Figure 84 shows the International Energy Agency (IEA) summary of the number of countries offering policy support towards these deployments. IEA estimates that 10 to 15 countries already offer policy support for each of hydrogen fuel infrastructure, fuel cell passenger vehicles and buses. Some jurisdictions have also extended policy support towards the use of hydrogen in the built environment (building heat and power) and industry.

154 *The Hydrogen Council. (2019). Fostering Deployments – Next Steps. Retrieved from* https://www.iea.org/media/workshops/2019/2019hydrogen/Session4-3-FRANC.pdf

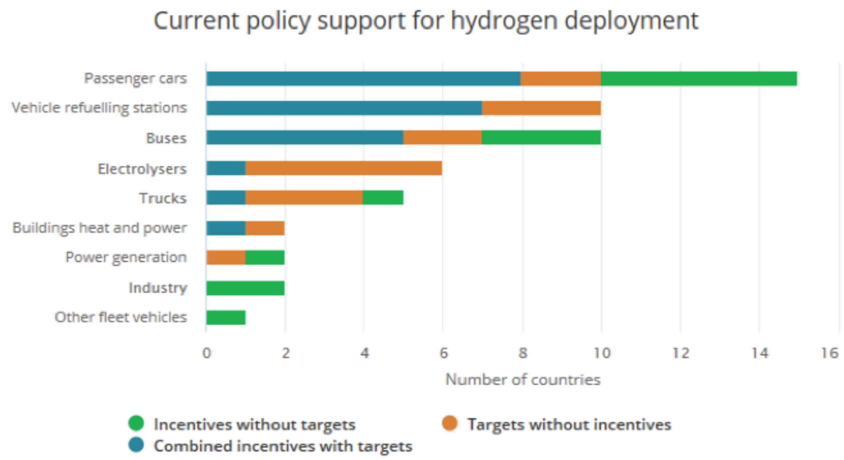


Figure 84. Number of Countries Offering Policy Support for Hydrogen Deployment. Source: International Energy Agency.

The review yielded several key insights:

- *Jurisdictions leading in hydrogen technology adoption have clearly laid out plans to incorporate hydrogen into their energy systems and well-defined targets to measure success.*
- *Jurisdictions are exploring hydrogen technologies to achieve different goals, such as energy security, local air quality, climate change mitigation, economic growth, and energy storage.*
- *Roughly 90% of hydrogen is currently produced from fossil fuels, but hydrogen combines well as an energy storage medium with variable power renewable sources. The carbon intensity of hydrogen production from fossil fuels could also be dramatically decreased through carbon capture and sequestration.*
- *Asia and California are expecting to dramatically increase hydrogen demand in the coming decade and will need to set up international supply chains to deliver clean hydrogen.*
- *Led by China, Asia is investing heavily in hydrogen fuel cell technology and is rapidly scaling up vehicle deployments, particularly in medium-duty trucks. Japan and the Republic of Korea are currently the only two countries producing light-duty fuel cell vehicles that are available for purchase in BC.*
- *Jurisdictions leading in light-duty fuel cell vehicle adoption have focused on building up fueling infrastructure, providing incentives (monetary and non-monetary), and tightening emissions standards. California, which leads adoption, also implemented a ZEV mandate.*
- *Europe has put the greatest emphasis on power-to-gas projects to better utilize intermittent renewable energy sources. Efforts there can be leveraged to inform safe levels of hydrogen injection and the most effective approach to improving the pipeline network.*

A series of one-page summaries outlining the current status of deployments in eight jurisdictions leading the world in adoption of hydrogen technologies is available in Appendix D: Jurisdictional Review summaries. These summaries include policies, incentives, and regulations in place in these jurisdictions.

Notable insights not featured in the one-page summaries included the following:

- *Switzerland's Lump-sum and Performance-based Heavy Vehicle Charges have greatly improved the competitiveness of zero emission trucking solutions. The Heavy Vehicle Charges apply to all vehicles with a permissible laden weight of more than 3.5 metric tonnes; certain vehicle types are exempted, including vehicles with electric drivetrains.*[155, 156] *They provide for the recovery of previously-externalized costs of diesel use based on the "polluter pays" principle*[157] *and are believed to have been pivotal in Hyundai's decision to deploy 1,600 hydrogen fuel cell-powered commercial trucks in the alpine country.*[158]
- *The United States has used tax credits to great effect in growing several clean energy technologies, including wind energy, solar photovoltaics, and fuel cells. US Federal incentives for the purchase of zero emission vehicles also take the form of tax credits instead of purchase subsidies. A key lesson from the US experience has been that long-term policy certainty is required for industries to benefit; among other factors, sales cycles can be lengthy. As shown in Figure 85, the American wind industry experienced several boom/bust cycles when its Production Tax Credit was allowed to repeatedly expire, then was repeatedly offered one-year extensions.*
- *Norway's spectacular success with ZEV adoption – plug-in electric vehicles accounted for 49% of passenger vehicle sales in calendar 2018 and accounted for 10% of the country's passenger vehicle stock – underscores the lesson of long-term policy commitments. Long before they were mass-produced in great numbers, ZEVs received exemptions from import taxes (1990), road tolls (1997), parking fees (1999), value-added tax (2001) and passenger ferry fees (2009). Other incentives included reduced annual registration taxes (1996) and nationwide bus lane access (2005). One insight could be to introduce policy measures before vehicles are sold in great numbers. While it is too late to do so for plug-in electric vehicles in British Columbia, there remains time to craft comprehensive incentives for hydrogen fuel cell vehicles.*
- *China's industrial policy, having established world leadership in batteries for battery electric vehicles, has shifted decisively in favour of hydrogen fuel cells.*[159] *While battery electric vehicle incentives are expected to end in 2020, hydrogen and fuel cell incentives remain generous: federal incentives amount to $40,000 CAD for fuel cell passenger vehicles and $100,000 CAD for heavy duty fuel cell vehicles, both of which can be supplemented by state or city incentives, covering up to 50% of the vehicle's purchase price. To offer a sense of scale of China's ambitions, BloombergNEF identified $17 billion USD in hydrogen and fuel cell investment commitments in China through 2023.*[160]

155 *Swiss Confederation, Federal Customs Administration. HVC - General / Rates. Retrieved from: https://www.ezv.admin.ch/ezv/en/home/information-companies/transport--travel-documents--road-taxes/heavy-vehicle-charges--performance-related-and-lump-sum-/hvc---general---rates.html*

156 *Swiss Confederation, Federal Customs Administration. Lump-sum heavy vehicle charge (PSVA) for Swiss vehicles. Retrieved from: https://www.ezv.admin.ch/ezv/en/home/information-companies/transport--travel-documents--road-taxes/heavy-vehicle-charges--performance-related-and-lump-sum-/lump-sum-heavy-vehicle-charge--psva--for-swiss-vehicles.html*

157 *Swiss Confederation, The Federal Council. Federal Council amends Heavy Vehicle Charge Ordinance. 23 September 2016. Retrieved from: https://www.newsd.admin.ch/newsd/message/attachments/45467.pdf*

158 *Reuters. Hyundai signs deal to sell 1,000 hydrogen powered trucks in Switzerland. 19 September 2018. Retrieved from: https://www.reuters.com/article/us-hyundai-motor-hydrogen-truck-idUSKCN1LZ1VI*

159 *Bloomberg. China's Father of Electric Cars Says Hydrogen Is the Future. 12 June 2019. Retrieved from: https://www.bloomberg.com/news/articles/2019-06-12/china-s-father-of-electric-cars-thinks-hydrogen-is-the-future*

160 *Bloomberg. China's Hydrogen Vehicle Dream Chased With $17 Billion of Funding. 27 June 2019. Retrieved from: https://www.bloomberg.com/news/articles/2019-06-27/china-s-hydrogen-vehicle-dream-chased-by-17-billion-of-funding*

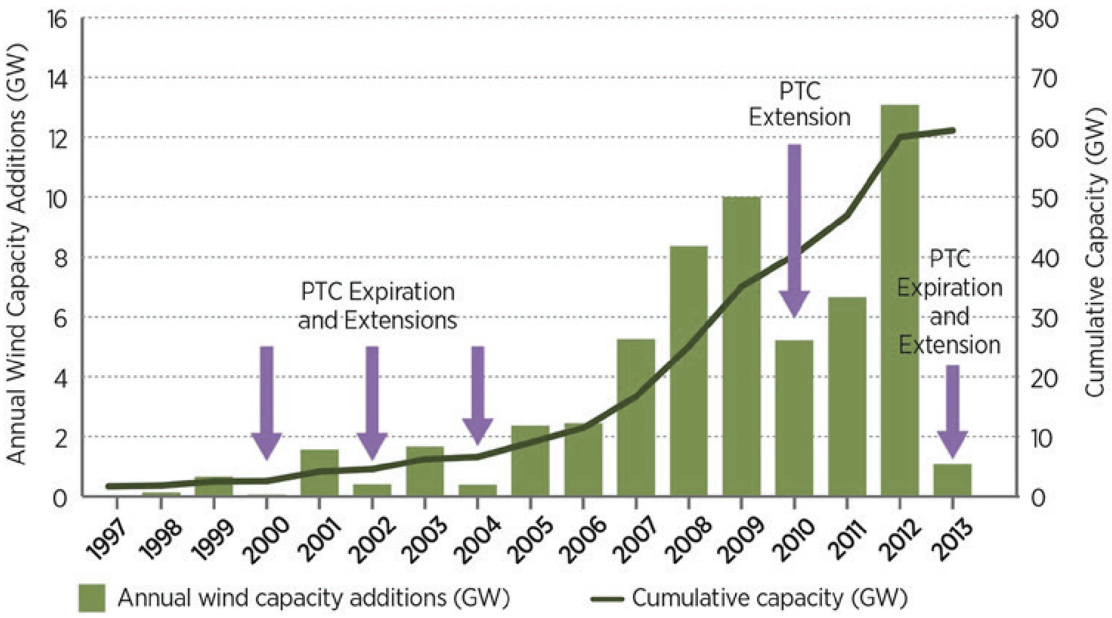


Figure 85. The Effect of Repeated Cycles of Production Tax Credit (PTC) Expiration and Extensions on US Wind Capacity Additions. Source: US Department of Energy.[161]

Based on the review, the project team assigned ratings from 0 to 4 to quantify the strength of each region in 5 categories: current adoption, future adoption, incentives, policy support, and financial commitment. The project team also assigned a rating of 0 to 4 indicating how great a priority the following 5 factors are for the jurisdiction: hydrogen exports, hydrogen imports, local power-to-gas adoption, local fuel cell vehicle adoption, and technology export. The results are summarized in Figure 86 and Figure 87.

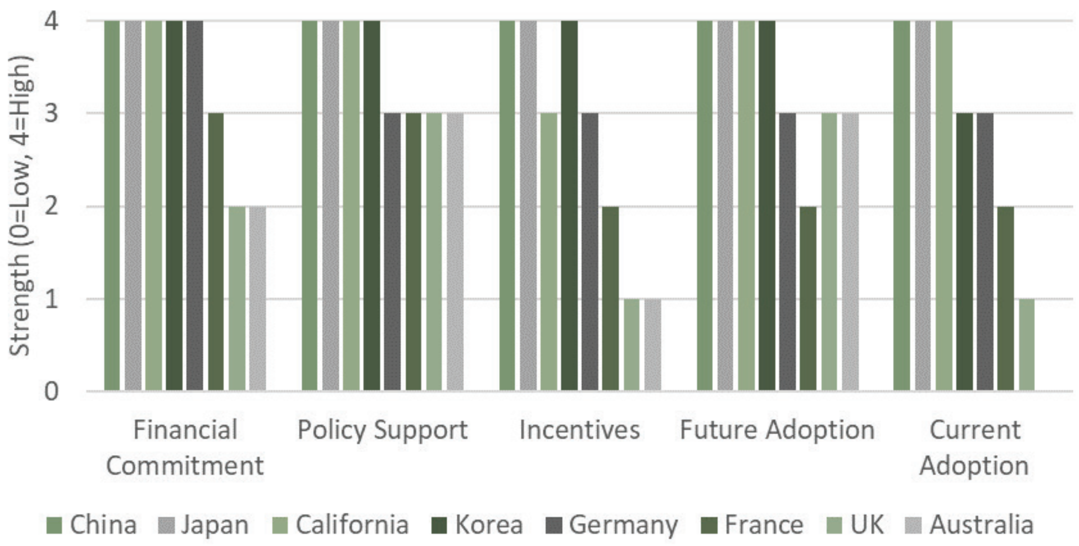


Figure 86. Strengths of Key Jurisdictions Relating to Hydrogen Technology Adoption and Development

161 US Department of Energy, Office of Energy Efficiency & Renewable Energy, Wind Energy Technologies Office. Production Tax Credit and Investment Tax Credit for Wind. Retrieved from: https://windexchange.energy.gov/projects/tax-credits

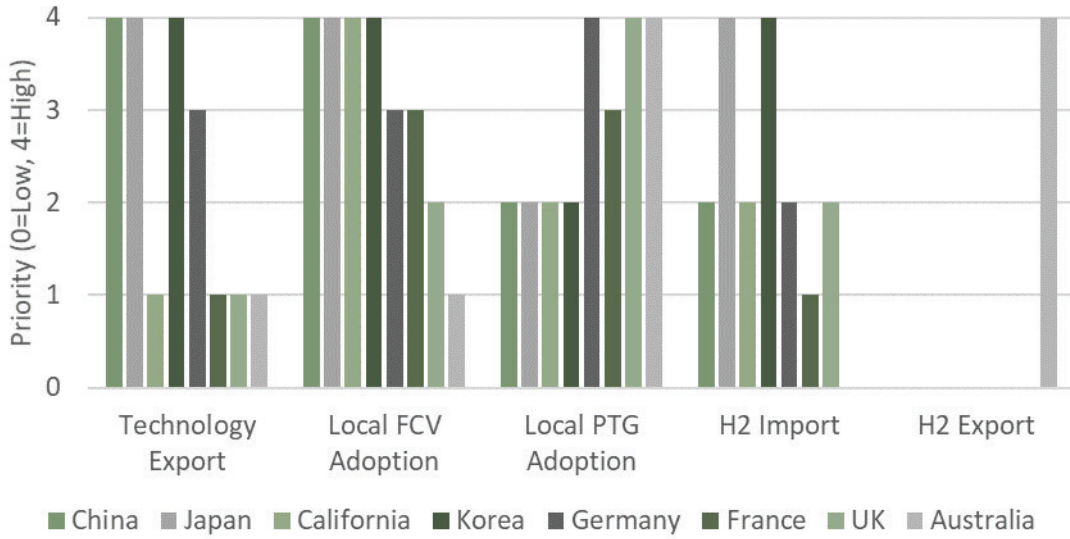


Figure 87. Priority of Key Jurisdictions Relating to Hydrogen Technology Adoption and Development

9.2 : Recommended Instruments and Policies for BC

The following instrument and policy recommendations highlight critical actions in the 2020 – 2025 timeframe that will support the development of a hydrogen economy in BC. Supporting details and rationale are documented in relevant sections of the report and are summarized here for simplicity.

Hydrogen Production Pathways

1	Allow all sources of 'Clean Hydrogen' to qualify as 'Renewable Gas' under CleanBC goal for 15% Renewable Gas by 2030.

There is an immediate urgency to decarbonize BC's energy supply across all industry sectors. Hydrogen produced at scale from natural gas currently offers the lowest cost and highest availability of low carbon hydrogen when coupled with carbon capture and storage technology. Restricting to renewable sources of hydrogen would limit hydrogen production to electrolysis and biomass gasification pathways, which are currently higher cost and have limited supply in BC based on available resources. Restricting to renewable sources only would slow market penetration of hydrogen in BC.

BC's low carbon hydrogen production pathways include:

a. *'Green' hydrogen produced by electrolysis powered by renewable electricity sources such as hydro, wind, geothermal, or solar;*
b. *'Blue' hydrogen produced by steam methane reforming (SMR) with carbon capture and storage (CCS), biomass gasification with CO_2 sequestration, or hydrocarbon dissociation with solid carbon storage/utilization.*
c. *Hydrogen by-product from industry such as hydrogen produced in the chlor-alkali process.*

'Clean hydrogen' should be defined based on an overall carbon intensity value with clearly defined methodology for calculating the carbon intensity (CI). CI < 36.4 g CO_2e/MJ is the recommended threshold. For clarity, the term 'Renewable Gas' could potentially be modified to 'Low Carbon Gas' in the CleanBC goal and Greenhouse Gas Reduction Regulation.

The LCFR awards credits based on carbon reduction, and hence is already aligned with this recommendation.

2 Support longer-term transition to renewable hydrogen by setting required renewable content in CleanBC's 'Renewable Gas' target and providing incentives for renewable pathways in the LCFR.

Ultimately BC must transition to sustainable energy sources. While the Province has abundant natural gas reserves, these fossil fuel reserves are not sustainable energy sources given the timeframe to replenish these reserves is so great. If there is no required percentage of renewable content, it is possible that current economics could drive developers towards large SMR plants with CCS that could inhibit the development of renewable pathway projects with higher hydrogen production costs. The Province needs policy to drive adoption of multiple pathways in near and mid-term, as well as long-term, in order to ensure both decarbonization and ultimate sustainability goals are met.

It is recommended that the Province add a requirement to the 15% Renewable Gas goal that states that a certain percentage of the hydrogen (e.g. 33% in California) must come from renewable sources, where renewable sources include: electrolysis powered by hydro, wind, or solar; biomass gasification with CO_2 sequestration; and by-product hydrogen capture. It is recommended that the Province classify by-product hydrogen as renewable, given in BC the grid is 90% hydroelectric and is the original power source for this pathway. The LCFR is currently only focused on carbon intensity of the fuel and does not provide extra credit for renewable sources of fuel in relation to hydrogen used in transportation. It is recommended that the Province consider a mechanism to incentivize for the longer-term transition to renewable sources of transportation fuels by closing the gap on production costs between fossil based and renewable pathways. For example, the LCFR could provide base credits based on CI of pathway, with additional credits awarded for renewable sources.

3 Set a threshold for the CI of the hydrogen for all provincially funded projects and stipulate that there must be a transition plan for hydrogen to be produced within the province during the project.

In the past large demonstration projects like the Whistler bus fleet imported hydrogen to demonstrate end use applications. This resulted in negative public perception and did not drive the long-term build-out of hydrogen production infrastructure in the province which is critical to the growth of deployments following pilot demonstration periods. Where possible, it is recommended that projects use renewable pathways when demonstrating end used applications, and this should be reflected in project scoring criteria. In some cases, demonstration projects may need to use imported fuel for a period of time while local fuel supplies are developed for the project.

4 Work with BC Hydro and BCUC to develop rate tariffs that make hydrogen production via electrolysis more economically viable.

There are strategic benefits to encouraging the development of grid connected electrolysis projects in the Province. At the current industrial electricity rates of ~$60/MWh, the economics for electrolysis are challenging and development of projects will be limited. The existing rate structure does not reflect the benefits that electrolysis installations offer.

The electrolysis hydrogen production pathway offers unique opportunities to connect the electric grid and natural gas energy infrastructure in an optimized and efficient system. BC's natural gas infrastructure can be used simultaneously as a clean energy storage and transmission system for the electric system. Utilizing the gas system for electricity storage through power-to-gas conversion can improve electricity system efficiency and load factor, provide a mechanism for BC Hydro to offer dispatchable capacity by having large electrolysis demand loads that can be turned down on demand, minimize costs for end users, and create new delivery channels for low carbon fuels. Electrolysis also enables a distributed model of hydrogen production that is inherently scalable. The electrolysis pathway is currently the most expensive hydrogen production pathway for at-scale hydrogen production in the province. The big cost driver is electricity, making up approximately 70% of the levelized cost of hydrogen based on BC Hydro's current industrial electricity rates. There are a number of potential special rate structures that could support the economic viability of hydrogen production via electrolysis. It is therefore recommended that the Province work with BC Hydro and BCUC to evaluate potential rate tariffs that would reflect the benefits of electrolysis projects. Rate structures to be considered include:

- *Introduce a special rate for electrolysis plants. This could be accomplished by introducing a mechanism to put a value on carbon reduction when presenting proposed rate tariffs to BCUC.*
- *Support permanent adoption of the Freshet Rate Schedule (1892), which would enable higher capacity production and reduced costs during certain times of the year.*
- *Support development of rate programs for interruptible power demand, which fits well with electrolyzer load following capability.*
- *Reconsider BC Hydro's proposal for a Load Attraction rate but consider restricting this rate program to projects that support the Province's decarbonization goals.*
- *Consider a rate structure based on time of use charge, such that electrolyzers can be controlled to operate only in off-peak periods and reduce demand charges.*
- *Investigate the potential to offer retail access to power for electrolyzer operators. This could be limited to purchase of power within the province.*

5 Develop a special funding program to support hydrogen production projects that directly lead to decarbonization within the province.

This program could be either specific to electrolysis pathways and administered by BC Hydro (e.g. similar mechanism to Power Smart to fund a portion of project capital such as interconnection costs) or could be broader and less technology specific and administered by the Province. Program funding is a less restrictive way to make the economics for hydrogen production more commercially viable in the near-term.

6 Investigate the possibility of regulated utilities in the Province (e.g. BC Hydro, FortisBC, and PNG) having expanded mandate to include option to produce, distribute and sell hydrogen.

Electrolyzers present an opportunity to improve the load factor on power generation assets and provide a means by which energy systems can be highly optimized and integrated. Fleets of electrolyzers can provide a mechanism for BC Hydro to offer dispatchable capacity through large demand loads that can be turned down rapidly. If BC Hydro owns and operates the electrolysis infrastructure, it could enable greater optimization of the grid. This would require a mandate change for BC Hydro, and it is recommended this be explored first via a pilot demonstration project. Utilities in Washington state are now able to produce hydrogen through recently passed legislation.[162]

7 Support development of a hydrogen liquefaction plant and distribution assets in the Province, via a P3 arrangement.

A liquefaction plant is a strategic infrastructure asset in BC required to support the wider spread adoption of hydrogen and transport fuel cost effectively throughout the province. Transportation of gaseous hydrogen over long distances is expensive compared to transportation of volumetrically dense cryogenic liquid hydrogen. For example, transporting gaseous hydrogen over a 500 km distance will add approximately $10/kg to the cost of the fuel, versus $3/kg to transport liquid. A liquefaction plant would have to be located next to a large-scale hydrogen production plant with access to various modes of transportation including highway and rail. It is recommended that the initial plant be located in the metro Vancouver area if possible, to create an economical supply of hydrogen to support critical lighthouse projects and early deployments in the 2020-2025 timeframe.

8 Lighthouse project: Support a study to look at the potential for centralized hydrogen production and transport from the Peace region of BC, both through the NG pipeline and as liquid through liquefaction plant.

This region is very strategic for the Province in terms of potential to generate large volumes of low-cost hydrogen. The region is unique as it brings together key resources that could enable bulk centralized production of hydrogen that would support rollout in the Province. Strategic regional assets include:

- *BC Hydro Peace Canyon Project, which includes the Williston reservoir – 7th largest reservoir in world - powering the W.A.C. Bennett Dam and the associated Gordon M. Shrum Generating Station and the Peace Canyon Dam;*
- *Montney gas basin –enormous gas reserves and potential sites to inject and store sequestered carbon;*
- *Major transmission infrastructure for both electricity and natural gas; and*
- *Significant wind resources.*

Centralized large-scale hydrogen production and distribution infrastructure will be critical to enabling hydrogen to play a significant role in decarbonizing BC's industry sectors in the coming years. Government investment in this strategic infrastructure asset will be required to drive down hydrogen production costs in the Province and to de-risk private investment in large installed capacity while the markets are still developing. In the near-term, a plant in the Peace Region could focus on using the NG transmission system to store and transport hydrogen, and there is already demand from Fortis to meet the 15% RG target by 2030. As higher value markets emerge, economics will support alternative transport and delivery methods, such as liquid cryogenic hydrogen. In addition to supporting hydrogen rollout in the province, this project could support regional economic development in the Peace Region.

162 *See footnote 143.*

Natural Gas

9 **See Recommendation #1 and #2 above for hydrogen definition related to CleanBC Renewable Gas Target.**

10 **Lighthouse project: starting with a feasibility study, support a hydrogen community demonstration that shows the benefits and synergies of integrated hydrogen production, storage, and end use applications in a single region of the Province. The concept would evaluate conversion of a full community to hydrogen.**

There are two approaches to achieving the Province's 15% Renewable Gas target for the Province. One approach is to inject RG into the broad network and achieve this average throughout. A second concept is to target specific regions for a full conversion to RG, and focus efforts in concentrated areas to achieve the overall target goals. Other regions around the world are evaluating or moving forward with similar concepts. For example, H21 North of England is planning for the full conversion of the North of England to hydrogen over the 2028-2034 timeframe, starting with Leeds. It is recommended that the Province evaluate the pros and cons of fully converted hydrogen communities compared to bulk hydrogen adoption throughout the Province. A community such as Revelstoke, which runs an isolated grid on LPG, could be considered for such a concept.

11 **Develop standards that enable hydrogen injection into the NG grid: create a mandate for technical bodies to address hydrogen injection into the NG grid in relevant codes, standards, and protocols**

The current regulatory framework governing BC's gas production, transmission, and distribution sectors is not fit-to-purpose for the inclusion of hydrogen. The current mix of federal and provincial acts, regulations, statutory codes and standards do not specify the exact constituents of natural gas or renewable gas and their allocable percentages. The framework is spread over multiple layers of authority, including the National Energy Board, Canadian Standards Association, BC Oil and Gas Commission, the BC Utilities Commission, and Technical Safety BC. In order to introduce hydrogen into the natural gas pipeline system, a combination of code and regulatory changes will be required. It is recommended that the province take a leadership role to develop the required regulatory framework by convening the relevant agencies and driving progress.

12 **Consider changing provincial codes to ensure all future gaseous pipelines are compatible with 100% hydrogen, develop plans to transition other critical components to support increasing volumes of hydrogen in the grid.**

In order to enable a potential transition to 100% hydrogen in the NG distribution system, it is important to ensure materials are compatible. The incremental costs to make pipelines 100% H_2 compatible during new construction and/or planned replacement are relatively small compared to digging up and replacing.

Other components in the system will also have to transition to material and design compatibility for hydrogen. It will be important to signal the timeframe by which other components (valves, turbines, appliances) will need to be hydrogen compatible in order to ensure a smooth and timely transition.

13 Support innovation related to injection of hydrogen into the natural gas grid through establishing a specific and dedicated funding tranche.

Under the current regulatory framework, Fortis is unable to invest in precommercial activities related to technologies, including hydrogen, required to meet the 15% Renewable Gas target. There are still considerable technological and practical gaps to deploying hydrogen at scale in the natural gas network. Dedicated funding to support pilot projects, studies, and research initiatives will be critical to enabling hydrogen to reach its potential in the decarbonization of the NG system. Fortis is currently working to establish an innovation fund that would be funded through the multi-year rate application which would also complement the proposed provincial fund.

Pilot demonstrations that could be supported by this fund would help to identify and develop solutions for existing regulatory barriers and would help to accelerate hydrogen adoption.

Transportation (General)

14 Support and collaborate with progressive municipalities in the development of zero emission zones (e.g. regions with no combustion vehicles allowed by 2040).

Progressive municipalities could provide a focal point for hydrogen and fuel cell deployment at scale, similar to certain regions in China. Coordination of federal, provincial, and municipal government efforts in these regions would be critical. Cities with aggressive targets will help drive development and adoption of medium- and heavy-duty vehicles that are not covered by the light-duty ZEV mandate in BC.

15 Establish a prescriptive call for hydrogen infrastructure LCFR Part 3 Agreements to support the development of hydrogen infrastructure.

Similar to past prescriptive calls to develop infrastructure for emerging technologies, such as the call for E85 fueling stations, a prescriptive call focused on funding for hydrogen fueling infrastructure is a key enabler to support the expansion of the hydrogen fueling infrastructure to support vehicle deployments in the province. Regions such as California have learned through experience that the development of infrastructure must lead vehicle deployment for successful rollout of fuel cell electric vehicles. Station developers must currently compete with a wide range of other projects, and this uncertain funding environment makes it challenging for developers to plan expansion of the network.

16 Strengthen funding to support rollout of hydrogen infrastructure in the Province.

It is critical to support the deployment of hydrogen fueling stations in the Province in order to attract vehicles and support the business case for station owners. The CEV program has some existing funding mechanisms in place, but further funds will be required in order to support the projected station requirements. Better communication of existing funding sources is also recommended.

Transportation (Light-duty)

17 Implement a zero-emission vehicle mandate in the province for light-duty vehicles that recognizes the incremental value of longer-range passenger vehicles, with shorter fueling times. Make British Columbia the world leader in credit value for hydrogen fueled vehicles

The biggest impediment to the deployment of fuel cell electric passenger vehicles in the province over the near- to mid-term is the availability of supply. OEMs must choose between regulated markets when determining which jurisdictions to supply vehicles. Fuel cell electric vehicles are currently manufactured at a different scale than battery electric vehicles, therefore the marginal cost of deploying these vehicles in regulated markets is higher for OEMs seeking to demonstrate compliance with these vehicles.

Current credit schemes in California and Quebec provide higher credit values for longer range, which favours fuel cell vehicles. For example, a Toyota Mirai (FCEV) receives 3.6 credits (502 km range) while a Chevrolet Bolt (BEV) receives 2.9 credits (383 km range) and a Nissan Leaf (BEV) receives 1.3 credits (135 km range). Input from the OEMs indicate these credit "adders" are insufficient to make up the difference in cost. The Province should consider increasing the impact of range in determining the credits per vehicle and/or adding credits based on vehicle fueling/charging time. This would be more impactful than increased subsidies to the end users in the near- to mid-term.

18 Fund and foster a centralized platform for the exchange of information between FCEV OEMs, the provincial and federal governments, and hydrogen infrastructure providers.

Like the California Fuel Cell Partnership, this body would be the formal clearing house for determining vehicle supply for the Province from participating OEMs and tracking infrastructure roll out. Volumes could be aggregated to ensure confidentiality. This body could set clear targets for the deployment of light-duty fuel cell electric vehicles within the Province and drive and track progress toward the goal.

The Province would take the lead to support an independent modeling effort to strategically identify where hydrogen infrastructure should be deployed in the Province. The vehicle OEMs would provide market rollout projections, as well as insight into target customers and markets. An independent group would aggregate this data and build out an analytical model that would identify regions for infrastructure rollout to support the vehicle projections. Government solicitations would fund stations in specific regions, similar to how the California Energy Commission (CEC) deploys funds in line with the California Air Resources Board (CARB) modeled areas of focus.

19 Create incentives that provide operational benefits to ZEV drivers that encourage the adoption of FCEVs and BEVs.

Other jurisdictions, such as Norway, California, and China, have had success driving adoption of ZEVs through "soft" incentives that provide benefits to the driver beyond reducing the initial capital cost. In addition to allowing lone ZEV drivers to use the HOV lane, the Province could consider measures like reduced tolls and ferry travel benefits (discounted travel, free reservations, a percentage of reservation space only available to ZEV drivers, preferred loading, etc.). These types of incentives can be low cost to the Province while still impactful in the decision-making process for consumers.

20 **Extend CEV incentive to cover early rollout of FCEVs (5% of current annual sales) and initiate a program to incentivize purchase of second-hand FCEVs and BEVs.**

The Province's CEV incentive was designed to support early adoption of zero emission vehicles in the Province. To date that initiative has cost ~$60 million and has gone primarily to BEVs and PHEVs. Now that those technologies are in a more commercial stage, it is recommended the CEV vehicle incentive roll over to cover FCEVs in a similar total program amount to stimulate early adoption.

A common criticism of ZEV incentives is that they subsidize expensive cars for wealthy people. Bolstering the market for second-hand ZEVs would make it easier for low-income households to purchase them and drive demand away from older fossil fuel vehicles, which generate the greatest emissions. CEV incentives are currently limited to new vehicles purchased in BC.

Transportation (Medium-Duty)

21 **Create a Province-to-Province program with other jurisdictions (e.g. China, Japan, Korea) that facilitates the deployment of BC and foreign technology in both jurisdictions focused on medium-duty trucks for city use.**

Support homologation efforts to enable the import of medium-duty (delivery trucks) from China, or other jurisdictions, that will provide load for the BC hydrogen infrastructure, export opportunities for local industry (e.g. Ballard, Loop) and competition for North American OEMs that will drive costs down. This would include demonstration programs to validate vehicle performance in BC.

Transportation (Heavy-Duty)

22 **Implement a Transit Bus zero-emission fleet rule in the province similar to the Innovative Clean Transit rule in California.**

The creation of a zero-emission transit fleet rule would require TransLink and BC Transit to outline a plan and move beyond the testing phase for battery electric and fuel cell electric buses. Fuel cell electric buses are not competitive in comparison to other technologies in small-scale demonstrations, primarily due to the cost of the fueling infrastructure. For this reason, agencies tend to choose the easier pathway to demonstrate autonomous zero-emission operations to meet near-term board or policy objectives. The implementation of a zero-emission transit fleet rule would require these agencies confront the realities of scaling up the fueling infrastructure for both battery electric and fuel cell technologies.

23 Create a fuel cell electric coach pilot program in the Province, open to both private and public bus operators. This program should fund both rolling stock and fueling infrastructure.

Fuel cell electric coaches require an operating range that disqualifies battery electric buses for many/most routes. TransLink operates a limited number of coaches within its fleet and has indicated an interest in pursuing fuel cell electric buses for this application where funding for the incremental costs are available. The coach bus configuration is different than transit buses, in that the hydrogen cannot be stored on the roof due to centre of gravity. Funding support is required to develop and trial a first fleet of prototype units that could lead to significant rollout in the Province.

24 Develop a targeted voucher program to subsidize the incremental capital costs of zero-emission buses and fueling infrastructure.

Distribute these vouchers regionally to ensure that a diverse set of communities has access to zero-emission transit. Vary the value of the vouchers between technologies to address the cost differences proportionally. This is similar to CARB's Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP) voucher program which subsidizes technologies that are beyond the development stage but are not yet commercially viable due to cost and scale.

Fuel cell electric and battery electric transit buses are at a sufficient technology readiness level, with hundreds of vehicles deployed globally, that demonstration projects are no longer necessary to prove out the functionality. Cost is the primary impediment to adoption, and a targeted voucher program -in conjunction with a transit fleet rule -will drive the scale of deployments, providing the scale to reduce costs.

25 Create a large-scale, zero-emission heavy-duty vehicle program focused on Vancouver ports that includes both hydrogen and battery electric technology. This program should fund both rolling stock and fueling infrastructure for both technologies.

Hydrogen powered goods movement equipment such as drayage or yard trucks are still relatively immature. A large-scale (10+ vehicle) program will encourage consortia to form, creating new product configurations, with enough volume to spread the non-recurring engineering costs across multiple units. The hydrogen demand will also drive innovation on the production, distribution and dispensing systems and substantially scale the volume of fuel being produced for passenger vehicles.

26 Review the results of the pilot co-combustion vehicle study. If emissions reduction benefits warrant, remove the fuel cell specification of the Motor Tax and Low Carbon Fuel Standard.

Hydrogen co-combustion technology being developed in BC offers near-term potential for hydrogen in the heavy-duty sector and provides a path to retrofit existing vehicles. The technology and GHG reduction claims need to be validated before other incentives are considered. Given the near-term potential of this technology, it is recommended that any language that specifically excludes this technology be carefully considered and removed where warranted.

27 Support feasibility study for the use of hydrogen in marine, rail and off-road applications in BC.

In demand modeling discussion it was agreed that by 2030-2050 timeframe there should be some adoption in marine and rail based on international pilot projects underway. Other industries in BC, such as mining and forestry, use large diesel-powered off-road vehicles that are also well suited to conversion to hydrogen. Feasibility studies would be precursors to funding pilot demonstration projects for these applications.

Industry

28 Maintain strong and ongoing low carbon fuel standards to show project developers that investment in hydrogen production for these markets will be sustained over the long-term to justify the high up-front capital investment.

The low carbon fuel standard is driving the forecasted demand for hydrogen in synthetic fuel production and refining.

29 Support and encourage longer-term R&D projects and scaled up demonstration projects for synthetic fuel production utilizing low carbon hydrogen in the province.

This is an area of potential innovation leadership for the Province.

Built Environment

30 Focus hydrogen efforts for the built environment in the reduction of carbon emissions through injection of hydrogen in the NG grid for use in heating and domestic hot water.

Focusing hydrogen efforts for the built environment in this area will result in the strongest benefits. Hydrogen backup power systems or distributed power generation systems do not provide a compelling business case in the province given the low cost and carbon emissions profile of electricity.

31 Encourage new construction to select future proof appliances which allow for increasing hydrogen content with no or minor changes.

Remote Communities

32

For communities relying solely on trucked or barged in energy supply, encourage studying potential development of micro grids which utilize 100% hydrogen distribution grid and local combined heat and power (CHP) generation.

A Hydrogen supplied grid offers significant advantages over diesel generation to help remote communities. Benefits include: elimination of spill pollution and local air pollutants, lower transport weight (in the case of LH_2 supply), ability to self-generate a portion of energy demand via renewables to H2 technologies, and higher overall efficiencies. Moreover, remote communities are often completely reliant on imported fuels for their power generation and transportation, and transport costs make energy supply to these regions expensive. As such, remote communities provide an attractive costs basis for new competing renewable electricity and hydrogen technologies that can offset imported diesel and generate environmental benefits.

33

Provide information resources to remoted communities related to hydrogen options, and support education outreach in remote communities.

Every remote community is different and solutions for reducing diesel dependence will be community and site specific. Many communities do not have the human capacity with the technical know-how to even start the planning process, let alone develop and implement a project. Provide a 'hydrogen toolkit' including support to navigate funding opportunities, technical expertise for planning, implementation and operations, and a database with technical and cost details of successful clean energy projects involving hydrogen that can provide information for communities just starting the planning process.

Export

34

Support export market studies and pilot programs in BC, particularly where international investment can contribute to production capacity that also benefits the local market.

BC's natural resources, including low carbon renewable hydroelectric reserves, natural gas reserves, and fresh water supply, coupled with coastal access and relative proximity to leading markets such as California, Japan, and South Korea, uniquely position the region to be an exporter of clean hydrogen. While study stakeholders indicated that there is insufficient hydrogen supply in the Province to meet local demand and decarbonization objectives, international investment for large-scale hydrogen production has the potential to benefit local markets as well as generate significant revenue. BC's economy is heavily dependent on export of natural resources, and hydrogen fits as a future export resource that can support both local and international decarbonization efforts. A successful export market will likely rely on producing hydrogen from natural gas reserves coupled with CCS technology, as other pathways tend to be more expensive and in limited supply.

35 Support a thorough analysis of the carbon intensity of various BC pathways, and start lobbying / marketing efforts which target export markets, and California in particular.

California has been identified as the most viable export market on an economic and access basis in the near-term. Market development will in part be reliant on BC having hydrogen produced via electrolysis, either through hydro or wind, to be considered renewable hydrogen toward the state's 33% requirement. For project developers to be able to sell to California, it will likely be necessary to convince them that BC hydrogen made via electrolysis from Hydro should qualify as renewable and low carbon.

Sector support

36 Identify hydrogen and fuel cells as a priority sector for BC and communicate this clearly and consistently to Federal Government.

The importance of hydrogen in the Province must be elevated. Clear and consistent messaging about the role and strategic importance is critical for both internal alignment and prioritization at the provincial level, and for communicating and driving support at the federal level.

37 Support targeted outreach initiatives related to hydrogen technology deployment.

The recommended outreach initiative would be a collaborative effort with industry and government partners to lead outreach to groups such as municipalities, first responders, and community leaders in a coordinated and effective way, similar to the California Fuel Cell Partnership. This could be managed through a working group in an existing organization such as CHFCA.

38 Provide provincial R&D funding in support of hydrogen and fuel cell technology that can be combined with matching funds from the Federal Government or other nations.

Investment is needed to maintain the province's leadership role in hydrogen and fuel cell R&D. Local organizations should have access to funding that can be leveraged to access greater funds from outside entities. For example, a recent federally funded Ballard Power R&D project was moved from BC to Ontario because there was no provincial funding available in BC, which was required to access the federal funds. The ARC program could be expanded to meet this need, or a new fund formed that isn't tied specifically to clean energy vehicles.

9.3 : Investment Required

Government investment is needed to establish a hydrogen economy in BC and support the abovementioned recommendations. That investment will provide the necessary infrastructure and sector support to allow industry to establish a foundation from which to grow commercial deployments. Government investment will yield necessary decarbonization benefits for the Province, economic growth potential, and long-term diversity and security of our energy systems.

Our analysis recommends a total spend from the Province in the order of $176,000,000 over the next five years, which is approximately $35,200,000 per year. This funding would be focused primarily on supporting lighthouse projects and studies, funding critical infrastructure development, providing subsidies for the rollout of light-duty FCEVs, and supporting the sector through establishing dedicated R&D funding. It is anticipated that this Provincial funding would be leveraged with federal and industry match funding, thereby amplifying the benefits of this investment in the Province. A high-level estimate of funding is included in Table 19.

BC Investment Summary 2020-2025	R#	Amount
Lighthouse Projects and Studies		
Central Production Study - Peace Region	8	$ 250,000
Hydrogen Community Study	10	$ 250,000
Marine, Rail and Specialty Vehicle Study	28	$ 250,000
Coach Program with Heavy Duty Fueling Stations	24	$ 6,800,000
Port Program with Heavy Duty Fueling Stations	26	$ 13,300,000
Medium Duty Delivery Vehicle Program	22	$ 7,500,000
Infrastructure Deployment		
Modeling initiative for infrastructure deployment	19	$ 375,000
Liquefaction Plant	7	$ 5,000,000
Distributed Electrolysis Supply - Program Funding	5	$ 20,000,000
Light Duty and Medium Duty Fueling Stations	17	$ 22,500,000
Central Hydrogen Production Plant, Peace Region	8	$ 30,000,000
Vehicle Subsidies		
Extension of CEV for FCEVs, used vehicle incentive	21	$ 50,000,000
Voucher program for transit and intercity buses	25	$ -
Research and Development, Outreach		
Innovation support for hydrogen into NG grid	11, 13	$ 12,000,000
Hydrogen and fuel cell R&D funding	39	$ 2,500,000
Synthetic fuel, CCS R&D	30	$ 5,000,000
Support targeted outreach initiative	38	$ 275,000
Total		**$ 176,000,000**
Annual Spend, 2020-2025		$ 35,200,000

Table 19. Investment in 2020-2025 Timeframe to Support Recommendations

Appendix A-7

BUILDING A RESILIENT ENERGY FUTURE – GUIDEHOUSE STUDY FOR AGA

American Gas FOUNDATION

January 2021

Building a Resilient Energy Future:

How the Gas System Contributes to US Energy System Resilience

An American Gas Foundation Study Prepared by:

Guidehouse

Background and Methodology

This study was conducted to investigate the resilience of the US gas system and the ways in which the gas system contributes to the overall resilience of the US energy system. This work was directed to ask and answer four key questions:

- What are the characteristics of the US gas system that contribute to its resilience?
- How do those resilience characteristics allow the US gas system to contribute to the overall resilience of the US energy system?
- How can the US gas system be leveraged more effectively to strengthen the US energy system?
- What are the policy and regulatory changes that may help ensure that gas infrastructure can be maintained and developed to continue to support energy system resilience?

These questions were explored through a qualitative assessment conducted by Guidehouse, including discussions and interviews with many energy industry subject matter experts. Case studies and examples of resilience were identified as a part of these discussions. Guidehouse used these studies and examples to develop a framework for considering the resilience of the US gas system and to identify barriers and opportunities related to the gas system's role in supporting the resilience of the US energy system. The findings presented in this work identify issues that merit consideration and further exploration when developing future energy policy and regulation to ensure a resilient, reliable, and clean future energy system in all regions and jurisdictions.

Disclaimers

American Gas Foundation

Founded in 1989, the American Gas Foundation (AGF) is a 501(c)(3) organization focused on being an independent source of information research and programs on energy and environmental issues that affect public policy, with a particular emphasis on natural gas. When it comes to issues that impact public policy on energy, the AGF is committed to making sure the right questions are being asked and answered. With oversight from its board of trustees, the foundation funds independent, critical research that can be used by policy experts, government officials, the media and others to help formulate fact-based energy policies that will serve this country well in the future.

Guidehouse

Guidehouse is a leading global provider of consulting services to the public and commercial markets with broad capabilities in management, technology, and risk consulting. We help clients address their toughest challenges with a focus on markets and clients facing transformational change, technology-driven innovation and significant regulatory pressure. Across a range of advisory, consulting, outsourcing, and technology/analytics services, we help clients create scalable, innovative solutions that prepare them for future growth and success. Headquartered in Washington DC, the company has more than 7,000 professionals in more than 50 locations. Guidehouse is led by seasoned professionals with proven and diverse expertise in traditional and emerging technologies, markets and agenda-setting issues driving national and global economies. For more information, please visit: www.guidehouse.com

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Abbreviations

Abbreviation	Definition
AGF	American Gas Foundation
AWIA	America's Water Infrastructure Act
Bcf	Billion Cubic Feet
Btu	British Thermal Units
C&I	Commercial and Industrial
CAGR	Compound Annual Growth Rate
CAISO	California Independent System Operator
CHP	Combined Heat and Power
CIP	Critical Infrastructure Protection
CNG	Compressed Natural Gas
DSM	Demand Side Management
Dth	Dekatherm
EIA	US Energy Information Administration
ESR	Energy Storage Resources
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HVAC	Heating, Ventilation, And Air Conditioning
ISO	Independent Service Operator
ISO-NE	Iso New England Inc.
LCOE	Levelized Cost of Electricity
LDC	Local Distribution Company
LNG	Liquified Natural Gas
KWh	Kilowatt-Hour
MMcf	Million Cubic Feet
MMcfd	Million Cubic Feet Per Day
MMBtu	Million British Thermal Units of Natural Gas
MW	Megawatt
MWh	Megawatt-Hour
NASA	National Aeronautics and Space Administration
NERC	North American Electric Reliability Corporation
NGV	Natural Gas Vehicle
NOAA	National Oceanic and Atmospheric Administration
NJNG	New Jersey Natural Gas
NYISO	New York Independent System Operator
OBA	Operational Balancing Agreement
PGE	Portland General Electric
psi	Pounds Per Square Inch
PSPS	Public Safety Power Shutoff
PUC	Public Utility Commission
PV	Photovoltaic
RNG	Renewable Natural Gas
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquisition
T&D	Transmission and Distribution
US	United States
UTMB	University of Texas Medical Branch

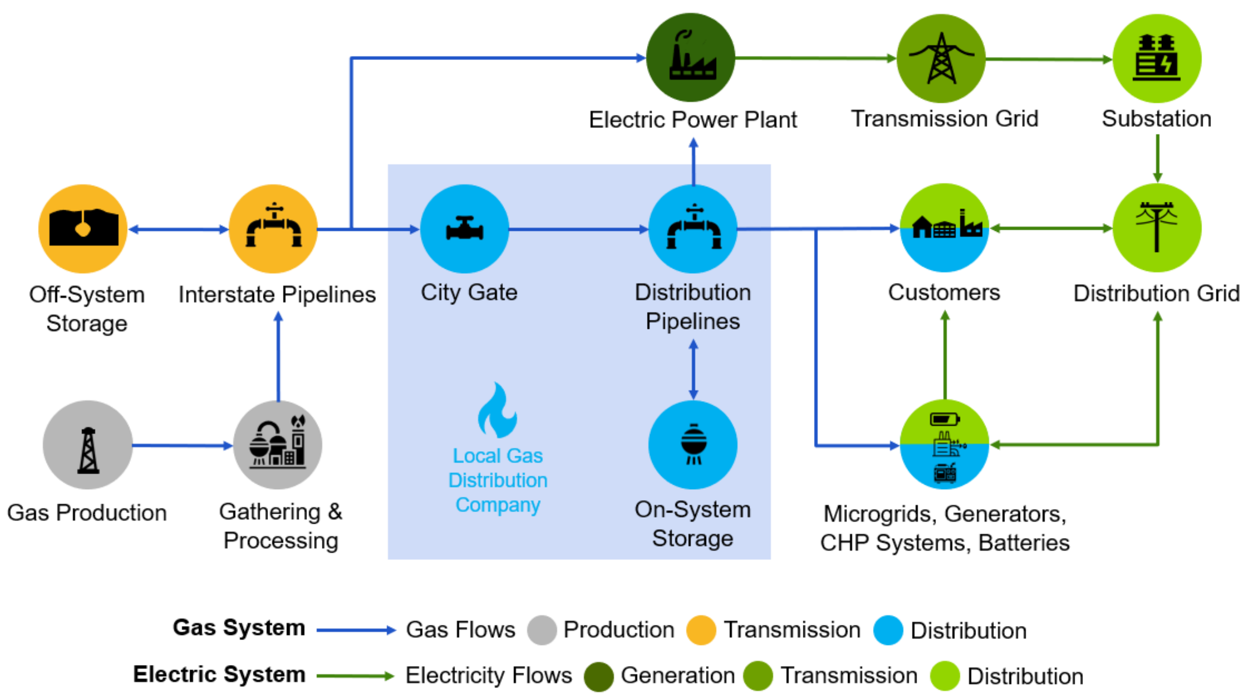
EXECUTIVE SUMMARY

A resilient energy system is essential to the operation of nearly every critical function and sector of the US economy as well as the communities that depend upon its services. Disruptions to the US energy system create widespread economic and social impacts, including losses in productivity, health and safety issues, and—in the most extreme cases—loss of life. As utilities, system operators, regulators, and policymakers deliberate the design and structure of the future energy infrastructure, they must consider the resilience of the entire energy system. As the transformation of the energy system accelerates, it is important for stakeholders to understand the increasing interdependence of gas and electric systems and their role in creating a more resilient future.

A Primer on the Energy System

An energy system is defined as the full range of components related to the production, conversion, delivery, and use of energy. Energy in the US can take many forms; this report focuses on the natural gas system, herein referred to as the gas system, and its interdependencies with the electric system (Figure 1).

Figure 1. Interdependencies Between the Gas and Electric Systems



Source: Guidehouse

What Is Resilience?

Resilience is defined as a system's ability to prevent, withstand, adapt to, and quickly recover from system damage or operational disruption. Resilience is defined in relation to a high-impact, low-likelihood events. The most common examples of these events are extreme weather events (which go beyond standard hot days or snowstorms) of a size and scale to cause significant operational disruption, system damage, and devastating societal impacts. Recent resilience events that affected the US energy system include the 2020 California heat waves, Hurricane Isaias, and the 2019 Polar Vortex.

> *Resilience and reliability are often referenced together, but they reflect critical differences in system design and operation. **Resilience** is defined as a system's ability to prevent, withstand, adapt to, and quickly recover from a high-impact, low-likelihood event such as a major disruption in a transmission pipeline. In comparison, **reliability** refers to a systems' ability to maintain energy delivery under standard operating conditions, such as the standard fluctuations in demand and supply.*

The increasing frequency and severity of climatic events amplifies the need to maintain the resilience of the US energy system. System resilience is gained through diversity and redundancy. The resilience of the US energy system is increased through evolving and holistic management of the gas and electric systems, valuing each of their unique characteristics. To ensure resilience, the energy system needs pipeline delivery infrastructure and storage capabilities meeting both short- and long-duration needs.

The nation's gas system is a critical resource for addressing resilience threats to the overall energy system. This report examines how the characteristics of the US natural gas system enable energy reliance today and opportunities to effectively use the gas system to achieve future energy resilience.

Resilience Characteristics of the Gas System

The gas system supports the overall resilience of the energy system through its inherent, physical, and operational capabilities (Figure 2) that enable it to meet the volatile demand profiles resulting from resilience events.

Figure 2. Resilience Characteristics of the Gas System

Inherent Resilience of Gas

A molecular form of energy storage; the natural gas molecule is an abundant energy form with long-duration and seasonal storage capabilities.

- Compressibility
  - Storage
  - Linepack
- Abundance and Diversity of Supply

Physical Resilience of Gas System Assets

Most gas system assets are underground and shielded from major disruptions. In most cases, the system is self-reliant, reducing its exposure to disruption.

- Underground infrastructure
- Looped and Parallel T&D Network
- Self-Reliant Gas-Fired Equipment
- Distributed Customer Generation
- System Storage Capacity

Operational Resilience of the Gas System

Operational flexibility is designed into the gas system within a set of system standards that ensure the system's safety and security.

- Robust Management Practices
- Flexible Delivery
- Demand Side Management
- Large Customer Contract Design

Source: Guidehouse

Resilience in Action

Large, catastrophic failures of the energy system have been few and far between—the energy system has performed well, overcoming periods of high stress that have threatened its resilience. These high stress events are becoming more frequent due to the increase in the frequency and severity of extreme weather events associated with climate change. To successfully build for the future and invest in the right set of resilience solutions, it is important for stakeholders to understand how the energy system has performed under recent resilience events.

Recent climate events have revealed the US energy system's potential vulnerabilities. However, the multitude and diversity of resilience assets that already exist as part of the energy system have made the difference—facilitating energy flows to critical services and customers. As the following case studies illustrate, the resilience assets that are part of the gas system have supported the overall integrity of the energy system during these high stress periods.

2019 Polar Vortex

In 2019, the Midwest experienced record-breaking cold temperatures, which led to increased demand on the energy system to meet heating needs.

- CenterPoint Energy curtailed gas service to interruptible customers and pulled gas from every possible storage resource to maintain service to homes and businesses. In one day, CenterPoint delivered almost 50% more than a standard January day.
- On January 30, 2019, Peoples Gas, North Shore Gas, and Nicor Gas together delivered gas in an amount equivalent to more than 3.5 times

	the amount of energy that ComEd, the electric utility serving an overlapping territory has ever delivered in a single day. • The Consumers Energy's Ray Compressor Station fire on January 30 took a primary storage supply resource offline. Consumers leveraged several gas resilience characteristics (linepack, backup storage, and a highly networked gas system) to ensure that no critical, priority, or residential customer lost service.
2014 Polar Vortex	During early February 2014, a polar vortex brought extreme cold temperatures, snowfall, and high winds to Oregon. On February 6, during the system peak, NW Natural set a company record for natural gas sendouts, which still stands today. Nearly 50% of this peak demand was met by natural gas storage capacity. In combination with diligent planning and dedicated employees, this case study highlights the critical role that natural gas storage plays in meeting demand during extreme weather events.
2020 Hurricane Isaias	On August 4, 2020, Hurricane Isaias made landfall in North Carolina. It caused significant destruction as it moved north, triggering electric outages that affected more than 1 million New Jersey homes and businesses. Many customers experiencing electric outages turned on their natural gas backup generators, resulting in a massive increase in demand for New Jersey Natural Gas (NJNG). In 24 hours, NJNG experienced a 60% increase in daily demand on its gas system—the daily demand for this one day was higher than any other August day for the previous 10 years. Because of the built-in storage capacity (compressibility and on-system storage) and flexibility of the gas system, NJNG was able to ramp up service to customers with disrupted electricity supply.
2020 Heat, Drought, and Wildfires	In August 2020, California was in the middle of its hottest August on record,[1] a severe drought, and its worst wildfire season in modern history. Concurrent to increased demand on the electric system driven by increased cooling loads, California also experienced a decrease in renewable output (due to smoke from the fires)[2] and lower imports than had been anticipated by electric supply planners. To meet increased electric demand, system operators turned to gas-fired generation facilities. During the week of August 11, all of SoCalGas' system storage assets were employed to fill the gap between abnormally high electric demand and low renewable energy generation experienced in Southern California.

In all of these case studies, the gas system provided significant support to the energy system in maintaining resilience and ensuring that energy service was maintained to customers. To understand the gas system's contribution to resilience, it is important to differentiate between the pipeline infrastructure system and the natural gas molecules that flow through it. The gas pipeline system is defined as a series of physical assets that transport energy molecules from the source of production to end users, including residential, commercial, and industrial customers who use gas in their buildings and processes, and electric generators who use gas to

[1] NOAA. *National Climate Report*. August 2020.
[2] EIA. *Smoke from California Wildfires Decreases Solar Generation in CAISO*. September 30, 2020.

make electricity. Today, the gas system is used to transport mostly geologic natural gas, but it can be leveraged to transport low-carbon gases such as renewable natural gas (RNG) and potentially hydrogen in the future as utilities move to decarbonize the energy system.

The Growing Resilience Challenge

Driven by changes in the cost and availability of new technologies and increasing political and social pressure to decarbonize, our energy system is undergoing a transformation. This transformation exposes an issue of energy system resilience related to the interaction of the gas and electric systems.

> *As the percentage of electricity generation from intermittent renewable sources increases, the volume of natural gas used for electric power generation may decline; however, in responding to resilience events the necessity of the services provided by gas-fired electric generators may increase. As current compensation models for the gas system serving the power generation sector are tied to the volume of gas delivered to the facility, there becomes an increasing disconnect between the value of the services provided and associated remuneration for said services.*

To further highlight the need for energy system resilience as part of the current transformation, it is worth considering a recent review of the root cause of the California Independent System Operator (CAISO) electric outages during the August 2020 heatwave. One of the three factors identified was: "In transitioning to a reliable, clean and affordable resource mix, resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet [electric] demand in the early evening hours. This makes balancing demand and supply more challenging. These challenges were amplified by the extreme heat storm."[3]

The current model for maintaining the resilience of our energy system was built to support a legacy view of how the energy system operates. As an example, natural gas infrastructure replacement and modernization programs were designed to enhance reliability and safety. As noted in this report they have also contributed to resilience. As the transition to the future energy system accelerates, it is important to understand how these programs complement future energy state resilience needs. The manner in which this energy system is regulated and managed is becoming outdated, and an update is necessary to maintain resilience of the evolving future energy system.

Ensuring a Resilient Future Energy System

The increasing frequency and intensity of climatic events combined with the transformation of the energy system to one increasingly powered by intermittent renewable sources establish the need for a new consideration of the resilience of the energy system. Utilities, system operators, regulators, and policymakers need to recognize that resilience will be achieved through a diverse set of integrated assets—for the foreseeable future, policies need to focus on optimizing the characteristics of both the gas and electric systems.

[3] CAISO. *Preliminary Root Cause Analysis: Mid-August 2020 Heat Storm*. 2020.

Achieving this is easier said than done. It will require a realignment of the valuation and cost recovery mechanisms that currently define the development of the US energy system:

- Energy system resilience must be defined as a measurable and observable set of metrics, similar to how reliability is considered.
- Resilience solutions must be developed considering all possible energy options and across utility jurisdictions, requiring electric, gas, and dual-fuel utilities to work together to determine optimal solutions.
- Methodologies need to be built to value resilience, such that it can be integrated into a standard cost-benefit analysis. Value should consider the avoided direct and indirect costs to the service provider, customers, and society.

The resilience of the current energy system is largely dependent on the gas system's ability to quickly respond to events and use its extensive long-duration storage resources to meet peak and seasonal demand. Ensuring future energy system resilience will require a careful assessment and recognition of the contributions provided by the gas system. Utilities, system operators, regulators, and policymakers need new frameworks to consider resilience impacts to ensure that resilience is not overlooked or jeopardized in the pursuit to achieve decarbonization goals.

1. Introduction

A resilient energy system is essential to the operation of nearly every critical function and sector of the US economy—and the need for energy system resilience is only increasing as emergency services, communications, transportation, banking, healthcare, water supply, and other critical systems become more interconnected than ever. Disruptions to the US energy system can have widespread economic and social impacts, including losses in economic productivity, health and safety issues, and—in the most extreme cases—loss of life.

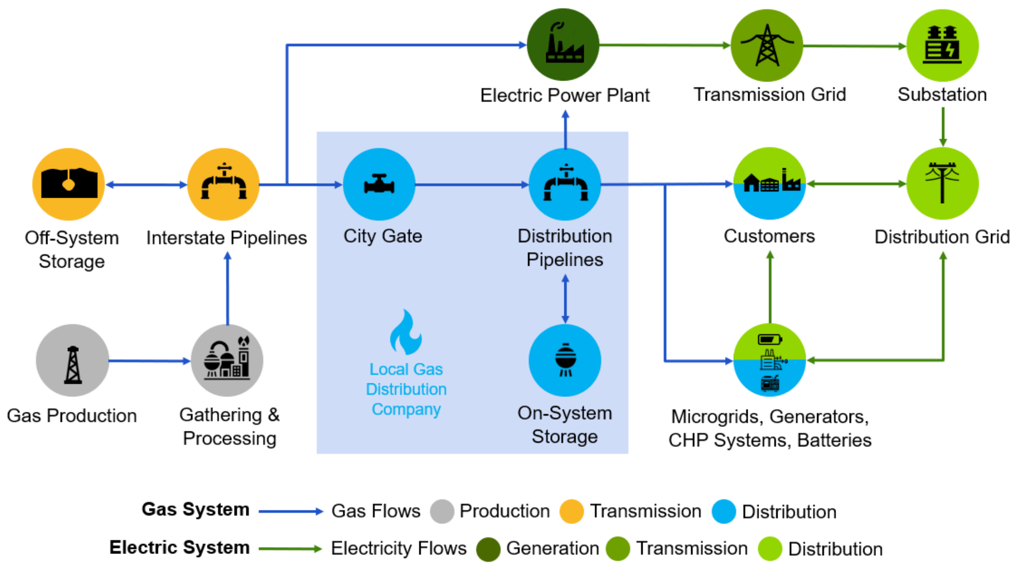
This report examines the resilience of the current gas system with a focus on the part of the system that is under the operational control of the gas local distribution company (LDC). It also examines how the gas system contributes to the resilience of the overall energy system. The work was directed to ask and answer four key questions:

1. What are the characteristics of the US gas system that contribute to its resilience?
2. How do those resilience characteristics allow the US gas system to contribute to the overall resilience of the US energy system?
3. How can the US gas system be leveraged more effectively to strengthen the US energy system?
4. What are the policy and regulatory changes needed to ensure that gas infrastructure can be maintained and developed to continue to support energy system resilience?

1.1 A Primer on the Energy System

An energy system is defined as the full range of components related to the production, conversion, delivery, and use of energy. Energy takes many forms; this report focuses on the natural gas system, herein referred to as the gas system, and its interdependencies with the electric system (Figure 1-1).

Figure 1-1. Interdependencies Between the Gas and Electric Systems

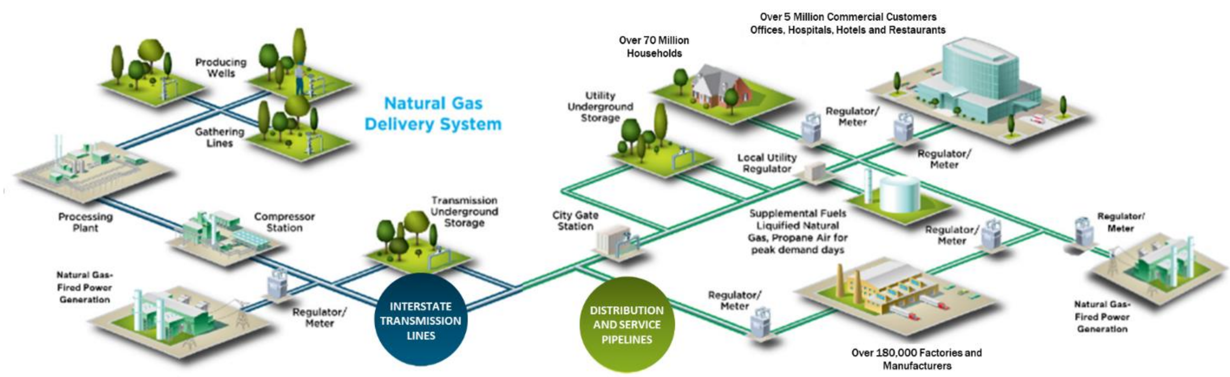


Source: Guidehouse

The gas system is the series of assets that transport energy molecules from the source of production to the site of consumption. The customers served by this system include residential, commercial, and industrial buildings and processes; gas-fired electric generation facilities; transportation fuel providers; and natural gas exporters.

Today, the gas system is used to transport mostly geologic natural gas and small amounts of renewable natural gas (RNG). In the future, the gas system can be leveraged, with only small upgrades, to transport a low carbon fuel supply including RNG, hydrogen, and synthetic methane.

Figure 1-2. Overview of the Gas System



Source: American Gas Association

The gas system can generally be divided into three sections (Appendix A presents further details):

1. **Production and Processing:** Encompasses the process of gathering the gas and treating it to remove impurities.
    - Wells extract natural gas primarily from geologic shale formations.
    - Gathering pipelines transport gas to processing facilities where impurities are removed.
    - Compressors move the gas through midstream pipelines to the connection with interstate transmission pipelines.

2. **Transmission:** Includes the network of high-pressure transmission lines that transport gas from supply basins to market demand centers and, in some cases, across local gas LDC systems.
    - Compressor stations are located approximately every 50 to 60 miles along long-haul transmission pipelines and within gas systems to regulate pressure and keep gas moving.
    - Storage assets connected to the transmission system (defined as off-system storage) exist along these transmission pipelines enabling operators to adjust flow to meet daily and seasonal demand requirements. Storage assets are either underground (i.e., depleted gas reservoirs, aquifers, or salt caverns) or aboveground (where gas is stored as LNG or CNG).

3. **Distribution:** Under the operational control of the LDC, the gas distribution system is primarily comprised of regulator stations, gas pipeline mainlines, and gas pipeline service lines that collectively reduce pressure and move gas from the transmission system to customers.

    - In many cases, gas passes through a city-gate where custody is transferred from the interstate transmission system to the LDC. At this point, gas volumes are measured, typically odorized, and pressure is reduced.
    - LDCs may have LNG, CNG, or underground storage assets on the distribution system (defined as on-system storage), allowing the LDC to maintain reliability and meet short-term demand increases.

1.2 A Primer on Resilience

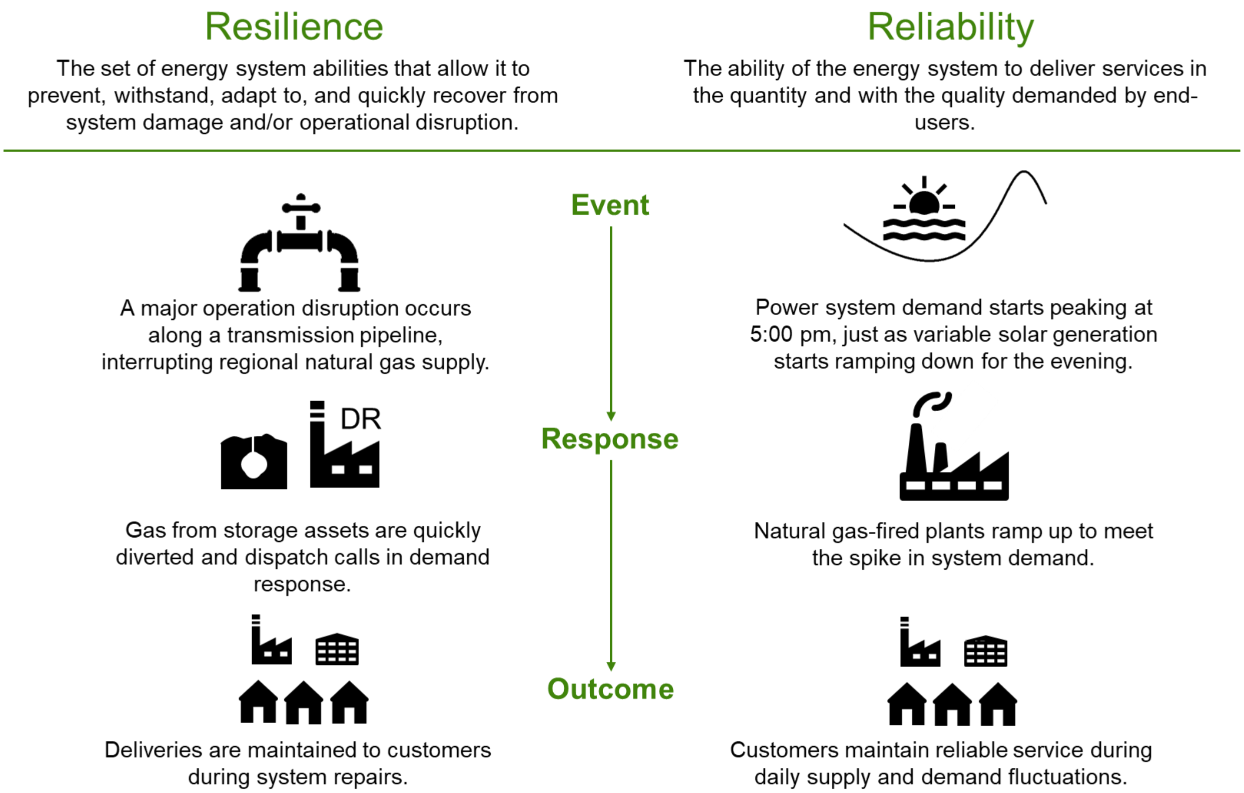
Resilience is defined as a system's ability to prevent, withstand, adapt to, and quickly recover from system damage or operational disruption. The term is defined in relation to a high-impact, low-likelihood event. The most common examples of these events are extreme weather events (which go beyond standard hot days or snowstorms) of a size and scale to cause significant operation disruption, system damage, and devastating human health impacts. Common threats that test the durability of the energy system include extreme weather events (e.g., hurricanes, wildfires, and extreme heat/cold), cyberattacks (e.g., malware and cyber intrusions), and accidents.

Recent examples of resilience events that affected the US energy system include the 2020 California heat waves, Hurricane Isaias, and the 2019 Polar Vortex; each of which are explored in greater detail in Section 3. Other recent resilience events that have exposed the value of the gas system in maintaining energy system delivery include the 2017 Bomb Cyclone,[4] the 2017 Californian wildfires and landslides, Hurricane Irma, and Hurricane Harvey.[5]

Resilience and reliability are often referenced in tandem, but there is a critical difference between the terms and their impact on the design and operation of energy systems. Reliability is defined in relation to a low-impact, high-likelihood event. The US energy system manages reliability daily—in the standard fluctuations in energy supply and demand. Figure 1-3 illustrates resilience and reliability events, along with typical energy system responses and associated outcomes.

[4] The Natural Gas Council; Prepared by RBN Energy. 2018. *Weather Resilience in the Natural Gas Industry: The 2017-18 Test and Results.*
[5] ICF. 2018. *Case Studies of Natural Gas Sector Resilience Following Four Climate-Related Disasters in 2017*.

Figure 1-3. Comparison of Resilience and Reliability

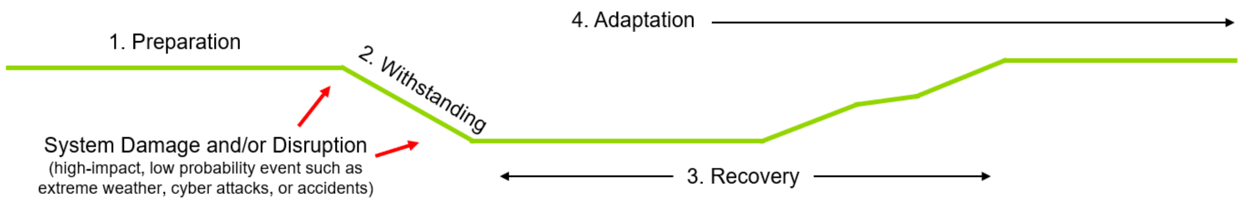


Source: Guidehouse

One way to conceptualize a resilience event is to separate it into distinct phases, where each phase is defined by a time period in relation to the event's onset. Figure 1-4. illustrates this approach with a resilience curve. Table 1-1Table 1-1. defines the four phases of this curve: preparation, withstanding, recovery, and adaptation.

The resilience curve provides a framework for understanding how an energy system's resilience can be strengthened. It is used in Section 2 to classify the resilience characteristics of the gas system.

Figure 1-4. The Energy System Resilience Curve



Source: Guidehouse

Table 1-1. Definition of the Phases of Resilience

Phase	Resilience Characteristics	Timeframe
1. Preparation	The ability to prepare for and prevent initial system disruption	Leading up to the disruption event

Phase	Resilience Characteristics	Timeframe
2. Withstanding	The ability to withstand, mitigate, and manage system disruption	During the disruption event
3. Recovery	The ability to quickly recover normal operations and repair system damage	Following the end of the disruption, until system functions are fully restored
4. Adaptation	The ability to adapt and take action to strengthen the energy system in face of future disruption events	Throughout, but especially during and following the recovery phase

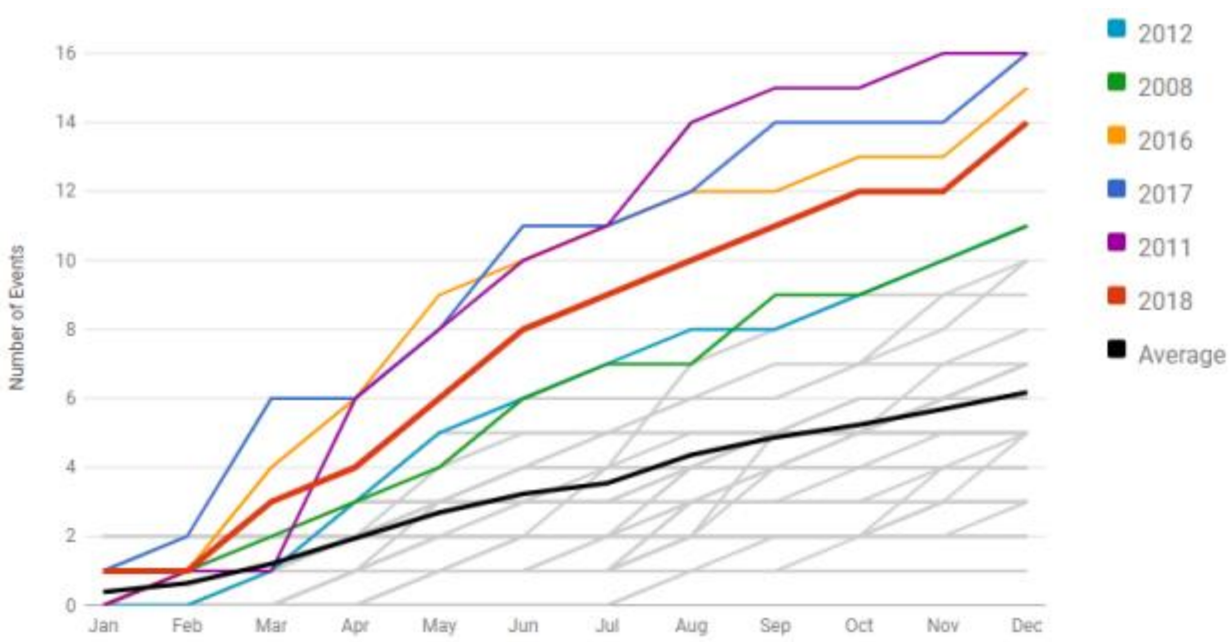
Source: Guidehouse

1.2.1 The Increasing Importance of Resilience

The increased frequency and severity of extreme weather events increasingly put the US energy system at risk. Over the last 50 years, much of the US has experienced increasingly extreme weather including prolonged periods of excessively high temperatures, heavy downpours, flooding, droughts, and severe storm activity.[6]

In the last decade, the US has experienced historic numbers of inflation-adjusted billion-dollar disasters. From 2016-2018 there were 15 billion-dollar disasters per year, up from an average of 6.2 billion-dollar disasters per year since 1980.[7] Figure 1-5. illustrates this trend and shows the cumulative inflation-adjusted billion-dollar disasters on an annual basis since 1980.

Figure 1-5. 1980-2018 Year-to-Date US Billion-Dollar Disaster Event Frequency (CPI-Adjusted, Events Statistics are Added According to the End Date)



Source: NOAA, [2018's Billion Dollar-Disasters in Context]

[6] NOAA. 2014. *Fourth National Climate Assessment*.
[7] NOAA. 2019. *2018's Billion Dollar Disasters in Context*.

To further highlight the importance of placing focus on the resilience of the energy system, consider California in August 2020. California was in the middle of its hottest August (record warmest in 126 years),[8] a severe drought, and its worst wildfire season in modern history. These weather events resulted in increased demand on the electric system, driven by increased cooling load. Concurrently, the state was experiencing a decrease in the anticipated electricity supply from hydroelectricity imports and solar electric generation due to smoke from the wildfires.[9] The coincidence of these events resulted in a significant gap between electricity demand and supply on the California system that led to rolling blackouts on August 14 and 15.[10]

As explored in Case Study 3, in Section 3, because the gas system filled a considerable portion of the gap between abnormally high electric demand and low renewable energy generation, Southern California avoided catastrophic failure.

The increasing frequency and severity of climate events amplify the need to maintain and strengthen the resilience of the US energy system. The energy system needs redundancy and storage capabilities to respond to dramatic shifts in supply and demand quickly.

1.3 An Orientation to this Report

The remaining content in this report is separated into five major sections.

- *Section 2 The Resilience of the Gas System* describes the various inherent, physical, and operational characteristics of the gas system that contribute to the resilience of the US energy system.

- *Section 3 Proving It: Resilience in Action* details five case studies that demonstrate how gas distribution companies across the country have demonstrated gas system resilience through real-world examples.

- *Section 4 Current Regulatory, Policy, and Market Structure* summarizes how current regulatory, policy, and market structures create challenges for building gas resilience assets.

- *Section 5 Ensuring A Resilient Future* explores how decarbonization-driven changes to the electric system may present challenges for future resilience and lessons learned from other economic sectors.

- *Section 6 Conclusions* presents a call to action for how the findings in this report can be used and their implications for policymakers and regulators.

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[8] NOAA. National Climate Report – August 2020. https://www.ncdc.noaa.gov/sotc/national/202008

[9] EIA. *Smoke from California Wildfires Decreases Solar Generation in CAISO.* September 30, 2020. https://www.eia.gov/todayinenergy/detail.php?id=45336

[10] California Independent System Operator. 2020. *Preliminary Root Cause Analysis.*

2. The Resilience of the Gas System

This section explores the fundamental resilience characteristics of the gas value chain and describes how it provides resilience services to customers. These characteristics are detailed further in Section 3 in case studies that demonstrate gas system resilience through real-world examples.

2.1 Fundamental Resilience Characteristics of the Gas System

Guidehouse examines the fundamental inherent, physical, and operational characteristics of the gas system in relation to their contribution along the resilience curve phases, i.e. how they help the gas system prepare for, withstand, recover from, and adapt to a resilience event. Table 2-1 outlines the key questions considered in evaluating these characteristics within the gas value chain.

Table 2-1. Key Questions Used to Identify Resilience Characteristics

Resilience Phase	Key Identifying Questions
1. Preparation	• Does it help the system prepare for or prevent threats? • Does it reduce the physical exposure of system infrastructure to the threat?
2. Withstanding	• Does it help minimize system impacts or sensitivity to potential disruptions? • Does it help prevent the occurrence of cascading failures? • Does it help the system maintain functioning if a disruption occurs?
3. Recovery	• Does it assist in restoring or repairing lost functionality?
4. Adaptation	• Does it help the system adjust to changing climate or operating conditions? • Does it facilitate learning and resilience investments to prevent future threats?

Source: Guidehouse

Gas system characteristics that contribute to energy system resilience are highlighted in Figure 2-1. they are also discussed in greater detail throughout this section.

Figure 2-1. Resilience Characteristics of the Gas System

Inherent Resilience of Gas

A molecular form of energy storage; the natural gas molecule is an abundant energy form with long-duration and seasonal storage capabilities.

- Compressibility
  - Storage
  - Linepack
- Abundance and Diversity of Supply

Physical Resilience of Gas System Assets

Most gas system assets are underground and shielded from major disruptions. In most cases, the system is self-reliant, reducing its exposure to disruption.

- Underground infrastructure
- Looped and Parallel T&D Network
- Self-Reliant Gas-Fired Equipment
- Distributed Customer Generation
- System Storage Capacity

Operational Resilience of the Gas System

Operational flexibility is designed into the gas system within a set of system standards that ensure the system's safety and security.

- Robust Management Practices
- Flexible Delivery
- Demand Side Management
- Large Customer Contract Design

Source: Guidehouse

2.2 Inherent Characteristics of Gas Resilience

As a molecular form of energy storage, natural gas molecules have several inherent characteristics that contribute to the resilience of the gas system. Chief among these characteristics is its compressibility, which allows additional volumes of gas to be packed into the pipeline or under- and above-ground storage. Natural gas supply is also abundant and geographically diverse, allowing it to meet current energy needs even in the event of a supply chain disruption. The inherent characteristics also hold true for low carbon forms of gas supply which may replace natural gas in the future gas system. Table 2-2 summarizes the inherent characteristics of gas resilience, which are also discussed further in this section.

Table 2-2. Inherent Resilience Across the Phases of Resilience

<table>
<tr><th></th><th colspan="4">Resilience Phases</th></tr>
<tr><th>Characteristic</th><th>Preparation</th><th>Withstanding</th><th>Recovery</th><th>Adaptation</th></tr>
<tr><td>Compressibility
Storage
Linepack</td><td colspan="2">Reduces sensitivity to disruptions</td><td>Buffers against cascading failures</td><td></td></tr>
<tr><td>Abundance and Diversity of Supply</td><td></td><td colspan="2">Maintains production in the event of a regionally isolated supply-side disruption</td><td>Low carbon options for a future energy system</td></tr>
</table>

Source: Guidehouse

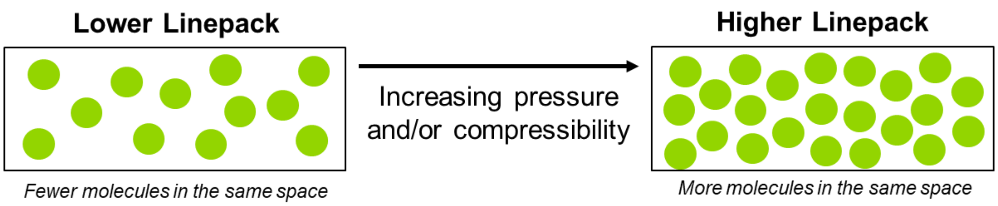
2.2.1 Compressibility

Natural gas is made up of inherently stable and compressible molecules, making it a desirable energy storage carrier and pipeline system buffer.

- **Storage** – Long-duration gas storage is frequently used to meet seasonal demand patterns and can be used as a complement to the electric system in meeting demand during low-likelihood, high-impact resilience events. Natural gas can be compressed and stored underground in geological formations (e.g., in depleted gas reservoirs, aquifers, or salt caverns) or aboveground in tanks (as LNG or CNG). As LNG, the volume of natural gas is about 600 times smaller than its gaseous form at atmospheric pressure; whereas, as CNG, it is 100 times smaller.

- **Linepack** – Excess natural gas molecules, i.e. more than what would be needed to meet customer demand can be compressed and stored within pipelines, acting as a buffer to minimize the impact of short-term hourly supply and demand fluctuations on the gas system (Figure 2-2).[11] Gas system operators, including LDCs, can control the amount of linepack in the pipes, allowing them to meet rapid, intraday changes in demand even if upstream supply is insufficient.

Figure 2-2. Linepack and Compressibility of Gas



Source: Guidehouse

Figure 2-2 provides a clear example of how linepack and storage can be used in tandem to prevent and mitigate the effects of a major gas system disruption. These characteristics are different from the electricity grid where disruptions can immediately impact all connected gas systems and increase the risk of cascading failures. Electric supply and demand must be balanced across the electric system near instantaneously and electricity can only be stored in specified storage assets, such as batteries.

2.2.2 Abundance and Diversity of Supply

Natural gas is supplied from a variety of sources across North America, including:

- **Conventional production:** Currently, natural gas is primarily produced from shale plays and formations; it is also produced in smaller quantities from conventional gas reservoirs, tight sands, carbonates, and coal-bed methane. Figure 2-3 highlights the geographic diversity of US shale plays and formations. Additionally, an evaluation by the Potential Gas Committee at year-end 2018 indicated that the US possesses a technically recoverable resource base of natural gas of nearly 3,400 trillion cubic feet (Tcf).[12] The US Energy Information Administration additionally reported that US proved

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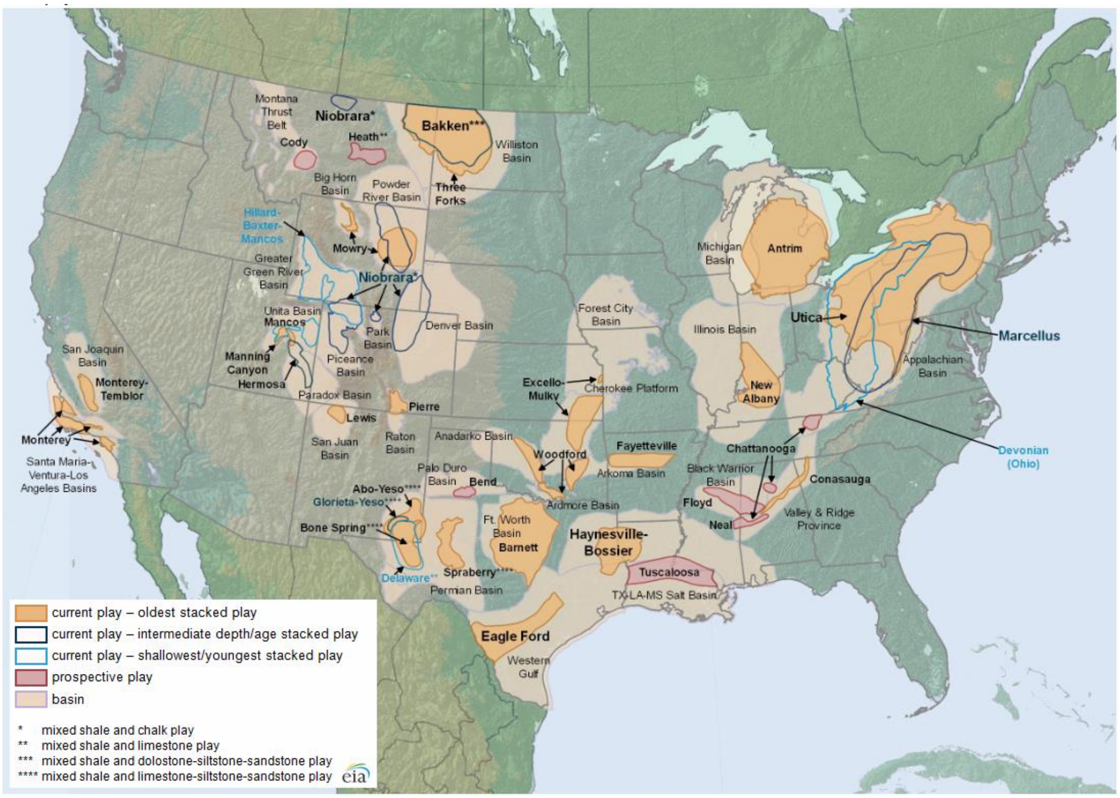
[11] Natural Gas Council. 2019. *Natural Gas: Reliable and Resilient.*

[12] Potential Gas Committee. 2019. *Potential Supply of Natural Gas in the United States.* Accessed November 2020.

reserves stood at 504.5 Tcf as of 2018. The combination of these supplies suggests a future gas supply resource enough to meet over 100 years of consumption at current levels.[13]

This abundance and diversity of natural gas supply ensures that natural gas can continue to meet customer demand even during regionally isolated supply-side disruptions such as a major storm event. For example, limited supply interruptions during recent hurricanes demonstrates the value of shifting natural gas production from the Gulf of Mexico to geographically diverse shale plays and formations.

Figure 2-3. US Shale Plays and Formations



Source: US Energy Information Administration

- **Low Carbon Production:** The abundance and diversity of resources transportable through the gas system will increase as RNG and hydrogen become increasingly commercially viable. Though it is only a small portion of current US gas supply, RNG supply is growing dramatically--produced from a variety of waste feedstocks from the sewage, agriculture, food, and forestry sectors, as detailed in Appendix B. Hydrogen is projected to serve a larger portion of future US gas demand, but it is earlier in the process of developing commercial viability in the US, though it is already flowing through the pipes in Europe as discussed in Appendix B.

[13] Natural Resources Canada. 2020. *Natural Gas Facts.* Accessed October 2020.

- **Pipeline Imports:** Natural gas is also imported via pipeline from Canada, and from elsewhere as LNG. These are critical supply sources during peak periods and lend to greater gas system flexibility.

2.3 Physical Characteristics of Gas System Resilience

The gas system's physical characteristics lend themselves to providing stability to the energy system. Most pipeline infrastructure is underground and looped, creating flexibility in a delivery system that is shielded from many major disruptive events. Much of the gas delivery system also runs on its own supply, making it self-reliant. The ability to store gas further strengthens the self-reliant attributes of the gas system, enabling it to respond to disruption or an extreme peak caused by unprecedented demand or upstream disruption. Table 2-3 summarizes these physical characteristics of gas resilience, which this section also discusses.

Table 2-3. Physical Resilience Across the Phases of Resilience

<table>
<tr><th></th><th colspan="4">Resilience Phases</th></tr>
<tr><th>Characteristic</th><th>Preparation</th><th>Withstanding</th><th>Recovery</th><th>Adaptation</th></tr>
<tr><td>Underground Infrastructure</td><td>Reduces exposure to threat</td><td>Minimizes impact of potential disruptions</td><td></td><td></td></tr>
<tr><td>Looped and Parallel T&D Network</td><td></td><td colspan="2">Improves deliverability in the event of regionally isolated gas network disruption</td><td></td></tr>
<tr><td>Self-Reliant Gas-Fired Equipment</td><td></td><td></td><td>Maintains gas delivery during an electric grid outage</td><td></td></tr>
<tr><td>Distributed Customer Generation</td><td></td><td>Reduces electric grid demand during extreme weather event</td><td colspan="2">Enables customer flexibility in the event of an electric grid disruption outage</td></tr>
<tr><td>System Storage Capacity</td><td>Prepares system for expected demand increase</td><td>Balances supply and demand fluctuations</td><td>Improves deliverability during disruption</td><td>Facilitates supply-side diversity (renewable integration)</td></tr>
</table>

Source: Guidehouse

2.3.1 Underground Infrastructure

Natural gas is one of the few energy resources predominantly delivered to customers by pipeline. In contrast, other common energy forms, such as electricity, are mostly delivered by aboveground wires. Although each delivery method has advantages, the underground gas delivery system has significantly reduced exposure to disruptive events from extreme weather such as hurricanes and snowstorms. Because of this, significant weather events rarely disrupt localized segments of the network and damage is typically limited to aboveground facilities where pipeline assets may be exposed.[14]

[14] EIA. *Natural Gas Explained: Natural Gas Pipelines*. Accessed October 2020.

2.3.2 Looped and Parallel Transmission and Distribution Network

The gas system is extensively interconnected with multiple pathways for rerouting deliveries. This interconnectivity enables the sourcing of natural gas from various production centers across the country. Additionally, distribution mains are typically interconnected in multiple grid patterns with strategically located shut-off valves. These valves allow operators the ability to isolate segments of a gas system, which minimizes customer service disruptions. To reinforce the resilience of gas delivery, the valves are paired with on-system storage and mobile pipeline solutions.

> *A 2019 study by the Rhodium Group on natural gas system reliability indicated that, "the US natural gas system typically deals with a handful of disruptions every month that last a day or more. Despite these disruptions, deliverability to end-use sectors, including electric power generators, is rarely impacted because of the redundancy built into the system."[15] While this study focused on reliability, it highlights the system redundancy that is available to respond to higher-impact resilience events.*

In addition to the interconnectivity of the gas system design, pipeline capacity is often increased by installing two or more parallel pipelines in the same right-of-way (called pipeline loops), making it possible to shut off one loop while keeping the other in service. Further, in the event of one or more equipment failures, gas pipelines can continue to operate at pressures necessary to maintain deliveries to pipeline customers, at least outside the affected segment. Considering customer impacts of individual equipment failures in the design of gas pipelines and facilities to determine where investment in redundant infrastructure is prudent, is part of the gas utility risk management process.

2.3.3 Self-Reliant Gas-Fired Equipment

Much of the equipment used on the gas system, including compressors, dehydration equipment, pressure regulators, and heaters, are usually powered by the gas that flows through the pipes they serve. Powering equipment by the gas in the system limits the gas system's reliance on external supply chains. If gas continues to flow through the pipes—which has demonstrated to be a resilient supply chain itself—the gas system will continue to operate, and gas will flow to customers.

In some cases, the pursuit of decarbonization goals has resulted in the replacement of gas compressors with electric compressors. While electric compressors are not yet widespread, their use does reduce this resilient aspect of gas system operation.

2.3.4 Distributed Customer Generation

The US Department of Energy has documented how combined-heat and power (CHP) systems serve as a resilience solution, with specific case studies on how CHP has provided resilience for critical facilities during major weather events, giving them the flexibility to produce thermal energy and electricity onsite.[16] Example 1 highlights one such case study. CHP systems at

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[15] Rhodium Group. 2019. *Natural Gas Supply Disruption: An Unlikely Threat to Electric Reliability*.

[16] US Department of Energy. 2018. "CHP Technology Fact Sheet Series."

these facilities are largely dependent on the resilience of the US gas system and its ability to continue delivering natural gas during resilience events.

At the end of 2019, there were 3,186 commercial and industrial (C&I) CHP sites fueled by natural gas with a total capacity of 58,140 MW.[17] This distributed generation is equivalent to over 5% of total US electric power generation capacity. Distributed CHP systems exemplify how the gas system supports the resilience of end-use customers by giving them alternative options to generate heat and electricity in the case of unplanned energy system disruptions. The costs and inconvenience of a power outage can be substantial, including losses in productivity, product, revenue, and customers. Gas-fired standby generators also provide a resilience benefit by helping to avoid the impact of a power outage. This benefit is discussed further in Case Study 5.

Example 1. CHP and Distributed Generation Support Critical Infrastructure During Extreme Weather Events[18]

Hurricanes. In 2008, Hurricane Ike flooded over 1 million square feet of the University of Texas Medical Branch (UTMB) in Galveston, Texas. The hurricane interrupted utility services and resulted in the complete loss of UTMB's underground steam distribution system. Learning from this experience, the UTMB installed a 15 MW CHP facility (11 MW fueled by natural gas) to improve resilience and allow for an immediate return of hospital and clinical operations.

This resilience solution was tested during Hurricane Harvey in 2017 when the campus lost power. In circumstances that would have otherwise caused a blackout, the CHP system continued to operate during and after the storm, allowing the hospital to maintain regular operations. As a co-benefit, the CHP system saves UTMB approximately $2 million per year in utility costs and reduces campus emissions by 16,476 tons of CO_2 per year.

2.3.5 Gas System Storage Capacity

The ability to store large quantities of energy supply is a fundamental strength of the gas system allowing it to respond to, prepare for, withstand, and recover from disruption. In addition, gas storage facilities offer further geographic supply diversity to the gas system, as these storage assets can often maintain supply if disruptions are experienced on the system. Gas system storage capacity is built as a result of long-term planning in response to forecasted seasonal and peak demand. Gas system storage can be classified by where it is connected to the gas value chain.

- **On-System Storage:** This storage is operated and controlled by the LDC, allowing it to respond quickly to peak demand requirements and emergency situations. On-system storage is often aboveground, and in some situations underground. One advantage of on-system storage is that it can be sited at specific locations on the gas distribution system to best provide a resilience benefit (both supply and pressure support) in the event of an upstream disruption. This benefit is exemplified in Case Study 4.

[17] U.S. Department of Energy. 2019. *U.S. Department of Energy Combined Heat and Power Installation Database*. Accessed October 2020.

[18] Southcentral CHP Technical Assistance Partnerships. 2019. *Project Profile: University of Texas Medical Branch 15 MW CHP System*. Accessed October 2020.

- **Off-System Storage:** This storage is connected to a transmission line and is not directly tied to an LDC's distribution system. In most cases, off-system storage is underground, which makes it resilient to many climate-driven disruptions.
- **Mobile Storage:** Stored as LNG or CNG, natural gas can be moved via truck to serve short duration needs such as providing temporary supply for emergency response, pipeline maintenance, and construction and peak shaving.

The gas system's storage capacity is critical to its ability to respond to disruption. For example, the gas system storage capacity allows the gas system to respond to extreme heat and cold events when large amounts of gas are drawn in a short period. In addition, system storage provides a supply buffer allowing the LDC vital time to respond to unplanned delivery constraints in the pipeline and distribution network, resulting from gas system disruptions. The capacity of US gas storage and the associated value of that storage is further explored in Example Box 2.

Example 2. The Value of Gas Storage

In 2019, the US consumed approximately 31 trillion cubic feet of natural gas. If this natural gas was consumed in the same amount every day, the US would consume approximately 85 Bcf per day (Bcfd). But natural gas usage is seasonal – in January 2019, the US consumed nearly 110 Bcfd on average compared to approximately 71 Bcfd in June.[19]

With seasonal fluctuations in use and additional fluctuations in daily consumption, gas storage plays a vital role in balancing supply and demand. The US has nearly 400 underground storage facilities in the lower 48 states with a total storage capacity of more than 4,000 Bcf. In 2019, approximately 2,300 Bcf of natural gas supply was delivered from storage facilities, roughly the energy equivalent of 700 million megawatt-hours (MWh).[20]

NW Natural operates the Mist underground storage facility in Oregon. Its 20.1 Bcf of gas storage capacity is equivalent to 6 million MWh. Installing a battery of equivalent size on the electric system would cost approximately $2 trillion in 2020 dollars.[21]

Storage assets are additionally well positioned to support future state resilience demands and are capable of using low carbon commodities. These long-lived assets can be re-missioned to meet evolving energy system resilience requirements.

2.4 Operational Characteristics of Gas System Resilience

The industry has several operational tools at its disposal to prepare for, withstand, recover from, and adapt to disruptions. The gas system has robust management practices for the flows of gas on the system and there are several opportunities to provide flexibility in delivery and to manage demand. Table 2-4 summarizes these operational characteristics of gas resilience, which are also discussed further in this section.

[19] https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

[20] https://www.eia.gov/naturalgas/ngqs/#?report=RP7&year1=2019&year2=2019&company=Name

[21] https://www.nrel.gov/docs/fy19osti/73222.pdf

Table 2-4. Operational Resilience Across the Phases of Resilience

<table>
<tr><th></th><th colspan="4">Resilience Phases</th></tr>
<tr><th>Characteristic</th><th>Preparation</th><th>Withstanding</th><th>Recovery</th><th>Adaptation</th></tr>
<tr><td>Robust Management Practices</td><td colspan="4">Activates backup resources, prevents and mitigates cyber threats, improves response to disruptions, facilitates learning from unanticipated disruptions</td></tr>
<tr><td>Flexible Delivery</td><td></td><td></td><td>Improves gas deliverability during extreme conditions</td><td></td></tr>
<tr><td>Demand-side management and energy efficiency</td><td colspan="2">Reduces demand before and during extreme events</td><td>Provides gas system operators demand-side control during disruptions</td><td></td></tr>
<tr><td>Large customer contract design</td><td></td><td colspan="2">Flexibility to curtail non-firm transport customers</td><td></td></tr>
</table>

Source: Guidehouse

2.4.1 Robust Management Practices

The gas industry maintains safe and resilient operations using a variety of tools including long-term resource planning, emergency response planning, standard operating procedures, and incident-response protocols. The industry also has a well-established Mutual Aid Program that allows utilities to provide and receive aid from other utility members in the event of disaster or emergency situations.[22] Pipeline operators are trained per the US Department of Transportation's pipeline safety requirements.

Gas utilities also follow robust cybersecurity protocols,[23] and align their cybersecurity programs to several key frameworks and standards including the NIST Cybersecurity Framework, the ISA/IEC 62443 Series of Standards on Industrial Automation and Control Systems (IACS) Security, ISO 27000, NIST 800-82, the TSA Pipeline Security Guidelines, and API Standard 1164.[24] Gas assets are also designed with manual override and manual backups in case of cyber disruption.

2.4.2 Flexible Delivery

In addition to on-system storage, some LDCs use mobile pipeline solutions. These non-pipeline solutions are frequently LNG or CNG tanker trucks that deliver needed supplies directly to an injection point on the distribution system in the event of a gas system disruption. The ability to deliver through multiple pathways is a valuable characteristic of the gas system.

[22] American Public Gas Association. *Mutual Aid Program.* Accessed November 2020.
[23] Oil and Natural Gas Sector Coordinating Council; Natural Gas Council. 2018. *Defense-in-Depth: Cyber Security in the Oil and Natural Gas Industry.*
[24] Natural Gas Council. 2019. *Natural Gas: Reliable and Resilient.*

Example 3. Operational Management Helps Prepare for and Withstand Extreme Weather Events

During the January 2019 polar vortex, a severe wave of cold weather swept over the midwestern US, bringing temperatures to well below -20°F in several states. Minnesota experienced its lowest air temperatures since 1996, reaching a low of -56°F and wind chills below -60°F in some areas.[25]

Leading up to the event, CenterPoint Energy used gas system modeling and SCADA to predict how its gas system would react to the extreme cold temperatures. Based on this data, CenterPoint Energy deployed two CNG trailers to strategic locations where additional supply might be needed and placed field crews on standby across the state. Engineering, operations, and gas control were in constant communication, as is standard practice for most cold-weather events. Though CenterPoint Energy's gas system met demand during record temperatures without the need of the CNG trailers, this example highlights how gas LDCs use robust management practices to prepare for and withstand extreme weather events.[26] CenterPoint Energy's response to the 2019 polar vortex is highlighted further in Case Study 1 in Section 3.

2.4.3 Demand Side Management and Energy Efficiency

Gas system operators have a robust toolbox to safely, effectively, and efficiently accommodate demand. Many gas utilities offer demand side management (DSM) and energy efficiency programs to support their customers in managing their gas consumption, while some are also piloting demand response (DR) programs that can include controllable devices such as connected thermostats. Implementation of these programs frequently results in resilience benefits. For example:

- Residential customers participating in weatherization programs to reduce their energy use associated with heating and cooling will enjoy a home that is more efficient and can better maintain comfortable indoor temperatures. These residents will be better able to shelter in place if they experience disruptions in their energy supply.
- Participation in energy efficiency programs in general will result in more efficient energy usage and lower annual spend on energy.
- DSM and DR programs offer grid operators the opportunity to improve the efficiency and stability of the power system by reducing the severity of demand spikes. Although these programs are often developed to increase reliability, they also offer significant resilience benefits in allowing grid operators the ability to adjust the demand side of the equation when a significant disruption is experienced.

2.4.4 Large Customer Contract Design

Gas system operators contract with large-volume customers in a way that mitigates potential physical constraints around deliverability. Large-volume customers voluntarily enter into either a firm contract (i.e., they are contractually guaranteed an agreed amount of supply, regardless of potential gas system capacity constraint issues) or an interruptible contract (i.e., their service can be interrupted if the gas system is experiencing capacity constraint issues) with the gas system. This means that gas system operators have the flexibility to contractually curtail delivery to large-volume interruptible customers in the event of disruption, a form of demand response, which is one reason why the gas system rarely experiences service disruptions.

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[25] Minnesota Department of Natural Resources. 2019. *Cold Outbreak: January 27-31, 2019.* Accessed October 2020.
[26] CenterPoint Energy, Interview. October 2020.

The definitions of firm and interruptible customers may need further clarification as the gas system sees more large-volume users with dramatic swings in their maximum and minimum usage throughout a day. However, the gas system's ability to contract differently with users that use the gas system differently is a resilience characteristic that must be recognized.

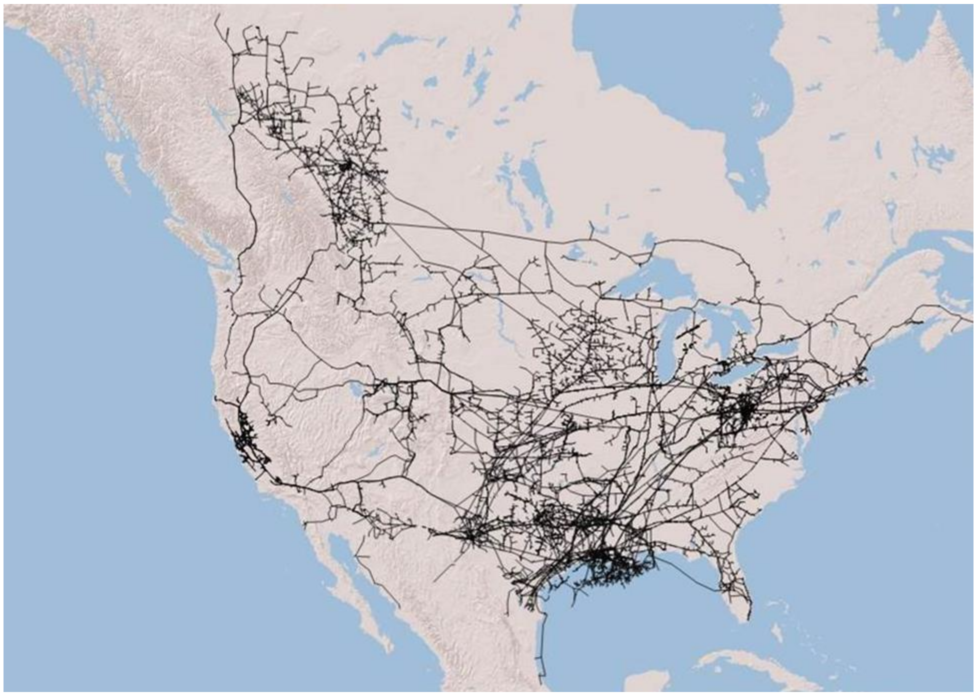
2.5 Resilience Limitations

The overall US gas system's network contributes to its stability but the degree of interconnectedness on the network can vary across LDCs based on the following two primary factors:

- The availability of operational capacity on upstream pipelines and storage
- The physical location of the LDC service territory in relation to pipelines and storage facilities

As Figure 2-4 illustrates, some US regions have more access to the transmission system than others. For example, the Pacific Northwest is supplied by fewer pipelines compared to the Upper Midwest and the Gulf Coast. A gas utility or geographic region with limited access to multiple transmission pipelines will need to leverage other resilience solutions to develop transportation and supply diversity, such as storage.

Figure 2-4. Major North American Natural Gas Pipelines



Source: S&P Global Market Intelligence

3. Proving It: Resilience in Action

The inherent, physical, and operational capabilities of the gas system—from receipt of supply from the upstream pipelines to the ability to provide short-notice storage withdrawal and injection rates—enable it to meet the volatile demand profiles resulting from resilience events. This section includes six case studies that exemplify how the gas system contributes to the resilience of the US energy system.

It is a testimony to the preparedness and true resilience of the industry that there are so few case studies of extra measures ever needing to be taken to respond to periods of extraordinarily high demand.

Polar Vortex (January 2019)

- In Case Study 1, the use of a diverse mix of gas resilience assets (upstream pipelines, storage, LNG and propane storage, flexible non-pipeline assets) allowed the gas system to meet record peak demand resulting from extreme cold temperatures.

- In Case Study 2, the integral role the gas system plays in supporting the space heating needs of customers in colder climates is explored. The case study also demonstrates that during a peak event, the gas system currently delivers substantially more energy than the electric system is built to deliver.

- In Case Study 3, the resilience attributes of the gas system were put to the test when a fire caused a failure on a critical gas compression and storage facility. Despite losing almost one-third of its on-system storage, the gas utility withstood this failure during a period of peak demand without involuntary loss to a single residential customer.

Polar Vortex (February 2014)

- In Case Study 4, the role of natural gas storage, both underground and aboveground, as a critical resilience solution to meet record gas demand is demonstrated.

Hurricane Isaias (August 2020)

- In Case Study 5, natural gas was used as a backup power source to ensure essential power functions could continue to be met for residential and commercial customers in the middle of a hurricane.

Heat, Drought, and Wildfires (August 2020)

- Case Study 6, storage capacity resources were used to meet the supply needs of gas-fired generation plants when the California electric system experienced high demand from a record-breaking heatwave and unplanned reductions in other sources of generation.

Case Study 1: Meeting Record Peak Demand (Minnesota)

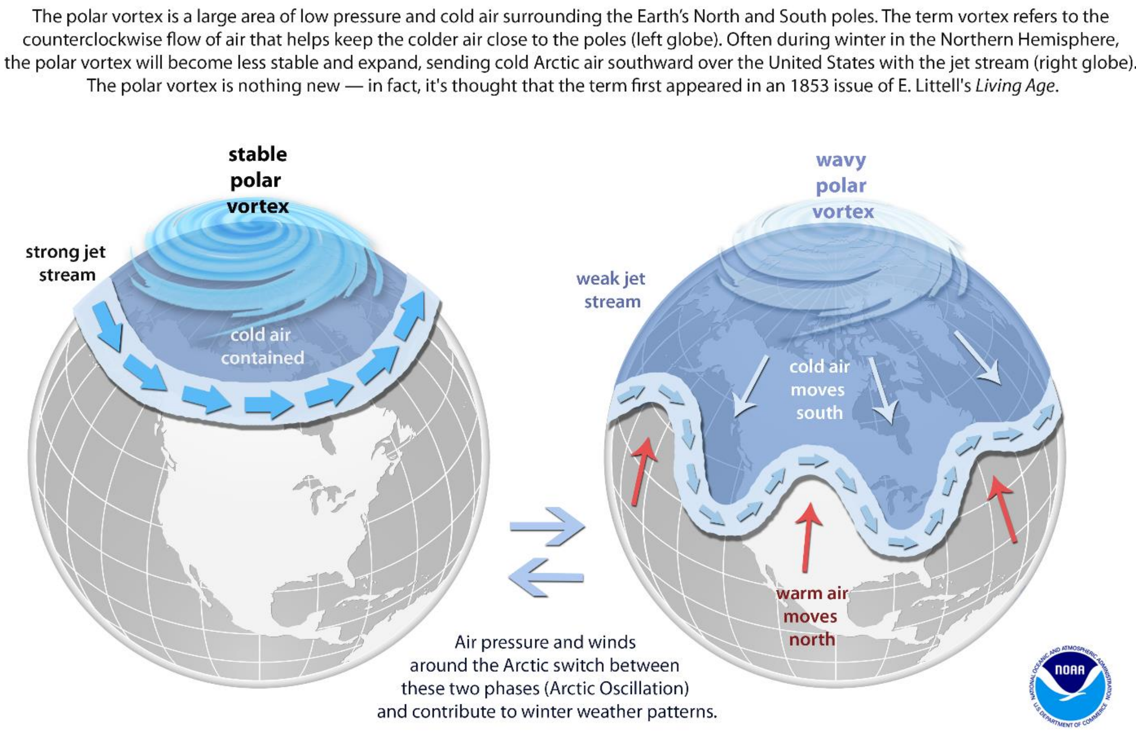
Key Finding

CenterPoint Energy used a diverse mix of gas resilience assets (upstream pipelines, storage, LNG and propane storage, flexible non-pipeline assets) to meet record peak demand resulting from extreme cold temperatures across the Midwest.

Introduction

The first three case studies pertain to the January 2019 Polar Vortex, when a weakened jet stream resulted in the coldest temperatures in over 20 years to most affected regions across the US and Canada (Figure 3-1). The event resulted in at least 22 deaths and grounded around 2,700 flights across the Midwest and Northeast.

Figure 3-1. The Science Behind the Polar Vortex



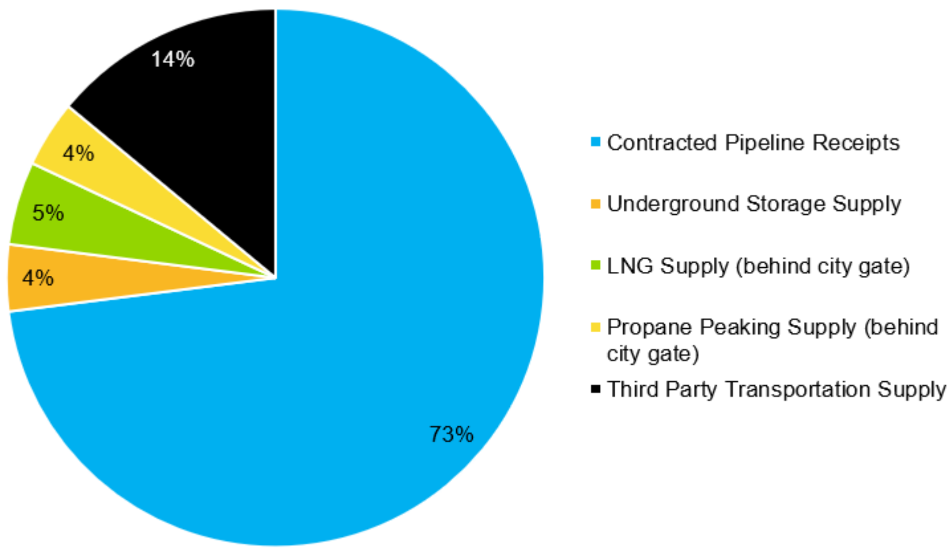
Source: National Oceanic and Atmospheric Administration

Overview

During the January 2019 Polar Vortex, in Minneapolis, Minnesota, the average temperature was -19°F from January 29 to 30. The coldest hour occurred at 6:00 a.m. on January 30 when the temperature was -30°F (before wind chill). On these days, CenterPoint Energy (which serves 870,000 customers in the greater Minneapolis region) experienced record daily delivery of natural gas of 1,495,000 Dth on January 29 and 1,448,000 Dth on January 30. This compares to 1,000,000 Dth of daily sendout in a typical January day, or a 49% and 44.8% increase over average for January 29 and 30, respectively.

Because the demand for gas was so high on CenterPoint's gas system on January 29 and 30, interruptible customers and interruptible transportation service deliveries were curtailed to maintain distribution system integrity for firm demand customers. Even after curtailing these customers, CenterPoint Energy needed to pull gas supply from every available source, as Figure 3-2 illustrates. Approximately 13% of the gas delivered to CenterPoint's customers in Minneapolis on these very cold days was supplied by storage, including LNG and propane assets, which played a critical role in providing additional supply and pressure to maintain gas system integrity.

Figure 3-2. Gas Supply by Source, CenterPoint Energy, Minneapolis, Minnesota, January 29-30, 2020



Source: Guidehouse, CenterPoint Energy

Like many gas utilities, this planning consists of a thorough review of gas supply plans and monitoring of distribution system performance in addition to heightened staffing to be prepared for quick response to issues.

Table 3-1. CenterPoint Energy Actions to Maintain Gas System Viability During the 2019 Polar Vortex

Phase of Resilience	CenterPoint Actions to Maintain Gas System Deliveries in Response to the 2019 Polar Vortex
1. Preparation	• Daily review of supply plans by gas supply, gas control, peak shaving, and engineering. • Daily preparation and execution of cold weather engineering plans. • Daily staging of operations technicians in critical locations to monitor/react. • Daily staffing of engineering personnel in the cold weather ops center to support system operations and gas control. • Dispatch Center: Extra staff added to coordinate with field operations. • Field operations: Implementation of cold-weather operating plans.

Phase of Resilience	CenterPoint Actions to Maintain Gas System Deliveries in Response to the 2019 Polar Vortex
	• The areas requiring CNG trailer deployment were identified using system modeling and SCADA to help predict how the system would react during the cold event. • Two CNG trailers were deployed and on standby. These flexible non-pipeline solutions provided just in time delivery to reinforce system operations
2. Withstanding	• Aside from the CNG locations, CenterPoint Energy positioned several field crews at different locations throughout its service territory on standby to be responsive should an unexpected issue arise. In addition, critical groups, including engineering, operations, and gas control were in constant communication to monitor the system.
3. Recovery	• The system did not incur any damage or major disruptions, so there was no recovery phase for this event.
4. Adaptation	• System reinforcements were identified and later completed for the areas where CNG trailer were deployed. • Regular review of distribution system performance as cold weather occurs. • Adjustments are made if needed and as possible. • Testing and operation of stations and equipment.

Source: Guidehouse, CenterPoint Energy

Conclusion

CenterPoint Energy’s use of a diverse mix of gas system resilience assets to meet record peak demand from a climate event exemplifies how the gas system contributes to the energy system’s overall stability. Upstream pipelines, storage, LNG and propane storage, and flexible non-pipeline assets were deployed for addressing unplanned or unforeseen events within the integrated energy system.

Case Study 2: The Role of Natural Gas (Illinois)

Key Finding

During the 2019 Polar Vortex, Nicor Gas, Peoples Gas, and North Shores Gas' daily distributions of natural gas (7.32 Bcf) were equivalent to 90GW of electricity—more than 3.5 times the amount of electricity that ComEd, the electric utility serving a similar territory has delivered in a single day. The gas system provides value in the volume of energy that can be delivered during peak events, which will require significant infrastructure buildout to be replaced.

Introduction

During the record-breaking cold weather that occurred January 30 and 31, 2019, Nicor Gas, the LDC serving 2.2 million customers in Illinois delivered more than 4.88 Bcf of natural gas per day. This is more than double the natural gas delivered on a typical day in January day. In terms of energy delivery, this amount of gas, an average of 0.20 Bcf per hour, compares to approximately 61 GW of electricity.[27] This is the single largest delivery of natural gas in the company's history—surpassing previous records set when 4.5 Bcf was delivered between January 6 and 7, 2014.

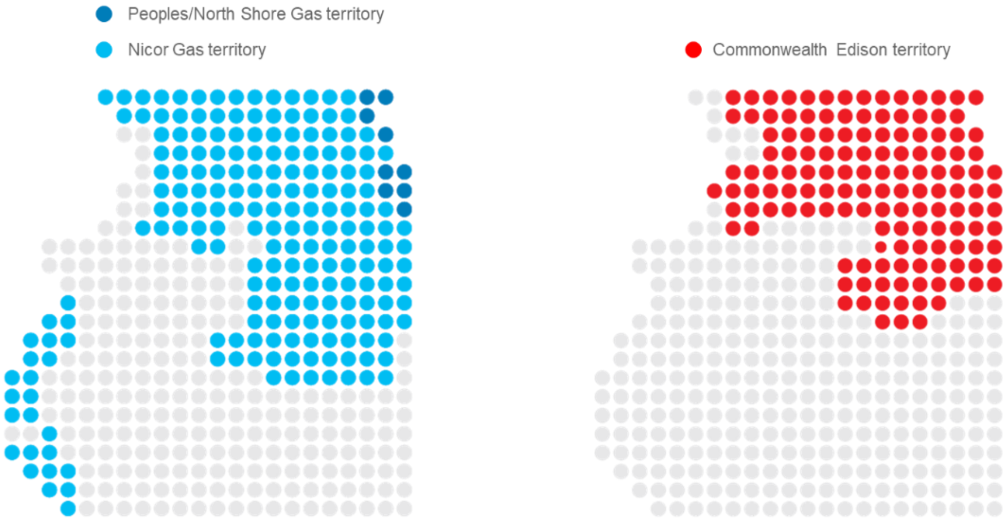
Nicor Gas employees worked around-the-clock during this cold weather to monitor the distribution system to ensure the safe performance and reliability of the infrastructure. More than 7,000 customer calls were received at the customer contact center and field operations responded to nearly 1,500 emergency calls for service during the two days. There were no major service outages during the weather event.

Overview

On January 30, 2019, together Peoples Gas, North Shore Gas, and Nicor Gas distributed more than 7.32 Bcf of natural gas—this is comparable to approximately 90 GW of electricity and represents more than 3.5 times the amount of electricity that ComEd, the electric utility serving northern Illinois, has ever delivered in single day (Figure 3-3). Even on a typical day, the Nicor Gas system alone delivers an amount of energy that is approximately equal to the maximum amount of energy that ComEd has ever delivered on a single day. The historic peak delivery day for the ComEd system is 24.8 GW, which occurred on July 20, 2011.

[27] Calculation: 4.88bcf/24 hours*10^9 scf* 1,020 Btu/scf * 1 kWh/3,412 Btu = 60, 785, 463 kW (or 60.8 GW)

Figure 3-3. Energy Distribution by Northern Illinois Utility



Utility	Peak demand (gas)	Peak demand (electricity)
Peoples Gas/North Shore Gas	~2.44 Bcf	~30.4 GW*
Nicor Gas	4.88 Bcf	~60.8 GW*
ComEd Historic Peak Demand on July 20,2011		24.8 GW

Source: Nicor Gas Company

There are several takeaways for regulators and policymakers that emerge from this case study. First off, it is critical to understand the implications of electrification on infrastructure investment, not just for a typical day, but for a peak event.

The gas system plays an integral role in supporting the space heating needs of customers in colder climates. Moreover, in the wintertime, space heating requirements typically begin to increase in the early morning and late afternoon hours; these are times when intermittent, renewable resources may not be available. Without the gas system, battery storage with significant duration and capacity capabilities would be required to bridge the gap between generation from intermittent, renewable resources and heating demands.

The gas system provides value in the volume of energy that can be delivered during peak events, which will require significant infrastructure buildout to be replaced.

Case Study 3: Ray Compressor Station Fire (Michigan)

Key Finding

Despite the loss of availability of the largest storage facility on its gas system, Consumers Energy was able to serve all of its customers without any involuntary disruption during a period of record cold temperature and peak demand.

Introduction

As the CenterPoint Energy and Nicor Gas case studies demonstrate, the Polar Vortex of January 2019 placed enormous stress on the gas delivery system under record-setting conditions. When extreme cold weather hit Michigan from January 29 to February 1, Consumers Energy was prepared to fulfill demand utilizing gas storage and pipeline supply as the primary supply sources. Consumers Energy had 61.9 Bcf of working natural gas inventory, above its target of 61.4 Bcf during a typical winter.

Gas storage fields play a critical role in enabling Consumers Energy to serve its customers during times of peak demand. They are used to meet demand at various levels:

- **Baseload demand:** Along with pipeline supply, baseload storage fields run daily during the winter to meet a foundation level of demand.
- **Intermediate demand:** Intermediate storage fields run during longer periods of higher demand.
- **Peak demand:** Peaker (and needle peaker) storage fields run during the extreme hours and days when demand changes quickly, typically in the early morning when customers start their day and their gas appliances.

Consumers Energy operates 15 storage fields with a total working capacity of 149 Bcf. The largest, the Ray Peaker field, has a capacity of 47.52 Bcf, or almost one-third of Consumers Energy's working storage capacity. The Ray facility is a combination compressor station and adjacent storage field.

Consumers Energy planned to fulfill demand during this cold period using baseload production storage fields, Ray field, and pipeline supply as the primary sources. Its other peaker fields were in reserve to support gas system packing and address any potential interruptions in pipeline supply, baseload fields, and compressor stations.

Incident

At approximately 10:30 a.m. on January 30, a fire occurred at the Ray Natural Gas Compressor Station. The fire reduced the amount of natural gas Consumers Energy could deliver to customers from underground storage in the Ray field near the compressor station. The damage to its largest storage and delivery system, which occurred during historically high natural gas demand due to cold temperatures, prompted Consumers Energy to take steps to ensure gas deliveries to its customers continued uninterrupted.

Response

Consumers used a variety of inherent, physical, and operational resilience characteristics to respond to the supply disruption during historic cold temperatures. Throughout the entire event, not a single critical, priority, or residential customer lost service involuntarily.

Table 3-2. Summary of Resilience Characteristics Used by Consumers Energy

Date	Key Resilience Characteristics
2018	• Consumers Energy held a training exercise in 2018 with a scenario involving a fire at Ray Compressor Station. This prepared employees by providing an opportunity to **rehearse emergency response** roles and responsibilities.
January 24, 2019	• In preparation of forecasted extreme cold temperatures, notice was given to **interruptible customers** that interruptible service would not be available beginning January 25.
January 30, 2019	• System **linepack** provides immediate buffer to sudden loss of storage supply from approximately 10:30 a.m. to 8:00 p.m. • At 10:45 a.m., Consumers Energy leveraged its **networked system** by calling five major interconnected pipelines that agreed to provide supply on a best effort basis. • **Peaker storage fields** were dispatched and began flowing at approximately 11 a.m., reducing sole reliance on linepack. • At 1 p.m., Consumers Energy began requests for **voluntary load reductions** from 104 of its highest volume customers. • Procurement of additional supply. • Formal **curtailment** for large transport customers began at approximately 3 p.m. • At 8 p.m., Consumers Energy worked with the governor to use the **Emergency Broadcast system** to ask residential customers for voluntary natural gas reductions. • Near 11 p.m., some of the Ray facilities supply capabilities were returned to service.
January 31, 2019	• Continued curtailment enables additional 40,000 Mcf of demand reduction.
February 1, 2019	• Announcement of cessation of curtailment at 8:22 a.m.

Source: Guidehouse, Consumers Energy

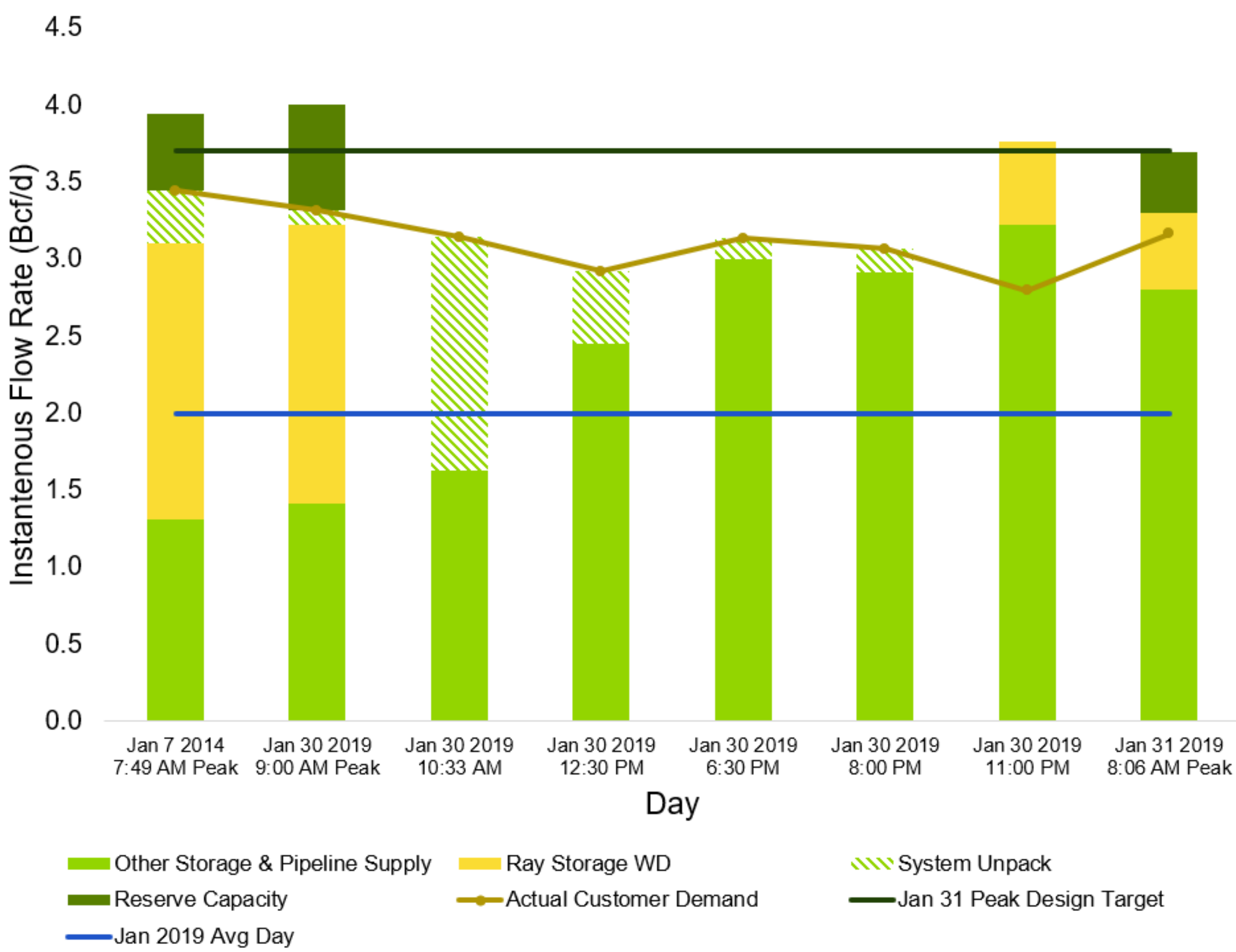
As Figure 3-4 shows, the loss of gas supply from the Ray facility caused the gas system to begin unpacking at an excessive rate. Unpacking means the amount of gas and the available pressure in the pipeline are decreasing and it occurs when the rate of total supply is lower than the rate of total delivery to customers. Figure 3-4 depicts the status of supply, demand, rate of gas system unpack,[28] and Ray Field flow on January 7, prior to the event. It also shows several points including the peak hour of January 30 at 11:00 p.m. and the peak hour of the next day at

[28] Unpack refers to the system's use of linepack.

8:06 a.m. on January 31. The loss of Ray and the rate at which the pipeline system was unpacking caused key gas system pressures to decline at excessive rates.

Shortly after the fire-gate alarm was received, Consumers Energy Gas Control adjusted the storage field rate orders to dispatch all peaking storage fields at maximum flow rates including those fields on standby. The peaking storage fields added approximately 975 MMcf/day of supply. The dispatch of the peaking fields maximized the total amount of storage supply delivered and reduced the gas system unpack rate. In addition, additional supplies provided by neighboring pipelines helped to mitigate the loss of supply from the Ray storage field (shown in light green in Figure 3-4 and the corresponding reduction in gas system unpack is shown in light green cross-hatching).

Figure 3-4. Consumers Energy System Supply, Demand, and Reserve Capacity January 30-31, 2019



Source: Guidehouse, Consumers Energy

Consumers Energy took several steps to mitigate the impact of the loss of access to the Ray storage field. These steps included requests for voluntary reductions in gas usage of all customers. Consumers Energy also implemented an Operational Flow Order (OFO) for the first time in its history for natural gas transportation customers, which required those customers to match their natural gas deliveries to Consumers Energy's system to their usages. When the requests for voluntary actions and the OFO did not result in the reductions in gas usage necessary to stabilize the gas system, Consumers Energy implemented a mandatory curtailment of gas deliveries to large business customers for the first time in its history, which required a reduction in their natural gas usage down to minimum loads required to protect equipment. In cooperation with Governor Whitmer, Consumers Energy also requested all-natural gas customers in Michigan to conserve natural gas by dialing down their thermostats. On Thursday, January 31, Consumers Energy announced that the appeal for assistance would end at 12:00 a.m. on February 1 for all customers—commercial, industrial, and residential.

Conclusion

This Ray Compressor fire event and the subsequent recovery by Consumers Energy is a unique story of the resilience characteristics of the gas system. Despite the loss of availability of the largest storage facility, not a single critical, priority, or residential customer lost service involuntarily during a peak of record cold temperature throughout the region, due to the fire-gate event.

Consumers Energy was able to withstand, recover, and adapt due to diligent advanced preparation and execution of its emergency response plan during the event. Access to physical assets is a key contributor to resilience. The ability to use alternate flow paths within facilities enables the recovery of the gas system and the return to customer's ability to use gas normally. Consumers Energy's ability to use existing storage assets as a first response demonstrates this opportunity. However, practice, preparation, and planning are also critical contributors to resilience, as demonstrated by Consumers Energy's response.

The company's capabilities in emergency management, including the use of an Incident Command System (ICS), enabled it to respond rapidly and organize into an ICS structure that included both a command post and an Emergency Operations Center (EOC). The well-defined chain of command, incident objectives, and tactics allowed for effective internal coordination of resources. It also enabled fast, complete, and transparent engagement with the MPSC, State Emergency Operations Center (SEOC), and the Governor's office throughout the event. Furthermore, it provided an organized approach to protect life and safety, to stabilize the incident, and to protect property and the environment.

Case Study 4: The Role of Winter Gas Storage (Oregon)

Key Finding

Storage assets, in combination with diligent planning and dedicated employees, play a critical role in providing natural gas during periods of critical demand in response to cold weather events.

Introduction

Northwest Natural (NW Natural) provides service to approximately 2.5 million people in Oregon and southwest Washington state (Figure 3-5). The Portland metro area represents the largest portion of NW Natural's customer demand, and its weather is characterized by a temperate oceanic climate with warm, dry summers and mildly cold, wet winters.

Figure 3-5. NW Natural Service Territory

Source: NW Natural

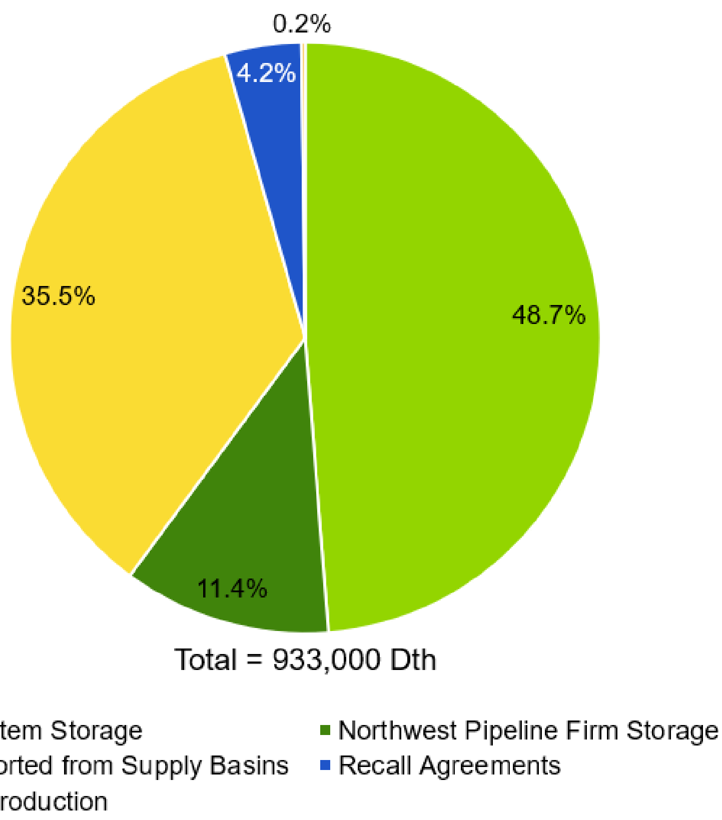
NW Natural personnel oversee the safe operation of 14,000 miles of transmission and distribution mains, monitor deliveries at over 40 interconnections with the upstream interstate pipeline system, and coordinate the usage of three on-system storage facilities (one underground storage and two LNG plants) along with off-system storage. The Gas Control department, as an example, is responsible for forecasting near-term loads, monitoring pressures, flows and other conditions using telemetry data fed from field devices, electronically controlling certain field equipment, and determining the usage rates of the on-system storage facilities, all on a 24/7 basis.

NW Natural's resource planning is designed to meet customer needs during an extreme cold weather event, occurring in late January or early February. One such event occurred in February 2014.

The Winter of 2013-2014

Extreme cold weather in early December 2013 set the stage for a challenging winter. Storage facilities are usually full at the start of the heating season, and large quantities can be withdrawn to meet sudden surges in sales. Stored gas is akin to a large battery, representing energy reserves that can be held indefinitely while remaining ready at short notice to satisfy customer requirements. On extremely cold days, stored gas is expected to supply approximately 60% of NW Natural's firm sales load (Figure 3-6). On February 6, 2014, total sendout set a record of 900,000 Dth that still stands today. NW Natural's prior record was 890,000 Dth, set on January 5, 2004. Stored gas played a critical role in meeting this record demand and provided nearly 50% of total sendout on this day.

Figure 3-6. NW Natural Peak Day Firm Resources, as of Nov 1, 2013



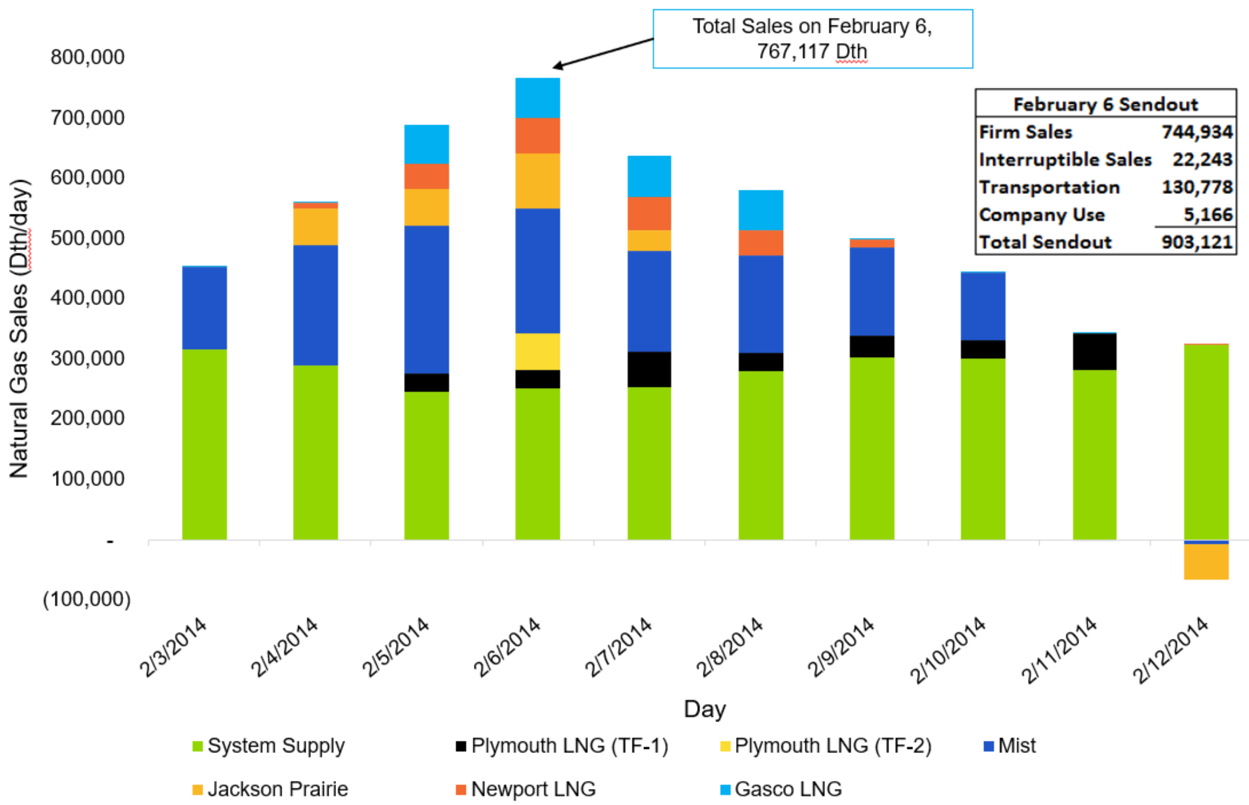
Source: Guidehouse, NW Natural

Stored gas, once withdrawn, will likely not be replenished until the following summer. Also, deliverability from storage can decrease as volumes are withdrawn, so the decision was made in December to procure additional supplies in the market in order to conserve the usage of storage gas. This planning proved extremely valuable later in the season.

The Peak Event

During early February, cold temperatures were accompanied by about a foot of snow and freezing rain. While this winter storm episode was not quite as long and cold as that experienced in the December event, a very high wind chill factor increased customer demand by an estimated 10 percent over what would be normal based on cold temperatures alone. During this period, storage resources were relied on heavily for both economic and delivery resilience reasons, growing to over 50% of daily sales requirements and then subsiding within a week's time (storage resources are all non-green colors in Figure 3-7).

Figure 3-7. NW Natural Resource Utilization During Cold Weather Event, February 3-12, 2014



Source: Guidehouse, NW Natural

Similar to the December event, in February, NW Natural had employees monitoring and controlling gas pressures at specific locations in North and East Vancouver (Washington), Southwest Salem, and South Eugene. The company also rotated two CNG trailers to support the morning peak demand in an isolated area of Northwest Vancouver, Washington.

Employee dedication and resourcefulness during the peak event included field crews manually controlling pressure regulators to ensure the maximum amount of gas could move through the pipes, storage operators working around the clock to maximize gas availability, Gas Control working with the upstream interstate pipeline to increase gate station throughput, and service technicians responding to four times the normal volume of customer calls.

Snow and ice took their toll on the gas system, requiring exceptional emergency response. For example, trees burdened by snow fell onto buildings and gas meters, some members of the public lost control of their vehicles and ran into gas meters, and parts of buildings collapsed onto gas meters. Some employees had to carry chainsaws in order to remove fallen trees blocking their way.

Aftermath

Several parts of NW Natural's service territory had seen significant customer growth over the prior two decades, and experience gained during the 2013-14 winter confirmed the need to reinforce the supply system to these areas. Besides reports of a handful of isolated customer outages, the only significant distribution system problem was in Clark County, Washington, where service had to be curtailed to four industrial interruptible customers during the morning burn hours.

Curtailment of service to interruptible sales and interruptible transportation customers is an explicit feature of NW Natural's resource planning. During the winter of 2013-14, interruptible customer curtailments were minimal because supplies were abundant, capacity was relatively unconstrained, and the gas system showed its resilience during weather conditions that tested but did not reach the extremes of the company's resource planning standards.

Case Study 5: Hurricane Response (New Jersey)

Key Finding

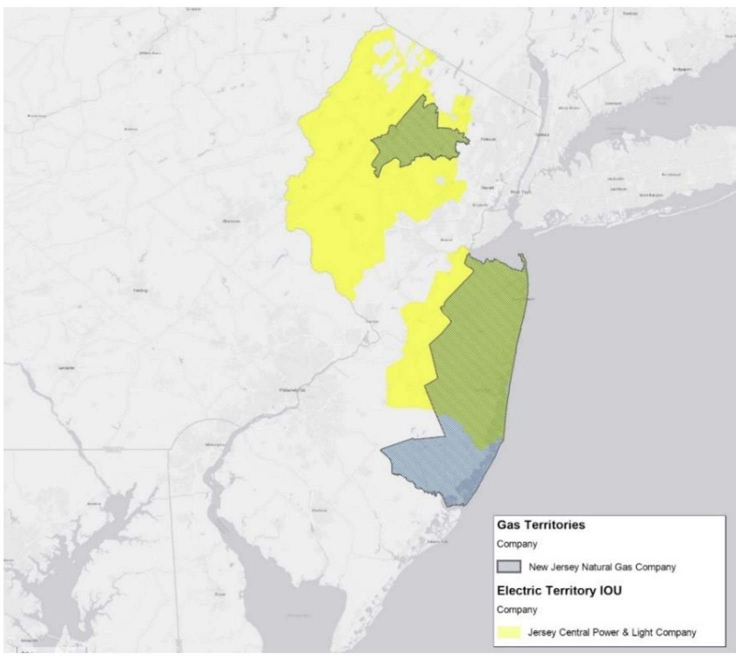
New Jersey Natural Gas Company delivered significantly more gas than normal in a short period to support backup electric power generation for residential and commercial customers in the middle of a hurricane.

Introduction

Hurricane Isaias was a destructive Category 1 hurricane that caused extensive damage across the Caribbean and the US East Coast. The hurricane made landfall near Ocean Isle Beach, North Carolina on August 4, 2020. Shortly after landfall, it was downgraded to a tropical storm.[29] When the storm reached the New Jersey region, it caused extensive damage and caused power outages that affected more than 1 million New Jersey homes and businesses.

Of the +1 million homes and businesses that lost power during Hurricane Isais, 788,000 were customers of Jersey Central Power & Light. As these customers saw an outage in their electric service, many turned to their natural gas generators to meet their power needs. New Jersey Natural Gas (NJNG), the gas provider for much of Jersey Central Power & Light's territory (Figure 3-8), experienced a massive increase in gas demand as these gas generators turned on.

Figure 3-8. Service Territories for Jersey Central Power & Light Company and New Jersey Natural Gas Company



Source: S&P Global Market Intelligence

[29] Len Melisurgo. August 8, 2020. "As bad as Tropical Storm Isaias was, here's why experts say N.J. dodged a bullet." *NJ.com*.

Overview

On Monday, August 3, the day before Hurricane Isaias caused the power outages, NJNG supplied 54,000 Dth to customers. On Tuesday, in response to the significant electric outages, NJNG supplied 84,536 Dth to customers, an almost 60% growth in daily demand in 24 hours. By the end of the week after most of the power was restored, the daily gas supplied by NJNG had dropped back to 58,394 Dth, in line with pre-storm sendout. Table 3-3 details the natural gas supplied by NJNG between August 3 and August 9, 2020.

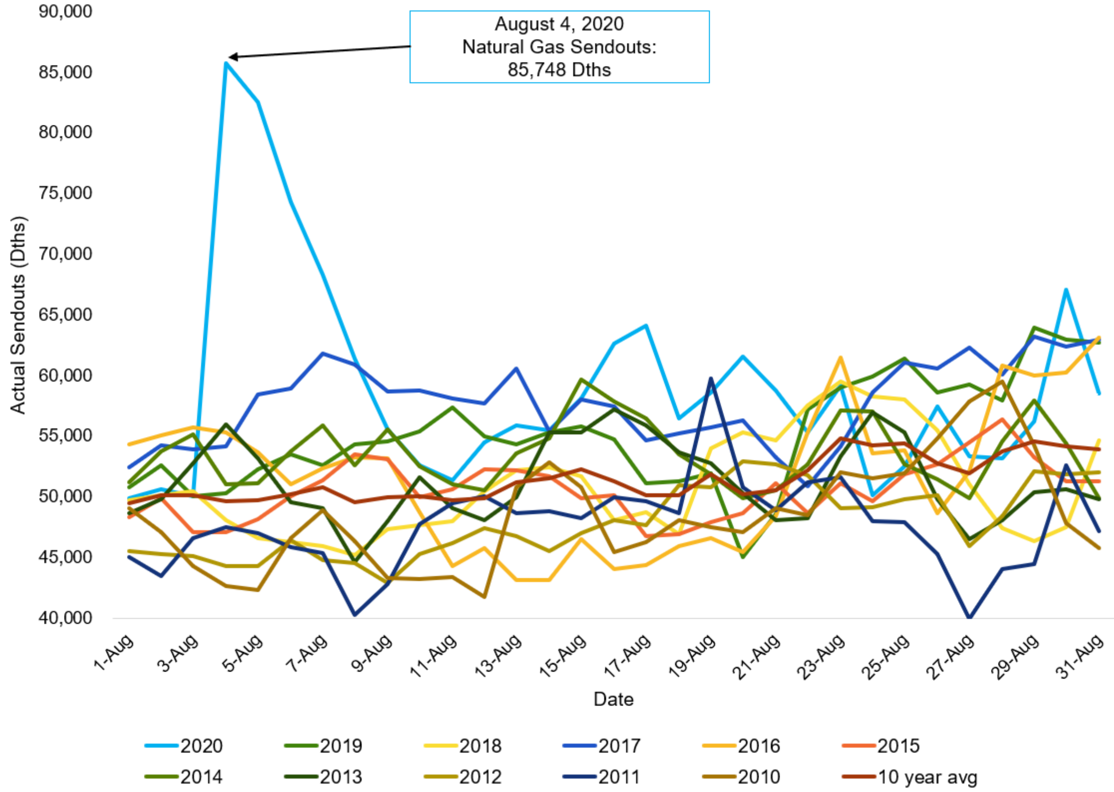
Table 3-3. NJNG Load Sendout: August 3, 2020 through August 9, 2020

Day	Date	Base Load Sendout (Dth)	Notes
Monday	8/3/2020	54,000	Pre-Storm Baseline
Tuesday	8/4/2020	85,536	Storm Hit 788,000 JCPL customers impacted
Wednesday	8/5/2020	84,198	Widespread Power Outages
Thursday	8/6/2020	78,688	Widespread Power Outages
Friday	8/7/2020	71,497	Widespread Power Outages
Saturday	8/8/2020	62,945	Majority of Power Restored
Sunday	8/9/2020	58,394	Majority of Power Restored

Source: Guidehouse, New Jersey Natural Gas

The daily natural gas output supplied by NJNG from August 4 through August 7, 2020 was higher than the daily output of any other August day for the previous 10 years. Figure 3-9 shows the 10-year average sendout from NJNG, the sendout from NJNG for the month of August 2020 identifying the dramatic peak from August 4 through 7, and the actual sendout from NJNG for August 2010-2019.

Figure 3-9. NJNG Comparison of August Actual Sendouts (Firm)



Source: Guidehouse, New Jersey Natural Gas

NJNG accredits most of the 30,000 Dth to 35,000 Dth increase in natural gas sendout during the storm to powering whole house generators, which served as backup power for customers who lost their electric supply. This load increase is estimated by NJNG to correlate with approximately 4,200, 20 kW generators running at full load (calculated using the assumptions in Table 3-4), or likely a larger number of natural gas generators running at partial load.

Table 3-4. Home Natural Gas Generator Assumptions

Generator Size (kW)	therms/ hour	dth/ hour	dth/ day	At 30,000dth/day number of 20 kW generators
20	3.00	0.30	7.20	Approximately 4,200

Source: Guidehouse, New Jersey Natural Gas

Conclusion

In August 2020, NJNG was not only able to withstand the hurricane, but it was also able to ramp up natural gas sendout quickly by relying on storage, allowing thousands of homes and businesses across New Jersey to keep their gas systems in operation when electric service was disrupted. Because of the built-in flexibility and dispatchable nature of the gas system, the gas system can complement the broader energy system as it responds to extreme climate events and keeps power flowing.

Case Study 6: Gas-to-Power Interface (California)

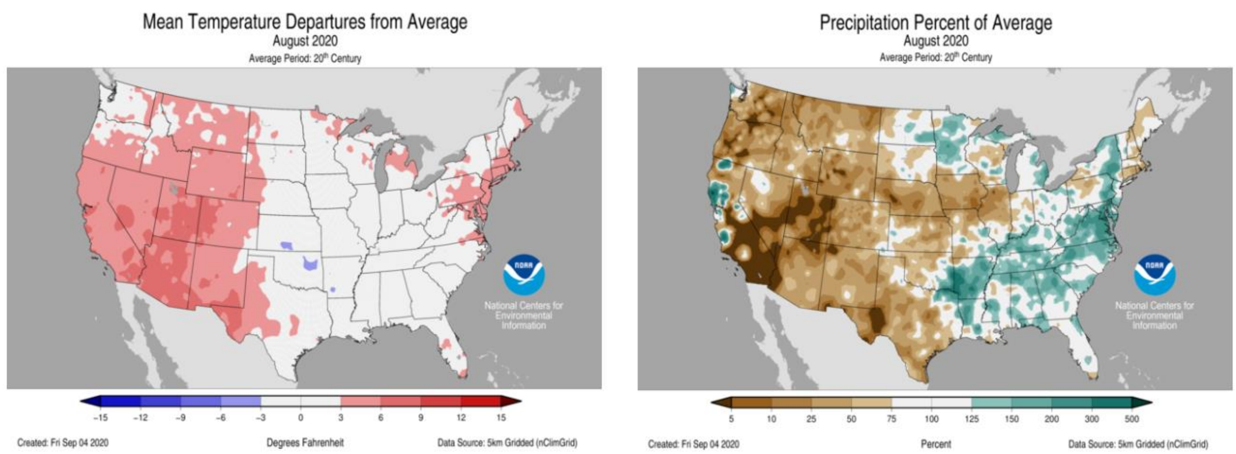
Key Finding

SoCalGas used storage capacity resources to meet the supply needs of gas-fired generation plants when the California electric system was experiencing multiple days of high demand from a record-breaking heatwave and unplanned decreases in other sources of electric generation.

Introduction

In August 2020, California was in the middle of its hottest August (record warmest in 126 years),[30] a severe drought (Figure 3-10), and its worst wildfire season in modern history. While California experienced increased demand on the electric system driven by increased cooling loads, it also experienced a decrease in the renewable output (due to smoke from the fires)[31] and imports than had been anticipated by electric supply planners. During these severe multi-day climate events, the gas system provided the flexible support required to ensure the broader energy system could provide power and prevented more extensive power outages.

Figure 3-10. August 2020 Mean Temperature and Precipitation, Departure from Average



Source: National Oceanic and Atmospheric Administration

On a standard summer day, California's electric grid is supplied by a wide variety of electric generation, renewables, natural gas, hydro, nuclear, coal, and imports from other regions. July 12, 2020 exemplifies a standard summer day in California (while the state was starting to experience a severe drought in July, average temperatures were within the normal range).[32]

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[30] NOAA. National Climate Report – August 2020. https://www.ncdc.noaa.gov/sotc/national/202008

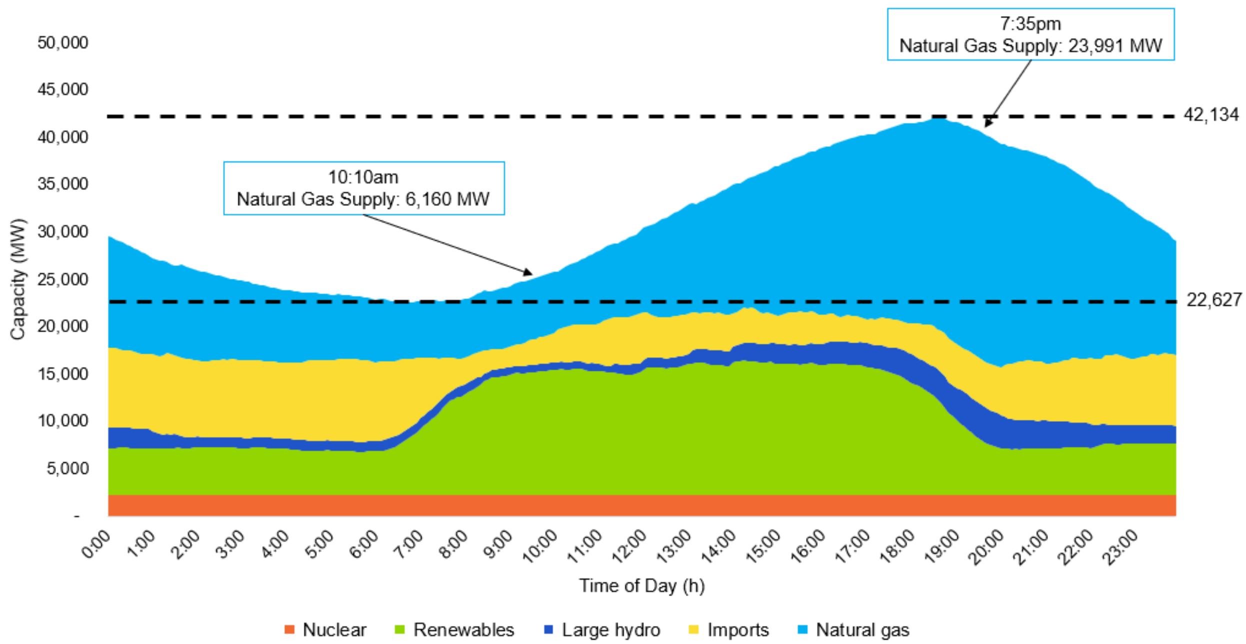
[31] EIA. *Smoke from California Wildfires Decreases Solar Generation in CAISO.* September 30, 2020. https://www.eia.gov/todayinenergy/detail.php?id=45336

[32] NOAA. National Climate Report – July 2020. https://www.ncdc.noaa.gov/sotc/national/202007

Overview

As Figure 3-11 shows, on July 12, 2020 renewable generation began to increase at around 06:30 hrs and remained relatively steady until approximately 17:00 hrs, driven primarily by solar generation during sunlit hours. By 08:00 hrs renewables provide 50% of the state's electric power generation, natural gas provides 25%, and the other sources provide the remaining 25%. As the day continues, gas-fired generation ramps up. By 20:00 hrs natural gas provides 60% of the electric power generation required to meet the peak load.

Figure 3-11. CAISO Supply Trend to Meet Electric Demand, July 12, 2020[33]



Source: Guidehouse, California Independent System Operator

Gas generation plants ramp up to meet peak demand, but the fuel demand of the generation plants is not ratable. Ratable is generally described as levelized demand where deliveries are made evenly throughout a delivery day. The hourly demand for gas to supply these generation plants often exceeds supply receipts, as arranged by the power plants, into the gas system. To overcome the imbalance between supply and use and to respond to the volatile demand needed to maintain the integrity of the electric system, underground storage plays a vital role.

Storage capacity and the stored commodity are contracted for in advance. Underground gas storage is expected to be used to maintain grid load balance and operation on high heat summer days (a hallmark of grid resilience). However, reliance on gas storage systems and the dispatchable nature of gas generation when the energy system is under higher stress (experiencing a resilience event), as seen in August 2020, requires a more significant drawdown of underground storage assets.

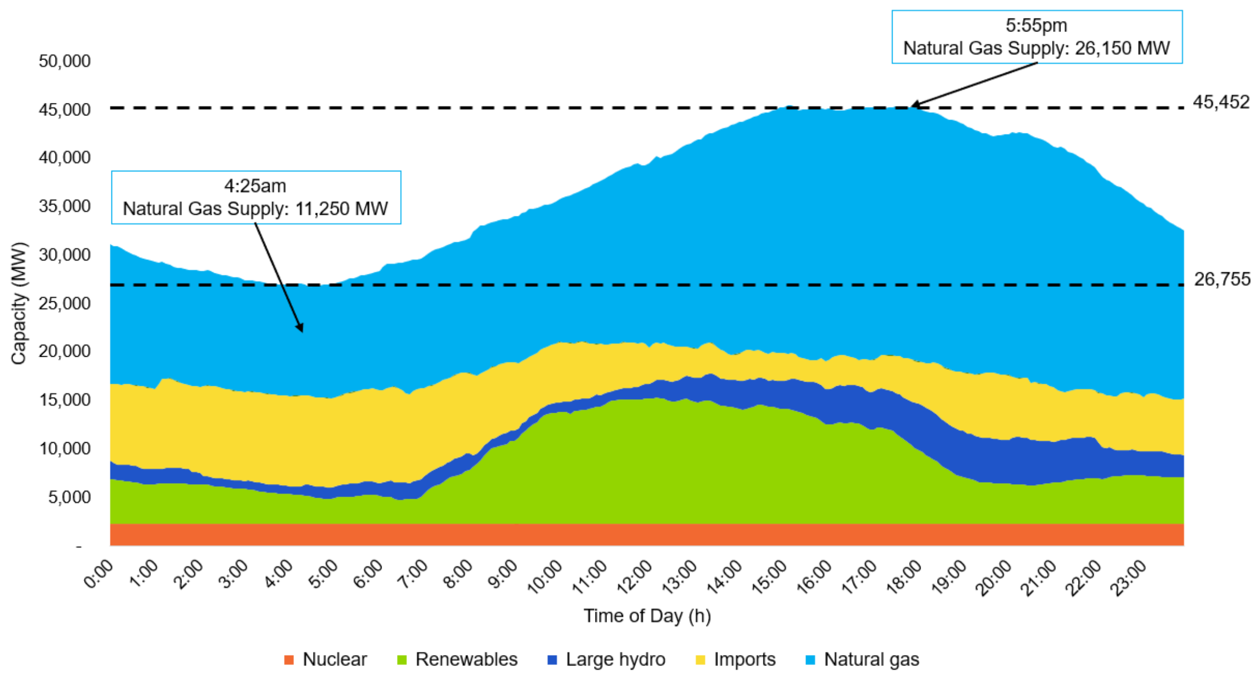
> *During the hours of highest electricity demand, gas generation provides the bulk of California's electric power generation.[34]*

[33] Batteries and coal contribute negligible amounts (± 50 MW) and are not shown within the figure.
[34] CAISO. 2020. "Supply and renewables."

The week of August 11, 2020 is a prime example of the California electric grid under a resilience event—coinciding extreme heat, drought, and wildfires. During this week, California experienced severe climatic events and associated higher electric consumption. Renewable output was also more variable and diminished due to heat, clouds, and wildfires, and power imports were lower than expected, since the entire western half of the US was experiencing the same heatwave as California.

Figure 3-12 illustrates the resources that contributed to CAISO's electric generation on August 17, 2020. Renewable generation supplied less electricity on August 17 compared to July 12 (peaking at around 13,000 MW at 12:00 hrs compared to over 14,000 MW at 14:00 hrs). Peak load was 45,452 MW on August 17, while on July 12 peak load was 42,134 MW. To meet the higher peak load and make up for the lower renewable generation, on August 17, gas-fired generation made up a higher percentage of CAISO's electric power generation capacity.

Figure 3-12. CAISO Supply Trend to Meet Electric Demand, August 17, 2020[35]



Source: Guidehouse, California Independent System Operator

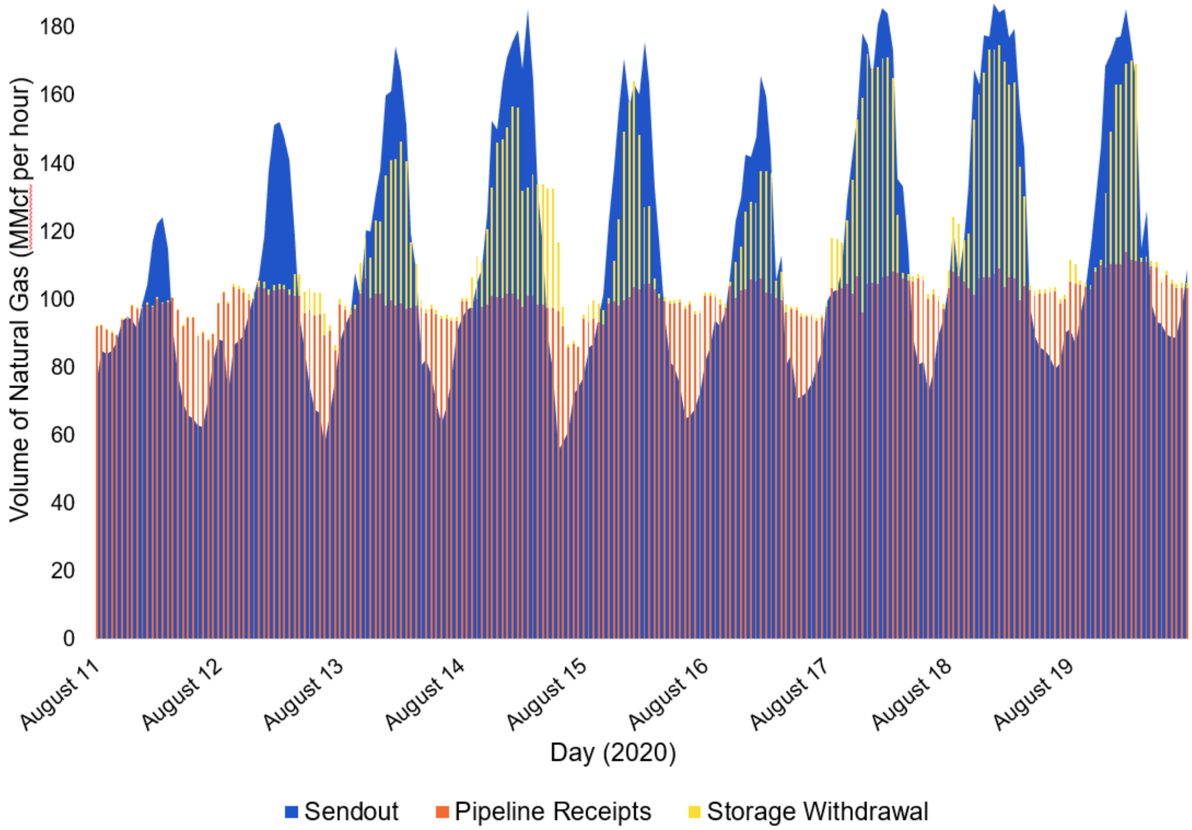
To meet the pressure on the CAISO system during the week of August 11, electric system operators turned to gas-fired generation facilities. To ensure that these generation plants had the natural gas supply to maintain the integrity of the electric grid, SoCalGas had to draw significantly on its gas system storage assets.

Figure 3-13 provides an hourly view of pipeline receipts into the SoCalGas distribution system, sendout, and withdrawals from storage. The blue vertical bars illustrate the hourly demand and sendout from the SoCalGas system. The orange vertical bars depict the quantities that were received into the system, which is generally received in steady hourly quantities over the course of the day. The yellow vertical bars above the receipts illustrate the volumes required to be withdrawn from storage on an hourly basis to meet the far more variable and changing intraday needs of electric generators, which exceeded the gas supplies arranged for delivery into the

[35] Batteries and coal contribute negligible amounts (± 100 MW) and are not shown within the figure.

SoCalGas system each day. The imbalance between daily pipeline receipts and sendout (mostly to serve the load of electric generators) was most significant on August 17 and 18, when sendout for each day was ~3.1 Bcf, while receipts were 2.5 Bcf, resulting in a deficit of ~0.6 Bcf daily, which was required to be made up by on-system storage.

Figure 3-13. Hourly Supply and Demand on the SoCalGas System



Source: Guidehouse, SoCalGas

From August 11 to 19, pipeline receipts on the SoCalGas system were approximately 100 MMcf per hour (2.4 Bcf per day/24 hours). In this same period, deliveries to SoCalGas customers exceeded 100 MMcf per hour during approximately 110 of 168 hours, or 65% of the time. August 11 was the only day SoCalGas was able to meet the peak delivery in excess of pipeline receipts through utilization of linepack (i.e., no storage withdrawal). On all following days, withdrawals from underground storage played a critical role when hourly consumption exceeded pipeline receipts.

Hourly withdrawals in excess of the equivalent of 800 MMcfd were experienced more than a dozen times between August 15 and 19. Those withdrawal rates were only possible with withdrawals from all SoCalGas' storage fields, including Aliso Canyon. The week of August 11, 2020, the totality of SoCalGas' system assets were employed to address the shortfall between abnormally high electric demand and low renewable energy generation experienced in Southern California.

Conclusion

Due to COVID-19-related impacts, C&I demand during this period was lower than normal. Although storage was critical to filling the gap between supply and demand, SoCalGas estimates that—had C&I demand been closer to average historic levels—it is likely that the capacity of the SoCalGas transmission and storage system would have been exceeded, which could have resulted in curtailment of electric generation. This is due to SoCalGas' planning standards and priority of services that are primarily focused on core customers, the SoCalGas tariff deprioritizes service to electric generators and allows curtailment during constrained/high demand periods. This situation is not unique to California, in other jurisdictions, electric generation, in the event of a curtailment, is given a lower level of prioritization compared to residential customers.

> *If the gas system was not able to fill the gap between abnormally high electric demand and low renewable energy generation to support the overall resilience of the electric system, Southern California would likely have experienced severe power outages during the system resilience event experienced in August 2020.*

The gas system fosters electric system reliability and serves as a resource that is capable of readily addressing unplanned or unforeseen events within the integrated energy system. When these resilience events occur, electric generators can experience large intraday swings in their need for gas supplies, often with little to no notice. In regions where the intermittent use of the gas system for electric power generation is a significant portion of total gas use on the system, this unpredictable non-ratable flow can stress the physical gas delivery system. Although the physical infrastructure including pipeline transportation and storage assets are in place and able to accommodate this type of intermittent usage, the underlying market framework and regulatory structure were not designed to provide this type of support service to the overall energy system. In general, the regulatory structure does not provide a means to construct and operate investments that provide resilience protection. That the gas system can provide this service demonstrates how resilience is a byproduct of the engineered reliability features of gas delivery system. The result being that the gas system and the gas LDC ratepayers provide this resilience service to the overall energy system without receiving compensation commensurate to its value.

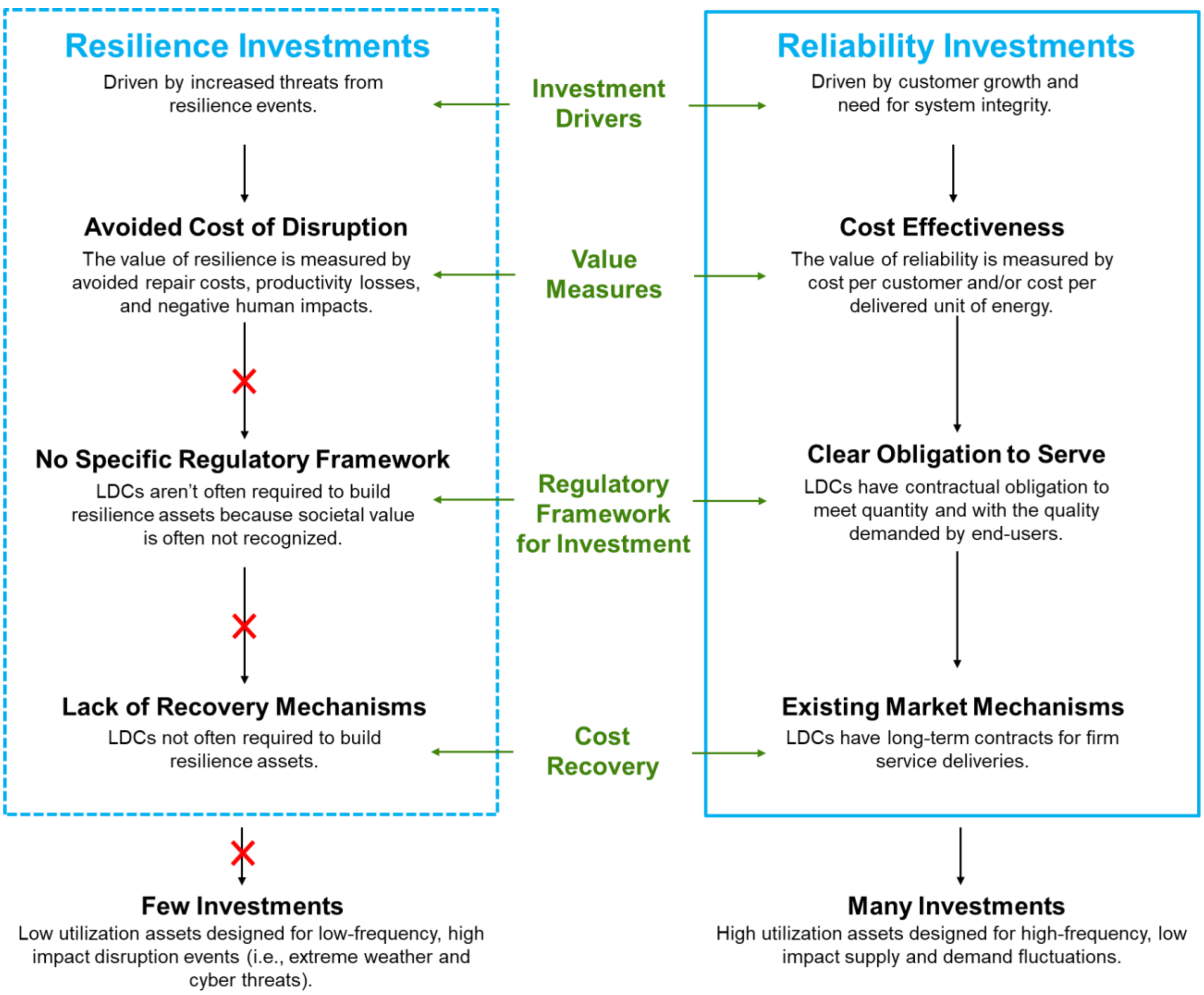
4. Current Regulatory, Policy, and Market Structures

The first half of this report established that the gas system provides resilience to the US energy system. The second half focuses on the regulatory, policy, and market structures that underpin the US energy market. This section explores the current state, including how these structures have developed and the challenges they create. Section 5 considers forward-looking considerations to ensure future energy system resilience.

4.1 The Difference Between Resilience and Reliability Investments

The current market economic framework is designed to support the development of physical assets with high utilization or those backed by long-term contracts. These assets provide reliability services to the energy system. Reliability assets often contribute to the resilience of the energy system as a byproduct, but they are not designed to meet the full needs of a resilience event. Figure 4-1 explores the differences between resilience and reliability investments.

Figure 4-1. Comparison of Resilience and Reliability Investments



Source: Guidehouse

4.2 Historical Context of Gas System Development

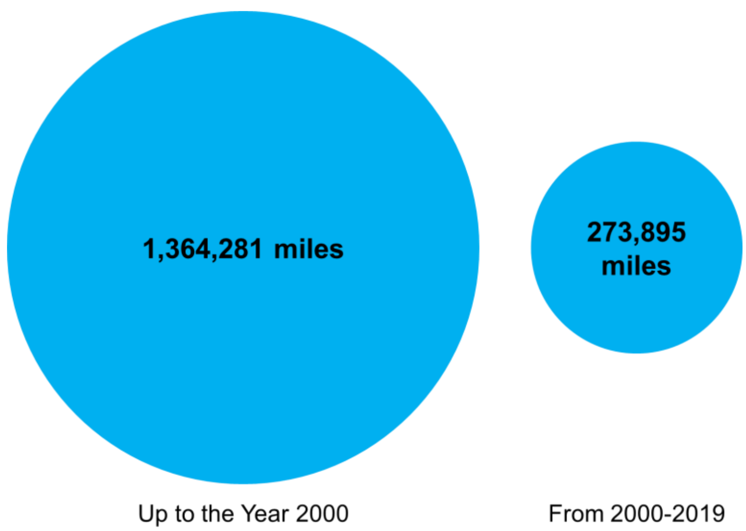
To fully understand some of the challenges in regulatory, policy, and market structures around the development and support for the use of natural gas as a resilience asset, it is necessary to understand the historical context around how these frameworks have developed. In this section, we consider the historical context of the development of the gas system and what implications that has had on the structure and the gas system's current support of energy system resilience.

Natural gas was first used in the early 1820s. However, lacking efficient transportation options, its usage was limited to powering light sources, usually close to natural gas wells. In the late 1890s, gas pipeline construction began and partnered with technological advances, this more efficient transportation of the resource fueled the growth of the US pipeline and connected natural gas wells to users—homes, businesses, and heavy industry. It was not until the late 1990s (really after 2000) that natural gas became a significant source of US electric power generation.

4.2.1 Residential, Commercial, Industrial Load (Pre-2000)

The majority of US natural gas gathering, transmission, and distribution pipeline infrastructure that exists today (approximately 83%) was built out prior to 2000, as Figure 4-2 shows. This infrastructure was built based on a paradigm of predictable and relatively stable demand from residential, commercial, and industrial loads—and stable investor returns. There are several mechanisms that pipeline companies and LDCs use to maintain the integrity of their systems in accordance with Federal law. Across the US, state utility commissions have approved infrastructure modernization programs and pipeline replacement programs to address aging infrastructure. A total of 41 states and the District of Columbia have adopted an approach to support the prioritization, financing, and execution of gas infrastructure upgrades. These programs not only increase the safety of the energy system, but also enhance the future resilience of the energy system.[36]

Figure 4-2. Incremental US Natural Gas Pipeline Additions

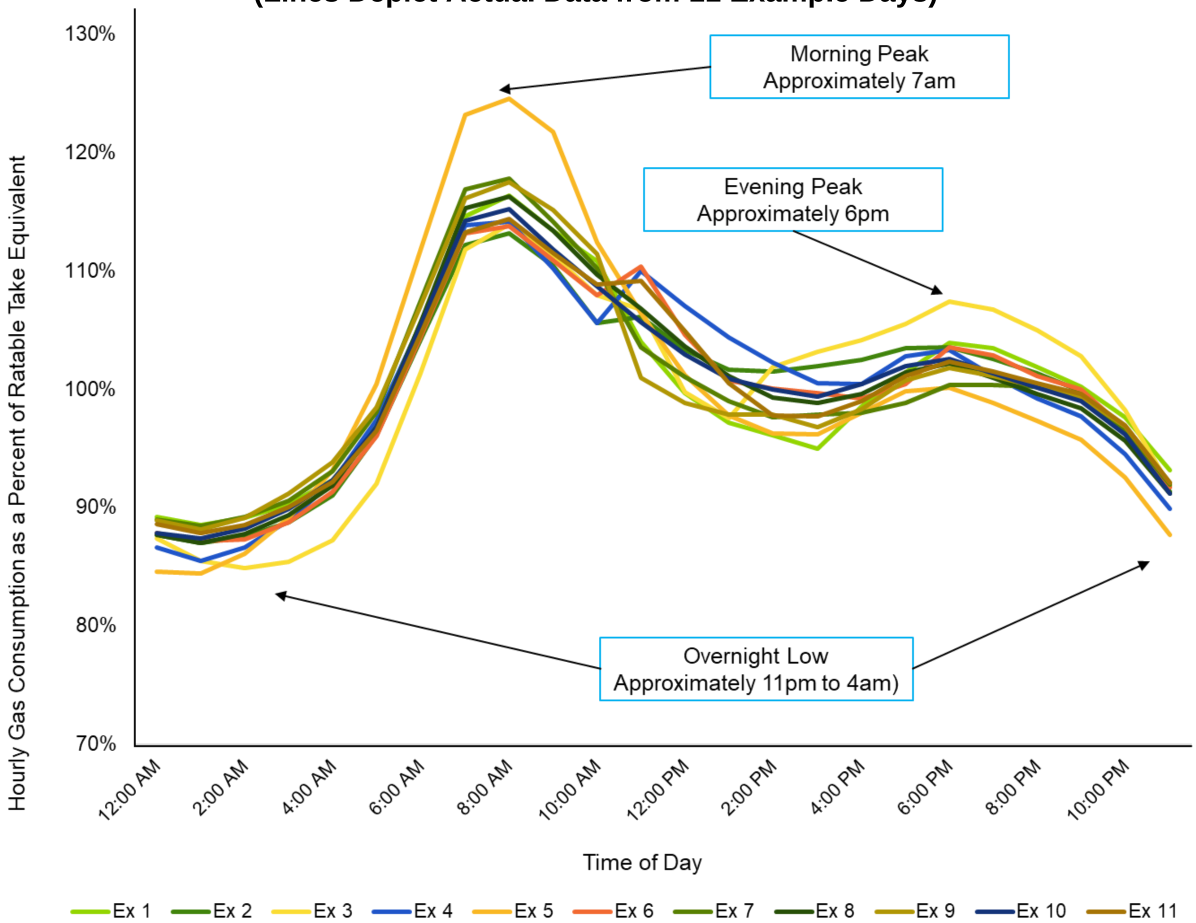


Source: Guidehouse, US Bureau of Transportation Statistics

[36] NARUC, January 2020. Natural Gas Distribution Infrastructure Replacement and Modernization.

The aggregate daily gas demand to serve residential, commercial, and industrial customers is predictable and relatively stable. Gas usage for these customers increases significantly in the morning before slowly decreasing over the course of the day. There is an additional, relatively minor, increase in the evening around dinner time before gas usage drops over the night. Figure 4-3 presents the aggregate load profile for these customers. The figure's y-axis indicates percent variation in hourly gas consumption as a percent of ratable take equivalent[37] and the minimum and maximum peaks only vary -16% to +25% from that daily average.

Figure 4-3. Aggregate Daily Natural Gas Load Profiles, for Residential, Small Commercial, and Industrial Customers (Lines Depict Actual Data from 11 Example Days) *



*Source: Guidehouse, Consumers Energy**

The gas usage pattern is predictable for these customer groups, even in varying climatic conditions. In colder conditions, the usage pattern features less volatility as demand for space heating is more constant throughout a cold day. In warmer conditions, the peaks and troughs widen, and the total daily usage is lower. The predictability of this trend enables gas LDCs to construct and operate the gas system and build new assets with a high degree of confidence in the use of those assets.

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[37] *Ratable take equivalent* refers to the comparable amount of gas consumed in one day on a levelized basis over a 24-hour period, i.e., in even 1/24th increments. This is further discussed in Appendix A, Section A.3.1.

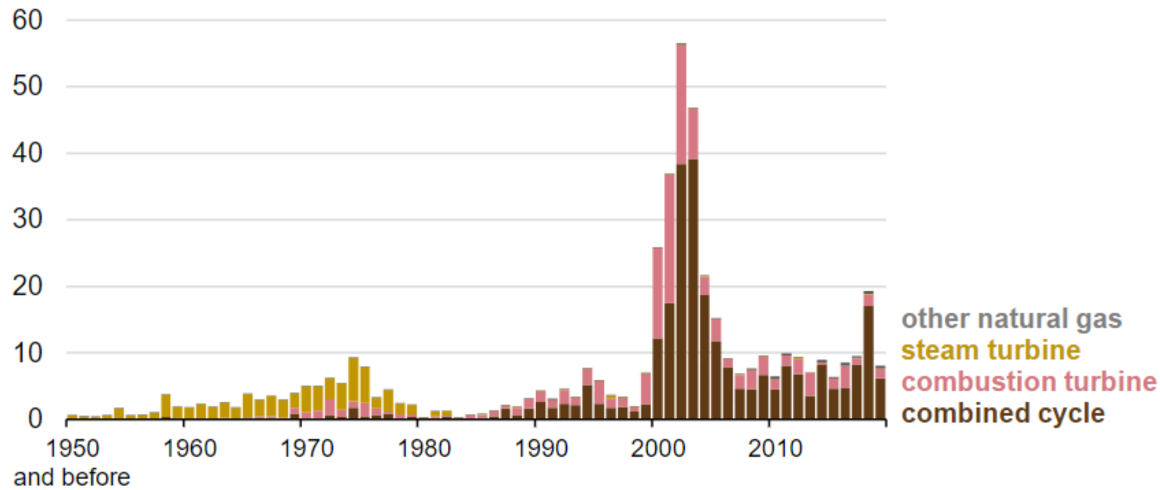
> *The gas system that serves the US today was built to serve the residential, commercial, and industrial sectors, where the relative predictability of usage over the course of a day (ratable takes) and throughout the year for these customer segments enabled LDCs to design, construct, and operate the gas system with a high degree of confidence in how the gas system would be used to serve demand.*

The entirety of the gas value chain's economic and operational framework is underpinned by this ratable system of supply and demand.

4.2.2 Gas-Fired Electric Generation (Post-2000)

When much of the current gas system was designed, the electric sector was a small component of overall demand. Between 1949 and 2000, gas-fired generation provided an average of just 16% of total electric power generation in the US on an annual basis. Since 2000, this has increased significantly. In 2019, natural gas accounted for 38% of US electric power generation and provided 43% of operating US electric power generating capacity.[38] Figure 4-4 explores this trend and shows that most of the growth in gas-fired generation capacity occurred between 2000 and 2020. More information on the role of natural gas in the electric power generation sector can be found in Appendix B.

Figure 4-4. US Gas-Fired Electric Power Generation



Source: US Energy Information Administration

4.3 Natural Gas in Electric Power Generation

There are critical differences in the way that gas-fired generation interacts with the gas system. This section explores those differences. In general, gas-fired generation plants fall into one of two classifications:

1. **High-capacity factor generation:** These low-heat rate/high-efficiency plants support electric power generation by operating often at close to full capacity 24/7.

[38] EIA. 2020. Electricity: Current Issues and Trends.

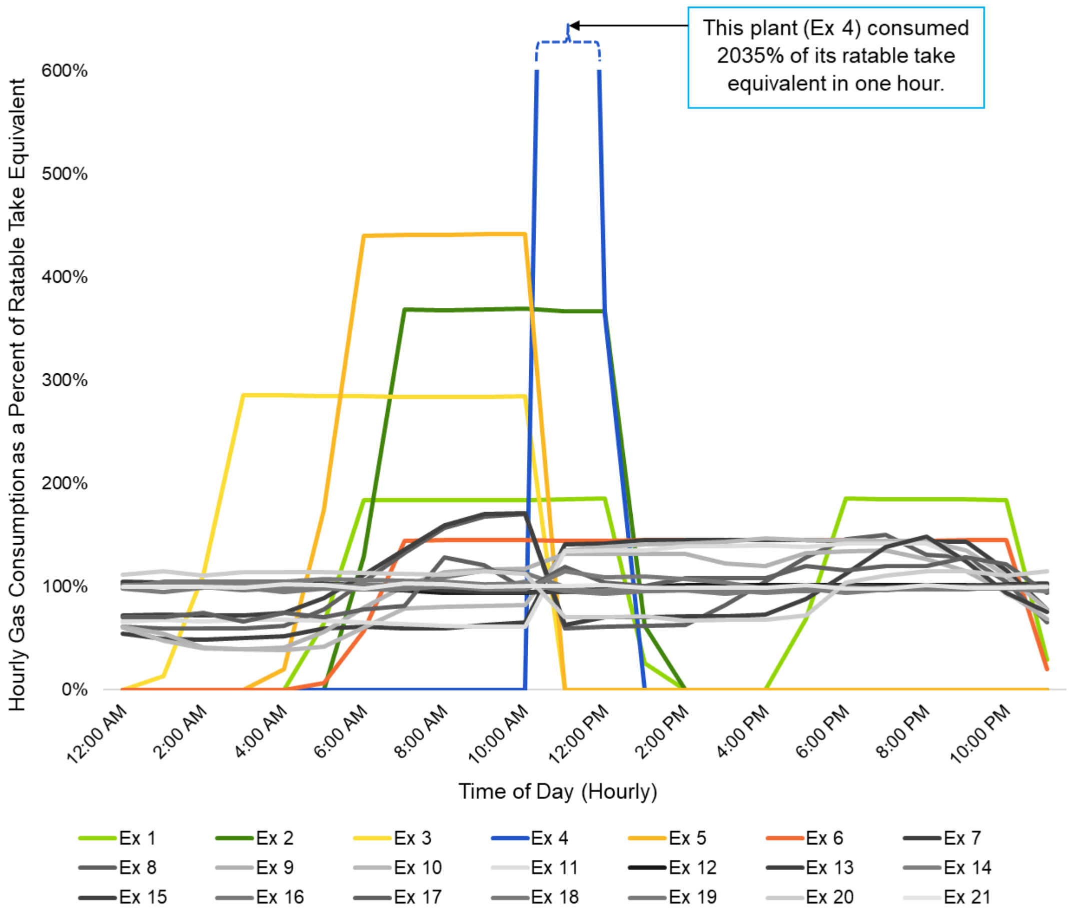
2. **Intermittent generation:** These plants serve as dispatchable resources for electric system operators, ramping their generation up and down quickly to fill the gaps between intermittent generation sources (such as renewable sources) and consumer demand.

4.3.1 Gas-Fired Electric Power Generation Load Profiles

Figure 4-5 illustrates the load profiles of six different gas-fired electric power generation plants over a period of 21 days. Gas load profiles of gas-fired electric power generation plants exhibit far more variance on a daily and hourly basis than the load profiles of residential, commercial, and industrial customers. In Figure 4-5, high-capacity factor generation plants are identified generally in gray (Ex 7 through Ex 21) and those serving intermittent generation capabilities are identified with varying colors (Ex 1 through Ex 6).

The load profile for high-capacity factor gas-fired plants (Ex 7 through Ex 21 in Figure 4-5) generally features a morning and evening peak, and the variation between the highest hour of usage and the lowest hour of usage from ratable take equivalent is 71% to -61%, similar in pattern to the load profiles for residential, commercial, and industrial customers but the magnitude of the swings are larger.

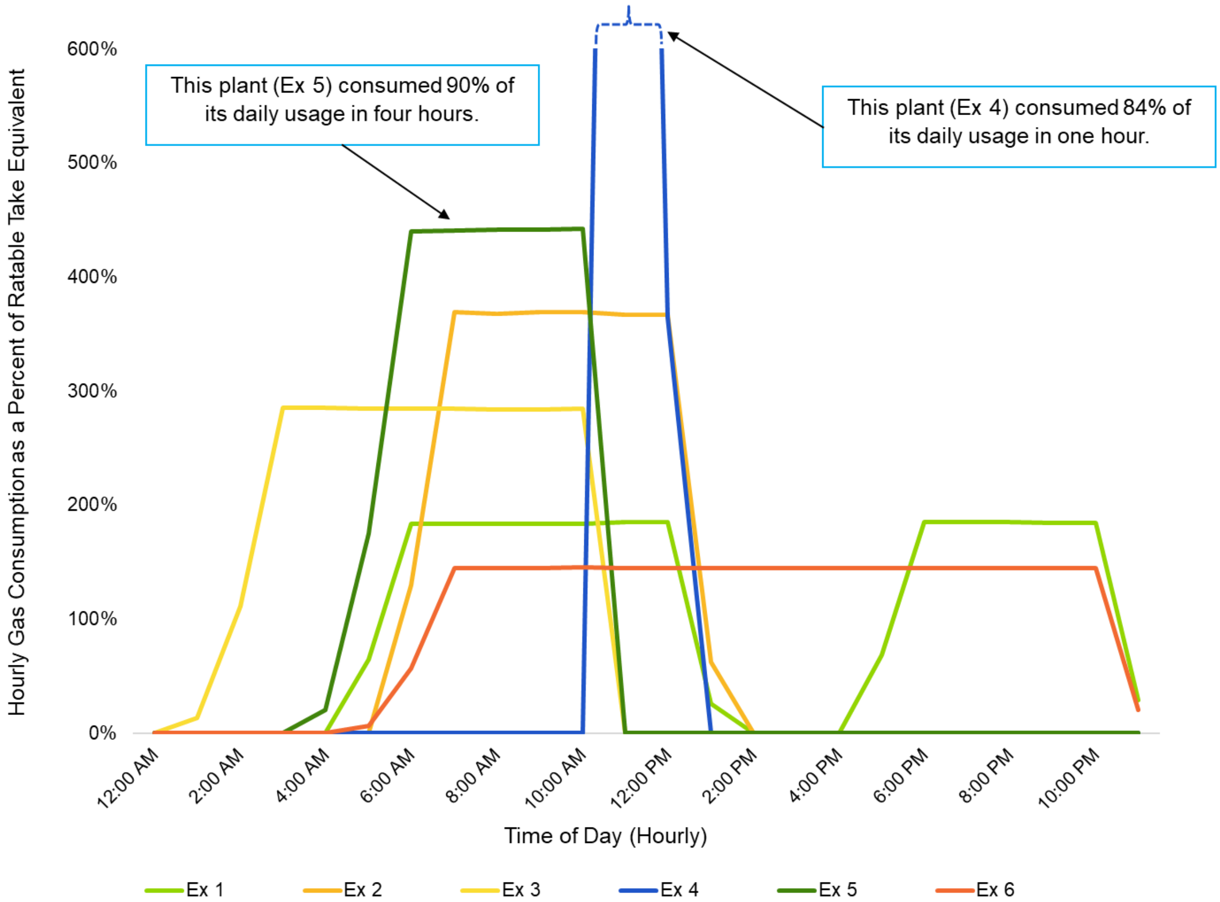
Figure 4-5. Daily Natural Gas Load Profiles for Gas-Fired Electric Power Generation (Lines Depict Actual Data for 21 Example Days, Data is Inclusive of Six Facilities)



Source: Guidehouse, Consumers Energy

Gas-fired plants that run intermittently exhibit a different load profile from the relatively predictable daily variation of high-capacity factor plants. In Figure 4-6, the high-capacity factor generation daily load profiles were removed to focus on the load profiles of intermittent gas-fired plants. The load profiles associated with these plants exhibit a high level of variability and intraday swings, as the plants quickly ramp up and down from their peak rates.

Figure 4-6. Daily Natural Gas Load Profile for Intermittent Gas-Fired Plants (Lines Depict Actual Data for Six Example Days, Data is Inclusive of Six Facilities)



Source: Guidehouse, Consumers Energy

The gas supply required by intermittent gas-fired plants is characterized by large volumes of fuel that are subject to a level of variability and intraday demand swings that are vastly different from how the residential, commercial, and industrial sectors consume gas over the course of a 24-hour period.

> *Intermittent gas-fired plants are primarily used to fill gaps between other intermittent generation sources (such as renewables) and customer demand for electricity. They are only capable of fulfilling this role because the gas delivery system enables the delivery of supply to serve the swings needed to provide such a quick-start response. Although the gas system fulfills these needs, the physical delivery system and the supporting market mechanisms and commercial terms that govern day-to-day operations were not designed for this type of usage*

4.3.2 Implications for the Gas Delivery System

Upstream pipeline deliveries to the gas distribution system occur at relatively steady hourly quantities throughout a day, but gas is not consumed in even hourly increments over the course of a day. Gas distributors have a variety of tools including linepack, storage, and mobile delivery capabilities to accommodate this intraday swing in demand and enable deliverability and respond to increases and decreases in consumption.

The gas transmission system is designed to accommodate the delivery needs of the predictable and low variability patterns required of residential, commercial, and industrial customers. Meeting the variable delivery needs of high capacity factor and intermittent gas-fired plants is a greater challenge as the gas consumption of these plants is much more variable, especially for intermittent gas-fired plants. Gas system operators supplement hourly pipeline receipts with linepack and storage withdrawals to maintain integrity and meet the needs of intermittent plants.

The gas distribution system's ability to provide this intermittent deliverability service is highly dependent on the amount of gas in the pipeline, the inventory levels in storage, the inventory in other storage assets, and contractual obligations to other customers. Providing service to gas-fired generators, particularly intermittent gas-fired generators requires coordinated planning from operators of the gas and electric systems.

4.4 The Regulatory Context

This section discusses how the current regulatory structures hinder the construction, utilization, and operation of new gas assets to serve resilience needs. Often, current regulatory structures tie the development of interstate pipeline and storage assets strictly to the needs of customers (producers, gas utilities, and other end users) willing to execute long-term firm service contracts. These do not easily support the construction, utilization, and operation of resilience assets that, by their nature, will be used infrequently to support low likelihood, high impact events. As a result, gas systems may not be appropriately compensated for the resilience services they provide.

Two critical principles often underlie the regulatory approval of infrastructure development:

- **Alignment between who benefits and who pays:** The ability to demonstrate how an asset provides a benefit to those who pay for its development is a standard principal of utility ratemaking.
- **The business case hinges on high utilization:** The construction and operation of most gas assets are founded upon the willingness to execute long-term firm service contracts; higher utilization translates to lower cost per unit.

This framework begins to break down when asset development activities or business model economics are not aligned with these principles. Applying these regulatory principals to the consideration of the construction, utilization, and operation of gas assets for resilience purposes, two key challenges are exposed:

- Current gas system resilience is a byproduct of reliability investments
- Gas systems may not be appropriately compensated for the resilience service they provide

The remainder of this section discusses these two challenges.

4.4.1 Current Regulatory Framework for Infrastructure Approval

To construct a new energy system asset, a gas utility must receive approval from its regulator, typically a state-level public utility commission. The investment is typically approved if the gas utility demonstrates the investment is prudent and serves the needs of its customers.

The principle of alignment between who benefits and who pays is applicable to regulating the expansion or new construction of interstate pipeline and storage infrastructure. A utility is responsible for the burden of proof of necessity on behalf of its customers. For interstate pipeline and storage assets, the burden of proof is on the market need demonstrated by customers who have executed precedent agreements.

The Federal Energy Regulatory Commission (FERC) regulates interstate pipeline and storage markets. Pipeline and storage operators seeking regulatory approval to construct or expand an asset must provide FERC with a demonstration of market interest to receive approval. FERC grants approval if this market interest can be demonstrated. Due to the long life of pipeline and storage assets, the regulators seek to balance the interests of customers with landowners and the public around environmental concerns,[39] as well as the financial viability of the project. Market interest is demonstrated in the form of customer execution of long-term firm service contracts, where firm service entails a right to a predetermined amount of capacity on the pipeline during the agreement period.

Natural gas utilities are regulated by state public utility commissions (PUCs). PUCs approve infrastructure investments based on the concept that the investment provides utility service and supports the utility's obligation to serve. Gas utilities enter long-term firm capacity contracts because they are required to fulfill an obligation to serve their customers, particularly during periods of peak usage. For example, a gas utility with a significant winter peaking load will subscribe to a long-term contract to serve that load even if its firm rights to pipeline capacity will be underutilized in the summer—resulting from the utility's obligation to serve.

> *A fundamental underpinning of regulatory approval for interstate pipeline and storage construction is the demonstration of market need, as supported by customer willingness to enter long-term contracts for firm capacity.*

When pipeline or storage customers are not willing to enter long-term firm contracts, the market structure creates barriers to obtain the right to a predetermined capacity that is not subject to a prior claim from another customer. This is an issue for certain gas-fired electric power generators. Electric power generators profit if their cost of producing power (fuel plus operations and maintenance) is lower than the average price they sell electricity. Given most gas-fired powered generators are unable to store fuel onsite, they must rely on quick response delivery of natural gas, resulting in two unequal options:

- **Sign a long-term firm contract.** While an option, it is not typical because it could increase the cost such that it is not competitive with other sources of generation, i.e. coal and fuel-oil plants that can store fuel onsite, and solar and wind power that do not require fuel input.
- **Sign a secondary or interruptible contract.** Most gas generators take this action because the economics are more favorable. Interruptible capacity refers to pipeline transportation capacity that is available when the holder of the firm right to this capacity

[39] FERC. 2020. "The Natural Gas Pipeline Application Process at FERC."

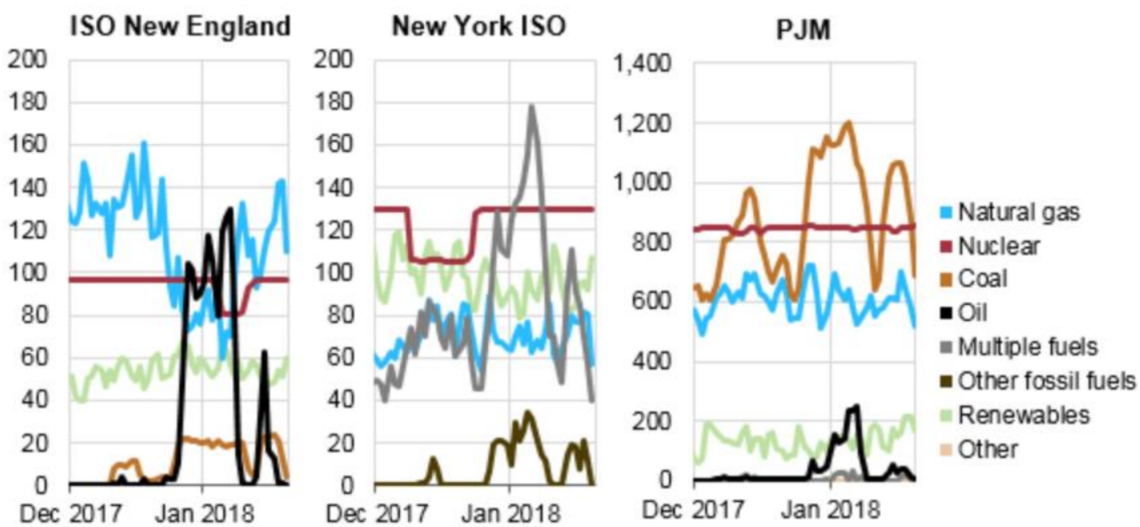
is not using it. The risk is that the pipeline or storage capacity may not be available when it is needed.

4.4.2 Regulatory Framework and Implications to Resilience

In periods of peak usage (e.g., during periods of high use), holders of firm pipeline transportation are likely to use their full allotment of capacity, leaving little to no capacity to secondary or interruptible contract holders. In these periods, gas-fired generators without firm capacity will likely be constrained. During periods of high use, a constrained gas pipeline can create economic or operational conditions that lead to increased fuel switching to oil-fired or dual-fuel generation. This has caused and can cause risk that electric generators lose the ability to serve peak electric load when customer demand for gas supply is also at its peak. This constraint is further illustrated in Figure 4-7.

Figure 4-7 details fuel switching in three electricity markets in the northeast (New England, New York, and PJM) during the January 2018 bomb cyclone. In early January, as the Northeast experienced the cold weather related to the bomb cyclone event, demand for electric power generators increased as natural gas transportation was constrained.

Figure 4-7. Comparison of Electric Power Generation During the January 2018 Bomb Cyclone[40]



Source: US Energy Information Administration

- In ISO New England (ISO-NE), oil generation jumped from almost nothing to a high of 36% of the daily generation mix. In comparison, gas-fired generation decreased from approximately 50% to less than 20% of supply.
- On New York ISO's (NYISO's) system, the output of dual-fuel generators, mostly gas-fired generators that can switch to fuel oil, and other fossil fuel generators rose significantly.
- In PJM, oil and coal generation increased while gas-fired generation remained consistent.

[40] EIA. 2018. Northeastern Winter Energy Alert.

Gas-fired generation did not make up the required increase in demand to meet the increased electric power generation needs during the 2018 bomb cyclone event. The structure of the underlying electricity markets, specifically the reliance on unused pipeline capacity for fuel delivery for gas-fired generation to maintain competitiveness, poses a challenge to investments in gas infrastructure in the electricity markets such as ISO-NE, NYISO, and PJM.

4.4.3 Current Gas System Resilience Is a Byproduct of Reliability

The current model for developing gas infrastructure supports construction of assets that support reliability of service and that can be underpinned by long-term contracts. This model has been supportive for maintaining the resilience of the gas system, but it must be recognized that the model does not reflect how the gas system will be operated in the future. It also does not support construction of assets that support resilience requirements.

As demonstrated by the case studies, gas infrastructure provides resilience benefits to the entire energy system. However, the strength of the current gas system is a byproduct of an outdated regulatory system, optimized around daily reliability instead of long-term resilience. Fortunately, the overlap between the two outcomes is considerable enough that the energy system currently experiences a reasonable level of resilience. However, the current regulatory structure does not provide a means to construct and operate investments primarily for resilience. As the transformation of the energy system continues, we anticipate the need for more resilience and a changing mix of assets required to provide that service. The manner in which this energy system is regulated and managed is becoming outdated; thus, an update is necessary to maintain resilience in the evolving future energy system.

4.4.4 Gas Systems Are Not Appropriately Compensated for Resilience Services

From a regulatory perspective, LDCs have an obligation to serve and must develop supply and transportation plans to provide gas reliably at the lowest sustainable cost. Typically, gas distribution utilities do not procure more gas supply than necessary for a given day and instead use storage and linepack to balance intraday supply and demand. In most cases, LDCs cannot secure regulatory recovery to procure and store additional gas supply for low likelihood, extreme climate events beyond that incorporated in reserve margin planning. When a customer draws significantly more gas from the gas system than its average demand, this additional supply comes from gas stored that is already allocated to another customer.

> *Any incremental supply that is available to serve electric power generation on short-notice will be gas that has been reallocated from other customers unless the pipeline or LDC offers a no-notice service.*[41]

Some interstate pipelines and gas distribution companies offer no-notice service on a firm basis by dedicating pipeline and storage infrastructure to support the delivery of gas on short notice—no-notice service is typically supported via interstate pipeline tariffs. An electric power generator may pay the cost of expansion of pipeline or storage assets to support the maximum volume consumed. Example 4 (page 57) is a good illustration of this scenario.

In other cases, providing gas supply on short notice to serve resilience events is limited by several features of the gas delivery system. From a physical perspective, the incremental supply

[41] No-notice service refers to the delivery of natural gas on as-needed basis, without the need to precisely specify the delivery quantity in advance (quantities within contract entitlements).

consumed on an intraday basis needs to be in the pipeline at the moment the electric power generator requires delivery throughout the period that the electric generator is producing power. The accommodation of non-ratable flows in the gas system depends on how other shippers use their contracted entitlement in the pipeline and the operational flexibility of the pipeline (e.g., line pack and storage availability). If the pipeline is already full, extreme spikes in demand from non-ratable users may not be met.

The LDC delivery system was not designed to provide large volumes of no-notice service to the electric power generation sector. However, in many circumstances, LDCs provide non-ratable service when capacity is available and when it does not threaten operations. In these cases, the gas system supports the energy system's overall resilience but is not adequately compensated for its service. This lapse in compensation occurs because an additional service is being provided with assets that were not designed for the circumstances.

4.5 Impacts on Consumers

This section considers the varying level of the impact of the findings on the current state on gas ratepayers and electric ratepayers. At a high level, gas ratepayers are more closely aligned with gas system resilience investments than electric ratepayers, as there is no misalignment around who benefits and who pays. Electric system ratepayers, who benefit from the gas system through gas-fired generation have greater misalignment with the development of gas system resilience investments.

4.5.1 Gas System Resilience to Benefit Gas Ratepayers

LDC customers benefit from the resilience provided by assets that are built to provide reliability. Assets are built to serve gas ratepayers. There is a disconnect between who benefits and who pays. The resilience byproduct of these assets benefits these customers. Construction of an asset that is primarily designed for resilience is problematic, because:

- **Lack of a Regulatory Framework:** Resilience of the gas system is not a current regulatory requirement.
- **Lack of Metrics:** Unlike reliability, which can be measured, resilience does not lend itself easily to quantification. For example, value of avoiding the socioeconomic consequences and costs of a prolonged disruption is difficult to measure.

The lack of a regulatory framework and the difficulty of measuring the value complicates the prudency review and cost-effectiveness evaluation of an asset whose business purpose is resilience. As such, reliability drives investment in gas infrastructure. Assets are designed and approved to meet reliability requirements driven by projected gas supply needs and delivery requirements for peak day usage based on historical data. A specific regulatory mechanism to support cost recovery for gas assets whose primary service is to serve resilience events does not exist and needs to be developed.

4.5.2 Gas System Resilience for Electric Ratepayers

There is a larger disconnect between current market structures and the development of resilience assets when the beneficiaries of gas system reliance are not direct gas system customers, such as electric market customers.

- **Difficulty to recover costs across complementary energy markets:** While there is a connection between the resilience of the gas and electric systems, there is no mechanism for electric market participants to collect revenue or provide cost recovery for investments in gas system resilience.

The gas delivery system was not constructed to handle the increasing frequency of large intraday swings in service demand by gas-fired generators that serve intermittent load. As discussed in Section 4.3.2 and as described in Case Study 6, the gas system accommodates the non-ratable flow of the electric sector on a best-efforts basis. In many cases, pipeline transportation arrangements, tariffs, and coordination efforts exist between an LDC and specific electric power generators. However, these are generally workarounds that do not address the core issue: the current state market framework was designed to promote reliability and does not support the construction of assets whose primary function is to serve resilience, especially when the beneficiaries of that resilience are outside of the gas infrastructure-ratepayer ecosystem (i.e., the electric sectors' customers), nor does it fairly compensate the LDCs as the provider of these resilience services.

To further highlight the cost associated with the development of resilience assets, in Example 4 we discuss a gas infrastructure project specifically designed to serve the resilience needs of the electric sector. This example illustrates the benefits that the gas system can provide to the overall energy system when there is alignment between who pays and who benefits and there is a long-term contract to support development.

Example 4. Gas-to-Power Coordination

Portland General Electric (PGE), an electric utility in Oregon, has traditionally relied on hydroelectric generation resources to provide electric system flexibility. However, it sought new ways to achieve flexibility to meet the expansion of solar and wind generation capacity. PGE needed an efficient technology capable of quick-starting, as well as fast ramp-up and ramp-down rates to fulfil the grid's need for flexibility. PGE constructed a 220 MW electric power plant to provide intermittent power during winter and summer periods, as well as load following and renewable integration throughout the year. The plant can ramp to full load in less than 10 minutes.

To assure deliverability of natural gas to accommodate this quick start-up time, PGE partnered with NW Natural, an Oregon-based LDC, to contract for no-notice storage service. To provide this service, NW Natural embarked on a $149 million project that included a 13-mile gas pipeline, a compressor station, and a 4.1 Bcf expansion of the NW Natural' North Mist natural gas storage reservoir. Through this storage service, PGE can draw on its natural gas resources from NW Natural's facilities in Mist, Oregon to meet its fueling needs and rapidly respond to peak demand and variability of wind, hydro, and solar generation. The facility is contracted for an initial 30-year period with a renewal option of up to 50 years beyond that.

Currently, no specific compensation mechanism exists for the resilience services that gas-fired electric power generation provides the electric sector. In the future, as the percentage of electricity generation from intermittent renewable sources increases, the volume of natural gas used for electric power generation may decline; however, in responding to resilience events the necessity of the services provided by gas-fired electric generators may increase. As current compensation models for the gas system serving the power generation sector are tied to the volume of gas delivered to the facility, there becomes an increasing disconnect between the value of the services provided and associated remuneration for said services.

> *Reliability assets are designed and economically justified based upon historical averages and relatively stable utilization. Resilience assets are essential to operation under infrequent and extreme conditions. The benefits of their existence often extend beyond the energy system for which they were designed, i.e., resulting in a greater socioeconomic benefit such as reduced economic loss resulting from an extreme event.*

5. Ensuring A Resilient Future

The energy system of today will not be the energy system of tomorrow. Decreases in the cost of technologies and increasing pressures to decarbonize the energy system are manifesting in increasing levels of renewable generation, a more distributed generation profile, and a less carbon intensive energy supply—there is some indication that certain versions of this future may have negative impacts on energy system resilience.

In a recent review of the root cause of CAISO outages during the August 2020 heatwave, one of the three factors identified was:

> "*In transitioning to a reliable, clean and affordable resource mix, resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours. This makes balancing demand and supply more challenging. These challenges were amplified by the extreme heat storm.*"[42]

As the resilience of the gas system grows in importance, cost recovery mechanisms need to be developed to support investments in assets that strengthen resilience. These cost recovery mechanisms should define the resilience requirement for both gas and electric ratepayers.

5.1 Lessons from Others

This section details key lessons learned from recent regulatory and legislative activities governing resilience in the electric, water, and healthcare sectors. These lessons highlight some opportunities that may exist to develop regulatory structures to support gas resilience investments.

5.1.1 FERC Order 841, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators

FERC Order 841,[43] issued in February 2018, directed regional grid operators to remove barriers to the participation of electric storage in wholesale markets. The order creates a legal framework for storage resources to operate in all wholesale electric markets and expands the universe of solutions that can compete to meet electric system needs. Order 841 was upheld in a federal appeals court decision in July 2020 that declared FERC has jurisdiction over how energy storage interacts with the interstate transmission markets it regulates, even if those energy systems are interconnected with state-regulated electric distribution grids.

> *By directing regional grid operators to establish rules that open capacity, energy, and ancillary services markets to energy storage, Order 841 affirms that storage resources must be compensated for all services provided and moves toward leveling the playing field for storage with other energy resources.*

A key component of the ruling is that "many participation models were designed for traditional generation resources—resulting in limitations or barriers to participation, which constrain competition,"[44] because novel resources technically capable of participating are precluded from doing so as they are forced to operate under participation models designed for existing

[42] CAISO. 2020. Preliminary Root Cause Analysis Mid-August 2020 Heat Storm.
[43] FERC. 2018. Order 841.
[44] US Court of Appeals. 2020. On Petitions for Review of Orders of the Federal Energy Regulatory Commission.

technologies. Energy storage resources (ESRs) such as batteries are especially affected by participation barriers because they have “unique physical and operational characteristics” distinct from traditional resources: ESRs can “both inject energy into the grid and receive energy from it.”

Although this order has limited direct applicability to the natural gas market, it does provide evidence that there are avenues to adapt the current market framework for valuable emerging technologies. Moreover, FERC Order 841 recognizes that the energy system is being used in a different way today than the current regulatory framework envisioned. The acknowledgment that the regulatory framework needs to be reconsidered to remove participation barriers supports the durability of the electric system.

5.1.2 FERC: ISO-NE, Cost-Recovery for Critical Infrastructure Protection (CIP)

Recent FERC orders approving cost recovery for CIP in the electric system showcase how the appropriate cost recovery mechanism can be designed. Federally mandated CIP requirements for electric systems assign protection standards at the low, medium, and high level, with higher standards carrying higher compliance costs. Left unresolved, however, was how generators in wholesale markets would recover the costs of compliance that cannot be competitively offered into the energy and capacity markets. This is because more stringent CIP requirements that result in higher compliance costs provide a disadvantage to a generator that is competing with a generator with lower compliance costs. In May 2020, FERC issued an order approving a proposal submitted by ISO-NE[45] to permit the recovery of incremental costs incurred when low-impact energy systems are reclassified as medium impact energy systems. The order permitted ISO-NE to allocate and collect those costs from transmission customers and disburse the funds to the pertinent facilities.

The concept behind CIP provides several lessons for the consideration of creating cost-recovery mechanisms to support resilience in the natural gas sector. The first is that there are examples in energy markets where resilience is legally mandated. Second, although these mandates can be a source of economic disadvantage to market participants in deregulated energy markets, FERC has approved RTO designed cost recovery mechanisms that socialize the costs.

FERC has mandated a set of protections for critical infrastructure in recognition of the vital role that the electric system plays in supporting the livelihoods of Americans and commerce in the US. The FERC CIP requirements can be viewed as a mandatory resilience requirement with a defined, measurable set of standards.

5.1.3 Energy Resilience in the Water Sector

Water utilities and their regulation offers key lessons on regulatory innovation and resilience. On September 13, 2008, Hurricane Ike made landfall on the upper Texas coast, causing significant damage. Millions of customers lost power, including 99% (more than 2.1 million) of CenterPoint Energy’s[46] customers. A critical pumping station that enables delivery of approximately 75% of Houston’s water supply was one of the casualties and was without power for approximately 10 days—Houston nearly had to declare a water emergency as a result.

[45] FERC. 2020. Docket No. ER20-739-002.
[46] CenterPoint Energy is the electric utility serving the Houston Area.

The Texas legislature enacted legislation[47] in 2015 mandating that water and wastewater treatment facilities have emergency backup power. The requirement also established a definition of resilience: duration at least equal to the longest power outage on record for the past 60 months, or at least 20 minutes, whichever is longer.

In addition, the America's Water Infrastructure Act (AWIA), passed by the US Congress in 2018 and reauthorized in May 2020, requires community water systems to conduct a risk and resilience assessment and develop an emergency response plan (ERP). The ERPs need to focus on more than merely being able to respond. They must include risk mitigation actions such as alternative source water, interconnections, redundancy improvements, asset hardening, and physical and cybersecurity countermeasures if and as justified through assessment. More specifically, the AWIA requires the following:

- Strategies and resources to improve the durability of the energy system, including physical security and cybersecurity.
- Plans and procedures that can be implemented, and identification of equipment that can be used, in the event of a malevolent act or natural hazard that threatens the ability of the community water system to deliver safe drinking water.
- Actions, procedures, and equipment that can obviate or significantly lessen the impact of a malevolent act or natural hazard on the public health and the safety and supply of drinking water provided to communities and individuals, including the development of alternative source water options, relocation of water intakes, and construction of flood protection barriers.
- Strategies that can be used to aid in the detection of malevolent acts or natural hazards that threaten the security or resilience of the energy system.

5.1.4 Energy Resilience in the Healthcare and Emergency Response Sectors

In 2012, Hurricane Sandy made landfall on the US coastline near Atlantic City, New Jersey, with winds upwards of 80 mph. The storm killed over 100 people, flooded coastal cities, destroyed structures, and tore down power lines. As the hurricane devastated the coast, 8.5 million people in 15 states lost power. The widespread power outages severely impacted medical facilities, leaving society's most vulnerable people in life-threatening situations.

Hospitals in New Jersey were forced to evacuate patients after floodwaters damaged backup generators needed to run elevators, lights, and ventilators. Transporting critically ill patients resulted in the loss of life and highlighted the need for more resilient solutions.[48] The total socioeconomic impact of Hurricane Sandy was also enormous, resulting in economic losses ranging from $27 billion to $52 billion.[49] According to the Executive Office of the President in

[47] Texas Administrative Code. 2015. Rule 217.63: Emergency Provisions for Lift Stations.

[48] Modern Healthcare. 2012. *Left in the dark: Seven years after Katrina, Sandy is teaching hospitals more lessons on how to survive nature's fury*.

[49] Executive Office of the President. 2013. *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*.

2012, "these costs of outages took various forms including lost output and wages, spoiled inventory, delayed production, inconvenience and damage to the electric grid."[50]

In response, legislation arose from the crisis. Assembly Bill 1561, the New Jersey Residents' Power Protection Act,[51] was passed in 2015, which requires "medical facilities, pharmacies, first aid squads, fire stations, gas stations,' and newly constructed grocery stores all have backup generators." These generators are expected to run for 96 hours in case of emergency. Additionally, generators must activate within 10 seconds and be inspected weekly. [52]

Senate Bill No 854 was also approved after the storm. It mandates healthcare facilities and retirement homes install emergency electric power generation should the need arise.

New Jersey's legislation focuses on investing in resilience and is impactful for the community and the economy. The legislation exemplifies the growing acceptance of the need for a resilient energy system. In the form of backup generation, the strength of the energy system can withstand shocks and protect vulnerable community members. It will mitigate the emergency costs hospitals face over time, "saving the economy billions of dollars and reducing the hardship experienced by millions of Americans when extreme weather strikes."[53]

5.2 Key Opportunities

Across the gas delivery value chain, the use of existing infrastructure assets is shifting. This shift in usage will undermine the current and future economics of how assets are compensated and limit the development of resilience-focused assets.

- **High-pressure intrastate and interstate pipelines** are developed based upon long-term agreements supported by shippers. Shippers are contract counterparties who provide the economic framework for development of pipeline infrastructure assets. These shippers have historically derived economic value from projects using high load factor ratable forecasts. In the past decade, most material projects were supported by a combination of electric power generation projects or increasing demand from LDCs. Primarily, these have been FERC regulated assets and regulatory approval is based upon a demonstration of demand by the referenced shippers. As utilization of gas-fired generation shifts due to the advent of more renewables and utility demand moderates under decarbonization pressure, forecasted utilization is likely to be significantly lower. As the use of the gas system changes, the way gas service is charged needs to change as well.
- **Storage assets** provide significant resilience benefits. Some utilities have the benefit of on-system storage due to the geologic formations being within the operating jurisdiction or they use aboveground storage assets. Other utilities subscribe to services from storage owners and operators upstream of city gates. Historically, the economic drivers for storage were seasonal pricing differentials and balancing services provided to the integrated gas infrastructure system. In the future state, these assets will continue to provide seasonal and long-duration supply services. Storage is an important resilience asset and will continue to be essential to an integrated energy system. The economics of legacy seasonal pricing

[50] Executive Office of the President. 2013. *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*.

[51] State of New Jersey. 2014. *Assembly Bill No. 1561.*

[52] Facilities Net. 2013. *NFPA 110's Fuel Requirements Can Help Guide Backup Power Plan For Hospitals*.

[53] Executive Office of the President. 2013. *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*.

differentials and balancing services may not provide sufficient revenue to encourage continued development and maintenance of these critical assets. If storage owners and developers were provided revenue for providing resilience benefits, however, the economic framework would sustain the availability of these necessary assets.

- **Distribution systems** have special duty assets including peak shaving storage, LNG storage, and non-pipeline solutions that provide resilience benefits. These assets historically have been designed to meet design day peak demand based upon historical heating degree days. However, as noted in the case studies, climate events create operating stress on existing gas systems. Like the interstate gas systems, the high frequency, high utilization economic framework that was used to justify investments in these legacy assets is not fit for stimulating future investments in a mix of assets that is becoming more intermittent.

The gas system is highly resilient and plays a critical role in supporting the stability of the overall energy system. Current regulatory, economic, and policy frameworks are not conducive to creating the vibrant energy system of the future. The gas and electric sectors are fortunate that the energy system designed to provide reliability has provided resilience benefits. However, the resilience benefits currently enjoyed are a regulatory byproduct and will not serve the needs of the future energy state.

6. Conclusions

The transformation of our energy system is well underway, driven by changes in the cost and availability of new technologies and increasing political and social pressure to decarbonize. The way energy is generated and used is changing rapidly, moving from a one-way power from centralized generation to end customers to a multidirectional network supporting two-way energy flows. As the energy system migrates to one increasingly powered by intermittent renewable sources, it also experiences increasingly frequent and intense climatic events—together these fundamental drivers are creating ever increasing operating stress on the energy system.

As discussed throughout this paper, the gas system is currently providing resilience benefits to the entire energy system. But, the strength of the current resilience is a byproduct of a regulatory environment that has valued investment in a reliable, ratable, and safe set of assets designed around a legacy demand forecast and historical heating degree day planning. As the transformation of the energy system continues, we anticipate a need to place a greater focus on resilience and a re-evaluation of the diversity of assets providing that service.

Full utilization of resilience assets is infrequent by nature. Yet, when a resilience service is demanded it is an essential product of the energy system and key to mitigating catastrophic risk and limiting socioeconomic costs to customers and communities. Utilities, system operators, regulators, and policymakers must make informed decisions to identify an economic framework to incent investments in resilience assets required to support a vibrant and strong future energy system. Resilience should be an energy system requirement like safety and not a byproduct of the existing framework.

6.1 Implications for Policymakers and Regulators

Looking into the future, evolving technology and the speed of transformation of the energy system will require a different economic and regulatory framework to support the appropriate mix of assets and fair compensation for continued investment. Achieving this is easier said than done. It will require a realignment of the valuation and cost recovery mechanisms that currently define the development of the US energy system.

Energy system resilience needs to be defined as a measurable and observable set of metrics, similar to how reliability is considered. To design a truly resilient system requires an ability to measure, evaluate, and optimize the benefit. Resilience needs to be considered as another dimension of system planning, similar to the way that reliability is considered today.

Resilience solutions must be considered from a fuel-neutral perspective and across utility jurisdictions, requiring electric, gas, and dual-fuel utilities to work together to determine optimal solutions. As this paper clearly illustrates through the case studies, when low likelihood, high impact events impact our energy system—the energy system responds through integrated responses that rely on fundamental characteristics of a diversity of assets. Energy system resilience solutions cannot be engineered through a siloed approach that considers only a portion of the energy system, they must consider the opportunity and value that can be brought to the energy system across a diversity of assets.

Methodologies need to be built for valuing resilience, such that it can be integrated into a standard cost-benefit analysis. Value must consider the avoided direct and indirect costs

to the service provider, customers, and society. LDCs and other pipeline infrastructure providers are not fully compensated for the true value of resilience services they provide to the overall energy system. Because the resilience of the gas system is largely a function of the reliability of the gas system, the true cost of resilience (i.e., return of and return on capital invested in physical infrastructure) is treated as a sunk cost. In other words, ratepayers are paying for reliability and enjoying resilience as a benefit—a disconnect that will become increasingly evident as extreme events become more frequent and the share of intermittent renewable generation increases.

In addition to the legacy evaluation criteria that determine cost-effectiveness, policymakers and regulators need to consider ways to evaluate the socioeconomic benefits and avoided costs to the communities resulting from a resilient energy system.

- What is the cost to the community of catastrophic loss of service during a climate event?
- If energy is not available to essential services can this value this be considered by analysis that primarily focuses on the costs per MMBtu or kWh?
- What level of insurance would these communities be willing to pay to have a future energy system that is robust enough to recover quickly and vibrantly from man-made and climate-driven events?

> *Resilience assets mitigate exposure to catastrophic impacts to the communities they serve and should be viewed as an insurance policy to limit risk.*

Cost recovery should be spread over the entire energy system when considering endorsement of capital projects for resilience assets. Further, cost recovery stimulated by utilization is not an appropriate metric for low load factor usage associated with low likelihood, high impact future scenarios.

6.2 A Call to Action

The development of a new regulatory framework will require innovation and collaboration from utilities, system operators, regulators, and policymakers to identify workable solutions that are fit for purpose and tailored to the requirements of regional markets. Preparing the future state to respond effectively to the current transformation requires the communication, coordination, cooperation and collaboration with all industry partners and stakeholders to identify, develop, and implement solutions.

Any future actions undertaken by regulators and other stakeholders should be evidence-based, fuel neutral, and based on objective criteria that scrutinized by all stakeholders. FERC has left it to the RTOs to assess how to best enhance the resilience of the power system and recognizes that solutions to improve gas/power resilience will need to be resolved at the RTO level, however federal direction may also be needed to coordinate productive discussion and facilitate collaboration.

Recent FERC regulatory activity and RTO-led stakeholder planning engagements indicates a precedent for this type of cross-industry collaboration. This activity suggests that the innovation required to address shifting requirements for energy system resilience and facilitate cost recovery for resilience assets is not only possible but achievable.

State PUCs have a vital role to play as well. As the primary regulator of LDCs, PUCs are charged with ensuring customer protection, fostering competition, and promoting high-quality infrastructure. Moreover, solutions to the issues identified in this report will require locally identified solutions that are tailored to the unique needs and circumstances of individual LDCs and the regions they serve.

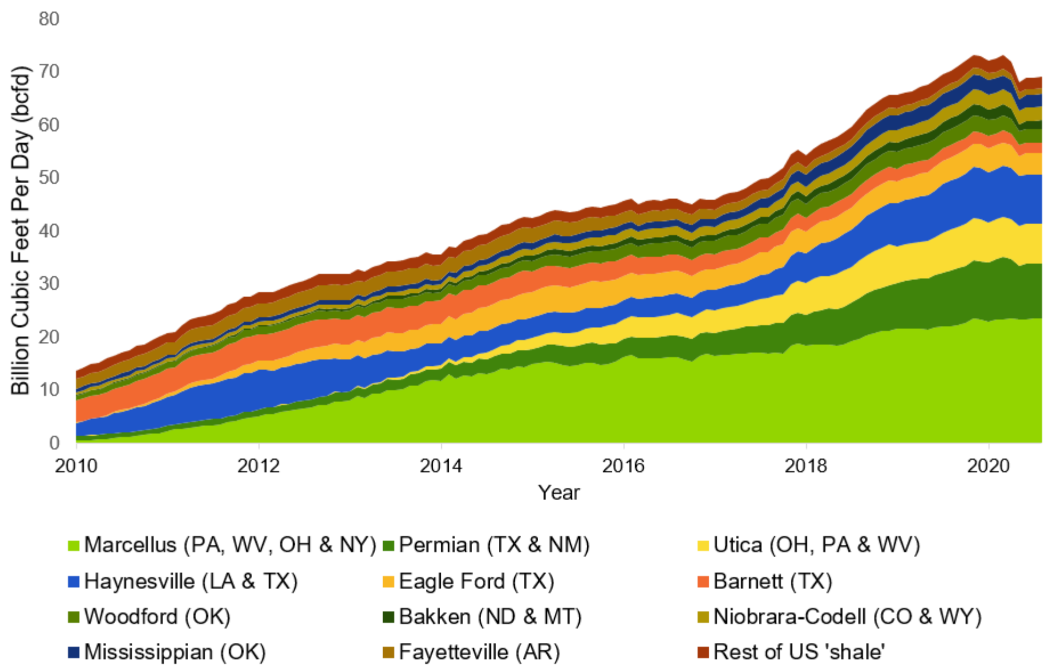
For energy system stakeholders at every level, resilience is not just a term that is currently in vogue, it is a characteristic that needs to be valued and engineered. Ensuring future energy system resilience will require careful assessments of all available solutions, maximizing the fundamental benefits of a diversity of assets. Utilities, system operators, regulators, and policymakers need new frameworks to consider resilience impacts as part of the energy system transformation, to ensure that resilience is not overlooked in the pursuit to achieve decarbonization goals.

Appendix A. The Natural Gas Value Chain

A.1 Production and Processing

Exploration and production companies explore, drill, and extract natural gas from geologic formations. In 2019, 81% of production came from shale.[66] Production from these formations has grown rapidly over the past decade, as Figure A-1 shows.

Figure A-1. US Dry Shale Gas Production, 2010-2020



Source: Guidehouse, US Energy Information Administration

Once produced and extracted, gathering pipelines transport natural gas to processing facilities where impurities are removed, resulting in pipeline-quality natural gas. Gathering systems use compressors to move gas through the midstream pipelines. Most compressors are fueled by natural gas from their own lines. This self-reliance increases resilience by allowing the movement of molecules without dependency on other fuel sources.

A.2 Transmission

From the gathering system, natural gas moves into the high-pressure transmission system for long-haul transportation to market centers. These pipelines efficiently move large amounts of natural gas thousands of miles.[54] In the US, there are approximately 3 million miles of mainline and other pipelines that connect gas production with consumption.[55] Over 30 companies in North America own and operate interstate pipelines, which the FERC regulates. Intrastate pipelines are generally owned by publicly traded entities and are regulated by the states in which they are located.

[54] American Gas Association. *How Does the Natural Gas Delivery System Work?*. Accessed October 2020.
[55] EIA. *Natural Gas Explained: Natural Gas Pipelines*. Accessed October 2020.

A.2.1 Compressor Stations

The pressure of gas in each section of the transmission system ranges from 200 psi to 1,500 psi, depending on where the pipeline operates. Compressor stations are located approximately every 50 to 60 miles along transmission pipelines to regulate pressure and keep gas moving.

A.2.2 Gas Storage

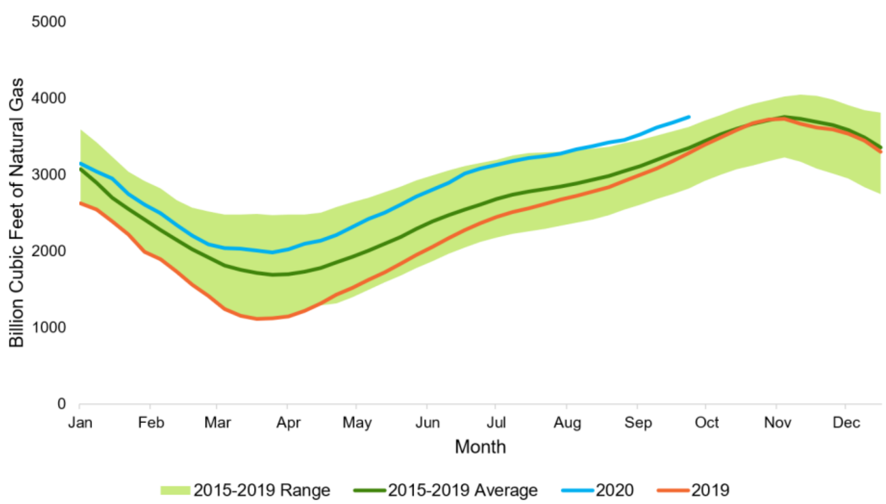
Storage capacity enables the delivery of reliable gas service to consumers and end-users throughout the year. While natural gas production remains relatively constant year-round, storage enables gas providers to adjust to daily and seasonal demand fluctuations (Figure A-2).

Storage can be owned or operated by natural gas transmission companies or LDCs. Off-system storage is not directly tied to a natural gas utility's distribution system, but that is accessible via the transmission system. Most off-system storage is underground; however, there are examples of aboveground off-system storage. Underground storage facilities can be developed from depleted gas reservoirs, aquifers, or salt caverns and are connected to one or more transmission pipelines; whereas aboveground storage is often provided through LNG or CNG.

In addition to offering storage services, some pipeline companies may provide a park and loan that enables shippers to borrow or lend gas. These services are typically used to balance daily or intraday markets. Some Pipelines also offer tariff-based delivery services called No Notice, which allows an LDC to receive gas at variable quantities throughout the day without placing nominations to the provider. These no-notice services are backed by storage and pipeline delivery assets.

In the lower 48 states, it is common for the gas system to have at least 2,000 Bcf to 3,000 Bcf of working natural gas in underground storage, as Figure A-2 shows. The entire US commercial sector consumed 3,500 Bcf in 2019. Base gas (or cushion gas) is the volume of natural gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season. Working gas is the volume of gas in the reservoir above the level of base gas. Base gas inventories remain relatively steady at approximately 4,300 Bcf throughout the year.

Figure A-2. Working Gas in Underground Storage, Lower 48 States



Source: Guidehouse, US Energy Information Administration

A.2.3 City Gate Stations

Natural gas typically passes through a city gate to move from the transmission pipeline to the pipelines under operational control of LDCs. At the city gate, the pressure is reduced from transmission to distribution levels, an odorant is added, if not already provided by the upstream pipeline, and incoming flow is measured to ensure it matches the LDC's distribution requirements. Deliveries from transmission pipelines are normally scheduled a day or more prior to delivery and include the estimated total quantities for demand in the day forward. Some transmission systems provide operators the ability to make intraday changes to nominations in attempt to sync scheduled demand with actual demand.

In addition, pipeline midstream companies and inter-connection pipelines (i.e., LDC or other midstream pipeline companies) have OBAs in place in which parties agree to specified procedures for balancing between nominated levels of service and actual quantities transferred between the two pipelines.

A.3 Distribution

After leaving the city gate, natural gas moves into distribution pipelines. Each distribution system has sections that operate at different pressures, with mechanical regulators controlling the pressure to optimize efficiency. Generally, the closer natural gas gets to a customer, the lower the pressure.

Many distribution systems also feature on-system storage. This is typically aboveground and includes small-scale LNG or CNG storage that enables the distribution company to meet short-term requirements for increased gas demand and pressure balancing needs. Such facilities enable LDCs to supplement, or shave, the amount of natural gas needed from external suppliers through on-system resources. Some distribution systems also feature underground storage.

A.3.1 Customer Delivery

As gas travels through the main lines of the distribution system, it is routed to customers through smaller service lines. Flow meters and mechanical regulators reduce the pressure to under 0.25 psi, the normal pressure for gas within a household, equivalent to less pressure than a child blowing bubbles through a straw.

The types of customers served by the system include the following:

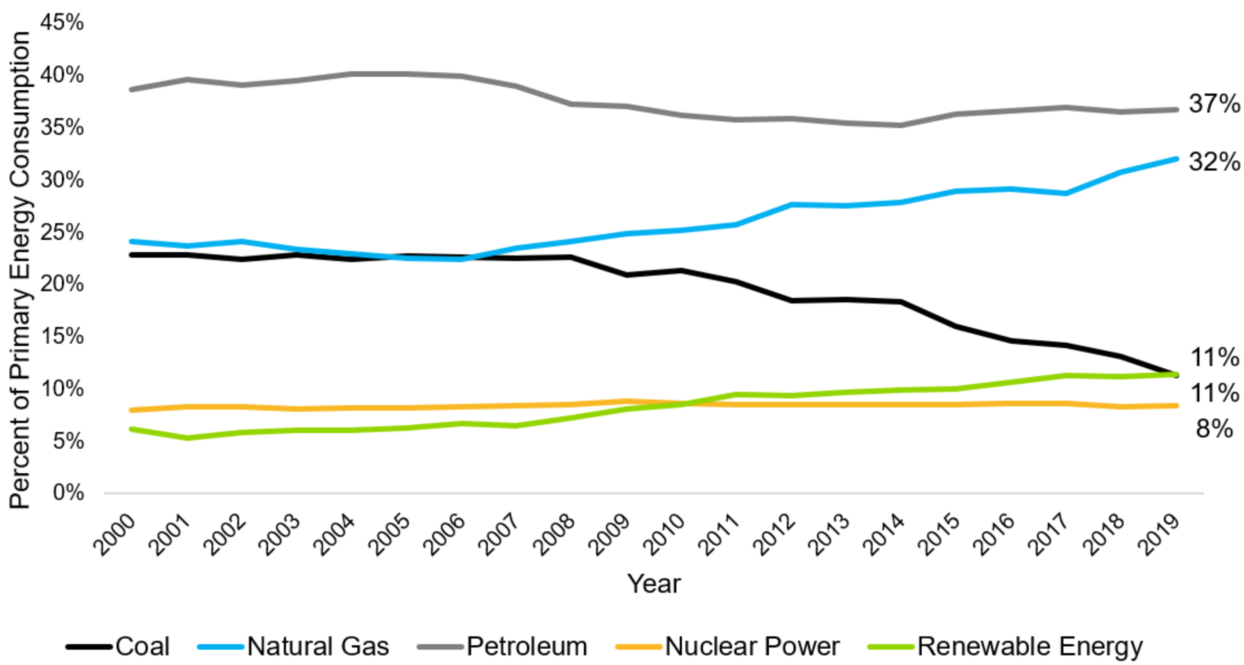
- **Interruptible vs. Firm Demand:** Interruptible customers are often large commercial or industrial customers that have selected to contract for natural gas service that can be interrupted when the delivery system is experiencing constraints. When a natural gas utility experiences a situation where gas consumption exceeds demand, such as during a peak heating day, system operators can curtail these interruptible customers while maintaining service to firm demand (or uninterruptible) customers.
- **Ratable vs Non-Ratable Flow:** Ratable flow refers to customers that will be delivered one-twenty-fourth of their nominated and scheduled daily quantity every hour—they receive the same amount of natural gas every hour of every day. Non-ratable flow refers to customers that receive uneven or varying consumption throughout the day.

Appendix B. The Current State of US Gas Consumption and Production

The US natural gas industry is larger today than ever before—gas consumption and production have grown since the 1950s and are currently at record levels. In 2019, the US consumed 31 trillion cubic feet of natural gas. Concurrently, the US produced approximately 33 trillion cubic feet of natural gas (dry production) in 2019.[56]

In 2019, natural gas accounted for 32% of US primary energy consumption.[57,58] Natural gas has been accounting for an increasing portion of the energy consumed in the US since 2000, as Figure B-1 illustrates.

Figure B-1. US Primary Energy Consumption by Source



Source: Guidehouse, US Energy Information Administration

B.1 Gas Consumption by Customer Segment

Natural gas is a significant energy source used to generate electricity in the electric sector and meet the end-use heating demands in the residential, commercial, and industrial sectors. It is also used in distributed electric power generation primarily through CHP in the industrial sector and as a transportation energy source.

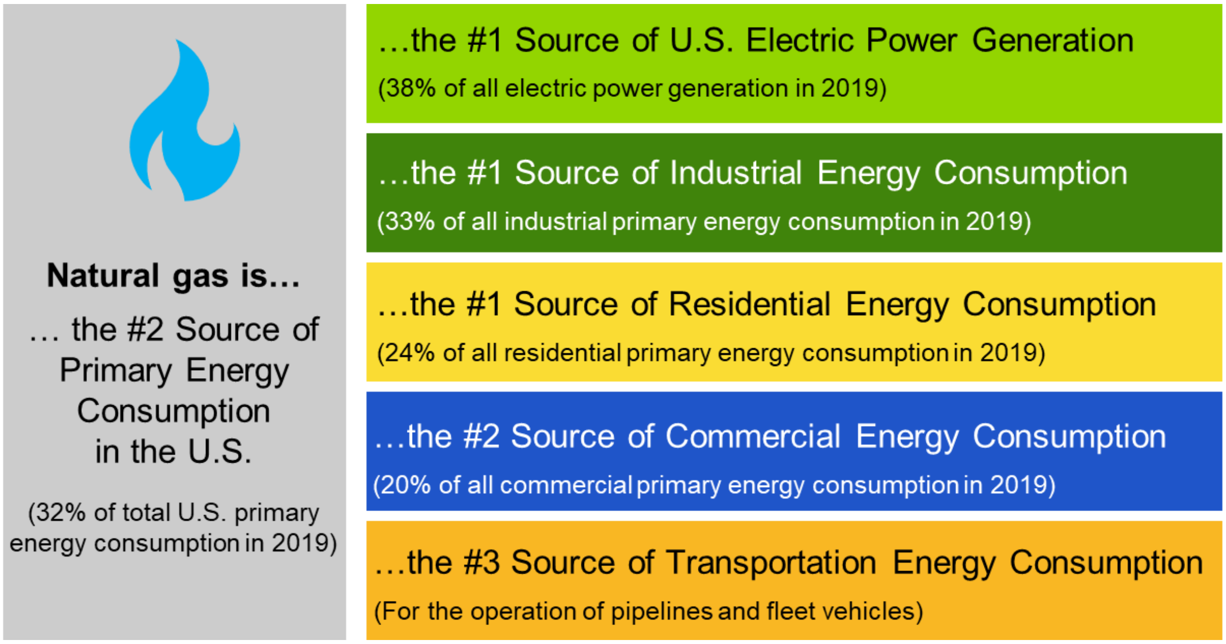
[56] EIA. 2020. *Annual Energy Outlook*.

[57] Primary energy consumption is a measure of total energy demand, covering the consumption of fossil fuels by end users like homes and businesses, the energy used to produce electricity, and losses during the transformation and distribution of energy.

[58] EIA. 2020. *Annual Energy Outlook*.

Figure B-2 illustrates the role that natural gas plays in powering each of these sectors. Natural gas supply is also detailed further throughout the remainder of this section.

Figure B-2. Natural Gas Deliveries and Consumption by Sector



Source: Guidehouse, US Energy Information Administration

B.1.1 Electric Power Generation

Growth in shale gas production has led to a decline in natural gas prices and has contributed to steady growth in the amount of electric power generated by natural gas (Figure B-3).

> *In 2019, 6,025 utility-scale gas generation facilities produced 38% of total US electricity, the largest share of any individual source. This is up from 5,722 gas generation facilities producing 33% of total US electricity in 2016.*[59]

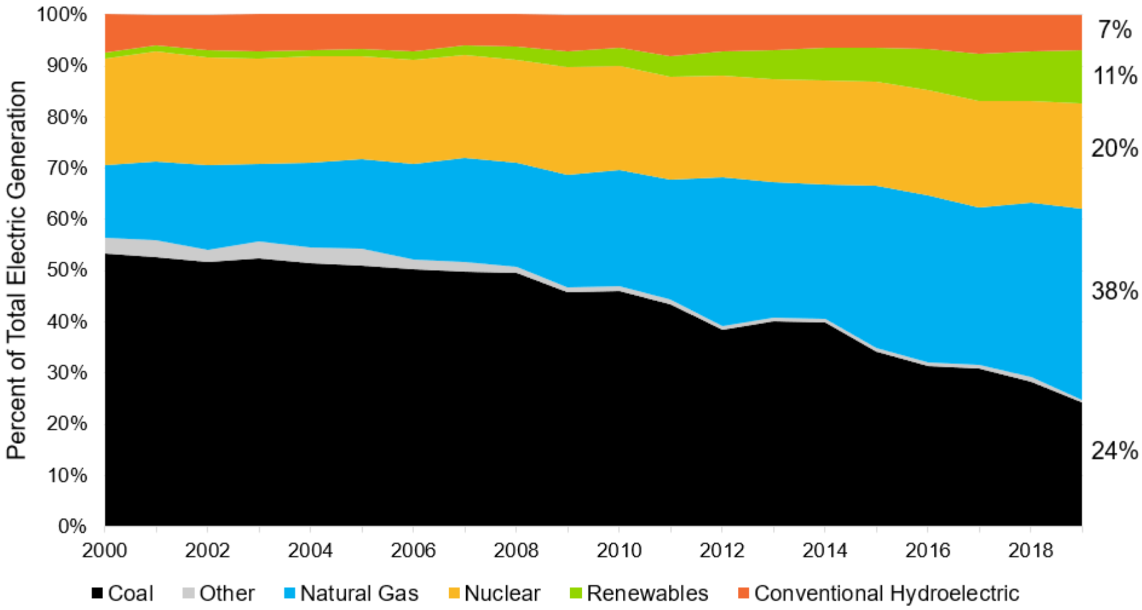
The price of natural gas is a key driver behind its growth as a source of electricity production. This trend continues today, with the 2025 EIA outlook for the levelized cost of electricity of next-generation coal plants hovering around \$76/MWh, and combined cycle natural gas plants around \$38/MWh. This is in-line with EIA projections for non-dispatchable technologies such as onshore wind (\$40/MWh) and solar PV (\$33/MWh), and cheaper than projections for offshore wind (\$122/MWh) and hydroelectric (\$53/MWh).[60]

Grid operators find value in gas-fired electric power generation because of its flexibility as an energy resource, serving as both high capacity factor baseload and dispatchable generation. The fast ramp-up and ramp-down times of natural gas generators are especially important in regions with a large share of renewables generation where natural gas plants are often required to balance the steep increase and decrease in generation capacity.

[59] EIA. 2020. *Preliminary Monthly Electric Generator Inventory, September 2020*.

[60] EIA. 2020. *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020.*

Figure B-3. Net Electric Power Generation by Source, 2000-2019



Source: Guidehouse, US Energy Information Administration

B.1.2 Industrial

Natural gas is critical to meeting the energy needs of the industrial sector. In 2019, the industrial sector accounted for 33% of total US natural gas consumption, which in turn accounted for 33% of the industrial sector's total energy consumption.[61]

Within the industrial sector, natural gas supports a wide range of uses including building heating, a feedstock for CHP, and as a feedstock for high energy-intense processes such as the production of chemicals, fertilizer, and steel.

B.1.3 Residential

In the US residential sector, natural gas is used to heat homes and water, cook, and dry clothes. Although the use of natural gas varies by geography (as Figure B-4 illustrates), about half of the homes in the US use it for space and water heating. In 2019, the residential sector accounted for approximately 16% of total US natural gas consumption, which translates to 24% of the residential sector's total primary energy consumption.[62]

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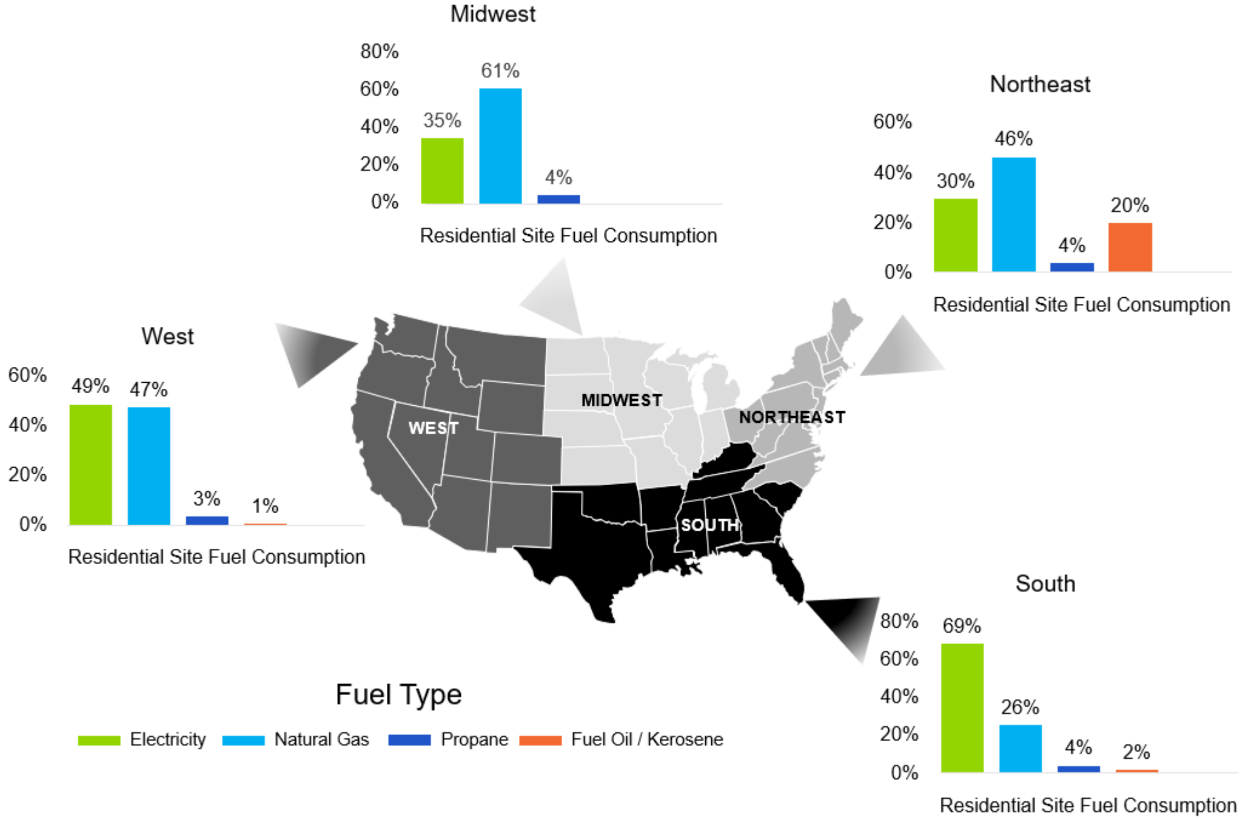
[61] EIA. *Natural gas explained: Use of natural gas*. Accessed September 2020.

[62] EIA. 2020. *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020.*

Figure B-4. Natural Gas Share of Total Residential Energy Consumption, 2015



Source: Guidehouse, US Energy Information Administration

B.1.4 Commercial

In the US commercial sector, natural gas is primarily used to heat buildings and water, to operate refrigeration and HVAC equipment, to cook, dry clothes, and provide outdoor lighting and heating. In 2019, the commercial sector accounted for approximately 11% of the total US natural gas consumption, which translates to 20% of the commercial sector's total primary energy consumption.[63]

B.1.5 Transportation

Natural gas plays a niche role in the US transportation sector, accounting for only 3% of the sector's total energy needs in 2019. Within the transportation sector, natural gas is used to operate compressors to move natural gas through pipelines and as a vehicle fuel in the form of CNG and LNG.

Most vehicles that use natural gas as a fuel are government and commercial fleet vehicles. CNG medium duty vehicles have gained increasing popularity over diesel due to lower prices and clean air benefits. In 2018, there were a total of 19,151 CNG public transit busses nationwide, compared to 32,671 diesel and 13,872 hybrid busses.[64] In 2020, there are 1,677

[63] EIA. 2020. *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020.*

[64] DOE. *Alternative Fuels Data Center, Transit Buses by Fuel Type*. Accessed October 2020.

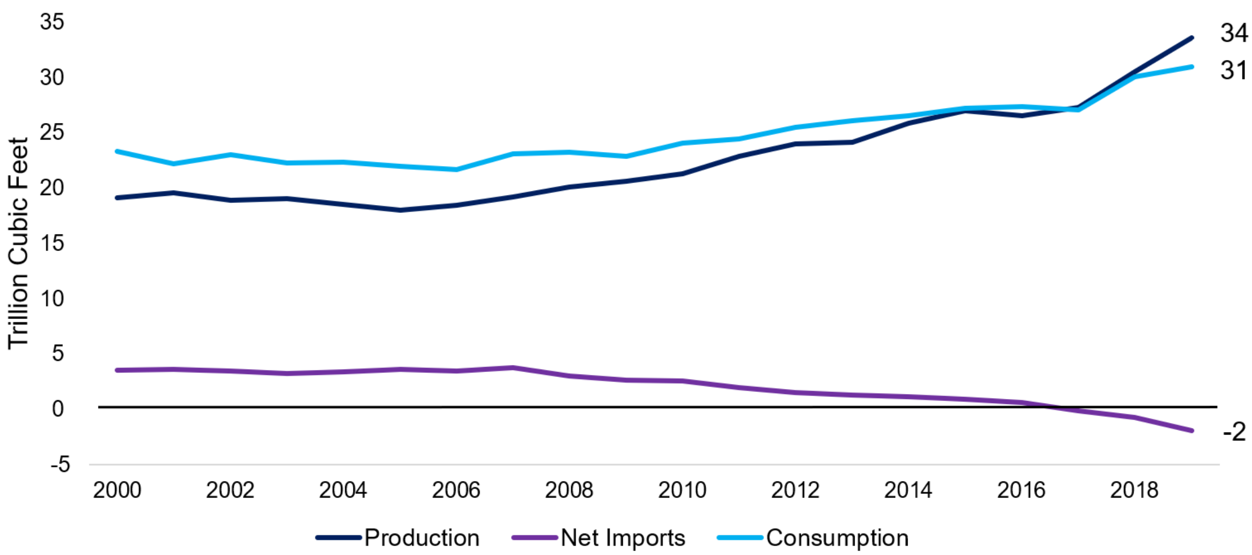
CNG and LNG refueling sites in the US compared to 29,738 EV stations. However, this infrastructure supports decarbonization of heavy and medium to light duty vehicles where EV infrastructure primarily supports light duty vehicles.[65]

B.2 US Gas Production

US natural gas production continues to grow; domestic production has exceeded consumption since 2017. The US now produces nearly all the gas it consumes, decreasing its reliance on imports from other countries. In large part due to accessible shale formations, most natural gas (97%) is produced onshore in a diversified base of over 30 states. Five states (Texas, Pennsylvania, Oklahoma, Louisiana, and Ohio) account for approximately 70% of the US total dry natural gas production.[66]

In 2019, 34 trillion cubic feet of natural gas was produced (Figure B-5).[67] Increased domestic production has contributed to a decline in prices, which has led to the significant increase in natural gas consumption across sectors, primarily in the electric power generation and industrial sectors.

Figure B-5. US Natural Gas Consumption, Dry Production, and Net Imports, 2000-2019



Source: Guidehouse, US Energy Information Administration

B.3 Low Carbon Gas Production

Since the early 2000s, US energy-related GHG emissions have been decreasing.[68] A significant driver of the emissions reduction has been a transition from higher-emissions fuels (e.g. coal) to natural gas. This transition is expected to continue, as natural gas supply is further decarbonized through the increase in low carbon gas production.

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[65] Oak Ridge National Laboratory. 2020. *Transportation Energy Data Book Edition 38, Table 6.12.*
[66] EIA. *Natural Gas Explained: Where our natural gas comes from*. Accessed October 2020.
[67] EIA. *U.S. Energy facts explained*. Accessed October 2020.
[68] EIA, *EIA Projects U.S. Energy-Related CO2 Emissions Will Remain Near Current Level Through 2050.*

Fueled by city and state commitments to decarbonize, investors are driving the capital necessary for companies to invest in the further research, development, and production of low carbon gases such as RNG, hydrogen-enriched natural gas, and hydrogen. Meanwhile, political and regulatory agencies are clearing the path for the growth of this low carbon gas development. Although low carbon gas production is nascent in the US, its growth potential provides a pathway for the natural gas industry to meet energy sector decarbonization goals. It also increases the resilience of the energy system by providing a locally sourced supply of clean energy.

B.3.1 Biogas

Biogas is produced primarily through landfill gas collection, thermal gasification, or anaerobic digestion of waste feedstocks from the sewage, agriculture, food, and forestry sectors. Biogas can be used to produce heat and electricity, or it can be further processed to remove impurities to meet the standards of conventional natural gas (defined as RNG) for distribution through the gas pipeline system, as Figure B-6 illustrates. Though most RNG produced is consumed onsite for electric power generation or heating, the American Gas Foundation found that there will be about 50 trillion Btu of RNG produced in the US for pipeline injection in 2020, a number that has grown at a compound annual growth rate (CAGR) of 30% over the past 5 years.[69]

> *The number of renewable natural gas (RNG) production facilities in North America grew by 145% from 2014 to 2019.*[70]

There are over 2,200 biogas production sites in the US. Investments into new biogas systems totaled $1 billion in 2018, a number that has been growing at a CAGR of 12%.[71] In 2019, the US produced approximately 230 billion cubic feet of biogas primarily from solid waste (83%), industrial (6%), wastewater (6.5%), and agricultural (4.5%) feedstocks.[72]

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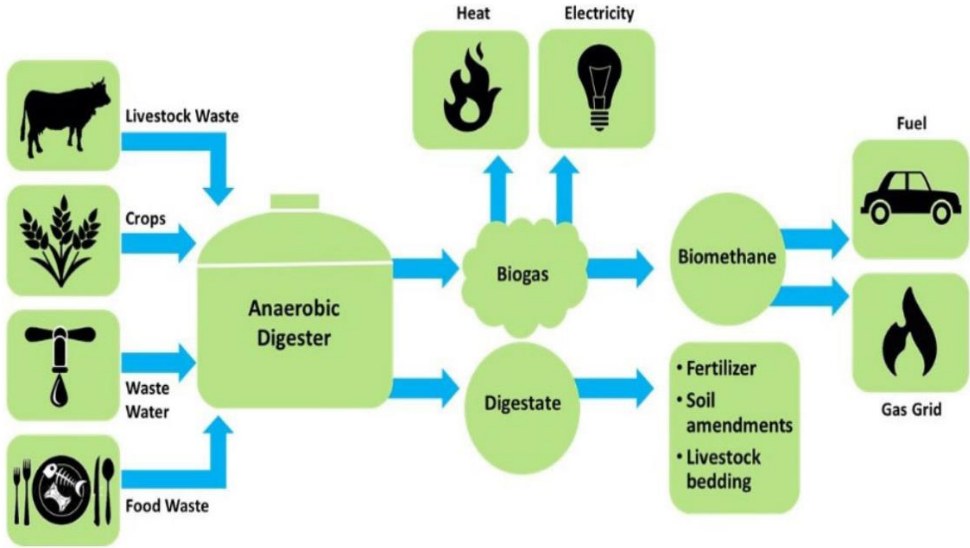
[69] American Gas Foundation. 2019. *Renewable Source of Natural Gas: Supply and Emissions Reduction Assessment.* Accessed October 2020.

[70] Coalition for Renewable Natural Gas. 2019. *Renewable Natural Gas Market Surpasses 100-Project Pinnacle in North America*. Accessed October 2020.

[71] American Biogas Council. 2019. *Why Biogas?*.

[72] Guidehouse Insights. 2020. *Renewable Natural Gas: Overview of the Current State of Biogas and Renewable Gas Markets*.

Figure B-6. Low Carbon Gas Production Through Anaerobic Digestion

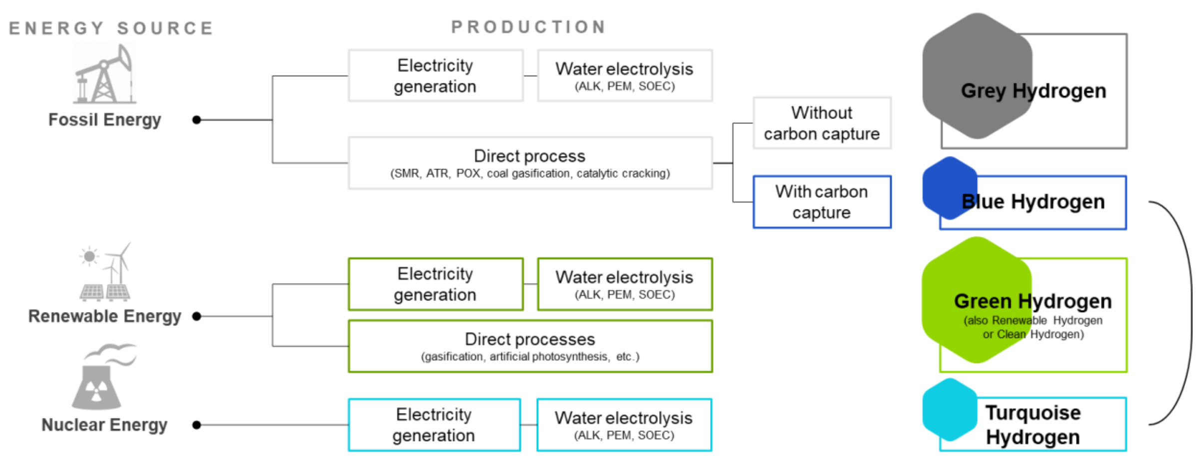


Source: Environmental and Energy Study Institute

B.3.2 Hydrogen

Hydrogen is produced through electrolysis, a splitting of water atoms into their component parts of hydrogen and oxygen. Producing hydrogen requires an input of energy, the type of energy that is used defines the carbon intensity of the process and ultimately whether it is considered low carbon. Figure B-7 describes the various types of hydrogen across a color spectrum (grey, blue, green, and turquoise hydrogen).

Figure B-7. Hydrogen Production Technologies



Source: Guidehouse

Steam methane reforming is used to form most hydrogen production. Hydrogen is often produced for use alongside its two largest consuming sectors, petroleum refining and fertilizer production. There are1,600 miles of hydrogen pipeline in the US, and most states have a large hydrogen production facility producing approximately 10 million metric tons of hydrogen annually.[73] However, a recent California Energy Commission study estimates that with market and policy action to facilitate scale-up of production capacity, California alone could produce an excess of 2,000 metric tons per day by 2030.[74]

[73] U.S. Office of Energy Efficiency & Renewable Energy. 2019. *10 Things You Might Now Know About Hydrogen and Fuel Cells*.

[74] California Energy Commission. 2020. *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California*.

Appendix A-8

FEI'S STATEMENT OF INDIGENOUS PRINCIPLES

Our Statement of Indigenous Principles

Twenty years ago, we developed our formal Statement of Indigenous Principles with input, guidance and direction from several Indigenous leaders across BC.

FortisBC is committed to building effective Indigenous relationships and to ensuring we have the structure, resources and skills necessary to maintain these relationships. To meet this commitment, the actions of the company and its employees will be guided by the following principles:

- FortisBC companies acknowledge, respect and understand that Indigenous Peoples have unique histories, cultures, protocols, values, beliefs and governments.
- FortisBC supports fair and equal access to employment and business opportunities within FortisBC companies for Indigenous Peoples.
- FortisBC will develop fair, accessible employment practices and plans that ensure Indigenous Peoples are considered fairly for employment opportunities within FortisBC.
- FortisBC will strive to attract Indigenous employees, consultants and contractors and business partnerships.
- FortisBC is committed to dialogue through clear and open communication with Indigenous communities on an ongoing and timely basis for the mutual interest and benefit of both parties.

- FortisBC encourages awareness and understanding of Indigenous issues within its work force, industry and communities where it operates.
- To achieve better understanding and appreciation of Indigenous culture, values and beliefs, FortisBC is committed to educating its employees regarding Indigenous issues, interests and goals.
- FortisBC will ensure that when interacting with Indigenous Peoples, its employees, consultants and contractors demonstrate respect, and understanding of Indigenous Peoples' culture, values and beliefs.
- To give effect to these principles, each of FortisBC's business units will develop, in dialogue with Indigenous communities, plans specific to their circumstances.

Progressive Aboriginal RELATIONS COMMITTED (https://www.ccab.com/programs/progressive-
Canadian Council for Aboriginal Business aboriginal-relations-par/)

Natural gas
1-888-224-2710 (tel:18882242710)

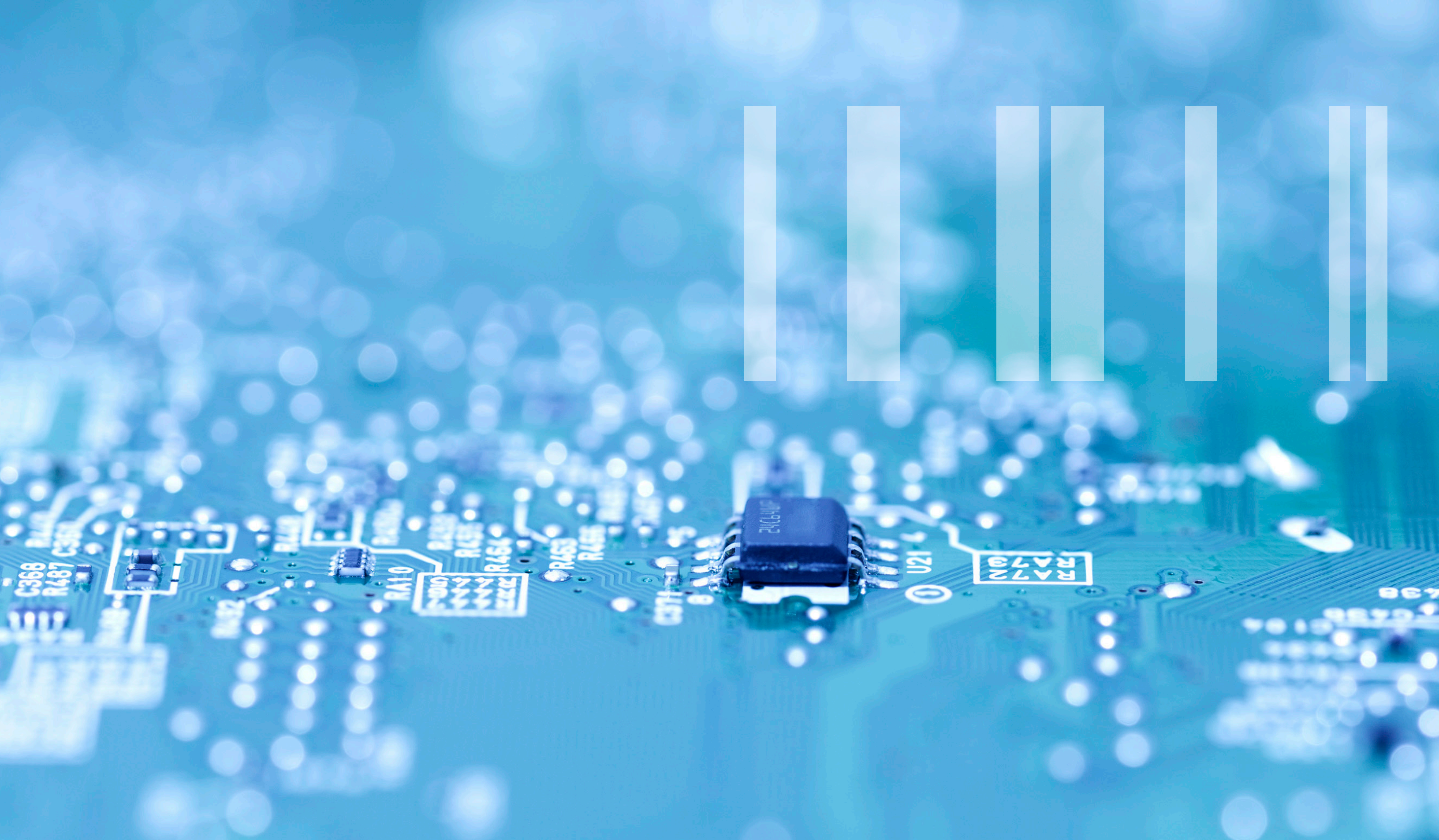
Monday-Friday
7 a.m. to 8 p.m.

Electricity
1-866-436-7847 (tel:18664367847)

Monday-Friday

Appendix A-9

STUDIES SUPPORTING THE DIVERSIFIED PATHWAYS APPROACH



Implications of **Policy-Driven Electrification in Canada**

A Canadian Gas Association Study
Prepared by ICF

October 2019

ENERGY

IMPORTANT NOTICE:

This is a Canadian Gas Association (CGA) commissioned study prepared for the CGA by ICF. The CGA defined the cases to be evaluated, including major assumptions driving the timing and degree of electrification to be considered. The CGA also requested that ICF develop and use optimistic assumptions, based on third party sources related to the electrification technology costs and electric technology performance characteristics, to assess the impacts of electrification. ICF then analysed the implications and impacts of these in four scenarios. This scenario-based approach does not attempt to predict what is most likely to happen by 2050, but rather uses some boundary scenarios to highlight the impacts of different policy approaches. The Canadian Energy Regulator (CER) Energy Futures 2018 Reference Case, including energy prices and energy consumption trends, was used as the starting point for this analysis, and was combined with ICF's Integrated Planning Model (IPM®) for the analysis of electric generation capacity expansion.

This report and information and statements herein are based in whole or in part on information obtained from various sources. The study is based on public data on energy costs, costs of customer conversions to electricity, and technology cost trends, and ICF modeling and analysis tools to analyze the costs and emissions impacts of policy-driven electrification for each study scenario. Neither ICF nor CGA make any assurances as to the accuracy of any such information or any conclusions based thereon. Neither ICF nor CGA are responsible for typographical, pictorial or other editorial errors. The report is provided AS IS.

No warranty, whether express or implied, including the implied warranties of merchantability and fitness for a particular purpose is given or made by ICF or by CGA in connection with this report.

You use this report at your own risk. Neither ICF nor CGA are liable for any damages of any kind attributable to your use of this report.

FOREWORD ON STUDY ASSUMPTIONS

The goal of this study is to examine the impacts of a policy choice to replace natural gas and other fossil fuel use in Canada with electricity. Most of the assumptions pertain to those systems and their structures. In all cases these assumptions were deliberately ***'cost-conservative'*** meaning they were designed to not overstate the possible cost implications of such a policy choice.

The time frame under consideration is the period from 2020 to 2050. Electrification is assumed to begin in 2020 and to lead to near complete electrification of residential and commercial fossil fuel load by 2050, depending on the scenario being considered. The investments needed in the electricity system are assumed to proceed without delay with existing natural gas and electric end use equipment replaced at its normal usual end of life without any artificial acceleration that might make the transition to electricity appear more costly. The required additional electricity is assumed to come from a combination of renewable sources (wind and solar power) augmented and backed up with battery storage technologies to ensure the necessary 'dispatchability' for the electricity that will be needed.

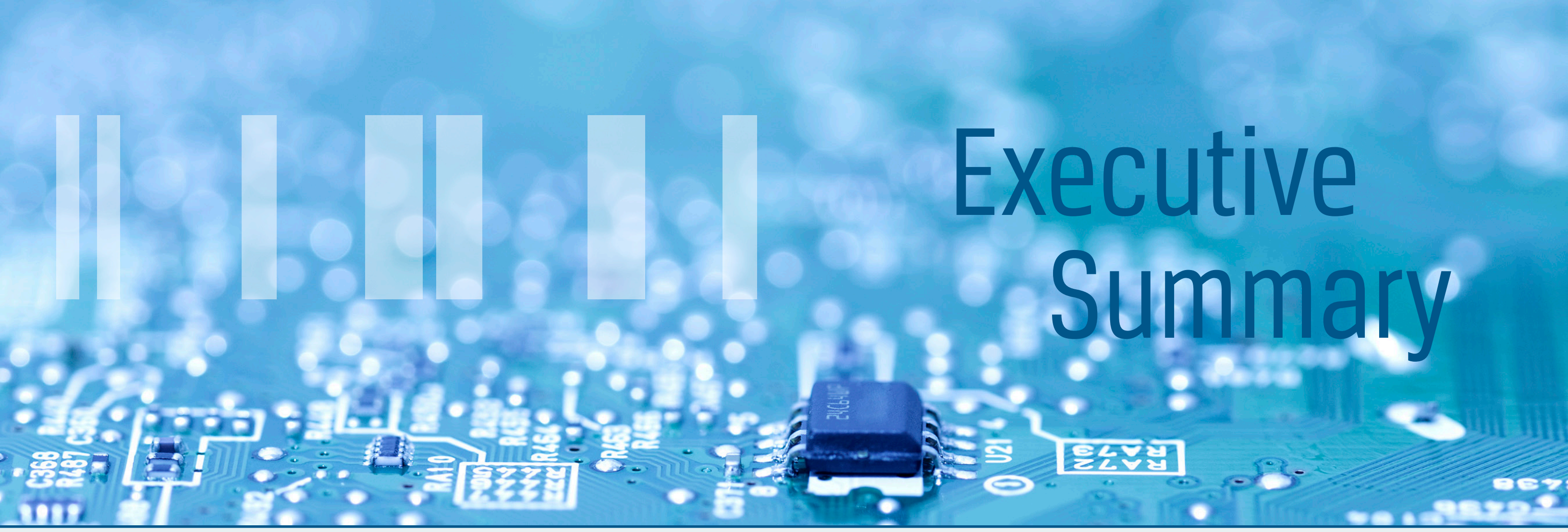
The starting reference case for the study is the Canadian Energy Regulator[1] 2018 Energy Futures Outlook. The study's scenarios then examine the impacts of a full move from natural gas and fossil fuels to electricity for residential use (e.g. space heating, water heating, cooking, etc.), for commercial use (in similar categories), for an assumed 50% of industrial natural gas and fossil fuel use that could most likely be electrified, and for significant electrification of motor vehicles. The study does not suggest this is a likely or even plausible future, it simply looks at the costs and requirements of a deliberate policy choice to electrify these elements of the natural gas and fossil fuel use.

These scenarios are based on aggressive assumptions regarding improvements in electric technology efficiency of performance and costs designed to hold down the costs of the electrification. To this end the National Renewable Energy Lab's (NREL) most aggressive outlook for the improved efficiencies of electric heat pump technologies was used. The NREL is a well-respected authority on future electrification technologies such as heat pumps. Heat pump technologies are assumed to improve from the current efficiency levels of 200-300% to achieve seasonal average efficiencies of 400-500% by 2050. Again, this is done to be deliberately cost-conservative as to the impacts on electricity requirements under a policy of electrification.

This study does not examine what the impacts or response from the natural gas and fossil fuel industry might be to an 'electrification policy'. Impacts on the natural gas systems' viability and its investors are not covered in this work. Similarly, the potential of new natural gas technologies, the impacts of electrification on the competitiveness of Canadian industry, the potential role of natural gas transmission and distribution infrastructure in enabling the future energy forms such as hydrogen, while important additional considerations, are not included within the scope of this analysis.

Certain costs have been 'excluded' from consideration in this study for cost-conservative reasons. The study did not consider the enhanced distribution system level infrastructure investment required to deliver incremental power load and assumes no change in price per unit of electricity. This approach means the resulting costs of electrification identified by this study are likely significantly understated, but a credible and comprehensive assessment of such added electricity distribution costs for the diverse regions of the country was not available at this time. Finally it is also important to note that the costs presented in this study are incremental to any costs embodied in the reference case.

[1] Formerly called the National Energy Board



Executive Summary

Moving away from an integrated multi-fuel, multi-grid energy system towards a fully electric single-grid system has been proposed in a number of jurisdictions as a pathway to significantly reduce Canada's greenhouse gas emissions. But, the viability of a policy of widespread electrification in Canada, in terms of the required new power infrastructure, the costs to households and businesses, and the relative cost and effectiveness of the GHG mitigation potential have not been comprehensively evaluated. With a goal of informing these aspects of this important discussion the Canadian Gas Association (CGA) engaged ICF to assess and illustrate the costs and benefits of several policy-driven electrification approaches in Canada.

Key Results from this Study:

- **A transition from current energy systems to high levels of mandated electrification will require a significant and costly expansion** of Canada's electrical infrastructure. Currently only 20% of Canada's energy requirements are met by electricity. Based on this analysis, replacing refined petroleum products and natural gas in homes, businesses, industry, and vehicles with electricity in Canada would require an expansion of generating capacity from 141 gigawatts (GW) today, to between 278 GW and 422 GW of capacity by 2050. This expansion, along with the associated incremental costs of added electric energy, electric technology adoption, new transmission infrastructure, and renewable natural gas (RNG), could increase national energy costs by between $580 billion to $1.4 trillion over the 30 year period between 2020 and 2050. These added requirements and their associated costs would be significantly higher were it not for the study's aggressive assumptions related to the improvement of electric end-use technologies (e.g., heat pumps) and assumed steep reductions in the heating load requirements of residential and commercial buildings.
- **Incremental costs associated with electrification will be driven by the need for the electricity system to meet a significantly increased peak load.** Critical energy infrastructure systems, including electricity and natural gas distribution systems are designed and implemented based on expected future demand and peak requirements. The design capacity of these systems is driven by the need to ensure reliability in extreme conditions. For example natural gas systems are typically designed to exceed the demand expected on the coldest day. It is understood that much of this infrastructure will rarely be required but must be in place for those extreme circumstances with the cost of that functionality being paid for by the energy end user. Replacing natural gas and fossil fuels in the transportation, residential, commercial, and industrial sectors of the Canadian economy via aggressive electrification is shown here to **increase peak electricity supply requirements to 287 GW by 2050 from 120 GW in the business as usual reference case.** This increase in energy demanded of the electric system and the significantly higher peak electric load requires significant additional electric system infrastructure to ensure reliable service at the peak design condition.
- **Not all types of electrification are equal.** If an electrification policy is not executed with consideration of the specific needs being met by each of the fuels it replaces, or the need for a reliable, sustainable, and affordable system, **the result could be an electrical system challenged to provide reliable service during the peak**

design condition at reasonable cost. This has led utilities and regulators to look for 'beneficial electrification'[2], that is electrification that saves consumers money over the longer term, reduces negative environmental impacts, and enables better grid management. Electrification is considered "beneficial" when it satisfies at least one of those conditions, without adversely affecting the other two.

Electrification initiatives need to be selective in their targets to meet these criteria. Consideration must be given to the pace of electrification, the amount of demand being converted to electricity, and the nature of local electrical infrastructure and supply. Some opportunities for electrification, such as in passenger commuter vehicles, could reduce operating and fuel costs, reduce GHG emissions, and have more limited impacts on system peak electric load (where utilities can stagger vehicle recharging). Conversely, other electrification opportunities, such as space heating, would only reduce GHG emissions in provinces with a sufficiently low emissions electric resource, and the cost of the added electric capacity required to reliably meet a new winter peaking load will be substantial.

- **GHG reduction policies that solely focus on electricity over gaseous fuels are more costly (\$289 / tCO_2) than approaches which allow for an integrated energy system to achieve GHG emission reductions (\$129 / tCO_2).** Canada's existing natural gas and low emitting electricity system and existing infrastructure combine effectively to serve different roles and together can be optimized for a reliable, affordable, low emissions solution. Natural gas infrastructure can continue to be leveraged for large peak loads on very cold days (when the efficiency of electric heating options drop), and in power generation to continue providing peak capacity. This integration enables lower cost use of intermittent renewables, drastically lowers the electric infrastructure requirements and costs compared to a scenario where gas is completely eliminated, and still achieves 90% of the GHG emission reductions seen in the significantly more costly electric-only scenario.

- **Local and regional context matters.** The costs and benefits of electrification vary considerably by province, and even by region within a province, making one-size fits all solutions ineffective and more expensive. Key regional factors must be considered when assessing whether or not electrification opportunities are 'beneficial' and ensure a reliable, affordable, and lower emitting energy system. These factors include local weather and climate, energy prices, local differences in the housing stock, the age and capacity of the existing electric generation, transmission, and distribution infrastructure, the GHG intensity of the electric grid, and the resource potential for non-emitting generation capacity.

Table 1: *Condensed Summary of Overall Impacts of Electrification*

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Scope of Electrification	Conversion of all residential and commercial space and water heating from natural gas and fossil fuels to electric heat pumps by 2050, all passenger vehicle sales to electric vehicles by 2040, and significant levels (50%) of electrification in the industrial sector.			Hybrid gas-electric heat pumps, only 25% industrial, and 10-15% RNG
Power Generation Impacts	252 GW of incremental capacity at cost of \$851 billion	232 GW of incremental capacity at cost of \$829 billion	169 GW of incremental capacity at cost of \$597 billion	108 GW of incremental capacity at cost of \$325 billion
Total Cost of Policy-Driven Electrification	Total energy costs increase by \$1.37 trillion	Total energy costs increase by \$1.33 trillion	Total energy costs increase by \$990 billion	Total energy costs increase by \$580 billion
GHG Emission Impacts	Annual CO_2 emissions reduced by 52% by 2050	Annual CO_2 emissions reduced by 47% by 2050	Annual CO_2 emissions reduced by 25% by 2050	Annual CO_2 emissions reduced by 47% by 2050
Cost of Emissions Reductions	\$289 per tonne of CO_2 reduction	\$291 per tonne of CO_2 reduction	\$411 per tonne of CO_2 reduction	\$129 per tonne of CO_2 reduction

[2]The Regulatory Assistance Project, Beneficial Electrification: Ensuring Electrification in the Public Interest, https://www.raponline.org/knowledge-center/beneficial-electrification-ensuring-electrification-public-interest/

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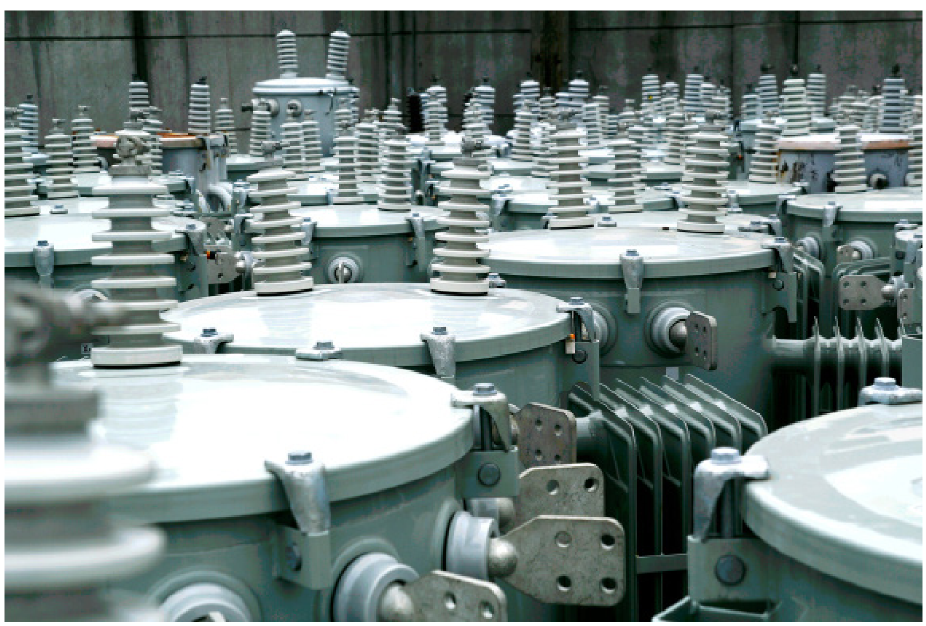
1 INTRODUCTION

Mitigation of greenhouse gas (GHG) emissions is a central tenet of most of the changes in Canadian energy policy currently under consideration. Much of this conversation has focused on the potential to transition away from natural gas and refined petroleum product use to just electricity. However the overall costs, benefits, and implications of potential policies for widespread electrification in Canada have not been comprehensively evaluated. The Canadian Gas Association (CGA) defined several policy-driven electrification scenarios and engaged ICF to assess and illustrate the costs and benefits, using optimistic assumptions for electric technology performance improvements. The study addresses three fundamental questions:

- What will be the impacts of policy-driven electrification on power sector infrastructure requirements?
- What will be the overall cost of policy-driven electrification?
- What would be the GHG emission impacts of policy-driven electrification?

This study's scenarios explore different combinations of technology options for customers on the demand side and different requirements for electricity generation on the supply side to achieve an overall reduction in GHG emissions. All of the scenarios are based on optimistic 'cost-conservative' assumptions regarding technology costs and performance for renewable power, power storage, electric heat pumps, and other electrification technologies considered.

This study does not attempt to predict what is most likely to happen by 2050, nor determine the lowest cost pathway to meet a specific GHG reduction target. Instead, the study compares several boundary scenarios to contrast the impacts resulting from a number of different technology pathways.



2 OVERVIEW OF THE CANADIAN ENERGY LANDSCAPE

In order to understand the impacts of an electrification policy for Canada, it is critical to understand what fuels Canada currently uses to meet its energy requirements. **Figure 1** below highlights the breakdown in 2018 end use energy consumption, based on the most recent Canadian Energy Regulator 2018 Energy Futures report. Electricity currently provides 19% of the country's energy needs – significantly less than natural gas (39%) and refined petroleum products, mainly gasoline & diesel (35%). This highlights the scale of transformation that widespread electrification of fossil fuels would require.

***Figure 1:** Breakdown of 2018 End Use Energy Consumption in Canada*[3]

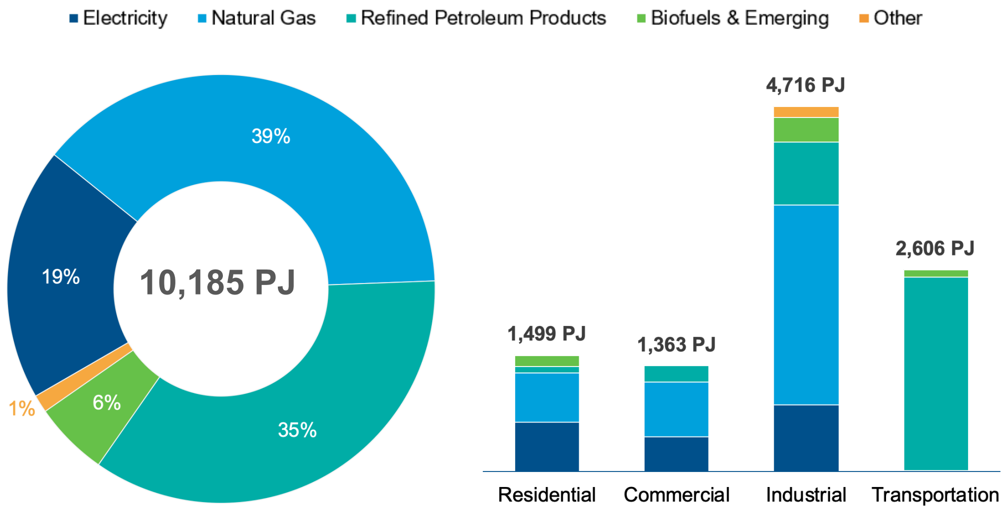


Figure 1 above also highlights the relative consumption of different fuel types in the major sectors of the Canadian economy, showing natural gas is the main source of energy in all sectors except transportation.

- **Residential:** Space heating represents most of the natural gas and refined petroleum products (RPPs) use in the residential sector, with about 7 million households[4] (~50%) in Canada using natural gas as their primary source of heat. Water heating and other uses like cooking also contribute to natural gas load.
- **Commercial:** Space heating represents the largest use of natural gas and RPPs in the commercial sector as well, followed by water heating and cooking.
- **Industrial:** Manufacturing and industrial processes are often energy intensive, with this sector using almost as much energy as the other three combined. 75% of industrial energy comes from fossil fuels, making this a critical area for GHG emission reductions.
- **Transportation:** Cars, trucks, trains, planes, and other forms of transportation represent the second largest energy consuming sector – and since 96% of this energy is derived from fossil fuels the transportation sector represents a major portion of Canada's GHG emissions.

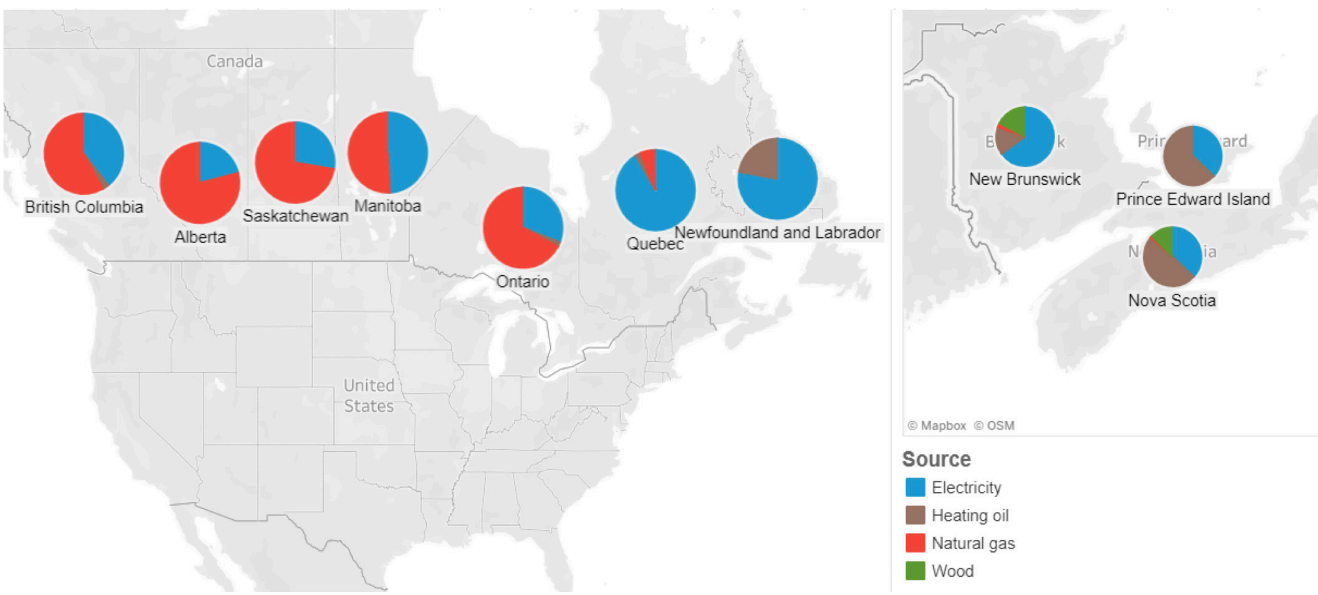
[3]Canada Energy Regulator (CER), "Canada's Energy Future 2018: Energy Supply and Demand Projections to 2040", https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2018/index-eng.html - with 300PJ/year and 1,150 PJ/year of natural gas and RPPs, respectively, removed from the total to account for non-energy consumption of these fuels that is included in CER numbers.

[4]Natural Resources Canada (NRCan), "Comprehensive Energy Use Database – Residential Sector, Table 20", http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=ca&rn=20&page=0#footnotes

Energy use and energy sources also vary significantly by province. Provincial electricity and natural gas distribution grids each face very different circumstances. As such, though not reported here, a full analysis of potential electrification opportunities and impacts would need to be conducted at a provincial level to properly reflect these major differences – including differences in existing infrastructure levels, existing electricity and fossil fuel requirements, efficiency of buildings, energy prices, the GHG intensity of the province's electric grid, and the province's specific seasonal temperature levels.

Figure 2 highlights one such important difference by province, namely the type of fuel used for space heating in the residential sector. While natural gas is the primary source of space heating for homes in British Columbia, Alberta, Saskatchewan, and Ontario – in Quebec and New Brunswick the majority of households use electricity while fuel oil heating is the primary choice in Nova Scotia. These space heating differences have major impacts on the cost and opportunity for electrification in those provinces.

Figure 2: *Comparison of Primary Energy Source used for Residential Heating by Province*[5]



3 ELECTRIFICATION SCENARIOS IN THIS STUDY

Table 2 provides an overview of the four different 'electrification' scenarios compared to the 'business as usual" reference case. The scenarios all include a high level of electrification – converting all natural gas and fossil fuel residential and commercial space and water heating to electric heat pumps or hybrid heat pump gas furnaces by 2050, all passenger vehicle sales to electric vehicles (EVs) by 2040, and significant levels of electrification in the industrial sector.

[5]Canada Energy Regulator (CER), "What is in a Canadian residential natural gas bill?", Figure 1: Energy source used for heating – primary heating system by Province, available at: https://www.cer-rec.gc.ca/nrg/sttstc/ntrlgs/rprt/cndnrsdntlntrlgsbll/index-eng.html (the reproduction of this figure has not been produced in affiliation with, or with the endorsement of the CER)

Scenarios 1-3 involve the same level of electric load growth – but showcase the impact of three different policy scenarios for how the electricity generation requirements would be met.

Scenario 4 differs in that natural gas is maintained as a back-up fuel for heat pumps on cold days (thus limiting peak electric load growth), industrial electrification is more limited, natural gas vehicles supplement EVs, and renewable natural gas (RNG) is brought in to lower GHG emissions from natural gas use. By design **scenario 4** power generation emissions were capped to provide the same overall emissions reduction as **scenario 2.**

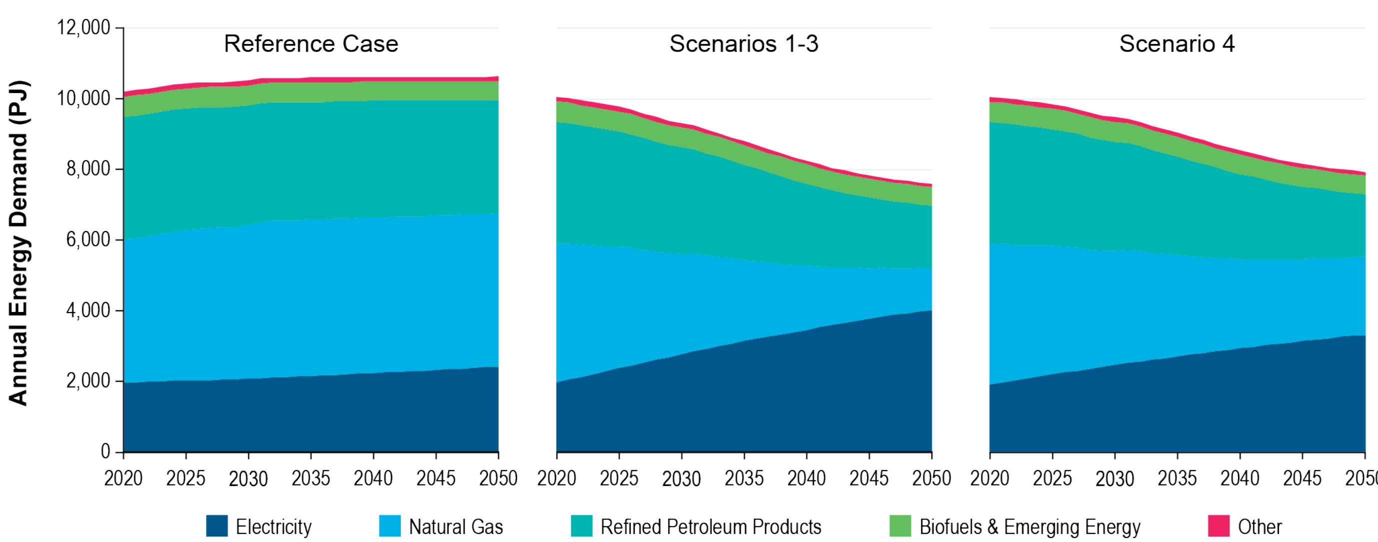
Table 2: *Scenario Descriptions*

Scenario 1 Renewables-Only	Scenario 2 Renewables & Existing Gas	Scenario 3 Market-Based Generation	Scenario 4 Integrated Energy Systems
Aggressive electrification & wind, solar, and battery storage replace all fossil fuel generation by 2050	Aggressive electrification & all new power generation capacity is wind, solar, and battery storage, but existing natural gas & oil power generation maintained	Aggressive electrification & all power generation expansion uses the most economic options	Alternative electrification approaches allowing fossil fuels to meet peak loads while driving GHG emission reductions

More details on each of the scenarios can be found in **Appendix A** and **Appendix C**. While the impacts of electrification were analyzed at a provincial level, the results are presented as an aggregate of the provinces covered in this study.[6]

Figure 3 illustrates the transition in Canada's energy consumption under each scenario. Whereas the reference case has modest growth in energy consumption to 2050, **scenarios 1-3 and 4** present a broad-based shift to the use of renewable electricity and electricity storage and an overall reduction in energy consumption. While electricity (dark blue) currently provides around 20% of energy requirements, widespread electrification nearly doubles the electricity needed in **scenarios 1-3** by 2050, even allowing for significant improvements in energy efficiency of electricity end uses.

Figure 3: *Change in Annual Energy Demand from 2020 to 2050*



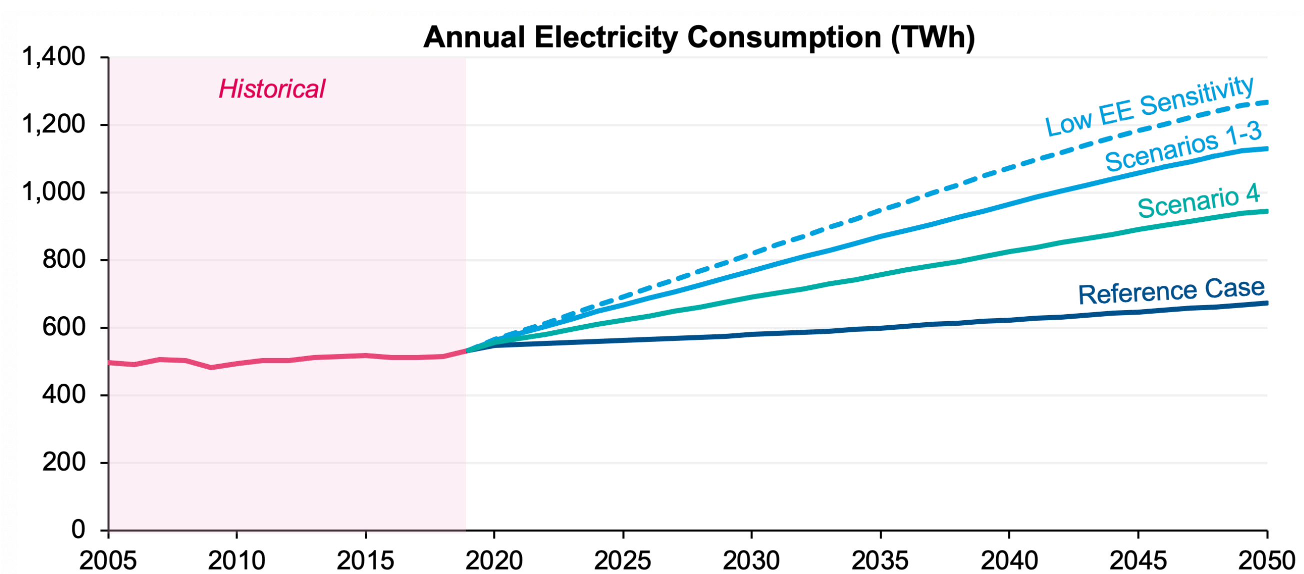
[6]Newfoundland and Labrador, Prince Edward Island, and the territories are not included in the results of this study – as natural gas distribution infrastructure is not present in these provinces.

4 GROWTH IN ANNUAL ELECTRICITY CONSUMPTION

Figure 4 illustrates historical levels of total electricity consumption as well as the growth in annual electricity consumption in each of the study's scenarios:

- Historically, from 2005 to 2018, annual electricity consumption was relatively stable.
- In the **reference case** annual electricity consumption increases at a modest pace, rising from 532 TWh in 2019 to 672 TWh in 2050.
- In **scenarios 1-3** annual electricity consumption rises to 1,130 TWh in 2050 – doubling from 2020, based on electrification in the residential, commercial, industrial, and transportation sectors.
- In **scenario 4** annual electricity consumption rises to 944 TWh in 2050, which is roughly 70% of the load growth seen in **scenarios 1-3**. This is because **scenario 4** assumes that Canadians install air-source heat pumps with natural gas (or other fossil fuels) as a back-up, and on average rely on this back-up fuel for 20% of heating needs. This reduction also reflects lower levels of industrial electrification in this scenario.
- In **scenarios 1-3** the growth in electricity consumption is held down by aggressive assumptions for the improvement in heat pump efficiency, rapid improvements in building shell efficiency, and the upgrade of inefficient electric resistance heating to heat pumps. The dashed blue **Low Energy Efficiency (EE) Sensitivity** line shows the change to **scenario 1-3** impacts without these 'electrification enabling' assumptions. Under these conditions annual electricity consumption rises to 1,266 TWh in 2050, or 12% higher.

Figure 4: Overall Annual Electricity Consumption



5
THE IMPORTANCE OF PEAK ELECTRIC LOAD

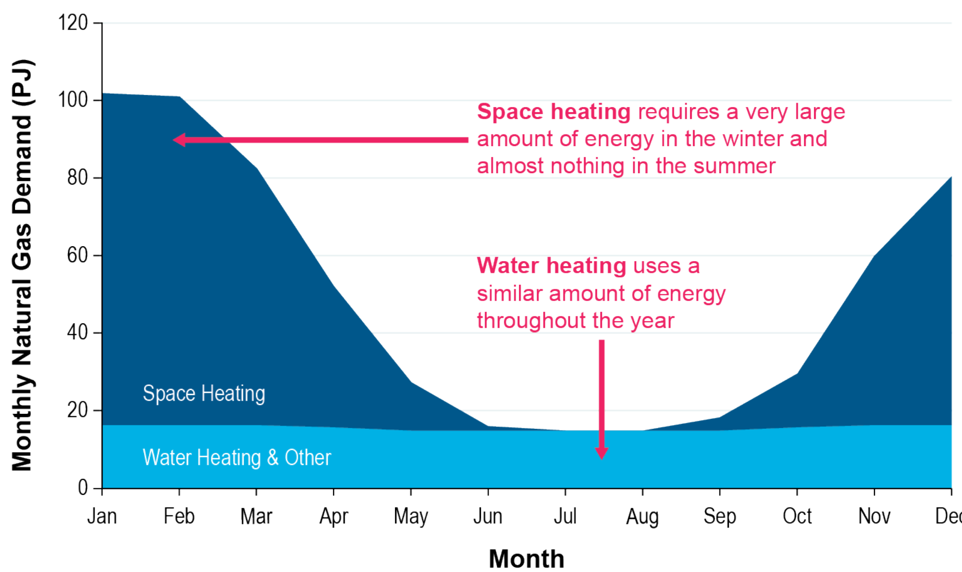
The challenge with electrification is meeting peak load, not just annual energy requirements, because it's peak load that drives infrastructure requirements and costs. In critical energy infrastructure systems, including our electricity and natural gas distribution systems, infrastructure costs are driven by the need to meet peak demand and ensure reliability in extreme conditions – for example, when temperatures drop to -40°C. Even though much of the required infrastructure might only be needed for a very short time, it needs to be in place to ensure system reliability and, in turn, consumer heating safety.

Electrification policy needs to be designed with consideration of the specific nature of the demand met by each of the fuels it seeks to replace, and with consideration of the need for a reliable, sustainable, and affordable system, or the result could be an ineffective electrical system unable to meet critical peak demands. Electrification initiatives need to be selective to avoid negatively impacting grid reliability.

Figure 5 highlights how some energy requirements, like space heating, are weather-driven and hence very concentrated in the few coldest months of the year. Electrifying these loads has a disproportionally large impact on peak electric load, relative to its annual consumption, because a tremendous amount of energy is required to meet space heating requirements when it is very cold. This addition of peak load to the grid makes it challenging for space heating electrification to meet the beneficial criteria.

In addition to the seasonal variation of the energy requirements, another important consideration is how 'manageable' the energy load is. If a utility can add new load without creating a new peak, or can 'shift load' to fill in the valleys between existing high demand periods, then it can better utilize its existing infrastructure and meet the incremental load without requiring major investments in new infrastructure. The ability for a utility to control the timing of load, for example ensuring electric vehicles charge at night when other electricity demands are low, could minimize increases to peak load without impacting system reliability.

***Figure 5:** Comparison of Monthly Natural Gas Consumption Patterns*



WHAT ARE HEAT PUMPS?

An air-source heat pump (ASHP) looks like an air-conditioning unit sitting in your backyard - but can both heat and cool your home.

ASHP efficiency varies based on the temperature outside – since the unit is extracting heat from that air.

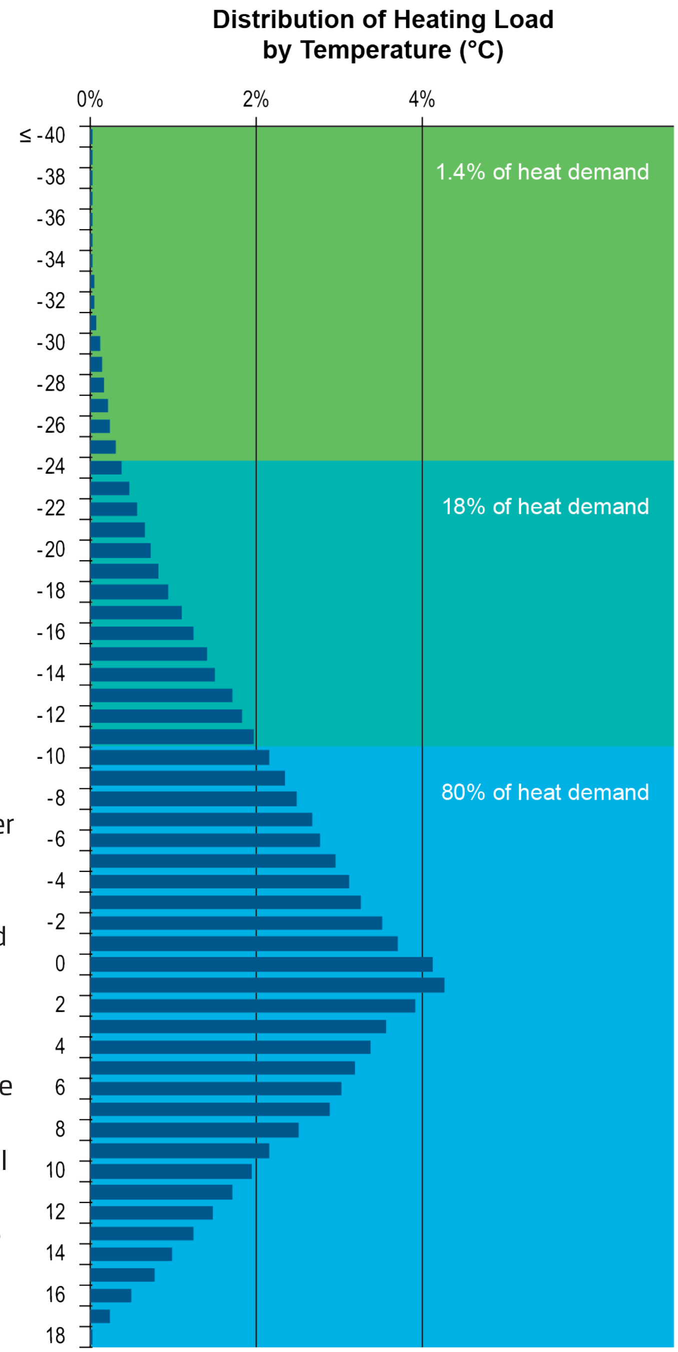
ASHPs can be very efficient (300%-500%) in mild temperatures but rely on less efficient (100%) electric-resistance back-up when it gets very cold outside and the ASHP cannot pull in enough heat from that cold air.

Cold-climate ASHPs are designed to operate more efficiently at lower temperatures but will still rely on back-up heating below certain temperatures.

While demand response efforts that would enable load to be shifted to "off-peak" periods are being considered by both the power and natural gas industries, to date, there have been only limited options for reducing space heating load on peak days. The inherent 'peakiness' of space heating energy requirements make it more challenging to electrify without the need for additional infrastructure. After widespread electrification, there would be much larger spikes in load that would occur when temperatures hit extreme cold – a situation that natural gas distribution and storage infrastructure currently handles in many provinces. The magnitude of such peaks is highlighted by the distribution of heating load by temperature presented in **Figure 6.** This figure shows that while energy infrastructure is required to plan for temperatures as cold as -40°C in some provinces, infrastructure built for such situations will infrequently be required. Overall in Canada, temperatures below -25°C represent just 1.4% of the heat demand, while temperatures below -10°C represent around 20% of the heat demand.

While these percentages vary significantly by province, this forms part of the logic for using hybrid gas-electric heat pumps, that use natural gas for the coldest 20% of the heat demand allowing peak electric infrastructure to be designed to accommodate temperatures of just -10°C and not -40°C.

***Figure 6**: Distribution of Heating Load by Temperature (°C)*

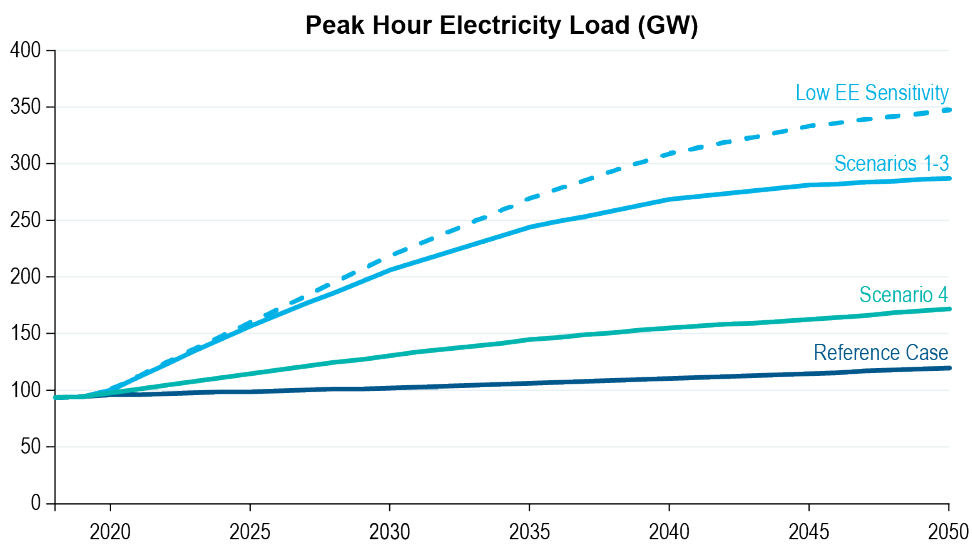


6
GROWTH IN PEAK ELECTRIC LOAD

Figure 7 shows the growth in peak electric load in each of the study's scenarios:

- In **scenarios 1-3** the total peak electricity load from the residential, commercial, industrial, and transportation sectors rises to 287 GW in 2050 – tripling from 91 GW in 2020. That growth occurs despite assuming that Canadian households and businesses install the most-efficient cold-climate air-source heat pumps available to them, whose efficiencies are assumed to improve rapidly over the study period through significant R&D developments[7], and the assumption of significant improvements to energy efficiency in the building stock.
- In **scenario 4** the incremental peak load growth is 56 GW, or roughly a third of the other scenarios. This is because this scenario assumes that Canadians install conventional air-source heat pumps but maintain natural gas (or other fossil fuels) as a back-up – allowing for electric heating most of the year, but relying on natural gas distribution infrastructure to continue dealing with spikes in heating requirements on cold days. This reduction also reflects lower levels of industrial electrification in this scenario.
- In **scenarios 1-3** the growth in electricity capacity requirements is held down by aggressive assumptions for the improvement in heat pump efficiency and rapid improvements in building shell efficiency. The dashed blue **Low Energy Efficiency (EE) Sensitivity** line shows the change to **scenario 1-3** impacts if energy efficiency was reduced and heat pump technology did not improve from the current performance levels of the top cold-climate air-source heat pumps. Under these conditions the peak electricity needs rise to 345 GW in 2050.

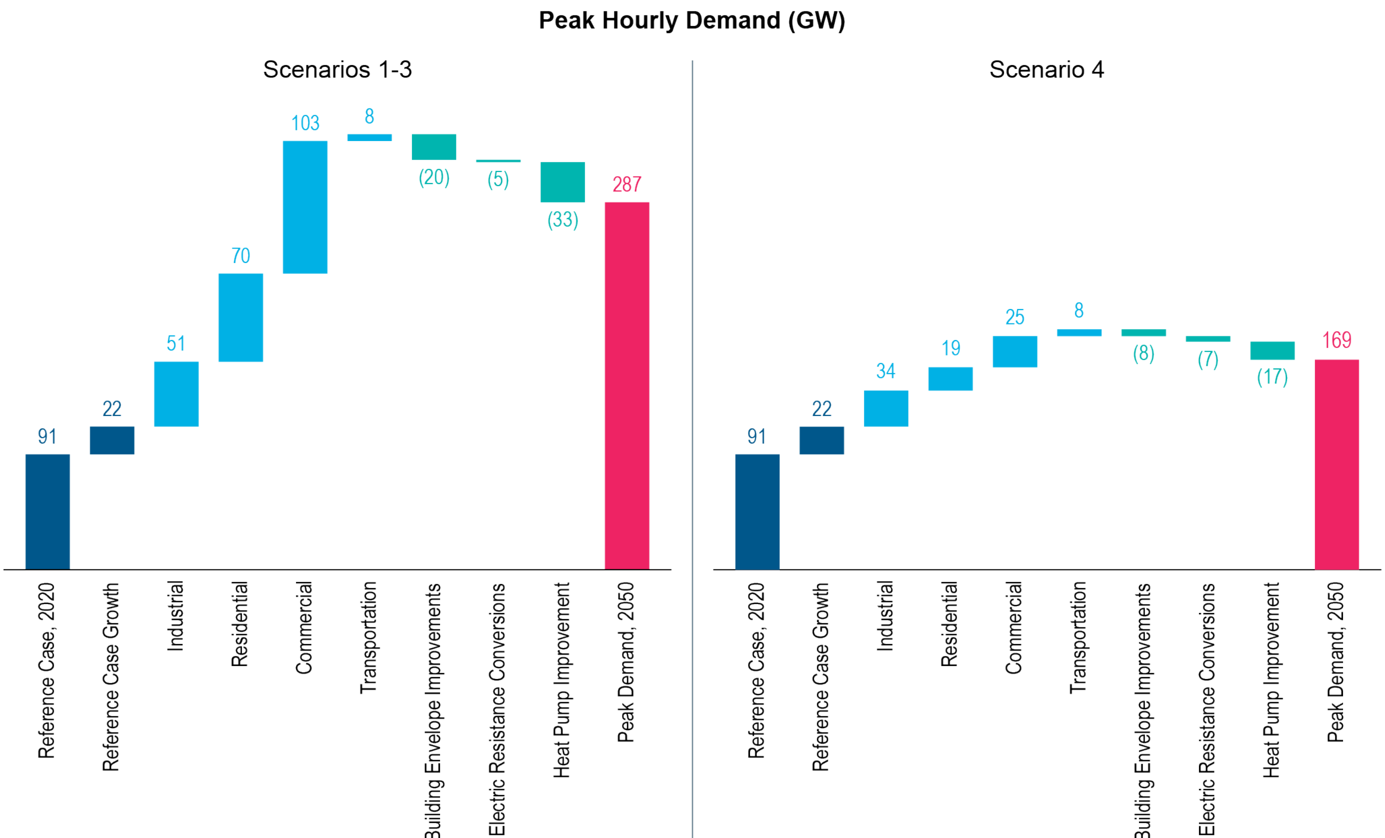
Figure 7: Overall Peak Hour Electricity Load



[7] For scenarios 1 through 3 in this study, cold-climate air-source heat pumps with major improvements in efficiency over time, were modeled to replace fossil fuel furnaces, as well as 75% of existing heat pumps and electric resistance heaters. The heat pump efficiency improvements made to 2050 are consistent with the 'rapid advancement' trajectory from NREL's 2017 Electrification Futures Study (https://www.nrel.gov/docs/fy18osti/70485.pdf).

The specific components of these peak load impacts are highlighted in **Figure 8** which compares the electricity requirements on the 2050 peak day in each scenario. Building on top of the reference case growth in electric demand (dark blue), the peak contributions of industrial, residential, commercial, and transportation electrification are stacked (light blue). The teal categories show the reductions in peak day requirements due to energy efficiency and technology improvements assumed to reduce the overall peak demand growth requirements in these scenarios.

***Figure 8:** Components of Incremental Peak Electricity Load*



Scenarios 1-3 on the left rely on **all electric heating, based primarily on highly efficient cold climate heat pumps**. Despite the significant improvement in heat pump performance assumed in this study (a near doubling of average seasonal efficiency by 2050), an all-electric space heating scenario would result in significantly higher peak loads for the residential and commercial sectors on the coldest days of the year, when even high-efficiency air-source heat pumps operate less efficiently.

The light blue bars represent 20 GW, 5 GW, and 33 GW of peak demand savings that result from the assumed improvements in building envelopes (i.e., reduced heating loads), the conversion of 75% of homes heated with electric resistance to heat pumps, and the assumed improvement in heat pump performance, respectively. These savings are concentrated in warmer provinces, as the peak day temperatures in colder provinces continue to force dependence on back-up resistance heating in 2050, despite the rapid technology improvement.

Scenario 4 on the right includes **heat pumps with natural gas backup heating**. On the coldest days of the year, when heat pumps operate less efficiently, all of the heating load will be met by natural gas (or other fossil fuels).

In provinces with high portions of existing electric space heating (Quebec and New Brunswick) the coldest day of the year remains the peak day, and the new heat pumps do not add to electric peak demand.

In the other provinces, the broad adoption of heat pumps that are assumed to operate until the temperature drops below -10°C, results in the peak electric day becoming that -10°C day, instead of the coldest day of the year. Benefits of this approach include increased heat pump efficiency at this more moderate peak temperature (reduced peak load) and better utilization of the capacity, since there will be numerous winter days around the -10°C level, as opposed to very few -40°C days.

7
POWER GENERATION REQUIRED FOR NEW LOADS

In **scenarios 1-3**, where electricity is the only heating fuel customers use, meeting peak period demand will require significant investments in new generation, transmission, and distribution infrastructure to serve the additional space heating load. Due to the nature of the demand this infrastructure would be essential for reliability purposes but would be called on to deliver energy only on a rare basis, driving up the cost of energy considerably.

Figure 9 shows the expansion of generating capacity required in each scenario to meet new peak load – growing from 141 GW of generating capacity to between 278 GW and 422 GW over the thirty year period. For comparison, the Site C hydro-electric dam in British Columbia is rated at 1.1 GW, hence this level of growth in peak load would require the equivalent of between 125 and 255 additional Site C projects, as well as the additional transmission and distribution system expansions needed to deliver the power to end-users.

In addition to the peak load levels, the amount of new capacity shown here depends on the types of power generation deployed to meet demand in the scenario. In **scenario 1**, which requires all fossil fuel to be retired by 2050, more capacity is required to ensure reliability – since the intermittent nature of renewable wind and solar generation limits their capacity and availability without significant investment in battery storage and system control. **Scenario 3** requires less capacity – because, in this scenario, natural gas generation can be relied upon during peak periods – but will produce more GHG emissions. **Scenario 4** requires less capacity growth because the peak load served here has been greatly reduced by allowing for natural gas/fossil fuels to remain as back-up in customer space heating, and natural gas fired generation is available to meet peak load reliability requirements – but this scenario also relies on significant amounts of renewable capacity to ensure the scenario achieves significant GHG reductions.

***Figure 9:** Growth in Total Electric Power Generation Capacity*

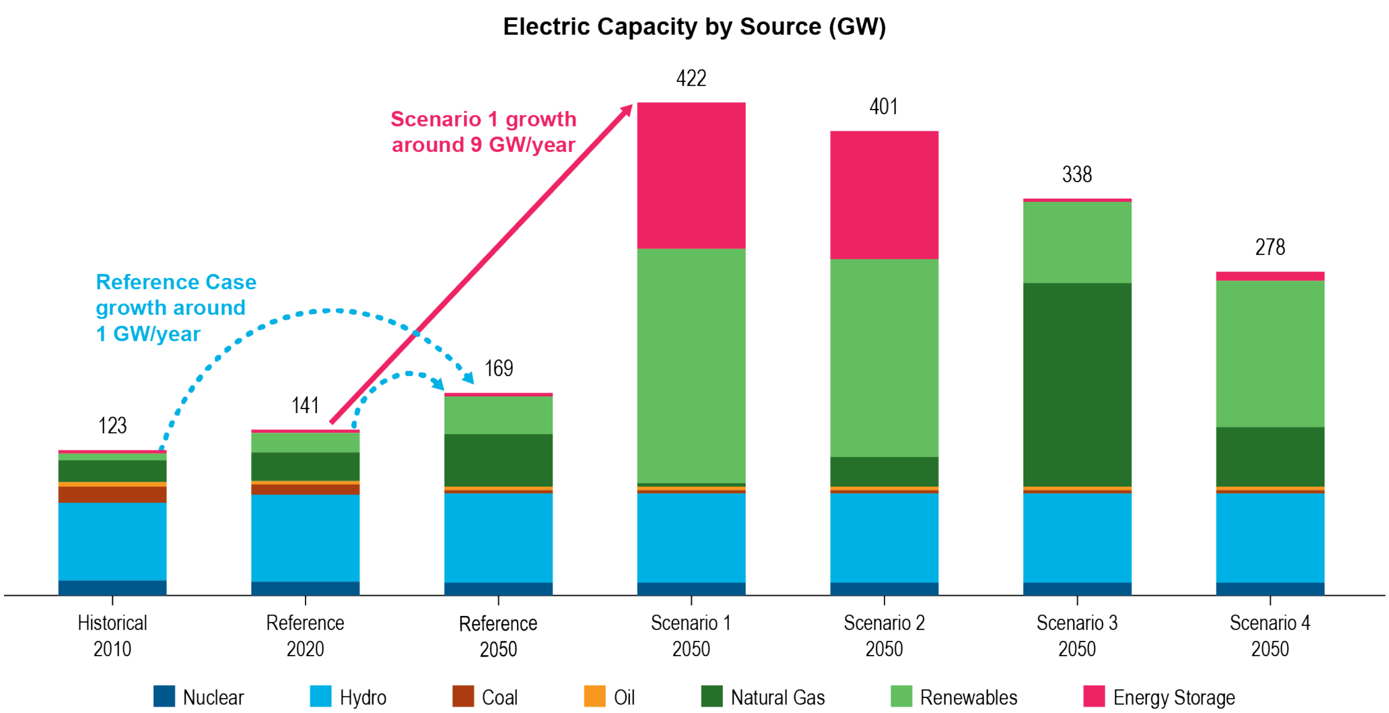


Figure 10 provides more detail on the expansion of generation capacity out to 2050 required in each scenario. In all scenarios, there are 10 GW of retirements for coal and oil units, and a net 1.4 GW of retirements for nuclear between 2020 and 2050.[8] Beyond these common changes, the additions and retirements of natural gas generation, renewables, and battery storage differ between the reference case and each of the scenarios.

***Figure 10:** Changes in Generation Capacity from 2020 to 2050 by Resource Type*

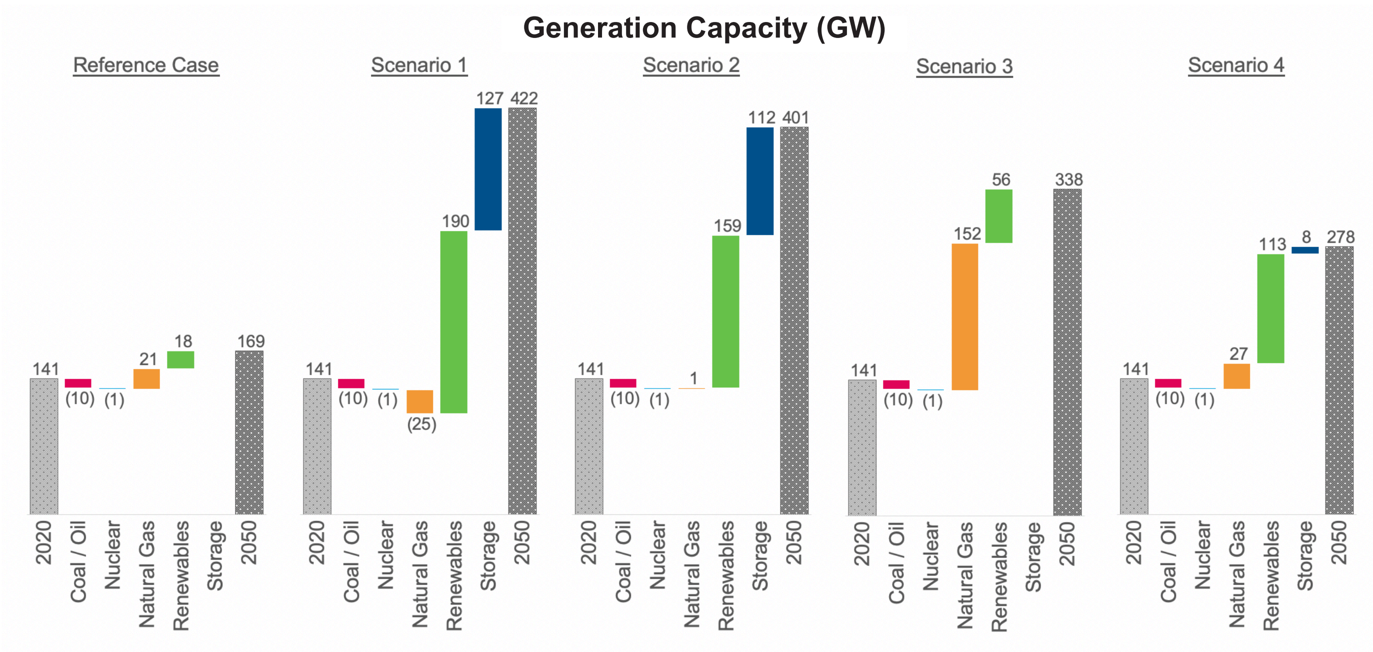
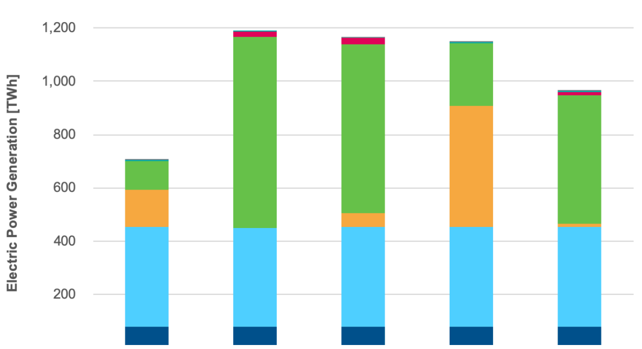


Figure 11 shows the changes in annual electricity generation for 2050 between the scenarios – indicating how the generation capacity shown above is used. All scenarios use essentially the same amount of baseload nuclear and hydro. The primary difference between how scenarios generate the required energy demand comes down to how much they use renewable (wind and solar) versus natural gas generation. It is noteworthy that **scenario 4** builds significant amounts of natural gas generation capacity, but uses this capacity infrequently in order to stay under an emissions cap. Most of this scenario's natural gas is built to be used only during peak periods, minimizing the need for battery capacity to complement intermittent renewables.

***Figure 11:** Total Electric Power Generation (TWh) in 2050 by Resource Type*



-	Reference Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Coal	1	-	1	1	1
Other	3	3	3	3	3
Storage	0	22	23	-	10
Renewables	107	715	633	235	484
Natural Gas	140	-	52	454	12
Hydro	375	374	375	375	375
Nuclear	77	77	78	78	78

[8]The modeled 2020 capacity is lower than the total installed capacity, as it excludes about 1.5 GW of nuclear units that are undergoing planned refurbishment. From a total capacity perspective (operating and under refurbishment), about 3 GW of nuclear units are retired between 2020 and 2050.

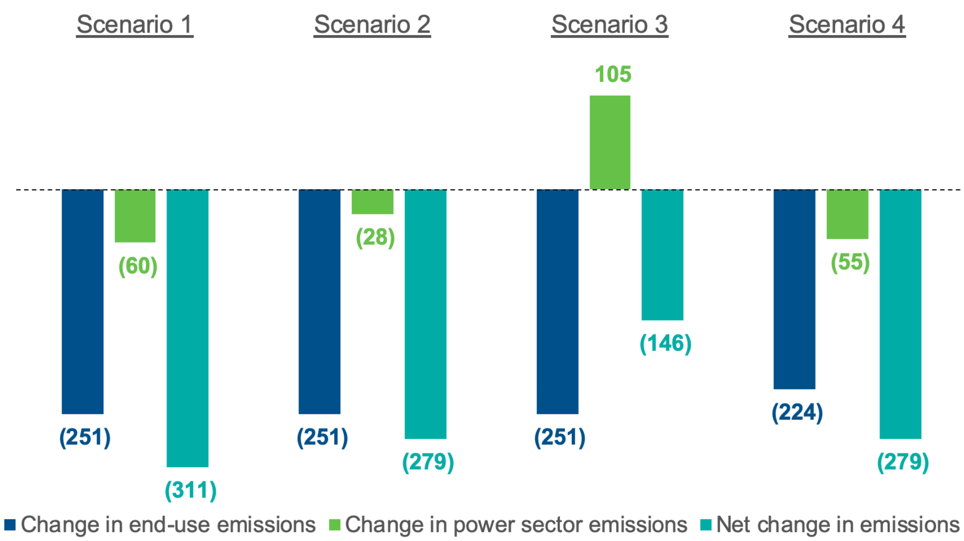
8
GHG EMISSION IMPACTS

Figure 12 illustrates the 2050 emissions associated with each scenario, relative to the reference case. The figure shows the annual emissions impact of:

1. The change in end-use (residential, commercial, industrial, transportation) CO_2 emissions[9],
2. The change in power sector CO_2 emissions, and
3. The net change in emissions.

All the scenarios see major reductions in end-use emissions through widespread electrification. **Scenario 1** (all renewables) achieves the greatest overall emissions reduction, with power sector emissions decreasing to zero. **Scenario 3** (market-based) achieves the smallest emissions reduction, as there are no limits on natural gas generation and this option is selected as the least-cost approach to meet much of the increased electrical demand. By design, **scenario 2** and **scenario 4** achieve the same net emission reductions, with **scenario 4's** power sector emissions capped to achieve the same level.[10]

Figure 12: 2050 Scenario Emissions Relative to the Reference Case (million metric tonnes of CO_2 / year)



9
TOTAL COSTS FOR ELECTRIFICATION SCENARIOS

The cost of this expansion of the power sector, as well as other aspects of the policy scenarios, are illustrated in **Figure 13**. The cumulative cost impacts from 2020 to 2050 in these scenarios range from $580 billion to $1.37 trillion, and are incremental to any energy cost increases resulting from the reference case growth. The cost categories included in the analysis are explained below, with more details available in **Appendix D**.

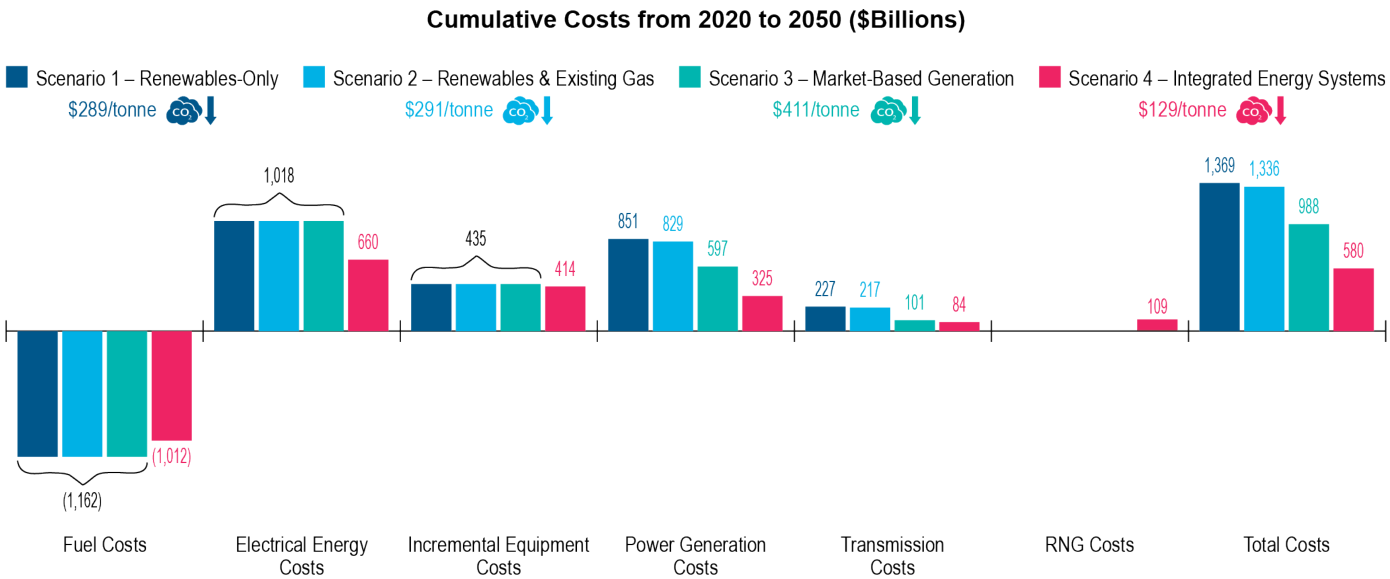
- Avoided **fuel costs** represents the monies not spent by energy consumers on the natural gas and refined petroleum products they are no longer assumed to be using. The energy prices used are those set out in the reference case forecast – the savings shown here include the avoided expenditures from passenger vehicles not needing gasoline or diesel, and fuel oil and natural gas replaced for space heating, water heating, and industrial processes.

[9] End-use emissions do not include any GHGs from electricity consumption, as the CO_2 emissions from electricity production are captured within the power sector emissions.

[10] Before accounting for CO_2 emissions from electricity generation, scenario 4 resulted in 27 million metric tonnes of CO_2 emissions more than scenario 2, from demand-side changes to energy consumption. To match scenario 2's overall emissions, scenario 4 power generation emissions were thus capped at a level 27 million metric tonnes of CO_2 below scenario 2 power generation emissions.

- Incremental **electrical energy costs** represent the increase in costs to energy consumers based on the increase in electricity consumption and based on the energy price levels set out in the reference case forecast. The cost increases shown here are the aggregate for residential, commercial, industrial, and transportation customers.
- Incremental **equipment upgrade costs** represent the additional upfront investment residential, commercial, transportation, and industrial end-users would need to make to purchase and install electric equipment and invest in energy efficiency, as compared to purchasing the traditional fossil fuel option.
- Incremental **power generation costs** (additional to the electrical energy costs) represent over half the overall cost impact in each scenario, and include the capital, fuel, operating, and maintenance costs necessary to deploy the additional electricity generation capacity and any required battery storage.
- Incremental **transmission costs** represent the wires required to connect electricity from new generating capacity to the customers that need this power, and are estimated as a ratio to incremental generation capital costs.
- **Renewable natural gas costs** represent the assumed incremental cost to supply the gas distribution system with RNG in **scenario 4**.
- **Total costs** represent the combined incremental energy cost changes that the Canadian economy will need to cover between 2020 and 2050, above and beyond 'business as usual' reference case energy costs.

Figure 13: *Cumulative Incremental Costs from 2020 to 2050*



The costs shown here are incremental to the reference case, so these would be in addition to any energy cost increases expected under 'business as usual'. The study also does not include the unique distribution system level investment required to enhance infrastructure to deliver incremental power load.

Even with optimistic 'cost-conservative' assumptions in terms of energy efficiency and electric technology improvement, the costs in these aggressive electrification scenarios are substantial. The integrated energy approach, using both natural gas and electricity, represents a significantly lower cost pathway. This emphasizes the need to be selective about which electrification opportunities are pursued and consider a broad range of technology options in pursuit of GHG emission reductions.

10 SUMMARY & CONCLUSIONS

The overall impacts of the policy-driven scenarios across the provinces considered in this study are highlighted in **Table 3**, which presents cumulative total impacts between 2020 and 2050, except where otherwise specified.

Table 3: *Summary of Overall Impacts of Electrification*

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Power Sector Impacts	252 GW of incremental generation capacity required at a cost of \$851 billion \$227 billion of associated transmission system upgrades	232 GW of incremental generation capacity required at a cost of \$829 billion \$217 billion of associated transmission system upgrades	169 GW of incremental generation capacity required at a cost of \$597 billion \$101 billion of associated transmission system upgrades	108 GW of incremental generation capacity required at a cost of \$325 billion \$84 billion of associated transmission system pgrades
Equipment and Energy Costs	16 million households, 23 million passenger vehicles, 25% of medium & heavy duty vehicles, 11 billion square feet of commercial space, and 50% of industrial fossil energy are converted to electric equipment \$291 billion in net energy & equipment costs over the 30-year period			Similar scope, with different equipment, only 25% industrial, and 10-15% RNG \$170 billion in net energy, equipment, and RNG costs
Total Cost of Policy-Driven Electrification	Total energy costs increase by \$1.37 trillion \$95,000 average per Canadian household[11] \$3,200 per year per Canadian household increase in energy costs	Total energy costs increase by \$1.33 trillion \$93,000 average per Canadian household[11] \$3,100 per year per Canadian household increase in energy costs	Total energy costs increase by \$988 billion \$69,000 average per Canadian household[11] \$2,300 per year per Canadian household increase in energy costs	Total energy costs increase by \$580 billion \$40,000 average per Canadian household[11] \$1,300 per year per Canadian household increase in energy costs
GHG Emission Impacts	Annual GHG emissions reduced by 311 million tonnes of CO_2 by 2050 compared to 2050 reference (52 percent)	Annual GHG emissions reduced by 279 million tonnes of CO_2 by 2050 compared to 2050 reference (47 percent)	Annual GHG emissions reduced by 146 million tonnes of CO_2 by 2050 compared to 2050 reference (25 percent)	Annual GHG emissions reduced by 279 million tonnes of CO_2 by 2050 compared to 2050 reference (47 percent)
Cost of Emissions Reductions	\$289 per tonne of CO_2 reduction (\$331 discounted[12])	\$291 per tonne of CO_2 reduction (\$334 discounted[12])	\$411 per tonne of CO_2 reduction (\$483 discounted[12])	\$129 per tonne of CO_2 reduction (\$164 discounted[12])

The analysis conducted for this study highlights both the role electrification can play in reducing GHG emissions and the need to be selective in its application to minimize impacts on peak demand. What is clear is that widespread electrification should not be considered as a stand-alone solution. Without significant levels of energy efficiency improvement embodied in the reference case, and the additional improvements assumed in the scenarios, peak load and the associated costs of electrification would be significantly higher. Without the use of natural gas to meet peak period space heating

[11]Cumulative costs from all sectors for 2020 to 2050 divided by 14.34 million total households (using all heating types) forecast for the provinces considered in this study in 2020.

[12] Discounted costs are Real 2019 \$, with both emissions and costs from the study period discounted to 2019 using a 5 percent discount rate.

requirements and to provide peaking capacity for the power generation grid, the costs of GHG emissions reductions increase dramatically.

In the results above, policies that rely on electrification and renewable power cost more than twice as much per tonne of carbon dioxide reduced ($289 / tCO_2) than the approach which allows for an integrated energy system to achieve GHG emission reductions ($129 / tCO_2). Canada's existing natural gas and electricity distribution infrastructure are good at serving different roles and together can be optimized for a lower cost solution. Allowing natural gas to continue being used for heating on very cold days (when the efficiency of electric options drop), and allowing some natural gas in the power generation sector to continue providing peak capacity, drastically lowers the electric infrastructure requirements and costs from the scenario where natural gas is completely eliminated – while still allowing for significant (90% of **scenario 1**) GHG emission reductions to be achieved.

These scenarios rely on wind and solar generation to achieve GHG emission reductions through electrification, even in **scenario 4** where natural gas continues to be built to meet peak capacity. There are questions about whether a grid can operate reliably running entirely on renewables and the scale of renewable capacity that could be feasibly deployed. While such concerns were not factored into this assessment, it stands that enabling renewables on the necessary scale for these scenarios will require improvements in battery storage, grid integration, smart appliances, and electric vehicle charging infrastructure.

In terms of system optimization, while it was not studied here, advanced control strategies for hybrid gas-electric heat pumps could allow even cheaper integration of renewables – a smart control system would be able to switch more hybrid heat pumps to electric-mode if renewables (e.g. wind turbines) are producing excess energy, or shift more heating load to natural gas if renewables are producing less than required on a given day, reducing the amount of battery storage required to accommodate intermittent renewables.

The widespread level of electrification studied here would not only require expansion of electric generation and transmission capacity, but also significant investments in local electricity distribution system upgrades, costs which are not assessed in this study. Such costs are very region-specific, but the transformation of widespread electrification considered here would likely require significant distribution infrastructure upgrades.

The costs and benefits of electrification vary considerably by province, and even by region within a province, making one-size fits all solutions ineffective and more expensive. Key regional factors that must be considered when assessing the potential costs and benefits of electrification and determining the investments in infrastructure needed to ensure a reliable, affordable, and lower emitting energy system include weather and climate, energy prices, differences in the housing stock, the amount and age of capacity in existing electric generation, transmission, and distribution infrastructure, the GHG intensity of the electric grid, and the resource potential for non-emitting generation capacity.

APPENDICES

Appendix A Scenario Details for Demand-Side Analysis

On the demand-side, this study included a detailed analysis of electrification in the residential and commercial sectors, alongside a simplified assessment of the industrial and transportation sectors. **Table 4** outlines the key assumptions used in each of the demand-side scenarios modeled in this study and is followed by a series of figures which highlight the scale of the transition assumed in the different sectors.

Table 4: Summary of Demand-Side Scenario Assumptions

<table>
<tr><th>Sector</th><th>Scenarios 1, 2, 3</th><th>Scenario 4</th></tr>
<tr><td rowspan="2">Residential & Commercial Electricity Demand</td><td>• All fossil fuel use is converted to electricity by 2050
• All new construction projects install electric equipment, starting in 2020
• Most provinces adopt CC-ASHPs, but BC uses ASHPs
• 75% of existing buildings heated with electric resistance are converted to CC-ASHPs by 2050</td><td>• All fossil fuel use for space heating is converted to hybrid systems by 2050 (ASHP with fossil fuel backup)
• All fossil fuel use for water heating is converted to electricity by 2050 (heat pump water heaters)
• Heating systems switch from an ASHP to the fossil fuel backup system when outdoor temperatures fall below -10°C. At a national level, this strategy reduces annual fossil fuel consumption is by ~80% while peak day requirements for gas remain unchanged.
• 75% of existing buildings heated with electric resistance are converted to ASHPs by 2050</td></tr>
<tr><td colspan="2">• All equipment conversions occur when existing fossil fuel equipment reaches the end of its useful life
• Energy efficiency improvements reduce average space and water heating loads (GJ/home or GJ/ft²) by 10% by 2050. This improvement is incremental to the 1.4% per year reduction in building energy use intensity assumed by the CER reference case.
• NREL's 'Rapid Advancement' curves are used to model the improvement of heat pumps over the study period (2020-2050)</td></tr>
<tr><td>Industrial Electricity Demand</td><td>• Partial electrification, with ~50% of fossil fuel energy consumption converted to electricity by 2050
• More specifically the following end uses are electrified:
    • 100% space heating
    • 100% steam boilers
    • 50% process heating
    • 0% non-energy use
    • 0% cogeneration
• Energy efficiency improvements are captured as part of the conversion to electric equipment</td><td>• Partial electrification, with ~25% of fossil fuel energy consumption converted to electricity by 2050
• More specifically the following end-uses are electrified:
    • 100% space heating
    • 50% steam boilers
    • 25% process heating
    • 0% non-energy use
    • 0% cogeneration
• Energy efficiency improvements are captured as part of the conversion to electric equipment, and a 10% energy efficiency improvement applied to fuel use that was electrified in scenarios 1-3 but not electrified in scenario 4</td></tr>
<tr><td rowspan="2">Transportation Electricity Demand</td><td colspan="2">• As per the Federal Government's target, light-duty EVs make up 10% of sales by 2025, 30% by 2030, and 100% by 2040
• Medium and heavy-duty vehicles: 25% electric by 2050
• Commuter trains and off-road vehicles: 25% electric by 2050</td></tr>
<tr><td></td><td>• An additional 25% of medium and heavy-duty vehicles, commuter trains, and off-road vehicles convert to CNG/LNG by 2050</td></tr>
<tr><td>Other Measures</td><td>• Nothing beyond CER Energy Futures 2018 Reference Case</td><td>• RNG is used to decarbonize natural gas supply. RNG as a percent of 2018 natural gas demand from the reference case:
    • QC 5% by 2025, 10% 2050
    • BC 15% by 2030, then flat
    • Other provinces all 5% by 2030, 10% by 2050</td></tr>
</table>

Figure 14 compares the types of residential heating systems used in the 'business as usual' reference case to the transition modeled in the electrification scenarios. The type of heat pumps used will vary between electrification scenarios, but the expanding light green band shows how heat pumps are assumed to replace natural gas and electric resistance heating on a massive scale – with around 15 million households converting to heat pumps by 2050 and close to complete elimination of natural gas and refined petroleum usage for residential heat.

Figure 14: Residential Sector Primary Heating Fuel Option

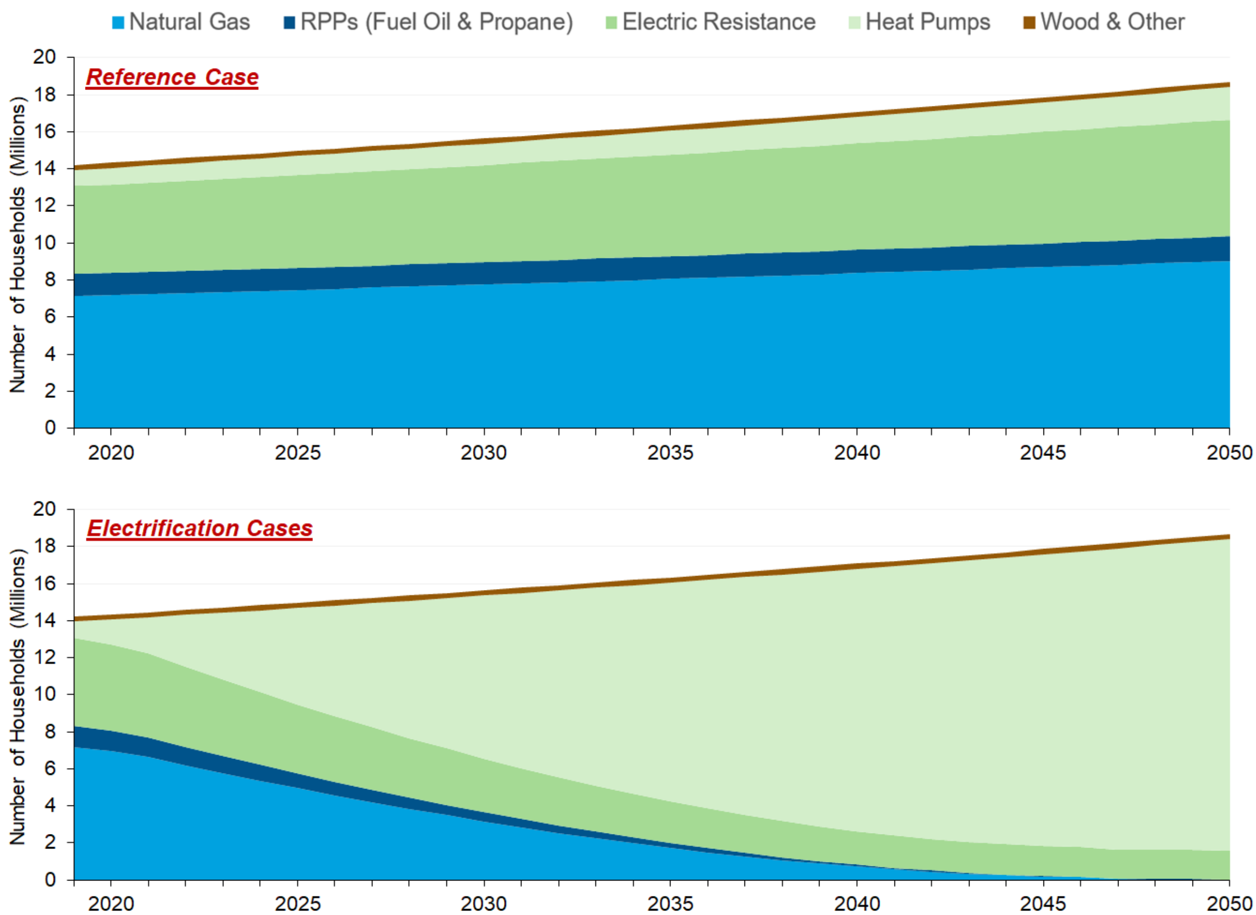


Figure 15 illustrates the result of a similar transition in the commercial sector, contrasting the breakdown in energy consumption in the 'business as usual' reference case to scenarios 1-3 (fully electric heating) and scenario 4 (hybrid gas-electric heating). These charts highlight the significant energy efficiency and technology improvements assumed in these scenarios, as growth in electric energy demand is significantly lower than the reduction in fuel consumption. For scenario 4, the natural gas segment also includes RNG volumes.

Figure 15: Commercial Sector Breakdown of Energy Consumption

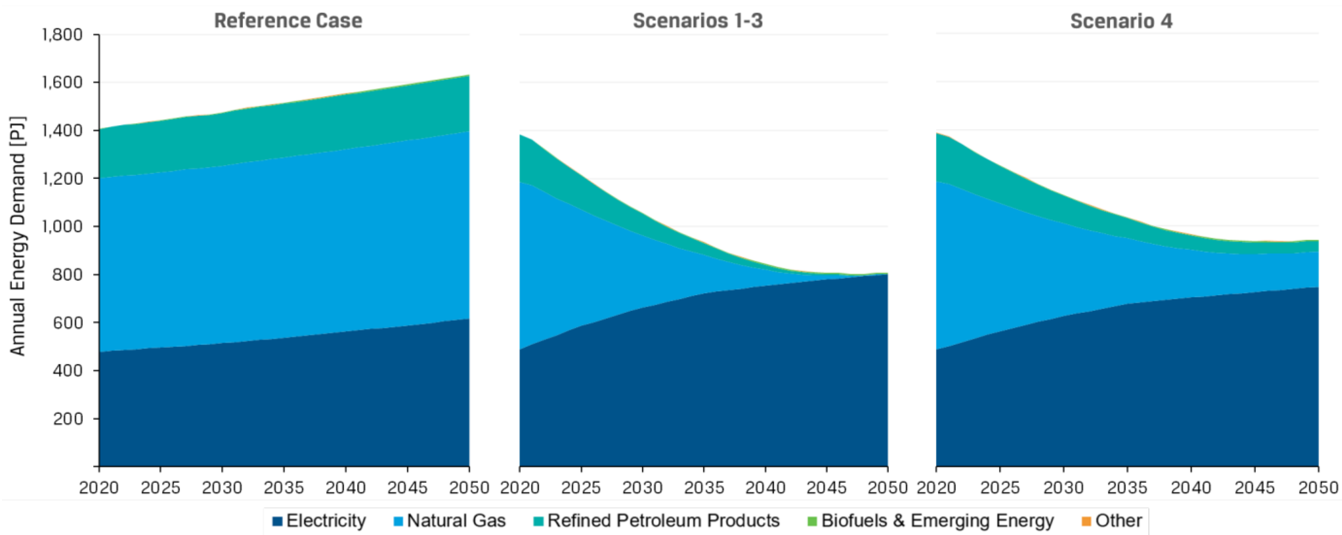


Figure 16 shows the resulting breakdown of energy consumption in the industrial sector, contrasting the 'business as usual' reference case to scenarios 1-3 (~50% electrification) and scenario 4 (~25% electrification) in the simplified analysis for this sector. These charts highlight the impact of conversion from fuels to electricity with more modest efficiency gains than the residential and commercial sectors, and hence less overall demand decline. While significant energy efficiency improvements are included along with electrification of space and process heating, there is little improvement along with the electrification of steam boilers, a major area of industrial fuel consumption. For scenario 4, the natural gas segment also includes RNG volumes.

Figure 16: Industrial Sector Breakdown of Energy Consumption

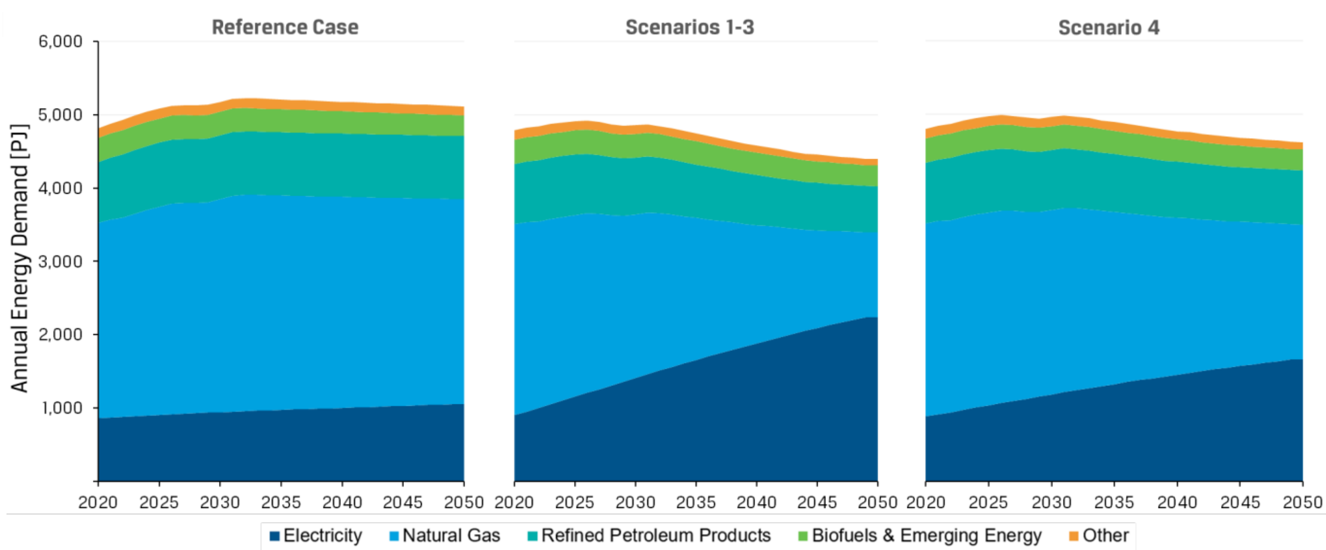
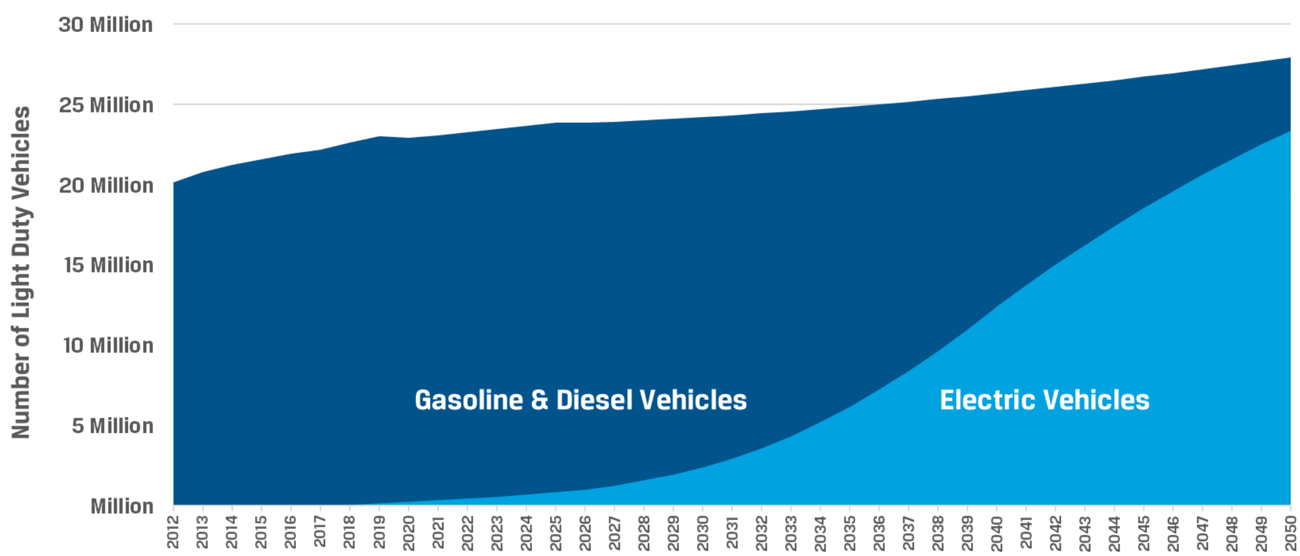


Figure 17 shows the change over in the light-duty vehicle stock from internal combustion engine vehicles to electric vehicles, with more than 20 million EVs on the road by 2050. While electrification of other transportation segments is also included (25% of medium- and heavy-duty trucks, off-road vehicles, and commuter trains), the light-duty segment represents the bulk of the electric load added from the transportation sector in this study. 80% of light-duty vehicles are assumed to be part of a 'managed charging' program – allowing utilities to shift re-charging hours overnight and minimize LDV EV contribution to peak

electricity load growth. A range of load shapes are used for other vehicle categories, with a more limited amount of shifting enabled, increasing the peak contributions from other transport segments.

Figure 17: Transition from Gasoline and Diesel to Electric Light Duty Vehicles



Electrification Enabling Assumptions

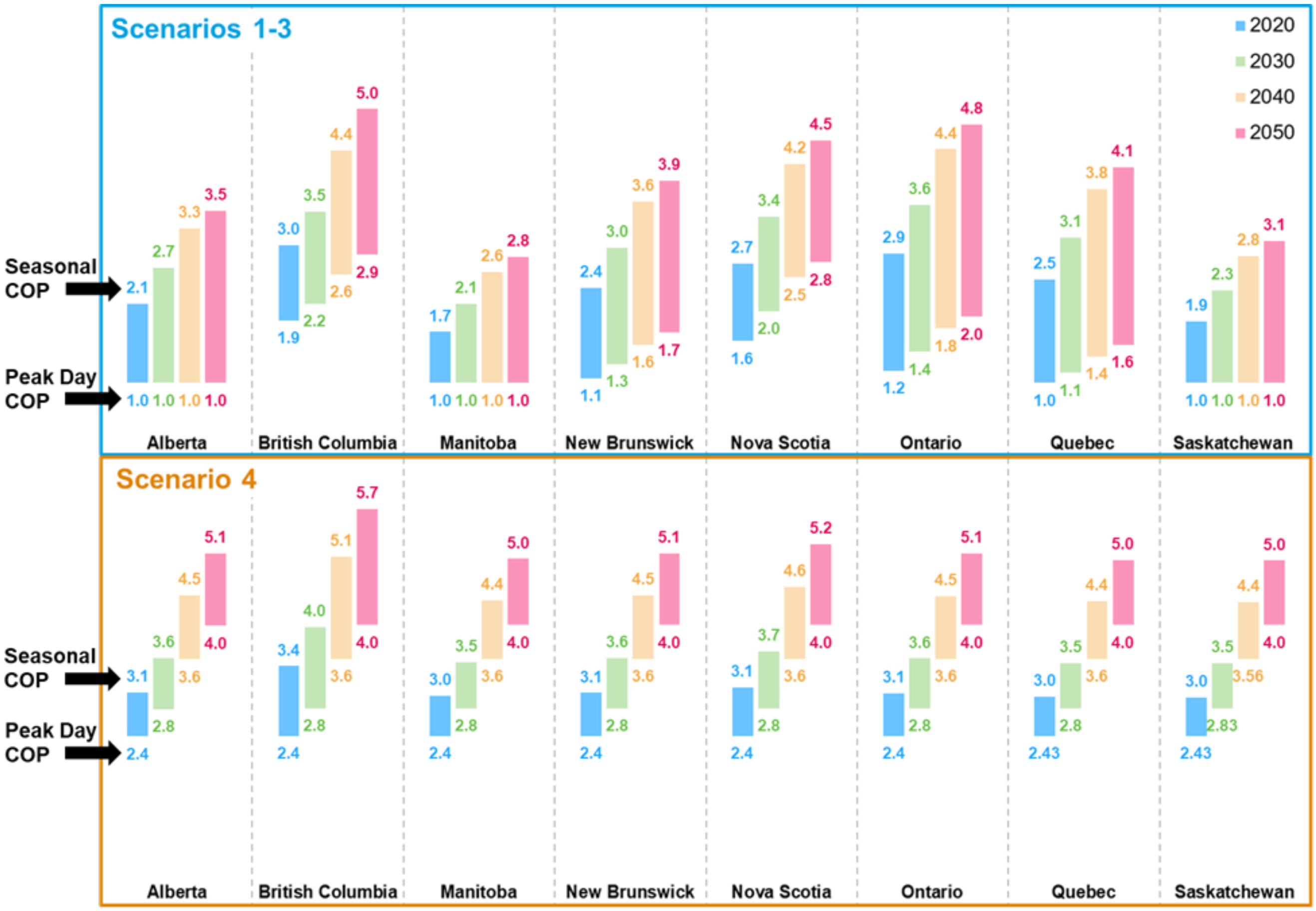
The impacts of electrification will depend on a range of factors, and the level of electric fuel switching illustrated comes with significant uncertainty as to how some of these factors will change by 2050. To enable the levels of electrification illustrated in this study, optimistic assumptions were used in a number of areas to reduce the impacts and costs of these scenarios. Three key enabling assumptions are described below:

- **Electric Technology Performance Improvement**

  For residential and commercial space heating, cold-climate air-source heat pumps were modeled to replace fossil fuel furnaces and boilers. Canadians are assumed to install these more expensive cold-climate heat pumps, despite electric heating options with lower upfront costs being available to them.

  The efficiency of these heat pumps was based on an average of several of the best performing heat pumps available today, and the efficiency was assumed to improve significantly over the 2020-2050 timeframe, as shown in **Figure 18**. The efficiency is presented in terms of the coefficient of performance (COP), which measures the ratio of heat energy delivered to the home to the electrical energy consumed by a heat pump. As an example of this improvement, in **scenarios 1-3** (in which the heat pump operates year-round) the average seasonal COP improves from 1.7 in 2020 to 2.8 in 2050 for the coldest province (MB), and from 3.0 in 2020 to 5.0 in 2050 for the mildest province (BC). Similarly, in scenario 4 (in which the heat pump does not operate below -10°C) the seasonal COP improves from 2.4 in 2020 to 5.0 in 2050 for the coldest province (MB), and from 2.4 in 2020 to 5.7 in 2050 for the mildest province (BC). These advances in performance are consistent with the 'rapid advancement' trajectory for COP improvement from NREL's 2017 Electrification Futures Study.

Figure 18: Assumed Heat Pump Improvement over Study Period



Similarly, residential and commercial water heating efficiencies are assumed to rise to COP 3 by 2050 through the adoption of heat pump water heaters, despite lower-cost electric resistance water heaters (COP 1) being significantly more common in the market today. In particular for water heating, a policy requiring electrification could instead drive adoption of the less expensive electric resistance water heaters, which would triple the load growth from water heater electrification relative to what is modelled here.

Industrial process heating electrification is also assumed to involve significant improvement in energy efficiency – improving from an average efficiency of 50% to an effective average efficiency of 200%, once accounting for improvements in productivity.

- **Reduced Energy Loads**

  Improvements in building envelopes and the adoption of hot water conservation measures were assumed to reduce space and water heating loads, respectively. As such, the model incorporated a gradual reduction of these loads, reaching a 10% reduction by 2050. These reductions in space and water heating loads were included on top of the 1.4% per year reduction in building energy use intensity assumed by the CER Energy Futures reference case. These assumed load reductions combine to significantly reduce the amount of electricity needed to electrify the residential and commercial sector, minimizing the impacts of electrification.

- **Electric Resistance Heating Conversions**

  Roughly 4.75 million homes in Canada currently rely on some form of electric resistance heating as their primary source of heating, with Quebec accounting for more than half of these homes. For a home in Quebec today, the energy requirements for electric resistance heating are two and a half times greater than that of a cold climate heat pump. By 2050, the energy requirements for electric resistance heating are expected to be more than four times greater than that of the cold climate heat pump. This study assumes that 75% of homes currently heated with electric resistance are upgraded to heat pumps by 2050. These heat pump upgrades result in a significant reduction in electricity demand, which dampens the impact of space heating electrification on electricity demand.

It is important to understand these assumptions when envisioning potential low-carbon pathways, as infrastructure and cost requirements in these scenarios would be increased if they did not materialize.

Appendix B Key Electrification Technologies

This section introduces the key electrification technologies considered in this study.

Residential & Commercial Sector

Nearly all fuel consumption in the residential and commercial sectors can be attributed to two end uses: space heating and water heating. As such, the key electrification technologies considered in this study fall into one of these two end use categories. Each space heating technology has its own costs and benefits and can offer potential synergies to minimize the disruptive impacts to consumers and other sectors. The key technologies are introduced below, followed by **Table 5**, which compares each option based on a few important factors.

The main heating systems currently being used:

Natural Gas Heating Systems: There are several types of space heating systems that combust natural gas to produce heat, with the two main types being forced air furnaces and hydronic heating systems. In a forced air furnace, the combustion of natural gas heats the air, which is then distributed throughout the house by the ventilation system. In a hydronic system, the combustion of natural gas heats water, which is then pumped throughout the building in a series of pipes, culminating in a heat delivering device such as a radiator. Natural gas-fired space heating systems have around 50% of the residential market share in Canada, and new systems are typically in the range of 92-98% efficient. Natural gas-fired water heaters are also standard, with 68% of the residential market share in Canada, and have efficiencies around 60-80%. In this study, no new natural gas systems are installed after 2020, and all existing natural gas heating systems are replaced by 2050.

Electric Resistance Systems: This type of system is currently used in the 80% of electrically heated households across Canada (4.75 million homes) and is also typically included as a back-up fuel option for heat pumps. These systems are convenient and inexpensive, can be installed in nearly all household types, and do not typically require an internal air-duct system. However these systems are the least efficient type of electric space heating system – and contribute significantly to peak electric loads. In this study, standalone electric resistance systems are replaced with heat pumps to improve efficiency. Historically, the most common electric water heating option are also electric resistance units.

The new electric heating options focused on in this study:

Conventional Air Source Heat Pumps (ASHP): This technology was chosen because it is well-developed, currently available and deployed across the country, and operates very efficiently most of the year. Some of the downsides of ASHPs are their higher installation costs for retrofits and their steep reduction in performance at low temperatures. The coefficient of performance (COP), which measures the ratio of heat energy delivered to the home to the electrical energy consumed by the ASHP, is typically between 3 and 5 when operating in mild temperatures (≥ 0°C) but quickly approaches a COP of 1 (equivalent to electric resistance heating) when outdoor temperatures fall below -10°C, as the ASHP is unable to extract sufficient heat from the cold ambient air.

Cold Climate Air Source Heat Pumps (ccASHP): ccASHPs have more recently gone from the development and testing phase to being commercially deployed in limited numbers. This technology is optimized to perform at a higher efficiency at colder temperatures, which limits the impact on electric grid requirements over the winter months. The downside of this technology is that the upfront costs are higher compared to a gas furnace and conventional ASHPs. Although ccASHPs are designed to operate more efficiently at lower temperatures, they still rely on back-up heating below certain temperatures.

Natural Gas-Electric Hybrid Heating System: This space heating system utilizes an electric ASHP paired with a natural gas furnace. The natural gas furnace provides back-up heating that supplements the electric system during colder periods, similar to how electric resistance heating currently supplements many electric heat pump systems at lower temperatures. This approach has the benefit of capturing the higher efficiency associated with ASHPs during milder temperatures, while minimizing electric grid impacts during the colder months of the year when natural gas can service as a back-up fuel.

Electric Heat Pump Water Heater (HPWH): Electric HPWH systems use similar methods as ASHPs to move heat from one medium to another, rather than generating direct heat that would be applied to water in a traditional water heater system. HPWHs are typically placed within the heated space of a home (and draw air from the heated space). There are locational concerns with HPWHs given that these units are required to be sited in areas with temperature ranges roughly between 4 to 26°C to allow for the proper functioning of these units. Because HPWHs are typically located within the heated space they have a negative impact on space heating, as the cool exhaust air is expelled into the home. As a result, HPWHs located in a heated space increase the load on any space heating device, an impact not quantified in this assessment. HPWHs are typically more expensive than a comparably sized high efficiency electric water heater.

Other high efficiency heating options not included in this study:

Ground Source Heat Pumps: Ground source heat pumps use the earth or large water bodies as a heat source and can therefore maintain better cold weather performance. However, they require drilling and placement of underground heat exchangers, which results in much higher costs and limits their applicability.

Absorption Heat Pumps: Absorption heat pumps are essentially air-source heat pumps driven not by electricity, but by a heat source such as natural gas, propane, solar-heated water, or geothermal-heated water. Because natural gas is the most common heat source for absorption heat pumps, they are also referred to as gas-fired heat pumps. These emerging systems are typically less efficient that comparable electric ASHP systems, however they are over 100% efficiency, and can both heat and cool a building.

Table 5 summarizes some of the key consideration for each technology option.

Table 5: Summary of Space Heating Technology Options

Used in this study?	Electric Heating System	Upfront Cost	Operating Cost	Impact on Electric Grid
Replaced	*Natural Gas Heating Systems*	Low	Low	None
Replaced	*Electric Resistance*	Low	High	Very High
Installed	*ASHP*	Medium	Medium	High
Installed	*CC ASHP*	Medium	Medium	Medium
Installed	*Hybrid Gas-Electric Heat Pump*	Medium	Low	Very Low
Not Included	*Ground Source Heat Pump*	Very High	Low	Low
Not Included	*Absorption Heat Pumps*	High	Low	None

Electric Heating System Performance

Electric heat pumps transfer heat from outdoors to indoors rather than transforming chemical energy to heat through combustion. While combustion-based systems can never provide more energy than they consume, i.e., be more than 100% efficient, heat pumps can transfer more energy than they consume, i.e., be more than 100% efficient. Heat pump efficiency is measured as coefficient of performance (COP) where a COP of 1 is equal to 100% efficiency. Nominal heat pump efficiency of 300% or a COP of 3 is not unusual. Having a high efficiency electric heating option can minimize the cost impacts for consumers who are typically switching from using low-cost natural gas to significantly higher cost electricity to meet their heating requirements. This high efficiency is also critical to reducing the impacts of electrification on the electricity system. However, heat pump performance degrades as the outdoor temperature drops.

Falling temperatures increase the temperature differential that must be achieved by the heat pump, and affect heat pump performance in three ways:

- The heat pump becomes less efficient.
- The heat pump provides less heat.
- The discharge air temperature of the heat pump gets lower.

At very low temperatures, heat pumps typically cannot provide adequate heat and require some form of back-up energy, typically electric resistance heating, resulting in much lower efficiency on the coldest days relative to the annual average efficiency.

The actual climate-adjusted heat pump performance must be calculated for each region to estimate the implications in that area, as there can be significantly different results for annual energy consumption and peak demand impacts based on different outdoor temperatures.

Transportation Sector

The transportation sector provides significant opportunities for electrification, including the following segments.

Passenger Vehicles: Battery powered electric vehicles (EVs) are increasingly common, and the Federal Government has a target of 100% of new passenger vehicle sales being EVs by 2040. Passenger vehicles can be an attractive electric technology because despite higher upfront costs the EV will save customers money over time (EVs are more efficient, and electricity prices are lower than gasoline prices). From a system perspective, the ability for a utility to control the timing of load, for example ensuring EVs charge at night when other electricity demands are low, could minimize or eliminate any increase to peak load from their adoption. Upgrades to local electricity distribution infrastructure would likely still be required under such a 'managed charging' scenario, and it is unlikely that utilities would be able to influence/control when all EVs charge.

Medium & Heavy Duty Vehicles: For longer range hauling trucks and buses electric options are under development, but not widely available at this time. The timing of battery re-charging for these larger vehicles will generally be less flexible and harder for utilities to manage (e.g. for many applications there will be less flexibility to wait and charge the vehicles over night), so the peak load impacts from this segment may be more significant.

Off-road Vehicles: This diverse category of vehicles can include everything from forklifts to mining haul trucks, and an increasing number of electric options are becoming available to replace fuel vehicles in different off-road segments.

Industrial Sector

In additional the same electric space-heating options outlined above, the industrial sector has electrification opportunities for electric boilers and process heating technologies.

Electric Boilers: Electric boilers can produce the steam required for various industrial applications. Heat is produced directly from electricity, typically using resistive heating elements for smaller applications up to 1-2 MW, while passing electric current directly through the water for larger applications up to 50 MW. The challenge for electric boilers typically lies in their operating costs. Since electric boilers have an efficiency of 100% efficiency (vs. 80-90% for fossil fuel boilers) there is little efficiency improvement to offset the substantial cost increase from purchasing higher-cost electricity instead of low-cost natural gas.

Process Heating Electrotechnologies: Industrial processes are very diverse, and there are a number of electric options to replace traditional fossil fuel use for process heating. These include induction heating and melting, electric infrared processing, microwave drying, ultraviolet curing, and many more examples. These processes often use a more targeted form of heating, for example transferring heat directly to a part, instead of heating the air inside an oven and then putting the part in that hot air to absorb some of the heat. In some applications this can lead to significant efficiency, product quality, and/or productivity improvements. But such overhauls can require the complete replacement of a process line, and electrotechnologies are much better for some applications than others – limiting their potential.

Appendix C Scenario Details for Power Sector Analysis

Table 6 provides an overview of the types of power generation capacity allowed in each of the scenarios to serve the growing electricity demand, and is followed by some additional context on the power generation capacity expansion modelling.

Table 6: Power Generation Scenario Descriptions

Reference Case	**Lowest cost options** *Use the most economic options to meet power generation requirements.*
Scenario 1	**All generation capacity is non-emitting** *All incremental generation requirements met using only renewables (wind & solar) generation and batteries, and all existing fossil-fuel fired generation (including natural gas) retires by 2050.*
Scenario 2	**All new generation capacity is renewables** *Maintain existing (& currently planned) fossil-fuel fired generation capacity (natural gas & oil, but coal retires), but all incremental generation capacity is required to be met with renewable (wind & solar) generation and batteries.*
Scenario 3	**Lowest cost options** *Use the most economic options to meet power generation requirements.*
Scenario 4	**Lowest cost options under a GHG emissions cap** *Capacity expansion that uses the most economic options to meet power generation requirements, while keeping overall GHG emission levels (net power & demand side emissions) for scenario 4 capped at the same level as scenario 2.*

The impact of widespread electrification on peak electric grid capacity requirements and electric infrastructure is often overlooked in studies of policy-driven electrification. This study explicitly projects the potential impact of policy-driven electrification on the power grid infrastructure requirements for generation capacity, and estimated the costs of associated transmission capacity needed to bring the power to market.

For the electric system analysis the study used IPM® to model the power grid requirements and incremental investments needed to meet electric load growth for each of the cases described in the table above. The difference between the reference case and each of the four scenarios is used to project the impact of the electrification policy on:

- New plant construction by province
- Plant retirements
- Capital expenditure on new plants
- Power plant fuel use and emissions

IPM® is a detailed economic capacity expansion and production-cost model of the power sector supported by an extensive database of every generator in the North America. It is a multi-region model that projects capacity expansion plans, unit dispatch and compliance decisions, and power and allowance prices based on power market fundamentals. IPM® explicitly considers fuel prices, power plant costs and performance characteristics, environmental constraints, and other power market fundamentals.

The Reference Case power generation capacity expansion is based on publicly announced plans for generating capacity builds and retirements, as well as legislative requirements such as Canada's phase out of coal. The remaining capacity required to meet reference case demand for electricity were selected by the model to provide the lowest-cost possible solution. The assumptions were then modified for the different scenarios to incorporate the increased electricity consumption and demand from the policy-driven electrification on a provincial and seasonal basis.

Power Model Build Assumptions

Table 7 lists the key costs used in the power modelling, based on the following sources.

- Wind, solar and energy storage cost assumptions were developed from the National Renewable Energy Laboratories Annual Technology Baseline report for 2018.
- Cost and performance assumptions for thermal technologies were based on EIA's 2019 Annual Energy Outlook

Table 7: Average Cost of New Generation Builds by Case and Capacity Type

Technologies	Vintage	Nominal $USD		
		Overnight Capital Costs ($/kW)	Fixed Operations and Maintenance Costs (FOM) ($/KW)	Variable Operations and Maintenance Costs (VOM) ($/MWh)
Combined Cycle	2020	828	10.7	2.1
	2025	918	11.9	2.4
	2030	1,019	13.2	2.6
	2035	1,130	14.7	2.9
	2040	1,254	16.3	3.3
	2045	1,392	18.1	3.6
	2050	1,544	20.0	4.0
Combustion Turbine	2020	720	7.3	11.5
	2025	799	8.1	12.7
	2030	887	9.0	14.1
	2035	984	10.0	15.7
	2040	1,092	11.1	17.4
	2045	1,211	12.3	19.3
	2050	1,344	13.6	21.4
Solar PV - Utility Scale	2020	1,292	11.0	0.0
	2025	1,297	10.9	0.0
	2030	1,354	11.4	0.0
	2035	1,438	12.1	0.0
	2040	1,523	12.8	0.0
	2045	1,599	13.5	0.0
	2050	1,672	14.2	0.0
Onshore Wind	2020	1,597	54.2	0.0
	2025	1,691	57.9	0.0
	2030	1,807	61.7	0.0
	2035	1,950	65.8	0.0
	2040	2,126	69.9	0.0
	2045	2,346	74.2	0.0
	2050	2,617	78.6	0.0
Offshore Wind	2020	3,428	147.8	0.0
	2025	3,247	162.2	0.0
	2030	2,961	178.0	0.0
	2035	3,138	195.3	0.0
	2040	3,307	214.2	0.0
	2045	3,460	235.0	0.0
	2050	3,596	257.7	0.0
Battery Storage	2020	2,432	8.6	2.5
	2025	1,751	7.9	2.3

Technologies	Vintage	Nominal $USD		
		Overnight Capital Costs ($/kW)	Fixed Operations and Maintenance Costs (FOM) ($/KW)	Variable Operations and Maintenance Costs (VOM) ($/MWh)
	2030	1,400	7.0	1.9
	2035	1,376	5.9	1.5
	2040	1,353	4.4	0.9
	2045	1,458	4.9	1.0
	2050	1,573	5.4	1.1

Additional key points of context on the power generation analysis

- Beyond currently planned projects included in the reference case, incremental nuclear & hydro-electric power projects were not considered in this study. Wind, solar, and batteries are the focus of the 'renewables-only' case. There is significant uncertainty surrounding whether new nuclear or hydro-electric mega-projects would be feasible or politically viable going-forward, and the timelines required for their development. Such mega-projects often end up significantly over budget, making costs more difficult to predict - but decreasing wind generation prices compare favourably to meet annual energy requirements, as do battery storage costs for reserve margin contributions (to meet peak demand).

- This project is not intended to be a 'renewable integration study'. The analysis does not aim to predict the maximum amount of wind or solar generation that could realistically be built in each province, the maximum penetration of intermittent renewable generation possible while avoiding unstable grid operations, or the declining contribution to peak demand requirements from incremental intermittent renewable capacity at high levels of penetration. There is uncertainty surrounding each of those challenges, which may or may not be mitigated through technology improvements out to 2050. As such, the study's cost estimates for capacity expansion under the renewables-only conditions likely underestimate the costs of such a scenario, if even feasible.

- The power sector modeling includes a characterization of the existing transmission system and optimizes flows of energy and capacity across the existing transmission system to minimize overall system cost. Inter-provincial transmission expansion is not modeled and transmission cost estimates that are included in this study are estimated based on a simplified ratio to the capital cost of new generation capacity they are connecting. For scenarios including high levels of renewable penetration this is likely to underestimate transmission costs, as there would be a need to build wind and solar resources over a wider footprint (to reduce correlation of generation from resources clustered in the same region).

- The power modelling optimizes, under the constraints of each scenario, to minimize overall power system costs for North American – the results of which provide a more representative depiction of impacts and costs at the national level for Canada and for larger Canadian provinces. The resulting capacity expansion and cost projections do not necessarily represent the lowest cost pathway for an individual province, and the impact of this is more strongly felt in smaller provinces with the ability to import power. The model also has 'perfect foresight' in making its decisions, allowing it to achieve the lowest cost solution over the time horizon of the study, informing decisions on capacity expansion and generation based on the assumptions of what the future demand requirements and construction costs will be (e.g., the model can wait to build solar if it knows cost will drop significantly in 5 years).

Appendix D Costs Assumptions

In order to understand the economic impacts of electrification, assumptions needed to be made related to the costs of energy, equipment, new power generation, transmission expansion, and renewable natural gas. Some of the key assumptions related to these costs are outlined below.

Fuel Costs and Electrical Energy Costs

The energy rates for electricity, natural gas, refined petroleum products, diesel, and gasoline were based on forecasted prices provided in the 2018 CER Energy Futures report. These forecasts were available from 2020 to 2040 at both the provincial and sectoral levels. The forecasts were extended to 2050 by applying a linear trend.

Equipment Upgrade & Conversion Costs

In this study, equipment costs represent the total incremental costs incurred by the end user for the installation of electric options instead of a replacement fossil fuel option, at the end of the life of the existing fossil fuel equipment, when a replacement is required anyways (cost is relative to purchasing equivalent fuel-fired baseline option). In some instances, equipment upgrade costs will also include costs associated with energy efficiency improvements, costs associated with upgrading electrical hardware to accommodate the power requirements of the electric equipment, and costs for the installation of vehicle charging infrastructure. The primary incremental equipment costs are summarized in **Table 8**.

Table 8: Primary Equipment Costs[13]

	Subsector	End Use	Upgrade Description	Average Incremental Cost
Residential	Single family homes	Space Heating	Replacement of furnace/central air conditioner with an air source heat pump (at equipment end of life)	$100 per home
			Replacement of furnace/central air conditioner with a cold climate air source heat pump (at equipment end of life)	$1,050 per home
			Replacement of furnace/central air conditioner with a hybrid heating system (furnace/ASHP) (at equipment end of life)	$1,425 per home
			Installation of cold climate heat pump(s) in a home previously heated with electric resistance (early replacement / full cost)	$8,400 per home
		Water Heating	Replacement of gas water heater with heat pump water heater	$1,500 per home

[13] Average incremental costs were derived from a variety of sources. Some of the key primary sources are listed below.
Residential and Commercial: RSMeans, distributor reported retail sales prices, Heat Pump Retrofit Strategies for Multifamily Buildings (Steven Winter Associates, Inc.)
Industrial: Illustrative cost estimates based on prior consultations with industrial OEMs and the review of various electrification case studies
Transportation: Canada Energy Regulator, U.S. Energy Information Administration Annual Energy Outlook, and ICF market research database

	Subsector	End Use	Upgrade Description	Average Incremental Cost
		Electrical Upgrade	Electrical upgrade to accommodate power requirements for the conversion to a heat pump and/or HPWH[14]	$2,000 per home
	MURBs (45 units per building)	Space Heating	Replacement of a central boiler and chiller with cold climate air source heat pumps	$425,000 per building
		Water Heating	Replacement of a central boiler with central heat pump water heater plant	$175,000 per building
Commercial	Small Commercial (7,500 ft^2)	Space Heating	Replacement of gas RTU with cold climate heat pumps	$9,500 per building
		Water Heating	Replacement of gas boiler with central heat pump water heater plant	$30,000 per building
	Large Commercial (150,000 ft^2)	Space Heating	Replacement of a central boiler and chiller with cold climate air source heat pumps	$590,000 per building
		Water Heating	Replacement of a central boiler with central heat pump water heater plant	$600,000 per building
Industrial	All Industry	Space Heating	Conversion of fuel fired space heating equipment to heat pumps	$30 per GJ/year of equipment fuel consumption
		Process Heating	Conversion of fuel fired process heating applications (e.g., heat treating, brazing, drying) to electrically powered processes (average cost if converting 50% / 25%)	$60 per GJ/year / $30 per GJ/year
		Steam Boilers	Replacement of fuel fired steam boilers to electric/electrode boilers (average cost if converting 100% / 50% of boilers)	$20 per GJ/year / $10 per GJ/year
Transportation	Light Duty Vehicles - Cars		2020 / 2050 incremental cost of EV relative to internal combustion engine (ICE) vehicle	$7,000 / $1,000
	Light Duty Vehicles - Trucks		2020 / 2050 incremental EV cost	$13,000 / $4,000
	Medium Duty Vehicles		2020 / 2050 incremental EV cost	$125,000 / $30,000
	Heavy Duty Vehicles		2020 / 2050 incremental EV cost	$215,000 / $80,000

Power Generation Costs

The power generation costs are calculated in IPM®, as part of the model's optimization for a low-cost solution. These power generation costs include separate capital, fuel, and operations & maintenance (fixed and variable) components. The difference between the costs modelled for each scenario and the reference case costs is calculated to get the incremental cost impact for that scenario.

[14] Assumed that only homes without existing central air-conditioning or electric resistance heating would require electrical upgrades, although it is likely that the combination of EV adoption and the addition of significant space heating electric loads would require upgrades to a portion of homes with air-conditioning as well.

Transmission Costs

The illustrative transmission costs are estimated from the capital cost component of power generation costs, based on a ratio of planned investments in transmission infrastructure and planned new construction investments in generation capacity, using a value of 0.308 that was calculated from data in a Conference Board of Canada study.[15]

Renewable Natural Gas

An average RNG cost of $20/GJ was assumed across all years of the study. RNG costs are expected to vary significantly by feedstock source, but this cost is indicative of the ranges cited in the limited studies of RNG in Canada available at this time. The natural gas commodity price for a given year, from the reference case, was subtracted from this RNG cost to calculate the incremental cost impact from RNG.

[15] The Conference Board of Canada, "Canada's Electricity Infrastructure: Building a Case for Investment." April 2011.

A Canadian Gas Association Study
Prepared by ICF | October 2019

Ontario Energy Association

Energy Platform

About

The Ontario Energy Association (OEA) is the credible and trusted voice of the energy sector. We earn our reputation by being an integral and influential part of energy policy development and decision making in Ontario. We represent Ontario's energy leaders that span the full diversity of the energy industry.

OEA takes a grassroots approach to policy development by combining thorough evidence based research with executive interviews and member polling. This unique approach ensures our policies are not only grounded in rigorous research, but represent the views of the majority of our members. This sound policy foundation allows us to advocate directly with government decision makers to tackle issues of strategic importance to our members.

Together, we are working to build a stronger energy future for Ontario.

KEY OBJECTIVES

The purpose of this document is to provide elected officials and key decision makers from Ontario's main political parties with clear and precise recommendations on energy policies to address the needs of Ontario energy consumers. Our recommendations have been guided by the key objectives of ensuring energy in Ontario is:

Affordable

Policies should deliver the lowest cost possible to promote affordability for Ontario consumers and economic growth objectives, while still delivering on the objectives below

Sustainable

Energy policies should be developed in an integrated manner to achieve Ontario's climate change and environmental objectives by reducing energy related emissions and facilitating emissions reductions in other sectors of the economy, such as transportation and industry. It is only through taking a comprehensive approach to energy system planning by linking different types of energy (e.g., electricity, natural gas, and liquid fuels) together with the end-uses (e.g., heating, cooling, transport) that decarbonization targets will be reached

Reliable

Energy policies should ensure that Ontarians continue to have uninterrupted access to reliable energy. Our modern society and economy are dependent on reliable energy, and interruptions can have very serious consequences. Policies should allow for continuous investment in Ontario's energy infrastructure so that it can withstand and recover from extreme weather events and continue to supply Ontario's energy consumers with reliable access to affordable clean energy

RECOMMENDATION

1 | Comprehensive & Co-ordinated Plan

1A A comprehensive energy-use plan is required to ensure that Ontario finds the most affordable, reliable, and sustainable pathway to achieving both energy needs and emissions reductions objectives

1B The plan should eliminate infrastructure planning siloes within the energy sector, but also across sectors (e.g., transportation, buildings, industrial processes)

1C The Ontario Energy Board (OEB) and Independent Electricity System Operator (IESO) need to move swiftly on implementing recent government guidance and direction regarding emissions reductions objectives into their decision-making and policy making. This will ensure that regulated utilities and market participants have certainty and guidance regarding what investments are allowed in the energy system

1D Federal, provincial, and municipal governments need to coordinate and align their policies and programs and collaborate on future programs to ensure that there is a clear, comprehensive, costed, and complementary emissions reduction strategy for Ontario

RECOMMENDATION

2 | Optimize Use of Existing Infrastructure

2A Optimize and co-ordinate the use of Ontario's substantial existing electricity and natural gas assets (transmission, generation, distribution, and storage facilities), where prudent and assessed against alternatives, to decarbonize our economy cost-effectively and provide reliable, sustainable energy choices for Ontario's homes and businesses.

2B To best leverage the natural gas system:

- Provide the OEB with a mandate to enable emissions reductions investments or energy sources even when more costly, when they meet cost of abatement thresholds
- Set targets for the blending of renewable natural gas (RNG) into the gas system, and move away from voluntary RNG option (as is already being done with ethanol for transportation fuel)
- Create a provincial strategy for hybrid heating systems with smart controls, replacing a conventional air-conditioner with a higher efficiency air-source heat pump, and pairing it with a gas furnace and smart controls through collaboration and partnership between electric and natural gas utilities
- Give the OEB a mandate for more aggressive demand-side management DSM targets and expanded programs, to reduce the volume of natural gas used for building heat and therefore reduce emissions
- Implement Automated Metering for natural gas customers to support and monitor DSM initiatives, promote usage awareness, and encourage behaviour change
- Immediately initiate a carbon, capture utilization and sequestration or storage pilot project for natural gas generation in Ontario
- Strengthen investments in RNG, and compressed natural gas to reduce emissions in medium- and heavy-duty transportation

RECOMMENDATION

2 | Optimize Use of Existing Infrastructure

2C To best leverage the electricity system:

- Leverage our existing almost emission-free electricity sector to electrify key segments (e.g., transport, industry, mining) of the economy where it is the most economic option and/or supports sustainability objectives
- Given the long lead times required for new infrastructure (e.g., generation, transmission or distribution upgrades) begin planning now to expand the electricity system so that it will be able to meet the significant increase in demand for electricity as a result of Net Zero and electrification objectives, including enabling investments in the capacity of the distribution system to handle the anticipated fast growth in electric vehicle charging
- Support the integration of distributed energy resources (DERs) into the electricity grid, including power storage and hydrogen, where they provide system benefit, and offer customers choices
- Invest and expand the transmission and distribution grids to address and enable economic development, accommodate changes in generation and prepare for decarbonization
- Invest in and expand conservation and demand management programs to reduce demand, emissions, and pressure on the electricity system. Expand these programs to include fuel switching to electricity to support decarbonization in key sectors such as building heating and industrial processes
- Continue to drive efficiencies in Ontario's distribution sector through collaboration, partnerships, and consolidation

RECOMMENDATION

3 | Invest in Infrastructure, Technology & Adaptation

3A Competitive and regulatory processes should be used, wherever prudent, to procure new infrastructure as they are needed to ensure consumers get the lowest cost reliable clean energy

3B Foster a flexible regulatory regime that enables market participation of new and evolving technology and resource types, including energy storage and demand response

3C Invest in an expansion of province wide hydrogen infrastructure to facilitate a fueling network for heavy transportation; this will also require legislative and regulatory updates to enable production, transportation, and consumption of blue and green hydrogen

3D The provincial government should update the Oil, Gas & Salt Resources Act to remove the current ban on carbon sequestration to unlock opportunities for industry to invest and create jobs in Ontario

3E The OEB should move quickly to consult, develop, and implement recent government direction to provide guidance to utilities on system investments to prepare for electric vehicle adoption, so that utilities can incorporate these investments in distribution rate applications submitted to the OEB for review

3F The provincial government needs a policy on energy efficiency and decarbonization goals for buildings to achieve emissions reductions related to heating and ventilation

3G Continue to make investments in Ontario's cybersecurity framework to protect customers and energy sources

RECOMMENDATION

4 | Invest in Energy Efficiency

4A Ontario should expand investment in energy efficiency and demand response programs that reduce energy needs across all sectors and fuels

4B Ontario should pursue a decentralized delivery model for energy efficiency and energy conservation programs, taking advantage of the strong relationships that utilities and energy services companies have with consumers

4C Regular meetings should be established between the federal government and provincial government with the objective of coordinating and aligning energy efficiency programs (and funding) to eliminate overlap, duplication, and customer confusion

4D The federal government's funding of energy efficiency in Ontario should align with and support the provincial comprehensive plan outlined above, and also be consistent with the principles in the letter from the Ministry of Energy to the federal government encouraging collaboration between DSM and the new Canada Greener Homes Program to benefit Ontario ratepayers

RECOMMENDATION

5 | Achieve Behavioural Change

5A Governments must work together to invest in public education to increase consumer awareness of the impact of daily decisions on emissions and the choices available to them, including

- The emissions impact of our various purchases
- The emissions profile of various products and services
- The impact of our transportation decisions
- How to make cost-effective purchases of goods and services to lower emissions
- Leverage the existing customers relationships of utilities and energy companies to develop and deliver education initiatives

Detailed Discussion of Recommendations

CHARTING THE COURSE

Achieving net zero emissions by 2050 requires a well thought out planning process and plan. The process will require numerous iterations and course corrections as we learn what works and what does not work to achieve the significant emissions reductions needed. Ontario needs to initiate a comprehensive integrated energy planning process. Businesses and investors need a roadmap to provide certainty to ensure consumers are well served during the energy transition and that Ontario attracts the investments necessary to make the transition. Ontario will need a plan to capitalize on the economic opportunities arising out of the energy transition.

The European Union has already taken steps towards integrated energy system planning, and takes the view that "Energy system integration refers to the planning and operating of the energy system "as a whole", across multiple energy carriers, infrastructures, and consumption sectors, by creating stronger links between them with the objective of delivering low-carbon, reliable and resource-efficient energy services, at the least possible cost for society."

The EU strategy states further that "Energy system integration will translate into more physical links between energy carriers. This calls for a new, holistic approach for both large-scale and local infrastructure planning, including the protection and resilience of critical infrastructures. The objective should be to make the most of the existing infrastructure while avoiding both lock-in effects and stranded assets. Infrastructure planning should facilitate the integration of various energy carriers and arbitrate between the development of new infrastructure or re-purposing of existing ones. It should consider alternatives to network-based options, especially demand-side solutions and storage."

Without a similar approach in Ontario (and Canada), businesses and households will experience fluctuating policies, unreliable service, uncertainty, and higher costs as uncoordinated and random policies and programs fail to both serve consumers and achieve net zero goals. Importantly, a credible plan is necessary to create coverall citizen and voter support in the implementation of the significant changes in energy use and individual behaviour required to meet climate targets.

1 COMPREHENSIVE & CO-ORDINATED PLAN

The past two decades have shown that without a transparent, coordinated plan to tackle emissions, we will see further inaction or slow response. This outcome is no longer acceptable as evidence continues to accumulate that the cost of inaction on climate change will far outweigh the costs of making the investments needed to reach net zero targets. The planning process will need to pull together all levels of government, industry, and the public to achieve success.

1A A comprehensive energy-use plan is required to ensure that Ontario finds the most affordable, reliable, and sustainable pathway to achieving both energy needs and emissions reductions objectives

1B The plan should eliminate infrastructure planning siloes within the energy sector, but also across sectors (e.g., transportation, buildings, industrial processes)

1C The Ontario Energy Board (OEB) and Independent Electricity System Operator (IESO) need to move swiftly on implementing recent government guidance and direction regarding emissions reductions objectives into their decision-making and policy making. This will ensure that regulated utilities and market participants have certainty and guidance regarding what investments are allowed in the energy system

1D Federal, provincial, and municipal governments need to coordinate and align their policies and programs and collaborate on future programs to ensure that there is a clear, comprehensive, costed, and complementary emissions reduction strategy for Ontario

In Canada, the provinces and territories are responsible for energy security, development and management of resources, regulation and legislative framework for energy supply, and energy pricing at the distribution level. However, increasingly, the federal, provincial, and municipal governments are all active in advancing energy policies related to emissions reductions strategies. Therefore, given the responsibilities of the provinces, and that the powers of municipalities are granted and defined by the provincial government, it is the view of the OEA that any comprehensive energy plan would best be led and developed by the provincial government (and its agencies), but in coordination with municipalities and the federal government.

This planning process will require clear and transparent mandates across government ministries and agencies (such as the OEB and IESO) to incorporate emission reductions into their policy, regulatory, system planning and other relevant decision-making.

The government has recently taken action to provide direction to the OEB (e.g., the Minister of Energy's renewed Mandate Letter) that provide guidance to the OEB with respect to developing policies related to electrification, integration and alignment between natural gas and electricity conservation programs, and support the decarbonization of the economy. Similarly, the Ministry of Energy has asked the IESO to evaluate a moratorium on procurements of new natural gas generating stations in Ontario and develop a pathway to zero emissions in the electricity sector.

Critical to this planning is that the energy industry be a partner in the development of plans as our industry is in the best position with respect to building the infrastructure necessary for the energy transition, the ability to quickly make course corrections when necessary, and understanding the differing needs and concerns of customers and communities.

The energy industry is keenly aware of the planning siloes (e.g., transportation infrastructure; building codes and standards; the needs of industrial customers) that need to be address across sectors of the economy to tackle the energy transition.

Energy industry partnership with government (and its agencies) has been extremely successful in Ontario with many recent examples in collaborating in developing Ontario energy plans and policy:

- During the COVID-19 pandemic, the Ministry of Energy and the sector and successfully worked together to develop and implement customer protections such as the COVID-19 Energy Assistance Program as well as extending the ban on disconnections related to non-payment

- The existing regional planning process, overseen by the OEB, recognizes that each region in Ontario has unique needs and that there are many ways for these needs to be met (e.g., conservation, generation, transmission, distribution, and innovative solutions, such as Distributed Energy Resources). It is an inclusive process with the IESO, local utilities, generators, local transmitter, gas utilities, Indigenous communities, and the public (i.e., municipalities, individuals, and business groups) working together to determine the best way for electricity needs to be met.

- Recent collaborations between the OEB and the sector and on planning and policy development, include the Energy[X]Change, Adjudication Modernization Committee, and the Framework for Energy Innovation Working Group.

- The IESO has a well-established Stakeholder Advisory Committee, in addition to Standing Committees and Working Groups.

This successful track record of industry-government cooperation outlined above provides a strong foundation for the sector, the provincial government, and other partners to work together to create and implement solutions to accomplish net zero goals on time, reliably, and cost-effectively

When considering issues related to costs the OEA believes energy costs should be borne typically by those that benefit from the access to energy. The widespread socialization of cost across all ratepayers and/or taxpayers should be avoided to achieve cost effective solutions. However, it is likely that affordability and access to energy will be an issue for some groups and targeted relief will be warranted to help those that need it. This will require careful analysis to ensure that the costs of pursuing the public policy objective of net zero will be allocated equitably among different customer classes of ratepayers, between ratepayers and taxpayers, and among different income levels.

STARTING THE JOURNEY

Once the course to reaching net zero is established, the journey to reach the destination can begin. A key component of this will be making the best use of Ontario's existing energy assets.

To its credit, the province has already started this work through the IESO's Natural Gas Phase-out study which found that completely phasing out natural gas generation by 2030 would lead to blackouts, require system changes that would increase residential electricity bills by 60 per cent, and also hinder the advancement of electrification of the broader economy (e.g., transportation). However, there is more work to be done.

2 OPTIMIZE USE OF EXISTING INFRASTRUCTURE

The first step in the energy transition is making the best use of our vast existing energy infrastructure investments. Prudent public policy should adopt a cost-effective approach that seeks to optimize the use of existing assets (and minimizing stranded assets). Pipelines, transmission lines, distribution infrastructure, power plants, refineries, storage facilities, distributed energy resources, demand response and energy efficiency resources are all major investments that have been made by utilities, customers, and other parties. These assets shape the energy landscape of the province.

Experience has shown that the public (i.e., voters) are very price sensitive to increases in the cost of energy. Taking advantage of existing infrastructure is the best way to ensure cost effective energy services and reliable supply for Ontario's residential and business consumers and meet public policy objectives.

As new system needs emerge in the future, Ontario should ensure that existing assets and their locations are assessed fairly for reinvestment potential. The recent past, in Ontario and other provinces, reveals that siting new energy infrastructure such as generation facilities and transmission lines can be very controversial and costly; this makes communities with existing facilities attractive locations for additional investment.

2A Optimize and co-ordinate the use of Ontario's substantial existing electricity and natural gas assets (transmission, generation, distribution, and storage facilities), where prudent and assessed against alternatives, to decarbonize our economy cost-effectively and provide reliable, sustainable energy choices for Ontario's homes and businesses.

2B To best leverage the natural gas system:

- Provide the OEB with a mandate to enable emissions reductions investments or energy sources even when more costly, when they meet cost of abatement thresholds
- Set targets for the blending of renewable natural gas (RNG) into the gas system, and move away from voluntary RNG option (as is already being done with ethanol for transportation fuel)

- Create a provincial strategy for hybrid heating systems with smart controls, replacing a conventional air-conditioner with a higher efficiency air-source heat pump, and pairing it with a gas furnace and smart controls through collaboration and partnership between electric and natural gas utilities
- Give the OEB a mandate for more aggressive demand-side management DSM targets and expanded programs, to reduce the volume of natural gas used for building heat and therefore reduce emissions
- Implement Automated Metering for natural gas customers to support and monitor DSM initiatives, promote usage awareness, and encourage behaviour change
- Immediately initiate a carbon, capture utilization and sequestration or storage pilot project for natural gas generation in Ontario
- Strengthen investments in RNG, and compressed natural gas to reduce emissions in medium- and heavy-duty transportation

2C To best leverage the electricity system:

- Leverage our existing almost emission-free electricity sector to electrify key segments (e.g., transport, industry, mining) of the economy where it is the most economic option and/or supports sustainability objectives
- Given the long lead times required for new infrastructure (e.g., generation, transmission or distribution upgrades) begin planning now to expand the electricity system so that it will be able to meet the significant increase in demand for electricity as a result of Net Zero and electrification objectives, including enabling investments in the capacity of the distribution system to handle the anticipated fast growth in electric vehicle charging
- Support the integration of distributed energy resources (DERs) into the electricity grid, including power storage and hydrogen, where they provide system benefit, and offer customers choices
- Invest and expand the transmission and distribution grids to address and enable economic development, accommodate changes in generation and prepare for decarbonization
- Invest in and expand conservation and demand management programs to reduce demand, emissions, and pressure on the electricity system. Expand these programs to include fuel switching to electricity to support decarbonization in key sectors such as building heating and industrial processes
- Continue to drive efficiencies in Ontario's distribution sector through collaboration, partnerships, and consolidation

Ontario has existing electricity distribution system assets of over $29 billion, electricity transmission assets of over $13 billion, and natural gas distribution system assets of over $25 billion. In addition, Ontario has billions of dollars of existing electricity generation, distributed energy resources, and other energy infrastructure assets located on the transmission and distributions systems as well as behind-the-meter on a customer's premise.

Maximizing the value of existing assets is the only way to meet NZ2050 targets in an affordable and reliable manner.

These investments are an important part of Ontario's energy future and must be leveraged by the government as it pursues the dual objectives of meeting climate change objectives. This should include giving the IESO clear direction on extending the life of existing power generation assets (particularly those with lower emissions and/or emissions-mitigation measures in place).

Additionally, the transportation sector is currently Ontario largest source of greenhouse gas emissions, representing Ontario's best opportunity to lower its carbon footprint in a cost-effective way by taking advantage of existing infrastructure (e.g., incorporating EV's into the electrical grid and RNG and CNG for heavy- and medium-duty transportation).

It is important to recognize that these existing assets include energy efficiency and demand response capacity. Ontario's utilities have invested significantly in conservation programs that deliver cost effective capacity to Ontario's energy system. The programs delivered by Ontario's electricity and gas utilities have an excellent track record of delivering value to their customers. Further, customers and other energy services providers have made investments in energy efficiency and demand response to lower their energy costs and reduce their environmental footprint.

For example, the government should leverage existing energy utility energy efficiency and conservation leadership and expertise for an expanded role in meeting GHG reduction goals. Utilities are in the best position to further expand conservation program offerings to the residential, multi-residential and commercial building sector as well as large industrial energy users.

Further, the investment by customers in new technologies and innovations that offer them greater autonomy over their energy use is steadily increasing. These distributed energy resources represent more existing infrastructure investments, and can include renewable generation, energy storage, combined heat and power, and micro-grids.

It behooves the province to take the fullest advantage possible of all the significant existing infrastructure described above that has already been paid for by ratepayers, taxpayers, utilities, energy service providers, and customers.

REACHING THE DESTINATION

Maximizing the value and utility of existing infrastructure as described in the previous section will enable the province to move forward with the new investments to reach NZ2050 in an expeditious, reliable, and cost-effective way. In many areas, industry and customers are already taking action to make the energy transition within the existing policy and regulatory framework. However, there are limitations in the current environment, requiring leadership and direction from the government to enable the sector to make additional infrastructure investments efficiently.

Moreover, Ontario will clearly have to develop new electricity generation capacity as the demands for electricity fuel switching increase. Any plans for a significant increase in generation capacity or imports will require a proportionate need for increased transmission and distribution capacity. New infrastructure will be required to reliably deliver this additional electricity from generators to loads, to allow for system optimization, and accommodate increases in two-way power flows. These long-lived key assets require long-lead times to both plan and build-out, involving intensive major planning processes, regulatory approvals, and extensive consultation processes. Therefore, it is imperative that work begin well before needs materialize to ensure this essential transmission and distribution infrastructure expansion will be ready on time to meet our 2050 targets.

Again, to its credit, the province has started work in this area through the request by the Minister of Energy that the develop an achievable pathway to phase-out natural gas generation and achieve zero emissions in the electricity system, taking into consideration reliability, cost, electrification of the broader economy, and the use of green fuels (e.g., hydrogen and RNG) and other technologies (e.g., pumped storage, battery storage, and demand response).

3 INVEST IN INFRASTRUCTURE, TECHNOLOGY & ADAPTATION

The path to net zero is uncertain. Experimentation and pilot projects will be necessary to reach the ultimate destination. There will be successes and failures along the way, but whether technologies live up to (or fail to live up) their promise will not be predictable. Therefore, the approach to planning should be technology agnostic going forward and evaluate promising evolving fuels and technologies based on their cost, feasibility, and scalability.

Timely technology investments, incentives, funding, and red tape reduction will be needed to achieve efficiency and commercial-scale in energy sources and production (e.g., alternative fuels, storage, and carbon capture and sequestration), but also in how energy is used across sectors (e.g., transportation, buildings, industrial processes).

Critically, these strategies and policies need to recognize that investments are required to not only lower emissions, but also to assist in adapting to climate change by making energy infrastructure more able to withstand and recover from extreme weather events (e.g., wind and flooding) caused by climate change

3A Competitive and regulatory processes should be used, wherever prudent, to procure new infrastructure as they are needed to ensure consumers get the lowest cost reliable clean energy

3B Foster a flexible regulatory regime that enables market participation of new and evolving technology and resource types, including energy storage and demand response

3C Invest in an expansion of province wide hydrogen infrastructure to facilitate a fueling network for heavy transportation; this will also require legislative and regulatory updates to enable production, transportation, and consumption of blue and green hydrogen

3D The provincial government should update the Oil, Gas & Salt Resources Act to remove the current ban on carbon sequestration to unlock opportunities for industry to invest and create jobs in Ontario

3E The OEB should move quickly to consult, develop, and implement recent government direction to provide guidance to utilities on system investments to prepare for electric vehicle adoption, so that utilities can incorporate these investments in distribution rate applications submitted to the OEB for review

3F The provincial government needs a policy on energy efficiency and decarbonization goals for buildings to achieve emissions reductions related to heating and ventilation

3G Continue to make investments in Ontario's cybersecurity framework to protect customers and energy sources

As Ontario builds its energy system for the future, when Ontario's requires resources, the use of a competitive (IESO procurement) and regulatory (OEB review) processes should be the main avenues of infrastructure acquisition to ensure that the system can meet environmental and reliability objectives at the lowest possible cost for consumers. In the case of the IESO, the government should also include access to procurement mechanisms with longer periods of return to support upgrades, repowering, and the addition of emerging technologies.

Also, given the likely long lead times required for new infrastructure (e.g., pipelines, underground carbon capture, large scale energy storage, generation, transmission or distribution) policy clarity as well as investments, incentives and regulatory mandates are in place in the near future to (1) expand the electricity system so that it will be able to meet the significantly increase in demand for electricity from transport and buildings (which are two of the largest sources of GHG in the province); and, (2) expanding the ability of the gas distribution system for the use of hydrogen in transportation and other future applications, that meeting emissions reduction targets requires.

As the province looks toward making these investments infrastructure and new technology, it should make sure that it leverages the significant amount of funds available from federal sources (e.g., Net Zero Accelerator Zero-Emission Vehicle (ZEV) programs) and encourage the growth of made-in-Ontario solutions.

4 INVEST IN ENERGY EFFICIENCY & DEMAND RESPONSE

Until recently, Ontario had projected a surplus electricity generation capacity and energy into 2030s, which led logically to system efficiency and affordability being policy priorities. However, pursuing NZ2050 changes the outlook significantly because it will result in a large increase in the use of cleaner forms of energy. The electrification of transportation and building will result in a significant increase in the demand and consumption of electricity. RNG and hydrogen will also increase in usage. Therefore, maintaining the critical need for both a reliable supply of energy and keeping energy costs affordable require that we not just increase the supply of clean energy and the infrastructure to deliver that energy to consumers, but produce and use all energy more efficiently.

Ontario has had great success in developing a culture of conservation behaviour that has demonstrably reduced the amount of electricity and natural gas we use at home and at work. The value of this conservation will need to be harnessed and expanded greatly as Ontario approaches 2050.

4A Ontario should expand investment in energy efficiency and demand response programs that reduce energy needs across all sectors and fuels

4B Ontario should pursue a decentralized delivery model for energy efficiency and energy conservation programs, taking advantage of the strong relationships that utilities and energy services companies have with consumers

4C Regular meetings should be established between the federal government and provincial government with the objective of coordinating and aligning energy efficiency programs (and funding) to eliminate overlap, duplication, and customer confusion

4D The federal government's funding of energy efficiency in Ontario should align with and support the provincial comprehensive plan outlined above, and also be consistent with the principles in the letter from the Ministry of Energy to the federal government encouraging collaboration between DSM and the new Canada Greener Homes Program to benefit Ontario ratepayers

Ontario's energy capacity can be enhanced through increased energy efficiency. Energy efficiency is a proven low-cost system resource in Ontario. As we look to expand the capability of our electricity system and other clean energy sources to replace carbon fuels, energy efficiency will have significant cost-effective potential.

Further, expanding DSM programs in the natural gas sector are also a critical component to reducing emissions.

Energy companies have the insights required to best deliver energy efficiency programs to customers; both residential (houses, apartments, and condominiums) and businesses (commercial and industrial), which require specifically tailored programs depending size, location on the energy system, region of the province (North v. South) and/or their particular line of business/industry. A decentralized delivery model would take the greatest advantage of the creativity and nimbleness of utilities and energy companies compared to the current centralized structure.

Ontario has been very successful in developing a new capacity auction in which demand response resources compete to provide low-cost energy capacity to our system. Demand response aggregators bring together electricity users who are willing to reduce their consumption in times of peak need. By reducing peak demand, the reliance on expensive, under-utilized peaking resources is reduced and in most cases carbon emissions are lowered. This resource has the potential to grow and to cost-effectively enhance Ontario's grid capacity with existing aggregation strategies.

As with other funding measures discussed earlier, investments in Ontario on energy efficiency and demand management should align with and leverage funding be offered by federal sources.

5 ACHIEVE BEHAVIOURAL CHANGE

Meeting NZ2050 requires a fundamental change in the behaviour and attitudes of society towards energy use. Lowering emissions and adaptation to climate change requires investments in ongoing communication with citizens and customers to make them aware of the role they can play in reducing their individual emissions, the options available to them to help them do so, and how to choose the options that best align with their needs and household budgets.

Greater awareness will allow consumers, families, and businesses to make informed choices about the impact they are having on emissions. Industry is in the best position to take a leadership role in delivering education and opportunities to customers, enabling their ability to change behaviour, lifestyle choices, and/or adopt low/zero emission technology.

5A Governments must work together to invest in public education to increase consumer awareness of the impact of daily decisions on emissions and the choices available to them, including

- The emissions impact of our various purchases
- The emissions profile of various products and services
- The impact of our transportation decisions
- How to make cost-effective purchases of goods and services to lower emissions
- Leverage the existing customers relationships of utilities and energy companies to develop and deliver education initiatives

Our behaviour can have a significant impact on our emissions footprint generally, including choices we make that impact how we use energy. As discussed earlier, Ontario has had great success in developing a culture of conservation behaviour with respect to electricity and natural gas. We also saw how behavioural practices have resulted in increasing transportation emissions even when technological advancement has resulted in much more fuel-efficient vehicles.

Reaching NZ2050 will require Ontarians to build on this progress by adapting our behaviour to continually reduce our emissions profile through all our activities and purchases. The education required to achieve emissions targets must go beyond the success Ontario has had in building a culture of conservation of electricity that was led by the utilities. It will require significant customized and individualized messaging to a diverse set of residential and business customers.

> Governments and the energy sector need to work together to provide ongoing education of citizens and all customers (residential and business) to make them aware of the role they can play in reducing their individual emissions and the options available to them to help them do so.

And we must all work together to build a culture of emissions consciousness just as we have successfully built a culture of conservation with respect to household energy consumption within our homes.

KEY OBJECTIVES

The purpose of this document is to provide elected officials and key decision makers from Ontario's main political parties with clear and precise recommendations on energy policies to address the needs of Ontario energy consumers. Our recommendations have been guided by the key objectives of ensuring energy in Ontario is:

Affordable

Policies should deliver the lowest cost possible to promote affordability for Ontario consumers and economic growth objectives, while still delivering on the objectives below

Sustainable

Energy policies should be developed in an integrated manner to achieve Ontario's climate change and environmental objectives by reducing energy related emissions and facilitating emissions reductions in other sectors of the economy, such as transportation and industry. It is only through taking a comprehensive approach to energy system planning by linking different types of energy (e.g., electricity, natural gas, and liquid fuels) together with the end-uses (e.g., heating, cooling, transport) that decarbonization targets will be reached

Reliable

Energy policies should ensure that Ontarians continue to have uninterrupted access to reliable energy. Our modern society and economy are dependent on reliable energy, and interruptions can have very serious consequences. Policies should allow for continuous investment in Ontario's energy infrastructure so that it can withstand and recover from extreme weather events and continue to supply Ontario's energy consumers with reliable access to affordable clean energy

To shape our energy future for a stronger Ontario

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COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS

Powering a climate-neutral economy: An EU Strategy for Energy System Integration

EN EN

1. AN INTEGRATED ENERGY SYSTEM FOR A CLIMATE-NEUTRAL EUROPE

The European Green Deal[1] puts the EU on a path to climate neutrality by 2050, through the deep decarbonisation of all sectors of the economy, and higher greenhouse gas emission reductions for 2030.

The energy system is crucial to deliver on these goals. The recent decline in the cost of renewable energy technologies, the digitalisation of our economy and emerging technologies in batteries, heat pumps, electric vehicles or hydrogen offer an opportunity to accelerate, over the next two decades, a profound transformation of our energy system and its structure. Europe's energy future must rely on an ever growing share of geographically distributed renewable energies, integrate different energy carriers flexibly, while remaining resource-efficient and avoiding pollution and biodiversity loss.

Today's energy system is still built on several parallel, vertical energy value chains, which rigidly link specific energy resources with specific end-use sectors. For instance, petroleum products are predominant in the transport sector and as feedstock for industry. Coal and natural gas are mainly used to produce electricity and heating. Electricity and gas networks are planned and managed independently from each other. Market rules are also largely specific to different sectors. This model of separate silos cannot deliver a climate neutral economy. It is technically and economically inefficient, and leads to substantial losses in the form of waste heat and low energy efficiency.

Energy system integration – the coordinated planning and operation of the energy system 'as a whole', across multiple energy carriers, infrastructures, and consumption sectors – is the pathway towards an effective, affordable and deep decarbonisation of the European economy in line with the Paris Agreement and the UN's 2030 Agenda for Sustainable Development**.**

Declining costs for renewable energy technologies, market developments, rapid innovation regarding storage systems, electric vehicles, as well as digitalisation are all factors leading naturally towards greater energy system integration in Europe. However, we have to go one step further and connect the missing links in the energy system in order to achieve higher decarbonisation objectives for 2030 and climate neutrality by 2050 – and do it in manner that is both cost effective and consistent with the European Green Deal's green oath to "do no harm". Relying on greater use of clean and innovative processes and tools, the path towards system integration will also trigger new investments, jobs and growth, and strengthen EU industrial leadership at a global level. It can also be a building block of the economic recovery in the aftermath of COVID-19 crisis. The Commission's recovery plan[2] presented on 27 May 2020 highlights the need to better integrate the energy system, as part of its efforts to unlock investment in key clean technologies and value chains and increase economy-wide resilience. In addition, the EU sustainable finance taxonomy will guide investment in these activities to ensure they are in line with our long-term ambitions[3]. An integrated energy system will minimise the costs of transition towards climate neutrality for consumers and open new opportunities for reducing their energy bills and active participation in the market.

[1] COM(2019) 640 final.

[2] 'Europe's moment: Repair and Prepare for the Next Generation', COM(2020) 456 final.

[3] Regulation (EU) 2020/852 of the European Parliament and of the Council of 18 June 2020 on the establishment of a framework to facilitate sustainable investment, and amending Regulation (EU) 2019/2088

The Clean Energy Package[4], adopted in 2018, provides a basis for better integration across infrastructure, energy carriers and sectors; however, regulatory and practical barriers remain. Without robust policy action, the energy system of 2030 will be more akin to that of 2020 than a reflection of what is needed to achieve climate neutrality by 2050.

This Strategy sets out a **vision on how to accelerate the transition towards a more integrated energy system**, one that supports a climate neutral economy at the least cost across sectors – while strengthening energy security, protecting health and the environment, and promoting growth, innovation and global industrial leadership.

Turning this vision into a reality requires resolute action, now. Investments in energy infrastructure typically have an economic life of 20 to 60 years. The steps taken in the next five-to-ten years will be crucial for building an energy system that drives Europe towards climate neutrality in 2050.

Thus, this **Strategy proposes concrete policy and legislative measures at EU level to gradually shape a new integrated energy system**, while respecting the differing starting points of Member States. It contributes to the work of the Commission on a comprehensive plan to increase the EU 2030 climate target to at least 50% and towards 55% in a responsible way and identifies follow-up proposals that will be prepared as part of the legislative reviews of June 2021, announced in the European Green Deal.

The parallel Communication '***A hydrogen strategy for a climate-neutral Europe***'[5] complements this Strategy to elaborate in more detail on the opportunities and necessary measures to scale up the uptake of hydrogen in the context of an integrated energy system.

2. ENERGY SYSTEM INTEGRATION AND ITS BENEFITS TO COST-EFFECTIVE DECARBONISATION

2.1. What is energy system integration?

Energy system integration refers to the planning and operating of the energy system "as a whole", across multiple energy carriers, infrastructures, and consumption sectors, by creating stronger links between them with the objective of delivering low-carbon, reliable and resource-efficient energy services, at the least possible cost for society. It encompasses three complementary and mutually reinforcing concepts.

First, a more 'circular' energy system, with energy efficiency at its core, in which the least energy intensive choices are prioritised, unavoidable waste streams are reused for energy purposes, and synergies are exploited across sectors. This is happening already in combined heat and power plants or through the use of certain waste and residues. There is however further potential, for example, in reusing waste heat from industrial processes, data centres, or energy produced from bio-waste or in wastewater treatment plants.

Second, a greater direct electrification of end-use sectors. The rapid growth and cost competitiveness of renewable electricity production can service a growing share of energy

[4] https://ec.europa.eu/energy/topics/energy-strategy/clean-energy-all-europeans_en.
[5] COM(2020) 301 final.

demand – for instance using heat pumps for space heating or low-temperature industrial processes, electric vehicles for transport, or electric furnaces in certain industries.

Third, the use of renewable and low-carbon fuels, including hydrogen, for end-use applications where direct heating or electrification are not feasible, not efficient or have higher costs. Renewable gases and liquids produced from biomass, or renewable and low-carbon hydrogen can offer solutions allowing to store the energy produced from variable renewable sources, exploiting synergies between the electricity sector, gas sector and end-use sectors. Examples include using renewable hydrogen in industrial processes and heavy-duty road and rail transport, synthetic fuels produced from renewable electricity in aviation and maritime transport, or biomass in the sectors where it has the biggest added value.

A more integrated system will also be a 'multi-directional' system in which consumers play an active role in energy supply. 'Vertically', decentralised production units and customers contribute actively to the overall balance and flexibility of the system – for instance, biomethane produced from organic waste injected in gas networks at a local level, or "vehicle-to-grid" services. 'Horizontally', exchanges of energy increasingly take place between consuming sectors – for instance, energy customers exchanging heat in smart district heating and cooling systems, or feeding in the electricity that they produce individually or as part of energy communities.

2.2. What are the benefits of energy system integration?

Energy system integration helps to **reduce greenhouse gas emissions in sectors that are more difficult to decarbonise**, for instance by using renewable electricity in buildings and road transport, or renewable and low carbon fuels in maritime, aviation, or certain industrial processes.

It could also ensure a more efficient use of energy sources, **reducing the amount of energy needed and related climate and environmental impacts**. In certain end-uses, new fuels will likely be required that use significant amounts of energy to be produced, such as hydrogen or synthetic fuels. At the same time, the electrification of a large share of our consumption can cut primary energy demand by a third[6] thanks to the efficiency of electrical end-use technologies. Also, 29% of industrial energy demand dissipates as waste heat, which can be reduced or reused. Small- and medium size enterprises can create synergies by both improving energy efficiency and increasing the use of renewable resources and waste heat. Overall, the transition to a more integrated energy system is projected to reduce gross inland consumption by a third by 2050[7], whilst supporting an increase in GDP of two thirds[8].

[6] For example, electric vehicles have an efficiency of around 60% compared to 20% for combustion engines on a tank-to-wheel basis, and heat pumps can deliver heat with three times less energy input than boilers.

[7] See COM(2018) 773 final, A Clean Planet for all. A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy. In-depth analysis in support of the Commission communication (LTS), figure 18: -21% in the 1.5TECH and -32% in the 1.5LIFE.

[8] See LTS, figure 92: 2050 GDP between 166% and 174% of 2015 or between GDP 154% and 161% of 2020 GDP.

Beyond energy and greenhouse gases emissions savings, it would also reduce air pollution and the energy water footprint[9], which is essential for climate adaptation, for health and to preserve natural resources.

Energy system integration will also **strengthen the competitiveness of the European economy** by promoting more sustainable and efficient technologies and solutions across industrial ecosystems related to the energy transition, their standardisation and market uptake. Specialised companies will provide services locally and create more regional economic benefits. This creates an opportunity for the Union to maintain and leverage its leadership in clean technologies such as smart grid technologies and district heating system, and lead on new, more efficient and complex technologies and processes that are expected to play a growing role in the energy systems worldwide, such as batteries or hydrogen technologies. Territories, regions and Member States facing the biggest transition challenges will be supported by the Just Transition Mechanism and, as part of it, the Just Transition Fund.

Moreover, better integration will **provide additional flexibility** for the overall management of the energy system and thus help to integrate increased shares of variable renewable energy production. It will also boost **storage technologies**: pumped hydropower, grid-scale batteries and electrolysers provide flexibility in the electricity sector. Home batteries and electric vehicles ('behind-the-meter') in buildings can help manage better the distribution grids. By 2050, electric vehicles could provide up to 20% of the flexibility required on a daily basis[10]. Thermal storage at factory-level can provide flexibility in the industrial sector. Through the closer integration of the power and heat sector, electric heat appliances could already make use of real time electricity prices to smarten demand response. Hybrid heat pumps[11] and smart district heating also provide opportunities for arbitrage between electricity and gas markets. Moreover, electrolysers can transform renewable electricity into renewable hydrogen, providing long-term storage and buffering capability, and further integrating the electricity and gases markets.

Finally, by linking up the different energy carriers and through localised production, self-production and smart use of distributed energy supply, system integration can also contribute to **greater consumer empowerment, improved resilience and security of supply.** Some of the technologies needed in an integrated energy system will require large amounts of raw materials, including some listed on the EU list of critical raw materials. But replacing imported natural gas and petroleum products with locally produced renewable electricity, gases and liquids, combined with the greater implementation of circular models, will first and foremost reduce the import bill and lessen dependency on external fossil fuel supplies, creating a more resilient European economy.

3. MAKING IT HAPPEN - AN ACTION PLAN TO ACCELERATE THE CLEAN ENERGY TRANSITION THROUGH ENERGY SYSTEM INTEGRATION

This strategy identifies six pillars where coordinated measures are outlined to address existing barriers for energy system integration.

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9 The water footprint of EU energy production was in 2015 198 km3 or 1068 litres per person and per day, or 242 km3 or 1301 litres per person and per day including energy imports. Source: JRC, Water – Energy Nexus in Europe, 2019.

10 According to METIS-2 S6 Study, baseline scenario (186TWh of 951TWh of total daily flexibility needs) would be provided by e-vehicles. Study to be published.

11 Heat pumps coupled with a boiler.

3.1. A more circular energy system, with ‘energy-efficiency-first’ at its core

Applying the energy-efficiency-first principle across sectoral policies is at the core of system integration. Energy efficiency reduces the overall investments needs and costs associated with energy production, infrastructure and use. It also reduces the related land and material resources use, and associated pollution and biodiversity losses. At the same time, system integration can help the EU achieve greater energy efficiency, through a more circular use of available resources and by switching to more efficient energy technologies. For instance, electric vehicles show much higher energy efficiency than combustion engines; and replacing a fossil-fuel based boiler with a heat pump using renewable electricity saves two thirds of primary energy[12].

The first challenge is to **apply the energy-efficiency-first principle consistently across the whole energy system**. This includes giving priority to demand-side solutions whenever they are more cost effective than investments in energy supply infrastructure in meeting policy objectives, but also properly factoring in energy efficiency in generation adequacy assessments. The Energy Efficiency Directive[13] and Energy Performance of Buildings Directive[14] already provide incentives for customers, but not enough for the full supply chain. Further measures are needed to ensure that customers’ decisions to save, switch or share energy **properly reflect the life cycle energy use and footprint** of the different energy carriers, including extraction, production and reuse or recycling of raw materials, conversion, transformation, transportation and storage of energy, and the growing share of renewables in electricity supply. In certain industries for which the shift from fossil fuels towards electricity will result in more consumption, trade-offs will have to be carefully considered.

In this context, the **Primary Energy Factor** (PEF)[15] is an important tool to facilitate comparisons of savings across energy carriers. Most renewables are 100% efficient and have a low PEF. The PEF should reflect the real savings brought about by renewable electricity and heat. The Commission will review the level of the PEF and assess whether current provisions in EU legislation ensure an adequate application of the PEF by Member States.

The upcoming ‘**Renovation Wave**’ initiative, announced in the European Green Deal, will also propose concrete actions to accelerate the uptake of energy and resource efficiency measures and of renewables in buildings across the EU in the next few years.

The second challenge is that **local energy sources are insufficiently or not effectively used in our buildings and communities**. Applying the principle of circularity in line with the new Circular Economy Action Plan[16], a big, yet largely unused potential is the reuse of **waste heat** from industrial sites, data centres, or other sources. Energy reuse can take place on-site (for example through the re-integration of process heat within manufacturing plants) or via a district heating and cooling network. The Energy Efficiency and Renewable Energy

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12 Kavvadias, K., Jimenez Navarro, J. and Thomassen, G., Decarbonising the EU heating sector: Integration of the power and heating sector, 2019.

13 Directive (EU) 2018/ 2002.

14 Directive (EU) 2018/844.

15 The primary energy factor indicates the amount of primary energy used to generate a unit of final energy (electrical or thermal), allowing a comparison of the primary energy consumption of products with the same functionality using different energy carriers. It shall be revised periodically according to Annex IV of the Energy Efficiency Directive.

16 COM(2020) 98 final.

Directives already contain provisions targeting this potential, but there is a need to further strengthen the regulatory framework to lift barriers hampering the wider application of these solutions. These barriers include insufficient awareness and knowledge about these solutions, the reluctance of companies to enter into a new business that is not their core activity, a lack of regulatory and contractual frameworks to share the costs and benefits of new investments, and barriers related to planning, transaction costs, and pricing signals. As regards data centres specifically, the Digital Strategy[17] has announced the ambition to make them climate-neutral and highly energy-efficient by no later than 2030; a greater re-use of their waste heat will significantly contribute to that objective.

A third challenge is linked to the untapped use of **wastewater**[18] **and biological waste and residues for bioenergy production**, including biogas. Biogas can be exploited on-site to reduce fossil fuel consumption, or upgraded to biomethane to allow injection into the natural gas grid or use in transport. Also, some farm infrastructures are suitable for an integrated production of solar-origin electricity and heat, creating the potential for renewable energy self-consumption and injection into the grid. The implementation of the new Circular Economy Action Plan and waste legislation and sustainable agriculture and forestry management systems could result in increased sustainable production of bioenergy from wastewater, waste and residues[19]. More efforts are needed to take advantage of the full potential for energy system integration, exploiting synergies and avoiding trade-offs. In agriculture, through the Common Agriculture Policy, farmers could be incentivised to contribute to a greater mobilisation of sustainable biomass for energy. Renewable energy communities can provide a sound framework for the use of such energy in a local context.

Key actions

To better apply the energy-efficiency-first principle:

- Issue **guidance** to Member States on how to **make the energy-efficiency-first principle operational** across the energy system when implementing EU and national legislation (by 2021).
- **Further promote** the energy-efficiency-first principle in all upcoming relevant methodologies (e.g. in the context of the European resource adequacy assessment) and legislative revisions (e.g. of the TEN-E Regulation[20]).
- Review the **Primary Energy Factor**, in order to fully recognise energy efficiency savings via renewable electricity and heat, as part of the review of the Energy Efficiency Directive (June 2021).

To build a more circular energy system:

- Facilitate the **reuse of waste heat from industrial sites and data centres,** through strengthened requirements for connection to district heating networks, energy

[17] C(2018) 7118 final.

[18] Wastewater treatment plants represent almost 1% of electricity consumption in Europe. This consumption can be reduced with more efficient technologies, and energy can be better recovered from those plants.

[19] The overall potential for increased biogas production from waste and residues remains high and, if fully exploited, could lead to biogas and biomethane production levels in 2030 of 2.7–3.7% of the EU’s energy consumption in 2030. See CE Delft, Eclareon, Wageningen Research, Optimal use of biogas from waste streams. An assessment of the potential of biogas from digestion in the EU beyond 2020, 2017.

[20] Regulation on Trans-European Networks in Energy, Regulation (EU) 347/2013.

performance accounting and contractual frameworks, as part of the revision of the Renewable Energy Directive and of the Energy Efficiency Directive (June 2021).

- Incentivise the **mobilisation of biological waste and residues from agriculture**, **food and forestry** sectors and support capacity-building for **rural circular energy communities** through the new Common Agriculture Policy, Structural Funds and the new LIFE programme (from 2021 onwards).

3.2. Accelerating the electrification of energy demand, building on a largely renewables-based power system

Electricity demand is projected to increase significantly on a pathway towards climate neutrality, with the share of electricity in final energy consumption growing from 23% today to around 30% in 2030, and towards 50% by 2050[21]. In comparison, that share has only increased by 5 percentage points over the last thirty years.

This growing electricity demand will have to be largely based on renewable energy. By 2030, the share of renewable energy in the electricity mix should double to 55-60%, and projections show a share of around 84% by 2050. The remaining gap should be covered by other low-carbon options[22].

Significant cost reductions in renewable power generation technologies have occurred in the last decades and are expected to continue – providing prospects that market forces will increasingly deliver investments. However, given the scale of the investments needed, it is urgent to tackle the barriers that still prevent a massive roll-out of renewable electricity, across all technologies. These include underdeveloped supply chains, the need for more and smarter grid infrastructure at national and cross-border level, the lack of public acceptance, administrative barriers and lengthy permitting (including for repowering), financing, the need for public or private long-term hedging options, or high costs for some less mature technologies.

The need for increased electricity supply can, alongside other relevant onshore renewable power technologies such as solar or wind energy, partly be met by offshore renewable energy production. The potential of offshore wind energy in the EU is between 300-450 GW by 2050[23], against today's capacity of some 12 GW[24]. This represents a huge opportunity for the EU industry to become the global leader in offshore technology, but will require considerable efforts to increase the European industrial capacity and build new value chains. Offshore electricity production also creates an opportunity for the nearby localisation of electrolysers for hydrogen production, including the possible reuse of the existing infrastructure of depleted natural gas fields. In addition, the development of solar energy will be further facilitated.

In the short term, the Commission will use the new recovery instrument Next Generation EU to support the continued deployment of renewable energy. It will assess opportunities to

[21] LTS, figure 20, looking at the 1.5LIFE and 1.5TECH scenarios for 2050.
[22] LTS, figure 23, looking at the 1.5LIFE and 1.5TECH scenarios for 2050.
[23] LTS, figure 24, including the UK.
[24] 20 GW including the UK.

channel EU funds through, or in combination with, the new **EU renewable energy financing mechanism**[25].

On the demand side, certain incentives to electrification are provided for instance through the sectoral targets set out in the Renewable Energy Directive, and in transport through CO_2 standards for vehicles, in the Alternative Fuel Infrastructure Directive and the Clean Vehicles Directive[26]. But challenges for **increased electrification remain** and differ per sector and across Member States **and more needs to be done**.

In **buildings,** electrification is expected to play a central role, in particular through the roll-out of heat pumps for space heating and cooling. In the residential sector, the share of electricity in heating demand should grow to 40% by 2030 and to 50-70% by 2050; in the services sector, these shares are expected to be around 65% by 2030 and 80% by 2050[27]. Large-scale heat pumps will play a relevant role in district heating and cooling. The most important barrier is the relatively higher level of taxes and levies applied to the electricity, and the lower levels of taxation for fossil fuels (oil, gas and coal) used in the heating sector, leading to lack of level playing field. Progress is also hampered by a number of other barriers, including unfit infrastructure planning, building codes and products standards, lack of skilled workforce for installation and maintenance, lack of public and private financing instruments, and lack of internalisation of CO_2 costs in heating fuels. This translates into low replacement rates of the EU fossil heating stocks, low development and modernisation of district heating/cooling networks, and low building refurbishment rates. With the Renovation Wave initiative, the Commission will ensure a higher penetration of renewables in buildings. It will also support training programmes under the Updated Skills Agenda.

In **industry**, heat represents more than 60% of energy use. Industrial heat pumps can help decarbonise the low temperature heat supply within industries, and can be coupled with waste heat recovery. Other technologies are being developed for higher temperature heating (such as microwave or ultrasound) and for electrifying processes by electrochemistry. Barriers to deployment include lack of information and long pay-back, due to the high price of electricity relative to gas and the high abatement cost associated with these technologies, relative to current CO_2 prices. Changes in the production process leading to higher costs could also affect the competitiveness of sectors exposed to international competition. EU support could help develop a number of flagship projects and demonstrate innovative electricity-based processes. Furthermore, the industrial supply chain for these technologies is not sufficiently mature and the integration of these electrification technologies into industrial processes requires training and new skills. The Commission will explore, together with industry, ways to address these issues.

In **transport**[28], the Sustainable and Smart Mobility Strategy is foreseen for later this year, and will set out how our transport system needs to decarbonise and modernise to reduce its emissions by 90% in 2050[29]. Electric mobility is key, and will accelerate decarbonisation and reduce pollution, especially in our cities, and new mobility services will increase the efficiency of the transport system and reduce congestion. The rapidly falling cost of electric

[25] https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/12369-Union-renewable-Financing-mechanism
[26] Directive (EU) 2019/1161 on the promotion of clean and energy-efficient road transport vehicles.
[27] LTS, figure 42.
[28] Including mobile machinery.
[29] LTS

vehicles means that they could be competitive with combustion engine vehicles around 2025, on a total cost of ownership basis[30]. The European Green Deal points to the need of stepping up the roll out of recharging infrastructure, starting with the ambitious objective of having at least one million publicly accessible recharging and refuelling points by 2025, as well as the use of on-shore power supply in ports. To that end the Commission will mobilise InvestEU – which will be reinforced and include a new Strategic Investment Facility – and the Connecting Europe Facility funding to broaden the coverage of the charging infrastructure network. Support through the Recovery and Resilience Facility and through Cohesion Policy to clean vehicles and alternative fuels infrastructure will be a priority as part of the strengthened focus on delivering the European Green Deal in our regions and cities, including in public buildings, offices, depots and private dwellings. The Renovation Wave initiative also offers opportunities to promote electric chargers and electric vehicle charging stations. The Commission will also propose to revise the Alternative Fuels Infrastructure Directive and the TEN-T Regulation – also assessing how to further strengthen synergies between the TEN-T and TEN-E policies. The Commission will accompany the continued support under the Connecting Europe Facility with a further mapping of funding opportunities and regulatory initiatives for the roll-out of recharging infrastructure. The Commission will also tackle challenges to make electro-mobility more attractive to the user such as the non-transparent pricing at public charging stations and the persistent lack of cross-border interoperability of charging services. Measures are also needed to boost the use of renewable electricity at ports, to facilitate the electrification of road freight transport. Further electrification of railways could be explored taking into account its economic viability[31].

Overall, **a growing use of electricity in end-use sectors will mean a need to keep under review the adequacy of renewable electricity supply**, to ensure that it can match the scale required to support the decarbonisation of the abovementioned sectors.

Electrification can present challenges for the management of the electricity system. Regional and cross-border coordination between Member States will become increasingly important. This will be addressed by the development of Regional Coordination Centres[32] in 2022, allowing for more robust security analysis, emergency and outage coordination and common infrastructure planning, and the deployment of storage and other flexibility options. The Commission will support the **uptake of energy storage** through full implementation of the Clean Energy Package and in the upcoming legislative reviews, including the review of the TEN-E Regulation.

Challenges are also expected at a more local level. For instance, the full electrification of passenger road transport will require in parts of the Union upgrades to the local grid infrastructure. At the same time, it can create **opportunities for providing storage and flexibility** to the system[33]. In particular, **smart charging** and so-called **Vehicle-to-Grid** (V2G) services will be essential to manage grid congestion and limit costly investments in grid capacity. The Electricity Directive contains a number of provisions that lay the basis for enabling smart charging and the development of V2G services, but challenges still remain, for instance regarding the deployment of smart recharging points, common standards and communication protocols, grid charges, taxation and access to the in-vehicle data. The

[30] See for instance BNEF, Electric Vehicle Outlook, 2020.
[31] Over 50% of the rail network and around 80% of the rail traffic is already electrified.
[32] Regulation (EU) 2019/943.
[33] See Trinomics, Energy storage – Contribution to the security of the electricity supply in Europe, 2020.

development of a new Network Code on Demand Side Flexibility as well as the review of the Alternative Fuels Infrastructure Directive both present opportunities to create a robust framework for the successful integration of demand-side flexibility in general, and electric vehicles in particular.

Electrification efforts of areas not connected to the continental grid, such as the Outermost Regions, some islands, or remote or sparsely populated areas present specific challenges. Technical and financial support for energy system integration is particularly relevant for a cost-effective transition in these regions.

Key actions

To ensure continued growth in the supply of renewable electricity:

- Through the Offshore Renewable Strategy and follow-up regulatory and financing actions, ensure the cost-effective planning and deployment of **offshore renewable electricity**, taking into account the potential for on-site or nearby hydrogen production, **and strengthen EU's industrial leadership in offshore technologies** (2020).
- Explore establishing minimum **mandatory green public procurement** (GPP) criteria and targets in relation to **renewable electricity**, possibly as part of the revision of the Renewable Energy Directive (June 2021), supported by **capacity building** financing under the LIFE programme.
- Tackle remaining barriers to a **high level of renewable electricity supply** that matches the expected growth in demand in end-use sectors, including through the review of the Renewable Energy Directive (June 2021).

To further accelerate the electrification of energy consumption:

- As part of the **Renovation Wave** initiative, promote the further electrification of buildings' heating (in particular through heat pumps), the deployment of on-buildings renewable energy, and the roll-out of electric vehicle charging points (from 2020 onwards) , using all available EU funding, including the Cohesion Fund and InvestEU.
- Develop more specific measures for the use of **renewable electricity in transport**, as well as for **heating and cooling** in buildings and industry, in particular through the revision of the Renewable Energy Directive, and building on its sectoral targets (June 2021).
- Finance pilot projects for the **electrification of low-temperature process heat in industrial sectors** through Horizon Europe and the Innovation Fund (by 2021).
- Assess options to support the further decarbonisation of industrial processes, including through electrification and energy efficiency, in the revision of the **Industrial Emissions Directive** (2021)[34].
- Propose to revise **CO_2 emission standards for cars and vans** to ensure a clear pathway from 2025 onwards towards zero-emission mobility (June 2021).

To accelerate the roll-out of electric vehicle infrastructure and ensure the integration of new loads:

- Support the roll-out of **1 million charging points by 2025**, using available EU funding, including the Cohesion Fund, InvestEU and Connecting Europe Facility funding, and communicate regularly on the funding opportunities and regulatory environment to roll out a charging infrastructure network (from 2020 onwards).

- Use the upcoming **revision of the Alternative Fuels Infrastructure Directive** to accelerate the roll-out of the alternative fuels infrastructure, including for electric vehicles, strengthen interoperability requirements, ensure adequate customer information, cross-border usability of charging infrastructure, and the efficient integration of electric vehicles in the electricity system (by 2021).
- Take up corresponding requirements for charging and refuelling infrastructure in the **revision of the** Regulation for the Trans-European Transport network **(TEN-T)** (by 2021) and explore greater synergies through the revision of the **TEN-E** Regulation in view of possible energy network related support for cross border high capacity recharging as well as possibly hydrogen refuelling infrastructure (by 2020).
- Develop a **Network Code on Demand Side Flexibility**[35] to unlock the potential of electric vehicles, heat pumps and other electricity consumption to contribute to the flexibility of the energy system (starting end-2021).

3.3. Promote renewable and low-carbon fuels, including hydrogen, for hard-to-decarbonise sectors

While direct electrification and renewable heat present the most cost-effective and energy-efficient decarbonisation options in many cases, there are a number of end-use applications where they might not be feasible or have higher costs. In such cases, a number of renewable or low-carbon fuels could be used, such as sustainable biogas, biomethane and biofuels, renewable and low-carbon hydrogen or synthetic fuels. These cases include a number of industrial processes, but also transport modes such as aviation and maritime, where sustainable alternative fuels such as advanced liquid biofuels and synthetic fuels will have an essential role to play. Rapid action is necessary: for example, in aviation, only around 0.05% of total jet fuel consumption comes from liquid biofuels.

Unlocking the potential of renewable fuels produced from sustainable biomass

Today, **biofuels**[36]**, biogas and biomethane**[37] account for only 3.5% of all gases and fuels consumption[38] and are largely based on food and feed crops. Their full potential should be achieved in a sustainable manner, which mitigates climate, pollution and biodiversity risks [39].

Biofuels will have an important role to play, notably in hard-to-decarbonise transport modes, such as aviation or maritime – including through hybridisation projects linking biofuels and renewable hydrogen production. The Commission will in particular explore how to support to

[35] Under Regulation (EU) 2019/943.

[36] Biofuels are liquid fuels produced from biomass, through a variety of processes and using a variety of feedstock, such as biodiesel, bioethanol and Hydrotreated Vegetable Oils (HVO).

[37] Biogas is a gaseous mixture (primarily methane and carbon dioxide) produced from biomass, through the decomposition of organic matter in the absence of oxygen (anaerobically). Biogas can be used directly as a fuel, or be purified or "upgraded" into biomethane, which can thus be used for the same applications as natural gas and injected into the gas grid.

[38] Source: Eurostat.

[39] Directive 2018/2001 establishes a cap to first generation biofuels and limitations to high Indirect Land Use Change (ILUC) risk food and feedstocks, while reinforcing and extending sustainability criteria.

the quick development of innovative low-carbon fuels such as advanced biofuels, alongside synthetic fuels, across the whole value chain of the industry in Europe, leading to better coordination of the market actors and rapid increase of production capacity. Biomethane can contribute to the decarbonisation of the gas supply. However, the deployment of biofuels and biogases has so far been hampered by regulatory uncertainty. The revised Renewable Energy Directive has taken a first step to address these issues by introducing a target of 3.5% for the consumption of advanced biofuels and biogas in transport[40]. The 6% greenhouse gas emission target of the Fuel Quality Directive also supports the deployment of biofuels. In addition, the Communication '*The role of Waste to Energy in the circular economy*'[41] clarifies which waste-to-energy approaches are more sustainable, including for the production of biomethane, while the Biodiversity Strategy underlines that the use of whole trees and food and feed crops for energy production should be minimised.

The revision of the Renewable Energy Directive, as well as the Commission initiatives to boost the supply and uptake of sustainable aviation and maritime fuels announced in the European Green Deal, will present opportunities for further targeted support to accelerate the development of the market for biofuels and biogases.

Promoting the use of renewable hydrogen in hard-to-decarbonise sectors

Today, hydrogen contributes less than 2% of Europe's energy consumption[42], and is almost exclusively produced from unabated fossil fuels. Hydrogen has an important role to play in reducing emissions in hard-to-decarbonise sectors, in particular as a fuel in certain transport applications (heavy-duty road transport, captive fleets of buses, or non-electrified rail transport, maritime transport and inland waterways) and as a fuel or feedstock in certain industrial processes (steel, refining or chemical industries – including to produce 'green fertilisers' for agriculture). Carbon dioxide in reaction with hydrogen can also be further processed into synthetic fuels, such as synthetic kerosene in aviation. In addition, hydrogen brings other environmental co-benefits, such as the lack of air pollutant emissions.

Hydrogen produced through electrolysis using renewable electricity can play a particularly important "nodal" role in an integrated energy system, where it can help integrate large shares of variable renewable generation, by offloading grids in times of abundant supply, and providing long term storage to the energy system. It can also allow local renewable electricity production to be used in a range of additional end-use applications.

The Hydrogen Strategy, adopted today, presents measures to create the conditions for hydrogen to contribute to decarbonising the economy in a cost-effective way, addressing the whole hydrogen value chain to support economic growth and recovery. The priority for the EU is to develop hydrogen production from renewable electricity which is the cleanest solution. In a transitional phase however, other forms of low-carbon hydrogen are needed to replace existing hydrogen and kick-start an economy of scale. In addition to providing financial support in certain end-use applications, the Commission will consider establishing

[40] The use of "advanced" biofuels and biogas (gained from certain residues and by-products from agriculture and forestry activities, industrial and municipal waste in full respect of the waste hierarchy, and other ligno-cellulosic material) is encouraged under the Directive 2018/2001. Biofuels and biogas need to meet sustainability requirements to be statistically accounted as renewable under that Directive.

[41] COM(2017) 034 final.

[42] Calculated on the basis of production data provided by Fuel Cells and Hydrogen Joint Undertaking, includes the use of hydrogen as a feedstock; FCHJI, Hydrogen roadmap, 2019.

minimum shares or quotas of renewable hydrogen in specific end-use sectors. Renewable and low-carbon fuels (including hydrogen) can be promoted most effectively if they can be easily distinguished from more polluting energy sources. Therefore, the Commission will work to introduce a comprehensive terminology and a European certification system covering all renewable and low carbon fuels[43]. Such a system, based notably on full life cycle greenhouse gas emissions savings, will allow for more informed choices when deciding on policy options at the EU or national level.

Enabling carbon capture, storage and use to support deep decarbonisation, including synthetic fuels

Even a fully integrated energy system cannot completely eliminate CO_2 emissions from all parts of the economy. Together with alternative process technologies**, carbon capture and storage** (CCS) is likely to play a role in a climate-neutral energy system. In particular CCS can address hard-to-abate emissions **in certain industrial processes**, thus enabling these industries to have a place in a climate neutral economy and maintaining industrial jobs in Europe. In addition, if the stored CO_2 was captured from biogenic sources or directly from the atmosphere, CCS could even compensate residual emissions in other sectors.

An alternative to the permanent storage of CO_2 is to combine it with renewable hydrogen to produce synthetic gases, fuels and feedstock (Carbon Capture and Use, or CCU). Synthetic fuels can be associated with very different levels of greenhouse gas emissions depending on the origin of CO_2 (fossil, biogenic, or captured from the air), and the process used. Fully carbon-neutral synthetic fuels require sourcing the CO_2 from biomass or the atmosphere. Synthetic fuels are currently inefficient in terms of energy required for production and are confronted with high production costs. Support to progress the development of this conversion technology, including demonstration and upscaling of the full production process, is relevant with a view to having substitutes for fossil fuels in particular in the most difficult to decarbonise sectors, which may continue to rely on high energy density liquid fuels, such as aviation. As their production requires large amounts of renewable energy, their uptake would have to be matched by a corresponding increase in renewable energy supply.

It is of key importance to properly monitor, report and account the emissions and removals of CO_2 associated with the production of synthetic fuels to reflect correctly their actual carbon footprint. Complementing the current greenhouse gas emission monitoring and reporting system, a robust carbon removal certification mechanism will ensure the traceability of the CO2 along its emission, capture, use and potential reemission throughout our economic system. The Development of a carbon removal certification system, as announced in the Circular Economy Action Plan[44], can provide regulatory incentives for market take-up of synthetic fuels.

The uptake of CO_2 capture and usage in Europe is slow, with investment and operational costs still high. There are also barriers that prevent the transport of CO_2 to those places where it will be stored or used. In some parts of the EU, there are also concerns among citizens and political decision-makers regarding the storage of CO_2. An annual European CCUS Forum could be convened as part of the Clean Energy Industrial Forum to further study options to foster CCUS projects.

[43] See also Hydrogen Strategy, COM(2020) 301 final.
[44] COM(2020) 98 final.

Key actions

- Propose a **comprehensive terminology for all renewable and low-carbon fuels** and a **European system of certification** of such fuels, based notably on full life cycle greenhouse gas emission savings and sustainability criteria, building on existing provisions including in the Renewable Energy Directive (June 2021).
- Consider **additional measures to support renewable and low-carbon fuels,** possibly through minimum shares or quotas in specific end-use sectors (including aviation and maritime), through the revision of the Renewable Energy Directive and building on its sectoral targets (June 2021), complemented, where appropriate, by additional measures assessed under the REFUEL Aviation and FUEL Maritime initiatives (2020). The support regime for hydrogen will be more targeted, allowing shares or quota only for renewable hydrogen.
- Promote the financing of **flagship projects** of **integrated, carbon-neutral industrial clusters** producing and consuming renewable and low-carbon fuels, through Horizon Europe, InvestEU and LIFE programmes and the European Regional Development Fund (from 2021).
- Stimulate first-of-a-kind production of **fertilisers from renewable hydrogen** through Horizon Europe (from 2021).
- Demonstrate and scale-up the **capture of carbon** for its use in the production of **synthetic fuels**, possibly through the Innovation Fund (from 2021).
- Develop a regulatory framework for the **certification of carbon removals** based on robust and transparent carbon accounting to monitor and verify the authenticity of carbon removals (by 2023).

3.4. Making energy markets fit for decarbonisation and distributed resources

In an integrated energy system, trustworthy and efficient markets should guide customers towards the most energy-efficient and cheapest decarbonisation option, on the basis of prices that properly reflect all the costs of the energy carrier used.

Ensuring non-energy price components contribute to decarbonisation across energy carriers

In many EU Member States, **taxes and levies on electricity are higher than for coal, gas or heating oil**, both in absolute value and as a share of total price[45]. Over the past years, charges and levies on electricity, such as those financing renewable support schemes, have continued to increase. At the same time, the *energy component* of the final (retail) electricity price has reduced both in absolute and relative terms. This has widened the asymmetry in non-energy costs between electricity and gas: for retail household electricity prices, for instance, taxes and levies now add up to 40% of the final price, compared to 26% of gas or 32% for heating oil[46]. Some other energy- or carbon-intensive sectors such as international aviation and maritime transport, as well as agriculture, can be subject to low or no VAT, and, under the current Energy Taxation Directive, to low energy excise duties.

Also, carbon costs are only partially internalised, or not internalised at all, in some sectors (e.g. road and maritime transport or space heating) or in some Member States, or may not be

[45] DG Energy, Energy Prices and Costs Report, 2019.
[46] DG Energy, Energy Prices and Costs Report, 2019.

sufficient to incentivise decarbonisation in some sectors covered by the ETS (e.g. aviation). Finally, fossil fuel subsidies also persist in the EU.

Overall, applicable taxes and levies, including carbon pricing, are not applied homogeneously across energy carriers and sectors, and create distortions towards the use of specific carriers.

Finally, the specificities of electricity used for energy storage or for hydrogen production should also be considered, avoiding double taxation (so that energy is only taxed once when delivered for final consumption), and avoiding unjustified double grid charges.

Placing consumers at the centre

Clear and easily accessible information is essential to enable citizens to change energy consumption patterns and switch to solutions that support an integrated energy system. Customers – citizens and businesses alike – should be informed on their rights, on the technology options available to them and their associated carbon and environmental footprint, so they can make informed choices and truly drive decarbonisation. It is important that vulnerable households are not left behind and energy poverty is addressed[47]. In the context of the Climate Pact, the Commission will launch a **consumer information campaign** on their rights related to the energy market.

Customer information rights for electricity customers have been enhanced with the Clean Energy Package – further work remains to be done for **gas and district heating customers** to align those with the electricity sector.

Furthermore, **markets for sustainable products and services** are still missing, for instance for products such as steel, cement and chemicals produced from renewable or low-carbon fuels. As part of the broader efforts announced in the Circular Economy Action Plan to improve sustainability of such intermediary products, consumers should receive relevant information that may encourage them to pay a price premium.

Making electricity and gas markets fit for decarbonisation[48]

The Clean Energy Package already laid the foundation to make **electricity markets** fit to integrate large amounts of variable electricity and the integration of flexibility from demand response and storage, while improving the market signals to stimulate investments and empowering electricity customers. The challenge now lies in implementing the measures properly, in particular the completion of market coupling through day-ahead and intraday trading.

As we progress towards climate-neutrality, the volume of natural gas consumed in Europe will progressively reduce. While **gaseous fuels** are expected to continue to play an important role in our energy mix[49], the mix of gaseous fuels will highly depend on the chosen decarbonisation pathway. By 2050, the share of natural gas in gaseous fuels is projected to

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[47] In line with the European Pillar of Social Rights (principle 20) that guarantees the access to essential services, including energy.

[48] Issues connected to the creation of open and competitive markets for hydrogen are covered in the dedicated Hydrogen Strategy.

[49] LTS, figure 33: the 1.5TECH and LTS 1.5LIFE scenarios project a share of 18-22% for gaseous fuels in the EU energy mix by 2050, compared to 25% today.

reduce to 20%, and most of the remaining 80% gaseous fuels should be of renewable origin[50]. But the future mix of these gaseous energy carriers – biogas, biomethane, hydrogen or synthetic gases – is hard to project.

The gas market regulatory framework should be re-examined so as to facilitate the uptake of renewable gases and customer empowerment, whilst ensuring an integrated, liquid and interoperable EU internal gas market.

In this context, issues to consider include the connection to infrastructure and the market access for distributed production of renewable gases, including at the distribution level, which would complement the use of renewable gases in a more local, circular context (such as biogas used on farm). In addition, with renewable gases injected into the gas network, and supply sources further diversified, the quality parameters of gas consumed and transported in the EU would change. To avoid this leading to market segmentation and trade restrictions, there is a need to look at how to ensure the interoperability across gas systems and the unhindered flow of gases across Member States' borders.

Updating the State aid framework

The current review of the State aid framework, and notably its guidelines on energy and environmental protection, will contribute to energy system integration by providing a fully updated and fit-for-purpose enabling framework for a cost-effective deployment of clean energy and the well-functioning of energy markets[51].

Key actions

To promote a level-playing field across all energy carriers:

- **Issue guidance to Member States** to address the high charges and levies borne by electricity and to ensure the **consistency of non-energy price components across energy carriers** (by 2021).
- Align the taxation of energy products and electricity with EU environment and climate policies, and ensure a harmonised taxation of both storage and hydrogen production, avoiding double taxation, through the **revision of the Energy Taxation Directive**[52].
- Provide more consistent carbon price signals across energy sectors and Member States, including through a **possible proposal for the extension of the ETS to new sectors** (by June 2021).
- Further work towards the **phasing out of direct fossil fuel subsidies,** including in the context of review of the State aid framework and the revision of the Energy Taxation Directive (from 2021 onwards).
- Ensure that the revision of the **State aid framework** supports cost-effective decarbonisation of the economy where public support remains necessary (by 2021).

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50 LTS, figures 28 to 32.

51 Beyond those provisions, the Research, Development and Innovation Framework and the Communication setting out criteria for the analysis of the compatibility with the internal market of State aid to promote the execution of important projects of common European interest are also relevant.

52 Initial Impact Assessment for the revision of the Energy Taxation Directive: https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/12227

To adapt the gas regulatory framework:

- **Review the legislative framework to design a competitive decarbonised gas market,** fit for renewable gases, **including to empower gas customers** with enhanced information and rights (by 2021).

To improve customer information:

- In the context of the Climate Pact, launch a **consumer information campaign** on energy customer rights (by 2021).
- **Improve information to customers on the sustainability of industrial products** (in particular steel, cement and chemicals) as part of the sustainable product policy initiative, and, as appropriate, through complementary legislative proposals (by 2022).

3.5. A more integrated energy infrastructure

Energy system integration will translate into more physical links *between* energy carriers. This calls for a **new, holistic approach for both large-scale and local infrastructure planning**, including the protection and resilience of critical infrastructures. The objective should be to make the most of the existing infrastructure while avoiding both lock-in effects and stranded assets. Infrastructure planning should facilitate the integration of various energy carriers and arbitrate between the development of new infrastructure or re-purposing of existing ones. It should consider alternatives to network-based options, especially demand-side solutions and storage.

The various components of the energy network will all need to evolve. Modern low-temperature **district heating systems** should be promoted, as they can connect local demand with renewable and waste energy sources, as well as the wider electric and gas grid – contributing to the optimisation of supply and demand across energy carriers. However, district heating networks account for 12% of the total final heating and cooling energy consumption, are highly concentrated in a few Member States, and only a limited share of them are highly efficient and based on renewables.

Implementing the Clean Energy Package will contribute to a more efficient use of **electricity grids**. Nevertheless, accelerated electrification of new end-uses will require to reinforce the grid, mainly at distribution but also at transmission level[53], and to make it smarter. Electrolysers will link up to the electricity grids, and possibly to existing gas grids. In the context of the assessment of Member States' National Energy and Climate Plans, the Commission will also analyse the progress towards the 15% electricity interconnection target and consider appropriate action, including in the context of the revision of the TEN-E Regulation.

The existing **gas network** provides ample capacities across the EU to integrate renewable and low-carbon gases and repurposing gas network for hydrogen applications may provide in some cases a cost-efficient solution, including to transport renewable hydrogen from offshore renewable electricity parks. Ports could transform into centres receiving electricity produced offshore, as well as liquid hydrogen, and thereby contribute to enable the global trade of renewable hydrogen or synthetic fuels.

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[53] In line also with the EU electricity interconnection target included under Regulation (EU) 2018/1999 on the Governance of the Energy Union and Climate Action

While gas networks may be used[54] to enable blending of hydrogen to a limited extent during a transitional phase, **dedicated infrastructures for large-scale storage and transportation of pure hydrogen**, going beyond point-to-point pipelines within industrial clusters, may be needed. The expansion of hydrogen refuelling stations will also be assessed as part of the revision of the Alternative Fuels Infrastructure Directive and the Regulation on the TEN-T guidelines.

Similarly, further reflection is needed on the role of **CO_2-dedicated infrastructure,** transporting CO_2 across industrial sites for further use, or to large scale storage facilities.

The Regulation on Trans-European Networks in Energy (TEN-E) provides a framework for the selection of infrastructure projects of common interest in electricity, gas and CO_2 networks. In this context, currently, **10-Year Network Development Plans** (TYNDPs) at national and EU level are developed in parallel for gas and electricity by Transmission System Operators. Future network planning will require a more integrated and cross-sectoral approach, notably of the electricity and gas sectors. It will also require full consistency with climate and energy targets, including alignment with National Energy and Climate Plans, an adequate consideration of all relevant actors, and should be informed by local conditions.

The Commission will ensure that the ongoing revision of the **TEN-E Regulation** makes it fully consistent with climate neutrality and enables the cost-effective integration of the energy system, as well as its integration with the digital and transport systems. The ongoing revision of the Regulation on the Trans-European Transport network (TEN-T) will also seek synergies with the TEN-E Regulation, aiming to generate additional opportunities for the decarbonisation of transport from the new vision of energy infrastructure planning.

Finally, increasing interdependencies mean that disruptions in one sector can have an immediate impact on operations in others and a new coherent security approach for both physical and digital infrastructures is necessary. The new Security Union Strategy will address both critical infrastructure and cybersecurity and needs to be accompanied by sector-specific initiatives to tackle the specific risks faced by critical infrastructures such as in an integrated energy system and infrastructure.

Key actions

- Ensure that the **revisions of the TEN-E and TEN-T regulations** (in 2020 and 2021, respectively) fully support a more integrated energy system, including through greater synergies between the energy and transport infrastructure, as well as the need to achieve the 15% electricity interconnection target for 2030.
- **Review the scope and governance of the TYNDP** to ensure full consistency with the EU's decarbonisation objectives and cross-sectoral infrastructure planning as part of the revision of the TEN-E Regulation (2020) and other relevant legislation (2021).
- Accelerate investment in **smart, highly-efficient, renewables-based district heating and cooling networks**, if appropriate by proposing stronger obligations through the revision of the Renewable Energy Directive and the Energy Efficiency Directive (June 2021), and the

[54] A blend of 5-20% by volume can be tolerated by most systems without the need for major infrastructure upgrades or end-use appliance retrofits or replacements. See for instance BNEF, Hydrogen Economy Outlook, 2020.

financing of flagship projects.

3.6. A digitalised energy system and a supportive innovation framework

Digitalisation supports energy system integration – it can enable dynamic and interlinked flows of energy carriers, allow for more diverse markets to be connected with another, and provide the necessary data to match supply and demand at a more disaggregated level and close to real time. A combination of novel sensors, advanced data exchange infrastructures, and data handling capabilities that make use of Big Data, Artificial Intelligence, 5G and distributed ledger technologies can enhance forecasting, allow the remote monitoring and management of distributed generation and improve asset optimisation, including the on-site use of self-generation. Digitalisation is also key to unleash the full potential of customers having a flexible energy consumption across different sectors to contribute to the efficient integration of more renewables. More generally, digitalisation provides an opportunity for economic growth and worldwide **technological leadership**.

Digitalisation represents a challenge in terms of **increased energy demand** for ICT equipment, networks and services which needs to be adequately managed in the context of an integrated energy system. Digitalisation also brings other challenges for the energy sector, in particular on **ethics, privacy and cybersecurity,** with consideration to the specificity of the energy sector.

A system-wide **Digitalisation of Energy action plan** could accelerate the implementation of digital solutions, building on the Common European energy data space[55], announced in the European Data strategy. As part of the implementation of the Clean Energy Package, it will roll-out smart metering, foster demand response, and ensure the interoperability of energy-related data. It will also use EU funding opportunities such as the Connecting Europe Facility, InvestEU, the Digital Europe Programme, and structural funds to scale-up solutions developed through Horizon Europe.

Finally, **research and innovation** will be a key enabler to create and exploit new synergies in the energy system, for instance in relation to e-mobility, to heating or to the decarbonisation of energy intensive industries. Research should focus on enabling lower maturity technologies to come into the market, while more mature and innovative technologies should be scaled up through large scale demonstrations through the proposed Horizon Europe and its partnerships and making use of complementarities among the various EU funding programmes. Technology development must go hand in hand with societal innovation.

Key actions

- Adopt a **Digitalisation of Energy Action plan** to develop a competitive market for digital energy services that ensures data privacy and sovereignty and supports investment in digital energy infrastructure (2021).
- Develop a Network Code on **cybersecurity in electricity**[56] with sector-specific rules to increase the resilience and cybersecurity aspects of cross-border electricity flows,

[55] https://ec.europa.eu/info/sites/info/files/communication-european-strategy-data-19feb2020_en.pdf
[56] Under Regulation (EU) 2019/943.

common minimum requirements, planning, monitoring, reporting and crisis management (by end 2021).

- Adopt the implementing acts on **interoperability** requirements and transparent procedures for access to data within the EU (first one in 2021)[57].
- Publish a new **impact-oriented clean energy research and innovation outlook** for the EU to ensure research and innovation supports energy system integration (by end 2020).

4. CONCLUSIONS

This communication sets out a strategy and a set of actions to ensure that energy system integration can contribute to the energy system of the future – one that is efficient, resilient, secure and driven by the twin goals of a cleaner planet and a stronger economy for all.

The transition to a more integrated energy system is of crucial importance for Europe, now more than ever. First, for recovery. The COVID-19 outbreak has weakened the European economy and undermines the future prosperity of European citizens and business. This strategy is part of the recovery plan. It proposes a path forward that is cost-effective, promotes well-targeted investments in infrastructure, avoids stranded assets and leads to lower bills for businesses and customers. In short, it is key to accelerating the EU's emergence from this crisis and for mobilising necessary EU funding, including the Cohesion Fund, as well as private investments. Second, for climate neutrality. Energy system integration is essential to reach increased 2030 climate targets and climate neutrality by 2050. It exploits energy efficiency potential, enables a larger integration of renewables, the deployment of new, decarbonised fuels, and a more circular approach to energy production and transmission.

Finally, a truly integrated energy system is vital for shaping Europe's global leadership in clean energy technologies, by leveraging Europe's existing strengths – an established leadership in renewable energy; a regional approach to system operation and infrastructure planning; liberalised energy markets; and excellence in energy innovation and digitalisation.

We are still far from where we need to be by 2050. To get there, both fundamental and far-reaching action is urgently needed. The Clean Energy Package adopted in 2018-2019 lays the foundation for system integration and should be fully implemented. In the context of the Green Deal, the new actions outlined in this communication will add the necessary scope and speed to move towards the energy system of the future, contributing to the EU's increased climate ambition and to shaping the legislative revisions to be proposed in June 2021. The time to act is now.

Obviously, system integration will not be a one-size-fits-all process: despite a common objective of EU climate neutrality by 2050, EU Member States have different starting points. As such, Member States will follow different pathways, depending on their respective circumstances, endowments and policy choices, which are already reflected in the respective National Energy and Climate Plans (NECPs). This strategy offers a compass to direct these efforts in the same direction.

Citizens have a central role in system integration. This means that they should contribute to shape the implementation of this Strategy, using the Climate Pact as well as other existing citizen fora to advance the system integration agenda.

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[57] Under Article 24 of Directive (EU) 2019/944.

With this document, the Commission invites the Council, the Parliament, other EU institutions and all stakeholders to focus on how to take forward energy system integration in Europe. It intends to invite interested parties to debate in a **large dedicated public event** at the end of this year and to contribute to the **public consultations and impact assessments that will inform the preparation of the follow-up proposals envisaged for 2021 and beyond**.

DECARBONISING HEAT IN BUILDINGS

PUTTING CONSUMERS FIRST

APRIL 2021

FOREWORD

As a nation, we are fast approaching a crunch point, with Net Zero and associated policies leading the pull away from fossil fuels. When discussing decarbonisation with friends and at work, I am struck by how often heat in homes is omitted from the conversation, and when it is remembered, by how much the peak heat demand in winter is underestimated. I therefore very much welcome the thoughtful contributions this report provides.

Clearly heat pumps have a huge role to play in the transition to low carbon heat in homes. Indeed, there is a temptation to assume we can rely on them exclusively. After all, they are available now and can be delivered house by house, while other solutions such as hydrogen must take place at the community or street scale, which introduces a whole new set of barriers to overcome, including finding new low carbon ways to scale up hydrogen production.

It is however, as this report highlights, much more complicated than simply switching from boilers to heat pumps, not least due to the unsuitability of some homes for heat pumps, but also because it appears that delivering peak heat to homes in winter may be an insurmountable challenge for all electrically delivered heat. Thus, alternative, and complimentary approaches are needed, to align with practical constraints of people's homes and deliver huge swings in demand and service peak heat, which is perhaps the brightest feather in the hydrogen's proponents cap.

Where the balance lies between combinations of these, and other technologies identified in this report, is not yet known. It will depend on many factors, not least the success of any future national domestic retrofit campaigns, consumer acceptance of different technologies, the speed of the decarbonisation of electricity and the emergence of new solutions like house batteries and energy storage.

It is a cliché to say there is no silver bullet to low carbon heating, but this document provides tangible evidence to inform policy decisions around the scale, speed and direction of future low carbon heating in UK homes. It presents a refreshingly accessible and pragmatic evaluation of low carbon heating options from the point of view of one of the most important stakeholders, who are -sadly - often excluded from discussions and decision making associated with decarbonising heat in homes: householders like you and me.

Dr David Glew,
Head of Energy Efficiency and Policy at the Leeds Sustainability Institute

EXECUTIVE SUMMARY

From an evaluation of the GB housing stock, it is clear that a mosaic of low carbon heating technologies will be needed to reach net zero. While heat pumps are an important component of this mix, our analysis shows that it is likely to be impractical to heat many GB homes with heat pumps only.

A combination of lack of exterior space and/or the thermal properties of the building fabric mean that a heat pump is not capable of meeting the space heating requirement of 8 to 12m homes (or 37% to 54% of the 22.7m homes assessed in this report) or can do so only through the installation of highly disruptive and intrusive measures such as solid wall insulation. Hybrid heat pumps that are designed to optimise efficiency of the system do not have the same requirements of a heat pump and may be a suitable solution for some of these homes. This is likely to mean that decarbonised gas networks are therefore critical to delivery of net zero.

3 to 4m homes[1] (or 14% to 18% of homes assessed in our analysis) could be made suitable for heat pump retrofit through energy efficiency measures such as cavity wall insulation. For 7 to 10m homes there are no limiting factors and they require minimal/no upgrade requirements to be made heat pump-ready.

Nevertheless, given firstly the levels of disruption to the floors and interiors of homes caused by the installation of heat pumps, and secondly the cost and disruption associated with the requirement to significantly upgrade the electricity distribution networks to cope with large numbers of heat pumps operating at peak demand times - combined with the availability of a decarbonised gas network which requires a simple like-for-like boiler replacement - is likely to mean that many of these 'swing' properties will be better served through a gas based technology such as hydrogen (particularly when consumer choice is factored in) or a hybrid system. A recent trial run in winter 2018-19 by the Energy System Catapult revealed that all participants were reluctant to make expensive investments to improve the energy efficiency of their homes just to enhance the performance of their heat pump. They were more interested in less costly upgrades and tangible benefits, such as lower bills or greater comfort.

This means that renewable gases including hydrogen as heating fuels are a crucial component of the journey to net zero and the UK's hydrogen ambitions should be reflective of this.

The analysis presented in this paper focuses on the external fabric of the buildings, further analysis should be undertaken to consider the internal system changes that would be required for heat pumps and hydrogen boilers, for example BEIS Domestic Heat Distribution Systems: Gathering Report from February 2021 which considers the suitability of radiators for the low carbon transition.

1 The analysis takes into account the number of energy efficiency measures that have already been installed in GB homes.

THE CHALLENGE OF DECARBONISING HEAT

Near-full decarbonisation of heat for buildings is one of the biggest challenges in reducing emissions from the energy system to net zero by 2050.

To date much of the success in reducing emissions has come from the power sector, with more recent successes in the transport sector. Having plucked the low hanging fruit, we now need to work on reaching the harder to decarbonise areas, and in particular heat in buildings.

In 2019, the residential sector emitted 65.2 Mt of carbon dioxide emissions (CO_2), accounting for 19 per cent of all CO_2[2]. The main source of emissions in the residential sector is the use of fossil fuels (mainly natural gas) for heating and cooking.

Currently 85% or 23 million homes are connected to the gas grid with the remaining 15% or 4 million using oil or LPG as their main heating fuel or electric heating. In the next 10 to 15 years, the majority of these systems will need to be replaced with low-carbon alternatives if the UK is to meet its net zero target.

Compared to decarbonisation of the power sector, where emission reductions were delivered without shifts required in consumer behaviour, reducing emissions from buildings need support from consumers and access to their homes.

This means it is also critical to consider what the consumer experience of the transition to low carbon heat feels like and how this might affect preferences.

A COMBINATION OF LOCALITY-SPECIFIC SOLUTIONS WILL DELIVER HEAT DECARBONISATION IN HOMES

Residential building emissions can be reduced through a combination of switching to low-carbon sources and energy efficiency improvements. However, the heterogeneity of the UK building stock means that heating decarbonisation will not be through a single nationwide solution and will likely require a mix of locality-specific solutions tailored to the opportunities, requirements and constraints of each location.

The two primary routes to reducing emissions in buildings are electrification of heat using heat pumps and/or to repurpose gas distribution grids to carry hydrogens rather than natural gas. A mix of electric and low-carbon gas technologies are expected to be predominantly used.

Other solutions such as biomethane, heat networks, hybrid heat pumps and direct electric heating are also expected to be part of the mosaic of technologies needed to deliver heat decarbonisation in different locations.

ENERGY EFFICIENCY WILL BE CRUCIAL TO ACHIEVE NET ZERO

Reducing underlying energy demand through increasing energy efficiency will be critical. Installing energy efficiency measures in homes and buildings has an upfront cost but reduces energy demand and carbon emissions. Some energy efficiency measures are simple to install and pay for themselves quickly, these should be installed in combination with any heating system replacement. For example, thermostatic radiator valves, smart thermostats and draughtproofing interventions fall into this category.

Insulation is a more tricky case, some types of insulation are relatively cheap and easy to install, whereas others can be highly disruptive. Insulation of cavity walls falls into the first category, as it is a non-intrusive measure which has a major impact on heat lost through the walls[3]. Over two-third of homes in the GB were built with cavity walls, and in nearly 65% of these, or 11.2[4] million homes, there is evidence of insulation being installed. Insulation of the remaining ~4,8 million homes that have unfilled walls should be a priority.

Meanwhile, nearly one third of homes in the GB were built with brick and stone solid walls, most of which remain uninsulated due to the costs and disruption caused by the installation of solid wall insulation. This typically involves either installing cladding on the exterior of the building, which fundamentally changes the aesthetic of the property and may require planning permission, or installing insulation on the interior face of the walls which is highly disruptive and reduces interior floor area as well as requiring redecoration works, floor insulation installation also follows a similarly disruptive process[5]. For this reason, it is likely to be highly challenging to make the case for these types of measures to be installed in significant numbers.

2 BEIS (2020). UK Greenhouse gas emissions, provisional figures 2019.
3 Loft insulation also falls into this category
4 Estimates based on sample of 22.7m properties used in this analysis. For further details on the methodology, please see section 'Housing stock analysis'
5 New technology solutions such as Q-Bot can be less disruptive

CUSTOMER EXPERIENCE IS KEY

Heat and comfort are necessities for life. And as the decarbonisation of heat will require changes to people's homes, the consumer needs to be bought into the process and actively participate. Therefore, in transitioning to a zero-carbon future it is imperative that firstly the quality of these services is maintained or improved and secondly that they are inclusive and accessible to all customer types, not just a subset.

Different heating technologies have different impacts on customer experience, both in terms of the enduring interaction with the product and also of the installation itself.

THE ENDURING EXPERIENCE OF DIFFERENT TECHNOLOGIES WILL SUIT DIFFERENT TYPES OF CONSUMERS

On the enduring experience, it is important to recognise that heat pumps tend to produce heat at lower temperatures to hydrogen boilers, meaning they are more suited to maintaining relatively static room temperatures and require larger surface areas for heat dissipation, making them highly suitable for underfloor heating, or otherwise requiring relatively larger radiators than boilers.

Heat pumps are also not suitable for replacing combi boilers for instantaneous production of hot water, instead requiring a hot water storage tank. Again the temperature output of heat pumps means this tank needs to run more continuously given the longer time required to heat the water.

THE INSTALLATION OF DIFFERENT HEAT TECHNOLOGIES WILL SUIT DIFFERENT TYPES OF PROPERTIES

The majority of homes in Great Britain are heated by either a natural gas or other fossil fuel boiler system. Replacing a boiler with a heat pump has a number of key challenges.

INSTALLING A HEAT PUMP IN EXISTING HOMES

For heat pumps to work effectively as the sole heating source, the buildings need to be thermally efficient. Heat pumps typically require both internal and external space as well as changes to internal systems such as radiators which can cause disruption to consumers.

INSTALLING A HYDROGEN-READY BOILER IN EXISTING HOMES

The installation of a hydrogen boiler is a like-for-like replacement for a conventional heating system which does not need to be supported by the interventions needed to fit a heat pump in a home. There is also no requirement in this case for exterior or additional interior space in the home. This can also be the case for some compact hybrid systems.

KEY ☆ New

THERMAL PROPERTIES

Buildings need to be thermally efficient in order for heat pumps to be a viable heating technology. As building regulations have evolved over the last century, the thermal properties of new builds have improved - however this means that there is a wide range of thermal characteristics depending on a properties age. In general, the older the property, the worse the thermal efficiency and hence the greater level of intervention required to make the property suitable for retrofit. As discussed above, while some insulation measures are entirely rational, others may well be impractical. This means there is likely to be a correlation between the construction date of a property and its applicability for heat pumps.

HEATING SYSTEMS

Heat pumps produce lower output temperatures than boilers meaning that the internal heating systems of properties need to be altered. Depending on the floor construction and covering, an underfloor heat distribution system may be most suitable alternatively, new, larger radiators may need to be added or replaced. The cost and disruption of changing internal systems mean that customer preference will play a role in uptake of different technologies.

SPACE REQUIREMENTS

There are interior and exterior space requirements for the installation of a heat pump. Storage cylinders for hot water are required [and are typically larger than those required for boilers]. Aside from the necessity of hot water storage, the heat pump itself requires equipment to be installed both on the exterior of the property and the interior. Whilst the internal equipment is similar in footprint to a boiler, the necessity of availability of exterior space can be a constraint especially in more densely populated areas and may also feature in consumer preference decisions.

On the other hand, the installation of a hydrogen boiler is a like-for-like replacement for a conventional heating system which does not need to be supported by the interventions needed to fit a heat pump in a home. There is also no requirement in this case for exterior or additional interior space in the home. This can also be the case for some compact hybrid systems.

Experience from schemes that require work to be carried out in the home such as the smart meter roll out or the energy company obligation (ECO) show that consumers are generally reticent to what are perceived to be enforced changes within their homes. Both of these schemes have ultimately underdelivered against expectations and they only required relatively small interventions. It is likely to be politically and practically challenging to impose obligations on householders to install highly intrusive and disruptive measures.

This has been evidenced in early heat pump retrofit trials, where even proactive consumers that were interested in heat pump installation have dropped out of the schemes once the scale of associated works to the home became apparent.

IT IS IMPORTANT TO CONSIDER THE REALITY NOT THE ABSTRACT

When considering the likely technology mix it is crucial to examine the actual make up of the housing stock, both in terms of the age and therefore thermal properties and the archetype and therefore likely availability of space. It is also imperative to consider consumer preference given the scale of challenge and need to engage with them.

Heat pumps are expected to be the most suitable technology to decarbonise heat in a number of situations. However, in other cases with less potential for electrification, low-carbon gas-based solutions will be the optimal solution. Examples of where heat pumps may be an optimal solution and where they may not be suitable are discussed next based on property archetypes.

LOW CARBON HEATING OPTIONS

HEAT PUMPS

Heat pumps are an established technology that can immediately and substantially reduce emissions from heating and hot water consumption. A heat pump uses the heat in the air or the ground as the main source of energy and requires electricity to operate. For every unit of electricity that is put in, the technology has the potential to produce 3 to 4 units of heat, depending on the type of heat pump.

Running costs will depend on heat demand, system efficiency and electricity prices. Depending on the heating fuel that it replaces, it can lead to energy bill savings. A heat pump operates at higher efficiencies at low flow temperatures which means that in buildings that are poorly insulated, the technologies is less efficient. Therefore, in order to make heat pumps viable, buildings need to be highly thermally efficient.

A report[6] prepared for BEIS in 2018 found the costs of the work involved to install an air-source heat pump to be between £8,750 and £21,550 depending on the heat pump size and interventions required. Meanwhile, the same report found the costs of the work involved to install a ground-source heat pump to be between £13,200 and £27,350, depending on the heat pump size and interventions required. Ground-source heat pumps may be more suitable for communal heating.

In 2019, heat pumps represented two per cent of the heat market.

HYDROGEN BOILERS

Hydrogen boilers can replace conventional gas boilers on a like-for-like basis and has the potential to eliminate carbon emissions from heating completely, with water as the only by-product. Hydrogen-ready boilers are being developed by UK leading boiler manufacturers in the UK. Two UK boiler manufacturers are currently involved in the Government's Hy4Heat programme that looks at the technical and safety challenges of replacing conventional appliances with hydrogen-ready ones. One of the workstreams of the programme focuses on development of consumer ready and fully certified prototype hydrogen boilers to be installed in consumer homes. The programme has already reported on the technical details of the technologies and more information will be made available in the annual report to be published in December. It is expected that hydrogen-ready boilers will be available to consumer at no or small additional cost to methane boilers.

'Green hydrogen' can be produced through a process that makes use of electricity - if the electricity comes from renewable sources such as wind, solar or hydro, then the hydrogen is effectively green. In the production of 'blue hydrogen', the gas is produced by steam methane reformation and the emissions are curtailed using carbon capture and storage.

HYBRID HEAT PUMPS

Hybrid heat pump systems combine a boiler and a heat pump to meet a building's space heating and hot water requirements. Hybrid heat pumps are a low-carbon heating solution that can deliver emission savings that vary depending on the overall efficiency of the system that in turn is determined by the mode of operation. Hybrids can be run such that the boiler meets the entire heat demand at times when the heat pump is unable to operate ('switch' mode) or such that the heat pump contributes to meeting the space heating demand and the boiler provides the remaining heat required for the water to reach the right temperature at all times ('parallel' mode).

Hybrid heat pumps can either be installed alongside existing high temperature emitters or with low temperature emitters. In contrast to electric heat pumps, relying on high temperature emitters is possible because the boiler component is capable of meeting the peak heat demand with higher flow temperatures, ensuring comfort can be achieved. Costs for installation are similar to heat pump only systems, on a £/kW basis though the heat pump size will be lower due to the hybrid nature of the system.

BIOMETHANE

Biomethane is a green gas chemically identical to methane that can be injected in the gas grid and deliver immediate carbon emission savings, without the requirement from consumers to change existing appliances.

Production of biomethane is based on anaerobic digestion of waste organic material through the breakdown of organic material by micro-organisms in the absence of oxygen to produce biogas. The biogas is then refined to produced biomethane.

The technology to produce biomethane is a commercially available solution. Until recently, installations have been supporting the injection of biomethane in the gas distribution network. In July 2020, National Grid connected a biomethane production facility (a farm) to the National Transmission System (NTS), injecting biomethane in the grid for the first time. The plant will support up to 15,000 cubic metres per hour of biogas flows which is enough renewable gas to supply ten households every hour.

The total potential supply of biomethane from waste in the UK will be limited by the amount of waste that can be cost-effectively accessed.

6 Delta-ee (2018). The Cost of Installing Heating. Measures in Domestic Properties. The findings are also reported in the fourth Environmental Audit Committee report on energy efficiency of existing homes.

HOUSING STOCK ANALYSIS

We have carried out an analysis of the GB housing stock based on the challenges discussed above.

Property archetypes are defined by their type and age. Data published in the National Energy Efficiency Data-Framework (NEED) Multiple Attributes Tables[7] is used to define the size of each archetype segment. This dataset, compiled in 2020, uses all properties contained on the 2019 VOA council tax database in Great Britain[8], where the property is assessed to have valid gas or electricity consumption. The dataset covers 82%[9] of properties registered to pay council tax in England and Wales[10] and 65%[11] in Scotland[12]. Building insulation and thermal elements are sourced from the English Housing Survey[13] from England and Wales[14] and from the House Condition Survey for Scotland[15,16].

While decarbonising heat will require a mosaic of solutions, our analysis focuses on the suitability of different building archetypes to the installation of an electric heat pump as the sole decarbonisation solution. We have considered heat pump suitability for each property archetype, focusing on the properties thermal efficiency, space availability and period features. When heat pump is not found to be a likely solution for the property archetype, a gas-based heating solution needs to be considered. Gas-based solutions include a range of options such as hydrogen boilers, hybrid heat pumps and biomethane injection into the grid. This approach allows us to establish whether network infrastructure to deliver gas-based solutions to consumer homes is requirement to deliver the country decarbonisation goals or whether the same objective can be achieved without it.

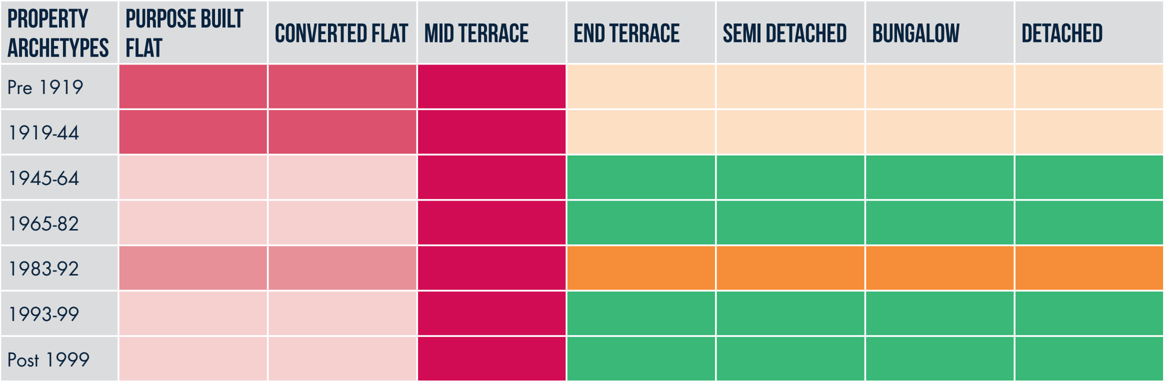
The results of this analysis are presented using a RAG assessment[17]. Based on their score against thermal efficiency and space availability metrics, each property archetype is considered as either:

- Likely suitable for a heat pump: these property archetypes require minimal or no energy efficiency upgrades and are not space-constrained;
- Possibly suitable for a heat pump: these property archetypes are either space-constrained or require energy efficiency and heating system upgrades;
- Not suitable for a heat pump: these property archetypes require significant energy efficiency and heating system upgrades, such as solid wall or underfloor insulation and/or are space-constrained.

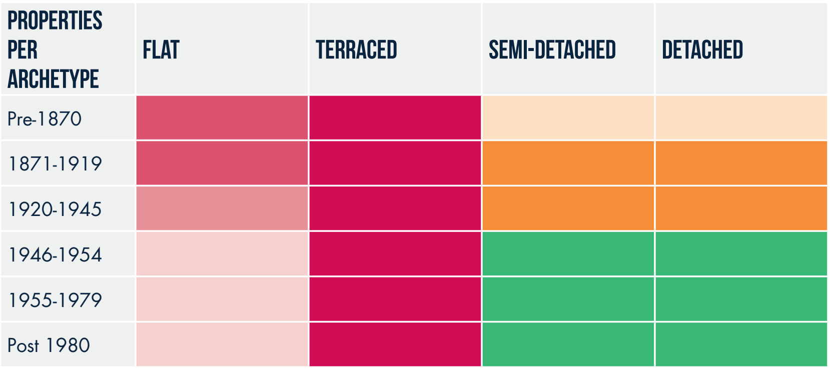
The score and suitability to a heat pump for each archetype is assigned based on the features of the typical property in each segment and on the overall number of properties that would require interventions in each group. The analysis of the estimated number of properties that may be suitable/possibly suitable/not suitable that is presented in the next section, takes into account the actual number of properties in each segment, the type of wall[18], and the number of energy efficiency upgrades that have been completed to date.

7 Multiple Attributes Table 2018 and Scotland Multiple Attribute Table 2018
8 The VOA database only covers properties that are registered to pay council tax. There are properties not included due to an inability to accurately match the property to an ordnance survey UPRN. The VOA dataset used for Scotland is based on 2014 data.
9 21.1 million
10 Coverage is limited by availability of information on electricity or gas consumption
11 1.57 million
12 Coverage is limited by availability of information on electricity or gas consumption.
13 DA6201: insulation - dwellings
14 Insulation and thermal properties of properties in Wales assumed to be the same as in England.
15 For Scotland, we used the wall type and insulation estimates published in the House Condition Survey as starting point. The percentage of homes with cavity walls and with insulation reported in the survey is broadly in line with the estimates reported for England. Given the lack of data on wall type and insulation by type and age for Scotland, we have assumed the same distribution observed for homes in England.
16 The percentage of homes build with solid walls assumed to be insulated is 8%, in line with the estimated published by the Climate Change Committee in 'Annex 2. Heat in UK buildings today'.
17 Please see appendix - RAG Assessment for the complete RAG assessment
18 For example, while the majority of properties built before 1940 were built with solid walls, some properties in this archetype were built with cavity walls. This is reflected in the analysis, as well as the number of energy efficiency interventions that has already been installed.

OVERALL SUITABILITY OF PROPERTIES IN ENGLAND AND WALES TO A HEAT PUMP[19]



OVERALL SUITABILITY OF PROPERTIES IN SCOTLAND TO A HEAT PUMP[20]



KEY

- Possibly suitable for communal heat pump with solid wall insulation/ not suitable
- Possibly suitable for communal heat pump with cavity wall insulation/ not suitable
- Possibly suitable for communal heat pump/ not suitable
- Possibly suitable for heat pump with cavity wall insulation
- Likely suitable for a heat pump
- Possibly suitable for heat pump with solid wall insulation
- Not suitable

Based on this analysis it is likely that heat pump only systems will be unsuitable for 37% to 54% of the existing housing stock.

While 14 to 18% could be practically adapted to be made suitable, consumer and societal choice will need to be factored in to determine whether this is the optimal technology solution.

There are limiting factors to installing a heat pump which means that the technology is highly unlikely to be suitable solution for 8 to 12m of homes or 37% to 54% of the properties considered in this analysis. These buildings include properties that were built with solid brick walls, uninsulated and/or space constrained e.g., flats and mid-terrace buildings as well as high rise buildings that would require non-standard insulation measures. There is likely to be variation among properties in the purpose-built flat and converted flat segments (some of these flats will be space constrained, others will not). This uncertainty is captured by the range estimate of properties considered to be unsuitable to a heat pump.

Hybrid heat pumps that are designed to optimise efficiency of the system do not have the same requirements of a heat pump and may be a suitable solution for some of the homes where a heat pump cannot work effectively as the sole heating source. Compact hybrids may be suitable for properties with space constraints.

Our analysis suggests that 3 to 4m homes or, 14% to 18% of homes considered in this paper could be made suitable for a heat pump following some energy efficiency improvements such as insulation of cavity walls. This includes detached, semi-detached, bungalow and end-terrace properties built with cavity walls. There is likely to be variation among properties in the purpose-built flat and converted flat segments (some of these flats will be space constrained, others will not). This uncertainty is captured by the range estimate of properties considered to be potentially suitable to a heat pump.

Our analysis suggests that 7 to 10m homes including detached, semi-detached, bungalow, end-terrace properties could be suitable for a heat pump given the limited space constraint and thermal efficiency of the buildings.

19 While the RAG assessment for mid terrace houses is the same as the assessment for flats, the installation of communal heat pump is not considered a potential solution for mid-terrace buildings given the buildings layout.

20 The assessment of terrace properties will vary depending on whether the properties are assumed to be mid-terrace or end-terrace houses. 70% of terrace properties in England are mid-terraces, the same assumption is made for Scotland, hence the table shows the assessment using this assumption. Our range captures the uncertainty in this variable.

CASE STUDIES

PRE-WAR MID-TERRACE

For nearly 1.6 million homes a combination of lack of exterior space and the thermal properties of the building fabric mean that a heat pump is not capable of meeting the space heating requirement of the property or can do so only through the installation of highly disruptive and intrusive measures.

Mid terraced houses are one of the most popular forms of housing in GB. There are 3.9 mid-terraced properties in GB[21] and 1.7 million were built pre 1930s, using solid bricks, the majority of which remains uninsulated

Several improvements to these properties would be required to make them suitable for a heat pump and lack of exterior space could make the installation challenging.

Insulating the envelope of the building is key to reduce the heat loss of the property. In addition to insulating the walls, a combination of roof, ceiling and/or floor insulation is likely to be necessary to reduce the heat loss to a level that can guarantee the efficient operation of the heat pump.

Replacement of existing radiators is likely to be needed to ensure the heat pump can operate at a low flow temperature. Alternatively, underfloor heating pipes may need to be installed.

Some of these interventions can be intrusive and disruptive to the householder. In addition, mid-terraced houses often lack the exterior space that is necessary to install the heat pump.

Another consideration is the period features of these properties which may be impacted by the interventions required to make them heat-pump ready and may reduce their value.

Overall, the building fabric requirements necessary for the efficient operation of a heat pump and the lack of exterior space means that the technology will not be the optimal solution to reduce emissions from heating from these properties.

DECARBONISING HEAT EMISSIONS FROM PRE-WAR MID-TERRACES

There are 1.8m mid-terrace houses in the UK that were built pre-war, using solid bricks. To be made heat-pump ready, a combination of the following interventions is likely to be required:

- Insulation of solid wall
- Insulation of ceiling and floor
- Replacement of radiators or installation of underfloor heating

These measures can cause significant disruption to the consumer. Even with these interventions, the installation of a heat pump may not only be challenging due to the disruptive improvements required but also impractical given the space constraint.

Given these barriers, decarbonisation of pre-war mid-terraced houses through a heat pump may be impractical. **A hydrogen boiler or compact hybrid is likely to be the most suitable and practical solution in this case.**

21 These estimates are based on a sample of 22.7m properties used in this analysis.

CONVERTED FLATS

For nearly 520,000 converted flats, a heat pump is not likely to be the optimal decarbonisation solution, due to the thermal properties of the buildings and space constraints.

Nearly 850,000 homes in the GB are converted flats, 60% of them built with uninsulated solid walls[22].

Several improvements are likely to be required to make the properties suitable for a heat pump.

The building envelope will require insulation. In addition to walls, ceiling and or floor will need to be insulated. Radiators or underfloor heating may need to be added or replaced to allow the heating system to operate optimally. These interventions can be intrusive and cause significant disruption to the householder.

In addition, converted flats could have limited exterior space and can be space constrained, particularly in dense urban areas. The space constraint combined with the thermal characteristics of converted flats means that a heat pump is not likely to be the optimal solution for the majority of converted flats.

DECARBONISING HEAT EMISSIONS FROM CONVERTED FLATS

There are 520,000 converted flats in GB that were built using solid bricks and that have not been insulated.

To be made heat-pump ready, a combination of the following interventions is likely to be required:

- Insulation of solid wall
- Insulation of ceiling/floor
- Replacement of radiators or underfloor heating

These measures can cause significant disruption to the end-user. Even with these interventions, the installation of a heat pump may still be impractical due lack of exterior and interior space for the installation of the technology.

Given these constraints, decarbonisation of converted flats through heat pump may not only be challenging due to the disruptive improvements required but also impractical. **A hydrogen boiler or compact hybrid is likely to be the most suitable and practical solution in this case.**

22 These estimates are based on a sample of 22.7m properties used in this analysis.

POST-WAR SEMI-DETACHED

For nearly 2.3m semi-detached properties built between 1945 and 1980s with cavity walls, heat pumps could be a suitable solution due to the thermal characteristics of the buildings and availability of both exterior and interior space. However, in some cases refurbishment work may still be required.

There are nearly 3.2 million semi-detached homes in GB[23], built between 1945 and 1980s with cavity walls. There is evidence of insulation in 2.3 million of these homes.

There properties are likely to be suitable for a heat pump, however some of them will require refurbishment work to ensure the heat loss is minimised. In addition, these buildings have no exterior or interior space constraints.

There is evidence that nearly 70% of semi-detached properties have filled cavity walls, however heating system upgrades such replacement or installation of radiators and underfloor heating may still be required.

Semi-detached properties are not space constrained, hence heat pumps could be fitted easily outside the property and a hot water cylinder and radiators be installed within the home.

Overall, heat pumps are likely to be a plausible solution for semi-detached homes with filled cavity walls, after small improvements to the properties.

DECARBONISING HEAT EMISSIONS FROM POST-WAR SEMI DETACHED HOMES

There are nearly 2.3 million semi-detached properties built between 1945 and 1964 with filled cavity walls.

These properties are likely to be suitable for a heat pump, however some of them will require refurbishment work, such as replacement of radiators or underfloor heating.

There less likely to be exterior or interior space constraints, hence a heat pump is likely to be a suitable solution, equally consumers may prefer a hydrogen boiler or hybrid system.

23 These estimates are based on a sample of 22.7m properties used in this analysis.

MODERN DETACHED

For nearly 720,000 detached properties in GB heat pumps are likely to be the optimal heating solution due to thermal characteristics of these buildings and availability of both exterior and interior space.

There are nearly 720,000 detached properties in the GB that were developed after 1999[24].

A heat pump is likely to be the optimal solution for detached properties built in the last two decades. There are no thermal insulation barriers and detached homes usually have both exterior and interior space.

With the tightening of building regulations, the majority of homes built after 1996 are assumed to have filled cavity walls.

Detached properties have adequate exterior space for the installation of a heat pump and sufficient interior space for heating system upgrades such as the installation or replacement of radiators, where that is a requirement. Overall, a heat pump is likely to be the optimal solution for these homes.

DECARBONISING HEAT EMISSIONS FROM MODERN DETACHED HOUSES

There are nearly 720,000 detached properties built in recent years.

The majority of properties built after 1996 are assumed to have filled cavity walls.

No major intervention is expected to be required in these homes to make them suitable for the installation of a heat pump, the optimal solution may however be driven by consumer preference.

24 These estimates are based on a sample of 22.7m properties used in this analysis.

FINDINGS

- Heat decarbonisation will require a mix of locality-specific solutions tailored to the needs of the housing stock and other geographical features. The best solution for each home will depend on a number of factors including the thermal insulation, space constraints, housing density, availability and capacity of energy infrastructure and whether the home is existing or new build. It is expected that both heat pumps and decarbonised gases amongst others will play a crucial role in the transition to Net Zero.
- However, there is no practical way of heating the majority of UK homes with heat pumps only. For 8 to 12m homes a combination of lack of exterior space and/or the thermal properties of the building fabric mean that a heat pump is not capable of meeting the space heating requirement of the property or can do so only through the installation of highly disruptive and intrusive measures such as solid wall insulation. Hybrid heat pumps that are designed to optimise efficiency of the system do not have the same requirements of a heat pump and may be a suitable solution for some of these homes. This is likely to mean that decarbonised gas networks are therefore critical to delivery of net zero.
- 3 to 4m homes could be made suitable for heat pump retrofit through energy efficiency measures such as cavity wall insulation.
- Nevertheless, given firstly the levels of disruption to the floors and interiors of homes caused by the installation of heat pumps and secondly the cost and disruption associated with the requirement to significantly upgrade the electricity distribution networks to cope with large numbers of heat pumps operating at peak demand times combined with the availability of a decarbonised gas network, many of these 'swing' properties will be better served through a gas-based technology (particularly when consumer choice is factored in).
- The analysis presented in this paper focuses on the external fabric of the buildings, further analysis should be undertaken to consider the internal system changes that would be required for heat pumps and hydrogen boilers, for example BEIS Domestic Heat Distribution Systems: Gathering Report from February 2021 which considers the suitability of radiators for the low carbon transition.
- In some cases, the best solution may be a combination of electrification and hydrogen. This would be delivered by hybrid heat pumps that combine a hydrogen boiler with an electrically driven heat pump, where the hydrogen boiler meets the winter peak and the heat pump provides the base heat demand.
- The UK gas transportation infrastructure can be converted incrementally from natural gas to hydrogen to support the switchover with limited disruption to the consumer. A number of trials focused on hydrogen as a potential option for decarbonising heat have already demonstrated the technical and economic feasibility of the conversion.
- This means that hydrogen as a heating fuel alongside renewable gases more broadly are a crucial component of the journey to net zero and the UK's hydrogen ambitions should be reflective of this.

APPENDIX

RAG ASSESSMENT - SUITABILITY OF PROPERTIES IN ENGLAND AND WALES TO A HEAT PUMP

PROPERTY ARCHETYPES	PURPOSE BUILT FLAT		CONVERTED FLAT		MID TERRACE		END TERRACE		SEMI DETACHED		BUNGALOW		DETACHED	
Constraints	Space constraints	Thermal properties	Space constraints	Thermal properties	Space constraints	Thermal properties	Space constraints	Thermal properties	Space constraints	Thermal properties	Space constraints	Thermal properties	Space constraints	Thermal properties
Pre 1919	Not suitable	Not suitable	Not suitable	Not suitable	Not suitable	Not suitable	Likely suitable	Not suitable	Likely suitable	Not suitable	Likely suitable	Not suitable	Likely suitable	Not suitable
1919-44	Not suitable	Not suitable	Not suitable	Not suitable	Not suitable	Not suitable	Likely suitable	Not suitable	Likely suitable	Not suitable	Likely suitable	Not suitable	Likely suitable	Not suitable
1945-64	Not suitable	Likely suitable	Not suitable	Likely suitable	Not suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable
1965-82	Not suitable	Likely suitable	Not suitable	Likely suitable	Not suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable
1983-92	Not suitable	Possibly suitable	Not suitable	Possibly suitable	Not suitable	Possibly suitable	Likely suitable	Possibly suitable	Likely suitable	Possibly suitable	Likely suitable	Possibly suitable	Likely suitable	Possibly suitable
1993-99	Not suitable	Likely suitable	Not suitable	Likely suitable	Not suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable
Post 1999	Not suitable	Likely suitable	Not suitable	Likely suitable	Not suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable

RAG ASSESSMENT - SUITABILITY OF PROPERTIES IN SCOTLAND TO A HEAT PUMP

PROPERTY ARCHETYPES	FLAT		TERRACED*		SEMI-DETACHED		DETACHED	
Constraints	Space constraints	Thermal properties	Space constraints	Thermal properties	Space constraints	Thermal properties	Space constraints	Thermal properties
Pre-1870	Not suitable	Not suitable	Not suitable	Not suitable	Likely suitable	Not suitable	Likely suitable	Not suitable
1871-1919	Not suitable	Not suitable	Not suitable	Not suitable	Likely suitable	Not suitable	Likely suitable	Not suitable
1920-1945	Not suitable	Possibly suitable	Not suitable	Possibly suitable	Likely suitable	Possibly suitable	Likely suitable	Possibly suitable
1946-1954	Not suitable	Likely suitable	Not suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable
1955-1979	Not suitable	Likely suitable	Not suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable
Post 1980	Not suitable	Likely suitable	Not suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable	Likely suitable

*end-terrace properties will not be space constrained. It is assumed the majority of properties in this segment are mid-terrace.

KEY

- Not suitable
- Possibly suitable
- Likely suitable
- Space constraints
- Thermal properties

University of Victoria | Institute for Integrated Energy Systems

Decarbonization of the building heating system in Metro Vancouver: comparison of two transition pathways.

A report prepared for FortisBC Inc.

by:

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07 May 2021

Executive summary

This report documents preliminary modelling methods and results from the investigation of natural gas substitution in the building heating sector of Metro Vancouver, British Columbia. The investigation aims to identify energy system transition pathways that achieve substantial greenhouse gas emission reductions from heating decarbonization. This report aims to inform stakeholders on the work completed to date, and to provide opportunity for comment in an effort to align future work with stakeholder needs.

Energy consumption in buildings causes 25% of greenhouse gas emissions in Metro Vancouver. Natural gas combustion for space and water heating is responsible for the vast majority of those emissions, making buildings the second largest source of greenhouse gases behind the transportation sector. The elimination of those emissions by mid-century is necessary to mitigate the global climate change.

Optimal approaches to address emissions in the building sector have been focused on improving efficiency and substituting natural gas with low-carbon electricity. Building heating electrification has been highlighted in BC's Building Electrification Roadmap as a key strategy to decarbonize this sector. Although British Columbia's hydroelectric power system provides very low-carbon electricity, the available energy and power generation capacity likely cannot replace all fossil fuels consumed in other sectors. Operating constraints limit flexible dispatch to about one third of annual hydroelectric energy supplies. The majority of water inflows occur in early summer when electricity and heat demand is low. This report concludes that significant additional low-carbon electricity production and storage capacity will be needed if electrification were chosen as a primary strategy to meet emission reduction targets.

This study conducts a quantitative assessment of key issues that require consideration when addressing heating decarbonization in Metro Vancouver. An energy system model is used to compare two transition pathways that substitute natural gas with electricity (electrification pathway) or biogas and electrolytic hydrogen (renewable gas pathway). The study evaluates the pathway differences and key uncertainties that impact the outcomes. The analysis starts by developing a representation of the region's building heat demand by fuel and equipment type. Next, the model cost-optimizes energy production and storage capacities able to supply space heat, water heat, and electricity for a one-year period at hourly resolution. To quantify energy system requirements for range of possible futures, seven scenarios are developed to evaluate different assumptions on technology costs, performance characteristics, energy demand, and renewable resource supply.

Preliminary results show that exclusive electrification can increase the peak electricity demand beyond available hydropower capacity. Lack of dispatchable generation alternatives then requires significant electricity storage. In this study, a five-day period without wind and solar availability required over 350 GWh of electric energy storage, equivalent to approximately 35 large pumped storage facilities. The environmental impact and the public opposition to such facilities may bar the installation of this infrastructure and pose a barrier to emission reduction targets. Due to the high cost of meeting peak electricity demand with storage technologies, avoiding an increase in this peak indicates high value.

Replacing natural gas with renewable gas can avoid increasing the peak electricity demand and use surplus electricity during off-peak times to produce hydrogen. Installing 4.5 GW of electrolyzers and 1000 GWh (3.6 PJ) of hydrogen storage capacity can sufficiently supplement limited biogas supplies to meet peak gas and electricity demand if wind and solar are unavailable during low-temperature weather conditions. That storage capacity may be available at low cost if barriers to underground hydrogen storage can be overcome. For comparison, the underground Aitken Creek facility can store up to 80,000 GWh of natural gas. Although the process of converting electricity to hydrogen to heat provides lower overall efficiency than direct electrification, this process can be cost-effective to avoid large electricity storage requirements.

The scenario analysis shows that costs of the electrification and renewable gas transition pathways are sensitive to assumptions around heat demand and variability of energy supply, but either pathway can be lower cost. At low heat demand, the existing hydroelectric capacity is almost sufficient to serve the additional electric power demand, making electrification the lowest cost option. If variable wind and solar power are not available during very cold periods, then the renewable gas pathway is lower cost because this pathway avoids the high cost of electricity storage. Overall, either pathway can be lower cost, but the range of costs is more narrow in the renewable gas pathway.

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1. Foreword

This report documents a collaborative research project between FortisBC Inc. and the Institute for Integrated Energy Systems (IESVic) at the University of Victoria. FortisBC is the largest retailer of natural gas in British Columbia. The organisation serves gas to over 1,000,000 customers across the province, and provides electricity to 180,000 customers across a smaller regional network. FortisBC is developing comprehensive plans to reduce greenhouse gas emissions in the province by expanding biogas production, replacing higher-emission fuels, and implementing energy efficiency measures.

IESVic unites interdisciplinary research capacity to identify feasible pathways that result in sustainable energy systems. Research on renewable energy, clean transportation, energy technology, sustainable communities, and human dimensions create comprehensive solutions for complex problems. Throughout its 30-year history, IESVic research has been driven by collaborations with numerous partners in academia, government, and the private sector. As a comprehensive resource and key partner for implementing Canada's climate strategy, IESVic is pleased to submit this report to help inform effective decarbonization policy and adaptation to a low-carbon economy.

Funding for this research was provided by FortisBC Inc., MITACS, and the Energy Modelling Initiative.

2. Introduction

Mitigating climate change and limiting global warming to below 2 °C by 2100 will require reducing global greenhouse gas emissions to net-zero by mid-century. The Canadian province of British Columbia (BC) has committed to reducing its 2007-level emissions by at least 80% by 2050. The Metro Vancouver Regional District plans to become carbon neutral that same year. Achieving these targets necessitates the elimination of fossil fuel combustion as an energy source.

Replacing fossil fuels with low-carbon electricity has been identified as among the lowest-cost strategies to mitigating climate change (Trottier Energy Futures Project, 2016). The BC Building Electrification Roadmap highlights the economic opportunities of this strategy, and details the necessary actions by public and private actors to facilitate the transition (Integral Group, 2021). BC generates 98% of its electricity from renewable sources; hydro power contributes the largest share at 91%, biomass and wind provide another 6% and 1%, respectively (Canada Energy Regulator, 2021). This low-carbon electricity offers immediate emission reduction potential via electrification, but the available energy and power generation capacity cannot replace the vast quantity of fossil fuel consumed in all other sectors.

Comparison of the fossil fuel-based energy consumption with sectoral greenhouse gas emissions highlights the large challenge of decarbonization via electrification. In the residential, commercial and institutional building sectors of British Columbia, natural gas provided 68% (124 PJ) of space and water heating in 2018, or 45% of the total secondary energy consumption in those building sectors (Natural Resources Canada, 2020). These 124 PJ of natural gas caused 12% (6.1 $Mt_{CO2eq.}$) of the province's overall emissions related to fossil fuel combustion, but the energy contained in that natural gas would equate to 46% (34.4 TWh) of the province's total electricity generation in that year (Canada Energy Regulator, 2021; Natural Resources Canada, 2020). An energy-equivalent replacement of that natural gas with electricity would eliminate a relatively small fraction of overall emissions while significantly increasing electricity demand.

To enable electrification, replacement of furnaces with energy efficient heating appliances like heat pumps can reduce energy consumption considerably. Improving the energy efficiency of building envelopes can further reduce thermal demand. Nevertheless, electrifying the heating system increases winter peak electricity demand because air-source heat pump efficiency declines in very low-temperature weather. Ground-source heat pumps are less affected by cold weather, but their underground complexity often prevents retrofitting existing building stock. Increasing the peak electricity demand will require installation of additional dispatchable generation capacity. Only one third of annual hydroelectric energy supplies can be dispatched flexibly in British Columbia, and the majority of water inflows occur in early summer when electricity demand is low (BC Hydro, 2017a). An additional challenge arises from the need to simultaneously reduce greenhouse gas emissions in other sectors because electrification of road transportation and industry would further increase electricity demand.

Figure 1 shows that between 2007 and 2018, the all-time peak hourly load on British Columbia's integrated transmission system approached BC Hydro's 2018 load carrying capability. That figure suggests that British Columbia's installed electricity generation capacity is constrained in peak demand hours with little surplus to accommodate additional winter peak load. Note that load on the integrated transmission system is likely not equivalent to loads "carried" exclusively by BC Hydro, and the electricity system may be able to accommodate a larger additional peak load than this analysis suggests. Nevertheless, meeting electrification demands in the absence of other dispatchable generation capacity will likely require installation of designated electricity storage facilities like batteries or pumped hydro.

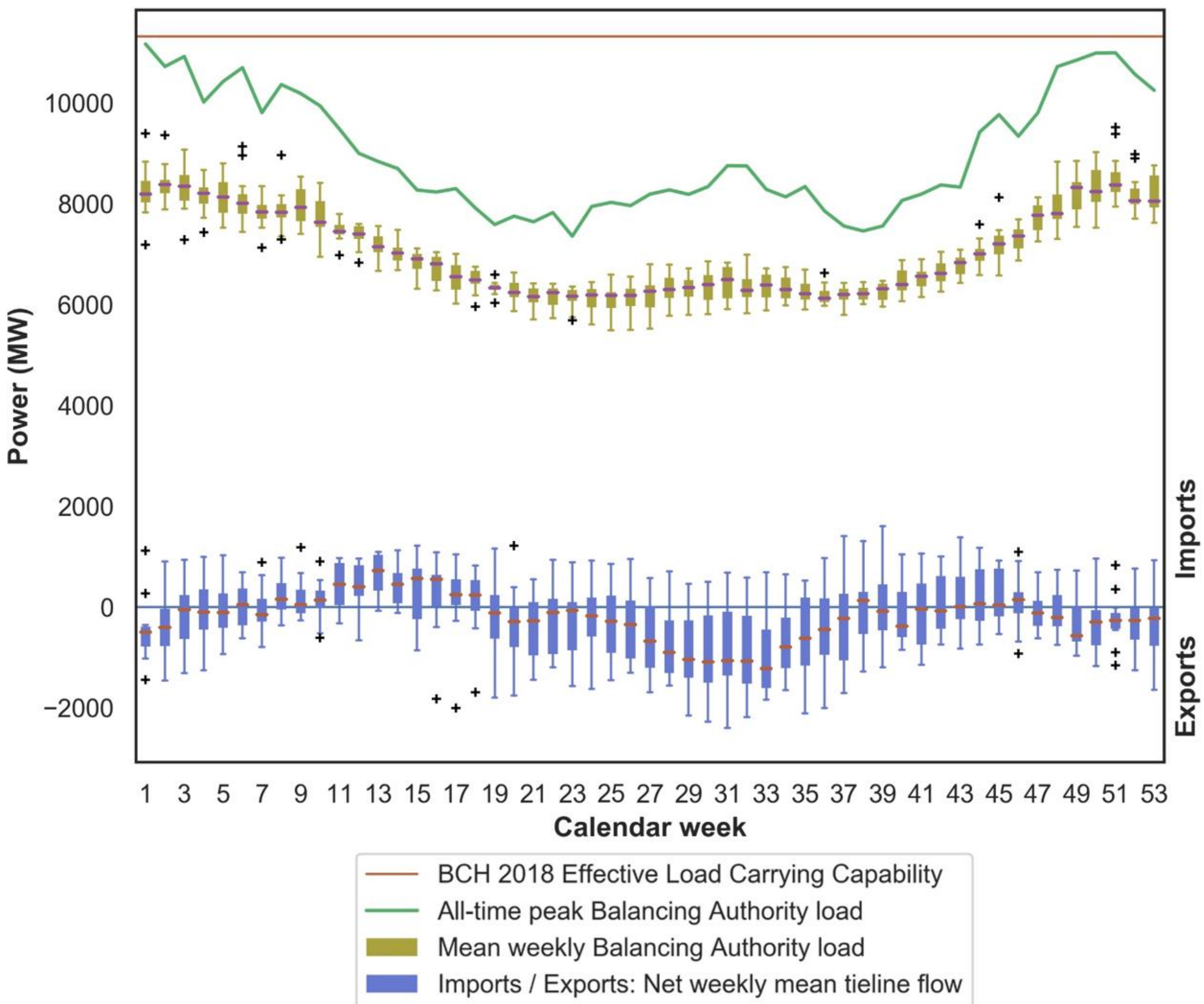

Figure 1. Comparison of electric load, cross-border trade, and load-carrying capability in British Columbia highlights the capacity constraint in winter peak-demand periods. The red straight line shows BC Hydro's 2018 Effective Load Carrying Capability of 11,315 MW (BC Hydro, 2016, Ch. 3, Table 3-9). The green line shows all-time peak load between 2007 and 2018 as recorded by the Balancing Authority's "Telemetred Load" (BC Balancing Authority, 2021). Boxplots of telemetered load in yellow and electricity net import/export in blue (BC Hydro, 2021) show the variability of weekly means between 2007 and 2018. Imports/exports show the sum of flows across BC-US and BC-AB tie lines.

Replacing natural gas with biogas or electrolytic hydrogen offers an alternative to direct electrification and does not increase winter-peak electricity demand. Power-to-gas technologies facilitate use of low-cost gas storage capacity to indirectly store electricity from variable renewable sources, reducing electricity storage requirements, retaining gas infrastructure to avoid stranded assets, and increasing resilience to energy demand and supply variability.

This report describes the investigation of substituting natural gas in the building heating sector of the Metro Vancouver Regional District in British Columbia, Canada. The following sections describe the system model development, energy demand estimation, scenario assumptions, and highlights important modelling results and sensitivities, followed by recommendations for future research.

3. Methods

The study presented in this report cost-optimizes a combined electricity and gas system model of the Metro Vancouver Regional District in British Columbia, Canada. Two distinct transition pathways compare electrification and renewable gas alternatives. The model reveals system costs, emission reductions, and electricity and gas production and storage capacity requirements. Along each transition pathway, seven scenarios vary technology costs, energy demand, and renewable energy resource availability. These scenarios delineate probable upper and lower energy system bounds for a range of potential futures.

Energy demands include space heat, water heat, and electricity that excludes heating. To overcome limited data availability, annual end-use energy demands are calculated from historic secondary energy consumption and technology efficiency records. Next, hourly demands are constructed by estimating normalized profiles and scaling these profiles to match annual demands (Section 3.2). Residential profiles are derived from proprietary electricity consumption data recorded at the household level. Commercial and institutional profiles are derived from building models. Correlating temperature records and space heat demand produces a profile for low-temperature conditions. The resulting hourly data enables the investigation of supplying demand with variable renewables like wind and solar power, and related storage requirements.

Note that the analysis investigates to supply past end-use energy demands. No estimation of future end-use demand occurs. This approach is chosen to avoid the additional uncertainty related to forecasting energy demand at hourly resolution. Building efficiency improvements might reduce energy demands, population growth might increase demand, and climate change might shift the demand profile. These factors and their effect on energy system requirements are not included here but warrant further study.

3.1. Energy system model

This study applies the Open Source Energy System Model OSeMOSYS (Howells et al., 2011) to investigate the energy system transition of Metro Vancouver. This linear programming framework expands and dispatches gas and electric energy production and storage to supply energy demands at minimum total annualized costs (Figure 2). The model determines the necessary capacities for natural gas substitution rates from 0 to 100% for a one-year period at hourly resolution.

In the electrification pathway, air-source heat pumps and electric resistance water heaters exogenously replace natural gas-consuming space and water heaters. Baseboard heaters are not replaced. In the renewable gas pathway, biogas and hydrogen replace natural gas via exogenously mandated renewable gas consumption rates. To limit the computational complexity of hourly time steps, the substitution occurs "overnight" at the beginning of the modelling period. No long-term evolution occurs. Instead, the model separately optimizes the energy system for each substitution rate. Iterating over the same one-year model period with varying electrification and renewable gas rates reveals energy system expansion trends.

The energy demands water heat and space heat constitute end-use demands. Electricity constitutes demand that serves non-heating loads. Air-source heat pumps and baseboard resistance heaters consume electricity, and furnaces consume gas to provide space heat. Electric and gas water heaters provide hot water.

The model uses existing hydro electricity and natural gas production to supply demands at the zero substitution rate. As necessary to meet demand at higher substitution rates, the model can choose to expand wind and solar electricity generation, biogas production, electricity and gas storage, and hydrogen production via electrolysis. This substitution reduces greenhouse gas emissions endogenously.

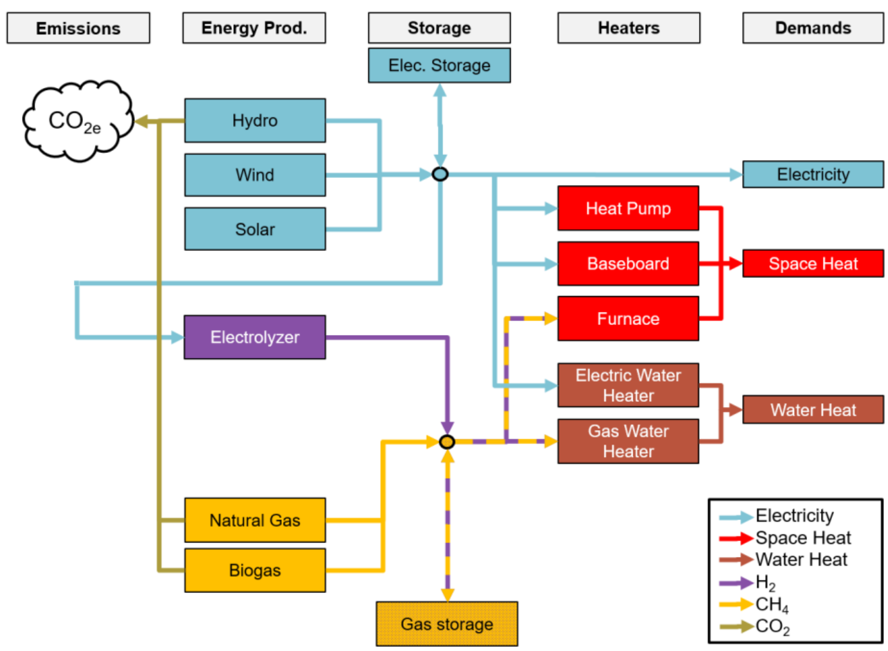

Figure 2. Energy system model used to investigate electrification and renewable gas pathways for Metro Vancouver. In the electrification pathway furnaces and gas water heaters are replaced by electric heat pumps and electric water heaters. In the renewable gas pathway, natural gas is replaced by biogas and electrolyzed hydrogen.

3.2. Energy demands

The end-use space heat, end-use water heat, and non-heating electricity demands shown in Figure 3 are each constructed from an annual demand and a normalized profile. The total annual space and water heat demands are population-scaled from provincial secondary energy consumption records for the year 2016 (Natural Resources Canada, 2020). Space heat and water heat include natural gas and electricity consumed in the residential and commercial sectors. Annual electricity demand is based on the BC Hydro fiscal 2016 total electricity supply (BC Hydro, 2016). Non-heating electricity excludes electric heating. Space heater efficiencies (Natural Resources Canada, 2020) and water heater efficiencies (NRCan, 2012) are used to estimate end-use energy demands from the available secondary energy consumption data.

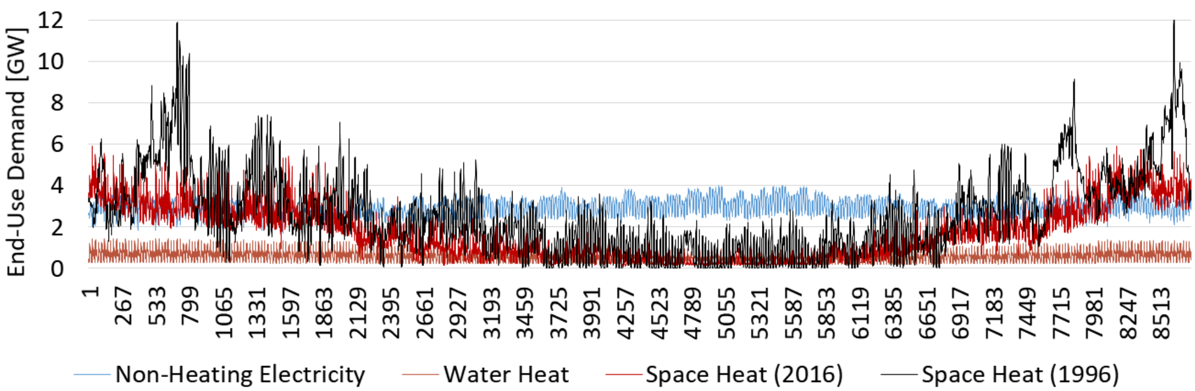

Figure 3. Estimated hourly end-use energy demands for Metro Vancouver are the product of annual secondary energy demand records, heater efficiencies, and normalized hourly demand profiles. The 2016 space heat demand profile is based on residential sector data recorded in 2016, and modelled commercial sector data produced from typical meteorological year (TMY3) temperatures. The 1996 space heat demand profile is hindcast using 1996 temperatures and represents the demand that Metro Vancouver – as it existed in 2016 – would have experienced under a 1996 temperature profile.

The energy demand profiles determine the fraction of annual energy demand that the model must provide in each hour of the year. The commercial space and water heat demand profiles are based on 15 commercial reference building models that represent ~ 70% of the commercial building stock in the United States of America (NREL, 2011). The residential water heat demand profile is based on data in the Cost Effectiveness tool published by Ontario's Independent Electricity System Operator (IESO, 2019). The residential space heat demand profile is derived from proprietary residential electricity demand data provided to the authors of this report by the utility BC Hydro, as described by Palmer-Wilson (2020, chap. 5.6). The non-heating electricity demand profile is the difference between the provincial electricity demand profile (BC Balancing Authority, 2021) and the space and water heat demands served by electricity.

Based on 2016 residential demand and typical mean year commercial demand, the estimated hourly end-use space heat energy demand in Metro Vancouver peaks at 5.9 GW. That demand may underestimate the peak demand under low temperature conditions. Personal correspondence between the authors of this report and FortisBC Inc. revealed that natural gas delivery in British Columbia reached over 18 GW of secondary energy above baseload during a minimum temperature weather event in 2020.

To better represent energy system requirements during low-temperature conditions, a regression analysis between space heat demand and ambient temperature is performed using hourly temperatures recorded at the Pitt Meadows Climate Station between 1995 and 2019. In that dataset, the lowest temperature of -16 °C occurred in 1996. The 3197 heating degree days in that year are the third highest in the dataset. For comparison, the lowest temperature in 2016 was -12.8 °C with 2568 heating degree days.

To hind cast a low-temperature space heat demand profile, the regression analysis is applied to the residential and commercial sectors separately (Figure 4). For the residential sector, a second-degree polynomial equation minimizes square errors between hourly end-use space heat demand and ambient temperature. For the commercial sector, the equation was fitted onto the 90th percentiles of 20 temperature bins of equal width. This fitting onto 90th percentiles introduces uncertainty to the analysis but better captures the expected peak space heat demand during low temperature events. This adaptation is chosen because the bottom-up method that created the commercial heat demand data for separate building types does not produce normally distributed residuals around the equation of best fit.

Next, the residential and commercial equations of best fit each hind cast respective hourly space heat demand profiles using the 1996 temperatures. The resulting demand profile peaks at 12 GW for the temperature profile recorded in 1996.

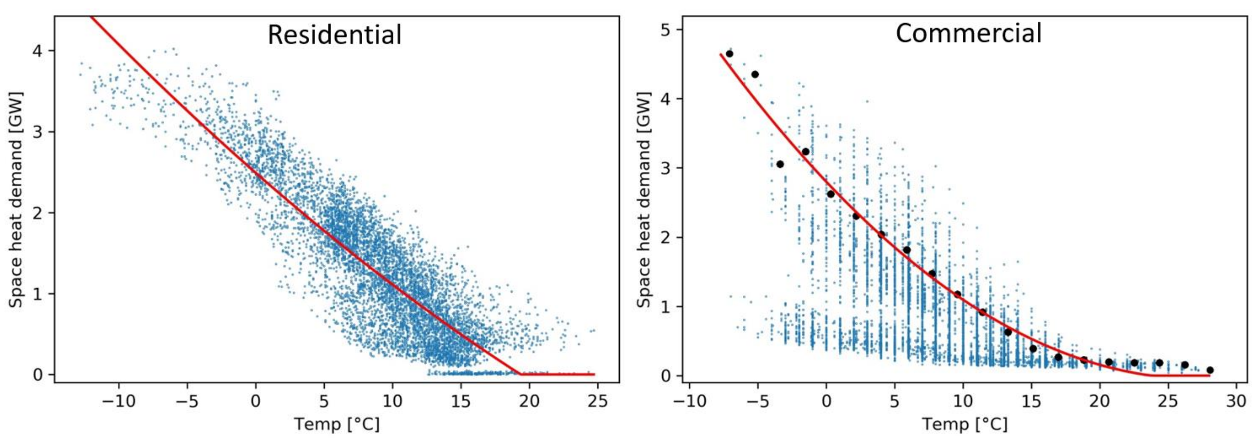

Figure 4. End-use space heat demand versus temperature in the residential and commercial sectors. The red curve shows the second-degree polynomial equation of best fit. The residential equation is fitted directly onto the temperature data and results in a Coefficient of Determination $R^2 = 0.84$. The commercial equation is fitted onto the 90th percentiles (black dots in right graph) of 20 temperature bins of equal width to better capture peak space heat demand during low temperature events.

3.1. Heating technologies

Heating technologies consume electricity or gas to supply the end-use space and end-use water heat demands. Heating efficiencies listed in Table 1 are constant throughout the modelling period for all technologies except heat pumps. Their coefficient of performance (COP) varies by hour and depends on ambient temperature recorded at the Pitt Meadows Climate Station.

Table 1. Space and water heater efficiencies or coefficient of performance (COP). The efficiency determines the quantity of secondary energy that the model must supply to heating technologies in order to meet end-use demands.

Technology	**Efficiency/COP**	**Rationale**
Heat Pump Space Heater	1.5 to 3.0 (-16 to +20 °C)	Temperature-dependant average coefficient of performance observed on 23 residential non-cold-climate heat pumps (The Cadmus Group Inc., 2016, fig. 55)
Baseboard Space Heater	1.0	Assumed
Furnace Space Heater	0.95	Annul Fuel Utilisation Efficiency energy performance standard for gas furnaces without an integrated cooling component (Natural Resources Canada, 2019)
Electric Water Heater	0.95	Assuming 5% standby losses for electric tank water heaters
Gas Water Heater	0.735	Mean Energy Factor of storage and tankless gas water heaters (NRCan, 2012, p. 10)

The COP is derived from data collected for several different non-cold-climate heat pump models in Massachusetts and Rhode Island in the winter of 2016 (The Cadmus Group Inc., 2016, fig. 55). A linear interpolation between the known COP of two temperatures creates an hourly COP profile. The COP ranges from 1.5 at -16 °C to 3.0 at +20 °C where the latter is the highest temperature at which space heat demand occurs. Figure 5 shows COP and end-use space heat demand within the recorded temperature range. For explanation, at -16 °C the heat pumps with a COP of 1.5 consume 8 GW of electric power to supply 12 GW end-use space heat demand.

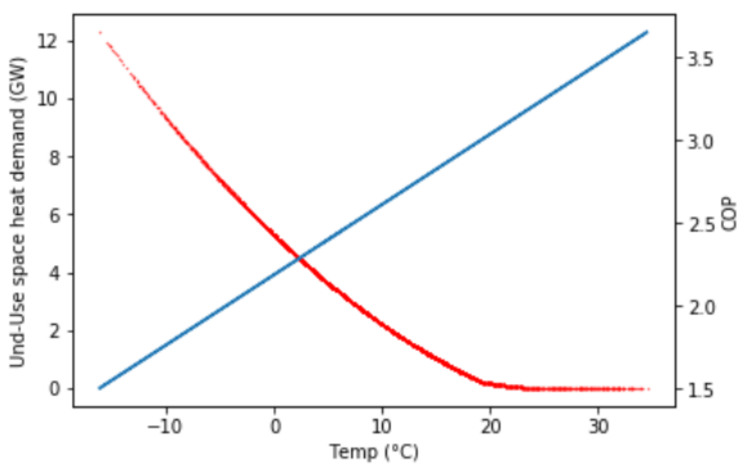

Figure 5. Coefficient of performance (blue line) and hourly end-use space heat demand using the 1996 temperature profile (red dots).

3.2. Energy production

Hydro power generation capacity (12.9 GW) and annually available energy (60 TWh) in British Columbia are based on the BC Hydro load-resource balance for fiscal year 2015 (BC Hydro, 2013, Tables 2 and 3). The energy and power available to the model are population-scaled to Metro Vancouver. The available energy is dispatched on a partially flexible, partially pre-determined profile (Figure 6) to simplify the complex operating constraints observed by British Columbia's large hydro and run-of-river power stations. These constraints include snowmelt-driven water inflows, minimum water discharge rates, or flood control. This study estimates that approximately 41 TWh are dispatched to meet operating constraints; approximately 19 TWh are dispatchable at any time of the year (BC Hydro, 2017b). The assumed cost and emission intensity of hydroelectric energy are 60 $/MWh and 29.9 $g_{CO2\_eq.}$/kWh (Government of British Columbia, 2019).

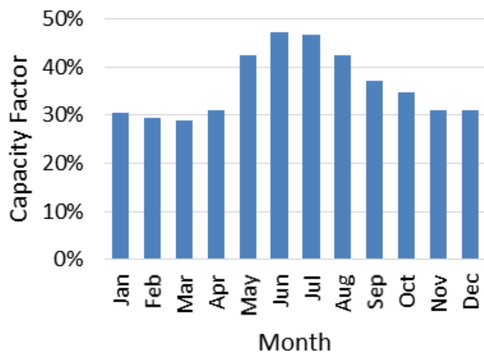

Figure 6. Estimated monthly minimum capacity factors define the profile shape of ~ 41 TWh generated by British Columbia's hydroelectric power stations on a pre-determined schedule (BC Hydro, 2017). Generation peaks in June and July when snowmelt-freshet inflows dominate.

Hydro power capacity is fixed and cannot be expanded by the model. Although the Site-C hydroelectric facility that is under construction on the Peace River will expand capacity and annual energy production by 1.1 GW and 5 TWh beyond 2024, this study models the transition of a past state and does not take into consideration future changes in energy supply or demand. This approach to disregard future capacity becoming available reflects the capacity deficit expected to occur by 2029 in spite of the Site-C expansion (BC Hydro, 2016, Table 3-9).

The model installs wind power capacity at scenario-dependant costs between 1219 and 2395 $/kW. The exogenous wind generation profile is based on the hourly mean capacity factor of 30 potential sites located in southern, central, coastal, and eastern British Columbia (GE Energy Consulting, 2016). The annual mean capacity factor is 33.2%.

The model chooses to install solar power capacity at scenario-dependant costs between 669 and 2021 $/kW. The exogenous solar generation profile is based on single-axis tracking potential in Vancouver as published by NREL's PV Watts (National Renewable Energy Laboratory, 2013). The annual mean capacity factor is 24.3%.

Gas production includes natural gas, biogas, and hydrogen produced from electrolysis. In this study, biogas and hydrogen substitute natural gas on an energy-equivalent basis. Natural gas costs 1.19 \$/GJ (U.S. Energy Information Administration, 2020) and emits 50.3 g_{CO2}/MJ (U.S. Energy Information Administration, 2011). FortisBC plans to procure 30 GJ of biogas that emit 11 g_{CO2}/MJ to meet renewable gas and emission reduction targets by 2030. Costs of biogas were estimated at 23 \$/GJ by the authors. Specific costs are confidential, but FortisBC confirmed that this estimate reasonably aligns with their portfolio average. Beyond the 30 GJ of biogas, the energy system model can choose to produce hydrogen by installing electrolyzer capacity at a scenario-dependant cost of 1400 \$/kW (ZEN, 2019) or 500 \$/kW (Thema et al., 2019) and an assumed efficiency of 78%.

3.3. Energy storage

Electricity and gas storage technologies provide flexibility to balance supply and demand. Storage technologies can store energy up to their installed energy capacity. Storage technologies can provide power to supply demand, or demand power to increase stored energy, up to the installed power and energy capacities, respectively. The model determines energy and power capacities independently of each other.

The model can choose to install electricity and gas storage technologies. Electricity storage has a round-trip efficiency of 86%. Installation costs are scenario dependant to reflect 2030 or 2050 battery storage as forecast by Schmidt et al. (2019). Gas storage capital costs (1 \$/kW and 0.1 \$/kWh) are consistent across all scenarios, with assumed operating costs being nil. Gas storage has an assumed round-trip efficiency of 100%.

3.4. Scenarios

Seven scenarios investigate energy system costs and capacity requirements across a range of possible futures. Technology costs, technology performance, energy demand, or renewable energy supply varies between each scenario. Table 2 summarizes the defining variation of each scenario.

- The *Reference* scenario applies 2030 lithium-ion battery storage costs, and present-day wind and solar costs determined by the latest resource options report performed by BC Hydro. FortisBC's provincial biogas target of 30 PJ is scaled to Metro Vancouver by population. The space heat demand is based on historic temperature correlation and hind cast for the 1996 temperature profile.

- The *LowCost* scenario applies 2050 capital costs for battery, wind, solar, and electrolyzer installation. The assumed 2050 battery cost is approximately equivalent to present-day pumped storage costs.

- The *MuchBiogas* scenario applies a large availability of biogas resources. The 93 PJ include estimated wood gasification supplies in British Columbia.

- The *LowHeatDemand* scenario applies 2016 space heat demand data. That data has a lower peak and lower overall energy demand than the hind cast 1996 demand applied in all other scenarios.

- The *GasHeatPump* scenario replaces all gas furnaces with gas heat pumps. The replacement increases gas-based space heating efficiency from 95% to 140% and consequently reduces natural gas and biogas consumption.

- The *Resilient* scenario forces the model to install sufficient energy storage capacity to supply energy demand during a five-day peak space heat demand event where no wind or solar generation is available. In the absence of other dispatchable technology alternatives, all capacity demand that exceeds the existing capacity of hydro power must be supplied by energy storage during that event.

- The *Transport* scenario assumes full electrification of the road transportation sector. This additional demand is implemented by increasing the electricity demand to include an evening-peaking battery-electric vehicle charging profile. This increase equally applies to the renewable gas and electrification pathways. This scenario serves to investigate the simultaneous electrification of several economic sectors.

Table 2. Seven scenarios determine low-carbon energy system costs and capacity requirements for a broad range of future technology costs, technology, performance, energy demand, and renewable energy resource potential.

Scenario	Description	Rationale
Reference	a) 2030 Li-Ion battery cost b) BC Hydro Wind/Solar cost c) 2030 Biogas target (30 PJ x 53%) d) 1996 temperature profile (high heat demand)	a) (Schmidt et al., 2019) b) (BC Hydro, 2020) c) Personal correspondence with FortisBC Inc. d) Section 3.2
LowCost	a) 2050 Battery ≈ pumped storage cost b) NREL 2050 Wind/Solar cost c) 2050 Electrolyzer cost	a) (Schmidt et al., 2019) b) (National Renewable Energy Laboratory, 2018) c) (Thema et al., 2019)
MuchBiogas	High biogas availability (93.6 PJ x 53%)	(Hallbar Consulting, 2017)
LowHeatDemand	2016 temperature profile	Section 3.2
GasHeatPump	Gas heating efficiency increases from 95% to 140%	Estimated gas heat pump efficiency
Resilient	No wind and solar electricity generation during five-day peak space heat demand event	Determines hydro + storage capacity requirements when electrified demand exceeds hydro's load carrying capability
Transport	Light- and heavy-duty road transport is electrified: -60% annual electricity demand increase -Doubles peak electricity demand	Electrification of additional sectors increases storage demand. Electrified demand estimate taken from (Palmer-Wilson, 2020)

4. Modelling Results

4.1. Greenhouse gas emissions

Substituting natural gas with electricity or renewable gas significantly reduces greenhouse gas emissions. The bars in Figure 7 show *Reference* scenario emissions in the electrification pathway (Elec) on the left and the renewable gas pathway (RNG) on the right. The whiskers delineate the range of emissions observed across all seven scenarios.

The annual emissions decline as natural gas substitution rates increase from 0 to 100%. At a substitution rate of 100%, the remaining emissions result from hydro power and, in the renewable gas pathway, from biogas.

The *MuchBiogas* scenario retains the largest emissions (top whiskers) because the larger biogas resource-availability enables larger emissions. The *LowHeatDemand* scenario retains the lowest emissions (bottom whiskers) because lower overall energy production leads to lower emissions.

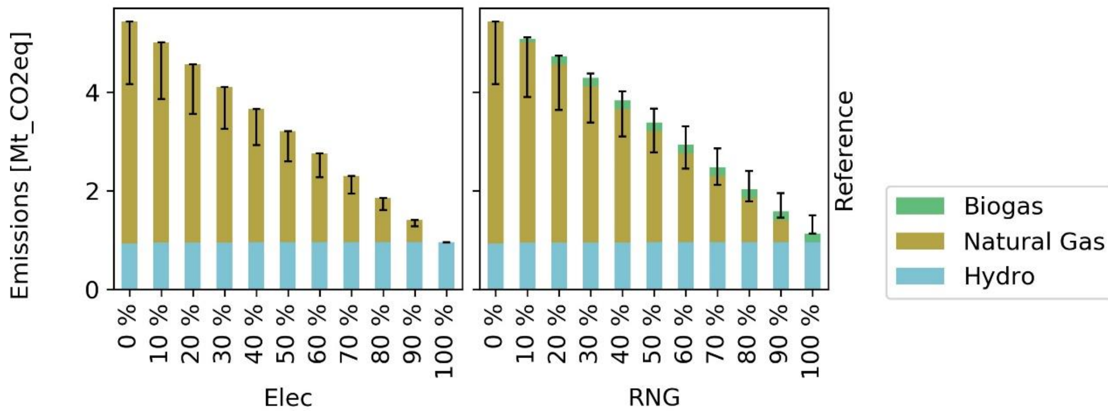

Figure 7. Greenhouse gas emissions related to all-sector electricity generation and gas combustion in the building heating sector of Metro Vancouver. Each stacked bar on the horizontal axes shows total emissions in the Reference scenario for the one-year modelling period as natural gas substitution rates increase from 0% to 100% in 10% increments. Whiskers denote emissions observed across all scenarios. The electrification pathway (Elec) is shown on the left, and in the renewable gas pathway (RNG) on the right.

4.2. Electricity generation and storage capacity

Substituting natural gas with electricity or renewable gas increases annual electricity production and necessitates installation of additional generation capacity. In this study, available generators are limited to the most abundant renewable energy sources wind and solar power. Their variability requires energy storage to balance supply and demand.

Figure 8 shows annual electricity generation (top row), generation capacity (center row), and energy storage capacity (bottom row) in the *Reference* scenario. Electrification (left column) or renewable gas (right column) gradually replace natural gas in 10% increments. Wind and solar electricity generation supplements hydro electricity in both pathways. Installed generation capacities increase more significantly in the electrification pathway. In the *Reference* scenario, electricity storage reaches 80 GWh in the electrification pathway, and gas storage reaches ~1000 GWh in the renewable gas pathway. Only in the *Transport* scenario does the larger electricity demand require installation of electricity and gas storage in the renewable gas pathway.

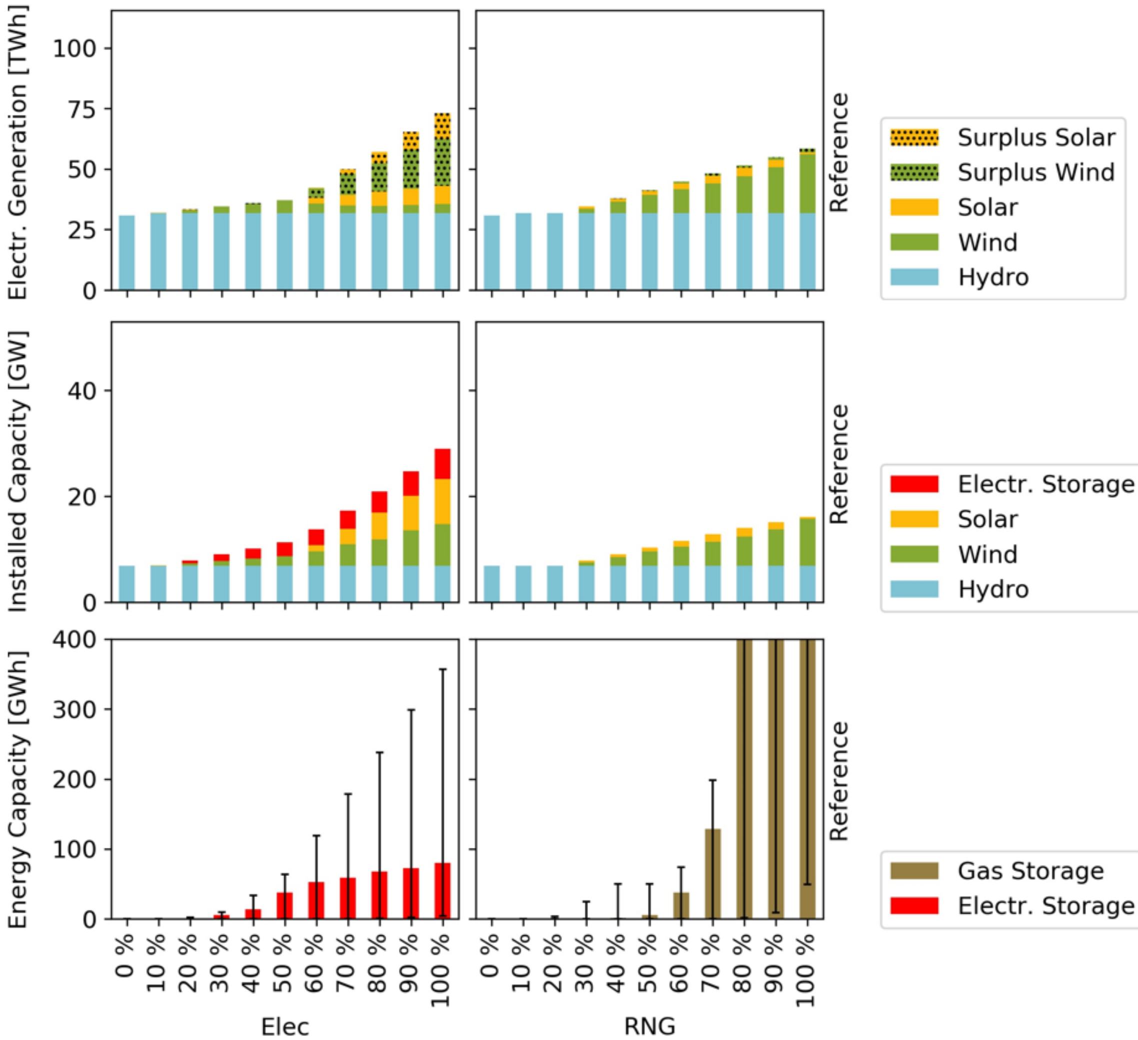

Figure 8. Reference scenario energy system transition in the electrification (Elec) and renewable gas (RNG) pathways. Horizontal axes show natural gas substitution rates ranging from 0% to 100% in 10% increments. The top row shows electricity generation and potential surplus for the one-year modelling period. The center row shows installed electric power generation capacities. The bottom row shows energy storage capacity. Gas storage capacity reaches ~ 1000 GWh; the axis range highlights the electric energy storage capacity because gas storage is low cost in comparison. Whiskers show minimum and maximum energy storage capacities observed across all scenarios.

In the electrification pathway of the *Reference* scenario, large wind and solar capacity installation generates a large electricity surplus. That large capacity installation is chosen by the model to meet peak space heat demand during a five-day cold period in January/February due to lack of dispatchable generation technology alternatives. The excess capacity generates surplus electricity in the remaining year, but is lower cost than installing additional high-cost electricity storage.

The magnitude of this peak-driven capacity installation is sensitive to the exogenous wind and solar profiles that, by coincidence, provide small amounts of power during the peak demand event. Figure 9 highlights this sensitivity by comparing electricity generation and storage levels in the *Resilient* and *Reference* scenarios. During the five-day peak period, demand exceeds the installed hydro power capacity. In the *Reference* scenario, wind, solar, and electricity storage supply demand in excess of hydro capacity. The 80 GWh of electric energy storage drain from maximum to nil within the first three days; the installation of 8 and 9 GW of wind and solar power result from the relatively low exogenous capacity factors during that period.

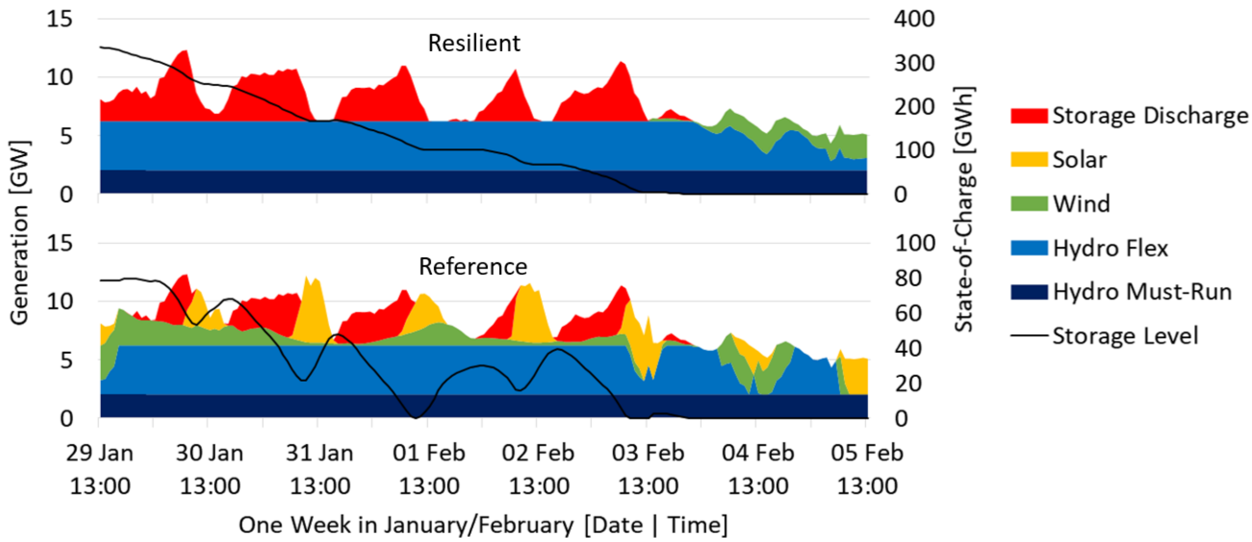

Figure 9. Electricity generation and storage level during the five-day peak demand event in the Resilient (top) and Reference (bottom) scenario of the electrification pathway. The top of the stacked areas delineates the electricity demand.

The *Resilient* scenario exogenously reduces wind and solar availability to zero for the five-day peak demand event. The model installs 357 GWh of electricity storage capacity (top whiskers in Figure 8), sufficient to meet all excess demand during the five-day period. That storage capacity reduces wind and solar installation and almost eliminates surplus electricity generation. In contrast to the *Resilient* scenario, the *LowHeatDemand* scenario requires only 4 GWh of electricity storage capacity (bottom whiskers in Figure 8) because peak electricity demand remains below the capacity of dispatchable hydro power. Table 3 shows the full list of energy and power capacities for electric energy storage installed by the model in each scenario.

Table 3. Installed energy and power capacity for electric energy storage in the electrification pathway of each scenario.

Scenario	Power Capacity [GW]	Energy Capacity [GWh]
Reference	6	80
LowCost	6	123
MuchBiogas	6	80
LowHeatDemand	1	4
GasHeatPump	6	80
Resilient	7	357
Transport	12	87

In the renewable gas pathway, the *Resilient* scenario requires 4.6 GW of electrolyzers and 1000 GWh of gas storage capacity. The electrolyzers operate at an annual average capacity factor of 66%. In this configuration, gas storage drains to nil from a full state-of-charge only once during the 1-year modelling period. In effect, gas storage balances supply and demand between seasons.

4.3. Pathway costs

The large range of storage capacity installation leads to significant total system cost differences between the electrification and the renewable gas pathways. Either pathway can result in lower overall costs, but the range of costs observed across all scenarios is more narrow in the renewable gas pathway. Figure 10 highlights the large range of total annualized system costs across scenarios. Note that costs include the annualized capital costs, and operation and maintenance costs for gas production, electricity generation, and electricity and gas storage. Costs do not include any costs associated with space and water heaters, and do not include costs for gas and electricity transmission and distribution.

The *Transport* scenario has the highest overall costs because the additional electricity demand increases costs across both pathways. Costs in the *Resilient* scenario are slightly lower than the *Transport* scenario in the electrification pathway, but much lower in the renewable gas pathway. This difference is caused by the low-cost gas storage available in the renewable gas pathway. The *LowHeatDemand* scenario has the lowest overall costs because the low demand requires the least amount of energy production. Due to the low peak demand and small electricity storage requirement, low-cost wind and solar render the *LowHeatDemand* scenario the only scenario where electrification pathway costs remain below renewable gas pathway costs.

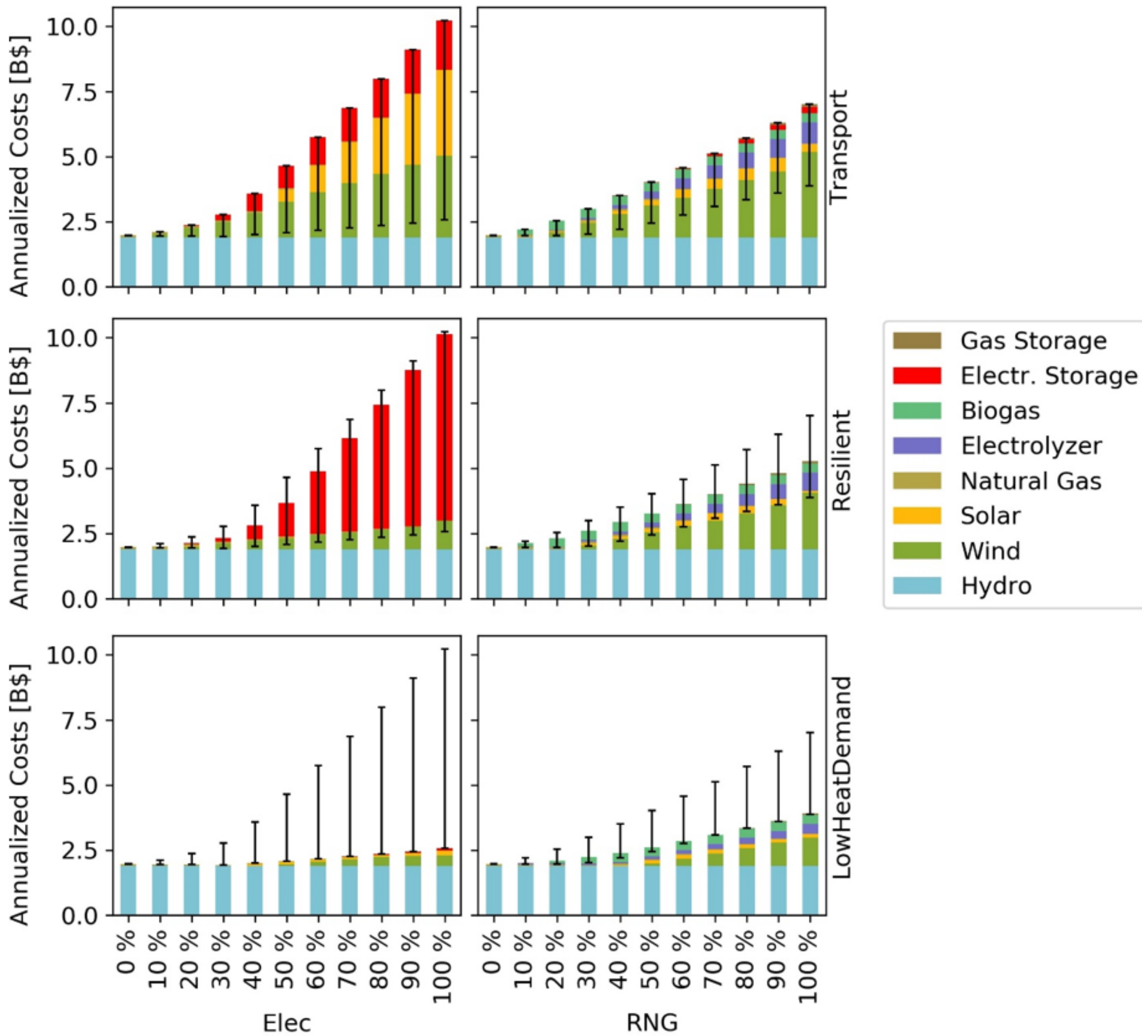

Figure 10. Annualized total system costs in the electrification (Elec) and renewable gas (RNG) pathways in the Transport, Resilient, and LowHeatDemand scenarios. Horizontal axes show natural gas substitution rates ranging from 0% to 100% in 10% increments. Whiskers show the full range of annualized costs observed across all scenarios.

To compare costs across scenarios, Figure 11 shows the percentage difference between electrification and renewable gas pathway costs at 100% natural gas substitution rates. Across all scenarios, the cost differences range from -52% in favour of electrification, to +48% in favour of renewable gas. The electrification pathway is most cost-favourable (-52%) in the *LowHeatDemand* scenario because the lower peak electricity demand requires relatively little electricity storage. The renewable gas pathway is most cost-favourable (+48%) in the *Resilient* scenario because the lower-cost storage of electrolytic hydrogen avoids the 357 GWh of electric energy storage required in the electrification pathway.

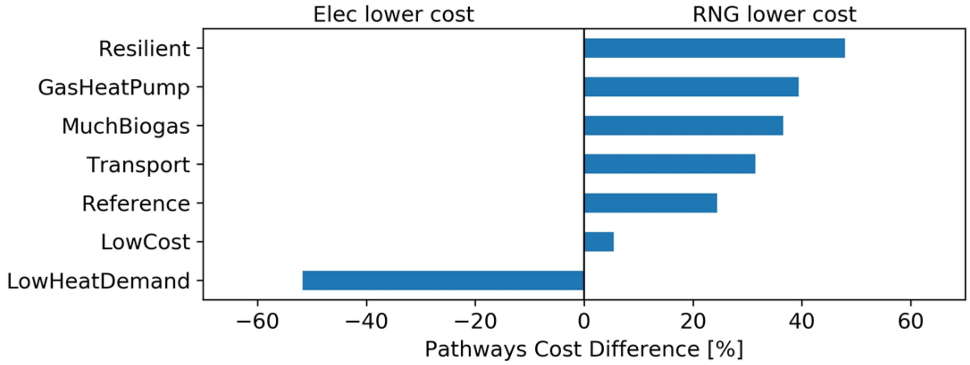

Figure 11. Percentage cost difference between electrification and renewable gas pathways at 100% natural gas substitution across all scenarios.

5. Discussion

This report investigates the elimination of natural gas consumption in the Metro Vancouver residential, commercial and institutional building heating sectors. The cost-optimization model shows that direct electrification or substitution via renewable gas provide feasible solutions to supply space heat, water heat, and electricity that serves non-heat demands. Scenario analysis reveals that energy storage capacity requirements and resulting total system costs are sensitive to technology costs, resource supplies, and energy demand.

Both transition pathways require the installation of additional electricity generation capacity to accommodate direct electrification or production of electrolytic hydrogen. The existing hydroelectric energy and power capacity is insufficient to substitute all natural gas in the building heating sector. In the absence of other dispatchable generation technologies, the installation of wind and solar power requires installation of energy storage. Consequently, the peak electricity demand that exceeds present-day dispatchable capacity is the largest cost driver in the electrification pathway. Avoiding the increase of peak demand can save costs. Since the present-day electricity demand peaks in winter months, electrifying economic sectors that do not peak in winter may render a better cost-benefit for use of surplus energy and the limited load-carrying capability of British Columbia's hydropower system.

Low-cost biogas supply (or lack thereof) is the largest cost driver in the renewable gas pathway. Higher-cost hydrogen production requires expansion of electrolyzers, additional electricity generation capacity, and gas storage. However, the significantly lower cost of storing gas instead of electricity may render the renewable gas transition cost effective. Designing an electrified energy system to accommodate low availability of wind and solar power during a peak demand event requires vast amounts of storage. The installation of 357 GWh of electricity storage in this study's *Resilience* scenario would equate to ~35 pumped storage facilities. Considering the associated environmental impact, public opposition to building pumped storage infrastructure may render an exclusive electrification pathway challenging to implement. For comparison, the existing underground Aitken Creek gas storage facility in northeastern BC can store 80,000 GWh of natural gas. Underground hydrogen storage may become possible at similar scale if geological, technological, economic, legal and social barriers can be overcome (Tarkowski, 2019).

Both pathways reduce the combined electricity and heating emissions by around 80%, but these sectors represent a fraction of overall sources. Grid-tied hydroelectric power with an emissions factor of ~30 $t_{CO2eq.}$/GWh (Government of British Columbia, 2019) causes the majority of remaining emissions. Emissions embodied in wind and solar power plants are not included in this study. In the renewable gas pathway, substituting natural gas with biogas reduces the emission intensity by 78% (from 50.3 to 11 g_{CO2}/MJ) but small biogas related emissions remain. The quantity of those emissions depend on available biogas supply. Achieving net-zero greenhouse gas emissions by mid-century to limit global warming to below 2°C will require additional emission reduction. If negative emission technologies like direct air capture are to be deployed, additional expansion of zero-carbon energy sources will be required.

This analysis highlights the scale of the challenge to addressing greenhouse gas emissions in the building heating sector. The existing natural gas system provides three services that a future low-carbon system will need to replicate. These services include 1) provision of a large quantity of energy that 2) can be stored for long durations at relatively low cost and 3) be dispatched to provide a large quantity of power when cold weather events cause large heat demand. British Columbia's low-carbon hydroelectric system provides those services, but its ability to accommodate additional demand from natural gas substitution is limited. The variable renewable energy sources wind and solar power provide energy, but they lack dispatchability and require separate storage capacity installation. Considering the scale of fossil fuel combustion that will need to be eliminated in all sectors of the economy, enabling the gas system to continue to provide its services via renewable gas adoption may be a cost-effective strategy to mitigating climate change.

6. Future work

The completed study contributes to understanding emission reduction options for the heating sector in Metro Vancouver, and exposes several key research questions that warrant further investigation. First, both transition pathways reduce greenhouse gas emissions by ~ 80%, but emissions will ultimately need to decline to net-zero. Extending the energy system model to include negative emission technologies can inform further mitigation options.

Second, both electricity and renewable gas can substitute natural gas in the building heating sector, but further study is required to understand the impact of simultaneously substituting fossil fuels in several economic sectors. Extending the energy system model to include transportation and industrial energy demands can help identify which substitution provides the most benefit in each sector.

Third, the completed study represents Metro Vancouver as a single node without energy transmission requirements, but fossil fuel substitution will require transmission system upgrades. Increasing the spatial resolution of the energy system model will enable accounting for electricity and gas transmission costs, and reveal cost-effective upgrades needed to accommodate increased electricity demand and hydrogen concentrations.

The interest generated by the completed study, and the relevance of the resulting research questions has led to an extension of this research project. In the coming two years, an expanded research team at the University of Victoria will investigate electrification and power-to-gas alternatives in more detail by conducting further long-term and medium-term modelling, and extending modelling resolution both spatially and temporally.

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THE UNIVERSITY OF BRITISH COLUMBIA

Clean Energy Research Centre (CERC)

Part I

Clean Energy Pathways to Meet British Columbia's Decarbonization Targets

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University of British Columbia

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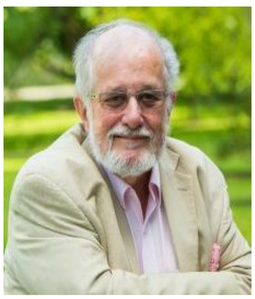
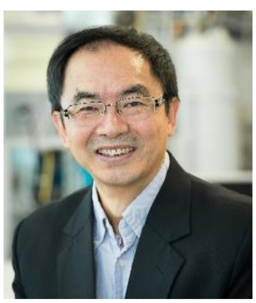
Biographies

Haoqi Wang worked on life cycle environmental analysis and techno-economic analysis of bioenergy systems in British Columbia during his PhD study as a PICS fellow and postdoctoral research at the Department of Chemical and Biological Engineering, University of British Columbia, under the supervision of Xiaotao Bi and Roland Clift. He is now an assistant professor in the College of Materials and Environmental Engineering, Hangzhou Dianzi University, China.



Roland Clift is emeritus professor (founding director) in the Centre for Environment and Sustainability, University of Surrey, UK, and an adjunct professor at the Department of Chemical and Biological Engineering, University of British Columbia. His research interests are in life cycle assessment, industrial ecology and sustainable energy systems. He is a fellow of the Royal Academy of Engineering, UK, and a past member of the UN Intergovernmental Panel on Climate Change (IPCC).



Xiaotao Bi is a professor in the Department of Chemical and Biological Engineering and the director of UBC's Clean Energy Research Centre. His current research focuses on particle technology and fluidized bed reactors for biomass thermo-catalytic conversion, green and sustainable engineering, and integrated assessments of clean energy systems. He is a fellow of the Canadian Academy of Engineering and Engineers Canada.

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Executive Summary

The two phases of CleanBC set out strong policy support for further developing renewable energy in the province as a contribution in achieving BC's 2030 Greenhouse Gas (GHG) mitigation target. However, the CleanBC framework lacks strong demand-side measures, to reverse the growth of energy demand in BC. Attempts have been made to reduce energy use in land transportation but action plans for other sectors, especially industry, are lacking. As a result, even with moderate energy demand reduction (10%), the CleanBC framework will not reach the 2030 target. Even if demand is reduced more sharply (25%), the current supply of renewable electricity and bioenergy is still insufficient to meet demand: the additional supply of renewable energy will be immense.

Future demand reduction cannot be predicted with precision, but any reduction reduces emissions. Growth in demand is predicted mainly for heating, mobility, and industrial production. The pursuit of lower cost and higher profit will lead to continuous but slow improvement in energy efficiency. However, decoupling demand from economic and population growth requires transformative change in business models and personal behaviors, and therefore more stringent policy measures.

Electrification is seen as a core strategy for GHG mitigation in BC. However, electricity supply is insufficient to meet the growth in demand inherent in the electrification-centered strategy. Even with Site C and radical demand reduction, about 60 PJ of additional supply will be needed to meet the 2030 target, and 160 PJ for carbon neutrality in 2050. New electricity generation will be needed by 2030 and beyond, comparable in magnitude to the projected output of the current Site C project. This implies installing hundreds of wind turbines and millions of solar panels.

The bioenergy-centered strategy is an alternative to a strategy dominated by electrification; it would dramatically increase demand for bioenergy. As the first step, it must fully exploit existing waste biomass, predominantly woody waste. Even then, roughly 250 and 450 PJ of additional primary bioenergy supply will be needed for 2030 and 2050, respectively. This is well beyond any foreseeable waste supply within BC.

Hence, strategies that rely solely on either electricity or bioenergy will raise demand beyond sustainable and manageable supplies. There is no single 'silver bullet' renewable energy source to meet BC's GHG mitigation targets: it is essential to utilize all the available bioenergy and renewable electricity resources and promote a balanced renewable energy portfolio. The limited time frame to 2030 emphasizes the difficulty of securing the renewable energy needed and the urgency of action to reduce demand. For the long-term target of carbon neutrality, the supply problems emphasize the need for a balanced renewable energy strategy.

Clean Energy Research Centre

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1. Background

In 2007, British Columbia introduced the Climate Change Accountability Act to mitigate provincial emissions of greenhouse gases (GHGs). Amendments introduced in 2018 established reduction targets: 40% below 2007 levels by 2030, 60% by 2040, and 80% by 2050. However, policy measures under the act, including the carbon tax and low-carbon fuel mandate, have not stemmed the rise in emissions: in 2019, BC's GHG emissions were 68.6 million tonnes (Mt), 5% above the 65.7 Mt emitted in 2007 [1]. The increase is mainly attributable to fossil fuel consumption - in 2019, 891 PJ of natural gas (NG) and refined petroleum products (RPP) provided 70% of energy supply in BC [2].

The CleanBC Phase 1 plan [3], published in 2018, gave more detail on the 2030 target and announced action plans to mitigate GHG emissions across BC's economy. It was supplemented in 2021 by a Roadmap to 2030 (CleanBC Phase 2 [4]), with quantified reduction targets for heating, mobility, industrial production, and waste management (see Table 3-1 below). CleanBC focuses on electrification, bioenergy, methane emission reduction, and efficiency improvement. Additionally, low-carbon hydrogen is to be promoted for heavy-duty vehicles and heating in buildings and industrial processes [3]. The plan depends on decoupling emissions from economic growth but does not address reducing economy-wide energy demand or matching renewable energy supply to demand. Only three policy actions to reduce demand are included: increasing the carbon tax, reducing distance travelled by light-duty vehicles by 25%, and reducing energy use by heavy-duty vehicles by 10% [4].

Electrification, relying on a low-carbon electricity supply mainly from hydroelectric sources, is a key component of the plan, to be promoted across all sectors. Some electrification technologies, such as heat pumps, electric motors, and electric vehicles, do have efficiency advantages over their fossil fuel counterparts. However, electrification increases the overall demand for electricity, raising the question of whether the supply of renewable electricity in BC will be sufficient.

Furthermore, the potential contribution of bioenergy needs to be examined. CleanBC sees renewable natural gas and liquid biofuels as low-carbon alternatives to natural gas distributed via the grid and fossil transport fuels, with the low-carbon fuel standard expected to be increasingly stringent. However, the plan ignores possible uses for biomass with higher efficiencies than refined biofuels, including low-grade heat for district heating and gasification-combustion to provide high-grade energy for industrial processes.

Against this background, this paper sets out an analysis to investigate pathways to achieve BC's GHG mitigation targets. Future clean energy scenarios to meet BC's GHG mitigation targets are presented in Section 2. Key findings on strategies for promoting and prioritizing clean energy development are presented in Section 3, and the details are included in Part II of this paper series.

2. Future Energy Profile in BC and the Potential Role of Bioenergy and Renewable Electricity

2.1 Baseline future energy demand

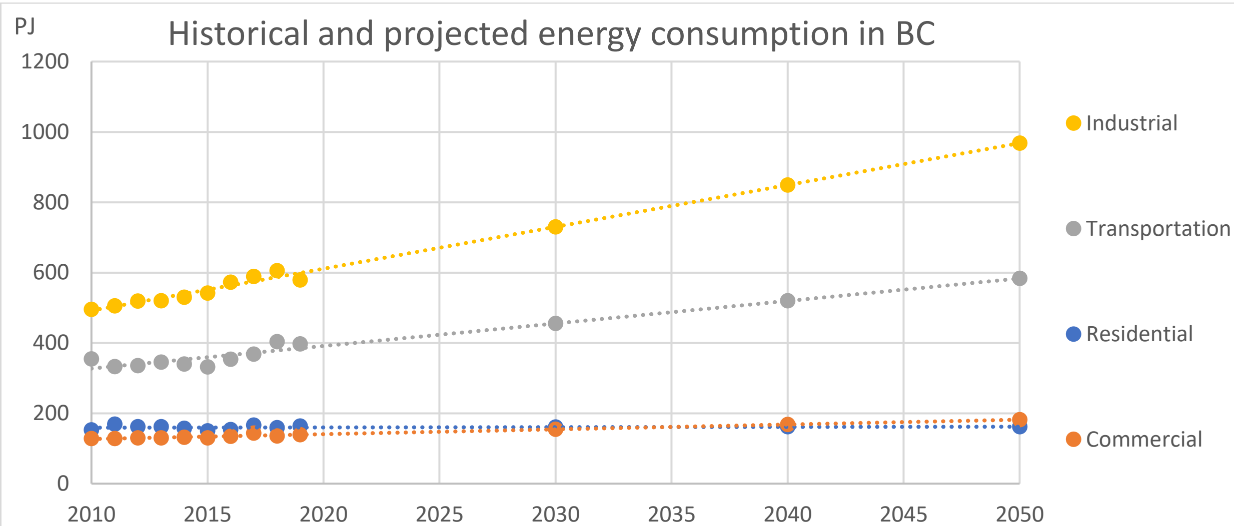

Figure 2-1 Historical and projected energy consumption in BC's different sectors

Baseline future energy demand refers to the anticipated energy demand for "business as usual", reflecting current projections of economic activity, population growth, and moderate efficiency improvement but excluding climate policies. Based on BC's historical energy consumption from 2010 to 2019 [5], baseline energy demand is expected to grow, particularly in the industrial and transportation sectors (see Figure 2-1). This will generate 68.6 Mt of GHGs from fossil fuels in 2030 and 87.4 Mt in 2050 (see Figure 2-2), a severe challenge for GHG mitigation.

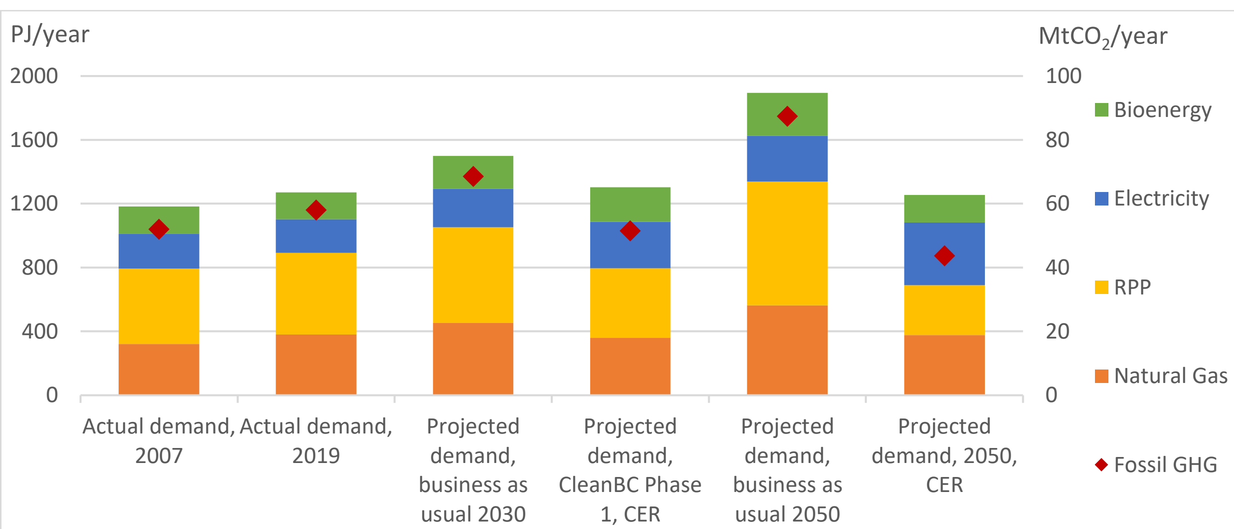

Figure 2-2 Projection for BC's energy demand and GHG emissions from fossil fuels in 2030

The growth in baseline energy demand is associated with industrial production, mobility, and heating in commercial and residential buildings. Canada Energy Regulator (CER) [2] has produced "optimistic" projections for BC, assuming CleanBC Phase 1 is fully implemented, augmented by further policy effort and continuous technological improvement. Even with the optimistic projections, fossil fuel consumption in 2030 will exceed 800 PJ (see Figure 2-2), directly emitting 51.5 Mt of GHGs, far above BC's 2030 target of 38.0 Mt. For 2050, ideally a time frame to approach carbon neutrality, CER's optimistic projection foresees 770 PJ of fossil fuel consumption, directly emitting 43.7 Mt of GHGs. This projection does not include the recently announced CleanBC Roadmap to 2030, but it still shows that meeting BC's GHG mitigation targets depends critically on decoupling energy use from economic growth.

Therefore, possible scenarios for BC to meet its GHG reductions for 2030 and 2050 are explored in the following sections. As a basis for constructing these energy scenarios, the potential in BC for increasing use of biomass, generation and use of renewable electricity, and using hydrogen as an energy carrier has been assessed. The salient conclusions are summarized in Section 3; details are given in the accompanying document "Part II: Clean Energy Strategies for Mitigating Greenhouse Gas Emissions in British Columbia". An important finding is that future energy scenarios must deploy the optimal uses of clean energy, giving the greatest GHG mitigation at the lowest cost, as both bioenergy and renewable electricity will be in short supply.

2.2 Energy scenarios for 2030 target

Energy flows in the different scenarios are represented in terms of Sankey diagrams: the left-hand axis in each case shows the different primary energy sources, the central line shows the forms in which the energy is distributed, and the right-hand axis shows end-use.

2.2.1 Scenario 1: CleanBC with moderate energy demand reduction

As shown in Figure 2-3, economy-wide electrification will substantially increase electricity demand. In addition to BC's current renewable electricity generation capacity and the capacity to be provided by the Site C project, Scenario 1 will require a further 54.1 PJ, which is 9 times the totality of BC's wind and solar capacity, or 2.9 times the capacity of the Site C project. As estimated in Part II of this paper series, the output of one Site C project equals that of 30 km^2 of solar panels or nearly 700 average sized (2.5 MW) wind turbines in BC. The challenges presented by the enormous new demand, limited time frame towards 2030, and intermittency of solar and wind electricity generation are obvious.

Scenario 1 also foresees substantial increase in demand for all forms of bioenergy. The current bioenergy supply refers to wood residues and liquid biofuels currently consumed in BC, as well as wood pellet exports (see Part II). As global bioenergy demands are expected to increase continuously, importing bioenergy will become increasingly difficult and expensive. Therefore, for the reason of energy security, pellets currently exported should be diverted for domestic uses.

Waste streams, mainly unused wood residues and methane from landfill gases and anaerobic digestion of waste, must be prioritized for bioenergy production. However, after fully exploiting the energy potential of these waste streams, an additional supply of 118.8 PJ of liquid biofuels will still be needed, which is equivalent to about 200 PJ of primary bioenergy before conversion and even higher than the current bioenergy supply. If this new bioenergy supply is to be provided within BC, fundamental changes in forest management and residue collection systems will be needed, to ensure thorough recovery and utilization of wood residues, dead trees, and forest thinning, which is also in the interest of wildfire prevention [6]. Planting energy crops on marginal land may also be considered.

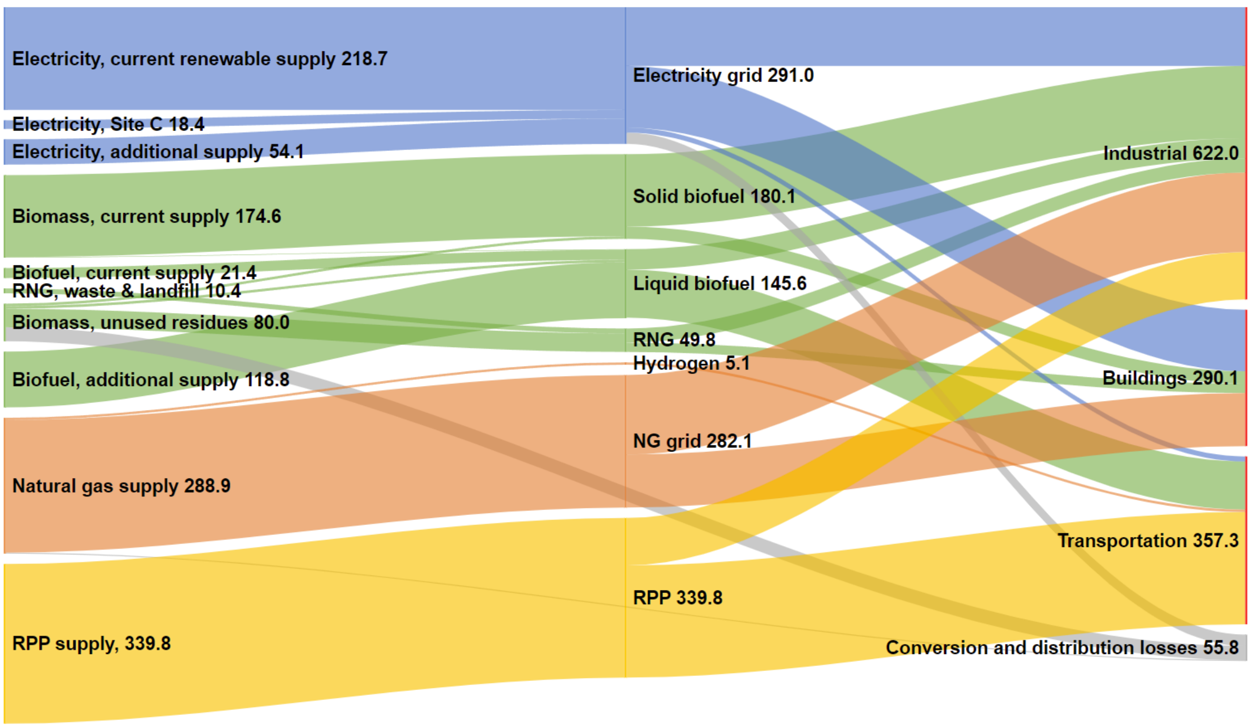

Figure 2-3 Scenario 1 (CleanBC with moderate energy demand reduction)

However, Scenario 1 can only achieve 12.6 Mt of GHG mitigation from energy transformation. As shown in Table 2-1, GHG mitigations across all sectors are far below the sectoral targets. Including the non-energy action plans in CleanBC, such as CCS and methane emission mitigation, the total GHG reduction is estimated to be 15.8 Mt, which is slightly more than half the 2030 target. As the additional renewable energy supply required for Scenario 1 is already enormous, securing even more will be technically and economically unrealistic. Therefore, much deeper reduction of energy demand is necessary across the economy.

Table 2-1 Sectoral GHG mitigations in 2030

	Buildings	Transportation	Industry
Sectoral targets	59-64%	27-32%	38-43%
Scenario 1	31%	29%	20%
Scenario 2	38%	37%	35%
Scenario 3	64%	37%	41%
Scenario 4	64%	37%	41%

2.2.2 Scenario 2: CleanBC with accelerated energy demand reduction

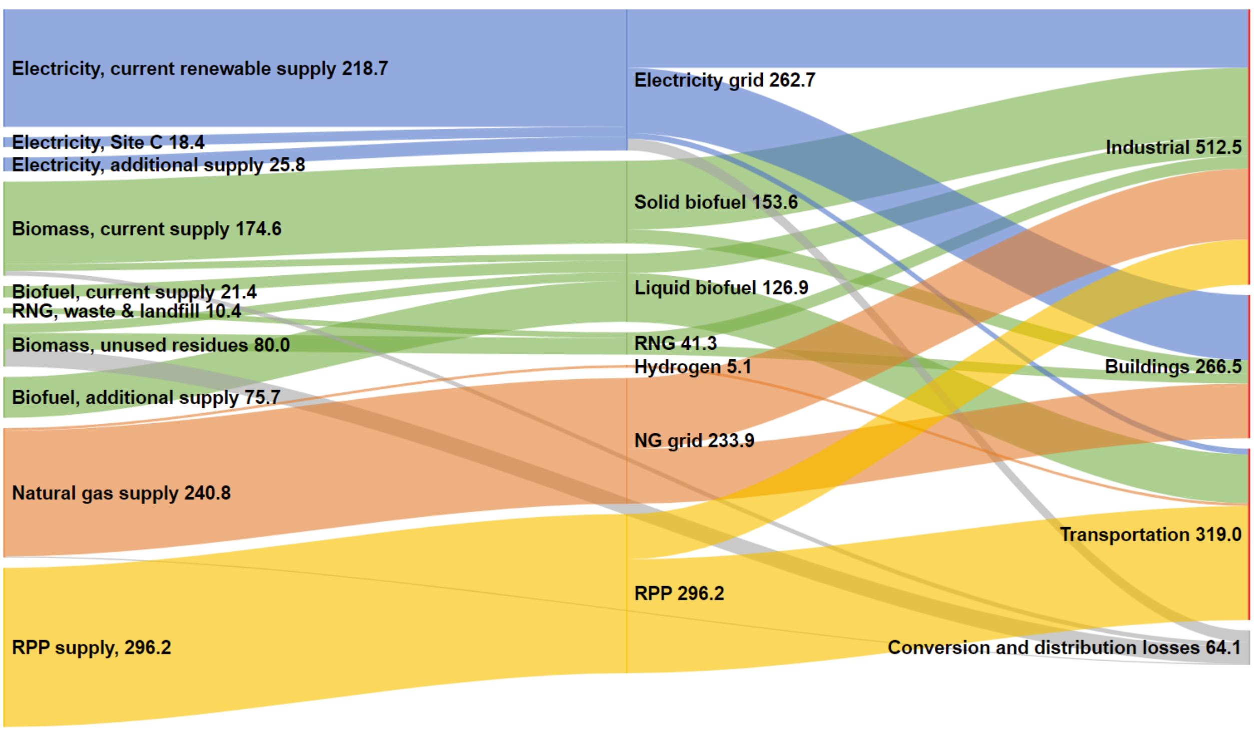

Figure 2-4 Scenario 2 (CleanBC with accelerated energy demand reduction)

Scenario 2 differs from Scenario 1 in assuming deeper reductions in economy-wide energy demand: 25% reduction by 2030 (2.5% annually from 2021). Given the historical rise in energy demand, this assumption is obviously ambitious and optimistic. In addition to reducing energy use in transportation, as laid out in CleanBC Roadmap, use in buildings and industries must be reduced substantially by efficiency improvement plus measures such as modifying buildings to reduce heating and cooling loads and integrating industrial operations to use waste heat.

Comparison between Scenarios 1 and 2 confirms that energy demand reduction is essential to contain renewable energy demand at manageable levels and achieve further mitigation: the additional demands for renewable electricity and biofuels in Scenario 2 are 25.8 and 75.7 PJ, respectively, much smaller than in Scenario 1. The additional renewable electricity could be supplied if the output of wind generation in BC grows by 14% annually, a global average predicted by IEA [7] (See Part II).

Together with non-energy GHG mitigation actions in CleanBC, GHG emissions are reduced by 22.2 Mt, a much greater reduction than in Scenario 1 but still 4.1 Mt short of the 2030 target. In terms of sectoral mitigations, Scenario 2 represents 37% reduction in the transportation sector, fulfilling BC's sectoral target. However, GHG mitigations in buildings and industries are 38% and 35%, slightly lower than the respective sectoral targets. Further actions to achieve the 2030 target are explored in Scenarios 3 and 4.

2.2.3 Scenario 3: Enhanced electrification and Scenario 4: increased use of bioenergy

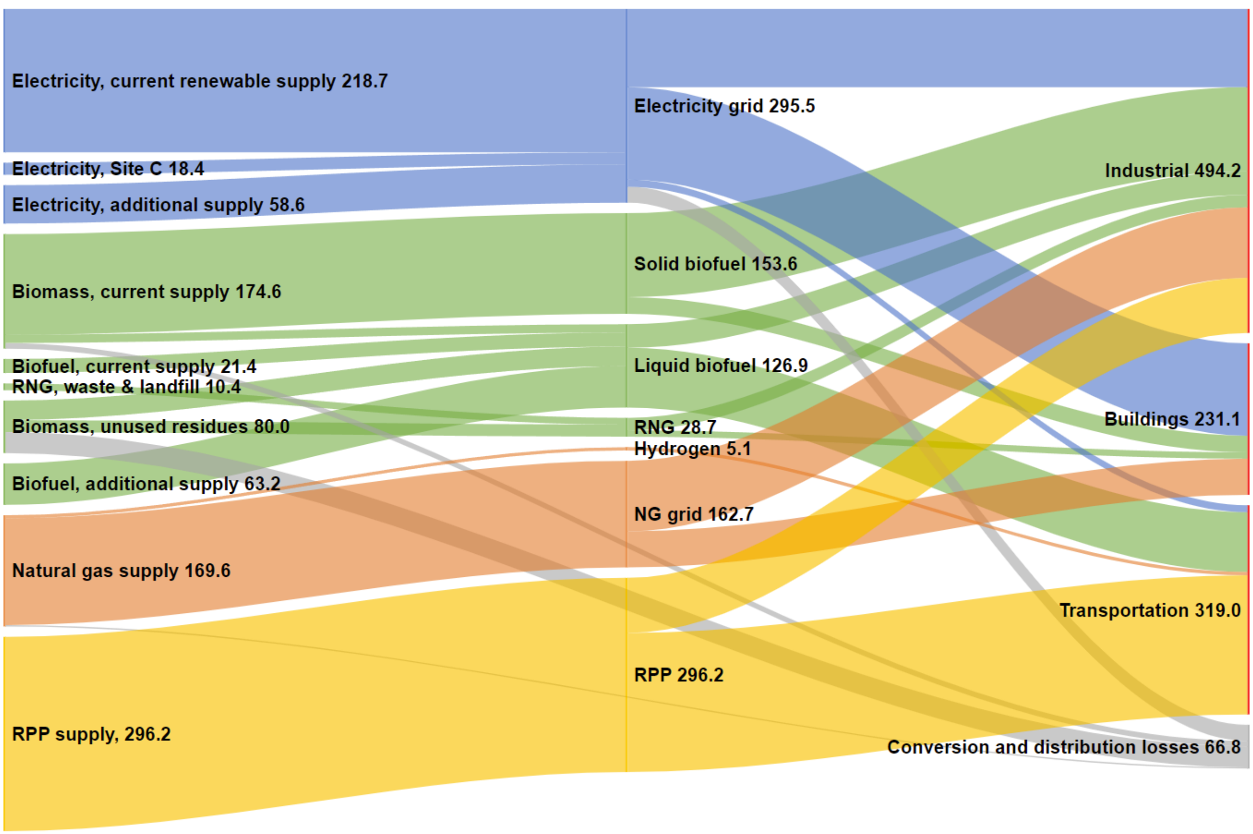

Figure 2-5 Scenario 3: CleanBC with enhanced electrification

Scenarios 3 and 4 build on the assumptions in Scenario 2, i.e., fully enacted CleanBC policies and accelerated energy demand reduction, but explore how the further reductions needed to achieve the GHG mitigation targets for 2030 might be achieved. In line with BC's sectoral mitigation targets, emissions are to be reduced by a further 2.7 Mt (64%) from buildings and 1.4 Mt (41%) from industries.

In Scenario 3, shown in Figure 2-5, the additional reductions are achieved by electrification to further reduce natural gas use, mainly through increased use of heat pumps in buildings and electric motors in industries. This increases demand for low-carbon electricity by an additional 58.6 PJ. Electrification will reduce the overall demand for RPP and natural gas and therefore reduce demand for biofuels to blend into these fossil fuels, so that Scenario 3 requires a slightly smaller additional supply (63.2 PJ) of liquid biofuels than Scenario 2.

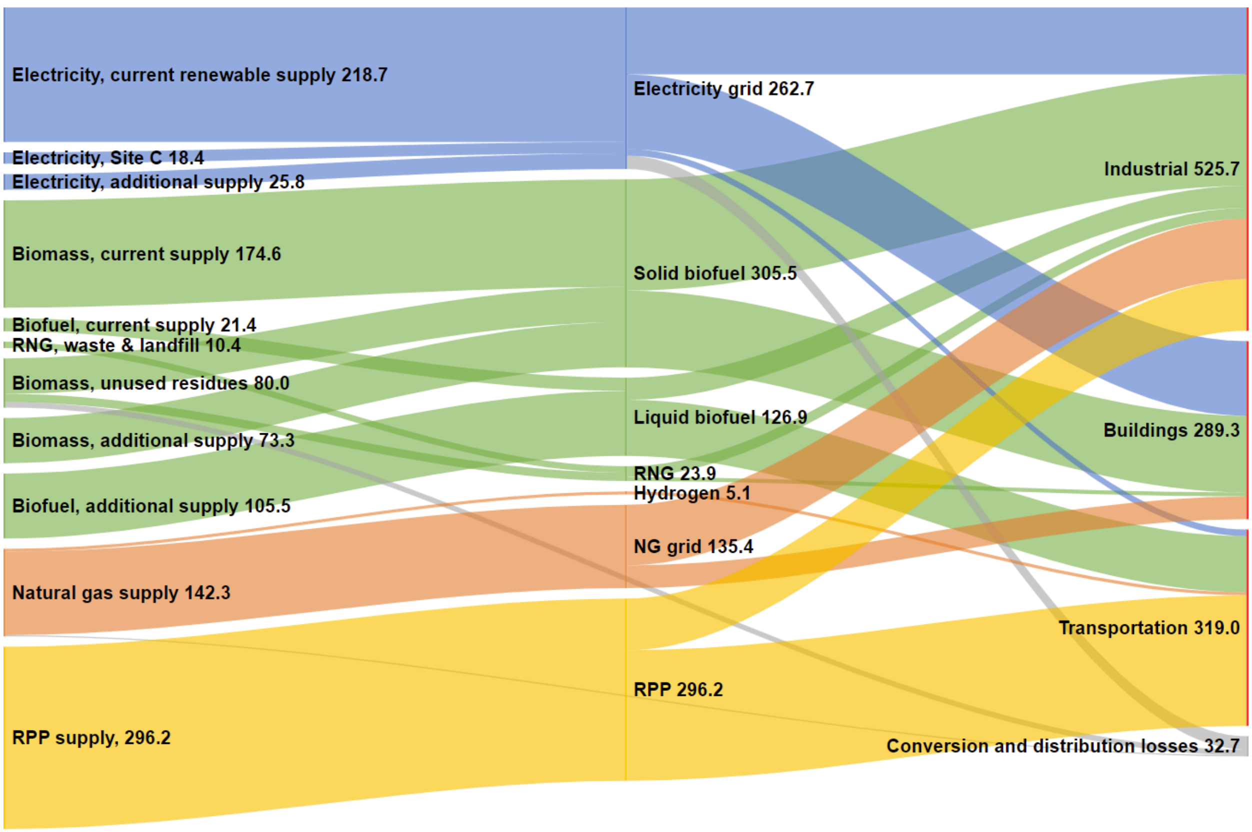

Figure 2-6 Scenario 4: CleanBC with increased use of bioenergy

Scenario 4, shown in Figure 2-6, relies on bioenergy for further GHG mitigation, including biomass-fired district heating systems for buildings and biomass gasification-combustion systems for industries. After fully exploiting the bioenergy potentially available in wood residues, other organic waste and landfill, Scenario 4 requires additionally 73.3 PJ (3.7 million ODT) of solid biomass and 105.5 PJ of liquid biofuels (176 PJ of primary bioenergy before conversion). Securing this additional bioenergy will be an enormous challenge (see Part II).

2.3 Energy scenarios for carbon neutrality in 2050

The time horizon is now extended to 2050 by exploring scenarios to achieve carbon neutrality, building on the CleanBC framework. Accelerated reduction of energy demand is no less indispensable. Therefore, all the scenarios assume that energy demand will decrease by 25% in buildings and 50% in other sectors by 2050. Light-duty vehicles will be 100% electric [4]. Following the BC Hydrogen Strategy, GHG reduction of 7.2 Mt [3] will be achieved through using hydrogen, by replacing diesel fuel in 88% of the heavy-duty vehicle fleet. This will require 50.7 PJ of blue hydrogen. Methane emissions from industries and waste management are assumed to be reduced by 95%. To illustrate the problems, two extreme scenarios are considered – maximum electrification and maximum use of bioenergy – but the most realistic scenarios are likely to lie between the two.

2.3.1 Scenario 5: Carbon neutrality via enhanced electrification

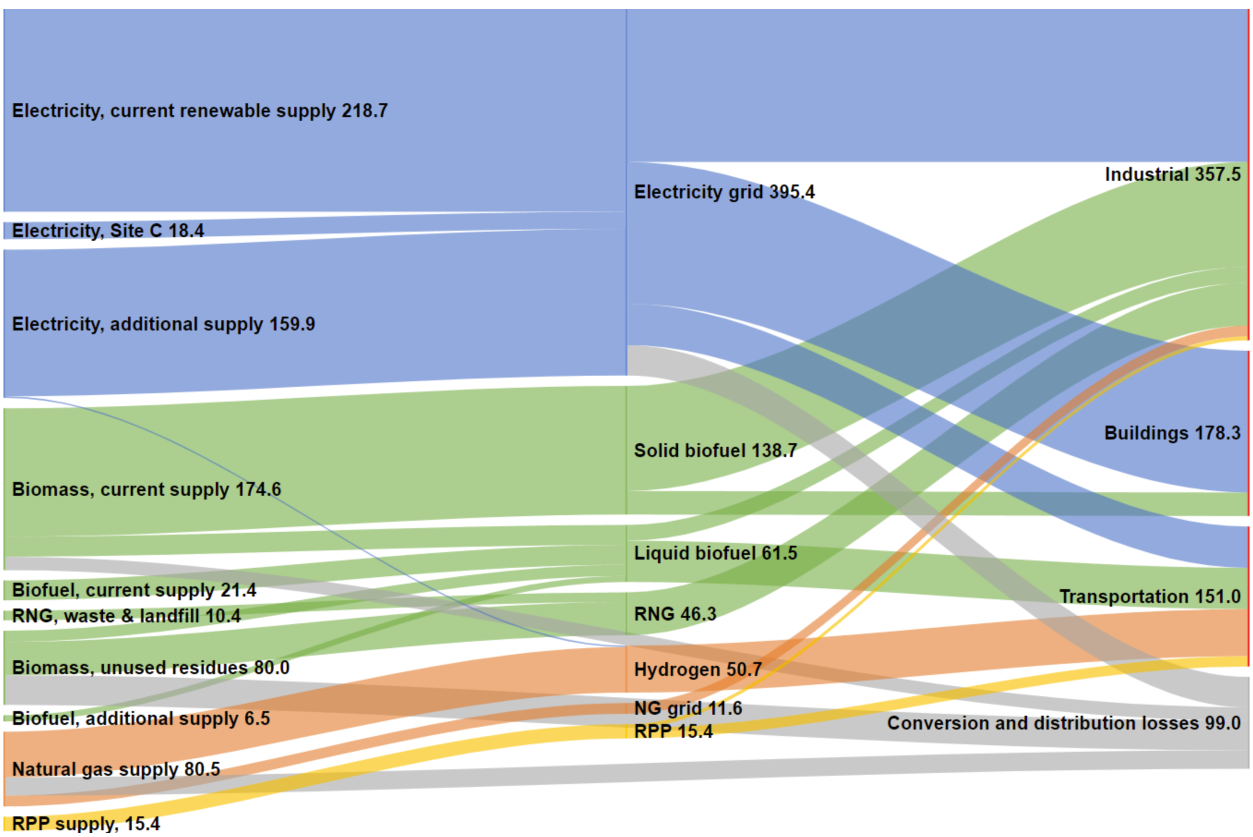

Figure 2-7 Scenario 5 (Carbon neutrality with electrification strategy)

In Scenario 5, shown in Figure 2-7, GHG mitigations beyond CleanBC are assumed to be achieved mainly by electrification, with the most efficient options prioritized in each sector. Heat pumps and EVs eliminate fossil fuel consumption in buildings and transportation, respectively. Electric motors eliminate industrial fossil fuel consumptions for motive power, including RPP for industrial machinery and hauling and natural gas for fluid compression in the oil and gas industry. However, natural gas use in manufacturing is mostly for thermal energy: high-temperature heating and kilns. In the absence of data on use in different applications, it is assumed here that the use of electric motors will displace 70% of natural gas and 80% of RPPs used throughout industry. For the remaining fossil fuel usage, it is assumed that low-carbon fuel standards for liquid fuels and natural gas will be increased to 80%. Taken together, these measures can mitigate GHG emissions from energy by more than 90%. Potential emissions from the remaining fossil fuel uses and non-energy sources are estimated to be 8 Mt, but are assumed to be eliminated by CCS.

As shown in Figure 2-7, 160 PJ of additional renewable electricity supply will be needed for the electrification strategy in Scenario 5, equivalent to the output of nine projects on the scale of Site C. While such dramatic expansion of renewable electricity may be technically possible, the investment needed is huge and action needs to start immediately. If the entirety of the additional supply is provided by intermittent wind and solar generation, the share of intermittent electricity in BC's grid will reach 40% by 2050, leading to difficult but accomplishable challenges to grid management (see Part II). However, in spite of the increase in low carbon fuel standards for liquid and gaseous fuels, the demand for bioenergy will be only slightly above current levels, mostly due to increased electrification and reduced overall energy demand, and should be easily manageable. Most natural gas will be used for hydrogen production; together with CCS at stationary sources, this should be technologically straightforward. Only 27.0 PJ of fossil fuels will be used in conventional industrial applications, with the GHG emissions mitigated by technologies involving direct air capture.

2.3.2 Scenario 6: Carbon neutrality through increased use of bioenergy

In Scenario 6, shown in Figure 3-8, carbon neutrality is achieved through enhanced production and use of bioenergy. Biomass-fired district heating systems, especially sufficiently large to incorporate pre-gasification for lower air emissions [8], and industrial gasification-combustion systems are further promoted to replace 60% of natural gas consumption in buildings and industries, due to their high conversion efficiencies. Low carbon fuel standards are increased to 100% to eliminate fossil fuels. The remaining 6.6 Mt of GHG emissions will be mitigated by CCS. This strategy will require an additional supply of 155 PJ of liquid biofuels (258 PJ of primary bioenergy before conversion) plus 202 PJ of solid biomass. As stated in Section 3.2.1, production of biomass is subject to restrictions of land availability and GHG emissions from land-use change. Therefore, securing such a large additional bioenergy supply sustainably within BC, through utilization of waste biomass and plantation of energy crops, is speculative.

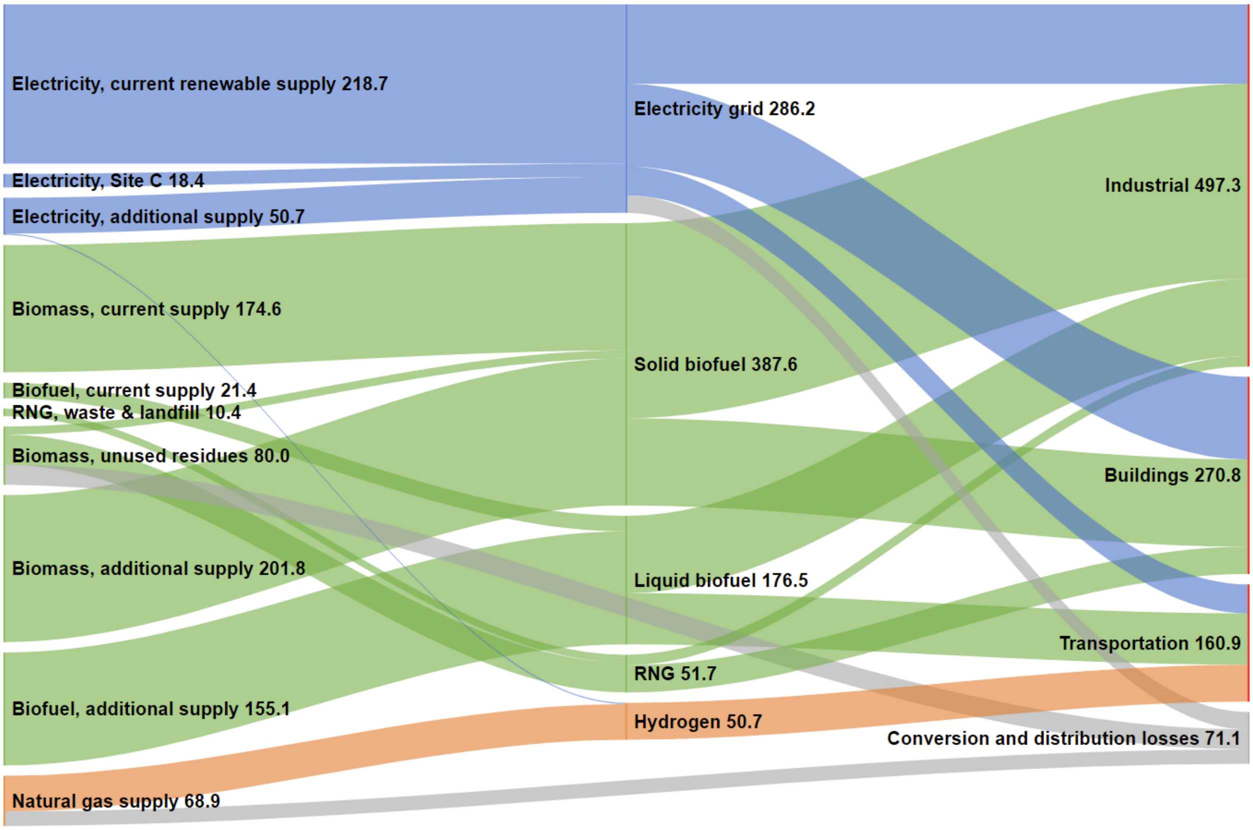

Figure 2-8 Scenario 6 (Carbon neutrality with promotion of bioenergy)

2.4 Discussion

Scenarios 3 and 5 represent maximal use of low-carbon electricity while scenarios 4 and 6 include maximum use of bioenergy. They show that any strategy relying primarily on either electrification or bioenergy faces enormous supply problems. The most realistic ways to decarbonize the energy system beyond the CleanBC action plans will no doubt lie between these extremes. However, the main conclusion remains: all available bioenergy and electricity resources need to be exploited to meet the province's targets.

The various electrification, bioenergy, and hydrogen options differ significantly in the efficiency of energy use. The scenarios all assume that, to minimize primary energy demand, the most efficient technologies are preferred: electric heat pumps and motors, biomass-fired heating system, and hydrogen fuel cells. Actual energy demand will be even higher if less efficient options are deployed: electric resistance heating, refined biofuels, and hydrogen combustion. Similarly, hydrogen is assumed to be produced by the most efficient route: steam-methane reforming (SMR) of natural gas combined with Carbon Capture and Sequestration (CCS). Using electrolysis or biomass gasification would raise future demands for renewable energy even further and diminish the role natural gas can play in a carbon-neutral economy.

Table 2-2 Impact of energy demand reduction on renewable energy needed in addition to supply in 2019, electricity from Site C project and bioenergy from existing waste streams

Demand reduction by 2030		15%	20%	25% (base)	35%	35%
Additional supply (PJ) in Scenario 3:	Electricity	79	69	59	49	38
	Liquid biofuel	96	80	63	47	30
	Solid biomass	0	0	0	0	0
Additional supply (PJ) in Scenario 4:	Electricity	46	36	26	16	5
	Liquid biofuel	122	114	106	97	89
	Solid biomass	100	87	73	60	46
Demand reduction by 2050		40%	45%	50% (base)	55%	60%
Additional supply (PJ) in Scenario 5:	Electricity	221	190	160	129	99
	Liquid biofuel	42	24	7	-11	-21
	Solid biomass	0	0	0	0	-13
Additional supply (PJ) in Scenario 6:	Electricity	83	67	51	35	19
	Liquid biofuel	211	183	155	127	99
	Solid biomass	274	244	202	155	108

Furthermore, all the Scenarios include accelerated energy demand reduction. A sensitivity analysis has been carried out to investigate the significance of reducing overall energy demand. As shown in Table 3-2, for every 5% of further reduction in overall energy demand, the additional renewable electricity supply required to achieve BC's 2030 target can be reduced by 10 PJ, with similar reductions in demand for biomass and biofuels. Demand reductions for the 2050 scenarios are even larger. Therefore, progressive reduction of overall energy demand is essential to meet BC's GHG targets for 2030 and beyond. This challenging task requires substantial efficiency improvement and also behavioral changes induced by more stringent policy measures.

3. Clean Energy Sources for BC

A full assessment of potential sources of low-carbon energy in BC is set out in the accompanying document: "Part II: Clean Energy Strategies for Mitigating Greenhouse Gas Emissions in British Columbia". A summary is provided here.

BC has enormous potential for bioenergy production. Waste biomass available in BC could provide about 20% of the energy currently provided by fossil fuels [9]. The main source is unused wood residues generated during logging and sawmilling; this material is currently destroyed by slash burning, to ensure that it does not provide a potential fuel for wildfires. Trees killed by mountain pine beetle infestation are another source, although long-term availability is uncertain. Waste biomass is available in animal manure, crop residues, and the organic fraction of municipal solid waste (MSW). Energy crops, such as short-rotation coppice, could also be produced [10].

Most of the available biomass is lignocellulosic ("woody"). It can be used directly as fuel for generation of electricity or heat, gasified to produce Renewable Natural Gas (RNG) or liquid fuels including methanol and ethanol, or pyrolyzed to produce a range of liquid biofuels including aviation fuel. Following a general principle, the greatest GHG mitigation with the lowest cost is achieved by the simplest processes: direct use as fuel, including for district and industrial heating [9]. Syngas combustion generates lower health impacts [8]. Converting biomass to refined biofuels has lower efficiency and much higher costs [11].

Animal manure and food waste can be processed into biogas by anaerobic digestion. The gas can be used directly to generate heat and/or electricity or can be upgraded to RNG, and the digestate residue can be used to displace synthetic fertilizers. The greatest GHG mitigation at the lowest cost results from using the biogas in integrated operations combining animal husbandry, glasshouse cultivation and, preferably, mushroom production, following the industrial symbiosis principle [12], [13]. Upgrading the biogas to RNG brings lower GHG benefits at higher cost [13].

It has been demonstrated in Section 2 that even with the Site C project completed and radical energy demand reduction, BC will not have surplus renewable electricity, as future electricity demands will dramatically increase. Other primary energy sources must therefore be explored. Wind energy could make a significant contribution in BC [7]. Solar Photovoltaic production is less favourable in BC [2] but can be deployed in niche applications, such as local uses for charging electric vehicles, as well as in large solar farms linked to the grid. Increasing wind and solar will increase the proportion of intermittent generation in the provincial grid way beyond the present level of 2.5% but, based on experience elsewhere, at least 20% should be readily manageable. Combined heat and power generation, providing dispatchable renewable electricity and low-carbon steam/heat to industrial operations, should be retained and possibly increased.

Given that the demand for renewable electricity is expected to rise in the future, the most effective uses should be prioritised. For land transport, this means powering electric vehicles, which is more energy-efficient than using electricity to produce liquid fuels ("electrofuels"). For industrial applications, replacing natural gas and diesel engines by electric motors is the preferred use. In buildings, the preferred use is in heat pumps to replace resistive and gas-fired heaters.

Hydrogen is an energy carrier that can be produced from different primary energy sources: electricity, by electrolysis of water; biomass, by gasification; or natural gas, by steam methane reforming [3]. Given the scarcity of renewable electricity and biomass in BC and the need to mitigate GHG emissions, "blue" hydrogen, which is produced from natural gas with the CO_2 sequestered, is recommended; this represents the only sizeable use for natural gas consistent with a low-carbon economy. The hydrogen is recommended for powering fuel cell vehicles, preferably heavy-duty ones, to replace internal combustion engines. Direct combustion of hydrogen is not a preferred use because it loses the advantage of fuel cells and is less efficient than direct use of the primary energy from which the hydrogen is produced.

4. Conclusions and Recommendations

The two phases of CleanBC include a full suite of policy measures for promoting renewable energy and reducing methane emissions and thus represent firm steps towards achieving BC's 2030 GHG mitigation target. However, a problem in the CleanBC framework is the lack of comprehensive action to address the growth of energy demand in BC associated with growth in economic activity and population. Even though the CleanBC Roadmap attempts to reduce energy use in the transportation sector, similar action plans in buildings and industries are lacking. Scenario 1 shows clearly that the CleanBC framework, together with moderate demand reduction of 5% by 2030, is unable to reach the 2030 target. In all the other scenarios, rapid demand reduction of 25% by 2030 and 50% by 2050 is assumed, but the current supply of renewable electricity and bioenergy is still far from enough to meet the growing needs. The additional supply of renewable energy needed for BC's GHG mitigation targets will be immense.

The extent of demand reduction achievable in 2030 and 2050 cannot be predicted reliably, but any further demand reduction moves closer to meeting GHG mitigation targets. Naturally driven by desire for lower cost, energy efficiency can be expected to improve continuously but slowly. Decoupling energy demand from economic and population growth needs stringent policy measures to achieve transformational rather than incremental change. Growth in demand in BC is predicted to arise mainly for heating, mobility, and industrial production. Energy consumption for home heating and personal mobility is largely a matter of behavioral change, which may be induced by both voluntary desire for a sustainable future and involuntary policy measures.

Electrification is seen as a core strategy for GHG mitigation in BC. With radical demand reduction and electrification-centered strategy, an additional electricity supply of about 60 PJ will be needed for BC's 2030 target, and 160 PJ for carbon neutrality in 2050. These numbers are obtained from hypothetical scenarios, but show that the current electricity supply is clearly insufficient. The new projects needed will be comparable in magnitude to the output of the Site C project, i.e., hundreds of wind turbines and millions of solar panels, representing both challenges and opportunities for utilizing all the available wind, solar, and hydroelectric generation resources in BC. On the other hand, as electrification progresses, the demand for conventional fuel and consequently biofuels for blending will be expected to peak and decline. By 2050, currently available biomass residues will meet demand for bioenergy if the electrification-centered strategy is implemented.

The bioenergy-centered strategy is an alternative to a strategy dominated by electrification. It would dramatically increase demand for bioenergy. As the first step, it must fully exploit existing waste biomass, including wood residues, agricultural waste, food waste, and landfill gases. In addition to securing sustainable bioenergy supply, this would reduce atmospheric emissions of non-GHG pollutants. Even so, roughly 250 and 450 PJ of additional primary bioenergy supply will be needed for BC's 2030 target and carbon neutrality in 2050, respectively. Provision of such a large quantity of biomass is well beyond foreseeable waste collection from BC's current forestry and agricultural sectors. To further expand bioenergy supply, the sustainability of forest and farmland management and emissions from land-use changes must be carefully investigated.

Hence, strategies that rely solely on either renewable electricity or bioenergy will raise demand for the respective renewable energy beyond sustainable and manageable levels. Therefore, there is no single 'silver bullet' renewable energy source to meet BC's GHG mitigation targets: it is essential to utilize all the available bioenergy and renewable electricity resources and promote a balanced renewable energy portfolio. The limited time frame to 2030 emphasizes the difficulty of securing the renewable energy needed. For the long-term target of carbon neutrality, the supply problems emphasize the need for a balanced renewable energy strategy.

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THE UNIVERSITY OF BRITISH COLUMBIA

Clean Energy Research Centre (CERC)

Part II

Clean Energy Strategies for Mitigating Greenhouse Gas Emissions in British Columbia

Haoqi Wang, Roland Clift, and Xiaotao Bi

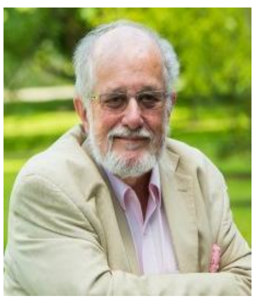
University of British Columbia

January 2022

Photos by unsplash.com

Biographies

Haoqi Wang worked on life cycle environmental analysis and techno-economic analysis of bioenergy systems in British Columbia during his PhD study as a PICS fellow and postdoctoral research at the Department of Chemical and Biological Engineering, University of British Columbia, under the supervision of Xiaotao Bi and Roland Clift. He is now an assistant professor in the College of Materials and Environmental Engineering, Hangzhou Dianzi University, China.



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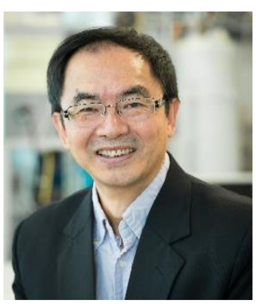

Xiaotao Bi is a professor in the Department of Chemical and Biological Engineering and the director of UBC's Clean Energy Research Centre. His current research focuses on particle technology and fluidized bed reactors for biomass thermo-catalytic conversion, green and sustainable engineering, and integrated assessments of clean energy systems. He is a fellow of the Canadian Academy of Engineering and Engineers Canada.

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Clean Energy Research Centre

Executive Summary

The potential in BC for increasing use of biomass, generation and use of renewable electricity, and using hydrogen as an energy carrier have been assessed. As demonstrated in Part I of this paper series, both bioenergy and electricity will be in short supply, as further decarbonization efforts are made. Therefore, all renewable energy sources must be used in the ways that give greatest mitigation of Greenhouse Gas (GHG) emissions at the lowest cost.

Waste biomass in BC could provide about 20% of the energy currently provided by fossil fuels, mainly wood residues from logging and sawmilling. Energy crops could also be grown in BC. Lignocellulosic (woody) biomass can be used to generate electricity and heat, gasified to produce Renewable Natural Gas (RNG) or liquid fuels, or pyrolyzed to produce a range of liquid biofuels including aviation fuel. Direct use for district and industrial heating gives greatest GHG mitigation at lowest cost. Pre-gasification combustion generates lower health impacts. Converting biomass to refined biofuels leads to energy losses and increases overall costs. Manure and food waste can be converted into biogas by anaerobic Digestion (AD). Biogas can be used directly to generate electricity and heat or upgraded to RNG. The digestate residue can displace synthetic fertilizers. Integrating AD with agricultural operations gives the greatest GHG mitigation at the lowest cost. Upgrading to RNG has the highest cost.

Even with Site C completed and operating, BC will not have surplus renewable electricity. Other primary energy sources must therefore be explored. Wind energy could be significant. Solar photovoltaic production is less favourable in BC but could be deployed in niche applications. Increasing wind and solar will greatly increase the proportion of intermittent generation but at least 20% should be readily manageable. Cogeneration of heat and power, providing dispatchable electricity and steam/heat for industrial operations, should be retained and possibly increased.

The most effective use of electricity for land transport is to power electric vehicles. Using electricity to produce liquid fuels (“electrofuels”) is much less efficient. For industrial applications, replacing natural gas and diesel engines by electric motors is the preferred use. In buildings, the preferred use is in heat pumps to replace resistive and gas-fired heaters.

Hydrogen can be produced from different energy sources: electricity, by electrolysis of water; biomass, by gasification; or natural gas, by steam methane reforming. Hydrogen produced from renewable energy sources is termed “green” hydrogen, but its application is limited due to scarcity of future renewable electricity and biomass supply. “Blue” hydrogen is made from natural gas with carbon capture, which represents the only major use for natural gas in a low-carbon economy. It should be used in fuel cell vehicles, to replace internal combustion engines which are inherently less efficient. Combustion of hydrogen loses the advantage of fuel cells and is less efficient than direct use of the energy from which the hydrogen is produced.

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1. Bioenergy

1.1 Bioenergy potential in BC

BC has enormous potential for bioenergy production from waste biomass: existing wastes and byproducts of existing economic activities do not require additional resources and therefore constitute sustainable bioenergy feedstock. Figure 1 shows the estimated total primary energy in currently unused waste biomass in BC, totaling 190 PJ per year [1], equivalent to 20% of fossil fuel consumption. BC's primary source of waste biomass is its forestry sector. During logging and sawmilling, millions of tonnes of wood residues are generated; most are used domestically for energy production (135 PJ) [2] or exported as pellets (40 PJ) [3], but a considerable amount (80 PJ) remains unused. To prevent wildfires, unused wood residues must be destroyed by slash burning, which generates CH_4, a potent GHG, and other hazardous emissions [4]; converting the residues to bioenergy avoids these emissions as well as displacing fossil fuels. Trees killed by mountain pine beetle infestation are another source of forestry waste biomass [5], but future availability is unpredictable. Waste biomass is also available in animal manure, crop residues, and the organic fraction of municipal solid waste (MSW). The total waste biomass resource could supply a significant part but not the whole of BC's energy demand. The priority for developing the available bioenergy resource is therefore to maximize GHG mitigation while keeping the total costs as low as possible.

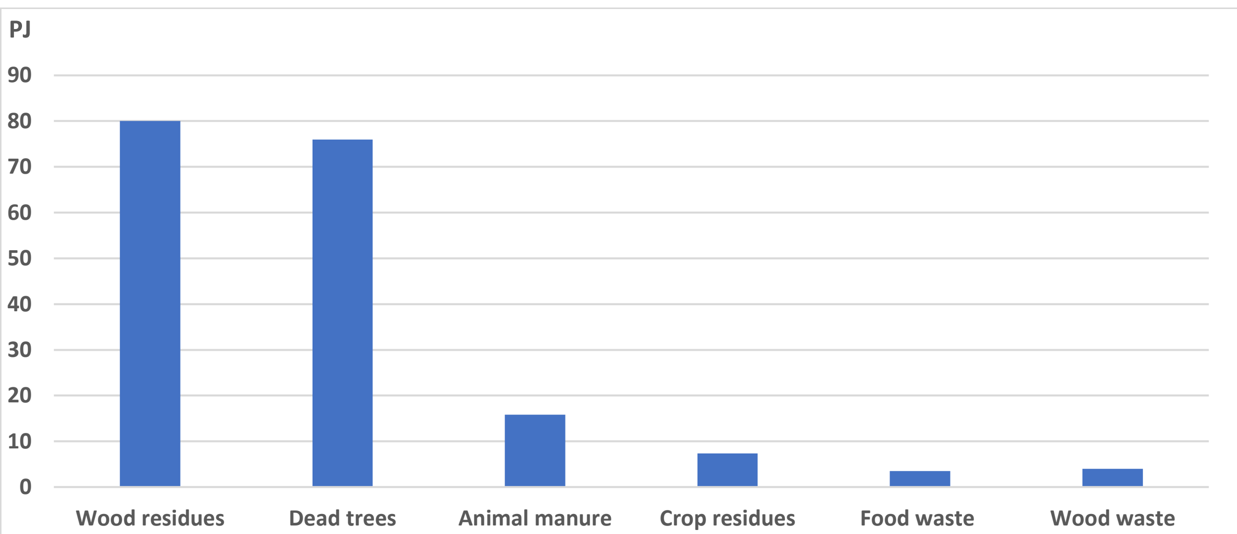

Figure 1 Primary energy in unused waste biomass in BC [1]

Beyond waste biomass streams, additional primary bioenergy could be obtained by expanding timber harvesting and growing energy crops. Short-rotation coppice (SRC) production of biomass should give an annual yield of 16-23 ODT/ha in Canada [6], [7]. However, producing 100 PJ of primary bioenergy would require roughly 250,000 ha, equivalent to 10% of BC's agricultural land [8]. Because the sustainability of these sources is contentious – they involve land-use change and potentially a conflict between food and energy production – they are not considered further here. However, they might be considered in future given that SRC is tolerant of flooding.

Most biomass resources in BC, including wood logs and residues, crop residues, and the woody fraction of MSW, and also SRC product, are lignocellulosic, composed of cellulose, hemicellulose, and lignin. The material can be converted to biofuels and energy by thermochemical processing (see Section 2.1.2). On the other hand, animal manure and food waste contain much more mixed constituents with higher moisture contents and are thus not suitable for thermochemical conversion; instead, anaerobic digestion (AD) should be employed (see Section 2.1.3).

1.2 Utilization of Lignocellulosic biomass

As illustrated in Figure 2, many thermochemical bioenergy conversion technologies start with gasification, a partial oxidation process that converts biomass into syngas, a mixture of mainly H_2, CO, CH_4, and CO_2 [9]. Biomass or biomass-derived syngas can be combusted for heat generation or cogeneration (CHP). Syngas combustion provides higher-grade heating, which can be used to replace natural gas for industrial use, such as in lime kilns in the pulp and paper industry. It also generates lower health impacts [10]. Alternatively, syngas can be synthesized into different biofuels, including methanol, ethanol, and methane (RNG). Biomass can also be pyrolyzed to produce hydrocarbons. An emerging pyrolysis technology is hydrothermal liquefaction (HTL), which turns biomass into a mixture of liquid biofuels including aviation fuel. Due to the nature of biogenic carbon cycle, bioenergy generally has lower GHG emissions than its fossil fuel counterpart [11]. Converting wood residues to bioenergy in BC can achieve additional reductions of GHGs and health impacts by avoiding slash burning [12].

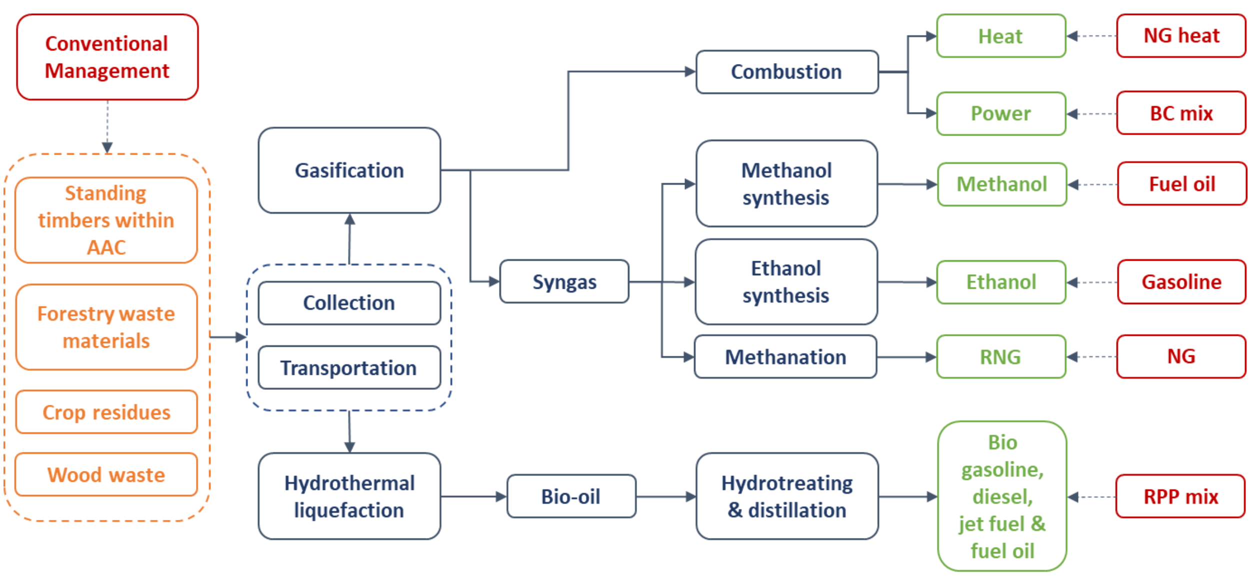

Figure 2 Systems for energy production from lignocellulosic biomass [12]

Conventionally, the carbon footprint of bioenergy is reported per GJ, which underplays the importance of conversion efficiencies. In Figure 3, GHG reduction potential of bioenergy derived from wood residues is compared per ODT biomass, which properly reflects the GHG benefit of utilizing limited biomass supply allowing for conversion efficiency [12]. GHG reduction cost ($/tCOeq) is shown in the ordinate of Figure 3, which represents the total carbon pricing (such as carbon tax and low-carbon fuel credit) needed to make bioenergy economically viable. Biomass-fired heating gives the highest GHG reduction per ODT, with negative reduction cost. Liquid biofuels and RNG have lower GHG mitigation benefits, due to extra energy losses in the conversion processes, but higher reduction costs. Typically, the conversion efficiency of biomass-fired heating can exceed 75%, whereas efficiencies of refined biofuels are below 60% [12]. Biomass-fired CHP has the lowest GHG reduction potential, due to the low carbon intensity of electricity in BC, but this could change in the long term (see Section 2.2.1). For other lignocellulosic biomass, the ranking of bioenergy options remains the same [13]. Overall, biomass-fired heating, in applications including high-pressure steam, kilns, and district heating, should be prioritized.

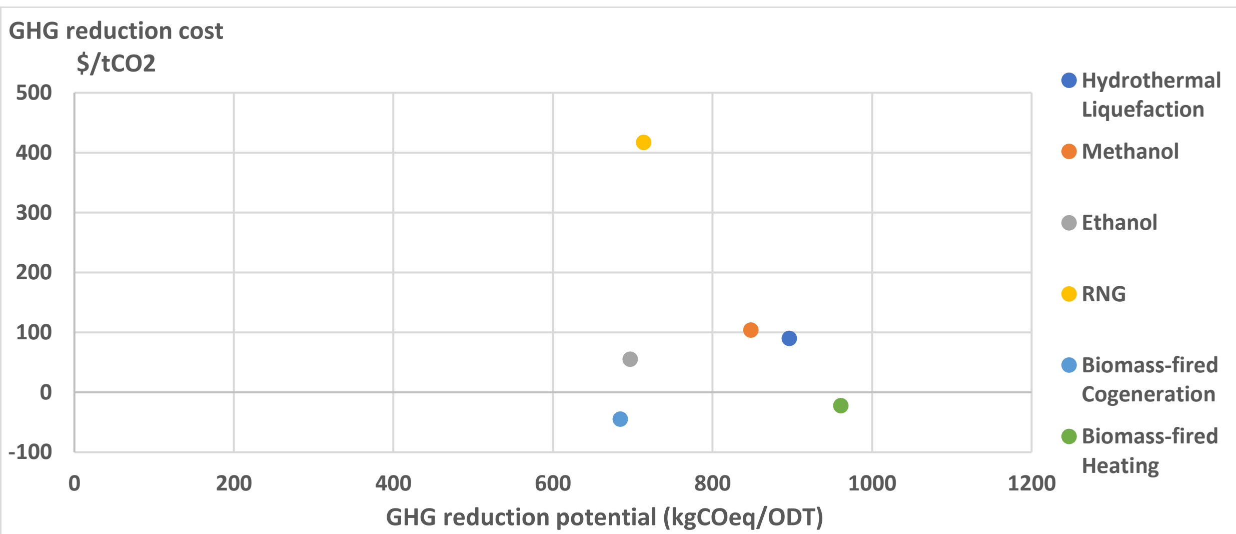

Figure 3 GHG reduction potential and costs of bioenergy produced from wood residues [12]

1.3 Anaerobic digestion

AD can decompose animal manure and food waste into biogas, which typically consists of 60% CH_4, 40% CO_2, and traces of other components. As shown in Figure 4, biogas can be directly combusted for heat production or CHP. Alternatively, it can be upgraded to RNG by removing CO_2 and trace gases. Thus AD can produce renewable energy and reduce the volume of waste. Furthermore, the organic residue of the AD process, namely digestate, retains nutrients in the feedstock. Using digestate as organic fertilizer can achieve additional environmental benefits by displacing synthetic fertilizers and improving nutrient management [14].

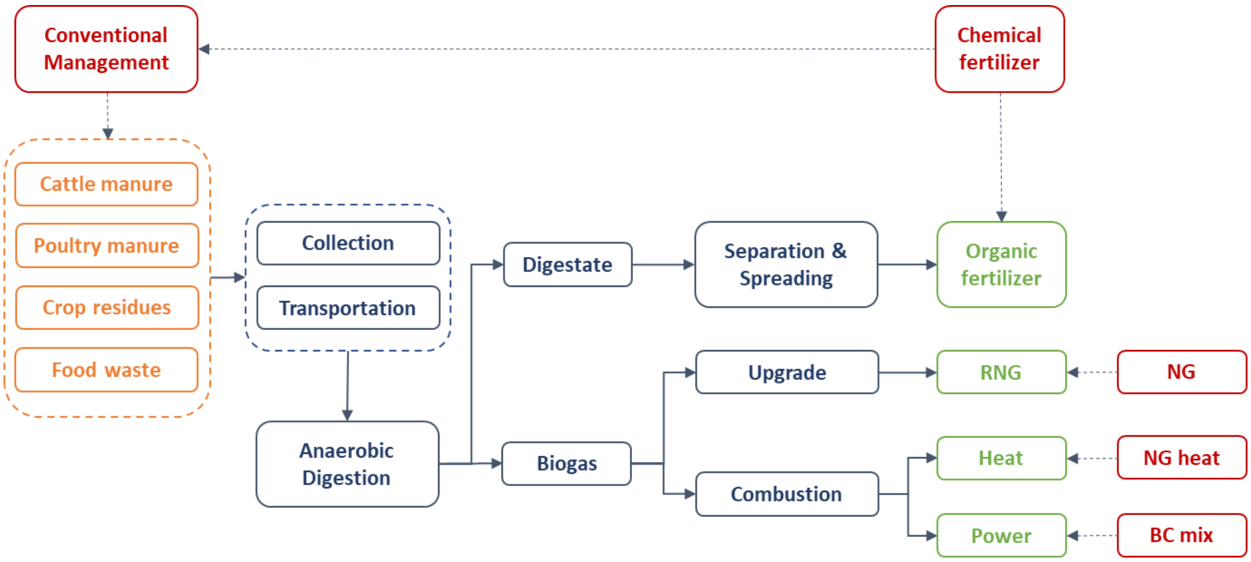

Figure 4 Systems for anaerobic digestion of organic wastes [15]

Figure 5 compares GHG reduction potential and costs of different biogas utilization options. Biogas-fired heating has the highest GHG mitigation potential and the lowest costs. RNG has slightly lower GHG benefits, due to extra energy losses and fugitive CH_4 emissions, but significantly higher costs. Biogas-fired CHP has the lowest GHG benefits but, like direct use of biomass for CHP, this could change in the long term (see Section 2.2.1). Economically, the GHG reduction costs of AD for standalone applications are higher than \$200/tCO_2, well above an ambitious future carbon tax level of \$170/tCO_2 (currently \$45/tCO_2). Such high GHG mitigation costs call for strong financial support from policy measures. Full utilization of the waste streams can generate 5.9 PJ of biogas and RNG [13], which is a small yet indispensable step towards reducing GHG emissions from natural gas consumption.

1.4 System integration for byproduct utilization

Utilization of byproducts from bioenergy conversion enhances the overall GHG mitigation potential and economic viability. For example, digestate residue from AD is rich in nutrients and can be used to substitute synthetic fertilizers [16]. Biochar generated by thermochemical conversion of biomass contains residual carbon and nutrients [17], [18] and can be used as a soil improver. Byproduct utilization may potentially improve the GHG benefits of AD and HTL by 100% and 50%, respectively, and also lead to cost savings [13].

A novel type of AD-centered system can effectively integrate animal, greenhouse, mushroom, and crop farming [15], [19], which are all common agricultural activities in BC. Biogas from AD of animal manure is combusted to heat participating farms. Biogenic CO_2 from combustion of biogas and ventilation of the mushroom farm replaces natural gas consumption for CO_2 enrichment in greenhouses. Digestate is used as growing medium in greenhouse and mushroom farming, in addition to fertilizers for crop farming. Co-digestion can further increase biogas yield and thus improve overall performance of the system. As shown in Figure 5, such integrated AD systems have substantially higher GHG benefits and lower GHG reduction costs than standalone AD options (Section 2.1.3) [15]. They represent an application of agricultural carbon sequestration and circular economy and so fit perfectly into BC's GHG mitigation roadmap [20].

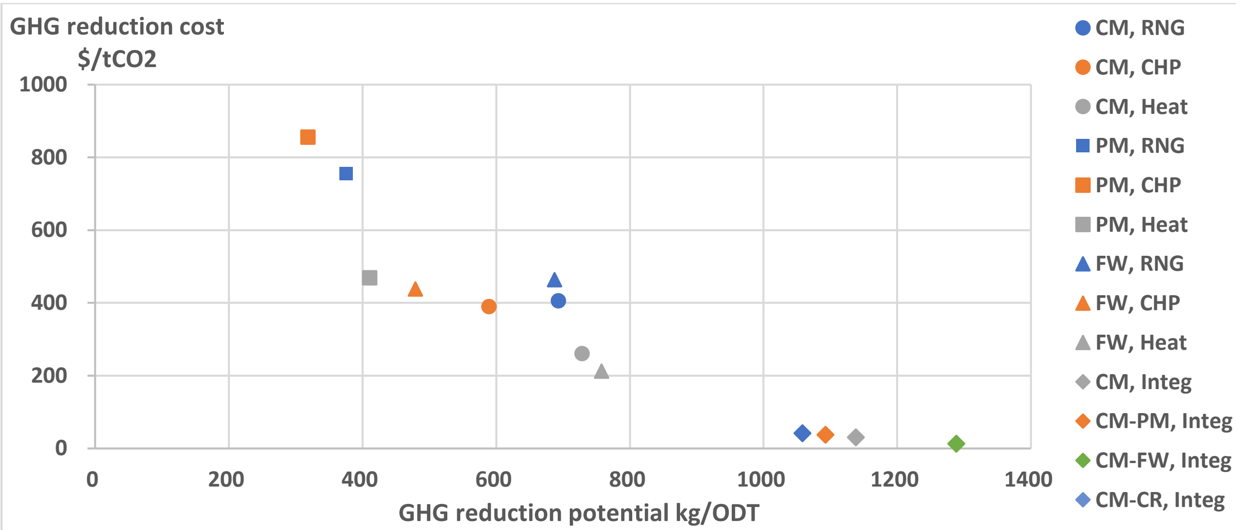

Figure 5 GHG reduction potential and costs of anaerobic digestion of organic wastes in BC [1], [15]**. CM = cattle manure, PM = poultry mature, FW = food waste.**

2. Renewable electricity and electrification

2.1 Renewable electricity sources

Hydroelectric generation is the main electricity source in BC, providing 90% of total supply [21] and expected to grow significantly. The Site C project currently under construction should provide an additional 18.4 PJ annually upon completion, expected in 2025. However, hydroelectric resources are limited, and no data are available on BC's total hydroelectric generation potential. Therefore, electricity from other renewable sources in BC should also be considered.

Biomass, mainly wood residues, fuels 5.5% of total generation in BC [21]. Section 2.1.1 identified the scope to expand the use of biomass, but power generation must compete with other uses of the feedstock. In the near term, with hydroelectricity dominating the mix of sources and the added capacity of Site C, biomass generation yields low GHG benefits and thus attracts little interest in BC [12]. In the long term, the position of biomass generation depends on whether other renewable sources can meet demand.

Wind energy is the third largest source of renewable electricity in BC and is growing: in 2019, .capacity reached 6.1 PJ, providing 2.5% of total generation in the province [21]. The average capacity factor, defined as output divided by maximum capacity, is about 33% in BC. Typical capacity for one wind turbine is 2.5 MW so, to match the output of Site C, about 700 turbines will be needed. Permanent direct land use for onshore turbines is about 3000 m^2/MW capacity, so 2.1 km^2 of land would be required. BC's location enables use of offshore wind turbines, which are more expensive although the additional cost is compensated at least partially by higher capacity factors. Assuming that wind generation in BC grows in line with the annual rate of 14% predicted globally by the IEA [22], annual output could reach 26 PJ in 2030, a substantial addition to future renewable electricity supply.

Solar photovoltaic (PV) generation is a major source of renewable electricity world-wide, but its contribution in BC is nugatory (0.043%) [21]. BC does not have strong solar radiation: average annual output of PV panels in BC is 1200 kWh/kW capacity (corresponding to an average capacity factor of 14%), and each kW capacity requires more than 7 m^2 of panel area [23]. To match the output of Site C would require as much as 30 km^2 of panels so that, if PV is to make a significant contribution in BC, distributed rooftop collectors and large-scale solar farms will all be needed.

Wind and solar generation are intermittent, i.e. not continuous or controllable. The possible proportion of intermittent generation in the grid depends on matching supply and demand, using dispatchable sources – hydroelectric (including pumped storage), biomass, and conventional fossil fuel-based generation. In many European countries, including Germany, Spain, and UK, the total share of wind and solar electricity has approached or exceeded 30% [24], [25], and may realistically increase to 45-50% by 2040 [26]. In US, EU, and China, the share of intermittent electricity is also expected to exceed 20% by 2026 [22]. It is therefore reasonable to expect BC's grid to be able to accommodate far more than the current 2.5% of intermittent generation; 20% appears to be a modest target for 2030, and 40% for 2050.

2.2 Efficiencies of electrification technologies

The most efficient ways to use electricity differ between the applications targeted in CleanBC: buildings, transportation, and industrial production. Energy demand in buildings is mainly for low-grade heat, which can be provided by electric heat pumps or resistance heaters. Heaters merely convert electrical input, whereas output from a modern heat pump can be at least three times the electrical input, giving an efficiency at least three times that of a resistance heater.

For transportation, the immediate option is the electric vehicle (EV). EVs use less than 30% energy per km than internal combustion engine vehicles (ICEVs) of similar size [27]. Electricity can also be used to produce other energy carriers, such as hydrocarbons for ICEVs from captured carbon (Carbon Capture and Utilization, CCU) and hydrogen for fuel cell vehicles (FCVs) by water electrolysis. ICEVs using synthesized hydrocarbons have similar efficiency to those using fossil fuels while FCVs have about twice the energy efficiency of ICEVs [27]. However, converting electricity to other energy carriers involves significant energy losses so that these options have much lower overall efficiency than EVs.

Electrification can reduce industrial energy consumption in two main ways: replacing natural gas and diesel engines by electric motors for motive power, and replacing fossil fuel boilers by electric resistance heaters for high-grade thermal energy. The efficiency of electric motors, defined as motive power output divided by energy input, can reach 85%, whereas the efficiency for natural gas engines is 30-40% [28]. Electric resistance heaters can approach 100% efficiency, whereas the efficiencies of modern natural gas furnaces and boilers are typically around 90% [29]. The efficiency advantage of electric motors is notably higher than that of electric heaters. However, both these applications depend on the availability of low-carbon electricity; if the electricity is generated from fossil fuels, the comparison depends on the application, with direct firing usually preferred for furnaces and boilers due to the inefficiencies in power generation.

3. Hydrogen

3.1 Hydrogen production pathways

Hydrogen is an energy carrier that can be derived from various primary energy sources. In BC, potential hydrogen production pathways include water electrolysis using renewable electricity, biomass gasification, and steam methane reforming (SMR) with or without carbon capture and storage (CCS). Hydrogen produced from low-carbon electricity and biomass is considered as "green hydrogen", which inherits the low carbon intensity of these renewable energy sources. Hydrogen produced by SMR of fossil natural gas coupled with CCS also has low carbon intensity and is termed "blue hydrogen". Hydrogen produced from fossil natural gas without CCS has high carbon intensity and is thus labeled "grey hydrogen". To ensure effective GHG mitigation, BC intends to set a gradually declining carbon intensity threshold for hydrogen [30], which means only green and blue hydrogen should be considered.

In principle, green hydrogen has the advantage of being renewable. However, green hydrogen suffers from additional energy losses during the conversion process and competes with alternative applications for the same renewable energy sources: in the context of limited renewable energy supply (see Section 3), energy used to produce hydrogen is diverted from more beneficial uses. Blue hydrogen is therefore more practical for BC, giving BC's abundant natural gas resources a role in a future carbon-neutral economy and helping relieve the pressure to expand renewable energy supply. However, a low carbon intensity for blue hydrogen depends on curtailing methane emissions from natural gas supply and hydrogen conversion.

3.2 Hydrogen utilization options

Like bioenergy and electricity, the most efficient uses of hydrogen must be identified and prioritized. The two main potential applications are (1) fuel-cell vehicles (FCV) replacing internal combustion engine vehicles (ICEV); and (2) direct combustion for thermal energy replacing combustion of fossil fuels, primarily natural gas for low-grade heating in buildings or high-grade thermal energy in industrial processes. FCVs are twice as efficient as ICEVs of similar size (see Section 2.2.2). On the other hand, combustion of hydrogen has similar efficiency as fossil fuels Therefore, using hydrogen in FCVs displaces more fossil fuels and achieves significantly higher GHG mitigation, and is therefore preferable to direct combustion.

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Appendix B

ANNUAL ENERGY DEMAND FORECASTING

Appendix B-1

DEMAND FORECAST – TRADITIONAL ANNUAL METHOD DESCRIPTION AND BUSINESS AS USUAL FORECAST RESULTS

APPENDIX B-1: DEMAND FORECAST - TRADITIONAL ANNUAL METHOD DESCRIPTION AND BUSINESS AS USUAL FORECAST RESULTS

This Appendix provides further background on the Traditional Annual Method of demand forecasting for FEI's residential, commercial and industrial customer groups, and key results from the Business As Usual (BAU) forecast. In this context "business as usual" means that the forecast methods are unchanged and that the trajectories of the forecast elements such as use rates and customer additions are expected to remain consistent with trajectories experienced in the recent 3-10 years for the duration of the planning horizon. In this context "BAU" does not mean that the customers, use rates and demand recorded as of 2019 are expected to remain "flat" for the planning horizon.

FEI's Traditional Annual Method is consistent with the recommendations in the FEI Forecasting Method Study filed as Appendix B2 in FortisBC's 2020-2024 MRP Application. The Forecasting Method Study represented the culmination of a number of years of research and testing of alternative forecasting methods in response to the forecasting directives in Order G-86-15 and accompanying decision related to the FEI Annual Review for 2015 Rates Application. The flow chart presented in Figure B1-1 summarizes the Traditional Annual Method and guides the discussion in this appendix.

Figure B1-1: Data Inputs for the Traditional Annual Method

The BAU forecast for the 2022 LTGRP uses 2019 as the base year. This base year is consistent with the End-use Annual Method for demand forecasting described in Section 4 and Appendix B-3 of the 2022 LTGRP. FEI notes that the following discussion of both the End Use Method and the BAU forecast developed from the Traditional Annual Method applies to the built environment category of demand only.

1.1 RESIDENTIAL AND COMMERCIAL DEMAND FORECAST

1.1.1 Customer Forecast Method

The BAU forecast starts with preparing the customer forecast. FEI notes that the customer forecast method described in this Appendix is used for both the BAU forecast developed using the Traditional Annual Method and the Reference Case and alternative future scenario forecasts developed using the End-Use Annual Method presented in Section 4 and Appendix B-3 of the 2022 LTGRP.

1.1.1.1 Residential Customers

The residential net customer additions forecast was developed based on housing starts data from the Conference Board of Canada (CBOC) as follows:

1) Determine the prior year actual net residential customer additions by region.
2) Based on internal data, proportion the net residential customer additions into single and multi-family additions.
3) Use the CBOC long term growth rates for single and multi-family housing starts to develop the long-term growth rate forecast for both single and multi-family net residential customer additions.
4) Sum up the single and multi-family net residential customer additions.
5) Add the additions to the prior year total customer count, starting with the base year.

1.1.1.2 Commercial Customers

The commercial customer additions forecast is calculated as the average of the net customer additions by region and rate class (RS 2, 3 and 23) for the prior three years. The customer additions forecast is assumed to remain constant for the first five years and then adjusted based on the long term BC STATS household formation forecast for the remaining 15 years. The customer additions are then added to each year of the forecast throughout the planning horizon. Due to rate switching between the large commercial rate schedules (specifically RS 3 and RS 23), forecasting for these two classes was done as a group and then divided between RS 3 and RS 23 based on the 2019 customer distribution.

1.1.1.3 Customer Forecast Uncertainty

The 2022 LTGRP relies on a statistical approach using 95 percent[1] confidence intervals to model customer forecast uncertainty. This approach applies FEI's historical customer

[1] FEI notes that the 95 percent confidence level a common choice in statistics, but that other levels could be used. Choosing a higher confidence level (e.g., 99 percent) results in wider uncertainty bands, while choosing lower levels (e.g., 90 percent) results in narrower bands. Further a 95% confidence level is associated with 1 in 20 year events and aligns with the 20 year forecast horizon of the LTGRP.

fluctuations to perturb the BAU customer forecast into respective high and low customer forecast outcomes. This statistical method serves as a proxy to model the potential impact of economic growth on customer numbers but may also account for other intrinsic factors, such as FEI marketing and promotional campaigns. FEI created a custom script using a statistical programming application with built-in CI functionality connected to FEI billing system databases to complete the CI analysis. Please see Figures B3-2 through B3-6 in Appendix B-3 for the customer forecast and uncertainty bands results.

1.1.1.4 Residential and Commercial Use Rates

Monthly residential and commercial use per customer (UPC) forecasts are developed for each region and rate schedule using weather normalized historic data. As a result of this study, FEI adopted the Exponential Smoothing method (ETS) for the purpose of forecasting residential and commercial use rates, as ETS proved to be the most accurate method for this purpose.

1.1.1.4.1 WEATHER NORMALIZATION OF RESIDENTIAL AND COMMERCIAL USE RATES

Residential and commercial rate schedules (RS 1, 2, 3 and 23) are weather sensitive. A weather normalization process is applied to all actual use rates for these rate schedules. Separate normalization factors are developed for each region, rate schedule and month.

Actual UPC is weather normalized on a monthly basis for each region and rate class by dividing the actual UPC by a normalization factor. The normalization factor is derived from a non-linear regression model that estimates the impact of the monthly weather variation on the load.

The heat sensitivity estimated from the model assumes that the sensitivity varies not only depending on the weather but also on the rate class. For example, the residential rate schedule shows higher sensitivity to weather compared to the commercial rate schedules, and FEI's normalization factors account for the difference.

1.1.1.5 UPC Forecast

Ten years of weather normalized actual use rate data is used to calculate the UPC forecast using ETS, as implemented in Microsoft Excel. Once the use rates are seasonalized and developed for each region and each rate schedule they are entered into Forecast Information System (FIS) software. The amalgamated use rates are calculated using the following relationship:

$$Use\ Rate = \frac{\sum Volume}{\sum Accounts}$$

FIS calculates both the monthly volume and accounts by region and rate class.

UPC trends present in the forecasts implicitly include the impact of broad changes in consumption patterns that might have been caused by such factors as energy efficiency, economic activity, policies and equipment standards up to the time of the most recently available annual usage data. For the purpose of the BAU forecast the trends were then extended out 20 years for the purposes of providing the long term BAU forecast.

1.1.1.6 Preparing the BAU Residential and Commercial Demand

The residential and commercial demand forecasts are the products of the monthly customer forecast and the corresponding monthly use rates forecast at the regional level. The regions and months are then summed to arrive at the amalgamated annual residential and commercial BAU forecast.

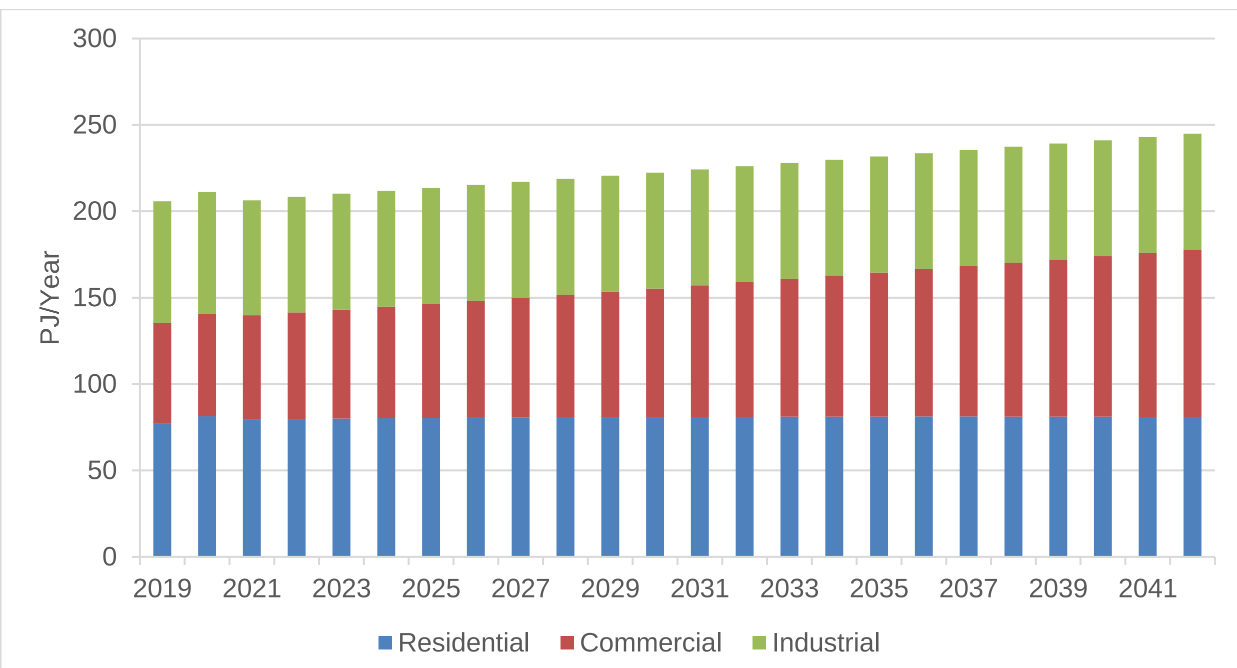
1.2 INDUSTRIAL DEMAND FORECAST

FEI utilized the results of the annual industrial customer survey to identify expected changes in industrial customer demand. The survey was conducted as part of FEI's short term demand forecasting process used for gas supply planning, revenue requirements and other BCUC submissions. The intentions of industrial customers over the next five years were held constant over the LTGRP planning horizon consistent with the design philosophy and intended purpose of the Traditional Annual Method and the BAU forecast.

1.3 BAU FORECAST RESULTS FOR RESIDENTIAL, COMMERCIAL AND INDUSTRIAL CUSTOMERS

The following figure shows the BAU forecast for the residential, commercial and industrial rate groups. The BAU forecast represents an extension across the planning period of intrinsic end-use trends from the most recent data. The resulting annual demand forecast is largely flat with moderate growth in the commercial sector.

Figure B1-2: BAU Forecast for Residential, Commercial and Industrial by Rate Groups



Appendix B-2

LONG-TERM DEMAND FORECASTING BENCHMARKING STUDY ON END USE METHODS INDUSTRY PRACTICE REVIEW

Long Term Demand Forecasting Benchmarking Study on End-Use Methods Industry Practices Review

August, 2020

Presented To

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1. EXECUTIVE SUMMARY

In the regulatory proceeding reviewing the 2014 Long Term Resource Plan for FortisBC Energy Utilities (2014 FEU LTRP), FEU was asked by the BC Utilities Commission ('the Commission') whether it had compared its end-use forecasting model with forecasting models used by other utilities. The Commission and interveners expressed some reservations about FEU's end-use model including the complexity and associated cost of updating the model. Accordingly, the Commission directed FEU to "provide a detailed analysis of the relative benefits/shortcomings of their particular end-use method as compared to other end-use methods". As a result, in 2016 FEU retained Boreas Consulting (Boreas) to review long-term forecasting practices of North American gas utilities to determine whether there is a preferred method for conducting demand forecasts for use in integrated resource planning activities. Boreas completed a comparison of long-term (over 10 years) annual demand forecasting activities among gas distribution utilities in North America – particularly in Canada, the US Pacific Northwest and California.

Subsequently, in the regulatory proceeding reviewing the 2019 Long Term Resource Plan for FEU, the Commission asked FEU to review the long-term forecasting methods used by other utilities and energy planning entities in North America. As a result, FEU retained Energitix Management & Consulting Corporation (Energitix) to review long-term annual demand forecasting methods used by other utilities and energy planning entities, particularly those in Canada, the US Pacific Northwest, and California. to determine whether there have been any changes in long-term demand forecasting practices of the entities studied in the 2016 Boreas report, as well as other appropriate utilities and energy planning entities.

Energitix completed this work by reviewing publicly available documents from 18 utilities and energy planning entities. These documents primarily consisted of regulatory filings by the utilities and included Integrated Resource Plans (IRPs), Capacity Supply Plans, Energy Efficiency Plans, Rate Applications, and Testimonies. Furthermore, Energitix identified the person and/or people responsible for forecasting at some of these organization and interviewed them to obtain more detailed insight into their forecasting methods. Most of these organizations included organizations that were included in the 2016 study. While information from some of the organizations included in the 2016 study was not available for this study, information from other organizations was obtained and included in this report.

Organizations with forecasting horizons of 10 years or more often use their long term forecast as part of their IRP, which often has a longer-term horizon.

Approximately 64% of the organizations that use long-term forecasts of 10 years or more either use an end-use model or a combination of end-use and econometric model. This compares to 44% in the 2016 study. Furthermore, 22% of the organizations that use long-term forecasts of 10 years or more currently use econometric models but are considering end-use models.

The end-use models are often used to forecast use per customer, while econometric models are used to forecast growth in the number of customers. The rationale being that as energy efficiency and changes to energy and climate change policies become more prevalent, the future energy demand will look significantly different from historic energy demand. As a result, econometric regression models that relay on historic energy demand data are not necessarily suited for forecasting demand that is different from the past, whereas end-use models provide a much more detailed understanding of the impact of efficiency improvements and policy changes on energy demand and long-term forecasts, particularly in new construction and replacement of old equipment. Organizations that are considering switching from econometric models to end-use models are primarily driven by the need to prepare long-term forecasts for a future that could be considerably different from the past.

Some of the leading jurisdictions in energy efficiency policy and regulation have used end-use modeling since the introduction of energy efficiency regulation over 20 years ago and continue to do so. One of the energy planning entities that prepares its own long-term forecasts for the state and the utilities in the state has used end-use forecasting since 1975.

In most cases, annual demand forecasts for residential and commercial customer classes are developed by multiplying the forecasted number of customers in each rate class by the average use per customer for that rate class. Economic forecasts from government agencies or other organizations are used to forecast the growth in number of customers. Average use per customer forecasts are based on either econometric models or end use models. Econometric models often use weather normalized historical consumption data and apply regression modeling to the data to forecast average use per customer. End-use models often use end-use data from end-use surveys to forecast average use per customer based on different end-uses.

End-use models tend to be much more data intensive than econometric models. However, the main driver for using end-use models by most organizations is the ability of end-use models to analyse various scenarios due to energy efficiency policies, codes and standards, and energy policies such as electrification and decarbonization; end-use models provide the level of detail required to assess the impact of energy efficiency standards and regulations as well as different energy policies. Similar to econometric models, the parameters used in end-use forecasting models vary from organization to organization, but in most cases, include energy prices, saturation levels of different end-uses, saturation levels of different energy sources, vintage or age of dwellings, dwelling type, dwelling size, and vintage or age of different end-use equipment. This data is often collected from end-use surveys.

Among the organizations investigated in this study, most organizations with high levels of DSM activity and IRPs use end-use modeling for their long-term forecasting. All end-use models require a medium to high degree of data intensiveness and can examine end-use trends within different scenarios, which in turn allow the organizations to show how changes to model inputs affect the results. Most organizations evaluate the performance of their forecasting model by comparing their forecast to actual energy demand, particularly for the early years of the forecast period. However, because long-term forecasts are based on forecasts of many input parameters, such as whether, energy prices, economic conditions, employment levels, new construction activity, etc. a straight comparison of forecasts to actuals without any adjusting for the input parameters does not necessarily reflect the effectiveness of the forecasting model. Thus, comparison of the forecast results to actuals may be quite resource intensive.

2. Introduction

In the regulatory proceeding reviewing the 2014 Long Term Resource Plan for FortisBC Energy Utilities (2014 FEU LTRP), FEU was asked by the BC Utilities Commission ('the Commission') whether it had compared its end-use forecasting model with forecasting models used by other utilities. FEU provided a high-level description of forecasting models from eight other utilities and characterized their approaches as one of: "top-down", "bottom-up statistical", "bottom-up engineering". In its Decision, the Commission agreed that FEU's intention to discontinue using a traditional method and to move towards an end-use forecasting approach had merit, but expressed reservations about the added expense related to further development of a model for forecasting the annual demand when it is the peak demand forecast that is the primary driver for infrastructure planning purposes. The Commission and interveners also expressed reservations regarding the complexity and associated cost of updating the FEU end-use model, as well as with the lack of testing with historical data to ascertain the accuracy of the model. Accordingly, the Commission directed FEU to "provide a detailed analysis of the relative benefits/shortcomings of their particular End-Use Method as compared to other end-use methods".

As a result, in 2016 FEU retained Boreas Consulting (Boreas) to review long-term forecasting practices of North American gas utilities to determine whether there is a preferred method for conducting demand forecasts for use in integrated resource planning activities.

Subsequently, in the regulatory proceeding reviewing the 2019 Long Term Resource Plan for FEU, the Commission asked FEU to review the long-term forecasting methods used by other utilities and energy planning entities in North America. As a result, FEU retained Energitix Management & Consulting Corporation (Energitix) to review long-term annual demand forecasting methods used by other utilities and energy planning entities, particularly those in Canada, the US Pacific Northwest, and California. to determine whether there have been any changes in long-term demand forecasting practices of the entities studied in the 2016 Boreas report, as well as other appropriate utilities and energy planning entities.

Specifically, FEU desired an update to the 2016 report.

3. FortisBC Model

FEU's end-use forecasting model was developed by a consultant. The model is built on top of the model that was used to develop the Conservation Potential Review (CPR), which allows for applying energy efficiency measures to a reference case.

FEU's long-term annual demand forecast starts by developing a detailed annual demand forecast for the base year. The base year demand forecast is built on demand forecasts for geographic regions, sectors and subsectors, rate classes, and different end-uses. FEU's annual demand forecast considers saturation levels of different end-uses, the market share of natural gas, and energy consumption for various end-uses. The base year forecast is then calibrated against FortisBC's sales, using the most recent data available. A detailed description of FEU's model is provided in FEU's LTRGP.

The forecast is built from the base year by growing the number of customers based on FortisBC's 20-year forecast number of customers by rate class. FEU's end-use model forecasts new customers based on the most recent vintage of buildings and building codes; it incorporates anticipated efficiency improvements (such as natural replacement of furnaces with condensing units), as well as anticipated changes in saturation and gas share for specific end uses.

The model uses saturation levels of different end-uses, natural gas market share, the vintage of buildings, rate class, dwelling type, and number of customers.

4. METHOD

Energitix completed a comparison of long-term (over 10 years) annual demand forecasting activities among utilities and energy planning entities in North America – particularly in Canada, the U.S. Pacific Northwest and California.

Energitix completed this work by reviewing publicly available documents from 18 utilities and energy planning entities. These documents primarily consisted of regulatory filings by the utilities and included Integrated Resource Plans (IRPs), Capacity Supply Plans, Energy Efficiency Plans, Rate Applications, and Testimonies. Furthermore, Energitix identified the person and/or people responsible for forecasting at some of these organization and interviewed them to obtain more detailed insight into their forecasting methods.

5. FINDINGS

Energitix's findings are summarized in this section, with detailed findings included in Appendix II.

As illustrated by Figure 1, 78% of the organizations prepare long-term forecasts of 10 years or more, while 22% prepare forecasts of five years. The organizations with forecasting horizons of less than 10 years often prepare their forecast for supply planning purposes or rate applications, while organizations with forecasting horizons of 10 years or more often use their long-term forecast as part of their IRP, which often has a longer-term horizon.

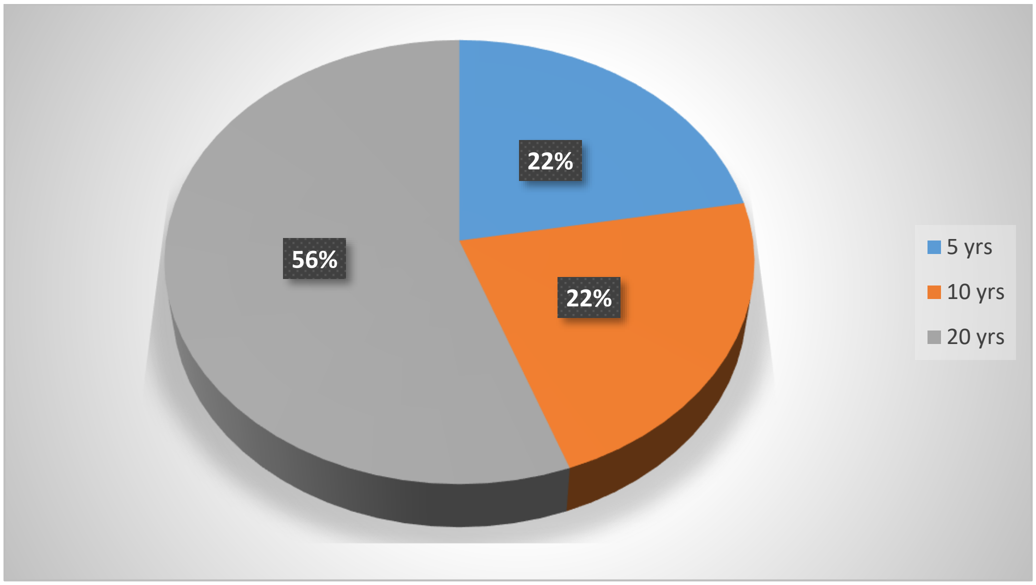

Figure 1. Distribution of Forecast Horizon

As illustrated by Figure 2, approximately 64% of the organizations that use long-term forecasts of 10 years or more either use an end-use model or a combination of end-use and econometric model. This compares to 44% in the 2016 study. Furthermore, 22% of the organizations that use long-term forecasts of 10 years or more currently use econometric models but are considering end-use models.

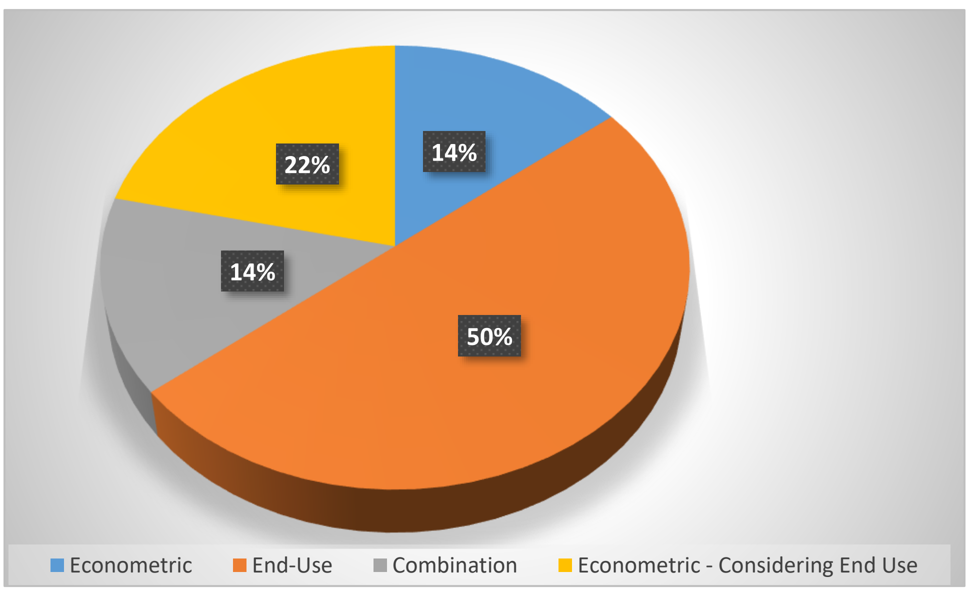

Figure 2. Distribution of Forecasting Method for Organizations w/ Forecast Horizon of Over 10 Years

The end-use models are often used to forecast use per customer, while econometric models are used to forecast growth in the number of customers. The rationale being that as energy efficiency and changes to energy and climate change policies become more prevalent, the future energy demand will look significantly different from historic energy demand. As a result, econometric regression models that relay on historic energy demand data are not necessarily suited for forecasting demand that is different from the past, whereas end-use models provide a much more detailed understanding of the impact of efficiency improvements and policy changes on energy demand and long-term forecasts, particularly in new construction and replacement of old equipment. Organizations that are considering switching from econometric models to end-use models are primarily driven by the need to prepare long-term forecasts for a future that could be considerably different from the past.

Some of the leading jurisdictions in energy efficiency policy and regulation have used end-use modeling since the introduction of energy efficiency regulation over 20 years ago and continue to do so. One of the energy planning entities that prepares its own long-term forecasts for the state and the utilities in the state has used end-use forecasting since 1975.

In most cases, annual demand forecasts for residential and commercial customer classes are developed by multiplying the forecasted number of customers in each rate class by the average use per customer for that rate class. Economic forecasts from government agencies or other organizations are used to forecast the growth in number of customers. Average use per customer forecasts are based on either econometric models or end use models. Econometric models often use weather normalized historical consumption data and apply regression modeling to the data to forecast average use per customer. End-use models often use end-use data from end-use surveys to forecast average use per customer based on different end-uses.

Most organizations build their annual demand forecast for their large industrial customers from individual customer forecasts, which are often based on historical trends with adjustments that are based on customer feedback and future plans and economic forecasts.

The parameters used in econometric forecasting models vary from organization to organization but in most cases include energy prices, GDP growth, population growth, household growth, income, and employment levels. Some econometric models also include an energy efficiency index, which takes into account improvements in energy efficiency standards and building codes.

End-use models tend to be much more data intensive than econometric models. However, the main driver for using end-use models by most organizations is the ability of end-use models to analyse various scenarios due to energy efficiency policies, codes and standards, and energy policies such as electrification and decarbonization; end-use models provide the level of detail required to assess the impact of energy efficiency standards and regulations as well as different energy policies. Similar to econometric models, the parameters used in end-use forecasting models vary from organization to organization, but in most cases include energy prices, saturation levels of different end-uses, saturation levels of different energy sources, vintage or age of dwellings, dwelling type, dwelling size, and vintage or age of different end-use equipment.

This data is often collected from end-use surveys. End-use surveys, therefore, are key in end-use modeling as such surveys provide the input to end-use models.

Irrespective of the type of forecasting model used, most organizations run a number of forecast scenarios. The forecast scenarios typically include a base case, which is the mostly likely scenario, plus a high and low case, which are based on high and low growth. Some organizations also run forecast scenarios to assess the potential impact of energy efficiency codes and standards as well as potential energy policies.

The organizations with long-term forecasts, where the forecast horizons are 10 years or more, provide annual demand forecasts for either every year or every five years during the forecast period.

Most organizations evaluate the performance of their forecasting model by comparing their forecast to actual energy demand, particularly for the early years of the forecast period. However, because long-term forecasts are based on forecasts of many input parameters, such as whether, energy prices, economic conditions, employment levels, new construction activity, etc. a straight comparison of forecasts to actuals without adjusting for the input parameters does not necessarily reflect the effectiveness of the forecasting model. Thus, comparison of the forecast results to actuals may be quite resource intensive. In general, performance of the models is assessed by comparing the long-term average of the adjusted actuals to forecast over several years. The adjustments vary from one organization to another; however, they typically consist of adjusting the forecasted input parameters such weather, energy prices, etc. and using the actuals when actuals are available. This allows the organization to evaluate the forecast model.

Most end-use models are developed by external resources but are operated by internal resources. There are several reasons using external resources to develop end-use models. These include, the expertise and experience required in developing the model and the intensive resources required over a short period of time in developing the model Because econometric models often use regression analysis techniques, they are sometimes developed internally.

Most organizations use their annual demand forecast to develop their peak-day demand forecast. Some of the common methods used in developing peak-day demand forecasts start with the annual demand forecast and apply the load factor of the different customer classes to the average-day demand for the applicable class, apply load shapes for different customer classes or end uses to the annual demand, and adjust the average-day demand for the peak-day weather conditions.

Table 1 summarizes the characteristics of the end-use models for the utilities and organizations that use end-use modeling in their long-term forecasting.

Among the organizations investigated in this study, those with high levels of DSM activity and IRPs use end-use modeling for their long-term forecasting. All end-use models require a medium to high degree of data intensiveness and can examine end-use trends within different scenarios, which in turn allow the organizations to show how changes to model inputs affect the results. This is particularly useful in analysing various scenario such as electrification, decarbonization, changes to energy and climate policy, and energy efficiency regulation.

Table 1. End-Use Model Characteristics

Organization Code	No. of Gas Customers	Utility Ownership	DSM Activity	Degree of Data Intensiveness	Degree of Customization	Ability to Examine End-use Trends/Scenarios	Ability to Show How Changes to Model Inputs Affect Results	Informs both Annual and Peak Demand	Cost to Maintain	Forecast Tested Against Actuals
A	5.9 million	IOU	High	High	High	Yes	Medium	Yes	Moderate	Some
B	873,000	IOU	High	High	High	Yes	Medium	Yes	Moderate	Some
C	1.4 million electric	IOU	High	High	High	Yes	Medium	Yes	Moderate	Some
D	N/A	N/A	High	High	High	Yes	Medium	Yes	Moderate	Yes
G	N/A	Crown	High	High	High	Yes	High	Yes	N/A	Yes
H	285,000	Crown	High	Moderate	High	Yes	Medium	No	Moderate	Yes
K	42,000	IOU	Low	Moderate	High	Yes	High	Yes	Moderate	Some
P	1 million	IOU	Low	Moderate	Moderate	N/A	N/A	No	N/A	N/A
Q	500,000	IOU	Low	Low	Low	Low	Low	No	Low	Yes
R	N/A	Municipal	Low	High	High	High	High	Yes	Low	Some
FEI	1.1 million	IOU	High	High	High	Yes	Yes	No*	Moderate	Not Yet**

Notes:

* Linkage with peak demand is being addressed as part of the ongoing improvement to the forecasting model.

** To date there has not been enough actual history to compare to the end-use demand forecast. Once enough historic data is available, FEI plans to compare end-use demand forecast to actual consumption.

Appendix I. LIST OF ORGANIZATIONS

Organization Code	Organization Name
A.	
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Appendix II. LONG TERM DEMAND FORECASTING PRACTICES

A. Organization A

1. Overview

The company is an investor owned utility. It has the same parent company as another utility company included in this report. The two companies often share forecasting resources. Although each company develops its own forecast, the two companies use the same models to develop their long-term forecasts.

The company is one of the largest natural gas distribution utilities and serves 21.8 million consumers through 5.9 million meters in more than 500 communities, with a service territory encompassing approximately 20,000 square miles.

The company forecasts its use per customer across most sectors and its total annual gas demand across all market sectors, including residential, commercial, and industrial sectors, to decline from 2018 to 2035. The decline in annual demand is due to modest economic growth, mandated energy efficiency (EE) standards and programs, tighter building codes and standards, renewable electricity goals, decline in commercial and industrial demand, and conservation savings linked to Advanced Metering Infrastructure (AMI).

2. Forecasting Method

The company used to use both an econometric model and an end-use model to create its long-term annual demand forecast. A number of years ago, it stopped using the econometric model because the econometric model was based on historic energy use data, which does not allow the company to capture changes in the demand forecast when the "future is different from the past." An end-use model allows the company to forecast future demand under scenarios that are different from historic conditions. The end-use model allows the company to analyse the impact of different energy policies on their annual demand forecast.

The company, currently, uses a bottom up or end-use approach to forecast the use per customer for different sectors in its long-term forecast and the long-term economic outlook for its service territory to forecast the number of customers. Together, the use per customer forecast and the forecasted number of customers are used to develop the annual demand forecast.

The company's forecasting model, EU Forecaster, takes into account the age of the equipment to determine when the equipment is to be replaced. As the model iterates from one year to the next, it distinguishes between the load added due to new meters, changes in the load due to existing customers replacing old equipment with newer, more energy efficient appliances or other equipment in each year. Historical accounts are segmented into the total number of customers in the base year and their distribution among the historical vintages. The model produces a forecast over the planning horizon by applying a forecast of equipment capital costs, energy consumption, and fuel prices to the customer choice parameters. It calculates energy use for each customer type by optimizing the underlying customer choices. EU Forecaster's structure is designed to keep track of energy use for each market segment, each end use and for each vintage as the model steps through the entire forecast time horizon.

The company develops forecasts for residential, small commercial/industrial, large commercial/industrial, and power generation sectors. The forecasts for these sectors are developed from the forecasts for subsectors within these sectors.

The company's previous econometric models produced forecasts that relied on historical data as inputs to regression models. The models were used to explain how changes in the independent variables drove changes in the dependent variable. The models forecasted future demand by extrapolating the same relationship over the forecast period and assumed that there were no structural changes in the relationship between the impendent and the dependent variables into the future. Improvements in energy efficiency were included in econometric models by including an efficiency index as an explanatory variable. This efficiency index was only a proxy that accounted for the downward trend in gas use because of energy efficiency improvements. In prior econometric work, the company used end-use models to develop the energy efficiency index.

3. Forecasting Parameters

The company uses data from end-use surveys conducted by one of the state's energy planning bodies in their forecasting model. The main parameters from the end-use surveys are end-use, market penetration of end-uses, and energy use per end-use.

The parameters used in the forecasting model include:

- Equipment usage equation forecast drivers
- Coefficients describing how usage varies by weather, customer characteristics, prices, and other variables
- Choice forecast drivers, including capital costs for equipment in existing, conversion, and new construction buildings, plus future availability of each equipment type
- Average and marginal market shares for existing, conversion, and new customers
- Fuel, product, or service price forecasts in native units
- Decay functional form indicator and parameters for existing, conversion, and new customers
- Number of existing customers, non-customers on main, and non-customers off main
- Forecast of new construction (economic activity driving demand), capture rates, units per customer, and number of units (i.e., units are a scale of measurement consistent with results of the usage forecast, such as buildings, square footage, apartments, etc.)

- Mean age of end-uses by historical vintage in the baseline (i.e., 0th) year of the forecast used to initialize the age dimension in the turnover/vintage module
- Decay functional form indicator and parameters for equipment (end-uses) in existing, conversion, and new buildings
- Saturation (percentage of customers that have the equipment) independent of market shares
- Total actual sales in base year
- Exogenous parameters that change market shares for existing, conversion, and/or new customers through 'what if' intervention strategies
- Exogenous parameters that adjust product usage through 'what if' convention strategies

The company makes some out of model adjustments to the results from the forecasting model to account for energy efficiency improvements resulting from energy efficiency programs and code changes.

4. Forecast Scenarios

Forecasting scenarios included sensitivity to temperatures and non-cogeneration electric generation.

Core demand forecasts are prepared for two design temperature conditions – average and cold – to quantify changes in space heating demand due to weather. The cold design temperature conditions are based on a statistical likelihood of occurrence of 1-in-35 on an annual basis, with a typical recurrence period of 35 years.

The non-cogeneration electricity generation forecasts are prepared for two hydro conditions – average and dry. The dry hydro case refers to gas demand in a 1-in-10 dry hydro year.

In the future, the company may run more scenarios for electrification if legislation for decarbonization is introduced.

5. Forecast Period and Update Frequency

The company prepares a 20-year forecast of customers, annual demand, peak-day demand every two years. While the company prepares a forecast for each year during the forecast period, they only report forecasts for every year for the first 2 years and in five-year intervals after that.

6. Forecast Evaluation

The company finds evaluating the performance of their long-term forecast to be very difficult as there are numerous assumption and inputs into the model. As a result, there is no formal evaluation process in place. Since the company updates its forecast every two years, it compares the forecast to actuals, when actual annual demand data is available and may adjust the longer term forecast to account for the variance between the forecast and the actual demand.

7. Forecast Resources

The company shares forecasting resources with a sister utility. The team responsible for the long-term forecast includes one person who is responsible for the residential sector, one person who is responsible for the core commercial and industrial sector, one person who is responsible for the large commercial and industrial sector, and a manager. The team also performs other tasks.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company uses their annual demand forecast and apply peak-day design temperature to forecast their peak-day demand.

The peak-day design temperature conditions are based on a statistical likelihood of occurrence of 1-in-35 on an annual basis, with a typical recurrence period of 35 years.

B. Organization B

1. Overview

The company is an investor owned utility. It has the same parent company as company A. The two companies often share forecasting resources. Although each company develops its own forecast, the two companies use the same models to develop their long-term forecasts.

The company is a combination gas and electric utility that provides energy service to 3.6 million people through 1.4 million electric meters and 873,000 natural gas meters, with a service area that spans 4,100 square miles.

The company forecasts its natural gas and electricity demand separately.

The company forecasts its total annual gas demand across all market sectors, including residential, commercial, and industrial sectors, to decline from 2018 to 2035. The decline in annual demand is due to modest economic growth, mandated EE standards and programs, tighter building codes and standards, renewable electricity goals, decline in commercial and industrial demand, and conservation savings linked to AMI.

2. Forecasting Method

Please see section 2 in Appendix II.

3. Forecasting Parameters

Please see section 3 in Appendix II.

4. Forecast Scenarios

Please see section 4 in Appendix II.

5. Forecast Period and Update Frequency

Please see section 5 in Appendix II.

6. Forecast Evaluation

Please see section 6 in Appendix II.

7. Forecast Resources

Please see section 7 in Appendix II.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

Please see section 8 in Appendix II.

C. Organization C

1. Overview

The company is an investor owned utility. It has the same parent company as company A.

The company is combination gas and electric utility that provides energy service to 3.6 million people through 1.4 million electric meters and 873,000 natural gas meters, with a service area that spans 4,100 square miles.

The company forecasts its natural gas and electricity demand separately.

The company forecasts its total annual electricity demand across all customer classes, including residential, small commercial, large commercial, agricultural, and street lighting. It uses a statistically adjusted end-use model to forecast its annual demand.

2. Forecasting Method

The company forecasts its total annual electricity demand across all customer classes, including residential, small commercial, large commercial, agricultural, and street lighting. It uses Itron's SAE model to forecast its average use per customer in its annual energy demand forecast. The average use per customer is then multiplied by the forecasted number of customers by rate class to the forecast the annual energy demand forecast. The forecasted number of customers by rate class is forecasted using an econometric model.

For the residential and commercial sectors, the model uses saturation and efficiencies for different end-uses, which is obtained from the EIA's regional data from the Annual Energy Outlook. The Annual Energy Outlook data is produced by the National Energy Modeling System (NEMS). The company uses the data from the state's Residential Appliance Saturation Survey (RASS) and Commercial End Use Study (CEUS) to adjust the regional NEMS from the EIA for their service territory.

For the non-weather sensitive industrial sector, agricultural sector and street lighting with static loads, the company uses trend analysis in preparing its long-term forecast.

The company does not breakdown its long-term forecast for the residential and commercial sectors into different subsectors.

The company has been using the current SAE model for approximately 10 years. Prior to using this model, the company used a econometric regression model for long-term forecasting. The company switched to the SAE model from the econometric model because of large changes in energy use due to gains in energy efficiency. While the SAE model is not a full end-use model, the company believes it has the ability to account for changes in gains in energy efficiency, whereas, the econometric model did not capture the changes in energy efficiency into the future.

The company is currently investigating how to use a full end-use model for its long-term forecasting.

3. Forecasting Parameters

Unlike traditional economic models which are based on macro-economic variables, the SAE model contains information about thermal shells, appliance saturations, and energy efficiency changes. This information allows the forecast to adjust with known changes in end-use codes and standards. Explicit assumptions for energy efficiency trends create opportunities for developing scenarios and accounting for energy efficiency programs. Furthermore, detailed end-use projections allow for understanding which end-uses are responsible for forecast growth.

4. Forecast Scenarios

While the company prepares high, medium, and low demand forecast scenarios, only the medium scenario is submitted to the state energy body that prepare the state wide energy demand forecast. The state energy body then aggregates the electricity demand forecast from all utilities to prepare the state wide energy demand forecast.

5. Forecast Period and Update Frequency

The company prepares its 10-year forecast every year for every year during the forecast period.

The company used to update its forecast every two years. However, it now updates the forecast every year because factors that impact electricity demand in their market, such as adoption of photovoltaic (PV) for electricity generation and electric vehicles (EV), are changing at a faster rate.

6. Forecast Evaluation

Since the company updates its forecast every year, it compares the forecast to weather normalized actuals, when actual annual demand data is available; it may adjust the longer term forecast to account for the variance between the forecast and the actual demand.

The company is starting to track the various parameters that may impact their forecast. Some of these include adoption PV for electricity generation and EV.

7. Forecast Resources

The company uses Itron's SAE model to prepare its long-term forecast and has 4 full-time-equivalent staff plus a manager responsible for preparing the forecast.

The company uses a consultant to update the NEMS data, which its internal resources use to update the forecast model.

8. Peak Demand Forecast vs. Annual Demand Forecast

The company's peak demand forecast and its annual demand forecast are related. The annual energy demand forecast is an input into the peak demand forecast. The company used to apply load factor to the annual energy demand forecast to determine its peak demand forecast, however, because of the high adoption of solar PV their mid-day peak demand has moved to late afternoon. As a result, their historical load factor does not provide them with an accurate forecast. The company has, therefore, developed an hourly framework that is calibrated to the annual energy demand forecast and layers in the hourly distributed generation resources to determine load shapes which are then applied to the annual energy demand forecast to forecast the peak demand.

D. Organization D

1. Overview

The organization forecasts energy demand for eight electric utility and four gas utility planning/service areas.

The organization has been responsible for forecasting electricity and natural gas (and other fuels) demand for the state since 1975. These include forecasts of statewide and regional electricity and natural gas consumption, annual and seasonal peak demand, factors contributing to projected demand growth, and the impacts of electricity and natural gas efficiency, load management and other demand response activities.

The forecasts are used in various proceedings, including the state public utility regulator's IRP process and the state's ISO Transmission Planning Process. The state public utility regulator identified the IEPR process as "the appropriate venue for considering issues of load forecasting, resource assessment, and scenario analyses, to determine the appropriate level and range of resource needs for load-serving entities in the state." In addition, the organization provides monthly peak demand forecasts for the resource adequacy process in coordination with the ISO and the public utility regulator.

A critical part of the demand forecast is estimating energy savings from DSM activities. The organization is required to include all such demand reductions which are "reasonably expected to occur" during the forecast period in its forecasts.

2. Forecasting Method

The organization's demand forecasting methodology features an annual electric consumption model, an hourly electric load model, and an annual natural gas consumption model. These models produce forecasts by sector or consumer types. In most sectors, the methodology attempts to simulate individual energy use decisions as they pertain to end-use energy services. Some examples of energy services are the comfort derived from a heated home, the clean dishes from a dishwasher, the illumination from a light fixture, and the evaporation of water from pulp in a paper making machine. Energy in the form of natural gas, electricity (or other fuels) operates machinery to produce the service derived. Therefore, energy demand is a derived demand, not a direct one.

End-use energy consumption estimates can be developed from the application of analytical engineering techniques and econometric techniques for extracting information from customer use data. Early generation end-use models were developed using largely engineering methods. As better data became available, disaggregate econometric techniques were incorporated.

Although the methods to estimate energy efficiency impacts and self-generation have undergone refinement, the energy demand baseline forecast uses the same technical methods as previous long-term demand forecasts, including detailed sector models supplemented with single equation econometric models applied to a revised geographic scheme.

The organization forecasts natural gas demand in the state as part of each IEPR cycle. The organization uses end-use and econometric models structured along utility planning areas for the residential, industrial, commercial, agricultural, transportation, communications, and utilities sectors.

End-use modeling is used for forecasting residential and commercial demand, while econometric/trend modeling is used for forecasting industrial and agricultural demand.

Residential use is forecasted for different building arch-types based. Vintage of the dwellings is used to adjust for changes in building code and standards.

Commercial use is forecasted for different building types by building gross area.

End-use surveys are used to collect average use per appliance, saturation levels, and equipment and building vintages. These are conducted every four to five years.

End-use modeling is used rather than other forecasting techniques because of the ability of the end-use model to better explain how energy is actually used and how various factors effect changes in energy use. For example, models involving different levels of end-use detail are used to characterize how efficiency programs affect both energy requirements and peak demand.

The sectoral groups the organization modeled balance the desire to capture end-use detail with available data resources. Moreover, while the composition of sectoral consumption among the planning areas differs, the same models are used to forecast electricity and natural gas demand. Data from individual planning areas is used in the models to the extent possible. Table 2 lists the end-use and consumer characteristics of each of the sectoral models.

Table 2. Characteristics of Forecast Sectoral Models

Sector	Consumer Type/NAICS Code	End uses Covered
Residential	Residential consumers 3 housing types	24 major appliance and space conditioning categories
Commercial	12 building types 21 NAICS codes	10 equipment and space conditioning categories
Transportation, Communications & Utilities (TCU)	NAICS codes 221, 48 (excluding 48841), 49, 513, 56151, 56152, 562, 62191, and 92811	Consumption is estimated for aggregated of the ten NAICS codes, not for specific end uses
Industrial	Process, extraction, and assembly industries included in NAICS 1133, 21, 23; 31-33, 511, and 516	Thermal processes, HVAC, process steam, and cogeneration.

Sector	Consumer Type/NAICS Code	End uses Covered
Agriculture	Crop production, livestock, and related commodities.	Irrigation pumping, building heating, crop drying

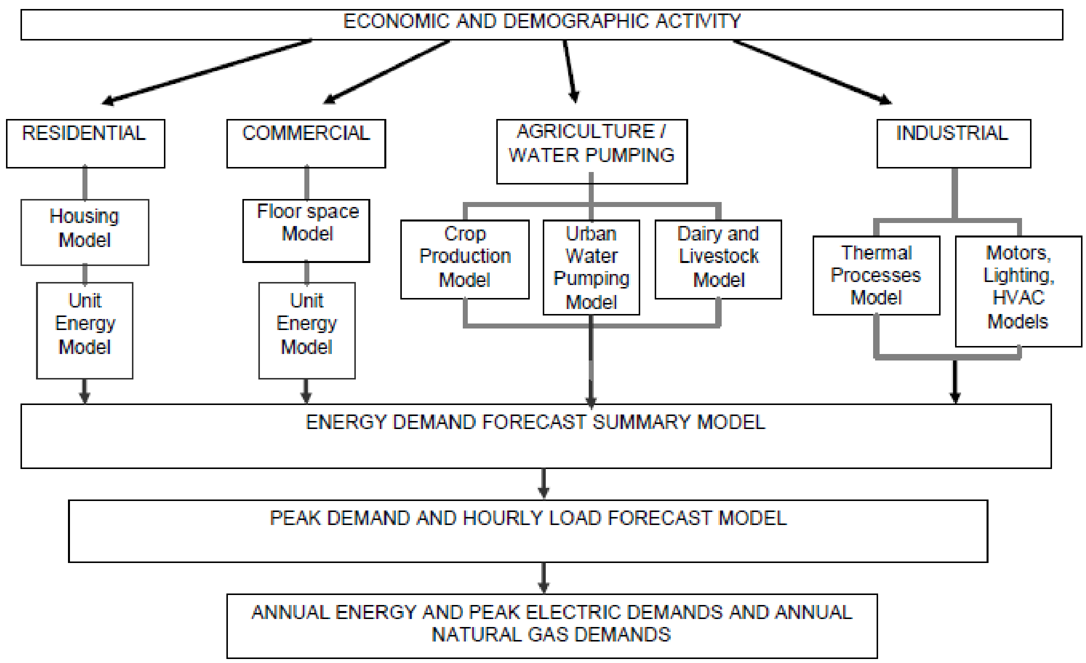
Planning area forecasts are developed by aggregating county data to the planning area level. For example, county-level housing construction, population and income estimates form the basis of a planning-area residential consumption forecast. Each county is apportioned to one or more of sixteen climate zones and each climate zone is assigned to a planning area.

The same models are used to forecast electricity and natural gas demand.

The aggregate demand for energy services increases with growth in economic activity and population and as new energy services become available due to technological development.

In addition, updated forecasts reflect the penetration rates at which more efficient equipment and new energy services come into use. In addition to the energy and peak demand sectoral forecasting models, the organization sometimes develops models that generate the values of economic variables used to drive the energy or peak sectoral models. This work has been necessary because suitable specific variables have not been readily available.

Figure 3 illustrates a schematic diagram of the major elements of the energy and peak demand forecasting models. The results from the energy forecasting models flow directly into the peak demand forecasting model.



Source: California Energy Commission staff, May 2005

Figure 3. Framework for Energy Demand Forecast Models

Residential Energy Demand Forecast Model

The residential model forecasts energy demand for 24 end uses, three housing types and three fuel types.

End-uses include space heaters, air conditioners, refrigerators, color televisions, lighting, water heating, etc. Electricity and natural gas consumption are fully modeled for all relevant end uses, while saturations are maintained for other fuels (principally wood, liquid propane gas, and solar).

Three housing types single-family, multi-family, and mobile homes are modeled; these are further grouped by climate zone. Sixteen climate zones are modeled; these are intended to capture differences in residential energy use for space conditioning across the state's microclimates.

Five vintages of housing construction are used to represent the eras in which building codes and revisions significantly influenced the thermal characteristics of residential buildings.

The residential model forecasts energy demand in three principal components:

1. The number of households of each housing type is forecasted.
2. The saturation of appliances for each of three fuel types is projected
3. The model determines the amount of energy expected to be used by each end-use appliance; this depends, in part, on the age profile of the appliance stock.

Total residential energy consumption is the product of projected households, the number of households possessing a particular appliance, and the yearly average energy use for that appliance, summed over all end uses.

Commercial Energy Demand Forecast Model

The commercial model uses end use intensities (EUIs), which are the energy use estimates per square foot by building type with corresponding end-uses and equipment.

The commercial energy forecasting model is similar to the residential model with respect to the degree of disaggregation. The model first forecasts the amount of building floor-space and vacancy rates for twelve different building types. The model then determines the fraction of floor-space in each building with commercial equipment for each of three fuel types. The nature of the energy-using equipment in each building type determines the commercial end-uses (for example, restaurants contain ovens and stoves, therefore, cooking is a principle end-use for that building type). The amount of energy required per square foot of floor-space is then determined for each fuel type. Total commercial energy demand is the product of these three factors and summed for all end-uses and building types. The model considers the effects of changes in floor space, vacancy rates, energy prices, building and appliance standards, and other major efficiency programs on energy use.

Industrial Energy Demand Forecast Model

The industrial sector is divided into process and assembly groups.

Projections of industrial energy demand for most sectors except extraction industries are driven by forecasts of GDP. For extraction industries, because the volatility of the prices of such commodities as oil, natural gas and precious metals leads to volatility in values of shipments or GDP forecasts of employment are used.

To forecast annual electricity and natural gas demand, the organization used to use the INFORM, developed by the EPRI until 2014. However, because EPRI does not support the model any longer, the organization decided to develop a new model for its 2014 report based on the INFORM method. The INFORM program accounted for energy use trends, price effects, and exogenous improvement in efficiency by end use and industry.

The major end-uses in the model are motors, thermal processes, lighting, HVAC and miscellaneous. The organization used to use the model to forecast demand for electricity, natural gas and other fuels for these five major end-uses over a 12-year period.

The new model forecasts industrial energy demand based on a number of factors, including:

- Projected growth in dollar output or employment for 28 categories
- Projected average industrial rates

- Changes in end-use characteristics, including energy intensities, which measure energy use per dollar of output

The marginal impact of economic growth on energy use in each of the 28 categories is estimated using regression analysis. Estimated coefficients are applied to the appropriate economic indicator to provide “business as usual” forecast for each industrial category. This forecast is adjusted for rate increases, using price elasticities estimated in the sector econometric models. Finally, the forecast is adjusted to account for changes in end-use energy intensity.

Since a full statewide industrial end-use survey has not been completed for more than 20 years, recent data on industrial end-use energy intensities and other characteristics to fully populate the model are not available. As a result, the organization started to populate end-use characteristics in the model using national data and smaller-scale state surveys. However, the organization expects the new model will require a full statewide industrial end-use survey to reach its full potential as a forecasting tool.

Energy Demands Summary Forecast Model

Individual sectoral model energy demand forecasts are processed by the Energy Demands Summary Forecast Model in order to calculate planning area total forecasts. The summary model adjusts the sectoral forecasts for weather and DSM program savings. The results are calibrated using recorded energy consumption.

Energy demand for weather sensitive end-uses is adjusted to accommodate the deviation between actual weather and normal weather for each climate zone in the planning area. After the weather adjustment, minor adjustments are performed to account for DSM programs that have not been incorporated into the input data used in the sectoral models. The final adjustment to the forecasts calibrates the results using recorded energy consumption.

3. Forecasting Parameters

Factors that affect natural gas supply and demand include production, population growth, pipeline capacity, economic outlook, weather, national and global markets, environmental concerns, and the effects of energy policies. Supply and demand, in turn, affect natural gas prices.

Four classes of data are needed as inputs to disaggregated forecast models:

- Consumer characteristics data such as end-use appliance saturations, dwelling size and age, occupants' income and demographic makeup, utility bills for the residential sector, and equipment saturations, hours of operation, etc. for the commercial sector
- Aggregated energy consumption data for the non-residential sectors (most notably the industrial sector) classified by the NAICS codes devised by the federal government

- Disaggregated economic and fuel price projections at a level of detail matching the customer sectors of the energy forecasting models
- Characteristics of demand side management programs

Customer surveys are the principle source of information on consumer characteristics. These surveys are used to collect data on customer electric and natural gas use, which form the core data needed for the end use forecasting models.

A major secondary data source on consumer attributes national census data.

Acquisition of reliable commercial floor-space data remains a difficult and unresolved problem for forecasters.

Monthly consumption data for different NAICS codes are used in the sector models.

Essential inputs into the forecasting models are annual economic and fuel price projections for each planning area for 10 years into the future. Several translation models are used to convert available economic data into the actual "energy driver variables" which are used in the models to forecast energy use. For example, in the commercial sector, the key energy driver is floor space by building type, while the economic variables are employment of various types, taxable sales, and various groupings of population.

The sector-specific economic variables used in developing the forecast are summarized in Table 3.

Table 3. Economic Variables Used in Forecast Models

Sector	Energy Driver	Economic Variable	Constructed Economic Variable
Residential	• Fuel Prices	• Population • Personal income • Households	• Household population • Persons per household • Group quarters • Income per capita
Commercial	• Floor-space, by building type • Fuel prices	• Employment • Retail sales • Population	
Industrial	• Output by industry • Fuel prices	• Output by industry • Employment (extraction sectors only)	
Agriculture	• Crop production • Rainfall • Electricity price • Diesel price • Cooling degree days • Dairy and livestock production	• Personal income • Population • Households	• Total households • Persons per household • Income per capita

4. Forecast Scenarios

The forecast includes three demand cases designed to capture a reasonable range of demand outcomes over the 10-year forecast period. The "high-energy demand case" incorporates relatively high economic/demographic growth, relatively low electricity and natural gas rates, and relatively low committed efficiency program, self-generation, and climate change impacts. The "low-energy demand case" includes lower economic/demographic growth, higher assumed rates, and higher committed efficiency program and self-generation impacts. The "mid" case uses input assumptions at levels between the "high" and "low" cases. It represents a future in which the economy and commercial activity remain consistent with trends experienced over the last several years. The high demand and low demand cases are created by altering assumptions, which move natural gas prices. The assumptions that are varied included economic growth, technology improvements, renewable portfolio standards, coal-fired generation retirements, natural gas supply cost curves, demand, and the production cost environment.

5. Forecast Period and Update Frequency

The forecast provides annual demand forecast for every year over the 10-year forecast period. It is updated every year as part of each IEPR cycle.

6. Forecast Evaluation

The organization evaluates the performance of its forecasts by having an expert panel review the forecasts. It also examines annual demand compared to subsequent actual consumption. In addition, it compares model backcasts, or predictions of historical outcomes, to historical consumption.

7. Forecast Resources

Although the original model was developed externally, the forecasts are prepared by internal resources.

Two full time equivalent (FTE) staff prepare the forecast for both gas and electricity in the residential sector.

One FTE prepares the forecast for both gas and electricity in the commercial sector.

One FTE prepares the forecast for both gas and electricity in the industrial sector.

One FTE prepares the forecast for both gas and electricity in the agricultural sector.

One FTE prepares the forecast summary for both gas and electricity for all sectors.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The organization uses hourly load shapes for each end-use and applies the load shapes to the annual demand forecast from the end-use model to determine the hourly demand for each end-use. It then aggregates all the hourly demand for all end-uses to forecast the peak-day demand.

The organization refreshed its hourly electric end-use load profiles, as well as hourly savings profiles for efficiency measure categories, generation profiles for behind-the-meter solar PV systems, and charging profiles for EV. For future forecasts, these profiles will be combined into a new bottom-up hourly electric load model (HELM 2.0) that will translate the organization's annual end-use consumption forecasts into hourly and peak-load forecasts. In the meantime, the organization continues to leverage its top-down hourly load model (HLM) to forecast annual and monthly peak loads. The HLM has been updated to incorporate the estimated impact of behind-the-meter battery storage, as well as EV charging profiles.

E. Organization E

1. Overview

The company provides natural gas and electricity to approximately 16 million people throughout a 70,000-square-mile service area. The company has approximately 42,141 miles of natural gas distribution pipelines and over 6,400 miles of transmission pipelines. It serves 5.4 million electric customer accounts and 4.3 million natural gas customer accounts.

The company has experienced declining growth rate in its annual demand in the core market and forecasts this decline in annual growth rate to continue primarily due to increasing emphasis on energy efficiency and electrification.

2. Forecasting Method

The company's gas demand forecasts for the residential, commercial, and industrial sectors are developed using econometric models. Forecasts for other sectors (NGV, wholesale) are developed based on market information. Forecasts of gas demand by power plants are developed by modeling the electricity market using the MarketBuilder software.

The company uses the current levels of energy efficiency programs included in its latest IEPR in the forecast.

3. Forecasting Parameters

While variations in short-term gas use depend mainly on prevailing weather conditions, longer term trends in gas demand are driven primarily by changes in customer usage patterns influenced by underlying economic, demographic, and technological changes, such as growth in population and employment, changes in prevailing prices, growth in electricity demand and in electric generation by renewables, changes in the efficiency profiles of residential and commercial buildings and the appliances within them, and the response to climate change.

Because space heating accounts for a high percentage of natural gas use, the company's natural gas requirements for residential and commercial customers are sensitive to prevailing temperature conditions.

Inputs for gas prices and rate assumptions are important for forecasting gas demand; this is especially true for market sectors that are particularly price sensitive, such as industrial or electric generation.

4. Forecast Scenarios

The company develops an alternative forecast of natural gas demand under assumed high-demand conditions. For the high-demand scenario, the company relies on weather conditions that have an approximate 1-in-10 likelihood of occurrence of cold temperature conditions and by considering a year for dry hydro conditions. In previous forecasts, the company used the average of observed temperatures during the past 20 years. However, the company is now building an assumption of climate change into its forecast.

The climate change scenario is developed from work done at the National Center for Atmospheric Research, adjusted to the company's service area.

Despite growth in number of households, total residential demand is expected to decrease due to continuing upgrades in appliance and building efficiencies, conversion to electric appliances, as well as warming temperatures.

Natural gas use per commercial customer is projected to decline over the forecast horizon due to continuing EE and electrification efforts as well as warmer temperatures.

Natural gas requirements for the industrial sector are affected by the level and type of industrial activity in the service area and changes in industrial processes.

Forecasts for the electricity generation sector are subject to greater uncertainty due to future gas prices; the retirement of existing power plants; the timing, location, and type of new generation, particularly renewable-energy facilities; construction of new electric transmission lines; and the impact of GHG policies and regulations on both generation and load.

The company forecasts natural gas demand by power plants and market-sensitive cogenerators using the MarketBuilder software. MarketBuilder enables the creation of economic-equilibrium models of markets with geographically distributed supplies and demands, such as the North American natural gas market.

The company's forecast for 2018-2035 uses the mid-case electricity demand forecast from the 2017 IEPR. The forecast assumes that renewable energy generation will provide 33 percent of the state's retail sales in 2020, 40 percent by 2024, and 50 percent by 2030. Additionally, the company included the impact of electric battery storage at the mandated level. The impact of battery storage may limit gas throughput from peaking electric generators.

5. Forecast Period and Update Frequency

The company prepares a 20-year forecast of customers, annual demand, peak-day demand every two years. While the company prepares a forecast for each year during the forecast period, it reports forecast results for every year for the first five years of the forecast period and at five-year intervals after that.

6. Forecast Evaluation

This information was not available.

7. Forecast Resources

This information was not available.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company uses a 1-in-90-year cold-temperature event as the design criterion for its abnormal peak-day demand forecast. The core market peak-day demand forecast is developed using the observed relationship between historical daily weather and core usage data. This relationship is then used to forecast the core load under peak-day conditions.

F. Organization F

1. Overview

The company is an investor owned utility that serves over 3.4 million customers in over 400 communities.

The company was formed by the merger of two natural gas distribution companies a few years ago. The company has made significant progress in integrating the operations and regulatory processes of the two companies, but there are some aspects of the regulatory process that are still different.

The company produces its forecast by rolling up the demand forecast for each division into one companywide demand forecast. The forecasting methods for both divisions are essentially the same, however, the models have some differences. The company is planning to evaluate its forecasting model and expects to use one model that it will be used to produce a companywide forecast in the near future.

The forecasting models for both divisions are primarily econometric models. The company does not produce a long-term forecast. It prepares a five-year forecast, which is filed with the regulator.

2. Forecasting Method

The company uses econometric models to prepare a five-year forecast, which it files with the regulator. Forecasts are prepared for different rate classes for each division, which are then rolled up to produce a companywide forecast.

Residential and Core Market Commercial

The company uses a separate econometric regression model for the residential and core market commercial customers for each division. One division uses annual data to create an annual demand forecast, while the second division uses monthly data to create monthly demand forecasts, which are rolled up to create the annual demand forecast.

The forecasts are prepared by rate class and by different geographic regions, which represent different climate conditions.

The regression models produce the average user per customer, which is then multiplied by the forecasted number of customers from econometric data.

The residential and core market commercial forecast for one division is derived using forecasted number of customers and normalized average use per customer forecast generated from the average use forecasting models. This econometric model allows the company to produce separate forecast for each rate class. While the model does not use specific end-uses in determining average use per customer, it includes bundles of end-uses grouped together. The model uses historical data to forecast annual demand for each rate class using regression techniques. The model determines average use per customer for each bundle of end-uses which are adjusted for efficiency improvements within the bundle.

The econometric model for residential and core commercial customers for the second division uses actual monthly average use per customer for each rate class for the previous 10 years and runs regression analysis of the data against demographic and econometric indicators. The regression model includes an "efficiency index."

Non-Core Industrial

The company uses bottom-up approach in forecasting for the non-core industrial sector. This approach is similar for both divisions. The company forecasts the demand for each individual customer for the large industrial customers based on data from the customers. The forecast for the medium sized industrial customers is based on the previous year's consumption. The company assumes little change in consumption year over year, unless they have information from the customer that the customer plans to change its natural gas use.

3. Forecasting Parameters

One division uses a number of parameters in its forecasting model. These include natural gas prices, historical annual demand, weather, vintage for residential customers, employment, real GDP, vacancy rates, and time trend

The vintage variable is constructed to reflect the impact that new homes, with more energy efficient gas equipment and enhanced building codes, have on average use.

The time trend, including the dynamic variable in the regression model, captures the historical actual average trend of the sectorial average use, conservation initiatives originated by customers themselves or promoted by government programs, stock turnover, and other historical impact not reflected in the mentioned driver variables.

The second division uses several parameters in its forecasting model, efficiency index, which represents the weighted average appliance efficiency; number of people per household; total gas bill in dollars, and weather.

4. Forecast Scenarios

The company does not run specific scenarios other than the base case. The company runs sensitivity analysis on the major drivers (inputs) of their forecast such as weather and number of customers.

5. Forecast Period and Update Frequency

The company does not prepare a long-term annual demand forecast. It only prepares a five-year forecast, which is updated annually.

The company provides a forecast for each year during the forecast period.

6. Forecast Evaluation

The company evaluates the performance of its forecasting model by comparing forecasted annual demand to normalized actuals using statistical methods such as MAPE to determine if their forecast has any built-in biases. In general, the difference between the forecasted annual demand and actual annual demand has been less than 1% for residential and small to medium commercial customers.

7. Forecast Resources

The company only uses internal resources in preparing its forecast. The forecasting department consists of four FTE dedicated to preparing the long-term forecast.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company applies the load factor for each rate class to the annual demand forecast to determine the peak-day demand forecast for each rate class. It then sums up the peak-day demand for each customer class to forecast the peak-day demand for the system.

G. Organization G

1. Overview

The company is a not-for-profit entity established by the provincial government. The company manages the province's power system so that the province receive power when and where they need it. It plans and prepares for future electricity needs.

2. Forecasting Method

The company uses an end-use model to forecast its annual energy demand by sector and by zone. Demographic and economic drivers are considered in the development of the annual gross forecast, including changes in household formation, commercial floor space, industrial output and energy price. Gross energy demand estimates are computed with the company's model EUF. EUF produces estimates of electricity consumption at the consumer level. The company applies transmission and distribution line losses to convert these energy values to the generator level. Figure 4. illustrates the company's load forecasting process.

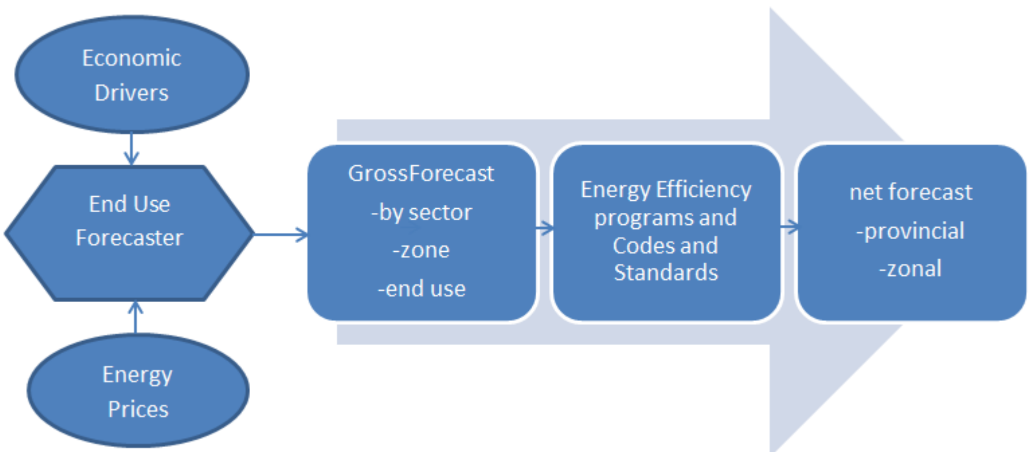


Figure 4. Load Forecasting Process

The EUF model is built at the zonal level with all zones aggregating up to the provincial total. EUF is an end-use model that tracks equipment and building stocks over time and simulates technology acquisition in the economy. The residential, commercial/institutional and industrial sectors are each analyzed separately. A schematic of the EUF model is shown in Figure 5.

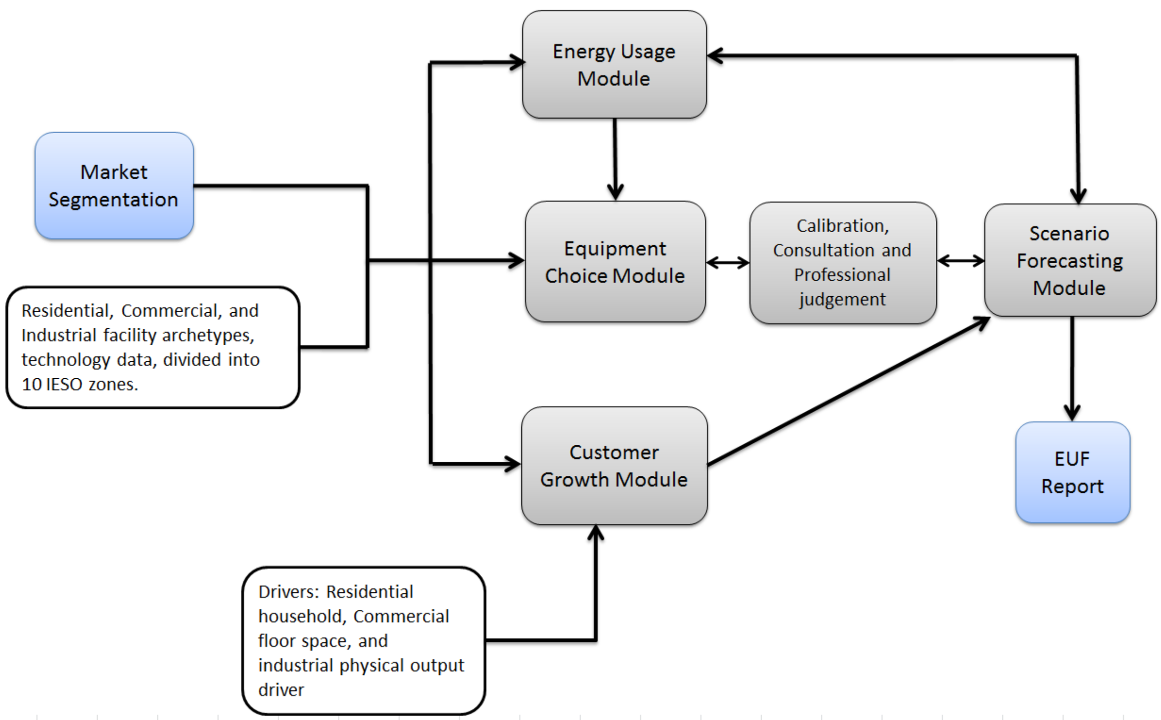


Figure 5. End-Use Forecaster Modules and Structure

There are several primary modules that form the heart of the EUF analytical framework. Figure 4. depicts the relationships between these modules.

- Market Segmentation Module
- Energy Usage Module
- Equipment Choice Module
- Customer Growth Module
- Scenario Forecasting Module

EUF's market segmentation module governs the development of customized market segmentation designs and the population of the model with the necessary data. A consultant supplied the majority of the data characterizing the end-uses as they apply to the province and its sub electric zones. The data includes: building characteristics, equipment saturations, fuel shares, end-use equipment efficiency shares, replacement technology relative efficiencies and capital costs. The company has been in the process of updating the end-use information whenever it becomes available. The market segmentation of the model contains sectors, zones, building types, end uses, fuel types and efficiency levels. Figure 6. shows the details of market segmentation by sector, zone, building type, end use, fuel type and efficiency level.

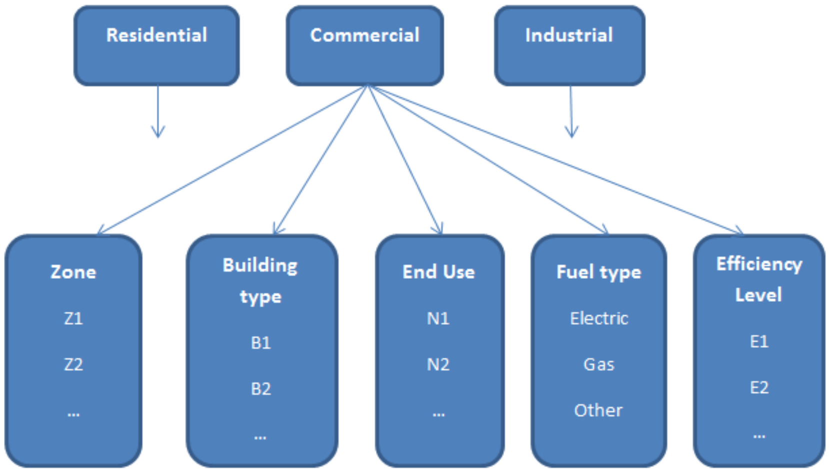


Figure 6. Market Segmentation Data Category

The energy usage module tracks equipment utilization given the stock of equipment, building characteristics, and customer behavior at any moment in time over the forecast horizon. For example, single-family homes may have a discrete set of central air conditioner efficiency choices, with each efficiency level having an associated electric consumption for each year. That consumption can vary in the short run as customers modify behavior that results in changes to the equipment utilization without changing the equipment itself. Factors that can affect consumption in the short run include weather, non-weather seasonal factors, building and customer characteristics, energy prices, disposable income, and other user-specified attributes. These relationships are specified in the Energy Usage Module by combining a forecast of consumption factors or drivers (independent or exogenous variables) with a set of coefficients associated with each exogenous variable.

The customer growth module tracks the number of customers (facilities) present within each vintage, geographic zone, and dwelling type or sub-sector from the market characterization. Customer growth varies over time through a range of factors, including forecasts of population (typically applicable to the residential sector) and square footage of different building types (typically applicable to the commercial sector). As with the energy usage module, these relationships are specified in the Customer Growth module by combining a forecast of customer growth factors or drivers (i.e., independent or exogenous variables) with a set of coefficients associated with each exogenous variable.

The main drivers used in customer growth module, residential household, commercial floor space and industrial physical drivers/activities, are provided either by third-party consultants or the company's in-house analysis.

Equipment stock changes in the model occur in response to new driver growth as well as to end-of-life retirement and replacement of equipment. Increasing saturation and utilization is also considered (e.g. increasing number of computers per household). Equipment acquisition choices are governed by choice equations that consider energy operating costs as well as capital costs. Different technologies are represented by five efficiency choice levels for each end-use. Discount rates by sector vary from 25% to 50%. The choice equations also recognize that price and cost savings are not the only factors that determine consumer action. The choice equation is, therefore, a weighting of financial and non-financial factors.

The equipment choice module analyzes customer choice decisions among competitors and product options. For example, customers choose their end-use equipment based on fuel types and efficiency levels. Purchase decisions are represented by a nested structure of provider (fuel choices) and product (efficiency choices) option choices. See Figure 7.

Choice equations are calibrated against base year new stock acquisition decisions across technology levels. For end-uses with a fuel choice (e.g. domestic water heating), purchase decisions are represented by nested fuel and efficiency option choices.

Short term behavioural response to price that reflects changes in equipment utilization without changing the equipment itself is captured through the use of behavioural price elasticity. The range of the elasticity is from -0.25 to -0.1 and captures behaviour such as lowering thermostats and turning off lights and computer monitors.

The hierarchy of equipment choice module is shown in Figure 7.

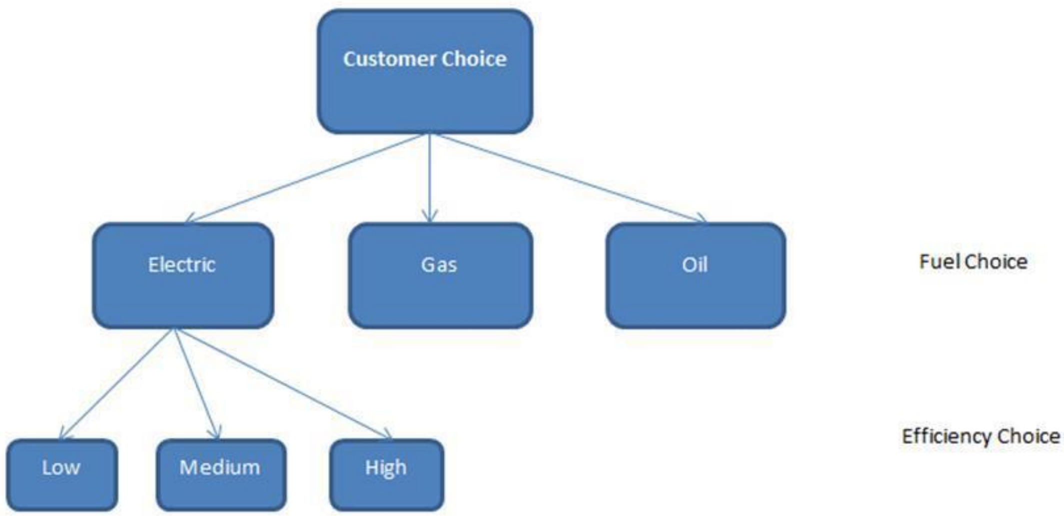


Figure 7. EUF Customer Choice Module Hierarchy

The company uses an end-use level model for a number of reasons, including:

1) The need to capture structural changes in the economy, including the growth and decline of specific industries and change in the relative strength of sectors;
2) The need to address the impact on demand of the penetration of new electricity using technologies;
3) The need to ensure linkages between conservation savings estimates and underlying assumptions of the load forecast;
4) The need to specifically address the impact on peak demand of the growth of different end-uses;
5) Forecasting is done by tracking energy at an end-use and equipment efficiency stock level. This is done so as to allow updates to the codes and standards.

3. Forecast Parameters

The company's EUF uses demographic and economic drivers in the developing its annual gross forecast, including changes in household formation, commercial floor space, industrial output and energy price.

The parameters used in the Market Segmentation Module are shown in Table 4, Table 5, Table 6, Table 7, Table 8, and Table 9.

Table 4. Residential End-Uses

AC Central	Cooking	Domestic Hot Water	Lighting	Swimming Pool Pumps
AC Room	Dehumidifiers	Forced Air Central Heating	Refrigerators	Space Heating Room
Baseboard	Dishwashers	Other Consumer Electronics	Set Top Boxes	
Clothes Washer	Elevators	Lighting Common Area	Televisions	
Computers	Freezers	Ventilation & Air Circulation	Miscellaneous	

Table 5. Residential Building Type

Multi Residential High Rise
Multi Residential Low Rise
Other Residential
Row House
Single Family

Table 6. Commercial End-Uses

CE Space Heating	Domestic Hot Water	Lighting Interior General
Computer Equipment	Elevators	Lighting Interior High Bay
Cooking	HVAC Fans Pumps	Miscellaneous Equipment
Cooling Chillers	Lighting Exterior	Other Plug Loads
Cooling DX	Lighting Interior Architectural	Refrigeration

Table 7. Commercial Building Type

Food Retail	Other Commercial Buildings	Schools
Hospital	Other Hotel Motel	University Colleges
Large Hotel	Other Non-Food Retail	Warehouse Wholesale
Large Non-Food Retail	Other Office	
Nursing Home	Restaurant	

Table 8. Industrial End-Uses

Compressed Air	Motors Other	Process Cooling
Electro Chemical	Pumps	Processing Heating
HVAC	Motors	Process Specific
Motors Fans Blowers	Other	

Table 9. Industrial Subsector

Chemical Manufacturing	Transportation & Machinery	Petroleum Refineries
Fabricated Metals	Miscellaneous Industrial	Plastic & Rubber Manufacturing
Food and Beverage	Non-Metallic Minerals	Primary Metals
Mining	Paper Manufacturing	Wood Products

Demand forecasting methodologies vary for each of the other miscellaneous sub-sectors and include adopting study results from third-party consultants, the company's regional resource planning, and consultations with LDCs. These sectors include agriculture, remote communities, street lighting, electricity generator demand, and water treatment facilities.

4. Forecast Scenarios

Scenario Forecasting Module combines the outputs from Energy Usage Module, Equipment Choice Module and Customer Growth Module. It then performs additional calculations regarding turning over equipment at the end of its useful life to produce forecasts for electricity usage.

5. Forecast Period and update Frequency

The company develops a 20-year forecast its annual demand, and peak-day demand for each year during the forecast period.

6. Forecast Evaluation

The company evaluates the performance of it forecasting model by comparing its zonal residential energy forecasts with the annual energy use data from the LDCs by rate class. The company's industrial forecast is also compared with its transmission connected customer trends and market intelligence based on research and consultation with the company's planners, industrial conservation program account managers and others.

Energy consumption trends from NRCan's OEE are also used as check points with respect to provincial end-use energy and sector and subsector consumption trends. Information from NRCan's Survey of Household Energy Use and sales data from Canada Appliance Manufacturers Association are used to check the company's equipment forecasts.

Other various sources are used to check the forecast results including but not limited to: ASHRAE, RECS and CBECS by U.S. EIA, Residential Energy Use Survey conducted by the company's Conservation Division, etc.

7. Forecast Resources

The company uses internal resources to run its forecast. It also uses consultants to provide some of the data required as inputs into its model.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company uses its annual sectoral and zonal gross energy demands to develop its gross hourly demand values through the application of end-use level hourly load shapes. It then corrects its hourly gross peak and energy demand values for projected policy-induced conservation savings (i.e. savings from efficiency codes, standards and incentive programs). The outcome of this derivation is the net hourly load forecast. The net hourly load forecast establishes the amount of electricity that is to be served and forms the starting point for reliability assessment and integrated planning analysis.

H. Organization H

1. Overview

The company is a crown corporation that serves approximately 587,000 electricity customer and 285,000 natural gas customers.

The company used to use a combination of end-use and econometric model to forecast its long-term electricity demand. It switched to a primarily econometric model for electricity demand in the residential sector in 2014 because it wanted to have a better handle on increases in electricity prices and their impact on energy demand. The results from the econometric only and the end-use model were very similar.

The company has used the same model for forecasting its natural gas demand for the past 10 years. This model uses a combination of end-use and econometric model in years with modest electric price increase.

The company's natural gas demand forecast only covers a 10-year period with a focus on the three to five years. This is because the company does not own any transmission assets and can react to changes in demand much faster for the distribution system. The company's electricity demand forecast covers a 20-year period because of the long lead time required for generation and transmission assets.

2. Forecasting Method

The company uses a combination of end-use modeling and econometric modeling for forecasting its annual natural gas demand.

The company uses weather normalized historical usage by rate class.

Future DSM savings are embedded in the company's annual natural gas demand forecast.

The company's annual electricity demand forecast does not include the impact of future DSM savings in the base forecast. However, the company has been reporting its electric DSM savings since 2018.

Residential Customers

The company uses an end-use model to forecast annual natural gas demand for its residential customers.

The company conducts a REUS approximately every five years to collect data, which it then uses in its end-use forecasting model. It uses REUS to collect data on end-use saturation levels, detailed information on newly constructed dwellings, and appliance age distributions and their life expectancy. It uses the results of the REUS together with conditional demand analysis in its forecasting model to forecast the average use per customer. The company uses economic forecasts from external sources to forecast the number of customers.

The end use assumptions used in the model include current usage information and efficiency improvement information. The number of appliances and their estimated usage are multiplied together to calculate an energy forecast for each end use. All uses are then combined to calculate the total use for the residential end-use forecast.

Commercial and Small Industrial Customers

The company uses an econometric model to forecast its annual natural gas demand for its commercial and small industrial customers.

The company forecasts the number of small commercial gas customers based on economic forecasts from external sources. It forecasts the average use per customer based on historical average use per customer for each rate class. Since commercial rate classes are based on annual gas use, the average use per customer for the commercial rate classes is relatively stable. This is because, as customers whose gas use changes move to the appropriate rate class based on their gas use.

Large Industrial Customers

The company forecasts the annual demand for its large industrial customers individually based on information collected on individual operating plans, including short-term expansion or contraction plans. The sources of information include industry news and publications, company prospectuses, and from the company's key and major account advisors.

3. Forecasting Parameters

Residential Customers

The parameters used in the forecasting model include end-use saturation rates, dwelling type, appliance age distribution, and appliance life expectancy, as well as energy prices.

Commercial and Small Industrial Customers

These customers typically supply products to the Provincial, Canadian and US markets. As a result, the company uses Manitoban, Canadian and US GDP forecasts in its model.

Large Industrial Customers

The company forecasts the annual demand for its large industrial customers individually based on information collected on individual operating plans, including short-term expansion or contraction plans.

4. Forecast Scenarios

The company prepares a base case forecast for its natural gas annual demand forecast. In the past, the company used to prepare forecasts under various scenarios but has now moved to probability planning approach.

The company presents a probability-based estimate of how much future actual volumes might vary from forecast. This can be used to produce forecasts with a specific probability of occurrence, or can be used to determine the probability of specific volumes occurring. The company determines the standard deviation and correlation coefficient of historical weather adjusted volume and applies to the forecast to give an estimate of the confidence bands. It used 10% and 90% confidence bands (-/+ 1.28 standard deviations) to represent a low and high scenario. This calculation gives the variability due to economic effects and the year-to-year variation in natural gas use. It does not include variability due to weather which was removed through the use of weather adjusted volumes.

5. Forecast Period and Update Frequency

The company prepares a 10-year annual natural gas demand forecast, which it updates annually and prepares a forecast for each year during the forecast period.

6. Forecast Evaluation

The company evaluates its model regularly by comparing the forecasted annual demand for the first two years of the forecast period to actuals and has found that over the long term after accounting for heating value and weather the absolute average variance is with an acceptable range.

7. Forecast Resources

The company's forecasting team consists of approximately five FTE who prepare the long short-term forecast for both natural gas and electricity.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company prepares both a Peak-Day demand forecast and an Annual Demand Forecast and the Peak-Day demand forecast is primarily used for natural gas purchase planning and cost of service rate allocations.

I. Organization I

1. Overview

The company is a crown corporation and owns and operates a natural gas distribution system that serves over 385,000 residential, farm, commercial and industrial customers through its natural gas distribution systems. One of its subsidiaries, operates a natural gas transmission system with over 14,000 kilometres of high-pressure natural gas pipelines and gas storage sites as well as serves the large industrial customers. The forecasting method for the transmission company is covered in section **Error! Reference source not found.** in this appendix.

2. Forecasting Method

The company does not prepare a long-term annual demand forecast; it only prepares a five-year annual demand forecast.

The company uses a top-down qualitative model to prepare its forecast for each rate class. This model is based on an econometric model that uses economic forecasts from external resources.

The forecast for growth in the number of customers is based on economic forecasts and most recent historical trends.

The forecast for average use per customer for residential and small commercial customers is based on weather normalized historical data, while the annual demand forecast for large commercial customers is based on the annual demand from the previous year.

The company has used this model for many years, as it has provided good results.

3. Forecasting Parameters

The company's econometric model uses a number of parameters, which include average use per customer by rate class economic forecasts from various external resources, input from builders to assess housing starts, and economic and housing starts forecasts from CMHC and Statistics Canada.

4. Forecast Scenarios

The company only develops a base case. While it does not develop any alternative scenarios, if they expect a significantly colder or warmer year than forecasted, they update their demand forecast to update their revenue forecast.

5. Forecast Period and Update Frequency

The company prepares a five-year annual demand forecast annually for every year during the forecast period to align with the company's five-year business plan. The forecast is prepared for each rate class.

6. Forecast Evaluation

The company evaluates the performance of its forecasting model by comparing weather normalized actual annual demand to weather normalized forecasted annual demand. Forecasts are generally within one to two percent of actuals.

7. Forecast Resources

The company uses internal resources to develop its annual demand forecast. It estimates approximately one FTE plus some support from other resources to prepare its forecast. The company, however, uses various external resources to research the econometric data required for the forecasting model.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The peak-day demand forecast is forecasted separately from the annual demand forecast. The peak-day demand forecast is based on the regression analysis of the coldest day in 20 years.

J. Organization J

1. Overview

The company is a fully owned subsidiary of the crown corporation and owns that operates the natural gas distribution system in the province. The company operates a natural gas transmission system with over 14,000 kilometres of high-pressure natural gas pipelines and gas storage sites that supply natural gas to the natural gas distribution company, as well as serve the large industrial customers in the province.

The transmission company uses its forecasts primarily to assess load requirements and urban growth, which may encroach on its assets and result in potential relocation of the assets.

2. Forecasting Method

The company prepares a long-term forecast, which includes the demand from the distribution company and its industrial customers.

Since the company's customers are large industrial customers and the distribution company, its annual demand forecast is based on forecasts provided by its customers. When it receives new service requests, it includes a probability of the customer coming online during the forecast period and includes it in its forecast based on probability.

3. Forecasting Parameters

The company uses forecasts provided by its customers and market intelligence on new customer additions or expansions.

4. Forecast Scenarios

The company develops a most likely case as well as high demand and low demand cases. These scenarios are based on customer feedback and the probability of the customer moving forward with the forecasted changes, if any.

5. Forecast Period and Update Frequency

The company prepares five to 10-year forecasts with results for each year during the forecast period and updates these annually as part of its budget planning cycle. However, most of its forecasts are five-year forecasts. The forecast is prepared for each customer, as the customers are large industrial customers and a distribution company.

6. Forecast Evaluation

The company evaluates the performance of its forecasting model by comparing its forecasted annual demand to its actual throughput. Forecasts are generally within one to two percent of actuals.

7. Forecast Resources

The company only uses internal resources to develop its annual demand forecast. While four people from different departments are involved in preparing the forecast, it estimates approximately one FTE is required to prepare its forecast.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company forecasts the peak-day demand for its customers based on historic customer demand and customer feedback. It uses the annual demand forecast to develop its peak-day demand forecast by applying a load factor coefficient to the annual demand forecast.

K. Organization K

1. Overview

The company provides gas service to approximately 42,000 residential, commercial and industrial customers in more than 16 communities.

The company used an end-use model in its annual demand forecast for the residential sector in its most recent long-term forecast, which was part of its 2019 consolidated resource plan.

The company has experienced declining use per customer in its residential and small commercial sectors, which is likely due to building code improvements and increased appliance efficiencies.

2. Forecasting Method

The company's annual demand forecast is weather normalized. The company uses three different approaches to forecasting annual demand for its three customer classes.

Forecasts for the large industrial and commercial customers are based on the results of a customer survey. The company sends out a survey to its large customers asking for customers to provide a forecast of their gas use. If the customer's forecast is significantly different from its historical trend, the company may adjust the customer's annual demand forecast to align the customer's historical annual demand.

Forecasts for small commercial customers are based on historical trend analysis coupled with forecasted household formations in the company's service area. Historical trend analysis is used to determine the average use per customer, while forecasted household formations is used to forecast growth in the number of commercial customers. The company applied an exponential decline rate extrapolated from the past 10 years of actual use per customer. The company forecasts a decline in use per customer and capture rates for commercial customers to reflect the impact of increased focus on electrification of space heating in the provincial energy plan.

The company uses an end-use model to forecast the average use per residential customer. The model uses a number of parameters to forecast gas use based on type of dwelling and number of appliances. It uses conditional demand analysis to determine the relationship between the various parameters and gas use per residential customer. The number of residential customers used in the forecast is based on forecasted additions to the number of households in the company's service area.

The company uses the results from its REUS, which provides data on the demographic makeup and consumption behavior of its residential customers. It uses this data together with historical customer billing data as key inputs into its residential forecasting model. The model accounts for building code improvements in new homes as well as replacement of appliances with more efficient appliances as customers replace appliances at the end of their useful life. The company uses conditional demand analysis techniques to develop end-use models for single family dwellings (SFD), duplexes (DUP), multi-family dwellings (MFD) such as triplexes and townhouses, apartments and condominiums in vertical subdivisions (VS), and mobile homes (MH). It takes into account various characteristics of natural gas consumption by residential customers such as the distribution of annual demand, the penetration rate and portion of the overall demand of each end-use based on the results of the REUS. The company adjusts its forecast to reflect the impact of increased focus on electrification of space heating in the provincial energy plan.

3. Forecasting Parameters

The company's end-use model uses a number of parameters, which include dwelling type, type of construction, number of gas appliances in the home, type of gas appliances in the home, and behaviour of the residents to forecast the average use per customer.

The company collected this data from its REUS.

4. Forecast Scenarios

The company develops a reference scenario that reflects the current mix of natural gas appliances and insulation in existing construction, and the current mix of SFD and MFD buildings being constructed in its service areas. Forecasts of use per customer for residential and commercial construction reflect changes to the mix of new construction as well as improvements to the energy efficiency of new construction, and building retrofits, that are aligned with the policy actions and targets identified in the provincial energy plan.

In addition to results for the reference scenario, alternative demand scenarios are developed to provide some indication of the sensitivity of the demand forecasts to changes in the assumptions of the reference scenario. The scenarios are referred to as the "Competitive Gas" and "Competitive Electricity" scenarios.

The scenarios are based on changes to the residential and small commercial demand resulting from changes in the penetration of natural gas as the fuel for space and water heating applications in response to the perceptions of customers regarding GHG emissions of natural gas and the relative cost advantage of natural gas over electricity, driven in part through changes to the carbon tax as well as eventual federal and provincial regulations mandating a blend of RNG in natural gas deliveries to end-use customers. The scenarios also reflect varying degrees to which the provincial targets for improved energy efficiency in existing and new construction are met.

The underlying growth in households and small commercial enterprises remains the same in all scenarios, while the capture rates are adjusted to reflect varying degrees of probability that these new households and commercial enterprises become customers of the company.

5. Forecast Period and Update Frequency

The company prepares a 20-year demand forecast and updates its long-term forecast when it files its resource plan. The company expects to file its resource plan with the regulator every five years.

The company prepares a forecast for each year during the forecast period.

6. Forecast Evaluation

The company does not explicitly evaluate the performance of its long-term forecast model by using the actual number of customers in the model and adjusting for different assumptions used in the model, however, it does compare actual annual demand to forecasted annual demand. It has found that the forecasts are reasonable and there are no significant variations.

7. Forecast Resources

The company uses internal resources, which are estimated at approximately one third of an FTE, to develop its long-term forecast.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company determines the design day demand for each of its customer segments based on a mathematical relationship between ambient air temperature and gas consumption that has been determined empirically from historical weather and billed consumption data. The design day demand of residential customers is calculated using the residential end-use model and multiplied by the number of customers forecasted. The design day demand for small and large commercial, and small industrial customers is determined from third- and first-order linear regressions, respectively, of their historical billing and weather data.

As a final step in forecasting peak-day demand, the company sums up the peak-day demand for each customer class to forecast the peak-day demand for the system.

The company used a 50-year period in determining the design day demand.

L. Organization L

1. Overview

The company is an investor owned utility that serves approximately 340,000 electric and 300,000 natural gas customers across 30,000 square miles in four northwestern states.

The company's annual natural gas demand forecasts are developed as part of its IRP. The company develops an annual demand forecast and a peak-day demand forecast.

The company's recent usage data indicated that long-term use per customer has been declining. The company attributes this to a confluence of factors including high unemployment, increased investments in energy efficiency measures, building code improvements, behavioral changes, and heightened focus on consumers managing their household budgets.

2. Forecasting Method

The company currently uses an econometric model to forecast its annual energy demand by rate class. The company sees many benefits in using and end-use forecasting model and is considering an end-use model to forecast its annual energy demand in the future. However, it believes an end-use forecasting model to be more data intensive and costly as the company would have to upgrade their systems. However, the company is currently implementing AMI, which may help in collecting better end-use data.

The company uses the IRP process to develop an annual demand forecast and a peak-day demand forecast. Annual average demand forecasts are used for preparing revenue budgets, developing natural gas procurement plans, and preparing purchased gas adjustment filings. Peak-day demand forecasts are critical for determining the adequacy of existing resources or the timing for acquiring new resources to meet customers' natural gas needs in extreme weather conditions.

The primary drivers of the company's overall demand forecast are customer growth and use per customer.

The company uses a regression model to forecast its use per customer. This produces a reliable forecast because of the high correlation between usage and temperature.

The company also uses 20-year DSM resource forecasts to identify cost-effective savings potential, which are used to reduce demand forecast over the forecast period.

The company forecasts the number of customers for each customer class using national economic forecasts and then drills down into regional economies. The company combines this data with local knowledge about sub-regional construction activity, age and other demographic trends, and historical data to develop its 20-year customer forecasts.

The company forecasts its use per customer using regression modeling. The company develops base and weather sensitive demand coefficients that are combined and applied to HDD weather parameters to determine average use per customer.

The company uses historical daily gas flow data from all of its city gate stations. It uses city gate data over revenue data because of the high correlation between weather and demand. The company's revenue system does not capture daily data; therefore, it could not be used in the daily regression modeling. The company, however, reconciles city gate station data against revenue data to ensure the total demand is properly captured. The company uses three years of historical data in its regression modeling and to derive the use per customer coefficients. The regression modeling is performed for each of the company's service territories and temperature zones.

The company analyzes an alternate planning scenario using the coldest temperature in the last 20 years.

As a final step, the company checks the reasonableness of its coefficient by applying the coefficients to actual customer count and weather data to backcast demand. This compares to actual demand with satisfactory results.

Figure 8 below illustrates the company's method in developing its forecast.

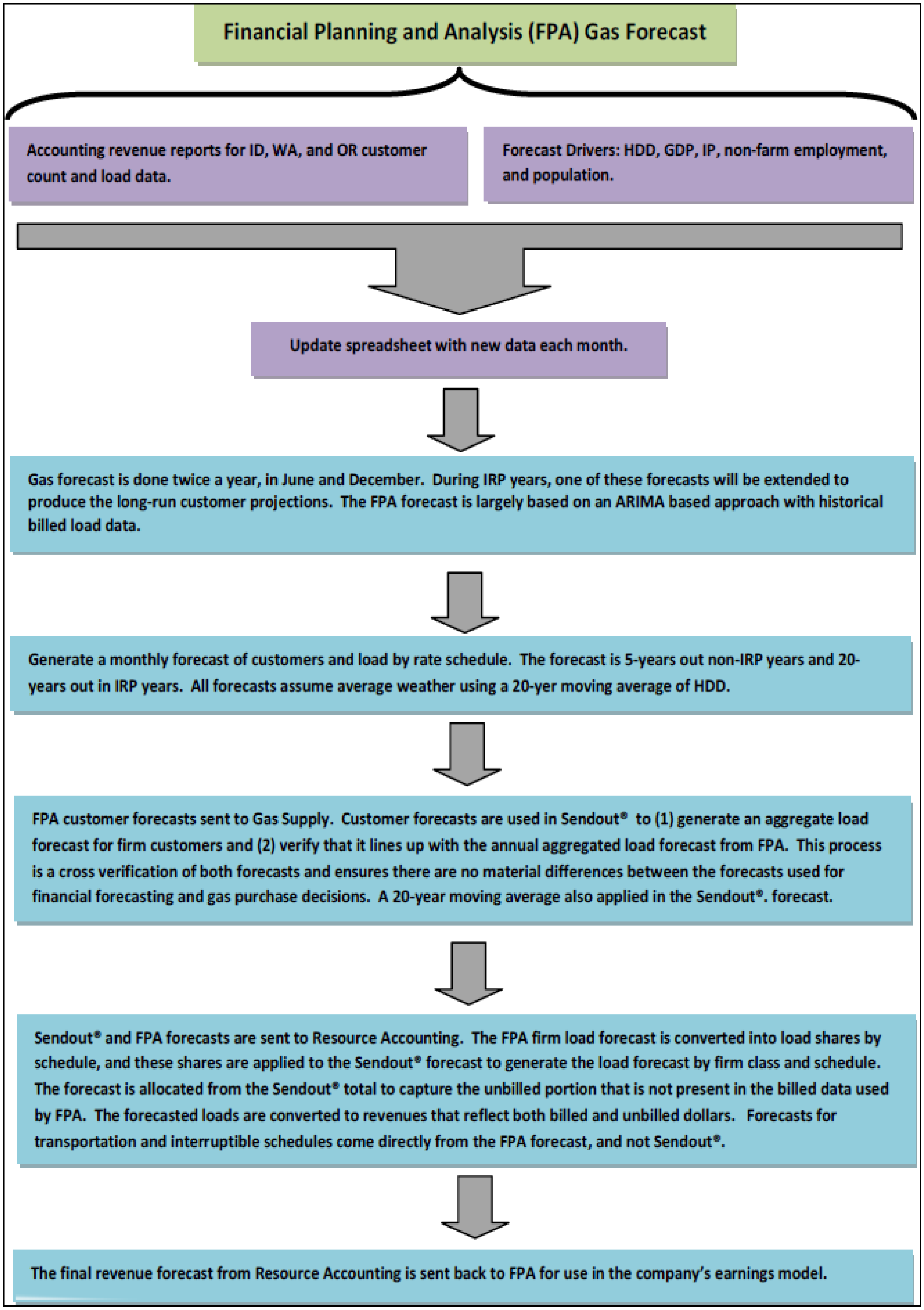


Figure 8. Forecasting Method

3. Forecasting Parameters

The company's econometric model incorporates national economic forecasts and drills down to regional economies. The model uses a number of parameters, which include US GDP growth, national and regional employment growth, and regional population growth expectations. The company combines this data with local knowledge about sub-regional construction activity, age and other demographic trends, and historical data to develop the 20-year forecast of the number of customers rate class.

Weather is the most significant factor influencing demand. Other factors that the company uses include population, employment trends, age and income demographics, construction trends, conservation technology, new uses (e.g. natural gas vehicles), and use-per-customer trends.

The company also analyzes factors that could influence natural gas prices and demand through price elasticity, as customers may adjust consumption in response to changes in price. These include, supply trends, infrastructure trends, regulatory trends, and other trends.

4. Forecast Scenarios

The company recognizes that historical energy use trends may fundamentally change. The company developed a dynamic demand forecasting model that is flexible to changing assumptions. This helps the company examine a range of potential outcomes, such as:

- Identifying key demand drivers behind natural gas consumption;
- Performing sensitivity analysis on each demand driver;
- Combining demand drivers under various scenarios to develop alternative potential outcomes for forecasted demand; and
- Matching demand scenarios with supply scenarios to identify unserved demand.

The company uses a reference case based on historical data and conducts sensitivity analysis on key demand drivers. The company uses this information and input from a technical advisory committee to create several alternate demand scenarios for detailed analysis.

The company groups the demand drivers into two categories:

- Demand Influencing Factors, which directly influence natural gas consumption of core customers.
- Price Influencing Factors, which indirectly influence natural gas consumption of core customers through a price elasticity response.

The company analyzed five demand sensitivities to determine the results relative to the reference case. These include the base case, high price case, low price case, high growth case, and low growth case.

5. Forecast Period and Update Frequency

The company prepares a 20-year annual natural gas demand forecast, which it updates every two years as part of its IRP. It prepares a forecast for each year during the forecast period.

6. Forecast Evaluation

The company evaluates its forecast as a step in its forecasting process, the company checks the reasonableness of the coefficients from its regression model by applying the coefficients to actual customer count and weather data to backcast demand. This compares to actual demand with satisfactory results.

7. Forecast Resources

The company uses SENDOUT for forecasting. The software was purchased and the company has an annual maintenance contract with the vendor, which provides some consulting service. The company uses internal 3 FTE resources to prepare its forecast.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company uses the same model to forecast its peak-day demand forecast and its annual demand forecast. It uses peak-day weather data to forecast its peak-day demand and average annual weather to forecast its annual demand forecast.

M. Organization M

1. Overview

The company serves more than 294,000 customers in 96 communities in two states in Northwest US.

The company developed its latest long-term natural gas demand forecast as part of its 2018 IRP. The company uses an econometric model to develop its demand forecast.

Residential and commercial load growth is primarily a result of increased customer counts.

The forecast is used in short-term (annual budgeting) and long-term (distribution and integrated resource planning) planning processes.

2. Forecasting Method

The company uses an econometric, dynamic, multi-variable, time-series regression model to develop its demand forecast.

The company has made a slight change to its forecasting methodology this year by using a dynamic regression approach to modeling. Dynamic regression is simply an ARIMA term in a standard regression model. The company is also using wind as a predictor for usage, and therefore a coefficient for the demand forecast formula. The company uses statistical analysis software programs R and SAS Analytics. It also uses models that follow a dynamic regression methodology. The company plans to continue improving the customer and demand forecast model through R and SAS.

The company starts demand forecasting process by looking at each city-gate serving firm service. These city-gates are then assigned a weather zone because a significant portion of the company’s customer demand is weather sensitive.

The company forecasts its total annual demand by forecasting its use per customer and number of customers by city gate station and for each rate class. It then multiplies the forecasted use per customer by the forecasted number of customers to determine its annual demand forecast. Figure 9. illustrates an overview of the demand forecasting process.

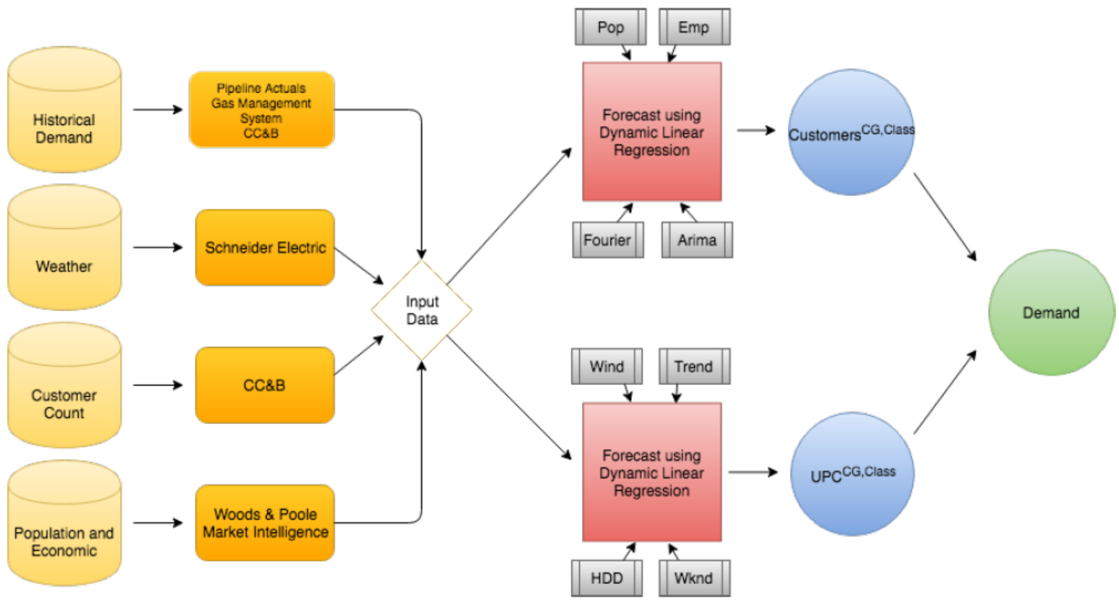


Figure 9. Demand Forecast Process Overview

Customer Growth

Customer count forecasts are designed to reflect both demographic trends and economic conditions both in the short- and long-term. The company uses population and employment growth data at the county level. The data is adjusted when the internal intelligence about a demand area indicates a significant difference on observed economic trends. The company utilizes dynamic regression models for the customer count forecast. Figure 10. illustrates how the company forecasts its number of customers.

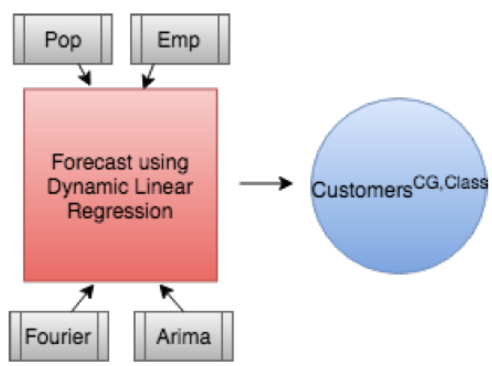


Figure 10. Customer Growth

Use-Per-Customer Forecast Methodology

The company utilizes regression models for the use per customer part of the demand forecast. Sources for the inputs into this model are pipeline actuals, the company's gas management system, and its customer care and billing system. The company develops the use per customer coefficient by gathering historical daily pipeline demand data. The pipeline demand data includes core and non-core usage. The non-core data is backed out using the company's measurement data. The daily data is then allocated to a rate schedule for each city gate by using the customer care and billing system. This data is then divided by number of customers to come up with the use per customer for each day and for each rate schedule at each city gate. Figure 11. illustrates how the company forecasts its use per customer.

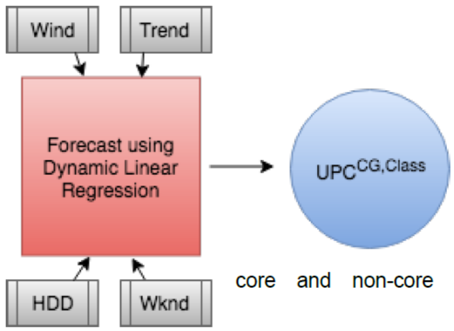


Figure 11. Use Per Customer

The results of the customers count and energy use per customer models are then used to determine the annual gas demand by customer class and district.

These forecasts exclude any saving that may result from the company's energy efficiency programs. The company's energy efficiency and conservation group reviews the forecast and adjusts these forecasts based on the forecasted energy savings from their energy efficiency programs.

The company uses the same model for short term and long-term forecasting.

3. Forecasting Parameters

The company's dynamic regression forecasting model uses a number of parameters. These parameters include a number of econometric parameters such as employment forecast, forecasted number of households, mortgage rates for residential customers, and prime rate for commercial and industrial customers to forecast the number of customers by rate class.

The model uses the forecasted median household income, HDD, and natural gas prices to forecast the average use per customer. The company recently introduced wind data into its forecasting model.

These indicators are used over other indicators as they are the most consistent in returning statistically valid results.

4. Forecast Scenarios

The company stress tests its forecasted annual demand results with high and low scenarios for varying future economic conditions.

These alternative forecasting assumptions refer to changing factors that influence demand. Alternative assumptions include high and low customer growth and a stochastic study of weather using Monte Carlo simulations. These assumptions provide an effective tool for analyzing and stress testing the forecasts. Table 10 shows these scenarios.

Table 10. Growth and Weather Scenarios

Scenario	Weather	Growth	Use per Customer
Base Case	Expected	Expected	Expected
Low Growth	Expected	Low	Expected
Low Growth Stochastic	Monet Carlo Weather	Low	Expected
High Growth	Expected	High	Expected
high Growth Stochastic	Monet Carlo Weather	High	Expected

5. Forecast Period and Update Frequency

The company develops a 20-year forecast of customers, annual demand, and peak-day demand for each year during the forecast period.

The company develops a 20-year forecast of customers, annual demand, and peak-day requirements for use in short (annual budgeting) and long-term (distribution and integrated resource planning) planning processes each year. Updates to the forecasts may be prepared three to four times per year for use in annual budgets, rate cases, and IRP filings. IRPs are prepared every two years.

6. Forecast Evaluation

The company evaluates its forecasting model by using actual weather conditions and actual number of customers in the model and comparing the results to previous forecasts. The company checks its forecast against actual demand and investigates its forecast if there is a variance of +/- 5%. The model has performed well overall.

7. Forecast Resources

The forecasts are prepared internally by the forecasting department which obtains economic forecast reports from external sources and also consults with other consultants as needed.

One person in the forecasting department maintains the models, while others in the energy efficiency and conservation department update the forecast prepared by the forecasting department to reflect impact of energy efficiency programs.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company develops peak-day forecasts in conjunction with its annual demand forecasts to ensure it can meet the demand by its core customers on the coldest days.

The company develops a normal, or expected, future weather year by shaping 30 years of proprietary, historical weather data. HDD values are assigned to each day in the model weather year. To ensure the company will be able to serve its firm customers during extreme weather, the company tests a system weighted peak HDD (the system weighted coldest day in the last 30 years).

The peak-day forecast is developed by adjusting the energy use on the coldest day in in annual demand forecast upwards using the HDD for the coldest day in the past 30 years.

This method assumes that core market load shape does not significantly change throughout the forecast period.

N. Organization N

1. Overview

The company serves more than 750,000 homes and businesses in 140 communities in Northwest US.

The company uses an econometric forecasting model to forecast its annual demand by region and customer class.

The company has used end-use forecasting for some specific studies such as a decarbonization study and a demand response study for its upcoming IRP. While the company's econometric forecasting model has historically performed well, with regulations pushing for decarbonization and direct response programs, which require the company to analyse numerous demand scenarios, the company believes end-use forecasting models are more relevant and the company is considering end-use forecasting models.

2. Forecasting Method

The company uses an econometric forecasting model to forecast its annual demand by region and customer class. It forecasts the total annual demand for residential and commercial customers by multiplying the customer count and annual use per customer. The company's demand forecast process is illustrated in Figure 12.

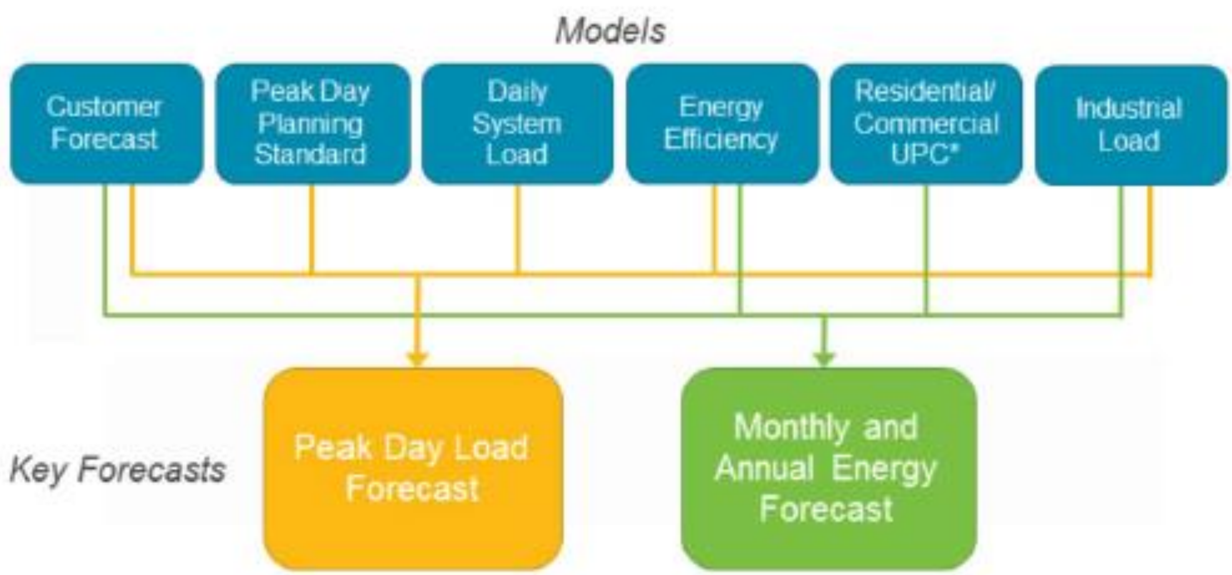


Figure 12. Demand Forecast Process

Customer Forecast

The customer forecast is the starting point of the company's load forecasting and is a key input into both the peak load forecast and the annual energy demand forecast. Customer growth is a primary driver of additional demand—both annually and peak.

The company develops separate customer count forecasts for residential and firm sales commercial customers for each state, as the differs in average annual use and load factor. The company does not forecast the number of industrial customers due to the extreme range of usage levels by these customers.

The company uses annual data in its forecasting model. The company assesses econometric models with alternative autoregressive integrated moving average structures for each forecast. Generally, selecting the structure with the best information. The company also evaluates multiple potential explanatory variables for each customer forecast. These include transformations of values, such as moving averages, leads/lags, and combinations of each.

The company forecasts its number of customers by directly forecasting year-end values of customers directly at the state level.

Use Per Customer Forecast

The company forecasts the annual weather-normalized use per customer for residential and commercial customer classes using billing data, temperature history, and energy efficiency savings projections.

Prior to the 2016 IRP, residential and commercial coefficients along with the industrial demand were used directly to estimate the highest firm sales demand day requirements. In the 2016 IRP, the company transitioned from using the UPC coefficients to using a daily system model to estimate the peak day demand needs. In its latest IRP and the 2016 IRP, UPC has a smaller role in determining system resource needs but is still necessary to forecast total energy demand.

The company forecast its UPC at the state level for the following customer groups:

1) Residential existing customers (current customer base)
2) Residential conversion customers (existing building stock fuel switching)
3) Residential new construction (newly build single and multifamily housing)
4) Commercial existing customers (current customer base)
5) Commercial conversion customers (existing building stock fuel switching)
6) Commercial new construction (newly constructed commercial buildings)

The company applies the forecasted annual energy savings from DSM programs by adjusting the annual usage coefficients such that the reductions match the projected savings for the DSM programs.

The company forecasts the annual demand for its large industrial customers by each customer.

The company has used end-use forecasting for some specific studies such as a decarbonization study and a demand response study for its upcoming IRP. While the company's econometric forecasting model has historically performed well, with regulations pushing for decarbonization and direct response programs, which require the company to analyse various demand scenarios, the company believes end-use forecasting models are more relevant and the company is considering end-use forecasting models.

3. Forecasting Parameters

The company uses some exogenous variables in its econometric customer forecast models. These exogenous variables include housing starts for the residential sector and population growth and non-farm employment for the commercial sector.

The customer forecast is a blend of two different types of forecasts; those developed using econometric methods and those developed using a panel of internal subject matter experts.

An external resource was the source of the forecast value for the exogenous variable used in each of the four customer forecast econometric models used in the 2018 IRP. Because the external resource provides forecasts of US housing starts and of the state's nonfarm employment for 10 years ahead, the company used the long-term forecast of the state's population from the external resource to project US housing starts and the state's nonfarm employment beyond 2027.

4. Forecast Scenarios

The company develops a base case forecast plus high customer count and low customer count cases. The company also analyzes weather uncertainty, gas price uncertainty, cost of compliance uncertainty, and resource costs uncertainty in its stochastic analysis.

The company also develops four additional scenarios based on high and low runs of two separate drivers: carbon policy and deployment ramp rates. These alternative scenarios are shown in Table 11. Scenarios 1 and 2 are based on changes to avoided costs under different carbon policy pricing scenarios. Scenarios 3 and 4 are based on changing deployment ramp rates, both an accelerated and a decelerated case.

Table 11. Additional Alternative Forecast Scenarios

Scenario	Description
Scenario 1	Base Case Ramp Rates / Low CO_2 Carbon Policy Adder Avoided Costs
Scenario 2	Base Case Ramp Rates / High CO_2 Carbon Policy Adder Avoided Costs
Scenario 3	Low Ramp Rates / Reference Case Avoided Costs
Scenario 4	High Ramp Rates / Reference Case Avoided Costs

These scenarios are meant to represent what may be seen on the company's system if savings are achieved faster or slower than the base case, which could be for a wide array of reasons and could be considered 'uncertainty bounds'.

5. Forecast Period and Update Frequency

The company prepares a 20-year annual demand forecast for every year during the forecast period. The company updates the customer count in the forecast annually, while it updates the full forecast every two years as of its IRP.

6. Forecast Evaluation

The company evaluates its forecast for each type of customer using the ARIMA structure selected for that forecast by comparing metrics associated with the errors of out-of-sample forecasts. The company uses three criteria to evaluate these alternative out-of-sample forecasts: MAPE, average error, and RMSE.

The company evaluated four different approaches to forecasting the number of customers. It evaluated its forecasted number of customers using the "levels" and the "components" approach at the state level and load centre level using MAPE, average error, and RMSE. The company refers to the approach in which levels of customers are directly forecast as the "levels" approach and the approach in which components of customer change are forecast as the "components" approach. The company used the "components" approach in recent IRPs, where the components are customer additions due to new construction and customer additions due to conversion from other fuel types, as well as customer "losses."

7. Forecast Resources

The company's forecasts are prepared internally by the forecasting department which includes four economists and one data scientist. The company's forecasting model was also developed internally.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company uses a multi-variable regression model to forecast its peak-day demand forecast for supply and capacity planning. This model uses the same number of customers as the annual demand forecast model. It uses many more variables than the annual demand forecast model. Some of these variables, which are not used in the annual demand forecast include wind, rain, and day of the week.

O. Organization O

1. Overview

The company is an investor owned utility. It serves aapproximately 1.1 million electric and 840,000 natural gas customers with a service territory of approximately 6,000 square miles with a population of approximately 4 million.

The company uses an econometric regression model to forecast its annual demand by rate class and service area.

2. Forecasting Method

The company uses an econometric regression model to forecast its annual demand for both natural gas and electricity by rate class and service area. The rate classes include residential, commercial, and industrial rate classes.

The company forecasts its total annual demand forecast by multiplying the forecasted number of customers in each rate class by the average use per customer for that rate class.

The company's forecasting model produces a forecast based on the historic relationship between energy demand and weather and economic growth.

The company forecasts its use per customer and customer count using econometric equations using sample dates from a historical monthly data series that extends from January 1990 to December 2015; the sample dates vary depending on sector or class. Use per customer is forecast monthly at a class level using several explanatory variables including weather, retail rates, monthly effects, and various economic and demographic variables such as income, household size and employment levels. Some of the variables, such as retail rates and economic variables, are added to the equation in a lagged or polynomial lagged form to account for both short-term and long-term effects of changes in these variables on energy consumption. Finally, depending on the equation, an ARIMA structure is imposed to acknowledge that future values of the predicted variables could be a function of its lag value or the lags of forecast errors.

Similar to use per customer, the company forecasts the customer count equations on a class level using several explanatory variables such as household population, building permits, total employment, or manufacturing employment. Some of the variables are also implemented in a lagged or polynomial distributed lag form to allow the impact of the variable to vary with time. Many of the customer equations use monthly customer growth as the dependent variable, rather than totals, to more accurately measure the impact of economic and demographic variables on growth, and to allow the forecast to grow from the last recorded actual value. ARIMA could also be imposed on certain customer counts equations.

While the company, currently, only prepares a forecast by rate class, it may in the future break down its forecast by subsectors within the broader residential and commercial sectors.

The company is considering moving to an end-use forecasting model because it believes an end-use model is better suited to help with changes in energy policy such as decarbonization. The company is currently running an end-use forecasting model in parallel with its econometric forecasting model to test the reliability and accuracy of the end-use model, but is not ready to move to an end-use model yet.

3. Forecasting Parameters

The company's forecast is based on estimated econometric equations, normal weather assumptions, rate forecasts, and forecasts of various economic and demographic inputs such as income, household size and employment levels.

4. Forecast Scenarios

The company prepares its forecast to model a range of potential economic conditions, weather conditions and potential modeling errors for its IRP analysis. The company also prepares low and high forecasts in addition to the base forecast. The low forecast models lower population and economic growth compared to the base forecast; the high forecast models higher population and economic growth compared to the base forecast. The high and low forecasts are performed using stochastic analysis of the variables.

While the company does not run multiple scenarios, it expects that it will be running many more scenarios in the future to analyse the impact of electrification and other energy policies. The company expects that the end-use model will allow them to analyse multiple scenarios.

5. Forecast Period and Update Frequency

The company prepares a 20-year annual demand forecast for every year during the forecast period. The company updates its forecast every year and files it every two years as part of its IRP filing.

6. Forecast Evaluation

The company evaluates its forecast for each type of customer by comparing its forecast against normalized actual demand.

7. Forecast Resources

The company's econometric forecasting model is run internally with approximately 2 FTEs.

The company's end-use forecasting model is Itron's SAE model. The company's forecasting staff are being trained to run and maintain the model and will be running the model once it is fully implemented. Once the company switches over to the end-use model, it may need additional forecasting resources because of the data requirements of the end-use model.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company's peak-day demand forecast and its annual demand forecast are related. The company uses its annual demand forecast as the starting point for its peak-day demand forecast and applies load shapes for various customer classes to forecast its peak-day demand.

P. Organization P

1. Overview

The company serves more than 1 million natural gas customers in three states.

The company uses statistical methods to forecast its annual natural gas demand in the residential sector. It also studies natural gas consumption for the residential sector by end-use.

2. Forecasting Method

The company uses several statistical methods to analyze and forecast residential gas demand. These methods include univariate and multivariate time series modeling of demand and such explanatory variables as demand history, customer growth and commodity price. The company uses SAS STAT 14.1 and SAS Enterprise Time Series 14.1 software tools for the statistical time series modeling.

The company also studies residential consumption by end-use such as space heating, water heating and cooking with respect to dwelling size, region, appliance efficiencies, and other such variables. This end-use analysis makes extensive use of data collected by the company's energy efficiency experts as they conduct in-home energy audits through the company's energy efficiency programs as well as data from the US EIA and US Census Bureau.

3. Forecasting Parameters

The company's forecasting model uses a number of parameters, which include population growth, personal income growth, employment levels, and housing starts.

4. Forecast Scenarios

The company only provides a base case forecast scenario in its IRP.

5. Forecast Period and Update Frequency

The company prepares a 10-year annual natural gas demand forecast, which it updates every two years as part of its IRP. It prepares a forecast for each year during the forecast period.

6. Forecast Evaluation

This information was not available.

7. Forecast Resources

This information was not available.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company forecasts its peak-day firm customer demand using the coldest design day. Heating degree days, wind speed, the day of the week, and prior-day demand are significant factors in the prediction of daily demand during the winter heating season.

Q. Organization Q

1. Overview

The company serves more than 500,000 natural gas customers in the US Northeast.

The company uses an Excel based econometric model with some consideration for end-use to forecast its annual gas demand by rate class. The forecast is used primarily for revenue forecasting.

2. Forecasting Method

The company uses an Excel based econometric model with some consideration for end-use to forecast its annual gas demand by rate class. The company has used its forecasting model for many years.

It uses an econometric model to forecast the number of customers and the number of customer additions.

The company forecasts its user per customer based on historic energy use data. It further adjusts its use per customer forecast based on its experience and knowledge of its market and customers, particularly for its large industrial customers. The company uses some elements of end-use modeling to forecast its residential use per customer; its residential use per customer is built by forecasting use per customer for customer groups with different end uses. For example, it may forecast annual use per customer for customers with natural gas space heating, customers with natural gas space and water heating, and customers with natural gas space, water, and pool heating. The company forecasts its use per customer for its large industrial customers for each customer and breaks in down into baseload and space heating load.

The total annual demand is forecasted by multiplying the forecasted use customer by rate class by the forecasted number of customers in that rate class.

3. Forecasting Parameters

The company's forecasting model uses historic user per customer data.

The company does not account for energy efficiency and building code changes in its forecast.

4. Forecast Scenarios

The company does not run multiple forecast scenarios because its user per customer is relatively stable. If there is a significant event that impacts their forecast It may run alternative scenarios.

5. Forecast Period and Update Frequency

The company develops a five-year forecast of the number of customers and annual demand for each year during the forecast period to coincide with its five-year business plan cycle. It updates its annual demand forecast annually and its customer count quarterly.

6. Forecast Evaluation

The company evaluates its forecasting model by comparing its forecast to actual energy use in the first few years of the forecast period.

7. Forecast Resources

The forecasts are prepared internally by the forecasting department with two FTEs.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company does not focus on peak demand forecast because it does not impact its revenue forecast.

R. Organization R

1. Overview

The company is the state's largest customer-owned utility. It provides water and electricity service to its customers. As a public utility, it does not operate to earn a profit or to serve the investment needs of stockholders. Instead, it is chartered by the city to serve the interests of its citizens.

The company uses a combination of end-use and econometric forecasting model. Historically, the company only used an econometric forecasting model, but because of the increasing disconnect between the economy and annual energy demand, it has started using an end-use model and will be moving to complete end-use modelling in the near future. The end-use model allows the company to better analyse the impact of various policy changes such as electrification on their load forecast.

2. Forecasting Method

The company uses a combination of end-use and econometric forecasting model.

Historically, the company only used an econometric forecasting model, but because of the increasing disconnect between the economy and annual energy demand, it has started using an end-use model and will be moving to complete end-use modelling in the near future.

The company's forecasting model was developed by a consultant who developed a similar model for the regional power administrator, which markets wholesale electrical power in the region. This allows the company to have connectivity to the regional forecast data.

The company's forecasting model is composed of approximately eight spreadsheets with a detailed database of end-uses for residential, commercial, and industrial sectors. The forecasts are developed by subsector, which are then rolled up to the three major sectors, residential, commercial, and industrial.

3. Forecasting Parameters

The company's forecasting model uses a number of parameters.

For the residential sectors, these parameters include fuel share (gas vs. electric), market saturation levels for different end-uses, building vintage, and equipment efficiency. This data is collected by the company's end use survey. The model then applies load shapes for different end-uses to forecast the use per customer. The company uses econometric methods to forecast the number of customers by subsector.

For the commercial sector, the company has energy use intensities by subsector and based on different end-uses. The forecasting model applies energy use intensities for different end-uses and applies these to the building type to build up the energy use intensity for the building.

4. Forecast Scenarios

The company analyses multiple scenarios to assess the impact of policy changes and legislation on their demand. Some of these scenarios include electrification, fuel switching, carbon tax, increased energy efficiency legislation, and evolving technologies.

5. Forecast Period and Update Frequency

The company develops a 20-year forecast of the number of customers and annual demand for every year during the forecast period. It updates its forecast every year.

6. Forecast Evaluation

The company does not have a formal evaluation process of its forecast. It runs multiple scenarios to see the impact of different scenarios on their forecast.

7. Forecast Resources

The company's forecasting model was developed by a consultant who developed a similar model for the regional power administrator, which markets wholesale electrical power in the region. The forecast is prepared by one FTE.

8. Peak-Day Demand Forecast vs. Annual Demand Forecast

The company's annual demand forecasting model builds on hourly demand forecasts. It's peak-day and peak-hour demand forecasts are developed using the same model as the annual demand forecast.

Appendix III. GLOSSARY

AMI – Advanced Metering Infrastructure

ARIMA - Auto Regressive Integrated Moving Average

ASHRAE – American Society of Heating Refrigeration and Air-conditioning Engineers

CBECS – Commercial Building Energy Consumption Survey

CMHC – Canada Mortgage and Housing Corporation

CO_2 – Carbon Dioxide

DSM – Demand Side Management

EIA – Energy Information Administration

EE – Energy Efficiency

EG – Electricity Generation

EIA – Energy Information Administration

EPRI – Electric Power Research Institute

EU – End Use

EUF – End-Use Forecaster

EUI – End Use Intensity

EV – Electrical Vehicle

FTE – Full Time Equivalent

FEU – FortisBC Energy Utilities

GDP – Gross Domestic Product

GHG – Greenhouse Gas

GIRP – Gas Integrated Resource Plan

HDD – Heating Degree Day

HVAC – Heating, Ventilation, and Air Conditioning

IEPR – Integrated Energy Policy Report

IESO – Independent Electricity System Operator

INFORM – Industrial End-Use Forecasting Model

IOU – Investor Owned Utility

IRP – Integrated Resource Plan

LDC – Local Distribution Company

LNG – Liquefied Natural Gas

LTRP – Long Term Resource Plan

LTGRP – Long Term Gas Resource Plan

m^3 – Cubic Metre

MAPE – Mean Absolute Percent Error

MFD – Multifamily Dwelling

MH – Mobile Home

Mscf – Million Standard Cubic Feet

MURB – Multi-Unit Residential Building

NAICS – North American Industry Classification System

NAMGas Model – North American Market Gas-Trade Model

NASA - National Aeronautical and Space Agency

NGV – Natural Gas Vehicle

NOAA – National Oceanic and Atmospheric Administration

NRCan – Natural Resources Canada

OEE – Office of Energy Efficiency

PV – Photovoltaic

RECS – Residential Energy Consumption Survey

REUS – Residential End Use Survey

RMSE – Root Mean Square Error

SAE - Statistically Adjusted End-use

SFD – Single Family Dwelling

TAC – Technical Advisory Committee

UPC – Use Per Customer

UPA – Use Per Account

VS – Vertical Subdivisions

ZNE – Zero Net Energy

Appendix IV. REFERENCES

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Appendix B-3

CRITICAL UNCERTAINTIES AND THEIR FORECAST MODELLING INPUT SETTINGS FOR THE END USE METHOD DEMAND FORECAST SCENARIOS

APPENDIX B-3: CRITICAL UNCERTAINTIES AND THEIR FORECAST MODELLING INPUT SETTINGS FOR THE END USE METHOD DEMAND FORECAST SCENARIOS

1.1 *RESIDENTIAL, COMMERCIAL AND INDUSTRIAL DEMAND CATEGORY*

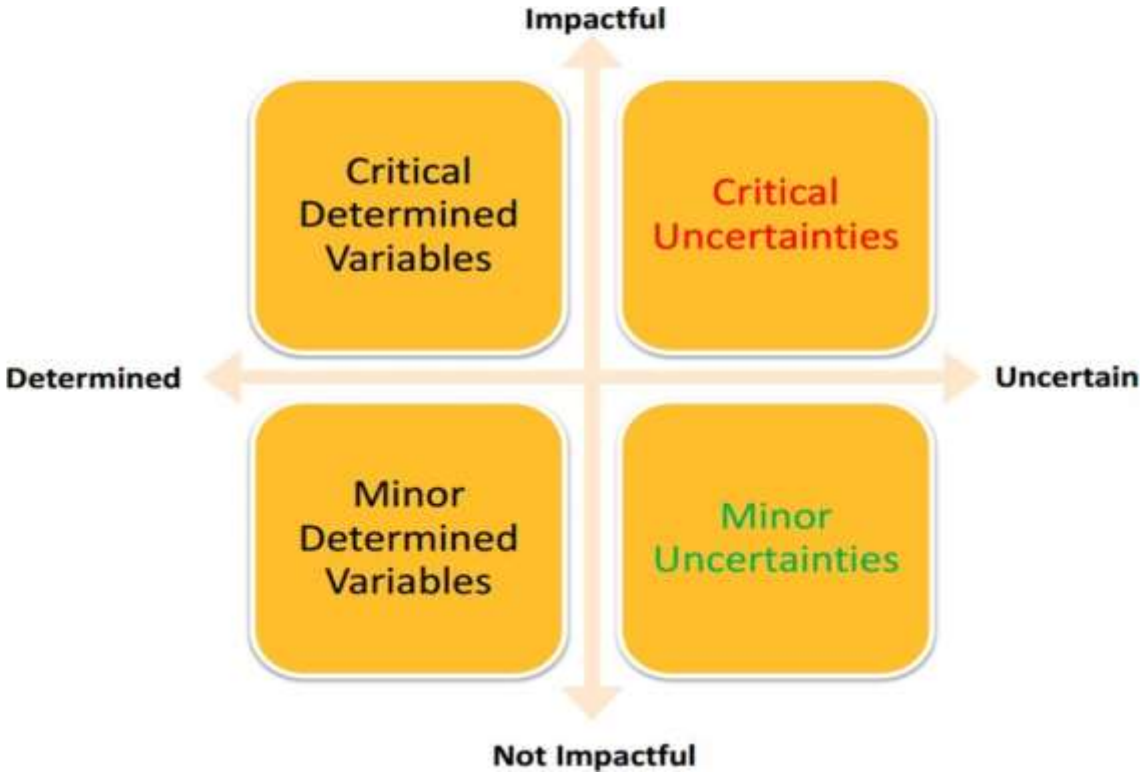
The Reference Case provides a baseline against which forecast demand under six different alternate future scenarios is examined. Since FEI's planning environment for energy services continues to change and present uncertainty, the six future scenarios are intended to provide insight into the impact on demand of a broader range of potential future conditions than has been examined in previous LTGRPs. These six scenarios were developed based on critical uncertainties identified with input from the scenario analysis work for the 2022 LTGRP, both internal FEI stakeholders and members of the external Resource Planning Advisory Group (RPAG), as well as themes that emerged from the 2022 LTGRP's community engagement workshops. The critical uncertainties represent those future conditions that subject matter experts and other stakeholders expect could have the biggest impact on FEI's business.

Following a standard scenario planning approach, FEI's scenario analysis proceeds in four steps:

1. Evaluating planning environment variables and identifying critical uncertainties;
2. Determining the number of outcomes and their broad qualitative boundaries for each selected critical uncertainty;
3. Determining plausible combinations of outcomes for each critical uncertainty and reasonable scenario plotlines; and
4. Populating quantitative data into the outcomes for each critical uncertainty and iterating with internal and external stakeholder feedback.

The first step in the above list intends to focus the scenario analysis by determining which of the manifold variables in the planning environment should be used to alter the Reference Case into various alternate future scenarios. This involves selecting the most impactful and most uncertain variables. Figure B3-1 below illustrates how FEI classified planning environment variables for this first step.

Figure B3-1: Classification of Planning Environment Variables



FEI intentionally held each step separate from the other steps. Selecting critical uncertainties first and then determining their qualitative boundaries before generating the plotlines and populating quantitative data guards against inadvertently favoring certain visions of the future over others by presupposing scenario results rather than focusing on inputs.

The following sections outline the qualitative boundaries of the outcomes of each critical uncertainty, illustrate the actual quantitative trajectories for these outcomes, and discuss how these trajectories impact the end use forecast model.

1.1.1 Qualitative Details on Scenario Critical Uncertainties – Residential, Commercial and Industrial Demand Categories

Table B3-1 below summarizes the outcomes that FEI modelled for each critical uncertainty and briefly discusses any specific attributes that apply to individual critical uncertainties

1 Table B3-1: Summary of Modelled Critical Uncertainty Trajectories for the Residential,
2 Commercial and Industrial Demand Category

Critical Uncertainty	Modelled Trajectories	Comments
Demand-Side Critical Uncertainties – Residential, Commercial and Industrial Demand Category		
Appliance Standards	- Reference - Accelerated	Minimum Energy Performance Standards (MEPS) for energy-using appliances; BC and federal MEPS applicable to the end uses in the LTGRP.
Carbon Price	- Reference - Low - Medium - Planning - High	BC carbon tax applied to natural gas.
Customer Growth	- Reference - Low - High	Number of customer accounts by rate class is forecast by FEI. Confidence intervals based on historical data provide upper/lower settings for scenarios.
Natural Gas Price	- Reference - High - Low	Commodity price for conventionally sourced natural gas relevant to FEI customers.
New Construction Code	- Reference - Accelerated - Delayed	The British Columbia Energy Step Code is the relevant building code for new construction in FEI's service territory. The Step Code energy-requirements were applied to relevant building types and end uses. Code requirements of the City of Vancouver are unique, as the City has its own building code (the Vancouver Building Bylaw) which has more stringent requirements than the provincial code.
Non-Price Driven Fuel Switching	- Moderate electrification - Accelerated electrification - Extensive electrification	Fuel switching caused by signals other than prices such as incentives and policies to encourage customers to switch from natural gas to electricity.
Retrofit Code	- Reference - Accelerated	Estimated impact and timing of a retrofit code based on publicly available information.

The following section discusses the detailed quantitative inputs of each critical uncertainty.

1.1.1.1 Critical Uncertainty Inputs (Quantitative Details) – Residential, Commercial and Industrial Demand Category

1.1.1.1.1 CUSTOMER GROWTH

The 2022 LTGRP provides further analysis to simulate the impact of economic growth on customer counts that relies on a statistical approach using confidence intervals (CI). This approach uses the historical variation in customers to provide high and low uncertainty bands for the BAU customer forecasts. See Appendix B1 for additional information. This statistical method serves as a proxy to model the potential impact of economic growth on customer numbers but may also account for other intrinsic factors, such as FEI marketing and promotional campaigns. Note that rate schedules with fewer customers experience a greater range between their high and low outcomes than larger rate schedules.

Figures B3-2 to B3-6 illustrate the customer number trajectories for key rate schedules.

Figure B3-2: Customer Forecast Parameters – Rate Schedule 1

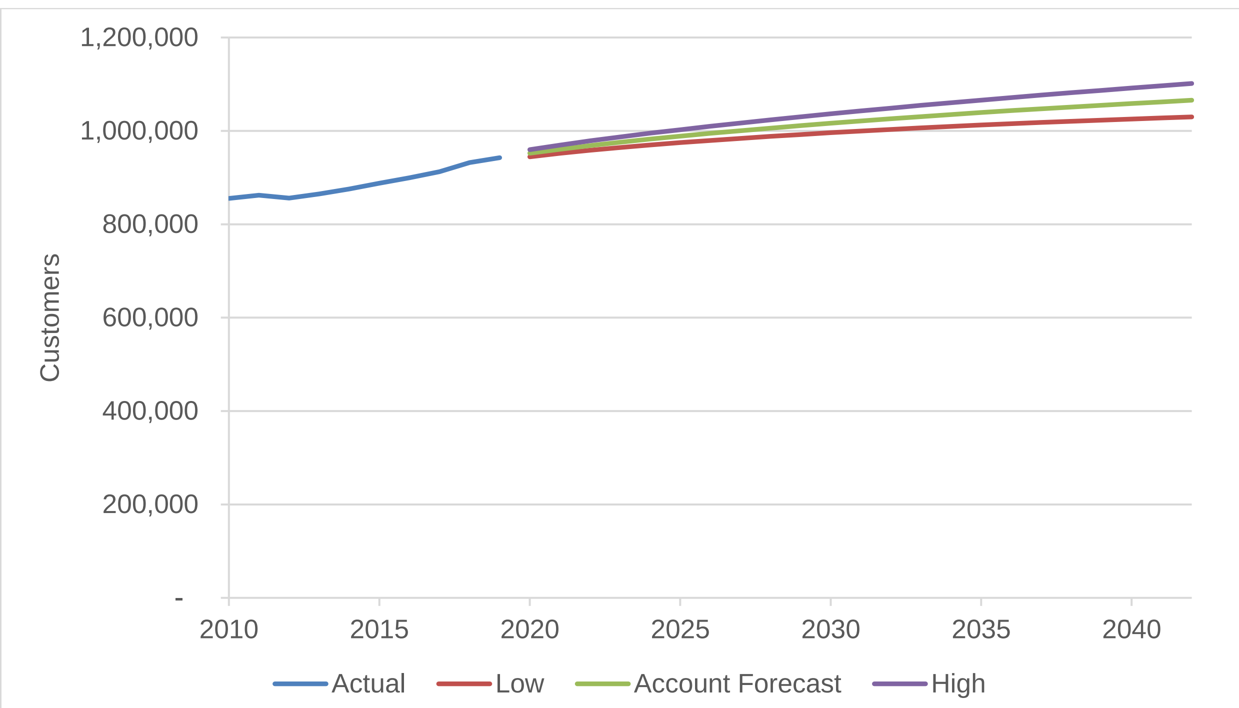


Figure B3-3: Customer Forecast Parameters – Rate Schedule 2

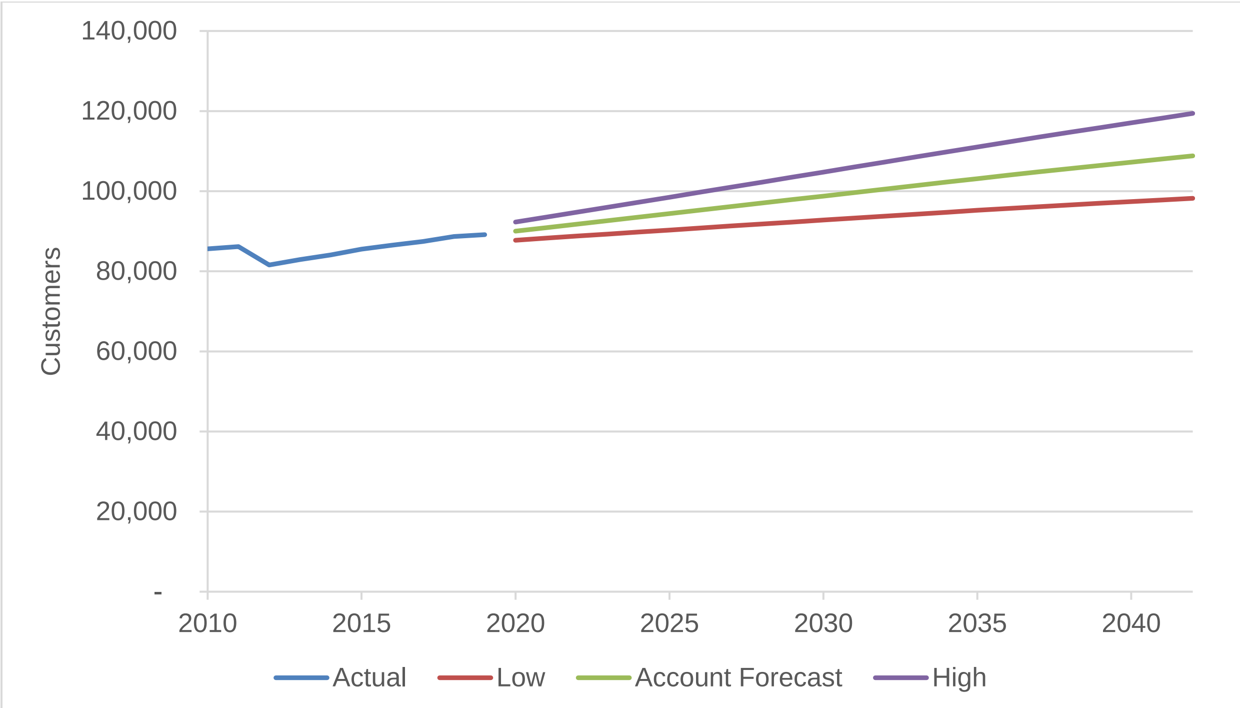


Figure B3-4: Customer Forecast Parameters – Rate Schedule 3

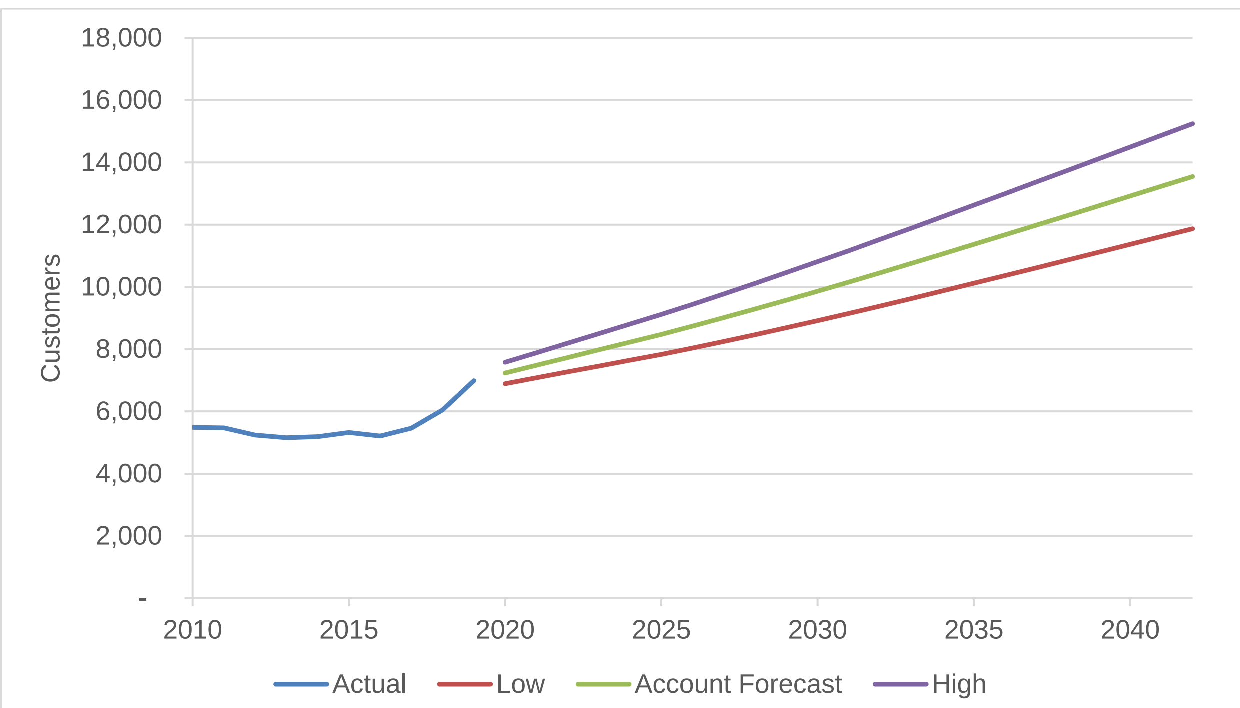


Figure B3-5: Customer Forecast Parameters – Rate Schedule 23

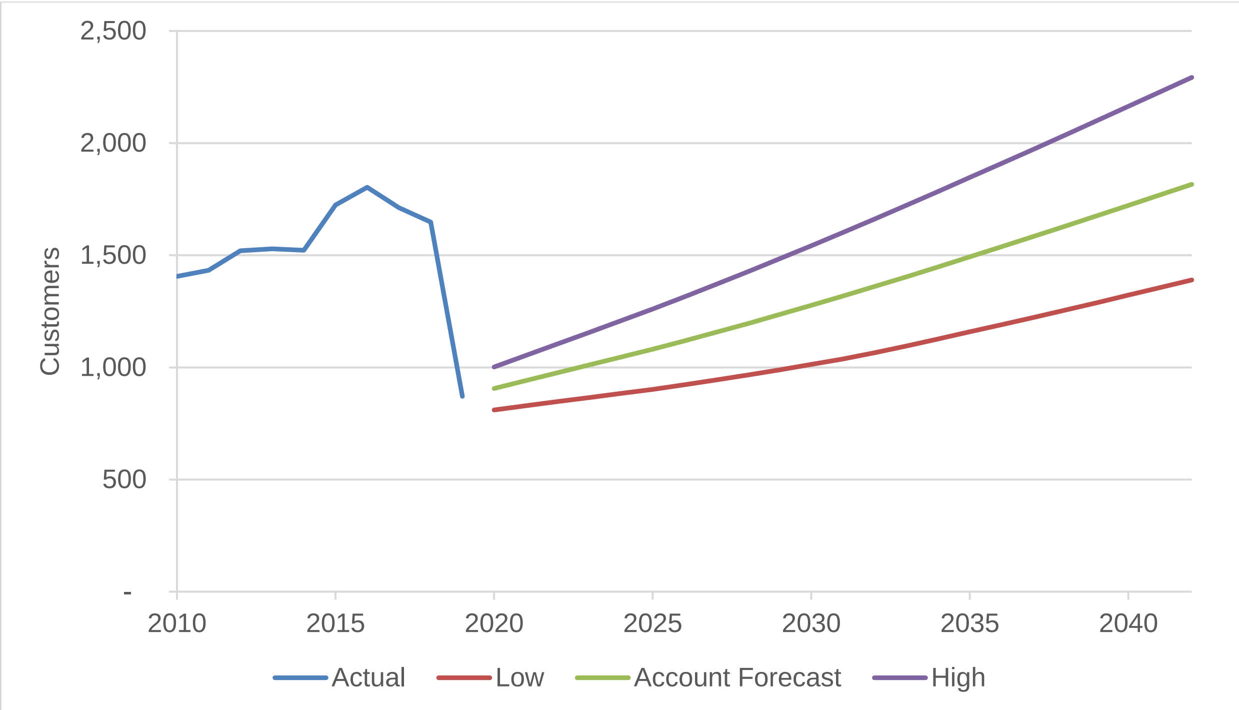
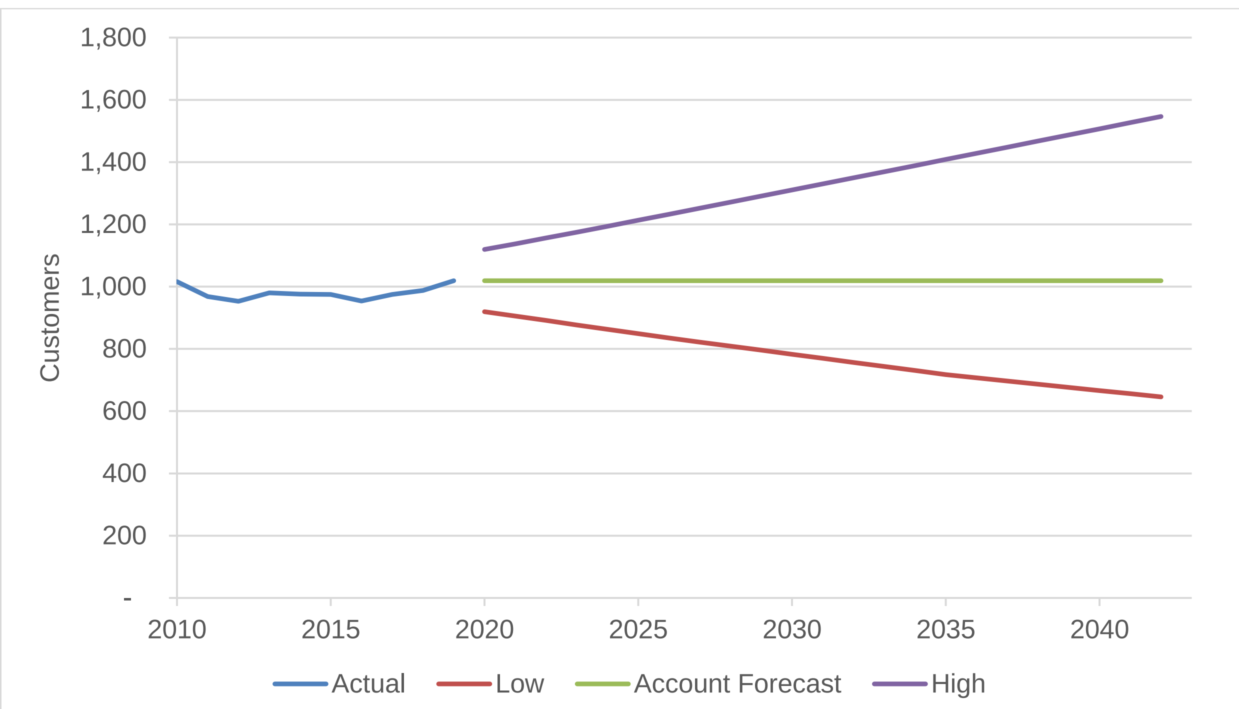


Figure B3-6: Customer Forecast Parameters – Industrial Rate Schedules



1.1.1.1.2 NATURAL GAS PRICE

FEI relied on forecasts from multiple third-party expert entities to prepare the 2022 LTGRP natural gas price forecast trajectories. The Reference Case natural gas price trajectory represents the same reference trajectory that FEI used for the 2021 CPR. FEI selected this trajectory for the 2022 LTGRP in order to facilitate the 2021 CPR results informing FEI's calibration of the 2022 LTGRP DSM analysis.

The natural gas market price forecasts are based on an average of the market price forecasts provided within the Northwest Power and Conservation Council (NPCC) 2021 Eighth Power Plan (2021 Power Plan)[1] and the long-term North American Gas Market Outlook from IHS Markit (IHS), released in February 2021.

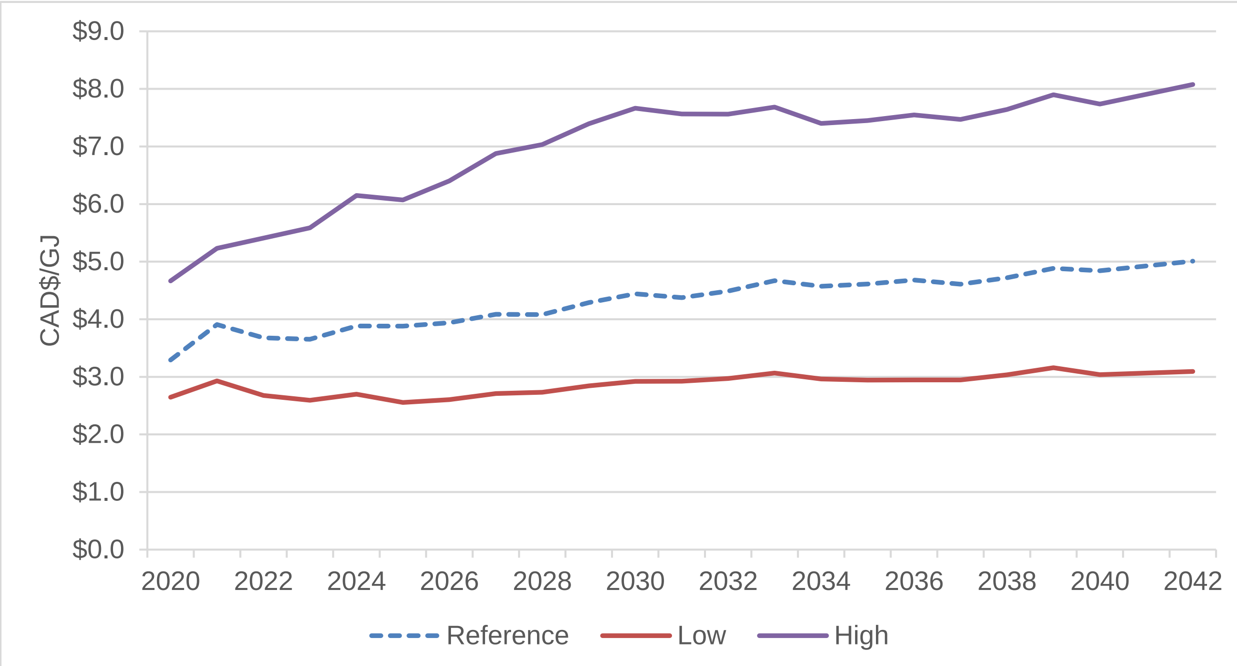
The Reference trajectory is based on expectations for natural gas prices, with prices increasing most years as demand increases due to LNG exports from BC and coal plant retirements in the PNW. The high and low-price trajectories provide reasonable extremes of possible future prices. The high trajectory assumes rapid world economic growth, increasing the demand for natural gas supplies. The low trajectory assumes slow economic growth with reduced demand for natural gas in favour of lower-carbon renewable energy sources.

FEI validated the resulting natural gas price trajectories against a range of existing recent third-party forecasts, including those developed by the International Energy Agency (IEA) and GLJ Petroleum Consultants Ltd. (GLJ).

Figure B3-7 below displays the resulting Reference, High, and Low natural gas price trajectories. The range between High and Low serves as a proxy not only for price changes due to shifting demand-supply conditions, but also potential policy actions that may impact the commodity price, such as upstream GHG reduction initiatives.

[1] https://www.nwcouncil.org/media/filer_public/4b/68/4b681860-f663-4728-987e-7f02cd09ef9c/2021powerplan_2022-3.pdf

Figure B3-7: Setting Options for Natural Gas Price

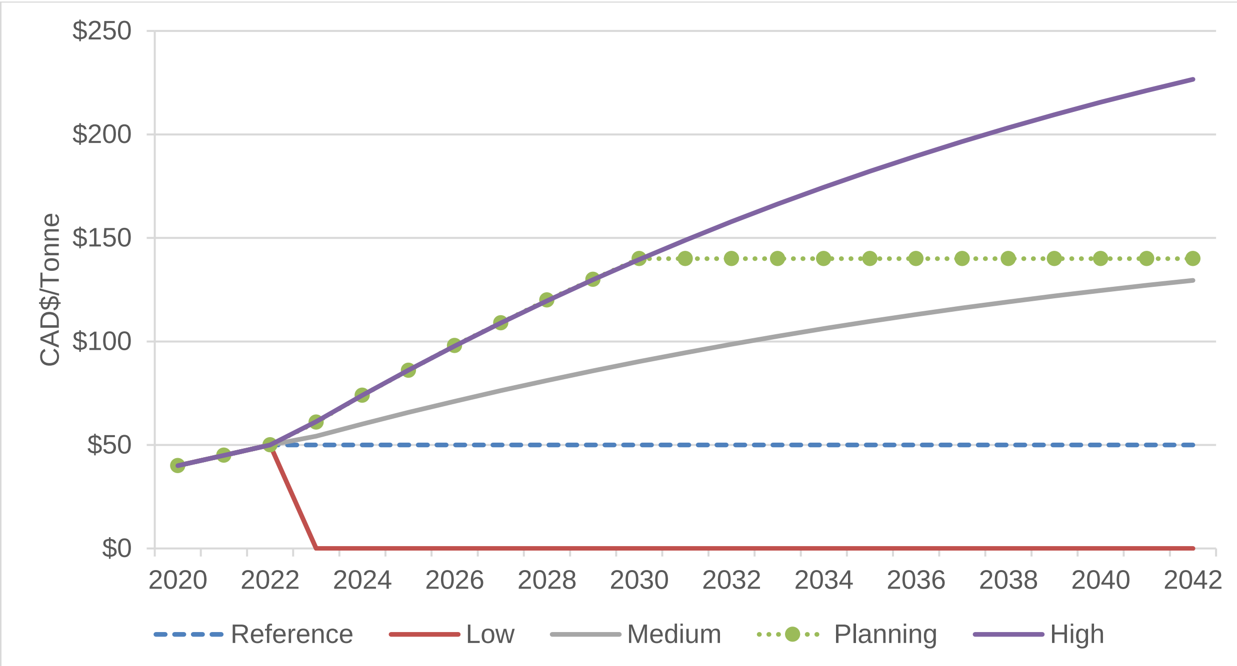


1.1.1.1.3 CARBON PRICE

FEI and FBC collaborated to develop their long-term carbon pricing trajectories by consulting internal and external subject matter experts. The resulting carbon pricing planning trajectory takes into account the Canadian federal carbon pricing backstop mechanism. The trajectories were determined early in the LTGRP planning process and have been validated by the LTGRP RPAG and reviewed by the LTGRP stakeholders (in the RPAG and FEI's community engagement workshops).

Figure B3-8 below displays the 2022 LTGRP's carbon pricing outcomes. The Low trajectory assumes that the carbon tax is removed early in the planning horizon and not replaced by other carbon pricing mechanisms. The Reference trajectory assumes the carbon tax is held constant once the maximum announced value (as of the time the settings were determined) was reached and held constant throughout the planning horizon. The Planning trajectory matches the federal carbon price announcement and grows to $170/tonne in 2030 (in nominal dollars), remaining constant thereafter. The High trajectory maintains this level of annual increase beyond 2030, while the Medium trajectory assumes a lower level of consistent annual increase over the planning horizon. This carbon pricing range intends to account for considerable policy uncertainty in relation to BC provincial, Canadian federal, and wider North American developments (as discussed in Section 2 of the Application).[1]

Figure B3-8: Settings for Carbon Price (2020$ Real)



1.1.1.1.4 CODES & STANDARDS

Codes & Standards accounts for the impact of building codes (for new construction) and retrofit code and appliance standards (for retrofits in existing buildings or appliance installations during new construction) that may prompt customers to switch from gas to another end use fuel type.

New Construction Code

The Reference Case assumptions are based on what was known and enforceable in the market as of 2019.

BC has enacted the BC Energy Step Code, and the provincial Climate Leadership Plan (CLP) declares a goal of net-zero-ready new construction for 2032. The 2022 LTGRP progressively applies two settings in the parametric analysis: accelerated and delayed. These settings are relative to the Reference Case where the accelerated setting contemplates earlier adoption/compliance and the delayed setting contemplates later adoption/compliance.

The 2022 LTGRP scenarios assume a differentiation between the City of Vancouver and all other regions, as the City of Vancouver has adopted by-laws, including its building code and the Vancouver Building Bylaw (VBBL), that are more stringent than those in other municipalities. Table B3-2 below illustrates the assumptions of the settings.

Table B3-2: New Construction Code Settings Assumptions

Setting	Years	Residential Assumptions	Commercial Assumptions
Reference	2020-2042	Step 4 (City of Vancouver)	Step 3 (City of Vancouver)
	2020-2042	Step 3 (all other regions)	Step 2 (all other regions)
Accelerated	2020-2027	Step 4 (City of Vancouver)	Step 3 (City of Vancouver)
	2028-2042	Step 5 (City of Vancouver)	Step 4 (City of Vancouver)
	2020-2027	Step 3 (all other regions)	Step 2 (all other regions)
	2028-2032	Step 4 (all other regions)	Step 3 (all other regions)
	2033-2042	Step 5 (all other regions)	Step 4 (all other regions)
Delayed	For all regions including the City of Vancouver: New buildings perform at discounted rates related to the code-mandated level. Based on industry research of how well BC buildings perform in relation to mandatory new construction performance requirements, the 2017 LTGRP assumed such buildings to perform at 63 and 70 percent of mandated performance, respectively, for residential and commercial buildings. We have applied these de-rated savings to the Reference Case to generate the savings in the delayed case for the 2022 LTGRP.		

Retrofit Code

The 2022 LTGRP applies two settings in the parametric analysis: reference and accelerated. The Reference Case, which is based on known, legally enshrined and mandatory requirements, assumes there would not be an impact for all regions, including the City of Vancouver. Nevertheless, the 2022 LTGRP estimates what the Retrofit Code could look like and when it could be implemented. Based on the research from two documents,[2] the accelerated setting contemplates the Retrofit Code being introduced in 2030, with 1.5 percent of existing buildings each year being retrofitted, so that heat load is reduced by 20 percent for residential customers and 15 percent for commercial customers

Appliance Standards

The Reference Case assumes that the 2019 in-market mandatory or legally enshrined appliance standards continue across the entire forecast period. Scenarios that are subject to the

[2] Canadian Commission on Building and Fire Codes, *Final Report – Alterations to Existing Buildings (April 2020), available at:* *https://nrc.canada.ca/sites/default/files/2020-07/final_report_alterations_to_existing_buildings_joint_CCBFC_PTPACC_task.pdf* and Navius Research, *Supporting the Development of CleanBC: Methodology report for assessing the impacts of CleanBC policies, available at:* https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/supporting-development-cleanbc_methodology-report_navius.pdf

Accelerated outcome assume the introduction of the following additional performance requirements for appliances:

- Gas Storage Water Heater: No change (BC MEPS are already slightly more stringent than Federal MEPS)
    - BC = energy factor must be ≥ 0.70 − (0.0005 × V), and
    - Federal = energy factor must be ≥ 0.675 – 0.00039 Vr.
- HRV: estimated new minimum performance of 50 percent (residential only); likely minimal impact, since there are few homes with HRVs.
- Gas Dryer: likely new testing requirements, but no expected efficiency requirements.
- Gas Range: estimated 10 percent improvement in minimum efficiency level (residential only)
    - Assuming 20 percent of existing ranges are non-conforming, and will be upgraded when they are replaced. Replacement rate is assumed at 1/lifespan or 1/15th per year.
- Windows: new minimum performance of USI 1.61 or ER 25 (residential only)
    - Assuming 20 percent of existing windows are non-conforming, and will be upgraded when they are replaced. Replacement rate is assumed at 1/lifespan or 1/20th per year, and
    - Previous work by Posterity Group found this upgrade has on average a 2.7 percent heating energy savings.
- Commercial Warm Air Furnace: estimated improvement to 85 percent efficiency from 80 percent efficiency
    - Assuming 20 percent of existing commercial furnaces are non-conforming, and will be upgraded when they are replaced. Replacement rate is assumed at 1/lifespan or 1/15th per year, and
    - Commercial furnaces are estimated to make up 37 percent of the gas heating mix in BC.

Non-Price Driven Fuel Switching

In the 2022 LTGRP, non-price driven fuel switching captures gas-to-electricity fuel switching as a function of policies and incentives. This type of fuel switching differs from price-driven fuel switching when the prices of conventional natural gas and carbon cause a change in demand for conventional natural gas.

The non-price driven fuel switching focuses on space and water heating end uses in the residential and commercial sectors, as it is thought that policies and incentives for electrification would focus on these end uses for these sectors. Non-price driven fuel switching is assumed to occur in the industrial sector as well, as there are spillover effects from the electrification of other sectors. Fuel switching in the industrial sector occurs in the end uses that are assumed to be able to switch to electricity.

There are three gas-to-electricity ("G2E") fuel switching settings to serve as inputs to the associated scenarios. These settings were developed to reflect various levels of electrification by the end of the forecast period. The fuel switching assumptions presented in the Pathways Report (Appendix A-2) were reviewed to establish the settings. The "moderate" and "accelerated" settings align with a specific pathway presented in that report, indicated below. Using the Pathways Report as a guide, the 2022 LTGRP estimated gas fuel share reduction targets for 2042. The "extensive electrification" setting explores electrification beyond what was analyzed. The targets were set for reductions in gas fuel share by 2042 relative to the 2019 fuel share for space and water heating end uses in existing residential and commercial buildings. In the case of the City of Vancouver region, separate targets were set, as the City has more stringent building code requirements.

For 2042, a linear interpolation was used to set the following electrification assumptions consistent with the Pathways Report of modelled values in 2050:

- Moderate electrification (aligned with the 'Diversified Pathway'): ~14 percent decline in gas fuel share;
- Accelerated electrification (aligned with the 'Electrification Pathway'): ~56 percent decline in gas fuel share; and
- Extensive electrification: ~67 percent decline in gas fuel share.

1.1.1.2 Critical Uncertainty Impacts on the Forecast Model – Residential, Commercial and Industrial Demand Category

Table B3-3 summarizes how each critical uncertainty impacts the mechanics of the 2022 LTGRP forecast model and discusses the attributes of individual critical uncertainties

Table B3-3: Summary of Critical Uncertainty Impacts on the Forecast Model

Critical Uncertainty	Model Levers	Comments
Demand-Side Critical Uncertainties – Residential, Commercial and Industrial Demand Category		
Appliance Standards	- Natural gas appliance efficiency	See Table B3-1 above.

Critical Uncertainty	Model Levers	Comments
Demand-Side Critical Uncertainties – Residential, Commercial and Industrial Demand Category		
Carbon Price	- Long run natural gas fuel share	This critical uncertainty relies on the same mechanics as the Natural Gas Price critical uncertainty.
Customer Growth	- Residential buildingstock - Commercial floor area - Industrial facilities	See Table B3-1 above.
Natural Gas Price	- Long run natural gas fuel share	Based on a literature review of existing research by FEI and Posterity, the 2022 LTGRP uses -0.380, -0.350 and -0.700 as the long run price sensitivity values for residential, commercial and industrial customers, respectively. Since these are long run values, the 2022 LTGRP forecast model calculates the total fuel share change from these values by the end of the forecast period and subsequently solves for the required annual change rates required to produce the total change. The model ensures that the calculated annual change rates are achievable in relation to the rate of end use equipment replacements.
New Construction Code	- Unit energy consumption in new construction in Residential and Commercial sectors by building type and end use.	See Table B3-1 above.
Non-price Driven Fuel Switching	- Long run natural gas fuel share	See Table B3-1 above.
Retrofit Code	- Unit energy consumption in retrofit projects in Residential and Commercial sectors	See Table B3-1 above.

1.2 LOW-CARBON TRANSPORTATION AND GLOBAL LNG DEMAND CATEGORY

FEI developed four long-term forecast demand settings or trajectories for the CNG segment and LNG segment, based on core end use forecast scenario parameters for this category. These parameters are: (1) GGRR vehicle incentive applications that FEI uses for incentive funding for LCT customers; (2) industry research; (3) policy expected to impact the demand for natural gas as a transportation fuel in the future; (4) the allowed funding period permitted under the GGRR; (5) actual LCT customer additions to date; and (6) the relative price of competing or incumbent fuels such as diesel. Sections 3.4.7.1 and 3.4.7.2 further elaborate on these factors. The settings are:

- **Reference**: the continuation of planning environment conditions and demand trends that existing during the base year (2019) of the demand forecast.
- **Planning**: the expected forecast under the transportation fuelling initiatives being undertaken as part of FEI's Clean Growth Pathway.
- **High**: an upper bound forecast of possible demand from the transportation sector under very favourable conditions for expanding service to this customer group.
- **Low**: a lower bound scenario of possible demand from this sector if future conditions were to be very unfavourable for serving this customer group.

1.2.1 Qualitative Details on Scenario Critical Uncertainties – LCT and Global LNG Demand Category

FEI created the demand forecast settings separately for the CNG segment and LNG segment, as each segment has distinct characteristics and different considerations. CNG is positioned as a fuel for on-road transport applications, such as transit buses, waste haulers and heavy duty on-road trucks. LNG is positioned as a fuel for off-road and high-horsepower applications, such as marine vessels, locomotives, mine haul trucks, and remote industrial power and heat generation applications. Potential also exists for LNG to be exported overseas. Table B3-4 summarizes the critical uncertainty trajectories for the LCT and global LNG Demand Category.

Table B3-4: Summary of Modelled Critical Uncertainty Trajectories for the LCT and Global LNG Demand Category

Critical Uncertainty	Modelled Trajectories	Comments
Demand-Side Critical Uncertainties – LCT and Global LNG Demand Category		
Low-Carbon Transportation (LCT) Demand	- Reference - Planning - Low - High	Supply of CNG for the LCT sector to be used by on-road vehicles. Supply of LNG for the LCT sector to be used by marine vessels.

Critical Uncertainty	Modelled Trajectories	Comments
Demand-Side Critical Uncertainties – LCT and Global LNG Demand Category		
Global Liquefied Natural Gas (LNG) Demand	- Reference - Planning - High	Supply of LNG for export outside of the province.

Each of the settings are described in the subsections below. The links between the core end use forecast parameters and the LCT annual demand forecast settings are qualitative only because LCT is an emerging market with frequent changes in technology and policy in the market. Therefore, with little information to assess trends, FEI made its best assessment based on its understanding of potential market changes. Each CNG and LNG trajectory is considered a setting that is then mapped to the 2022 LTGRP Annual Demand Reference Case and Scenarios, as shown in Table B3-5 and Table B3-6.

Table B3-5: Mapping CNG/LNG Demand Forecast Settings to the 2022 LTGRP Annual Demand Scenarios – Transportation Fuel

CNG / LNG Demand Forecast Setting	Is Applied to this 2022 LTGRP Annual Demand Scenario
Reference	Reference Case
Low	Lower Bound, Deep Electrification, Economic Stagnation
Planning	Diversified Energy (Planning)
High	Upper Bound, Priced-Base Regulation

Table 3-6: Mapping Global LNG Demand Forecast Settings to the 2022 LTGRP Annual Demand Scenarios

Global LNG Demand Forecast Setting	Is Applied to this 2022 LTGRP Annual Demand Scenario
Reference	Reference Case, Price-Based Regulation, Economic Stagnation, Lower Bound
Planning	Diversified Energy (Planning), Deep Electrification
High	Upper Bound

Notes: - Because in the Reference Setting Global LNG Demand drops to zero, there is no "Low" setting.
Tables B3-5 and B3-6 = Tables 4-2 and 4-3 respectively in Section 4 of the 2022 LTGRP

Utilizing the above information, including demand from a number of different market segments that are suited to adopt LNG as a fuel, FEI developed Reference, Low, Planning and High demand forecast settings, described below.

1.2.1.1 LNG Reference Demand Forecast Setting

For the Reference forecast setting, FEI has assumed that incentives supporting LNG infrastructure under the GGRR will be extended to beyond 2030 with development in the short sea market segment as FEI's customers proceed with adoption of additional LNG marine vessels. The Reference setting assumed that there is no growth in trans-Pacific marine vessels adopting LNG as a fuel. As such, the marine bunkering jetty[3] at Tilbury is not constructed and does not apply in this setting. Similarly, completion of the EGP project is not assumed and the addition of Woodfibre LNG demand is not included. A solution to the discontinued 15L road engine for truck fleet customers does not emerge and consumption by these on-road customers will halt by 2026. Over the forecast horizon to 2042 in the Reference setting, FEI has forecast an average growth rate of about 1 percent from 2020 to 2030 and no growth beyond 2030.

1.2.1.2 LNG Low Demand Forecast Setting

For the Low demand forecast setting, FEI assumes that incentives supporting LNG infrastructure under the GGRR are not extended. Further, FEI has projected that short sea LNG demand would slightly increase annually until 2026 based on the current projection of short sea vessel additions. However, this would stabilize thereafter and maintain that volume of consumption for the remainder of the forecast period. This setting assumes that trans-Pacific marine vessels will not be adopting LNG as marine fuel and that a marine bunkering jetty at Tilbury does not get constructed. Additionally, it is assumed that there will not be a solution to the discontinued 15L road engine for truck fleet customers and therefore further decreases the LNG consumption demand for on-road customers. Although it is forecasted that ISO exports will remain consistent at 3PJ per year for the initial two years, it is expected that the ISO export demand will significantly decrease thereafter for the remainder of the planning horizon. There is no growth in LNG demand assumed under this setting through to the end of the forecast period of 2042.

1.2.1.3 LNG Planning Demand Forecast Setting

In the Planning forecast setting, FEI assumes that incentives supporting LNG infrastructure under GGRR will be extended beyond 2030. FEI has assumed that there will be development in the short sea market segment as our marine customers will proceed with adoption of additional LNG marine vessels. In the Planning setting, the marine bunkering jetty at Tilbury is constructed, which will accelerate the adoption of LNG by trans-Pacific marine vessels as facilitated by ship-to-ship bunkering. This setting assumes that there will not be a solution to the discontinued 15L road engine for truck fleet customers and consumption by these customers will halt by 2026. The ISO exports market segment is assumed to increase by 0.68PJ per year from 2021-2042. The Planning setting includes completion of the EGP project resulting in an average of 94.8 PJ annually of LNG from 2025-2042. Moreover, the mining and remote power market segments will grow which will increase LNG demand by an average of 2.9PJ annually from 2024 to 2042.

[3] The proposed Jetty is a non-regulated activity and is not part FEI's initiatives included in the LTGRP.

1.2.1.4 LNG High Demand Forecast Setting

For the High forecast setting, FEI assumes that incentives supporting LNG infrastructure under the GGRR will be extended beyond 2030. As in the Planning setting, the marine bunkering jetty at Tilbury is constructed, accelerating the adoption of LNG by trans-Pacific marine vessels as facilitated by ship-to-ship bunkering. However, in the High setting there is a more aggressive LNG adoption, particularly from the trans-Pacific marine vessels.

The High setting begins to diverge from the Planning setting beginning in 2022 and 2023, as the marine transportation market begins addressing the impending IMO sulphur cap on marine industry emissions. The IMO sulphur cap regulation accelerates a need for gas as an alternative fuel to meet these tighter emissions restrictions.

Similar to the Planning setting, the High setting assumes that the ISO exports market segment increases by 0.68PJ per year from 2021-2042. In addition to the Planning setting expectation, the EGP project will be completed and also result in 94.8PJ LNG annually from 2025-2042. Moreover, the mining and remote power market segments grow, increasing LNG demand by an average of 4.6PJ annually from 2024 to 2042.

In the High setting, it is projected that an introduction of a new high horsepower engine would be available for on-road customers as a solution to the discontinuance of the 15L road engine. It is assumed that this 400 horsepower engine would enable FEI to retain our current on-road customer LNG demand up to 2042.

1.2.1.5 CNG Reference Demand Forecast Setting

The Reference setting assumes that incentives supporting CNG infrastructure under GGRR will be extended beyond 2030, and that the CNG demand from current customers will be consistent throughout the forecast period. The setting forecasts new customer additions, and that all new customer load is expected to grow on average of 3% annually until 2030 at which it will be stagnant thereafter. This setting assumes that CNG engines are continued to be manufactured and improved while the price of CNG vehicles and fuel savings from adopting CNG vehicles are assumed to remain relatively consistent. The Reference setting assumes that the cost difference between diesel and CNG will vary. It is assumed that EV and hydrogen adoption is slow due to technology uncertainty. By 2031, EV technology advancements have progressed which results in limited CNG growth. The Reference setting is forecast to capture 2.5 percent of the demand from the eligible CNG market by the end of the forecast period of 2042.

1.2.1.6 CNG Low Demand Forecast Setting

The Low setting assumes an annual growth rate of about 1 percent per year on average until 2030, at which point it will decrease at 1.9 percent per year until 2042 due to an assumed transition to EV for this setting in the eligible market. In this setting, incentives supporting CNG infrastructure under the GGRR and the BC-LCFS are assumed to end in 2030. Demand from current customers is forecast to remain consistent and, based on demand from new customers, the load will grow on an average of 1 percent annually until 2030 at which point all GGRR stations are completed. In 2030 and beyond, CNG consumption will decrease as adoption of other potential low-carbon fuels increases and existing CNG fleets are replaced. Unlike in the Reference setting, the Low setting assumes that CNG vehicle prices will increase, and medium and heavy duty EV and hydrogen vehicle adoption is accelerated. The Low setting assumes that the acceleration of EV and hydrogen vehicle adoption will result in CNG stations closing and CNG trucks are retired, reducing demand. As a result, the Low setting forecasts a market share of about 2 percent of the eligible market size by 2042.

1.2.1.7 CNG Planning Demand Forecast Setting

For the Planning setting, the incentives supporting CNG infrastructure under the GGRR are expected to be extended beyond 2030 and the BC-LCFS continues beyond 2042. For this setting, demand from current customer base is forecast to remain consistent throughout the forecast period, based on demand from new customers, load is forecast to grow on an average of 2 percent annually until 2030 at which point all GGRR stations are completed. This setting assumes that current customers will continue to renew or replace their CNG vehicles with the same gas equivalent. CNG engines continue to be manufactured and improved and the price of CNG vehicles as well as fuel savings from adopting CNG vehicles is assumed to remain relatively consistent. It is assumed that medium and heavy duty EV and hydrogen vehicle adoption is slow due to delayed development of these heavy and medium duty vehicle technologies and supporting supply chain readiness. The growth of CNG demand is forecast to capture about 2.9 percent of the eligible market by the end of the forecast period of 2042. This level of market capture constitutes a growth rate of approximately 3 percent per year with average demand increase of 15 thousand GJ per year from 2031 to 2042.

1.2.1.8 CNG High Demand Forecast Setting

For the CNG High setting, incentives supporting CNG infrastructure under the GGRR are assumed to be extended beyond 2030 and the BC-LCFS continues beyond 2042. For this setting, current customer load is forecast to be consistent throughout the forecast period while new customer load grows on average at 5 percent annually until 2042. Additionally, the spread between diesel prices and CNG prices increases in favour of CNG, which contributes to higher customer consumption. CNG engines are assumed to continue to be manufactured and improved and the price of CNG vehicles and fuel savings from adopting CNG vehicles are assumed to decrease. The popularity of LCT vehicles continues to increase due to fuel savings over diesel. The High setting assumes that medium and heavy-duty electric vehicle (EV) and hydrogen vehicle adoption is relatively slow, as is the case with the Planning setting.

By 2042, the High setting assumes FEI will capture approximately 5.8 percent of the potential eligible market in BC, which equates to an average annual growth rate of about 5 percent per year or an average demand addition of approximately 100 thousand GJ per year from 2027 to 2042.

1.2.2 Critical Uncertainty Impacts on the Forecast Model – Low-Carbon Transportation and Global LNG Demand Category

Table B3-7 summarizes how each critical uncertainty impacts the mechanics of the 2022 LTGRP forecast model and discusses the attributes of individual critical uncertainties.

Table B3-7: Summary of Critical Uncertainty Impacts on the Forecast Model

Critical Uncertainty	Model Levers	Comments
Demand Side Critical Uncertainties - LCT and Global LNG Demand Category		
Low-Carbon Transportation (LCT) Demand	- Commercial rate schedule demand - Industrial rate schedule demand	See Table B3-1 above.
Liquefied Natural Gas (LNG) Export Demand	- Industrial rate schedule demand	See Table B3-1 above.

1.3 CRITICAL UNCERTAINTIES FOR THE NEW LARGE INDUSTRIAL DEMAND CATEGORY

The New Large Industrial Demand Category is in itself a critical uncertainty in that such demand is either added or it is not. There are only three settings for new large industrial demand:

- High – in which both Woodfibre and a second generic large industrial facility are added to FEI's demand in 2025 and 2028, respectively.
- Planning – in which only Woodfibre is added to FEI's demand in 2025.
- Reference – in which no new large industrial facilities are added to FEI's demand over the planning horizon.

The high setting is applied only to the Upper Bound Scenario. The planning setting is applied to the Diversified Energy (Planning) and the Deep Electrification Scenarios. The Reference setting is applied to all other scenarios.

1.4 CONCLUSION

In response to the complex and partially uncertain planning environment discussed in Section 2 of the LTGRP, FEI has built on the end use forecast method scenario analysis from the 2017 LTGRP and identified a range of critical uncertainties to account for potential changes in the planning environment across the forecast period. These uncertainties include customer growth, natural gas prices, the carbon price, Codes & Standards, non-price driven fuel switching, and the impact of emerging markets, such as LCT and the potential impact of LNG export. FEI used a rigorous process for developing the inputs for each critical uncertainty and for implementing these into the 2022 LTGRP forecast model. In doing so, FEI drew on the expertise of its internal LTGRP working groups, its forecast consultant (Posterity Group), and the experience of stakeholders in the RPAG and across FEI's community engagement workshops. The resulting critical uncertainty data accounts for a wide range of possible alternate future scenarios and enables FEI to account for planning environment risks in its 2022 LTGRP analysis. The critical uncertainties also serve as signposts for FEI to evaluate which future scenarios may be unfolding as it proceeds through the planning horizon.

Appendix B-4

ANNUAL DEMAND FORECAST TABLES

APPENDIX B-4: ANNUAL DEMAND FORECAST TABLES[1]

1.1 Reference Case

Year End Customers by Rate Schedule

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	942,769	952,204	959,904	968,373	975,522	982,245	988,426	994,357	1,000,045	1,005,513	1,010,764	1,015,826	1,020,705	1,025,417	1,029,967	1,034,365	1,038,609	1,042,710	1,046,668	1,050,486	1,054,180	1,057,756	1,061,334	1,064,902
RATE2	89,023	89,864	90,740	91,605	92,482	93,357	94,231	95,108	95,979	96,852	97,731	98,593	99,467	100,339	101,214	102,074	102,940	103,787	104,616	105,429	106,238	107,023	107,820	108,616
RATE3	6,990	7,234	7,480	7,731	7,979	8,228	8,474	8,743	9,012	9,293	9,579	9,866	10,154	10,455	10,757	11,064	11,364	11,679	11,985	12,300	12,609	12,921	13,234	13,551
RATE4	15	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
RATE5	572	575	578	580	582	585	585	585	585	585	585	585	584	584	584	584	584	584	584	584	584	584	584	584
RATE6	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
RATE7	46	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
RATE22	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
RATE23	867	899	937	974	1,010	1,046	1,080	1,115	1,156	1,192	1,231	1,269	1,313	1,358	1,401	1,445	1,492	1,531	1,578	1,627	1,668	1,719	1,760	1,811
RATE25	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525
RATE27	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
RATE46	16	13	13	9	9	9	9	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Grand Total	**1,040,990**	**1,051,542**	**1,060,405**	**1,070,025**	**1,078,337**	**1,086,223**	**1,093,558**	**1,100,664**	**1,107,533**	**1,114,191**	**1,120,646**	**1,126,895**	**1,132,979**	**1,138,909**	**1,144,679**	**1,150,288**	**1,155,745**	**1,161,047**	**1,166,187**	**1,171,182**	**1,176,035**	**1,180,759**	**1,185,488**	**1,190,220**

Annual Use Rate per Customer by Rate Schedule (GJ)

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	82.0	80.6	79.2	77.2	75.2	73.6	72.4	71.3	70.2	69.4	68.7	68.1	67.4	66.8	66.3	65.7	65.2	64.7	64.2	63.8	63.4	62.9	62.5	62.2
RATE2	317.6	318.1	315.0	309.2	303.2	298.4	295.4	292.3	289.1	287.3	285.8	284.3	282.8	281.3	279.9	278.6	277.2	275.9	274.7	273.5	272.3	271.2	270.1	269.0
RATE3	3,241.0	3,278.1	3,249.4	3,182.6	3,110.9	3,055.1	3,016.7	2,978.2	2,936.6	2,915.4	2,895.1	2,876.1	2,857.7	2,839.6	2,826.5	2,811.0	2,796.2	2,782.8	2,770.1	2,759.3	2,748.1	2,736.3	2,726.5	2,718.5
RATE4	10,202.4	9,524.5	9,646.0	9,462.2	9,360.5	9,209.7	9,143.4	9,074.2	8,987.7	8,970.4	8,962.7	8,955.2	8,944.9	8,934.7	8,925.0	8,919.0	8,909.0	8,899.2	8,889.4	8,880.4	8,870.9	8,861.4	8,851.9	8,843.1
RATE5	10,009.3	10,286.3	10,218.8	10,050.0	9,853.2	9,702.9	9,667.2	9,638.0	9,596.8	9,613.2	9,637.9	9,662.9	9,652.9	9,626.7	9,601.1	9,578.3	9,552.9	9,527.9	9,503.0	9,478.9	9,454.6	9,430.6	9,406.8	9,383.7
RATE6	3,220.2	3,209.5	3,195.7	3,156.1	3,113.4	3,081.7	3,065.2	3,048.0	3,029.1	3,023.4	3,019.5	3,015.6	3,010.9	3,006.3	3,001.7	2,997.5	2,992.9	2,988.4	2,983.9	2,979.5	2,975.1	2,970.7	2,966.3	2,962.0
RATE7	64,403.7	80,571.0	77,312.5	76,840.9	74,973.5	73,646.2	73,067.6	72,497.5	71,745.8	71,649.9	71,644.9	71,641.6	71,614.0	71,588.0	71,566.4	71,582.6	71,557.8	71,533.5	71,509.6	71,492.7	71,470.9	71,449.1	71,427.0	71,411.6
RATE22	866,639.9	897,325.5	831,813.7	812,367.4	792,492.6	772,341.8	767,624.7	761,479.5	753,271.7	752,327.9	752,389.7	752,473.4	752,295.8	752,134.2	752,022.7	752,338.7	752,189.8	752,046.0	751,905.4	751,843.7	751,725.8	751,606.2	751,484.5	751,436.0
RATE23	8,392.5	8,729.2	8,492.4	8,338.8	8,092.7	7,950.4	7,815.8	7,734.3	7,603.0	7,529.8	7,468.6	7,444.1	7,375.2	7,320.6	7,275.8	7,605.6	7,524.4	7,477.5	7,406.4	7,370.0	7,335.9	7,279.9	7,245.2	7,207.0
RATE25	26,638.9	27,797.4	27,405.1	26,898.2	26,320.9	25,924.3	25,729.8	25,524.6	25,276.4	25,218.7	25,187.9	25,157.6	25,119.4	25,082.0	25,052.6	25,033.3	25,003.5	24,973.9	24,944.7	24,917.4	24,889.0	24,860.8	24,832.7	24,806.5
RATE27	57,856.9	63,582.7	61,803.8	60,550.8	59,183.0	58,259.8	57,832.9	57,394.5	56,827.0	56,743.1	56,726.6	56,711.1	56,676.9	56,643.9	56,614.1	56,611.4	56,579.5	56,548.1	56,516.9	56,490.9	56,461.4	56,431.9	56,402.4	56,377.6
RATE46	102,523.5	342,312.1	337,739.0	152,125.9	163,515.2	161,414.3	193,102.8	660,702.8	751,874.3	798,231.0	892,857.0	940,520.3	940,138.3	939,776.7	939,433.0	939,236.0	938,890.0	938,557.0	938,226.7	937,928.0	937,612.3	937,306.0	937,002.3	936,729.7

Annual Demand by Rate Schedule (GJ)

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	77,329,188	76,701,320	76,000,632	74,717,445	73,351,348	72,273,096	71,567,808	70,871,683	70,159,689	69,771,903	69,446,006	69,135,495	68,821,566	68,523,414	68,240,499	67,978,673	67,719,262	67,471,476	67,233,419	67,006,012	66,786,240	66,575,401	66,377,114	66,192,466
RATE2	28,276,686	28,582,583	28,587,597	28,327,379	28,039,101	27,860,638	27,833,608	27,800,588	27,746,991	27,827,654	27,930,132	28,029,526	28,127,278	28,226,748	28,329,274	28,434,121	28,538,663	28,639,467	28,737,647	28,834,006	28,930,435	29,022,322	29,118,691	29,219,597
RATE3	22,654,720	23,713,782	24,305,356	24,604,453	24,821,923	25,137,023	25,563,618	26,038,780	26,464,491	27,092,397	27,731,719	28,375,631	29,016,788	29,688,312	30,404,125	31,101,015	31,775,658	32,500,773	33,199,587	33,939,114	34,650,842	35,355,731	36,082,388	36,838,385
RATE4	153,036	152,391	154,336	151,396	149,768	147,355	146,294	145,187	143,803	143,526	143,404	143,284	143,118	142,955	142,800	142,704	142,545	142,387	142,231	142,086	141,934	141,782	141,631	141,490
RATE5	5,725,320	5,914,649	5,906,447	5,828,976	5,734,553	5,676,201	5,655,322	5,638,249	5,614,102	5,623,698	5,638,189	5,652,769	5,637,276	5,622,014	5,607,056	5,593,730	5,578,912	5,564,273	5,549,767	5,535,675	5,521,505	5,507,483	5,493,579	5,480,067
RATE6	48,303	48,142	47,936	47,341	46,701	46,225	45,978	45,720	45,437	45,350	45,293	45,234	45,164	45,094	45,025	44,963	44,894	44,826	44,759	44,693	44,626	44,560	44,495	44,431
RATE7	2,962,569	3,625,695	3,479,062	3,457,840	3,373,808	3,314,077	3,288,040	3,262,387	3,228,563	3,224,244	3,224,019	3,223,874	3,222,632	3,221,460	3,220,488	3,221,215	3,220,100	3,219,010	3,217,933	3,217,173	3,216,192	3,215,207	3,214,217	3,213,520
RATE22	43,331,994	44,866,277	41,590,685	40,618,370	39,624,631	38,617,089	38,381,236	38,073,976	37,663,585	37,616,396	37,619,486	37,623,669	37,614,788	37,606,711	37,601,133	37,616,933	37,609,492	37,602,301	37,595,271	37,592,184	37,586,290	37,580,309	37,574,225	37,571,800
RATE23	7,276,338	7,847,585	7,957,364	8,121,994	8,173,655	8,316,140	8,441,073	8,623,727	8,789,047	8,975,552	9,193,830	9,446,624	9,683,589	9,941,347	10,193,435	10,990,164	11,226,345	11,448,105	11,687,283	11,990,943	12,236,201	12,514,224	12,751,527	13,051,933
RATE25	13,985,419	14,593,629	14,387,697	14,121,575	13,818,449	13,610,240	13,508,127	13,400,424	13,270,112	13,239,838	13,223,662	13,207,732	13,187,704	13,168,065	13,152,636	13,142,499	13,126,813	13,111,321	13,095,949	13,081,637	13,066,724	13,051,913	13,037,164	13,023,408
RATE27	5,901,402	6,485,439	6,303,987	6,176,177	6,036,670	5,942,497	5,898,960	5,854,244	5,796,358	5,787,800	5,786,111	5,784,536	5,781,044	5,777,678	5,774,641	5,774,360	5,771,104	5,767,902	5,764,726	5,762,068	5,759,058	5,756,054	5,753,045	5,750,519
RATE46	1,640,376	4,450,057	4,390,607	1,369,133	1,471,637	1,452,728	1,737,925	1,982,108	2,255,623	2,394,693	2,678,571	2,821,561	2,820,415	2,819,330	2,818,299	2,817,708	2,816,670	2,815,671	2,814,680	2,813,784	2,812,837	2,811,918	2,811,007	2,810,189
Grand Total	**209,285,351**	**216,981,550**	**213,111,705**	**207,542,081**	**204,642,244**	**202,393,309**	**202,067,989**	**201,737,073**	**201,177,802**	**201,743,053**	**202,660,421**	**203,489,935**	**204,101,361**	**204,783,129**	**205,529,410**	**206,858,085**	**207,570,458**	**208,327,513**	**209,083,252**	**209,959,375**	**210,752,885**	**211,576,906**	**212,399,083**	**213,337,804**

[1] All tables in this appendix display results from the end-use annual demand forecast method and exclude renewable and low carbon gases, the impact of Conservation and Energy Management Programs (C&EM), and the Woodfibre LNG Project.

1.2 Diversified Energy (Planning)

Year End Customers by Rate Schedule

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	942,769	952,204	959,904	968,373	975,522	982,245	988,426	994,357	1,000,045	1,005,513	1,010,764	1,015,826	1,020,705	1,025,417	1,029,967	1,034,365	1,038,609	1,042,710	1,046,668	1,050,486	1,054,180	1,057,756	1,061,334	1,064,902
RATE2	89,023	89,864	90,740	91,605	92,482	93,357	94,231	95,108	95,979	96,852	97,731	98,593	99,467	100,339	101,214	102,074	102,940	103,787	104,616	105,429	106,238	107,023	107,820	108,616
RATE3	6,990	7,234	7,480	7,731	7,979	8,228	8,474	8,743	9,012	9,293	9,579	9,866	10,154	10,455	10,757	11,064	11,364	11,679	11,985	12,300	12,609	12,921	13,234	13,551
RATE4	15	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
RATE5	572	575	578	580	582	585	585	585	585	585	585	585	584	584	584	584	584	584	584	584	584	584	584	584
RATE6	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
RATE7	46	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
RATE22	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
RATE23	867	899	937	974	1,010	1,046	1,080	1,115	1,156	1,192	1,231	1,269	1,313	1,358	1,401	1,445	1,492	1,531	1,578	1,627	1,668	1,719	1,760	1,811
RATE25	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525
RATE27	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
RATE46	16	13	13	12	13	14	14	14	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Grand Total	**1,040,990**	**1,051,542**	**1,060,405**	**1,070,028**	**1,078,341**	**1,086,228**	**1,093,563**	**1,100,675**	**1,107,538**	**1,114,196**	**1,120,651**	**1,126,900**	**1,132,984**	**1,138,914**	**1,144,684**	**1,150,293**	**1,155,750**	**1,161,052**	**1,166,192**	**1,171,187**	**1,176,040**	**1,180,764**	**1,185,493**	**1,190,225**

Annual Use Rate per Customer by Rate Schedule (GJ)

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	82.0	80.2	78.5	75.1	72.1	69.4	66.6	63.9	61.4	59.2	57.0	54.4	52.8	51.3	49.8	48.3	46.9	45.6	44.2	42.9	41.6	40.4	39.2	38.0
RATE2	317.6	313.7	307.2	298.6	289.7	281.2	272.5	264.0	255.7	248.2	240.4	231.9	225.4	219.0	212.7	206.6	200.6	194.8	189.0	183.4	178.0	172.7	167.6	162.6
RATE3	3,241.0	3,239.6	3,180.9	3,085.3	2,982.5	2,889.6	2,793.5	2,698.4	2,605.3	2,525.1	2,439.2	2,346.7	2,279.4	2,214.4	2,152.3	2,090.2	2,029.5	1,970.2	1,911.1	1,854.3	1,797.9	1,742.9	1,690.4	1,640.1
RATE4	10,202.4	9,474.2	9,563.0	9,282.5	9,090.3	8,832.2	8,584.7	8,333.4	8,076.7	7,840.7	7,574.2	7,276.6	7,080.3	6,890.3	6,692.5	6,500.3	6,303.9	6,106.6	5,901.7	5,700.7	5,492.2	5,290.8	5,091.9	4,890.6
RATE5	10,009.3	10,203.0	10,074.5	9,807.1	9,512.3	9,253.1	9,033.2	8,824.0	8,580.8	8,371.3	8,137.8	7,887.3	7,727.7	7,562.4	7,391.0	7,226.1	7,059.9	6,892.7	6,721.1	6,556.1	6,386.7	6,224.3	6,067.1	5,910.9
RATE6	3,220.2	3,194.6	3,172.1	3,101.0	3,028.5	2,963.2	2,889.1	2,816.5	2,748.5	2,689.1	2,622.1	2,541.6	2,496.3	2,452.2	2,406.5	2,361.9	2,315.5	2,269.9	2,222.7	2,176.1	2,128.4	2,081.2	2,032.3	1,984.9
RATE7	64,403.7	80,526.4	77,333.3	75,969.4	73,446.5	71,210.0	69,092.4	66,853.5	64,259.1	62,126.2	59,734.7	57,444.2	56,186.1	55,036.0	53,780.1	52,615.7	51,421.9	50,200.6	48,911.1	47,697.2	46,371.7	45,118.5	43,902.4	42,633.1
RATE22	866,639.9	897,057.0	832,438.0	803,455.1	773,493.3	739,640.3	714,563.9	683,074.6	644,570.5	611,301.6	575,112.0	543,802.0	523,914.2	505,800.5	486,303.8	467,794.8	450,678.8	431,731.6	412,208.2	394,411.1	374,879.0	356,173.8	340,287.2	323,826.2
RATE23	8,392.5	8,657.5	8,369.1	8,135.9	7,808.3	7,570.9	7,285.7	7,047.4	6,777.7	6,548.4	6,309.7	6,072.6	5,879.7	5,703.4	5,533.8	5,652.9	5,460.4	5,294.0	5,109.7	4,945.7	4,788.8	4,624.6	4,481.8	4,330.9
RATE25	26,638.9	27,668.2	27,201.2	26,406.4	25,574.7	24,782.8	23,990.6	23,096.8	22,022.3	21,097.1	20,101.5	19,284.3	18,784.3	18,327.8	17,841.0	17,379.0	16,930.3	16,461.3	15,978.9	15,532.6	15,052.0	14,593.6	14,164.1	13,715.4
RATE27	57,856.9	63,466.4	61,669.4	59,721.9	57,801.2	56,052.7	54,321.1	52,405.8	50,113.0	48,170.0	46,034.7	44,175.4	43,111.6	42,146.0	41,092.0	40,104.8	39,122.7	38,104.6	37,040.7	36,052.1	34,973.7	33,946.9	32,971.5	31,950.5
RATE46	102,523.5	342,601.5	338,840.7	392,244.1	896,659.2	1,562,846.2	2,137,669.1	2,521,638.6	5,058,695.6	5,975,704.8	6,260,646.6	6,555,576.5	6,489,171.0	6,434,441.7	6,373,843.9	6,318,300.0	6,255,607.7	6,197,437.4	6,132,815.8	6,071,377.0	6,007,762.2	5,944,286.4	5,876,265.6	5,810,691.5

Annual Demand by Rate Schedule (GJ)

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	77,329,188	76,344,986	75,358,673	72,761,676	70,346,263	68,157,326	65,810,936	63,551,146	61,439,722	59,573,984	57,573,614	55,311,474	53,910,354	52,593,755	51,259,567	50,006,379	48,719,539	47,503,019	46,259,596	45,073,063	43,883,115	42,746,943	41,586,994	40,475,157
RATE2	28,276,686	28,193,508	27,877,785	27,356,421	26,788,250	26,255,321	25,680,352	25,105,002	24,545,405	24,040,423	23,492,983	22,863,573	22,417,772	21,978,673	21,532,665	21,091,387	20,651,964	20,213,949	19,772,156	19,340,015	18,906,894	18,482,089	18,067,516	17,662,448
RATE3	22,654,720	23,435,258	23,793,240	23,852,489	23,797,393	23,775,614	23,671,769	23,592,081	23,478,899	23,466,010	23,365,557	23,152,831	23,145,491	23,151,730	23,152,305	23,125,736	23,062,948	23,009,824	22,904,752	22,807,637	22,669,735	22,519,662	22,370,745	22,225,667
RATE4	153,036	151,587	153,008	148,519	145,445	141,315	137,355	133,335	129,227	125,451	121,187	116,426	113,284	110,245	107,080	104,004	100,863	97,705	94,427	91,211	87,876	84,653	81,470	78,250
RATE5	5,725,320	5,866,704	5,823,081	5,688,091	5,536,138	5,413,087	5,284,425	5,162,035	5,019,789	4,897,217	4,760,615	4,614,058	4,512,993	4,416,451	4,316,341	4,220,020	4,122,972	4,025,350	3,925,112	3,828,751	3,729,839	3,635,003	3,543,194	3,451,985
RATE6	48,303	47,919	47,581	46,515	45,428	44,448	43,336	42,248	41,228	40,336	39,331	38,124	37,445	36,783	36,097	35,429	34,732	34,049	33,340	32,641	31,926	31,218	30,485	29,773
RATE7	2,962,569	3,623,689	3,479,999	3,418,625	3,305,095	3,204,449	3,109,159	3,008,407	2,891,659	2,795,680	2,688,061	2,584,988	2,528,377	2,476,621	2,420,105	2,367,704	2,313,985	2,259,028	2,200,999	2,146,373	2,086,725	2,030,333	1,975,606	1,918,489
RATE22	43,331,994	44,852,849	41,621,898	40,172,755	38,674,666	36,982,016	35,728,197	34,153,728	32,228,525	30,565,082	28,755,600	27,190,098	26,195,709	25,290,024	24,315,188	23,389,740	22,533,940	21,586,579	20,610,411	19,720,556	18,743,948	17,808,690	17,014,362	16,191,312
RATE23	7,276,338	7,783,126	7,841,834	7,924,395	7,886,433	7,919,172	7,868,592	7,857,874	7,835,068	7,805,706	7,767,228	7,706,102	7,720,004	7,745,188	7,752,903	8,168,477	8,146,907	8,105,166	8,063,080	8,046,706	7,987,784	7,949,697	7,888,028	7,843,304
RATE25	13,985,419	14,525,779	14,280,625	13,863,346	13,426,739	13,010,990	12,595,058	12,125,842	11,561,731	11,075,984	10,553,307	10,124,233	9,861,737	9,622,070	9,366,520	9,123,983	8,888,398	8,642,158	8,388,907	8,154,591	7,902,319	7,661,629	7,436,142	7,200,566
RATE27	5,901,402	6,473,573	6,290,279	6,091,639	5,895,726	5,717,372	5,540,752	5,345,395	5,111,527	4,913,344	4,695,543	4,505,895	4,397,386	4,298,889	4,191,381	4,090,692	3,990,517	3,886,669	3,778,149	3,677,316	3,567,313	3,462,588	3,363,095	3,258,954
RATE46	1,640,376	4,453,820	4,404,929	4,706,930	11,656,569	21,879,847	29,927,367	35,302,940	40,469,564	47,805,639	50,085,173	52,444,612	51,913,368	51,475,533	50,990,751	50,546,400	50,044,862	49,579,500	49,062,526	48,571,016	48,062,098	47,554,291	47,010,125	46,485,532
Grand Total	**209,285,351**	**215,752,798**	**210,972,933**	**206,031,399**	**207,504,144**	**212,500,955**	**215,397,298**	**215,380,033**	**214,752,344**	**217,104,854**	**213,898,199**	**210,652,413**	**206,753,918**	**203,195,961**	**199,440,904**	**196,269,952**	**192,611,627**	**188,942,997**	**185,093,455**	**181,489,876**	**177,659,571**	**173,966,796**	**170,367,763**	**166,821,438**

1.3 Deep Electrification

Year End Customers by Rate Schedule

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	942,769	944,540	951,806	958,311	964,200	969,655	974,644	979,303	983,715	987,779	991,740	995,502	999,231	1,002,653	1,005,745	1,008,839	1,011,961	1,014,583	1,017,240	1,019,758	1,022,149	1,024,423	1,026,691	1,028,963
RATE2	89,023	87,601	88,119	88,628	89,133	89,642	90,141	90,649	91,136	91,631	92,131	92,620	93,099	93,596	94,085	94,565	95,044	95,507	95,958	96,388	96,806	97,208	97,625	98,017
RATE3	6,990	6,899	7,080	7,266	7,451	7,638	7,837	8,033	8,248	8,461	8,693	8,918	9,144	9,386	9,625	9,866	10,115	10,370	10,620	10,864	11,118	11,360	11,610	11,867
RATE4	15	4	4	3	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
RATE5	572	555	552	548	545	544	539	536	525	515	513	507	503	496	489	482	477	471	471	468	466	463	461	460
RATE6	15	14	14	14	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
RATE7	46	45	45	45	45	44	44	44	44	44	44	42	42	42	42	42	42	42	42	42	42	42	42	42
RATE22	50	46	46	46	44	44	44	40	40	40	40	39	35	35	35	30	30	30	29	28	28	26	23	22
RATE23	867	815	827	847	864	875	891	915	939	964	984	1,004	1,031	1,056	1,089	1,120	1,152	1,184	1,217	1,244	1,280	1,317	1,345	1,380
RATE25	525	448	443	438	428	420	415	408	399	390	383	376	363	357	348	345	340	332	327	319	310	303	289	274
RATE27	102	95	95	94	93	93	89	87	84	81	80	78	78	77	71	70	70	70	68	67	67	66	66	66
RATE46	16	13	13	12	12	12	12	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Grand Total	**1,040,990**	**1,041,075**	**1,049,044**	**1,056,252**	**1,062,830**	**1,068,981**	**1,074,670**	**1,080,035**	**1,085,150**	**1,089,925**	**1,094,628**	**1,099,106**	**1,103,546**	**1,107,718**	**1,111,549**	**1,115,379**	**1,119,251**	**1,122,609**	**1,125,992**	**1,129,198**	**1,132,286**	**1,135,228**	**1,138,172**	**1,141,111**

Annual Use Rate per Customer by Rate Schedule (GJ)

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	82.0	79.9	77.3	74.1	71.1	68.7	66.4	64.2	61.8	59.4	57.0	54.6	52.2	49.8	47.3	44.8	42.3	39.8	37.3	34.9	32.8	30.9	29.3	27.8
RATE2	317.6	309.5	296.3	280.8	266.0	253.9	242.0	230.5	219.0	208.0	197.7	187.9	178.2	169.4	161.5	154.0	147.3	141.0	135.2	129.9	124.9	120.3	116.0	112.0
RATE3	3,241.0	3,220.3	3,100.5	2,951.4	2,809.3	2,697.1	2,590.4	2,480.9	2,370.3	2,262.9	2,159.6	2,060.5	1,958.5	1,868.7	1,788.3	1,716.7	1,650.2	1,589.4	1,537.7	1,483.7	1,436.3	1,391.1	1,347.8	1,308.5
RATE4	10,202.4	9,456.1	9,670.1	9,113.9	10,778.4	10,732.6	10,696.8	10,656.0	10,612.8	10,576.3	10,540.4	10,501.8	10,452.8	10,409.4	10,367.4	10,319.9	10,276.9	10,232.3	10,184.9	10,133.9	10,086.6	10,036.0	9,985.9	9,938.4
RATE5	10,009.3	10,351.6	10,083.2	9,772.8	9,430.1	9,200.2	8,958.2	8,755.6	8,588.5	8,280.8	8,081.3	7,901.5	7,658.6	7,458.6	7,209.7	7,065.6	6,885.6	6,769.0	6,606.5	6,478.8	6,333.9	6,218.3	6,073.5	5,952.3
RATE6	3,220.2	3,089.1	3,046.1	2,977.6	2,835.4	2,800.7	2,764.5	2,730.1	2,694.7	2,657.8	2,619.4	2,577.5	2,532.9	2,487.4	2,442.6	2,399.3	2,360.8	2,324.9	2,291.4	2,259.7	2,230.9	2,203.8	2,177.4	2,154.3
RATE7	64,403.7	82,515.1	79,328.3	79,677.4	78,848.9	77,906.3	77,665.7	77,445.3	77,232.2	77,016.5	76,797.3	77,833.5	77,497.3	77,216.3	76,966.5	76,683.2	76,443.1	76,197.0	75,933.5	75,633.8	75,332.1	74,943.2	74,417.1	73,801.0
RATE22	866,639.9	958,322.5	888,391.9	873,751.5	879,084.9	866,500.4	862,114.7	892,538.1	886,517.2	880,525.0	874,642.4	888,398.6	913,661.1	898,924.0	896,054.8	944,759.2	942,215.6	939,455.9	959,000.0	965,839.4	960,960.8	1,008,925.7	1,077,625.2	1,095,776.6
RATE23	8,392.5	8,830.3	8,437.4	8,095.4	7,738.6	7,459.2	7,217.8	6,966.2	6,789.6	6,535.4	6,333.7	6,076.9	5,841.0	5,582.1	5,425.7	5,273.7	5,098.2	4,958.4	4,837.5	4,699.3	4,571.9	4,463.7	4,359.2	4,660.4
RATE25	26,638.9	28,683.6	27,708.9	27,012.4	26,304.2	26,126.8	25,834.7	25,663.3	25,142.5	25,061.4	24,605.6	23,934.0	23,640.2	23,394.2	22,904.8	22,669.5	22,563.0	22,517.8	22,330.5	21,596.7	21,788.2	21,763.5	21,475.2	21,248.7
RATE27	57,856.9	65,804.6	63,749.3	62,532.8	61,402.5	61,089.1	61,745.7	62,321.9	61,326.0	60,558.9	60,762.4	60,813.4	60,199.5	59,862.6	59,391.5	59,668.4	59,345.6	59,018.5	58,704.3	58,521.1	58,151.3	57,320.2	56,805.5	56,243.3
RATE46	102,523.5	342,618.3	338,771.3	381,931.4	408,714.5	435,718.6	487,660.5	1,073,046.5	1,127,841.8	1,182,642.2	1,237,449.6	1,347,221.5	1,346,884.2	1,346,667.5	1,346,405.1	1,345,914.9	1,345,663.4	1,345,405.7	1,345,119.3	1,344,773.0	1,344,522.9	1,344,231.0	1,343,761.6	1,343,520.3

Annual Demand by Rate Schedule (GJ)

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	77,329,419	75,460,885	73,597,590	71,034,349	68,559,043	66,655,400	64,721,349	62,838,101	60,747,247	58,638,703	56,535,026	54,341,435	52,130,423	49,933,383	47,590,566	45,176,111	42,774,323	40,343,372	37,920,985	35,601,565	33,532,463	31,697,787	30,062,048	28,644,680
RATE2	28,276,686	27,112,738	26,113,346	24,886,283	23,710,431	22,758,310	21,811,467	20,897,540	19,956,664	19,062,165	18,215,485	17,399,013	16,588,493	15,853,038	15,190,261	14,563,973	13,996,097	13,468,436	12,978,102	12,519,040	12,095,029	11,697,926	11,327,362	10,981,871
RATE3	22,654,720	22,217,065	21,951,887	21,445,085	20,932,282	20,600,637	20,301,118	19,929,421	19,550,352	19,146,531	18,773,682	18,375,385	17,908,083	17,539,956	17,212,077	16,937,289	16,691,657	16,482,145	16,330,620	16,118,866	15,968,302	15,802,970	15,648,196	15,527,463
RATE4	153,036	37,825	38,680	27,342	21,557	10,733	10,697	10,656	10,613	10,576	10,540	10,502	10,453	10,409	10,367	10,320	10,277	10,232	10,185	10,134	10,087	10,036	9,986	9,938
RATE5	5,725,320	5,745,150	5,565,930	5,355,515	5,139,420	5,004,902	4,828,475	4,693,008	4,508,961	4,264,595	4,145,687	4,006,077	3,852,296	3,699,481	3,525,546	3,405,616	3,284,426	3,188,193	3,111,666	3,032,100	2,951,602	2,879,064	2,799,874	2,738,068
RATE6	48,303	43,248	42,645	41,686	36,860	36,409	35,938	35,491	35,031	34,552	34,052	33,507	32,927	32,336	31,754	31,190	30,690	30,224	29,788	29,376	29,002	28,650	28,306	28,006
RATE7	2,962,569	3,713,178	3,569,771	3,585,485	3,548,199	3,427,876	3,417,291	3,407,591	3,398,215	3,388,725	3,379,083	3,269,008	3,254,886	3,243,085	3,232,595	3,220,696	3,210,611	3,200,274	3,189,207	3,176,620	3,163,947	3,147,614	3,125,517	3,099,640
RATE22	43,331,994	44,082,834	40,866,026	40,192,570	38,679,737	38,126,019	37,933,048	35,701,523	35,460,690	35,220,999	34,985,697	34,647,546	31,978,137	31,462,340	31,361,917	28,342,775	28,266,467	28,183,677	27,811,001	27,043,503	26,906,902	26,232,068	24,785,380	24,107,085
RATE23	7,276,338	7,196,714	6,977,763	6,856,804	6,686,173	6,526,771	6,431,096	6,374,108	6,375,427	6,300,147	6,232,347	6,101,238	6,022,032	5,894,682	5,908,588	5,906,574	5,873,113	5,870,762	5,887,240	5,845,974	5,851,977	5,878,745	5,863,128	6,431,349
RATE25	13,985,419	12,850,249	12,275,054	11,831,444	11,258,192	10,973,257	10,721,402	10,470,645	10,031,860	9,773,946	9,423,960	8,999,177	8,581,376	8,351,737	7,970,885	7,820,962	7,671,433	7,475,905	7,302,069	6,889,342	6,754,357	6,594,346	6,206,343	5,822,133
RATE27	5,901,402	6,251,439	6,056,188	5,878,088	5,710,433	5,681,283	5,495,366	5,422,009	5,151,387	4,905,269	4,860,993	4,743,444	4,695,559	4,609,423	4,216,798	4,176,786	4,154,191	4,131,294	3,991,895	3,920,916	3,896,134	3,783,135	3,749,163	3,712,057
RATE46	1,640,376	4,454,038	4,404,027	4,583,177	4,904,574	5,228,623	5,851,926	6,438,279	6,767,051	7,095,853	7,424,698	8,083,329	8,081,305	8,080,005	8,078,431	8,075,490	8,073,981	8,072,434	8,070,716	8,068,638	8,067,138	8,065,386	8,062,569	8,061,122
Grand Total	**209,285,582**	**209,165,363**	**201,458,906**	**195,717,827**	**189,186,903**	**185,030,220**	**181,559,172**	**176,218,372**	**171,993,497**	**167,842,061**	**164,021,250**	**160,009,661**	**153,135,971**	**148,709,875**	**144,329,785**	**137,667,781**	**134,037,264**	**130,456,948**	**126,633,472**	**122,256,075**	**119,226,940**	**115,817,727**	**111,667,873**	**109,163,411**

1.4 Priced-Based Regulation

Year End Customers by Rate Schedule

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	942,769	952,204	959,904	968,373	975,522	982,245	988,426	994,357	1,000,045	1,005,513	1,010,764	1,015,826	1,020,705	1,025,417	1,029,967	1,034,365	1,038,609	1,042,710	1,046,668	1,050,486	1,054,180	1,057,756	1,061,334	1,064,902
RATE2	89,023	89,864	90,740	91,605	92,482	93,357	94,231	95,108	95,979	96,852	97,731	98,593	99,467	100,339	101,214	102,074	102,940	103,787	104,616	105,429	106,238	107,023	107,820	108,616
RATE3	6,990	7,234	7,480	7,731	7,979	8,228	8,474	8,743	9,012	9,293	9,579	9,866	10,154	10,455	10,757	11,064	11,364	11,679	11,985	12,300	12,609	12,921	13,234	13,551
RATE4	15	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
RATE5	572	575	578	580	582	585	585	585	585	585	585	585	584	584	584	584	584	584	584	584	584	584	584	584
RATE6	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
RATE7	46	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
RATE22	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
RATE23	867	899	937	974	1,010	1,046	1,080	1,115	1,156	1,192	1,231	1,269	1,313	1,358	1,401	1,445	1,492	1,531	1,578	1,627	1,668	1,719	1,760	1,811
RATE25	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525
RATE27	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
RATE46	16	13	13	9	10	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Grand Total	**1,040,990**	**1,051,542**	**1,060,405**	**1,070,025**	**1,078,338**	**1,086,225**	**1,093,560**	**1,100,672**	**1,107,541**	**1,114,199**	**1,120,654**	**1,126,903**	**1,132,987**	**1,138,917**	**1,144,687**	**1,150,296**	**1,155,753**	**1,161,055**	**1,166,195**	**1,171,190**	**1,176,043**	**1,180,767**	**1,185,496**	**1,190,228**

Annual Use Rate per Customer by Rate Schedule (GJ)

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	82.0	80.4	77.4	74.5	71.8	68.2	65.0	61.9	59.0	56.4	53.7	51.2	48.1	45.2	42.3	39.6	36.9	34.3	31.8	29.4	27.2	25.0	22.9	20.9
RATE2	317.6	317.6	308.6	299.4	290.8	278.1	266.4	254.8	243.7	234.0	223.2	212.8	200.3	188.0	175.9	164.2	152.5	140.9	129.7	118.6	107.7	96.9	86.3	75.9
RATE3	3,241.0	3,274.1	3,184.2	3,082.3	2,984.8	2,847.3	2,720.8	2,595.8	2,472.9	2,369.6	2,254.3	2,143.0	2,011.0	1,881.2	1,755.9	1,633.8	1,511.2	1,391.3	1,277.1	1,164.8	1,053.8	943.8	835.1	729.1
RATE4	10,202.4	9,517.8	9,457.8	9,175.8	9,002.5	8,609.9	8,274.0	7,932.8	7,575.5	7,274.3	6,920.8	6,561.0	6,131.5	5,695.5	5,252.2	4,816.3	4,358.5	3,897.0	3,467.5	3,037.3	2,607.2	2,175.9	1,742.8	1,312.8
RATE5	10,009.3	10,277.3	10,018.5	9,740.4	9,465.3	9,170.7	8,954.1	8,739.0	8,478.5	8,266.4	8,003.1	7,736.8	7,410.3	7,060.4	6,701.8	6,344.8	5,965.1	5,577.3	5,200.3	4,815.2	4,420.1	4,015.4	3,599.3	3,179.8
RATE6	3,220.2	3,208.0	3,136.7	3,065.9	3,001.3	2,893.4	2,793.1	2,694.3	2,600.8	2,520.7	2,429.0	2,339.7	2,226.1	2,113.1	2,001.4	1,892.5	1,782.0	1,672.0	1,562.3	1,453.6	1,344.7	1,236.0	1,127.4	1,020.8
RATE7	64,403.7	80,560.5	75,850.4	74,581.2	72,213.9	68,813.6	65,944.3	62,904.8	59,386.1	56,435.2	53,086.3	49,700.9	46,166.7	42,566.2	38,889.1	35,290.5	31,474.3	27,622.4	24,128.5	20,629.0	17,136.5	13,644.9	10,135.9	6,656.4
RATE22	866,639.9	897,219.9	816,009.6	784,937.3	756,478.7	708,520.4	673,745.7	633,309.8	582,571.1	539,096.6	492,838.4	447,673.7	405,531.2	364,147.9	323,502.9	284,957.1	245,775.4	208,157.0	177,921.1	147,954.0	118,535.1	89,550.1	60,734.7	32,476.3
RATE23	8,392.5	8,721.6	8,325.5	8,075.9	7,763.7	7,405.9	7,042.4	6,724.9	6,374.9	6,082.3	5,764.3	5,474.0	5,098.6	4,736.9	4,387.7	4,235.0	3,856.4	3,505.4	3,172.8	2,849.5	2,538.0	2,223.5	1,920.1	1,617.6
RATE25	26,638.9	27,781.3	26,875.6	26,076.2	25,294.7	24,088.8	23,019.8	21,837.0	20,429.4	19,214.7	17,908.9	16,636.8	15,469.4	14,307.6	13,155.5	12,040.8	10,897.7	9,768.5	8,737.5	7,719.0	6,713.9	5,722.6	4,738.9	3,777.7
RATE27	57,856.9	63,563.8	60,627.7	58,741.6	56,950.3	54,278.3	51,943.6	49,392.1	46,353.0	43,764.7	40,915.8	38,091.8	35,375.2	32,636.8	29,872.1	27,181.4	24,371.2	21,563.3	19,018.2	16,485.2	13,971.8	11,475.6	8,981.7	6,524.9
RATE46	102,523.5	342,617.1	336,849.2	150,592.3	965,528.9	2,116,107.2	3,036,015.9	3,588,063.9	4,111,450.0	4,874,567.8	5,036,654.9	5,170,825.0	4,949,185.8	4,725,618.8	4,501,557.7	4,280,397.5	4,052,059.8	3,821,767.4	3,588,511.2	3,353,925.6	3,115,497.1	2,874,086.0	2,629,003.3	2,385,241.6

Annual Demand by Rate Schedule (GJ)

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	77,329,188	76,522,329	74,333,570	72,146,171	70,040,798	67,017,014	64,220,228	61,503,931	58,954,890	56,737,270	54,322,564	52,025,194	49,134,700	46,331,840	43,594,622	40,954,701	38,333,707	35,786,963	33,313,645	30,928,016	28,637,453	26,445,874	24,344,403	22,236,764
RATE2	28,276,686	28,541,501	28,005,290	27,428,093	26,894,575	25,962,771	25,102,071	24,236,042	23,388,699	22,661,917	21,817,964	20,981,859	19,923,113	18,861,456	17,802,874	16,761,509	15,694,126	14,623,317	13,565,881	12,508,179	11,444,726	10,375,678	9,302,122	8,241,948
RATE3	22,654,720	23,684,508	23,817,569	23,829,232	23,815,452	23,427,916	23,055,667	22,694,968	22,285,831	22,020,313	21,594,418	21,142,654	20,419,500	19,667,751	18,888,264	18,076,237	17,172,776	16,248,758	15,306,056	14,326,838	13,287,453	12,195,365	11,051,109	9,879,669
RATE4	153,036	152,284	151,324	146,813	144,040	137,758	132,384	126,925	121,208	116,389	110,734	104,976	98,105	91,128	84,035	77,061	69,737	62,352	55,481	48,596	41,715	34,815	27,886	21,004
RATE5	5,725,320	5,909,449	5,790,672	5,649,428	5,508,781	5,364,837	5,238,170	5,112,299	4,959,893	4,835,837	4,681,796	4,526,031	4,327,617	4,123,300	3,913,838	3,705,391	3,483,632	3,257,126	3,036,961	2,812,090	2,581,355	2,344,991	2,101,990	1,857,005
RATE6	48,303	48,120	47,050	45,988	45,019	43,400	41,896	40,414	39,012	37,810	36,434	35,095	33,391	31,697	30,022	28,388	26,729	25,081	23,435	21,803	20,170	18,541	16,911	15,312
RATE7	2,962,569	3,625,223	3,413,267	3,356,153	3,249,624	3,096,614	2,967,492	2,830,718	2,672,373	2,539,586	2,388,885	2,236,542	2,077,503	1,915,479	1,750,010	1,588,074	1,416,342	1,243,010	1,085,783	928,303	771,142	614,021	456,117	299,538
RATE22	43,331,994	44,860,994	40,800,478	39,246,864	37,823,935	35,426,021	33,687,287	31,665,491	29,128,556	26,954,832	24,641,921	22,383,686	20,276,562	18,207,393	16,175,143	14,247,854	12,288,769	10,407,852	8,896,054	7,397,698	5,926,755	4,477,506	3,036,733	1,623,817
RATE23	7,276,338	7,840,732	7,800,952	7,865,966	7,841,346	7,746,523	7,605,811	7,498,310	7,369,357	7,250,110	7,095,910	6,946,520	6,694,416	6,432,763	6,147,104	6,119,632	5,753,696	5,366,798	5,006,603	4,636,070	4,233,457	3,822,146	3,379,393	2,929,558
RATE25	13,985,419	14,585,159	14,109,694	13,689,986	13,279,723	12,646,603	12,085,414	11,464,412	10,725,436	10,087,701	9,402,196	8,734,331	8,121,432	7,511,480	6,906,646	6,321,428	5,721,275	5,128,465	4,587,199	4,052,452	3,524,807	3,004,368	2,487,943	1,983,278
RATE27	5,901,402	6,483,512	6,184,030	5,991,647	5,808,934	5,536,387	5,298,252	5,037,989	4,728,011	4,464,003	4,173,409	3,885,359	3,608,267	3,328,955	3,046,956	2,772,507	2,485,860	2,199,459	1,939,856	1,681,494	1,425,128	1,170,514	916,138	665,540
RATE46	1,640,376	4,454,022	4,379,039	1,355,331	9,655,289	23,277,179	33,396,174	39,468,703	45,225,950	53,620,245	55,403,203	56,879,075	54,441,044	51,981,807	49,517,134	47,084,373	44,572,658	42,039,441	39,473,623	36,893,181	34,270,468	31,614,946	28,919,036	26,237,658
Grand Total	**209,285,351**	**216,707,832**	**208,832,937**	**200,751,670**	**204,107,516**	**209,683,023**	**212,830,845**	**211,680,203**	**209,599,216**	**211,326,014**	**205,669,435**	**199,881,324**	**189,155,651**	**178,485,048**	**167,856,648**	**157,737,156**	**147,019,309**	**136,388,621**	**126,290,578**	**116,234,721**	**106,164,631**	**96,118,765**	**86,039,780**	**75,991,092**

1.5 Economic Stagnation

Year End Customers by Rate Schedule

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RATE1	942,769	944,540	951,806	958,311	964,302	969,784	974,710	979,204	983,606	987,995	991,740	995,502
RATE2	89,023	87,601	88,119	88,628	89,133	89,642	90,141	90,649	91,136	91,631	92,131	92,620
RATE3	6,990	6,899	7,080	7,266	7,451	7,638	7,837	8,033	8,248	8,461	8,693	8,918
RATE4	15	4	4	3	2	1	1	1	1	1	1	1
RATE5	572	555	552	548	545	544	539	536	525	515	513	507
RATE6	15	14	14	14	13	13	13	13	13	13	13	13
RATE7	46	45	45	45	45	44	44	44	44	44	44	42
RATE22	50	46	46	46	44	44	44	40	40	40	40	39
RATE23	867	815	827	847	864	875	891	915	939	964	984	1,004
RATE25	525	448	443	438	428	420	415	408	399	390	383	376
RATE27	102	95	95	94	93	93	89	87	84	81	80	78
RATE46	16	13	13	9	9	9	9	3	3	3	3	3
Grand Total	**1,040,990**	**1,041,075**	**1,049,044**	**1,056,249**	**1,062,929**	**1,069,107**	**1,074,733**	**1,079,933**	**1,085,038**	**1,090,138**	**1,094,625**	**1,099,103**

Rate Class	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	999,082	1,002,780	1,005,745	1,008,839	1,012,107	1,014,583	1,017,240	1,020,116	1,022,517	1,024,800	1,027,077	1,028,963
RATE2	93,099	93,596	94,085	94,565	95,044	95,507	95,958	96,388	96,806	97,208	97,625	98,017
RATE3	9,144	9,386	9,625	9,866	10,115	10,370	10,620	10,864	11,118	11,360	11,610	11,867
RATE4	1	1	1	1	1	1	1	1	1	1	1	1
RATE5	503	496	489	482	477	471	471	468	466	463	461	460
RATE6	13	13	13	13	13	13	13	13	13	13	13	13
RATE7	42	42	42	42	42	42	42	42	42	42	42	42
RATE22	35	35	35	30	30	30	29	28	28	26	23	22
RATE23	1,031	1,056	1,089	1,120	1,152	1,184	1,217	1,244	1,280	1,317	1,345	1,380
RATE25	363	357	348	345	340	332	327	319	310	303	289	274
RATE27	78	77	71	70	70	70	68	67	67	66	66	66
RATE46	3	3	3	3	3	3	3	3	3	3	3	3
Grand Total	**1,103,394**	**1,107,842**	**1,111,546**	**1,115,376**	**1,119,394**	**1,122,606**	**1,125,989**	**1,129,553**	**1,132,651**	**1,135,602**	**1,138,555**	**1,141,108**

Annual Use Rate per Customer by Rate Schedule (GJ)

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RATE1	82.0	82.0	81.9	81.1	80.6	80.2	80.1	80.0	79.8	80.0	80.2	80.4
RATE2	317.6	320.0	318.1	313.5	312.3	312.3	314.0	315.4	316.5	318.9	321.4	323.8
RATE3	3,241.0	3,307.2	3,287.0	3,231.3	3,202.9	3,188.0	3,193.9	3,190.4	3,186.4	3,196.7	3,208.3	3,219.7
RATE4	10,202.4	9,563.1	9,903.7	9,494.1	11,160.1	11,140.9	11,195.5	11,225.1	11,247.9	11,328.7	11,418.0	11,505.8
RATE5	10,009.3	10,489.7	10,442.0	10,335.4	10,235.0	10,202.8	10,233.8	10,283.8	10,329.4	10,343.5	10,430.5	10,552.0
RATE6	3,220.2	3,120.9	3,110.2	3,073.9	2,942.0	2,923.3	2,919.6	2,913.7	2,906.4	2,911.2	2,917.4	2,922.8
RATE7	64,403.7	80,836.1	77,823.1	77,830.6	76,485.8	74,883.4	74,616.0	74,292.5	73,854.2	73,968.2	74,160.5	75,621.3
RATE22	866,639.9	936,655.9	870,624.5	858,100.6	863,800.5	847,983.5	847,013.8	879,584.5	874,616.8	875,481.3	877,167.6	896,592.5
RATE23	8,392.5	8,956.9	8,742.7	8,559.5	8,383.8	8,253.0	8,205.7	8,148.1	8,142.7	8,110.1	8,122.2	8,072.5
RATE25	26,638.9	28,339.9	27,742.8	27,398.0	27,086.0	27,153.2	27,297.4	27,520.5	27,409.3	27,755.8	27,854.6	27,743.7
RATE27	57,856.9	64,493.4	62,897.3	61,896.0	60,950.5	60,555.0	61,588.3	62,381.6	61,202.0	61,063.7	61,876.9	62,651.6
RATE46	102,523.5	342,614.3	338,745.2	139,176.5	137,883.5	136,247.4	168,177.4	586,779.9	583,978.1	583,676.7	583,745.7	583,743.4

Rate Class	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	80.5	80.6	80.6	80.6	80.4	80.2	79.9	79.5	79.2	78.9	78.6	78.3
RATE2	326.0	328.2	330.3	332.3	334.5	336.7	338.8	340.7	342.6	344.5	346.2	348.0
RATE3	3,229.0	3,241.5	3,250.3	3,259.4	3,270.3	3,283.6	3,298.6	3,307.1	3,318.1	3,327.7	3,334.0	3,344.2
RATE4	11,585.2	11,671.7	11,756.2	11,830.5	11,900.7	11,970.7	12,039.1	12,106.2	12,175.9	12,172.0	12,161.7	12,159.9
RATE5	10,619.9	10,721.1	10,719.4	10,808.6	10,844.1	10,931.2	10,958.2	11,004.3	11,035.9	11,066.0	11,073.4	11,093.1
RATE6	2,925.9	2,930.3	2,933.9	2,935.2	2,938.8	2,942.2	2,945.0	2,946.9	2,949.1	2,950.9	2,951.1	2,952.8
RATE7	75,740.2	75,909.2	76,065.1	76,160.9	76,298.1	76,433.0	76,554.0	76,667.6	76,796.2	76,804.9	76,765.2	76,788.6
RATE22	938,048.5	939,546.4	940,885.9	972,011.0	973,496.2	974,961.4	1,000,605.3	1,014,528.0	1,015,980.5	1,075,209.0	1,129,208.6	1,167,552.3
RATE23	8,065.6	8,028.6	8,038.3	8,062.9	8,023.3	8,027.8	8,032.0	8,012.3	7,988.2	8,002.6	7,994.0	8,356.7
RATE25	27,992.9	28,304.1	28,287.4	28,450.4	28,734.0	29,067.6	29,176.4	28,872.4	29,419.2	29,729.2	29,597.7	29,514.5
RATE27	62,835.8	63,187.9	62,622.6	63,434.6	63,607.7	63,778.8	64,091.1	64,373.1	64,534.7	64,281.0	64,274.9	64,317.5
RATE46	583,378.4	583,308.3	583,140.7	582,560.2	582,467.5	582,367.0	582,214.4	581,962.0	581,852.6	581,655.5	581,212.9	581,088.1

Annual Demand by Rate Schedule (GJ)

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RATE1	77,329,375	77,485,216	77,966,958	77,720,067	77,677,901	77,784,912	78,122,806	78,347,252	78,515,017	79,004,462	79,527,122	80,022,027
RATE2	28,276,686	28,035,043	28,034,225	27,785,778	27,839,356	27,997,697	28,308,117	28,591,545	28,844,596	29,223,232	29,614,869	29,994,653
RATE3	22,654,720	22,816,051	23,271,708	23,478,662	23,864,839	24,349,894	25,030,259	25,628,841	26,281,092	27,047,601	27,889,373	28,713,517
RATE4	153,036	38,253	39,615	28,482	22,320	11,141	11,196	11,225	11,248	11,329	11,418	11,506
RATE5	5,725,320	5,821,787	5,763,982	5,663,781	5,578,076	5,550,306	5,516,044	5,512,132	5,422,941	5,326,900	5,350,822	5,349,859
RATE6	48,303	43,693	43,543	43,035	38,246	38,003	37,954	37,878	37,783	37,845	37,926	37,996
RATE7	2,962,569	3,637,623	3,502,039	3,502,375	3,441,863	3,294,870	3,283,106	3,268,871	3,249,585	3,254,599	3,263,063	3,176,095
RATE22	43,331,994	43,086,172	40,048,729	39,472,627	38,007,224	37,311,273	37,268,608	35,183,380	34,984,672	35,019,253	35,086,705	34,967,107
RATE23	7,276,338	7,299,835	7,230,228	7,249,892	7,243,631	7,221,386	7,311,244	7,455,515	7,645,952	7,818,157	7,992,285	8,104,827
RATE25	13,985,419	12,696,290	12,290,049	12,000,344	11,592,822	11,404,330	11,328,432	11,228,360	10,936,301	10,824,780	10,668,293	10,431,647
RATE27	5,901,402	6,126,877	5,975,240	5,818,225	5,668,395	5,631,613	5,481,360	5,427,202	5,140,965	4,946,156	4,950,152	4,886,827
RATE46	1,640,376	4,453,986	4,403,688	1,252,589	1,240,952	1,226,227	1,513,597	1,760,340	1,751,934	1,751,030	1,751,237	1,751,230
Grand Total	**209,285,538**	**211,540,825**	**208,570,003**	**204,015,858**	**202,215,625**	**201,821,653**	**203,212,722**	**202,452,542**	**202,822,085**	**204,265,346**	**206,143,264**	**207,447,291**

Rate Class	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	80,447,965	80,824,195	81,108,866	81,268,945	81,388,535	81,381,404	81,261,128	81,117,437	80,993,919	80,848,002	80,677,818	80,564,020
RATE2	30,346,077	30,718,419	31,080,509	31,422,220	31,789,588	32,153,939	32,506,481	32,840,454	33,167,985	33,485,948	33,793,185	34,111,373
RATE3	29,526,009	30,424,572	31,284,398	32,157,617	33,079,195	34,050,587	35,030,906	35,928,351	36,890,380	37,802,898	38,708,045	39,685,357
RATE4	11,585	11,672	11,756	11,831	11,901	11,971	12,039	12,106	12,176	12,172	12,162	12,160
RATE5	5,341,807	5,317,665	5,241,802	5,209,728	5,172,627	5,148,595	5,161,306	5,149,997	5,142,723	5,123,539	5,104,846	5,102,807
RATE6	38,037	38,094	38,140	38,158	38,205	38,249	38,285	38,309	38,338	38,362	38,364	38,386
RATE7	3,181,090	3,188,184	3,194,732	3,198,759	3,204,520	3,210,187	3,215,269	3,220,041	3,225,439	3,225,805	3,224,139	3,225,121
RATE22	32,831,698	32,884,124	32,931,007	29,160,331	29,204,886	29,248,842	29,017,552	28,406,784	28,447,453	27,955,434	25,971,798	25,686,150
RATE23	8,315,609	8,478,176	8,753,685	9,030,438	9,242,836	9,504,894	9,774,946	9,967,297	10,224,892	10,539,380	10,751,983	11,532,312
RATE25	10,161,436	10,104,573	9,844,020	9,815,397	9,769,547	9,650,460	9,540,668	9,210,310	9,119,957	9,007,935	8,553,747	8,086,967
RATE27	4,901,192	4,865,471	4,446,206	4,440,424	4,452,539	4,464,513	4,358,193	4,312,998	4,323,825	4,242,548	4,242,143	4,244,956
RATE46	1,750,135	1,749,925	1,749,422	1,747,681	1,747,402	1,747,101	1,746,643	1,745,886	1,745,558	1,744,966	1,743,639	1,743,264
Grand Total	**206,852,642**	**208,605,070**	**209,684,544**	**207,501,528**	**209,101,782**	**210,610,742**	**211,663,417**	**211,949,970**	**213,332,646**	**214,026,990**	**212,821,867**	**214,032,873**

1.6 Upper Bound

Year End Customers by Rate Schedule

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	942,769	959,876	966,714	976,408	985,618	994,479	1,002,143	1,009,337	1,016,298	1,023,032	1,029,564	1,035,902	1,042,063	1,048,060	1,053,898	1,059,584	1,065,120	1,070,504	1,075,755	1,080,869	1,085,853	1,090,718	1,095,587	1,100,453
RATE2	89,023	92,139	93,341	94,594	95,836	97,073	98,327	99,571	100,829	102,066	103,325	104,583	105,831	107,092	108,341	109,588	110,832	112,069	113,284	114,488	115,676	116,843	118,025	119,203
RATE3	6,990	7,574	7,882	8,187	8,496	8,794	9,122	9,443	9,779	10,103	10,458	10,815	11,168	11,523	11,884	12,246	12,623	12,999	13,370	13,738	14,114	14,485	14,866	15,234
RATE4	15	24	24	26	26	28	28	33	33	35	38	39	41	41	42	42	43	45	45	48	48	51	53	54
RATE5	572	597	605	611	619	626	633	637	649	655	658	661	665	672	679	686	691	698	700	703	712	716	721	726
RATE6	15	16	16	16	17	17	17	17	17	17	17	17	18	18	18	18	18	19	19	19	19	19	19	19
RATE7	46	45	45	45	45	46	46	46	46	46	46	48	48	48	48	48	48	48	48	48	48	48	48	48
RATE22	50	56	57	57	58	58	58	63	63	63	67	68	68	68	68	72	72	72	74	74	74	76	77	78
RATE23	867	1,004	1,048	1,099	1,152	1,197	1,250	1,308	1,373	1,428	1,481	1,536	1,596	1,655	1,714	1,780	1,843	1,905	1,966	2,029	2,086	2,154	2,221	2,284
RATE25	525	608	623	645	663	682	698	715	734	754	767	789	816	833	852	868	883	904	918	938	960	985	1,006	1,024
RATE27	102	109	109	110	111	112	116	116	121	123	124	125	125	129	133	135	135	135	136	140	142	144	144	145
RATE46	16	13	13	12	13	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Grand Total	**1,040,990**	**1,062,061**	**1,070,477**	**1,081,810**	**1,092,654**	**1,103,126**	**1,112,452**	**1,121,300**	**1,129,956**	**1,138,336**	**1,146,559**	**1,154,597**	**1,162,453**	**1,170,153**	**1,177,691**	**1,185,081**	**1,192,322**	**1,199,412**	**1,206,329**	**1,213,108**	**1,219,746**	**1,226,253**	**1,232,781**	**1,239,282**

Annual Use Rate per Customer by Rate Schedule (GJ)

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	82.0	80.7	78.4	76.1	74.5	71.9	69.6	67.6	65.6	63.9	62.0	60.2	57.8	55.5	53.3	51.2	49.1	47.1	45.2	43.3	41.5	39.7	38.1	36.4
RATE2	317.6	317.4	309.6	301.8	296.7	287.8	279.9	272.9	265.8	259.8	253.4	247.0	238.7	230.6	222.8	215.8	208.2	200.9	193.9	186.8	179.8	173.2	167.1	160.6
RATE3	3,241.0	3,263.2	3,182.1	3,095.8	3,032.1	2,928.4	2,839.3	2,757.0	2,671.9	2,599.4	2,527.0	2,454.3	2,362.5	2,271.5	2,185.3	2,109.2	2,025.7	1,944.2	1,867.1	1,790.5	1,713.5	1,641.1	1,575.3	1,503.8
RATE4	10,202.4	10,117.8	10,107.6	9,752.6	9,720.6	9,312.8	9,073.2	8,637.6	8,403.3	8,020.5	7,910.9	7,881.1	7,511.8	7,207.1	6,919.0	6,647.6	6,343.9	5,984.3	5,687.7	5,460.4	5,149.3	4,837.0	4,593.7	4,275.9
RATE5	10,009.3	10,206.2	9,982.6	9,740.9	9,537.4	9,323.4	9,247.4	9,131.9	8,965.6	8,868.9	8,726.5	8,568.1	8,340.8	8,090.4	7,884.7	7,659.4	7,431.7	7,179.5	6,960.8	6,715.3	6,461.9	6,230.1	6,017.6	5,763.2
RATE6	3,220.2	3,239.0	3,173.2	3,110.0	3,084.9	2,995.6	2,914.9	2,842.9	2,771.9	2,711.3	2,646.5	2,581.6	2,515.3	2,430.2	2,347.8	2,272.3	2,191.5	2,127.4	2,050.8	1,973.6	1,897.2	1,824.0	1,755.0	1,682.7
RATE7	64,403.7	80,693.4	76,183.1	75,384.8	73,587.6	71,344.1	68,865.4	66,451.4	63,532.0	61,045.4	58,477.1	54,906.5	52,153.9	49,362.6	46,648.0	44,191.2	41,409.7	38,648.4	36,035.1	33,309.6	30,544.8	27,875.0	25,440.7	22,718.5
RATE22	866,639.9	855,685.3	780,468.3	758,510.2	731,887.9	694,553.3	667,262.5	641,024.6	602,914.1	569,298.8	528,426.8	490,532.4	459,271.8	428,220.1	398,916.4	370,539.8	342,353.7	315,163.8	287,454.2	262,470.7	237,796.2	211,357.5	192,519.2	169,199.5
RATE23	8,392.5	8,606.5	8,261.5	8,061.2	7,815.6	7,505.4	7,212.7	7,369.5	7,106.6	6,872.4	6,641.2	6,392.4	6,109.6	5,818.1	5,550.3	5,319.4	5,061.0	4,802.2	4,574.4	4,337.9	4,098.1	3,873.2	3,685.5	3,463.4
RATE25	26,638.9	27,946.7	27,465.5	27,039.7	26,770.3	25,912.7	25,040.0	24,222.4	23,250.0	22,314.1	21,429.7	20,525.7	19,654.0	18,803.6	18,073.4	17,332.8	16,546.5	15,797.1	15,062.0	14,319.6	13,622.2	12,824.7	12,212.4	11,489.0
RATE27	57,856.9	63,703.6	61,031.7	59,870.7	58,879.1	56,712.2	54,307.1	52,398.6	50,491.2	48,353.9	45,921.0	43,868.8	41,804.5	39,455.3	37,931.2	35,935.4	33,900.9	31,897.7	30,092.0	27,989.2	25,885.4	24,176.3	22,458.9	20,548.7
RATE46	102,523.5	342,622.9	389,428.9	476,928.0	1,134,900.1	2,087,738.8	2,877,466.1	3,388,447.4	3,880,052.0	11,347,285.5	11,568,097.8	11,768,306.4	11,687,987.8	11,608,953.3	11,533,925.7	11,469,515.7	11,395,958.8	11,324,409.4	11,257,769.5	11,189,950.2	11,123,071.2	11,060,770.9	11,005,286.4	10,943,748.5

Annual Demand by Rate Schedule (GJ)

Rate Class	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
RATE1	77,329,188	77,430,843	75,811,842	74,339,451	73,444,346	71,544,912	69,790,724	68,222,123	66,653,919	65,325,082	63,861,690	62,355,032	60,266,832	58,182,355	56,152,072	54,293,763	52,315,134	50,408,908	48,618,296	46,810,239	45,014,564	43,304,047	41,701,810	40,003,113
RATE2	28,276,686	29,241,889	28,893,997	28,545,789	28,429,930	27,935,718	27,521,220	27,168,185	26,796,730	26,512,429	26,180,081	25,831,111	25,264,020	24,695,926	24,137,545	23,649,132	23,079,354	22,511,825	21,962,890	21,387,636	20,801,137	20,237,540	19,722,151	19,144,929
RATE3	22,654,720	24,715,851	25,081,175	25,345,676	25,761,044	25,751,998	25,900,407	26,033,983	26,128,171	26,261,872	26,427,513	26,542,910	26,384,479	26,174,169	25,969,985	25,828,909	25,570,232	25,272,769	24,962,719	24,598,143	24,184,564	23,771,918	23,418,366	22,909,265
RATE4	153,036	242,827	242,583	253,569	252,735	260,757	254,051	285,040	277,310	280,718	300,614	307,362	307,985	295,492	290,598	279,201	272,788	269,293	255,948	262,100	247,167	246,686	243,468	230,898
RATE5	5,725,320	6,093,077	6,039,464	5,951,668	5,903,665	5,836,438	5,853,603	5,816,999	5,818,679	5,809,129	5,742,037	5,663,539	5,546,611	5,436,737	5,353,733	5,254,337	5,135,285	5,011,305	4,872,587	4,720,822	4,600,872	4,460,767	4,338,680	4,184,108
RATE6	48,303	51,823	50,772	49,761	52,443	50,926	49,553	48,329	47,122	46,093	44,990	43,888	45,275	43,744	42,260	40,902	39,446	40,421	38,965	37,498	36,047	34,656	33,346	31,972
RATE7	2,962,569	3,631,203	3,428,238	3,392,315	3,311,443	3,281,828	3,167,806	3,056,765	2,922,472	2,808,087	2,689,946	2,635,510	2,503,388	2,369,404	2,239,103	2,121,178	1,987,666	1,855,125	1,729,687	1,598,860	1,466,151	1,337,998	1,221,152	1,090,489
RATE22	43,331,994	47,918,379	44,486,692	43,235,084	42,449,497	40,284,092	38,701,227	40,384,550	37,983,590	35,865,824	35,404,598	33,356,203	31,230,483	29,118,969	27,126,314	26,678,867	24,649,466	22,691,796	21,271,608	19,422,832	17,596,916	16,063,173	14,823,975	13,197,565
RATE23	7,276,338	8,640,907	8,658,058	8,859,216	9,003,569	8,983,950	9,015,889	9,639,362	9,757,361	9,813,736	9,835,543	9,818,768	9,750,877	9,629,037	9,513,279	9,468,556	9,327,331	9,148,164	8,993,254	8,801,622	8,548,725	8,342,792	8,185,560	7,910,431
RATE25	13,985,419	16,991,598	17,111,027	17,440,593	17,748,722	17,672,437	17,477,917	17,319,019	17,065,479	16,824,864	16,436,582	16,194,793	16,037,674	15,663,372	15,398,578	15,044,871	14,610,598	14,280,560	13,826,909	13,431,803	13,077,306	12,632,346	12,285,676	11,764,775
RATE27	5,901,402	6,943,691	6,652,459	6,585,779	6,535,583	6,351,768	6,299,629	6,078,239	6,109,439	5,947,525	5,694,201	5,483,598	5,225,568	5,089,731	5,044,851	4,851,282	4,576,628	4,306,185	4,092,505	3,918,493	3,675,726	3,481,383	3,234,088	2,979,568
RATE46	1,640,376	4,454,098	5,062,576	5,723,136	14,753,701	29,228,343	40,284,525	47,438,264	54,320,727	158,861,998	161,953,369	164,756,289	163,631,829	162,525,346	161,474,959	160,573,220	159,543,424	158,541,731	157,608,773	156,659,302	155,722,997	154,850,793	154,074,010	153,212,479
Grand Total	**209,285,351**	**226,356,186**	**221,518,883**	**219,722,036**	**227,646,678**	**237,183,166**	**244,316,551**	**251,490,858**	**253,880,999**	**354,357,356**	**354,571,165**	**352,989,005**	**346,195,020**	**339,224,281**	**332,743,276**	**328,084,218**	**321,107,353**	**314,338,083**	**308,234,141**	**301,649,350**	**294,972,172**	**288,764,098**	**283,282,283**	**276,659,590**

Appendix B-5

ANNUAL DEMAND FORECAST RESULTS

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Appendix B-6

HIGH-LEVEL ASSESSMENT OF THE EFFECTIVENESS OF THE TRADITIONAL AND END USE METHODS

APPENDIX B-6: HIGH LEVEL ASSESSMENT OF THE EFFECTIVENESS OF THE TRADITIONAL AND END USE METHODS

In the Decision and Order G-39-19 related to the 2017 Long Term Gas Resource Plan FEI was directed to include a high-level assessment of the effectiveness of the Traditional and End Use Models compared to actual results.

Measuring the effectiveness of the long-term forecasting method in a scenario analysis context goes far beyond how accurately the method predicted the actual outcome in a given year, since by its very nature forecasting cannot predict the outcome of all uncertainties. A complete evaluation of a long-term forecasting method includes how well the forecast model can explore different future outcomes and how useful it is for the organization employing the method to analyze and understand the nature of future uncertainties, discuss these uncertainties and potential future outcomes with stakeholders, and inform the decisions the organization needs to make. On these parameters, the end use annual demand forecast method employed by Posterity Group on behalf of FEI has performed well, having enabled FEI to examine a broad range of uncertainties across different future scenarios, to understand the degree to which these uncertainties will impact future demand, to discuss these uncertainties and findings with stakeholders, and to identify a future scenario on which to plan shorter-term actions.

Nevertheless, the following discussion presents a review of LTGRP forecast annual demand against actuals for each year of the forecast that is available from the 2014, 2017 and 2022 LTGRP models. As shown below the 2014 and 2017 Reference Case and BAU forecasts performed well in the initial years of their forecast horizon. Residential and industrial demand increased after the publication of the 2017 forecasts and actual demand has remained above forecast since then. The 2022 Reference Case and BAU forecasts reflect the increased demand, and both extend the demand trend observed in recent years.

Figure B6-1: Comparing the Reference Case Forecasts with Actuals

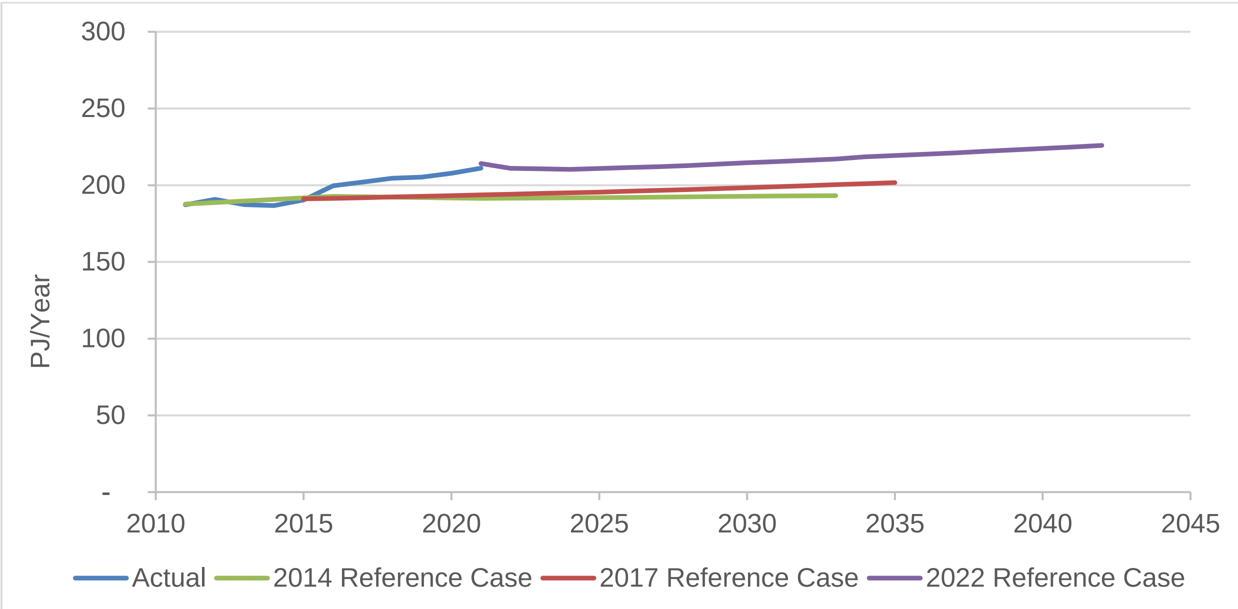
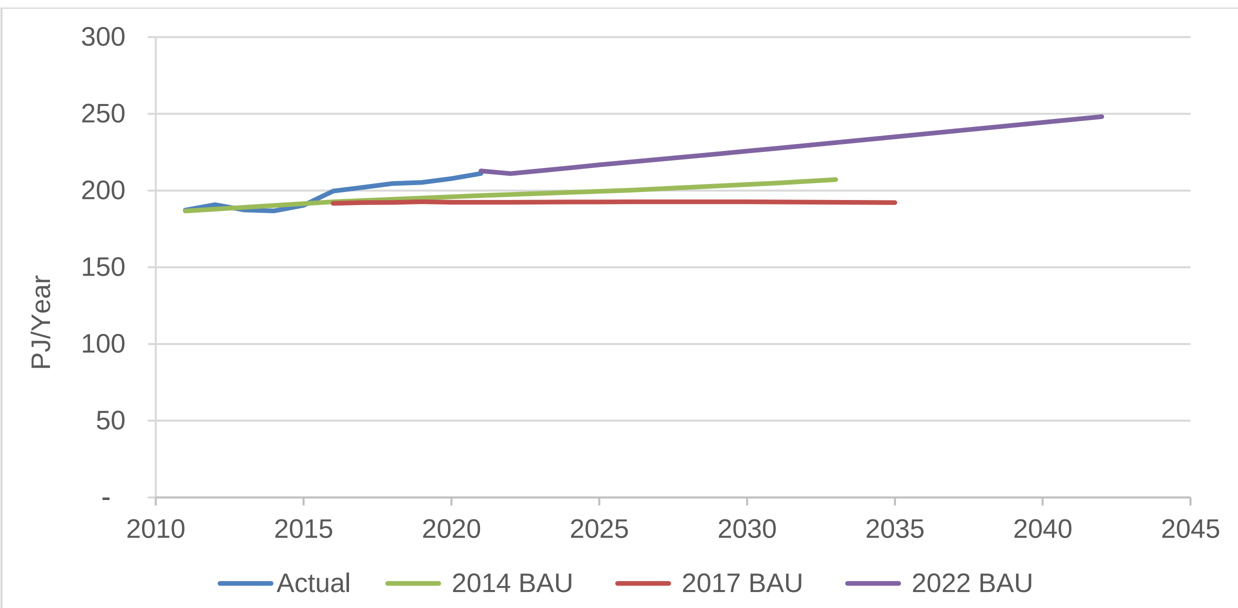


Figure B6-2: Comparing the BAU Forecasts with Actuals



For the period up to 2021, the 2014 and 2017 BAU forecasts and Reference Case forecasts performed similarly. FEI notes that the BAU forecast, as used in this context, is to check the reasonableness of the end use method Reference Case (as the starting point for alternate future scenarios), regardless of how either forecast compares to actual results.

As noted above, the end use method provides features critical for long term planning that cannot be achieved using the traditional method. Figures B6-1 and B6-2 demonstrate that the results from the two methods are comparable in the early years of the forecast, and therefore it is reasonable to use the extended capabilities of the end use method to examine future scenarios.

Appendix C

DEMAND SIDE RESOURCES

Appendix C-1

2021 CONSERVATION POTENTIAL REVIEW REPORT FOR FEI

POSTERITY GROUP

2021 Conservation Potential Review

Final Report

Date: 12 July 2021

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Contents

List of Exhibits

Executive Summary

Background and Objectives

The 2021 Conservation Potential Review (CPR) is the review of energy efficiency opportunities available among FortisBC's residential, commercial, and industrial natural gas customers.

The CPR will support two of FortisBC Energy Inc's (FEI) major regulatory filings in 2022: the long-term gas resource plan (LTGRP) and the Demand Side Management (DSM) plan. For this CPR, Posterity Group reviewed estimated technical, economic, and market potential natural gas savings in FEI's service territory over a 20-year period. The CPR is an important guiding document for ongoing conservation and energy management program development and support at FortisBC.

FEI has also retained Posterity Group to produce the load forecast of natural gas demand of FEI's customers to support the 2022 LTGRP filing. The base year and reference case forecast developed by Posterity Group is common to both the LTGRP and CPR. As a result of the integrated nature of the two projects, the LTGRP project is frequently referenced in this document.

Findings Summary

- This study has found significant cost-effective and market achievable natural gas savings throughout the study period 2020-2040, and in all sectors and segments.

  Across all sectors, and using the MTRC screen, medium market potential savings are estimated at approximately 8 PJ, or 4% of reference consumption in 2025, rising to 24 PJ, or 10% of reference consumption in 2040.

  This estimated 24 PJ savings by 2040 includes potential savings from Residential, Industrial, and Commercial sectors of 9.9 PJ, 8.6 PJ, and 5.8 PJ respectively.

- In the ***residential sector***, only a small number of measures are cost-effective based on the TRC test, most being low-cost retrofit measures. Measures that pass the MTRC screen only become more important in the residential sector as the study period progresses.
  - The opportunities for equipment replacement measures, especially space heating measures, are much smaller relative to previous studies. This is primarily due to increasingly higher federal and provincial minimum energy performance standards (MEPS) for furnaces, which have caused DSM opportunities to become increasingly scarce.
  - In terms of percentage of reference case consumption forecast, more residential opportunities are available in the domestic hot water end use than the space heating end use throughout the study period. In absolute terms, savings potential for DHW measures (4 PJ by 2040 in the medium market potential scenario, MTRC screen) approaches that of space heating measures (5 PJ by 2040 in the medium market potential scenario, MTRC screen).

- *Commercial sector* savings show the most variance between the high and medium market potential scenarios. Using the MTRC screen, by 2040 the difference in potential between the medium and high market scenarios is 11.6 PJ.

  Gas heat pumps (GHPs) and efficient new construction are major contributing factors to this difference. These measures have high technical and economic potential, but future uptake is uncertain. For example, in the medium scenario, GHPs are modeled as an innovative technology with low forecasted growth. In the high scenario, they are modeled as an innovative technology with high forecasted growth, especially in the second half of the study period (2030-2040).
- The *industrial sector* is estimated to have the largest cost-effective savings potential on the TRC economic screen relative to other sectors. However, industrial customers require shorter payback periods relative to commercial and residential customers. Achieving savings from industrial measures that are cost-effective but have longer customer payback periods may be challenging and/or more expensive due to higher incentives and program costs.

Scope

Timing: The base year for this study is the 2019 calendar year, where the reference case forecast is from 2020 to 2040 with results calculated for each intervening year.

Regions: This study divides the FortisBC gas regions in British Columbia into six: City of Vancouver, Lower Mainland (excluding Vancouver), Vancouver Island, Northern BC, Southern Interior, and Whistler.

Sectors: The study addresses three sectors: residential, commercial, and industrial. The LTGRP also includes transportation in its scope. EX 1 shows the breakdown of each sector (except transportation), which are organized into segments.

EX 1 – CPR Segments

Residential	Commercial	Industrial
• Single Family Detached/Duplexes • Single Family Attached/Row • Mobile/Other Residential	• Apartments – Medium • Apartments – Large Food Retail • Hospital • Hotel – Medium • Hotel – Large • Non-Food Retail – Medium • Non-Food Retail – Large • Nursing Home • Office – Medium • Office – Large • Other Commercial • Restaurant • School – Medium • School – Large • University/College • Warehouse	• Agriculture (includes greenhouses[1]) • Chemical • District energy providers • Fabricated Metal • Food & Beverage • Other Manufacturing (includes transportation[2] and other industrial) • Mining • Non-metallic Mineral (includes cement) • Pulp & Paper – Kraft • Pulp & Paper – TMP • Utilities • Wood Products

End uses vary and are described in more detail in Section 2 of this report. The residential sector is also broken down into vintages that define the time periods when the dwellings were constructed.

Approach

The CPR model was developed using Posterity Group's Navigator™ Energy and Emissions Simulation Suite. Data was collected from various sources for the analysis and inputted to the model.

The CPR followed these key steps to perform the analysis:

1. **Determine the current (Base Year) customer base and their energy consumption.**
    a. Collect and review data on the building stock in FortisBC's service territory, including end use surveys and previous CPRs.
    b. Develop energy use models of each building or facility type (segments) and model energy consumption by end use.

1 Cannabis included in agriculture segment since there is not enough data at FEI to create a cannabis-specific forecast.
2 In the 2015 CPR, 'transportation' pertained to facilities that supported the transportation sector.

c. Collect and review actual base year (2019) energy use and billing data of FortisBC's customers.
d. Use the billing data to calibrate the base year energy consumption in each sector's energy model.

2. Develop reference case energy consumption forecast.

   a. Collect and review data on all factors that will affect energy use trends over the study period (2020 to 2040 in this study's case).
      i. This includes analyzing and modelling natural improvements in building energy use intensities (e.g. from natural replacement of furnaces with new, higher efficiency ones at replacement time).
      ii. Other factors are existing building demolition / renovation trends, rate of new building stock construction, baseline energy efficiency of new buildings and equipment, and known changes to policies and codes and standards that will impact the energy use of buildings.
   b. Use this data to develop an energy consumption forecast model for each sector.
   c. Calibrate the reference case based on FortisBC's own account forecasts and industrial survey information at the region and rate class level.

3. Characterize energy conservation measures.

   a. Select a set of energy conservation measures for each sector. Measures range from mature, widely known measures that are currently part of FortisBC's program portfolio (e.g. commercial condensing boilers) to innovative or enabling technologies (e.g. smart residential water heater controllers). Behavioural measures are also considered (e.g. thermostat setback).
   b. For each measure, review and collect data on energy savings, costs, useful life, and the baseline equipment or technology that it should be compared with (if applicable).
   c. Use the data to characterize the technology's energy savings potential, cost-effectiveness, and financial attractiveness.
   d. Use the data as inputs to the energy model for each sector.

4. Estimate technical savings potential.

   a. For each measure, determine its technical applicability (i.e. how many buildings or facilities can this measure be applied to, considering only technical barriers).
   b. Determine the measures' current market penetration (i.e. how many buildings or facilities have already installed a measure).
   c. Estimate the measures' reference adoption – their natural rate of uptake in the absence of incentives or utility program intervention.

   d. Input all data into the energy model for each sector and develop a hypothetical estimate of the technically feasible energy savings potential within FortisBC's service territory.[3]

5. Estimate economic savings potential.
   a. Screen each measure for cost-effectiveness from FortisBC's perspective by determining whether the benefit to cost ratio of each measure is 1.0 or above (pass) or if it is below 1.0 (fail) for two cost effectiveness tests: TRC and MTRC.
   b. Update the technical potential model with only the TRC-passing measures, removing measures that are not cost-effective.
   c. Estimate the economic savings potential of all cost-effective measures applied to all technically feasible buildings in the customer base.[4]
   d. Repeat steps 5b and 5c using the MTRC screen. This study presents findings from two economic (and subsequent market potential) models: One with TRC as the economic screen and one with MTRC.

6. Estimate market savings potential.
   a. Based on existing research, develop sets of "generic" adoption curves based on customer payback acceptance and typical market diffusion patterns.[5]
   b. Apply these generic curves to each measure in the economic potential model to develop "simplified market potential" estimates at the measure level.
   c. This data is input into the TRC economic potential model to develop a simplified market potential.
   d. Develop a more realistic market potential for each measure by soliciting feedback from FortisBC and its external stakeholders on the simplified market potential.[6]
   e. Revise the simplified market potential model based on this feedback to develop a realistic market potential scenario (referred to in this study as "medium market potential").
   f. Perform sensitivity analysis by varying incentive levels to model "low" and "high" market potential scenarios.
   g. Repeat steps 6c to 6f using the MTRC economic potential model to estimate low, medium, and high market potential scenarios using the MTRC economic screen.

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3 See Exhibit 2 for an overview of the constraints considered in the technical potential scenario, and the difference between different potential scenarios.
4 See Exhibit 2 for an overview of the constraints considered in an economic potential scenario.
5 Generic adoption curves primarily consider two things: the current market penetration of the measure, and its simple payback. Based on these factors, the curves are applied to each measure to estimate generic participation rates as a percentage of economic potential.
6 This process includes selecting representative, high-impact measures and adjusting their generic participation rates using historical program data, local market knowledge, and industry insights/feedback, then extrapolating these calibrated participation rates to other similar measures within each sector.

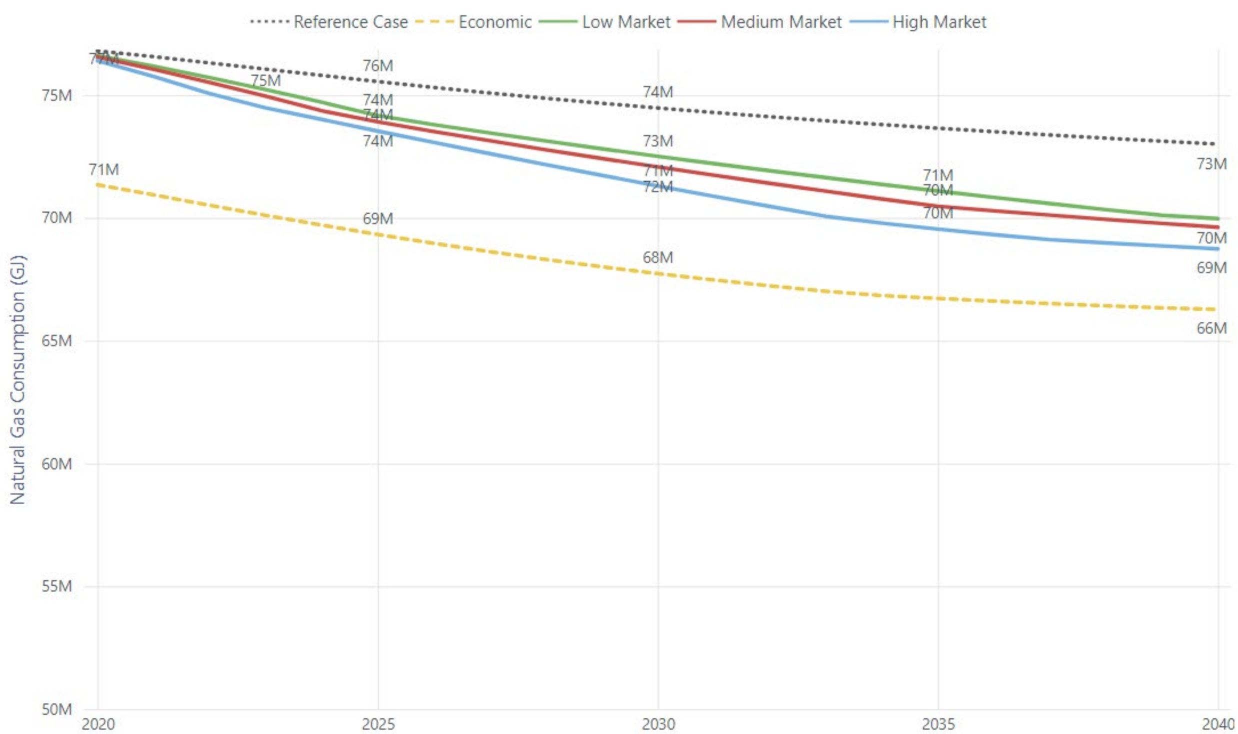
7. **Estimate other energy and non-energy benefits of the potential energy savings.**
    a. Greenhouse gas emissions savings.
    b. Impact of energy conservation measure investments and energy bill savings on provincial employment.

Results and Findings

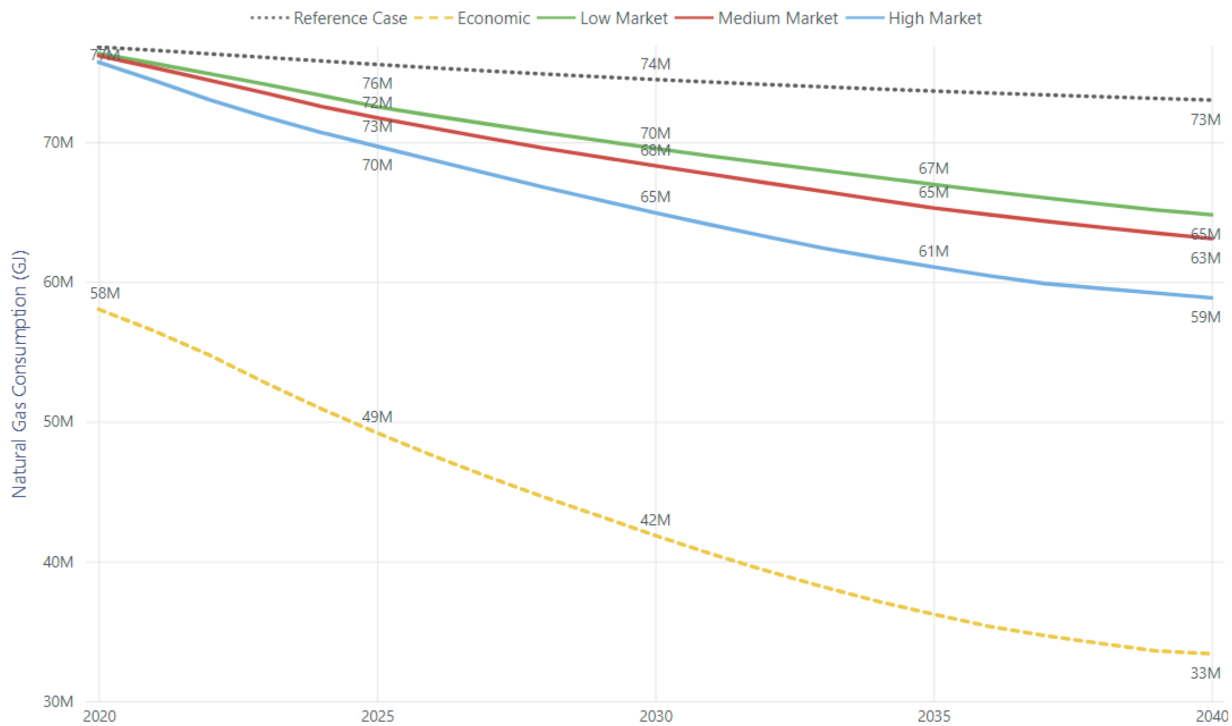
Residential

EX 2 (TRC) and EX 3 (MTRC) show the forecasted gas consumption under the three market potential scenarios for the commercial sector. The reference consumption is forecasted to drop to 73 PJ in 2040 from 77 PJ today. The residential low, medium, and high market TRC potential consumption levels are estimated to be 70 PJ, 69.6 PJ, and 69 PJ by 2040. For MTRC, the potential consumption levels are estimated to be 65 PJ, 63 PJ, and 59 PJ, respectively.

EX 2 – Market Potential Consumption (GJ) Forecasts – Residential, TRC



EX 3 – Market Potential Consumption (GJ) Forecasts – Residential, MTRC



EX 4 (TRC) and EX 5 (MTRC) show the incentive and non-incentive spending required to achieve the medium and high market potential. Medium and high market incentives are 50% and 100% of measures' incremental costs, respectively. The tables show the total and incremental savings from the new measures installed every year.

EX 4 – Medium and High Market Incentive Costs and Natural Gas Savings – Residential, TRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$3.5M	$0.5M	$4.0M	255K	255K	$12.6M	$1.9M	$14.5M	397K	397K
2021	$3.6M	$0.5M	$4.2M	513K	258K	$13.0M	$2.0M	$15.0M	801K	405K
2022	$4.0M	$0.6M	$4.6M	793K	280K	$14.6M	$2.2M	$16.8M	1,251K	450K
2023	$4.5M	$0.7M	$5.2M	1,100K	307K	$10.9M	$1.6M	$12.6M	1,576K	325K
2024	$5.1M	$0.8M	$5.9M	1,442K	342K	$8.1M	$1.2M	$9.3M	1,794K	219K
2025	$3.0M	$0.4M	$3.4M	1,642K	199K	$8.3M	$1.2M	$9.5M	2,016K	221K
2026	$2.4M	$0.4M	$2.8M	1,792K	151K	$8.4M	$1.3M	$9.7M	2,240K	225K
2027	$2.5M	$0.4M	$2.8M	1,943K	151K	$8.6M	$1.3M	$9.9M	2,468K	228K
2028	$2.5M	$0.4M	$2.9M	2,095K	152K	$8.8M	$1.3M	$10.1M	2,700K	232K
2029	$2.6M	$0.4M	$3.0M	2,248K	153K	$9.0M	$1.3M	$10.3M	2,935K	236K
2030	$2.6M	$0.4M	$3.0M	2,401K	154K	$9.2M	$1.4M	$10.6M	3,175K	240K
2031	$2.7M	$0.4M	$3.1M	2,556K	155K	$9.1M	$1.4M	$10.5M	3,414K	239K
2032	$2.7M	$0.4M	$3.2M	2,712K	156K	$9.1M	$1.4M	$10.5M	3,653K	239K
2033	$2.8M	$0.4M	$3.2M	2,870K	157K	$9.1M	$1.4M	$10.5M	3,893K	239K
2034	$2.9M	$0.4M	$3.3M	3,029K	159K	$8.0M	$1.2M	$9.2M	4,015K	123K
2035	$2.9M	$0.4M	$3.4M	3,178K	149K	$8.0M	$1.2M	$9.2M	4,107K	92K
2036	$2.5M	$0.4M	$2.9M	3,222K	43K	$7.8M	$1.2M	$9.0M	4,196K	89K
2037	$2.5M	$0.4M	$2.9M	3,265K	43K	$6.7M	$1.0M	$7.7M	4,265K	69K
2038	$2.4M	$0.4M	$2.8M	3,307K	42K	$4.3M	$0.6M	$4.9M	4,264K	-1K
2039	$2.4M	$0.4M	$2.7M	3,347K	41K	$4.3M	$0.6M	$4.9M	4,265K	1K
2040	$2.3M	$0.4M	$2.7M	3,388K	40K	$4.4M	$0.7M	$5.1M	4,268K	4K

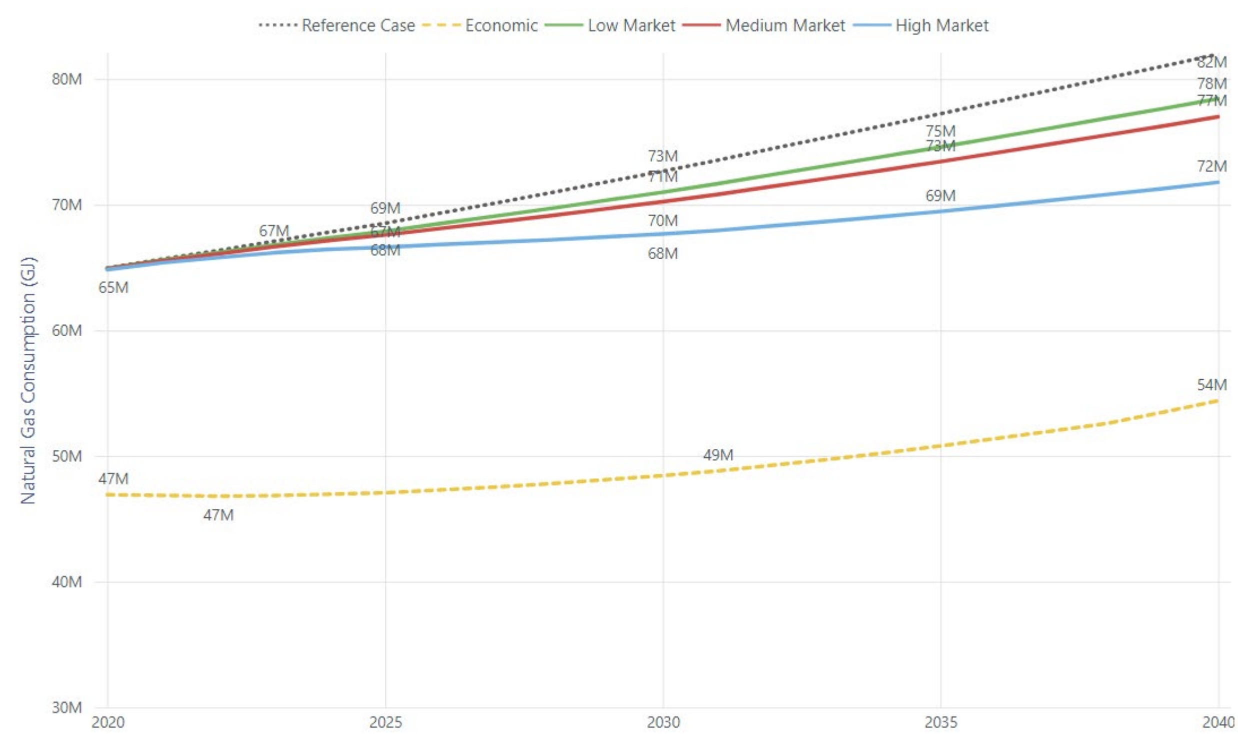
EX 5 – Medium and High Market Incentive Costs and Natural Gas Savings – Residential, MTRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$41.2M	$6.2M	$47.4M	622K	622K	$152.3M	$22.8M	$175.1M	1,080K	1,080K
2021	$42.2M	$6.3M	$48.5M	1,250K	628K	$155.5M	$23.3M	$178.9M	2,170K	1,089K
2022	$43.1M	$6.5M	$49.6M	1,897K	647K	$159.7M	$24.0M	$183.6M	3,300K	1,130K
2023	$44.0M	$6.6M	$50.6M	2,556K	659K	$156.9M	$23.5M	$180.4M	4,267K	967K
2024	$45.2M	$6.8M	$51.9M	3,262K	706K	$148.8M	$22.3M	$171.1M	5,117K	850K
2025	$43.1M	$6.5M	$49.6M	3,810K	548K	$132.1M	$19.8M	$151.9M	5,855K	738K
2026	$43.3M	$6.5M	$49.8M	4,310K	500K	$135.8M	$20.4M	$156.2M	6,601K	746K
2027	$44.0M	$6.6M	$50.6M	4,811K	501K	$140.0M	$21.0M	$160.9M	7,355K	754K
2028	$44.5M	$6.7M	$51.2M	5,310K	499K	$142.9M	$21.4M	$164.3M	8,112K	757K
2029	$36.9M	$5.5M	$42.4M	5,735K	424K	$130.6M	$19.6M	$150.2M	8,822K	710K
2030	$38.0M	$5.7M	$43.7M	6,164K	429K	$130.4M	$19.6M	$150.0M	9,529K	706K
2031	$39.0M	$5.9M	$44.9M	6,598K	434K	$128.0M	$19.2M	$147.2M	10,214K	685K
2032	$40.2M	$6.0M	$46.2M	7,036K	438K	$125.9M	$18.9M	$144.8M	10,879K	665K
2033	$41.4M	$6.2M	$47.6M	7,479K	443K	$124.4M	$18.7M	$143.0M	11,527K	648K
2034	$42.7M	$6.4M	$49.1M	7,926K	448K	$121.6M	$18.2M	$139.9M	12,077K	550K
2035	$44.0M	$6.6M	$50.6M	8,370K	443K	$119.1M	$17.9M	$137.0M	12,589K	511K
2036	$41.9M	$6.3M	$48.2M	8,707K	337K	$116.2M	$17.4M	$133.6M	13,076K	487K
2037	$41.4M	$6.2M	$47.6M	9,038K	331K	$109.0M	$16.4M	$125.4M	13,502K	426K
2038	$39.5M	$5.9M	$45.4M	9,345K	307K	$89.6M	$13.4M	$103.0M	13,710K	207K
2039	$37.7M	$5.7M	$43.3M	9,633K	289K	$89.6M	$13.4M	$103.1M	13,923K	213K
2040	$36.9M	$5.5M	$42.4M	9,910K	276K	$91.9M	$13.8M	$105.7M	14,153K	230K

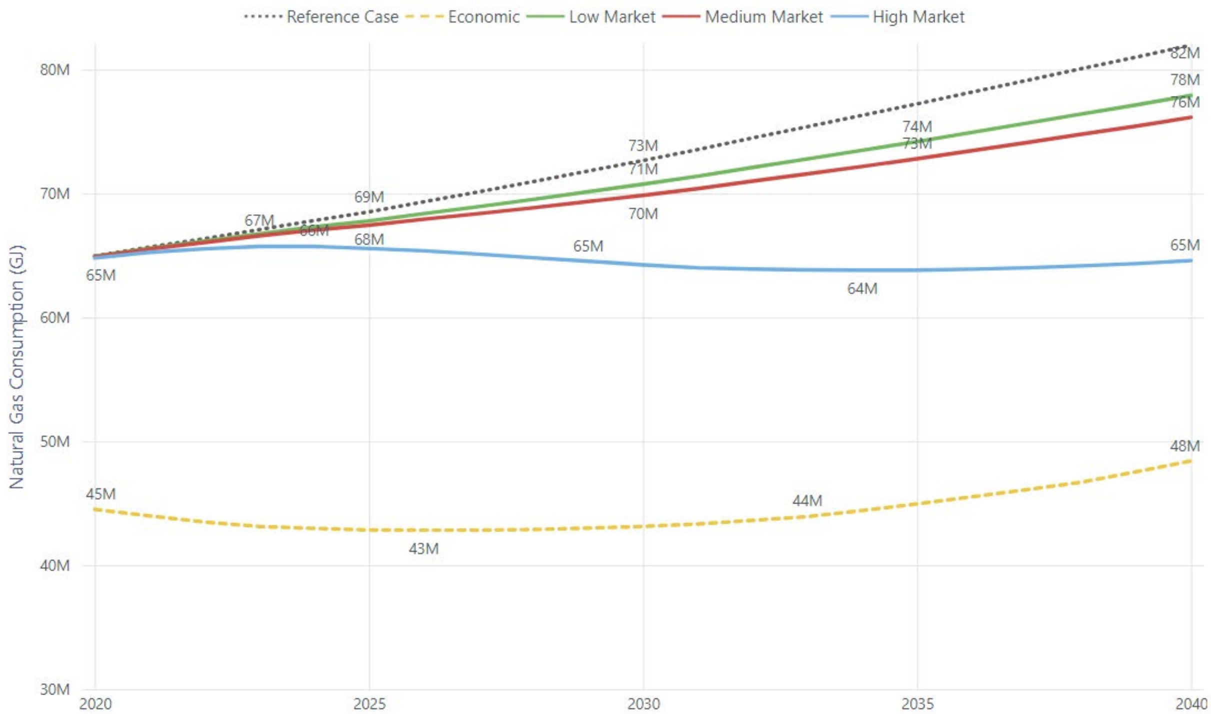
Commercial

EX 6 (TRC) and EX 7 (MTRC) show the forecasted gas consumption under the three market potential scenarios for the commercial sector. The commercial low, medium, and high market TRC potential consumption levels are estimated to be 78 PJ, 77 PJ, and 72 PJ by 2040, while reference consumption is forecasted to reach 82 PJ. The commercial low, medium, and high market MTRC potential consumption levels are estimated to be 78 PJ, 76 PJ, and 65 PJ by 2040, while reference consumption is forecasted to reach 82 PJ.

EX 6 – Commercial Market Potential Consumption (GJ) Forecasts – Commercial, TRC



EX 7 – Commercial Market Potential Consumption (GJ) Forecasts – Commercial, MTRC



The incentive and non-incentive spending in the MTRC scenario required to achieve the medium and high market potential are shown in EX 8 and EX 9. Medium and high market incentives are assumed to be 50% and 100% of measures' incremental costs, respectively. The tables show the total and incremental savings from the new measures installed every year.

EX 8 – Medium and High Market Incentive Costs and Natural Gas Savings – Commercial, TRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$1.0M	$0.1M	$1.1M	57K	57K	$5.9M	$0.9M	$6.8M	124K	124K
2021	$1.6M	$0.2M	$1.9M	142K	85K	$9.9M	$1.5M	$11.4M	306K	183K
2022	$2.6M	$0.4M	$3.0M	267K	125K	$15.7M	$2.4M	$18.0M	563K	256K
2023	$3.9M	$0.6M	$4.5M	441K	174K	$24.1M	$3.6M	$27.7M	914K	352K
2024	$5.4M	$0.8M	$6.2M	667K	226K	$34.1M	$5.1M	$39.2M	1,370K	456K
2025	$6.8M	$1.0M	$7.8M	934K	267K	$43.9M	$6.6M	$50.5M	1,912K	542K
2026	$8.1M	$1.2M	$9.3M	1,223K	289K	$53.2M	$8.0M	$61.2M	2,501K	589K
2027	$8.9M	$1.3M	$10.2M	1,526K	302K	$59.1M	$8.9M	$68.0M	3,124K	623K
2028	$9.5M	$1.4M	$10.9M	1,830K	304K	$63.7M	$9.6M	$73.2M	3,757K	633K
2029	$9.7M	$1.5M	$11.2M	2,132K	302K	$65.4M	$9.8M	$75.2M	4,384K	627K
2030	$9.9M	$1.5M	$11.4M	2,430K	298K	$66.3M	$9.9M	$76.3M	4,999K	615K
2031	$9.9M	$1.5M	$11.4M	2,723K	293K	$67.0M	$10.0M	$77.0M	5,597K	599K
2032	$10.1M	$1.5M	$11.7M	3,009K	286K	$67.7M	$10.2M	$77.9M	6,170K	572K
2033	$9.7M	$1.5M	$11.2M	3,285K	276K	$64.9M	$9.7M	$74.6M	6,712K	542K
2034	$9.9M	$1.5M	$11.4M	3,555K	270K	$65.9M	$9.9M	$75.8M	7,249K	537K
2035	$9.6M	$1.4M	$11.1M	3,810K	255K	$64.6M	$9.7M	$74.2M	7,773K	524K
2036	$9.5M	$1.4M	$11.0M	4,058K	248K	$63.5M	$9.5M	$73.0M	8,283K	510K
2037	$9.5M	$1.4M	$11.0M	4,298K	240K	$64.0M	$9.6M	$73.6M	8,782K	498K
2038	$9.5M	$1.4M	$10.9M	4,534K	237K	$62.0M	$9.3M	$71.2M	9,269K	488K
2039	$9.1M	$1.4M	$10.5M	4,760K	226K	$58.1M	$8.7M	$66.8M	9,735K	466K
2040	$9.2M	$1.4M	$10.6M	4,981K	221K	$59.2M	$8.9M	$68.0M	10,197K	462K

EX 9 – Medium and High Market Incentive Costs and Natural Gas Savings – Commercial, MTRC

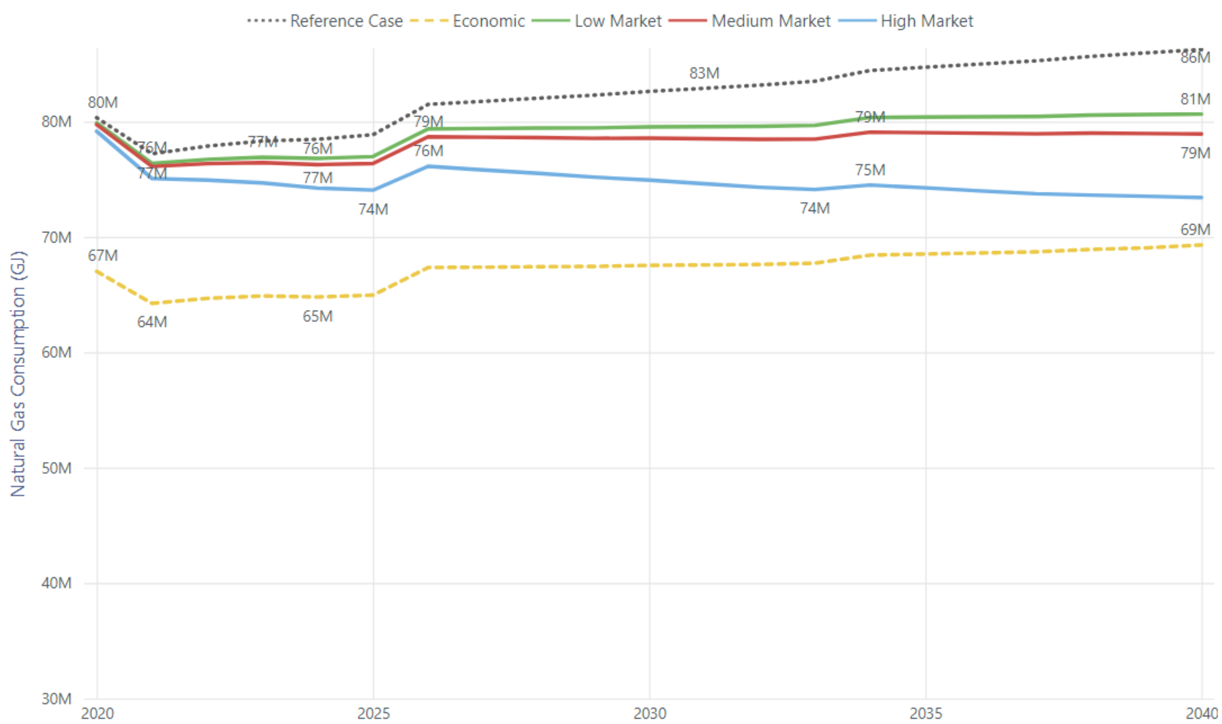
Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$1.2M	$0.2M	$1.4M	62K	62K	$10.8M	$1.6M	$12.4M	160K	160K
2021	$2.1M	$0.3M	$2.4M	159K	97K	$20.1M	$3.0M	$23.1M	422K	262K
2022	$3.4M	$0.5M	$3.9M	303K	144K	$32.7M	$4.9M	$37.6M	810K	388K
2023	$5.1M	$0.8M	$5.8M	505K	201K	$49.6M	$7.4M	$57.1M	1,359K	549K
2024	$6.9M	$1.0M	$7.9M	767K	262K	$70.0M	$10.5M	$80.5M	2,083K	724K
2025	$8.6M	$1.3M	$9.9M	1,075K	309K	$89.6M	$13.4M	$103.1M	2,961K	879K
2026	$10.3M	$1.5M	$11.8M	1,412K	336K	$109.6M	$16.4M	$126.0M	3,954K	993K
2027	$11.3M	$1.7M	$13.0M	1,762K	351K	$122.4M	$18.4M	$140.7M	5,027K	1,072K
2028	$12.1M	$1.8M	$13.9M	2,115K	352K	$132.5M	$19.9M	$152.3M	6,143K	1,116K
2029	$12.4M	$1.9M	$14.2M	2,465K	350K	$137.1M	$20.6M	$157.6M	7,280K	1,137K
2030	$12.6M	$1.9M	$14.5M	2,811K	345K	$140.6M	$21.1M	$161.6M	8,419K	1,139K
2031	$12.7M	$1.9M	$14.6M	3,151K	340K	$140.9M	$21.1M	$162.0M	9,541K	1,122K
2032	$12.9M	$1.9M	$14.9M	3,485K	335K	$142.3M	$21.3M	$163.7M	10,589K	1,049K
2033	$12.5M	$1.9M	$14.4M	3,810K	325K	$135.8M	$20.4M	$156.2M	11,557K	968K
2034	$12.6M	$1.9M	$14.5M	4,130K	319K	$135.8M	$20.4M	$156.1M	12,504K	946K
2035	$12.3M	$1.8M	$14.2M	4,431K	302K	$133.0M	$19.9M	$152.9M	13,422K	918K
2036	$12.3M	$1.8M	$14.1M	4,726K	295K	$131.3M	$19.7M	$151.0M	14,292K	870K
2037	$12.2M	$1.8M	$14.1M	5,014K	288K	$129.9M	$19.5M	$149.4M	15,127K	836K
2038	$12.2M	$1.8M	$14.0M	5,297K	283K	$124.3M	$18.6M	$143.0M	15,918K	790K
2039	$11.9M	$1.8M	$13.7M	5,568K	271K	$118.5M	$17.8M	$136.3M	16,673K	755K
2040	$12.0M	$1.8M	$13.8M	5,833K	266K	$116.1M	$17.4M	$133.5M	17,391K	718K

Industrial

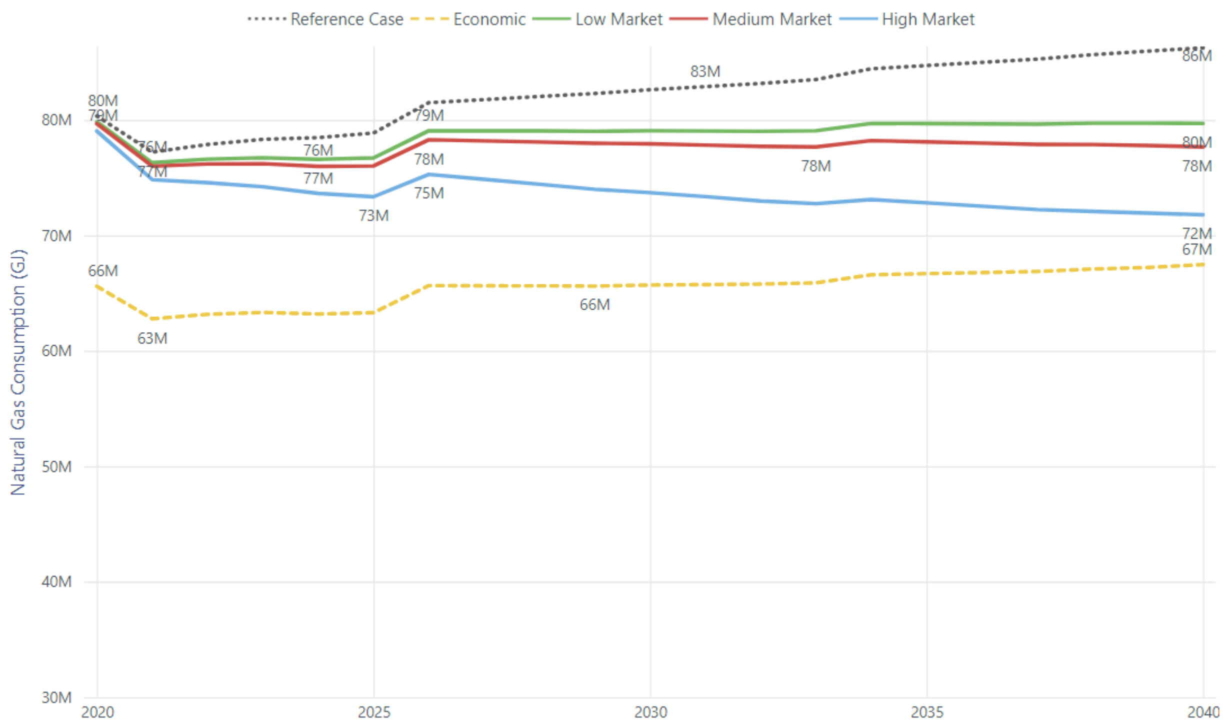
The market potential consumption results are shown in EX 10 and EX 11. The results for the TRC and MTRC screens appear quite similar because of the 39 measures included in the assessment, 34 pass the TRC and 38 pass the MTRC.

The industrial low, medium, and high market TRC potential consumption levels are estimated to be 81 PJ, 79 PJ, and 73 PJ by 2040, while reference consumption is forecasted to reach 86 PJ. The industrial low, medium, and high market MTRC potential consumption levels are estimated to be 80 PJ, 78 PJ, and 72 PJ, by 2040.

EX 10 – Market Potential Consumption (GJ) Forecasts – Industrial, TRC



EX 11 – Market Potential Consumption (GJ) Forecasts – Industrial, MTRC



EX 12 (TRC) and EX 13 (MTRC) show the incentive and non-incentive spending required to achieve the medium and high market potential. Medium and high market incentives are assumed to be 50% and 100% of measures' incremental costs, respectively. The tables show the total and incremental savings from the new measures installed every year.

EX 12 – Medium and High Market Incentive Costs and Natural Gas Savings – Industrial, TRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$3.3M	$0.5M	$3.8M	600K	600K	$13.0M	$2.0M	$15.0M	1,178K	1,178K
2021	$3.3M	$0.5M	$3.8M	1,099K	499K	$12.9M	$1.9M	$14.8M	2,144K	966K
2022	$3.2M	$0.5M	$3.7M	1,518K	419K	$12.7M	$1.9M	$14.6M	2,949K	805K
2023	$3.1M	$0.5M	$3.5M	1,874K	356K	$12.1M	$1.8M	$13.9M	3,631K	681K
2024	$3.0M	$0.4M	$3.4M	2,196K	323K	$11.5M	$1.7M	$13.2M	4,234K	603K
2025	$2.9M	$0.4M	$3.3M	2,501K	305K	$11.3M	$1.7M	$13.0M	4,805K	572K
2026	$2.9M	$0.4M	$3.4M	2,804K	303K	$11.4M	$1.7M	$13.1M	5,373K	568K
2027	$3.0M	$0.5M	$3.5M	3,109K	305K	$11.6M	$1.7M	$13.4M	5,944K	571K
2028	$3.1M	$0.5M	$3.6M	3,419K	310K	$12.0M	$1.8M	$13.8M	6,520K	577K
2029	$3.2M	$0.5M	$3.7M	3,733K	315K	$12.5M	$1.9M	$14.4M	7,103K	583K
2030	$3.4M	$0.5M	$3.9M	4,051K	317K	$13.0M	$2.0M	$15.0M	7,689K	585K
2031	$3.5M	$0.5M	$4.0M	4,371K	320K	$13.4M	$2.0M	$15.4M	8,276K	587K
2032	$3.5M	$0.5M	$4.0M	4,694K	323K	$13.2M	$2.0M	$15.2M	8,848K	572K
2033	$3.5M	$0.5M	$4.0M	5,018K	324K	$12.7M	$1.9M	$14.6M	9,386K	538K
2034	$3.5M	$0.5M	$4.0M	5,343K	325K	$12.6M	$1.9M	$14.4M	9,924K	538K
2035	$3.5M	$0.5M	$4.0M	5,667K	324K	$12.4M	$1.9M	$14.3M	10,458K	534K
2036	$3.5M	$0.5M	$4.0M	5,994K	327K	$12.4M	$1.9M	$14.2M	10,990K	532K
2037	$3.5M	$0.5M	$4.0M	6,323K	329K	$12.4M	$1.9M	$14.2M	11,518K	528K
2038	$3.6M	$0.5M	$4.1M	6,653K	331K	$12.0M	$1.8M	$13.8M	12,020K	502K
2039	$3.6M	$0.5M	$4.1M	6,986K	333K	$9.1M	$1.4M	$10.5M	12,434K	414K
2040	$3.7M	$0.6M	$4.2M	7,323K	337K	$8.8M	$1.3M	$10.1M	12,833K	399K

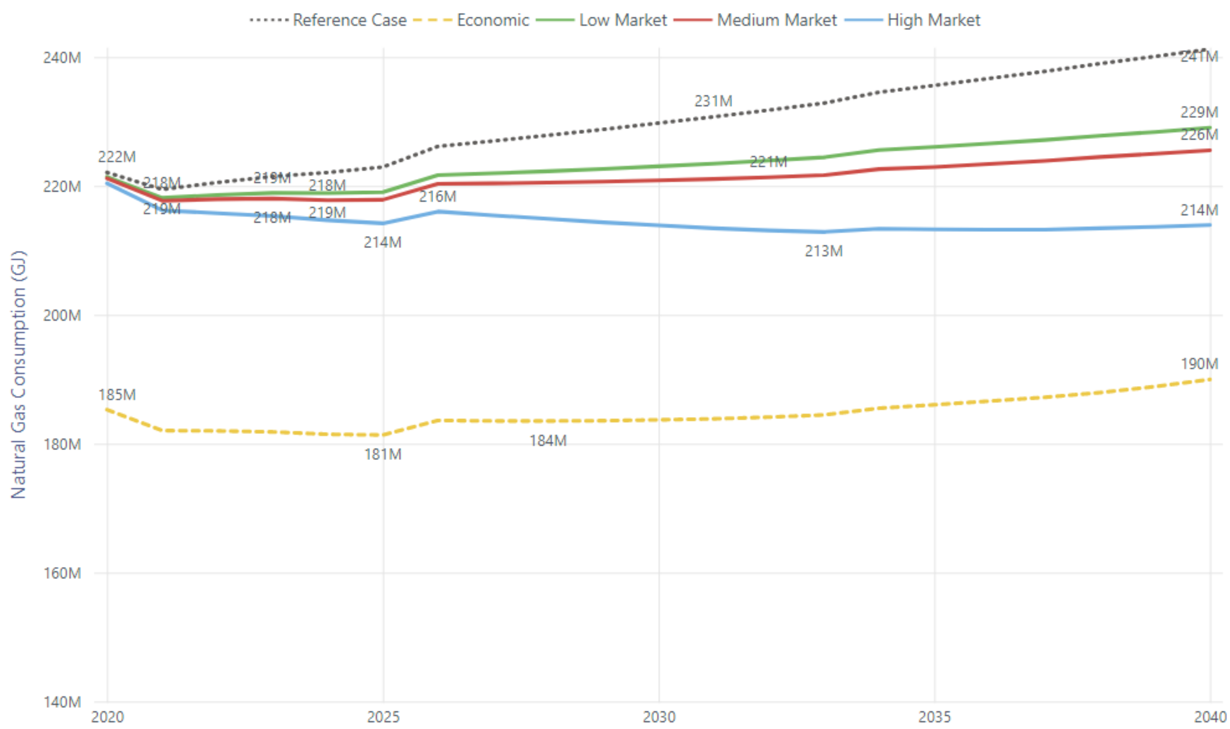
EX 13 – Medium and High Market Incentive Costs and Natural Gas Savings – Industrial, MTRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$8.8M	$1.3M	$10.2M	658K	658K	$35.2M	$5.3M	$40.5M	1,298K	1,298K
2021	$8.8M	$1.3M	$10.1M	1,215K	557K	$35.0M	$5.3M	$40.3M	2,384K	1,086K
2022	$8.8M	$1.3M	$10.1M	1,692K	477K	$34.9M	$5.2M	$40.1M	3,309K	925K
2023	$8.6M	$1.3M	$9.9M	2,105K	414K	$34.3M	$5.1M	$39.4M	4,110K	801K
2024	$8.5M	$1.3M	$9.8M	2,486K	381K	$33.7M	$5.1M	$38.8M	4,833K	723K
2025	$8.5M	$1.3M	$9.7M	2,848K	362K	$33.5M	$5.0M	$38.6M	5,524K	691K
2026	$8.5M	$1.3M	$9.7M	3,209K	361K	$33.6M	$5.0M	$38.7M	6,211K	687K
2027	$8.6M	$1.3M	$9.8M	3,572K	363K	$33.9M	$5.1M	$39.0M	6,901K	690K
2028	$8.7M	$1.3M	$10.0M	3,940K	367K	$34.3M	$5.1M	$39.4M	7,597K	696K
2029	$8.8M	$1.3M	$10.1M	4,313K	373K	$34.8M	$5.2M	$40.0M	8,299K	703K
2030	$8.9M	$1.3M	$10.3M	4,688K	376K	$15.2M	$2.3M	$17.5M	8,914K	615K
2031	$9.1M	$1.4M	$10.4M	5,067K	379K	$15.7M	$2.3M	$18.0M	9,532K	618K
2032	$9.1M	$1.4M	$10.5M	5,451K	383K	$25.7M	$3.9M	$29.5M	10,182K	649K
2033	$9.1M	$1.4M	$10.5M	5,835K	384K	$15.2M	$2.3M	$17.5M	10,753K	571K
2034	$9.1M	$1.4M	$10.5M	6,221K	386K	$15.1M	$2.3M	$17.4M	11,326K	572K
2035	$9.1M	$1.4M	$10.5M	6,607K	386K	$15.1M	$2.3M	$17.3M	11,895K	569K
2036	$9.2M	$1.4M	$10.5M	6,997K	389K	$15.1M	$2.3M	$17.4M	12,464K	569K
2037	$9.2M	$1.4M	$10.6M	7,389K	392K	$15.2M	$2.3M	$17.5M	13,030K	566K
2038	$9.3M	$1.4M	$10.7M	7,783K	394K	$14.9M	$2.2M	$17.1M	13,572K	542K
2039	$9.4M	$1.4M	$10.8M	8,180K	397K	$12.1M	$1.8M	$13.9M	14,026K	454K
2040	$9.5M	$1.4M	$10.9M	8,582K	402K	$11.9M	$1.8M	$13.7M	14,467K	441K

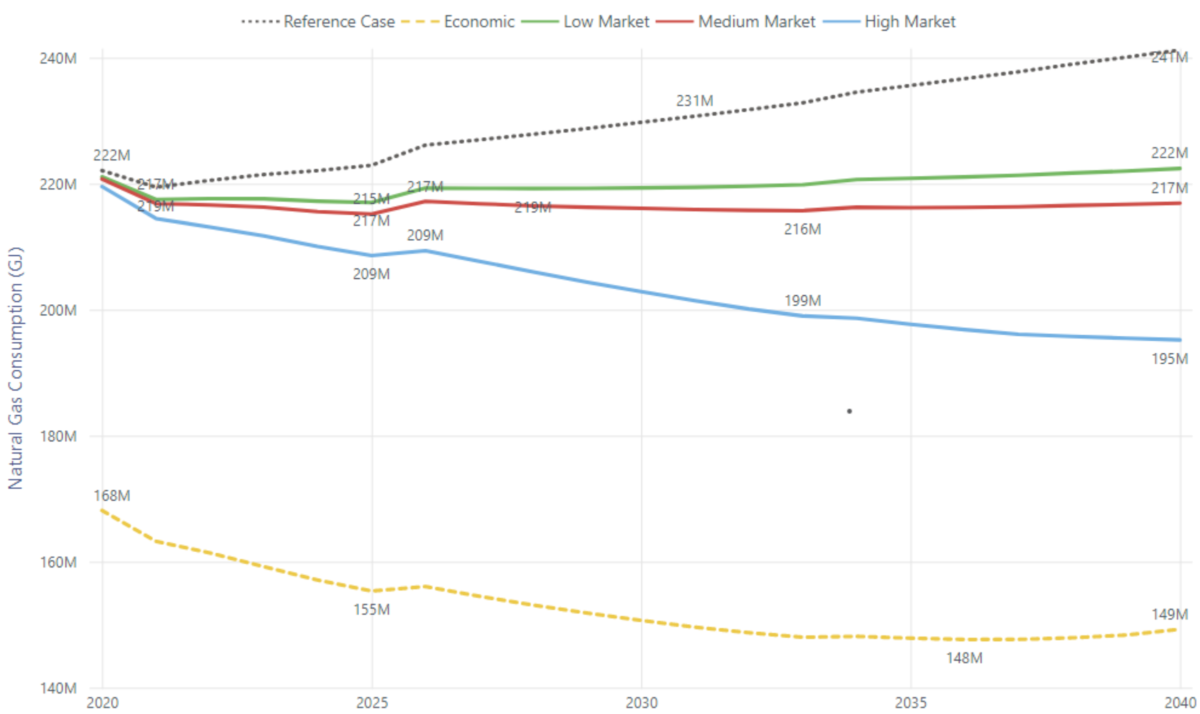
Portfolio

EX 14 (TRC) and EX 15 (MTRC) show the forecasted total natural gas consumption under the three market potential scenarios. The reference consumption is forecasted to increase to 241 PJ in 2040 from 222 PJ today. The total low, medium, and high market TRC potential consumption levels are estimated to be 229 PJ, 226 PJ, and 214 PJ. The low, medium, and high market MTRC potential consumption levels are estimated to be 222 PJ, 217 PJ, and 195 PJ.

EX 14 – Market Potential Consumption (GJ) Forecasts – All Sectors, TRC



EX 15 – Market Potential Consumption (GJ) Forecasts – All Sectors, MTRC

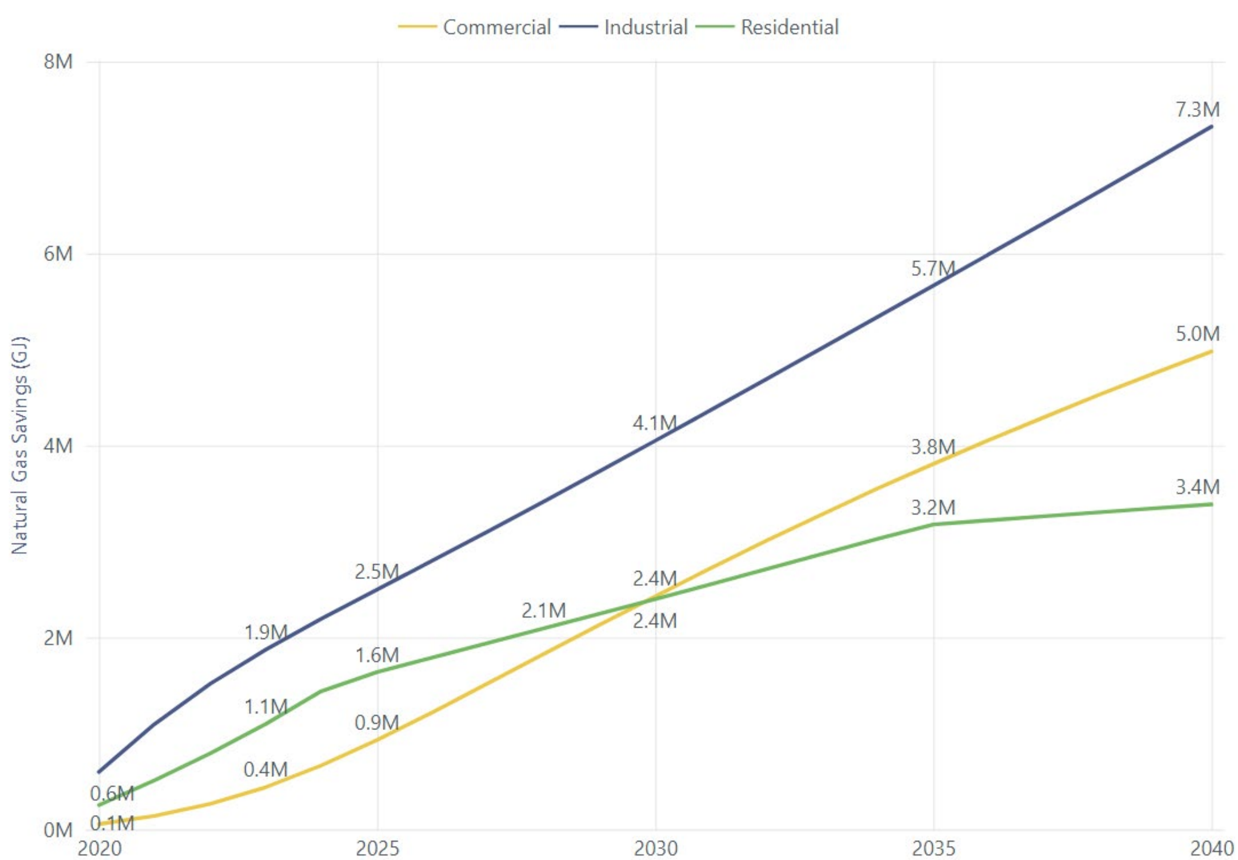


The medium market potential savings from the commercial, industrial, residential sectors are plotted together in EX 16 (TRC) and EX 17 (MTRC).

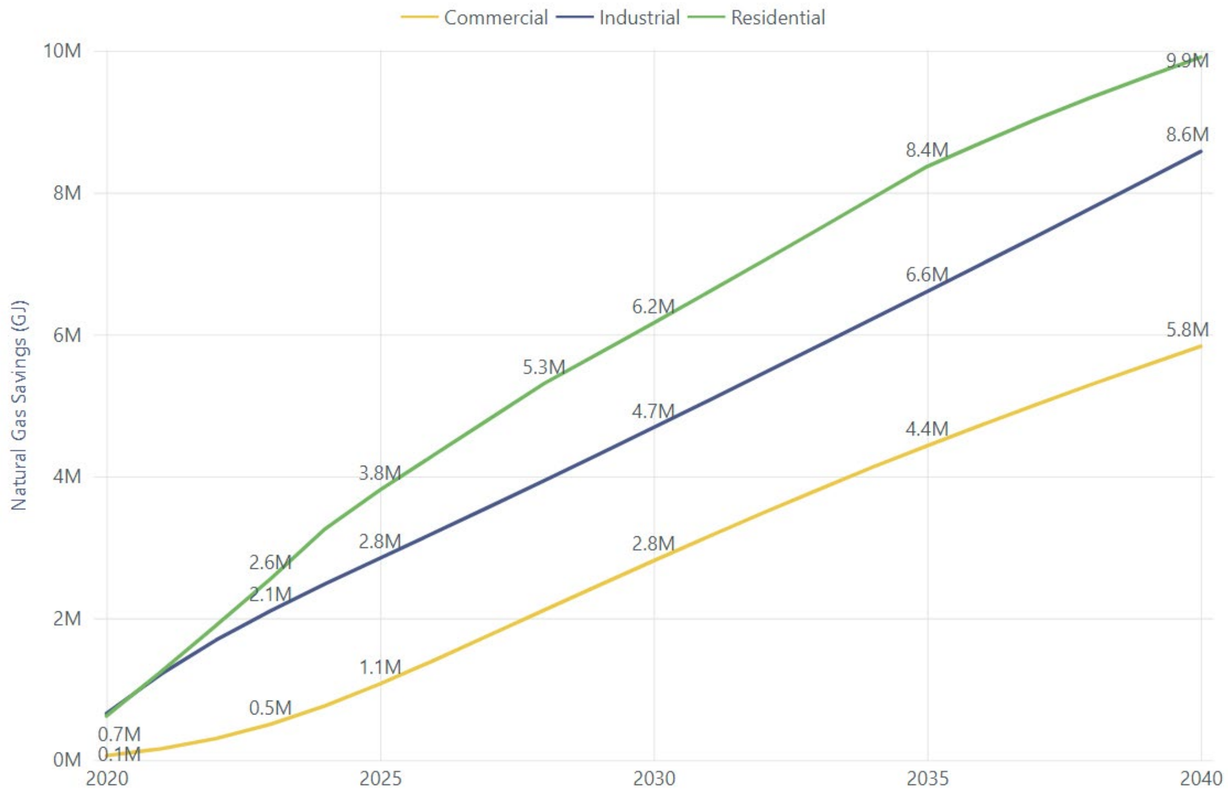
By 2025, the TRC medium market scenario for the industrial sector is expected to have the most savings potential, followed by residential and then commercial sectors. By 2030, the commercial sector overtakes residential. This is because there are only 14 residential measures that pass the TRC, and almost all of them are retrofit measures that can be implemented early in the study period. By 2040, potential savings from industrial, commercial, and residential sectors are estimated to be 7.3 PJ, 5.0 PJ, and 3.4 PJ.

Under the MTRC medium market scenario, the residential sector is estimated to have the most savings potential for the entire study period, followed by the industrial and then commercial. By 2040, potential savings from residential, industrial, and commercial sectors are estimated to be 9.9 PJ, 8.6 PJ, and 5.8 PJ.

EX 16 – Medium Market Potential Savings (GJ) – All Sectors, TRC



EX 17 – Medium Market Potential Savings (GJ) – All Sectors, MTRC



EX 18 (TRC) and EX 19 (MTRC) show the incentive and non-incentive spending required to achieve the medium and high market potential. Medium and high market incentives are assumed to be 50% and 100% of measures' incremental costs, respectively. The tables show the total and incremental savings from the new measures installed every year.

EX 18 – Medium and High Market Incentive Costs and Natural Gas Savings – All Sectors, TRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$7.8M	$1.2M	$8.9M	912K	912K	$31.5M	$4.7M	$36.3M	1,698K	1,698K
2021	$8.5M	$1.3M	$9.8M	1,754K	842K	$35.8M	$5.4M	$41.2M	3,252K	1,554K
2022	$9.9M	$1.5M	$11.3M	2,578K	824K	$42.9M	$6.4M	$49.4M	4,763K	1,511K
2023	$11.5M	$1.7M	$13.2M	3,415K	837K	$47.0M	$7.1M	$54.1M	6,120K	1,357K
2024	$13.5M	$2.0M	$15.5M	4,306K	891K	$53.7M	$8.1M	$61.8M	7,398K	1,278K
2025	$12.6M	$1.9M	$14.5M	5,077K	771K	$63.5M	$9.5M	$73.0M	8,733K	1,334K
2026	$13.5M	$2.0M	$15.5M	5,819K	743K	$73.0M	$11.0M	$84.0M	10,114K	1,382K
2027	$14.4M	$2.2M	$16.5M	6,578K	759K	$79.3M	$11.9M	$91.2M	11,536K	1,421K
2028	$15.1M	$2.3M	$17.4M	7,344K	766K	$84.5M	$12.7M	$97.1M	12,976K	1,441K
2029	$15.5M	$2.3M	$17.9M	8,114K	770K	$86.9M	$13.0M	$99.9M	14,422K	1,446K
2030	$15.9M	$2.4M	$18.3M	8,882K	769K	$88.5M	$13.3M	$101.8M	15,863K	1,440K
2031	$16.1M	$2.4M	$18.5M	9,650K	767K	$89.5M	$13.4M	$102.9M	17,288K	1,425K
2032	$16.4M	$2.5M	$18.9M	10,415K	766K	$90.1M	$13.5M	$103.6M	18,671K	1,384K
2033	$16.1M	$2.4M	$18.5M	11,172K	757K	$86.7M	$13.0M	$99.7M	19,991K	1,320K
2034	$16.2M	$2.4M	$18.7M	11,926K	754K	$86.5M	$13.0M	$99.5M	21,189K	1,198K
2035	$16.0M	$2.4M	$18.4M	12,655K	729K	$85.0M	$12.7M	$97.7M	22,338K	1,149K
2036	$15.5M	$2.3M	$17.8M	13,273K	618K	$83.7M	$12.5M	$96.2M	23,469K	1,131K
2037	$15.5M	$2.3M	$17.9M	13,885K	612K	$83.0M	$12.5M	$95.5M	24,565K	1,095K
2038	$15.4M	$2.3M	$17.8M	14,494K	609K	$78.2M	$11.7M	$90.0M	25,554K	989K
2039	$15.1M	$2.3M	$17.4M	15,094K	599K	$71.6M	$10.7M	$82.3M	26,434K	880K
2040	$15.2M	$2.3M	$17.5M	15,692K	598K	$72.4M	$10.9M	$83.3M	27,299K	865K

EX 19 – Medium and High Market Incentive Costs and Natural Gas Savings – All Sectors, MTRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$51.3M	$7.7M	$59.0M	1,343K	1,343K	$198.3M	$29.8M	$228.1M	2,538K	2,538K
2021	$53.1M	$8.0M	$61.1M	2,625K	1,282K	$210.7M	$31.6M	$242.3M	4,975K	2,437K
2022	$55.3M	$8.3M	$63.6M	3,892K	1,267K	$227.2M	$34.1M	$261.3M	7,418K	2,443K
2023	$57.7M	$8.7M	$66.3M	5,166K	1,274K	$240.8M	$36.1M	$276.9M	9,736K	2,317K
2024	$60.6M	$9.1M	$69.7M	6,514K	1,349K	$252.5M	$37.9M	$290.3M	12,032K	2,296K
2025	$60.2M	$9.0M	$69.2M	7,734K	1,219K	$255.2M	$38.3M	$293.5M	14,340K	2,308K
2026	$62.1M	$9.3M	$71.4M	8,931K	1,197K	$279.0M	$41.9M	$320.9M	16,766K	2,426K
2027	$63.9M	$9.6M	$73.5M	10,146K	1,215K	$296.2M	$44.4M	$340.6M	19,282K	2,516K
2028	$65.3M	$9.8M	$75.1M	11,365K	1,219K	$309.6M	$46.4M	$356.1M	21,852K	2,569K
2029	$58.0M	$8.7M	$66.7M	12,512K	1,147K	$302.5M	$45.4M	$347.8M	24,402K	2,550K
2030	$59.5M	$8.9M	$68.5M	13,663K	1,151K	$286.2M	$42.9M	$329.1M	26,862K	2,461K
2031	$60.8M	$9.1M	$69.9M	14,816K	1,153K	$284.5M	$42.7M	$327.2M	29,287K	2,424K
2032	$62.2M	$9.3M	$71.6M	15,972K	1,156K	$293.9M	$44.1M	$338.0M	31,650K	2,363K
2033	$63.0M	$9.5M	$72.5M	17,124K	1,152K	$275.4M	$41.3M	$316.7M	33,838K	2,188K
2034	$64.4M	$9.7M	$74.1M	18,277K	1,153K	$272.5M	$40.9M	$313.4M	35,907K	2,069K
2035	$65.4M	$9.8M	$75.3M	19,408K	1,131K	$267.1M	$40.1M	$307.2M	37,905K	1,999K
2036	$63.3M	$9.5M	$72.8M	20,430K	1,022K	$262.6M	$39.4M	$302.0M	39,832K	1,927K
2037	$62.9M	$9.4M	$72.3M	21,440K	1,011K	$254.1M	$38.1M	$292.2M	41,660K	1,828K
2038	$61.0M	$9.1M	$70.1M	22,425K	984K	$228.8M	$34.3M	$263.1M	43,199K	1,539K
2039	$58.9M	$8.8M	$67.7M	23,381K	957K	$220.3M	$33.0M	$253.3M	44,622K	1,423K
2040	$58.3M	$8.8M	$67.1M	24,325K	944K	$219.8M	$33.0M	$252.8M	46,010K	1,388K

1 Introduction

1.1 Background and Study Goals

The 2021 Conservation Potential Review (CPR) is the review of energy efficiency opportunities available among FortisBC's residential, commercial, and industrial natural gas customers.

The CPR will support two of FortisBC Energy Inc's (FEI) major regulatory filings in 2022: the long-term gas resource plan (LTGRP) and the Demand Side Management (DSM) plan. For this CPR, Posterity Group (PG) reviewed estimated technical, economic, and market potential natural gas savings in FEI's service territory over a 20-year period. The CPR is an important guiding document for ongoing conservation and energy management program development and support at FortisBC.

FEI has also retained Posterity Group to produce the load forecast of natural gas demand of FEI's customers to support the 2022 LTGRP filing. The base year and reference case forecast developed by Posterity Group is common to both the LTGRP and CPR. As a result of the integrated nature of the two projects, the LTGRP project is frequently referenced in this document.

1.2 Report Organization and Results Presentation

This Report

The 2021 CPR has been prepared as <u>a single report that contains results for three sectors: residential, commercial, and industrial.</u> The report has been structured as follows:

Section 1 provides an overview of the CPR scope and definitions of key terms and acronyms.

Section 2 presents the overall steps taken and approach followed to complete this CPR. This section is applicable to all three sectors.

Section 3 presents the **residential** sector results. These include findings on base year and reference case energy forecasts, measure analysis, technical potential, economic potential, and market potential.

Section 4 presents the **commercial** sector results, following the same format as Section 4.

Section 5 presents the **industrial** sector results, following the same format as Section 4.

Section 6 presents aggregate portfolio-level results covering all three sectors. These include market potential, greenhouse gas emissions impacts, and employment impacts.

Presentation of CPR Potential Results

There are five deliverables included in the CPR report:

- **This report**, which presents the conservation potential results for the residential, commercial, and industrial sectors.
- **Method Appendices Document** that includes all method-related memos that were shared between the study and client team through the course of the project, compiled into a stand-alone document.
- **CPR Data Visualization Tool** that provides a dashboard built using Power BI, with access provided to the FortisBC project team and sector leads. During project execution, this

dashboard was used to facilitate detailed review of draft potential analysis outputs. In its final form, it can be used by FortisBC staff to explore output data for the purposes of DSM planning, program research and program design.

- **Market Potential Model Outputs** that include raw model output that has been organized into Excel workbooks with built-in tables and graphs and provided with this report. There are two workbooks per sector: one using TRC as the economic screen and one with MTRC.
- **Measure Analysis Workbooks** that provide final versions of the workbooks containing measure assumptions for each sector have been shared for reference.

1.3 Caveats and Limitations

Forecasting and modelling are a key part of this CPR study. Both activities require extensive research and more importantly, require assumptions, engineering estimates and the professional judgement of the study team. The study team strove to ensure that these assumptions are in line with the FortisBC team's knowledge of their customer base and are made with the best information available. However, given the nature of forecasting, the results in this report should be considered as estimates.

All potential scenarios in this report are estimated in relation to a "business as usual" reference case scenario. The CPR reference case incorporates FortisBC's account forecast, observed customer consumption trends, and industrial customer demand survey results. By incorporating these sources, the reference case implicitly includes the effects of current policy, but does not adjust for potential future policy changes. Scenarios with specific regulation/policy drivers, including high electrification, are not assessed within the scope of the CPR. High electrification scenarios have been modelled separately, in support of FortisBC's LTGRP.

2 Study Scope

This section defines some common terms used in this study and an overview of what is covered in this CPR.

2.1 Definition of Terms

Accounts – Number of FEI customer accounts. This report refers to 'accounts' rather than customers, as one customer could have multiple accounts.

Benefit/Cost Ratio – Expresses the attractiveness of a measure relative to its costs. A measure with a ratio of 1 or higher has benefits that outweigh its costs. For this study, two measure cost tests were used, both expressed as a Benefit/Cost ratio. These tests, the Total Resource Cost (TRC) test and the Modified Total Resource Cost Test (MTRC), are defined below.

Early Replacement – The act of replacing equipment prior to failure, while it has some remaining useful life. Contrast with "Replace on Burnout (ROB)", below.

End Use, Sub-End Use – The final purpose for which energy is being used. For example, space heating, domestic hot water (DHW), or industrial process heat. In the CPR model, end uses are occasionally further divided into smaller subcategories referred to as Sub-End Uses. For example, Residential DHW is further divided by into shower DHW, washer DHW, dishwasher DHW, and other DHW to facilitate analysis of measures that apply to a specific portion of the und-use energy.

Energy Conservation Measure (ECM, or Measure) – An equipment, technology, or a behavior that results in reduction of energy use in a dwelling, building, or facility.

Fuel Share – Ratio of a specific end use load that is met by a particular fuel. For example, if 90% of single-family dwelling space heating load is met by natural gas equipment, the natural gas fuel share for space heating in single-family dwellings is 90%.

Full Cost Measure – A measure whose benefit/cost ratio is evaluated on the basis of its full cost, as opposed to their incremental cost between the measure and a less-efficient "baseline" alternative. See "Retrofit (RET)" below for further explanation.

Gas-Heated Dwelling, Non-Gas-Heated Dwelling – In the residential sector, a dwelling that primarily uses gas for space heating heat (>50% of the fuel share for space heating) is considered a gas-heated dwelling. A dwelling that has a natural gas space heating fuel share <50% is considered a non-gas-heated dwelling. Gas-heated dwellings may have other fuels serving the space heating end use, but gas comprises at least 50% of the fuel share.

GJ – Gigajoule, or one billion joules. The unit of energy used by FortisBC for billing purposes.

Incremental Cost Measure – A measure whose benefit/cost ratio is evaluated on the basis of its incremental cost relative to a less-efficient alternative. See definition of "Replace on Burnout (ROB)" for further explanation.

Modified Total Resource Cost (MTRC) – A modified version of the TRC test that includes an alternate avoided cost and an adder for non-energy benefits. Per section 4(1.1)(a) of the province's DSM Regulation, the MTRC test incorporates the avoided cost of electricity – BC Hydro's marginal cost of acquiring electricity generated from clean or renewable resources, called the Zero Emission Energy Alternative (ZEEA) - rather than the marginal cost of new gas supply.

Participation or Participation Rate – The rate or percentage of buildings or end users that take part in a utility's program. This is a measurement of customer uptake of a measure and is an input to determine market potential.

Region – In this CPR, FEI's gas service territory is divided into six regions: City of Vancouver, Lower Mainland excluding Vancouver ("Lower Mainland x Vancouver"), Vancouver Island, Northern BC, Southern Interior, and Whistler.

Replace on Burnout (ROB) – One of two primary measure replacement types. Replace-on-burnout measures are typically time, labor, and cost intensive and are applied at the end of the useful life of the underlying equipment. For example, boiler replacements are typically evaluated as replace on burnout. ROB measures are typically evaluated on the basis of their incremental cost relative to a less-efficient, code-compliant alternative. Contrast with "Early Replacement", above and Retrofit (RET) below.

Retrofit (RET) – One of two primary measure replacement types. Retrofit measures are typically less costly measures that can be installed at any time. For example, a communicating thermostat or low-flow showerhead. RET measures are typically evaluated on their full costs. Contrast with "Early Replacement" and "Replace on Burnout (ROB)" above.

R-Value – A measure of a material's resistance to heat flow. In the context of building science, R-value is used to measure the effectiveness of insulation for building envelope components (e.g. attic insulation). The higher the R value, the better the measure's ability to insulate.

Saturation – For most end uses, Saturation is the extent to which an end use is present in a region, and segment. For some specific end uses that are associated with appliances, Saturation is defined as the average number of appliances per Unit.

Sector – Grouping or category of customers or buildings by customer type: residential, commercial, and industrial.

Segment – Grouping or category of buildings (e.g., single-family detached in residential, large offices in commercial). Segments reflect the main purpose of the building and helps to differentiate between energy use intensity or patterns across building types within a sector.

Simple Payback – The duration of time to recover the cost of a project based on cumulative savings, without taking into account the time value of money. In the context of energy conservation measures, savings are accrued based on the value of energy savings. Simple payback is calculated from the perspective of the end user and is presented as a number of years. For example, a measure that costs $600 and results in energy savings valued at $200 annually has a simple payback $600 / $200 = 3 years.

Size Factor – The change in average number of units per account. This is primarily used to reflect the forecast change in production volumes in industry.

Step Code – Compliance path in British Columbia Building Code (BCBC) for achieving energy efficiency in new construction beyond the minimum code requirements.

Stock Average Efficiency – Average efficiency of equipment serving the tertiary load for that end use.

Tertiary Load – The useful energy delivered to an end use. In the context of the CPR, tertiary load is the amount of energy required to be delivered as an end use service, for example, heat delivered by a furnace to a residential dwelling.

Total Resource Cost (TRC) – A metric for evaluating the cost-effectiveness of an energy conservation measure based on both the participants and utility's costs and benefits.

Unit Energy Consumption (UEC) – The amount of energy used by each end use per unit.

Units – The sector-specific unit of analysis: dwellings in the residential sector, square metres in the commercial sector, and production capacity in the industrial sector.

Vintage – A grouping of facilities based on their age.

2.1.1 Acronyms

BAS	Building Automation System
C&EM	Conservation and Energy Management
CCE	Cost of Conserved Energy
CEUS	Commercial End Use Survey
CPR	Conservation Potential Review
DHW	Domestic Hot Water
DIY	Do-It-Yourself
DSM	Demand Side Management
ECM	Energy Conservation Measure
EECAG	Energy Efficiency and Conservation Advisory Group
EUI	Energy Use Intensity
FEI	FortisBC Energy Inc.
GJ	Gigajoule
HE	High Efficiency
HVAC	Heating, Ventilation, and Air Conditioning
LTGRP	Long Term Gas Resource Plan
MUA	Make Up Air
NAICS	North American Industry Classification System
NEW	New Construction
O&M	Operation and Maintenance
PJ	Petajoule, i.e. 1 million gigajoules
RET	Retrofit
REUS	Residential End Use Survey
ROB	Replace-on-burnout
RTU	Remote Terminal Unit
TAC	Technical Advisory Committee
TMP	Thermomechanical Pulping – an industrial Pulp & Paper segment term
TRM	Technical Resource Manual
UEC	Unit Energy Consumption
ZEEA	Zero Emission Energy Alternative

2.2 CPR Coverage

2.2.1 Timing

The base year for the CPR Study is the 2019 calendar year. The reference case forecast is for 2020 to 2040. Results are calculated for each intervening year.

2.2.2 Regions

The CPR divides the FortisBC gas regions in British Columbia (BC) into six:

- City of Vancouver
- Lower Mainland excluding Vancouver ("Lower Mainland x Vancouver")
- Vancouver Island
- Northern BC
- Southern Interior
- Whistler

A segment is a grouping or category of buildings, such as a single-family Detached dwelling in Residential, or large offices in Commercial, for example. Segments reflect the main purpose of the building and help to differentiate between energy use intensity or patterns across building types within a sector.

2.2.3 Sectors, Segments, and End Uses

The 2021 CPR covers three sectors: residential, commercial, and industrial.[7] Each sector is unique and has important differences which are reflected in how inputs and outputs are organized. Please see the supporting Method Appendices Document for details of how the sector model was developed. Exhibit 1 presents the specific way each sector is organized into segments, energy end uses, and building vintages in the CPR model.

7 The LTGRP includes these three sectors as well as transportation.

Exhibit 1 – CPR Segments, End Uses, & Vintages by Sector

	Residential	Commercial	Industrial
Segments	• Single Family Detached/Duplexes • Single Family Attached/Row • Mobile/Other Residential	• Apartments – Medium • Apartments – Large • Food Retail • Hospital • Hotel – Medium • Hotel – Large • Non-Food Retail – Medium • Non-Food Retail – Large • Nursing Home • Office – Medium • Office – Large • Other Commercial • Restaurant • School – Medium • School – Large • University/College • Warehouse	• Agriculture (includes greenhouses[8]) • Chemical • District energy providers • Fabricated Metal • Food & Beverage • Other Manufacturing (includes transportation[9] and other industrial) • Mining • Non-metallic Mineral (includes cement) • Pulp & Paper – Kraft • Pulp & Paper – TMP • Utilities • Wood Products

8 Cannabis included in agriculture segment since there is not enough data at FEI to create a cannabis-specific forecast.
9 In the 2015 CPR, ‘transportation’ pertained to facilities that supported the transportation sector.

	Residential	Commercial	Industrial

End Uses[10]	• Clothes dryer
	• Cooking
	• Domestic hot water[11]
	  ○ Dishwasher DHW
	  ○ Washer DHW
	  ○ Shower DHW
	  ○ Other DHW
	• Fireplace
	• Other gas uses (outdoor fireplaces, patio heaters)
	• Pool & spa heaters
	• Space heating
		• Cooking
		• Domestic Hot Water
		• Other[12]
		• Pools, Spas & Hot tubs
		• Space Heating
			• Direct-fired heating
			• Direct Consumption of Gas in Process[13]
			• Heat Treating
			• Kilns
			• On-Site Power Generation[13]
			• Other[12]
			• Ovens
			• Petrochemical Refining and Process Heating
			• Process Boilers
			• Product Drying
			• Space Heating [includes HVAC air heating and HVAC boilers]
			• Water heaters

Vintages[14]	• Pre-1950 • 1950-1975 • 1976-1985 • 1986-1995 • 1996-2005 • 2006-2015 • Post-2015 (Existing) • New	• Existing • New	• Existing • New

10 All-electric end uses, such as clothes washer, lighting or plug loads, are not included in the reported results therefore are excluded from the End Uses row of this table.
11 In some cases, end uses are broken out into sub-end uses to facilitate CPR measure analysis. DHW can be reported at the end use or sub-end use level in the CPR.
12 The 'other' end use is a catch all for equipment that account for a small portion of consumption in the sector. In the commercial sector, examples of 'other' equipment are patio heaters and laundry dryers.
13 No CPR measures are applied to this end use; included for tracking purposes only.
14 The residential sector segments are divided into vintages that define time periods when residential dwellings were built. 'New' residential dwellings do not appear until the first year of the reference case.

3 Study Approach

This section presents the major steps that were taken to complete this CPR. Subsequent sections present the process for completing each CPR step in further detail.

For this study, Posterity Group developed a common base year and reference case model (steps 1 and 2 below) for the CPR and FortisBC's 2022 LTGRP.

3.1 Major CPR Analysis Steps

1. **Determine the current (Base Year) customer base and their energy consumption.**
    a. Collect and review data on the building stock in FortisBC's service territory, including end use surveys and previous CPRs.
    b. Develop energy use models of each building or facility type (segments) and model energy consumption by end use.
    c. Collect and review actual base year (2019) energy use and billing data of FortisBC's customers.
    d. Use the billing data to calibrate the base year energy consumption in each sector's energy model.
2. **Develop reference case energy consumption forecast.**
    a. Collect and review data on all factors that will affect energy use trends over the study period (2020 to 2040 in this study's case).
        i. This includes analyzing and modelling natural improvements in building energy use intensities (e.g. from natural replacement of furnaces with new, higher efficiency ones at replacement time).
        ii. Other factors are existing building demolition / renovation trends, rate of new building stock construction, baseline energy efficiency of new buildings and equipment, and known changes to policies and codes and standards that will impact the energy use of buildings.
    b. Use this data to develop an energy consumption forecast model for each sector.
    c. Calibrate the reference case based on FortisBC's own account forecasts and industrial survey information at the region and rate class level.
3. **Characterize energy conservation measures.**
    a. Select a set of energy conservation measures for each sector. Measures range from mature, widely known measures that are currently part of FortisBC's program portfolio (e.g. commercial condensing boilers) to innovative or enabling technologies (e.g. smart residential water heater controllers). Behavioural measures are also considered (e.g. thermostat setback).
    b. For each measure, review and collect data on energy savings, costs, useful life, and the baseline equipment or technology that it should be compared with (if applicable).
    c. Use the data to characterize the technology's energy savings potential, cost-effectiveness, and financial attractiveness.

   d. Use the data as inputs to the energy model for each sector.

4. **Estimate technical savings potential.**
   a. For each measure, determine its technical applicability (i.e. how many buildings or facilities can this measure be applied to, considering only technical barriers).
   b. Determine the measures' current market penetration (i.e. how many buildings or facilities have already installed a measure).
   c. Estimate the measures' reference adoption – their natural rate of uptake in the absence of incentives or utility program intervention.
   d. Input all data into the energy model for each sector and develop a hypothetical estimate of the technically feasible energy savings potential within FortisBC's service territory.[15]
5. **Estimate economic savings potential.**
   a. Screen each measure for cost-effectiveness from FortisBC's perspective by determining whether the benefit to cost ratio of each measure is 1.0 or above (pass) or if it is below 1.0 (fail) for two cost effectiveness tests: TRC and MTRC.
   b. Update the technical potential model with only the TRC-passing measures, removing measures that are not cost-effective.
   c. Estimate the economic savings potential of all cost-effective measures applied to all technically feasible buildings in the customer base.[16]
   d. Repeat steps 5b and 5c using the MTRC screen. This study presents findings from two economic (and subsequent market potential) models: One with TRC as the economic screen and one with MTRC.
6. **Estimate market savings potential.**
   a. Based on existing research, develop sets of "generic" adoption curves based on customer payback acceptance and typical market diffusion patterns.[17]
   b. Apply these generic curves to each measure in the economic potential model to develop "simplified market potential" estimates at the measure level.
   c. This data is input into the TRC economic potential model to develop a simplified market potential.
   d. Develop a more realistic market potential for each measure by soliciting feedback from FortisBC and its external stakeholders on the simplified market potential.[18]

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15 See Exhibit 2 for an overview of the constraints considered in the technical potential scenario, and the difference between different potential scenarios.
16 See Exhibit 2 for an overview of the constraints considered in an economic potential scenario.
17 Generic adoption curves primarily consider two things: the current market penetration of the measure, and its simple payback. Based on these factors, the curves are applied to each measure to estimate generic participation rates as a percentage of economic potential.
18 This process includes selecting representative, high-impact measures and adjusting their generic participation rates using historical program data, local market knowledge, and industry insights/feedback, then extrapolating these calibrated participation rates to other similar measures within each sector.

e. Revise the simplified market potential model based on this feedback to develop a realistic market potential scenario (referred to in this study as "medium market potential").
f. Perform sensitivity analysis by varying incentive levels to model "low" and "high" market potential scenarios.
g. Repeat steps 6c to 6f using the MTRC economic potential model to estimate low, medium, and high market potential scenarios using the MTRC economic screen.

7. **Estimate other energy and non-energy benefits of the potential energy savings.**[19]

a. Greenhouse gas emissions savings.
b. Impact of energy conservation measure investments and energy bill savings on provincial employment.

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19 Due to uncertainty regarding measure-level impacts on regional and system peak demand, detailed analysis of the system peak impacts from energy efficiency measures has not been undertaken as part of the CPR.

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Exhibit 2 – Difference Between Technical, Economic, and Market Potential

Constraints	Description	
Technical applicability	Is the measure compatible with the current systems in place in the building or facility? Are there any technical constraints that will prevent installation in specific buildings or facilities? If not, then the measure's hypothetical energy savings can be included in the technical potential. Example: If this is a furnace-related measure, do I have a forced air heating system in my building?	Technical Potential
Cost-Effectiveness	In addition to the technical constraints above: From the utility's perspective, are the energy savings that result from installing the measure financially attractive? Do they provide a return on investment (i.e., the capital and installation costs) based on the economic screen the utility is required to use? If yes, then the measure's hypothetical energy savings can be included in the economic potential.	Economic Potential
Market-related	In addition to the technical and economic constraints above: Are there any constraints related to the market, logistics, or the target customers? Is the measure readily available in the market? Are customers aware of the measure? Realistically, how many customers will have the willingness or interest to install the measure given its costs and benefits? How would the customers' willingness change if the incentives to install these measures increased?	Market Potential *(this study's ultimate objective)*
Utility-related *(out of scope for this study, as this is typically a program design activity)*	In addition to all the constraints above: What are the utility's constraints around encouraging the uptake of this measure? How much budget does the utility have to spend on a program and incentives for a measure? How many resources can a utility allocate to delivering a program realistically?	Program Potential

3.2 Base Year Energy Use Model Development

The CPR model is developed in the following sequence for each sector:

- Base Year (2019): the first year of a forecast period and is based on historical data provided by FEI.
- Reference Case (2020-2040)[20]: forecast of natural gas consumption over a twenty-year (2020-2040) period based on exogenous conditions that follow a "business-as-usual" scenario.

The base year and reference case was modelled for each sector using Posterity Group's Navigator™ Energy and Emissions Simulation Suite. This section provides an overview of the model structure and the process to develop the base year and reference case.

Exhibit 3 defines the six parameters that provide the structure for the model used for the CPR.[21]

Exhibit 3 – 2021 CPR Model Parameters

Parameter	Definition
Accounts[22]	Number of FEI customer accounts.
Units	The basis for how energy consumption is expressed. The unit of analysis is unique to each sector: dwellings in the residential sector, square metres in the commercial sector and production capacity in the industrial sector.
Size Factor	The change in average number of units per account. This is primarily used to reflect the forecast change in production volumes in industry.
Saturation	For most end uses, saturation is the extent to which an end use is present in a region, and segment.[23] For some specific end uses that are associated with appliances, Saturation is defined as the average number of appliances per Unit.
Fuel Share	The percentage of the energy end use that is supplied by each fuel.
Unit Energy Consumption (UEC)	The amount of energy used by each end use per unit.

20 Note that the LTGRP forecast period is 2020-2042. The LTGRP will not be filed until 2022 and requires a twenty-year reference case.
21 Some of the model parameters are adjusted when necessary to reflect a distinct characteristic of a sector. Any adjustments are explained in this document.
22 PG uses 'accounts' instead of customers in this document as one customer could have multiple accounts.
23 A segment is a grouping or category of buildings (e.g., single-family detached in residential, large offices in commercial). Segments reflect the main purpose of the building and helps to differentiate between energy use intensity or patterns across building types within a sector.

Once each parameter of the model is populated with the applicable data, energy consumption is calculated for a specific end use for each region, segment, and vintage each year using the following equation:

$$Consumption = Units * Saturation * Fuel\ Share * Unit\ Energy\ Consumption$$

Exhibit 4 presents the detailed steps that the team took to calibrate the base year energy consumption in the CPR model with FortisBC's actual customer energy use.

Exhibit 4 – Base Year Calibration Steps for All Sectors

Step	Description
1	Compile and analyze available data on FortisBC's existing building stock by segment, including consultation of Residential End Use Survey (REUS), Commercial End Use Survey (CEUS) and relevant third-party data.
2	Develop detailed technical descriptions of the existing building stock at the subsector, end use, and end use equipment level. For each sector, detailed regional and subsector assumptions regarding fuel shares, end use penetrations, equipment saturations and equipment efficiency levels are aggregated in Excel workbooks as inputs into the Navigator™ model under step 4.
3	Compile utility billing data by subsector and region.
4	Create sector model inputs and generate preliminary results.
5	Adjust input assumptions for end uses with greater uncertainty until the results closely match the actual utility billing data.

The results of the base year energy consumption model are presented in Section 4.2 (residential), Section 5.2 (commercial), and Section 6.2 (industrial).

3.3 Reference Case Forecast Development

As explained in Section 3.2 Base Year Energy Use Model Development, the reference case begins with the base year values and forecasts natural gas use based on exogenous conditions that follow a "business-as-usual" scenario. The reference case for the CPR is intended to represent the baseline from which calculation of new potential can be calculated. It considers current energy consumption patterns and known future changes, including expected customer growth, current and known future changes to codes and standards, and natural replacement of equipment at end of life. The reference case does not account for potential changes in fuel share or end use saturations, except those that would occur incidentally because of different rates of new construction for different types of buildings or in the different regions.

The reference case starts with actual 2019 consumption, which includes all DSM activity up to that point. The subsequent years of the reference case incorporate natural conservation, such as the natural turnover of furnaces and other appliances. It does not include conservation from DSM activities carried out after 2019.

Exhibit 5 – Reference Case Development Steps for All Sectors

Step	Description
1	Compile and analyze available data on FortisBC's new building stock by segment and gather forward-looking estimates of demolition rates.
2	Develop detailed technical descriptions of the new building stock at the subsector, end use, and equipment level.
3	Compile data on forecast levels of construction, demolition and natural (non-utility-influenced) efficiency within the existing and new (post 2020) buildings stock.
4	Create sector model inputs and generate gas use forecasts by adding accounts to match forecast construction levels in cooperation with FortisBC Load Forecasting staff.

The results of the reference case energy consumption forecasts are presented in Section 4.3 (residential), Section 5.3 (commercial), and Section 6.3 (industrial).

3.4 Measure Characterization

In this CPR activity, energy conservation measures were selected and analyzed. The team started with developing a list of measures to consider, then finalized this list in collaboration with FortisBC and external stakeholders. For each measure, the team collected and reviewed information on energy savings, costs, useful life, and the baseline equipment or technology that it should be compared with (if applicable). This data was used to characterize the technology's energy savings potential, cost-effectiveness, and financial attractiveness to the utility and the end user.

3.4.1 Development of Measures List

Under this task, the study team reviewed existing energy efficiency measure analysis and program assumptions, assessed gaps and developed a measure list for input by FortisBC staff.

The team started by reviewing the 2015 CPR measure analysis, existing FortisBC Conservation and Energy Management (C&EM) program assumptions, and publicly available resources, especially Technical Resource Manuals (TRMs) from other utilities. Previous measure analysis and prefeasibility studies completed by FortisBC were also reviewed.

Measures range from mature and widely known to innovative or enabling technologies. Several behavioural measures (e.g. thermostat setback) are included as well. The team also developed "mature market" versions of several innovative technologies, such as gas heat pumps. These mature market measures assumed that within two to five years, various measures that are currently at an early stage of market entry would have lower costs, improved energy performance, or both. This approach allowed the study team to include these measures in subsequent analysis at a point after the first forecast year (2020) consistent with best estimates of market entry.

The study team solicited feedback on the measures list from both FortisBC as well as external stakeholders, the CPR Technical Advisory Committee (TAC). Ultimately, more than 180 measures were shortlisted for inclusion in this CPR: 70 in residential, 72 in commercial, and 40 in industrial. For comparison, the 2015 CPR included 97 measures: 45 residential, 36 commercial, and 16 industrial.

3.4.2 Energy Performance and Costs of Selected Measures

Under this task, the study team collected and reviewed information on each selected measure's energy savings, costs, useful life, and other relevant information. The analysis used several types of data sources to gather and establish this information: FortisBC's TRMs, previous FortisBC measure analysis (e.g. 2015 CPR, pre-feasibility studies), TRMs and literature from other jurisdictions, as well as the study team's own technical analysis and building modelling.

Using a typical FortisBC TRM template as guidance, the team developed one Excel-based measure analysis workbook per sector in which all measure data was recorded. The intent of these workbooks was to have each measure's metrics and assumptions easily reviewable, referenceable, and reusable by the FortisBC team. Exhibit 6 shows an example of a measure from the workbook.

Measures were characterized in a way that was consistent with FortisBC's measure TRM templates:

- Type of replacement (Retrofit or Replace on Burnout)
- Cost basis on which the measure should be evaluated – full or incremental
- Energy performance metrics and savings (% against end use and absolute)
- Technical applicability to various segments and / or vintages

- Cost of Conserved Energy (CCE) and simple payback metrics
- Cost-effectiveness on TRC and MTRC scales
- Ability to enter previous program results and customer enrollment (participation) rates, specific regional and segment subtleties

Exhibit 6 – CPR Measure Characterization Workbook Example: Residential Communicating Thermostat

MEASURE SUMMARY		NOTES	DATA SOURCES
Measure Description	Installation of a communicating (also often referred to as "smart," advanced, wi-fi or connected) thermostat to replace a manually operated or conventional programmable thermostat. Thermostat must be on the ENERGY STAR® list of Smart Thermostats and be able to: - Work as a basic thermostat in absence of connectivity to the service provider. - Give residents some form of feedback about the energy consequences of their settings. - Provide information about HVAC energy use, such as monthly run time. - Provide the ability to set a schedule. - Provide the ability to work with utility programs to prevent brownouts and blackouts, while preserving consumers' ability to override those grid requests.		
Measure Type	Controls		
Baseline Condition Description	The baseline condition is an assumed mix of manual and programmable thermostats.		
Calculation Method Description	Space heating and cooling savings estimated based on review of MN and Mid-Atlantic TRMs assumptions for ENERGY STAR® qualifying communicating thermostats. Also reviewed FortisBC's SLT pilot study results. See general notes and sources section below for additional details.		
Measure Applicability	Applies to existsing homes where a manual or programmable thermostat previously existed.		

APPLICABILITY					
Affected Natural Gas End-Uses	Space Heating				You can select up to 2 end-uses affected by this measure. Leave second one blank if not
Affected Electricity End-Uses	Space Cooling				You can select up to 2 end-uses affected by this measure. Leave second one blank if not
Applicable Codes / Standards	n/a				
Meets DSM Definition	Yes				
Meets Tech Innovation Definition	Yes				
Applicable Years	**First:**	2020	**Last:**	2040	

MODEL INPUT ASSUMPTIONS				
Measure Specifications	**Base Case**	**Upgrade Case**	**Notes**	**Data Sources**
Effective Useful Life (years)	12	12	FortisBC's EUL estimate is high compared to other TRMs (e.g., Mid-Atlantic TRM states 7.5 years, MN TRM states 10 years). 12 years is still in a reasonable range, so did not change it.	1, 6, 7

RESULTS (SPECIFIC TO A GIVEN REGION, SEGMENT AND VINTAGE)			
Region	Whistler	Segment Sheet Row #	Change the selections in light blue to see the results specific to a region, segment and vintage.
Segment	SFD/Duplex	82	
Vintage	Post-2015	Comm T-Stat - Segment	

Costs	**Base Case**	**Upgrade**	**Increme**	**Units**	**Notes**	**Data Sources**
Capital	$ -	$ 250	$ 250	per thermostat	FortisBC's estimate of $250 per connected thermostat seems reasonable compared to costs listed in other TRMs.	1, 6, 7
Installation	$ -	$ -	$ -	per thermostat		
O&M	$ -	$ -	$ -	per thermostat		

Energy Savings (%)	**Space Heating**	**Notes**	**Data Sources**
Natural Gas (%)	6%	Estimating 6% savings based on MN and Mid-Atlantic TRMs.	1,7
	Space Cooling		
Electricity (%)	8%	Estimating 8% savings based on MN and Mid-Atlantic TRMs.	1,7

Energy Use (Absolute)	**Base Case**	**Upgrade**	**Saving**	**Units**
Natural Gas	51.9	48.8	3.1	GJ /year
Electricity	515.3	474.1	41.2	kWh /year
Water	-	-	-	m3 /year

Financial Metrics		**Units**
Simple Payback	8.86	years
NPV of Avoided Utility Costs (TRC)	244.94	$ / yr
NPV of Avoided Utility Costs (mTRC)	897.46	$ / yr
Cost of Conserved Energy (CCE)	6.69	$ / GJ

Cost Effectiveness		**Units**
Measure TRC	1.0	total
Measure mTRC	4.1	total

The final measures and their information can be found in Section 4.4 (residential), Section 5.4 (commercial), and Section 6.4 (industrial).

3.5 Technical Potential Forecast Development

The technical potential forecast includes the installation of all conservation measures that are technically feasible. This exercise is hypothetical in nature and is used to provide the team with a starting point on which to develop the economic and market potential. Refer to Exhibit 2 for an overview of the differences between the potential scenarios.

Technical potential estimates ignore all non-engineering and financial constraints, such as cost-effectiveness and the willingness of end users to adopt measures. This is done to estimate the theoretical maximum amount of energy use that could be captured by energy efficiency measures. In this study, the following assumptions were made:

- Retrofit (RET) measures that are technically feasible are applied immediately (that is, in the first year of CPR study period, 2020).
- Replace on burnout (ROB) measures that are technically feasible are implemented at the rate of failure of the underlying baseline equipment, to better match in-market replacement rates. However, there are ROB measures that have “Early Replacement” versions (e.g. early replacement of a commercial boiler) that are treated the same way as RET measures.
- New construction measures that are technically feasible are implemented immediately as new buildings are added to the stock each year.

Development of the technical potential involved the following steps:

- Select the measures to be included from the Measure Analysis Workbook.
- Determine each measure’s technical applicability (i.e. what portion of buildings can a measure be applied to considering only technical constraints) and current market penetration (i.e. what portion of buildings have already installed a measure).

  This information is gathered from various data sources and literature review, including FortisBC’s Residential End-Use Survey (REUS), Commercial End-Use Survey (CEUS), and industrial datasets. The percentage of technically applicable customers that have already adopted a measure are excluded from the technical potential.
- Estimate reference adoption – the natural rate of adoption of a measure. For example, if 2% of the technically eligible customers are expected to implement a measure each year without any utility intervention, reference adoption is 2%. These customers are excluded from the technical potential.
- Apply measure information to the model. For each measure, the following inputs are required: measure’s description, the baseline equipment it affects, incremental or full costs, energy savings information, the total proportion of accounts or dwellings under different segments and vintages that the measure is applicable to, and the pre-retrofit and post-retrofit energy consumption.
- Determine the order that measures should be applied against the baseline energy end-use, and whether these measures are applied in series (in which case measure impacts

"cascade") or in parallel (in which case measure impacts are directly additive). This is an important feature of Posterity Group's modelling software that serves two purposes:

- It avoids overestimation and double counting of savings in instances where measures are not additive. For example, assume there is a reference-case house that uses 100 GJ of natural gas for the space heating end use. An air sealing measure is applied to this house, and it is expected to save 20% of space heating energy. A communicating thermostat can also be installed – it is expected to save 5% of total remaining space heating natural gas use.
- If both measures are applied to the same house, the air sealing measure would reduce the overall heating load, reducing the absolute potential savings for the thermostat. In other words, the thermostat saves 5% of 80 GJ (post-air-sealing consumption), not 5% of 100 GJ. Total natural gas savings in this example are 20 GJ + 4 GJ = 24 GJ.
- It avoids applying two mutually exclusive technologies to the same building. For example, a typical single-family house can be upgraded to a new high-efficiency furnace, or a new high-efficiency boiler, but almost never both. Additionally, there are many upgrade measures that apply to the same end use and baseline equipment. The model's cascade feature ensures that only one appropriate upgrade measure is applied to an eligible account or building.

- Run the model to calculate technical potential – this includes savings from all retrofit measures that can be immediately applied, savings from replace-on-burnout measure at their natural rate of replacement, and savings from new construction measures.

The results of the technical potential forecasts can be found in Section 4.5 (residential), Section 5.5 (commercial), and Section 6.5 (industrial).

3.6 Economic Potential Forecast Development

Economic potential is the subset of technical potential that is financially cost-effective. Cost-effectiveness is determined by screening each measure with the benefit/cost ratio test required by the utility's regulatory authorities. Economic potential considers the cost of the efficiency measures themselves, ignoring market constraints and programmatic barriers. Using economic screening, measures that have a benefit/cost ratio of greater than 1.0 under either the Total Resource Cost Test (TRC) or modified TRC (MTRC) "pass" the screening test and are included in the economic potential. Measures that score below 1.0 are not considered cost-effective and are excluded from future analysis.

Retrofit (RET) measures are evaluated on the basis of their full costs including capital, labor and maintenance costs. This is because the baseline for a retrofit measure is typically "do-nothing": the customer has the option to not install the measure, in which case they would not incur any costs.

Replace on burnout (ROB) measures are evaluated on the basis of their incremental costs – the cost difference between the high-efficiency measure versus the baseline, less-efficient option. This is because the baseline for a replace on burnout measure is typically "do something" because the underlying base equipment has reached the end of its useful life.

New construction measures were also evaluated based on their incremental costs.

Two economic models were developed for each sector – one with TRC as the economic screen and one with MTRC.

Development of the economic potential scenarios involved:

- Determining how measures should be assessed based on their replacement type: retrofit (immediate replacement at full cost), replace on burnout (end of life replacement at incremental cost), or new construction (immediate installation at incremental cost).
- Running the technical potential model using the TRC economic screen – this produces the subset of measures that are cost-effective in terms of TRC (i.e. they have a TRC benefit/cost ratio 1.0 or higher).
- Rerunning the technical potential model using the MTRC economic screen – this produces the subset of measures that are cost-effective in terms of MTRC (i.e. they have an MTRC benefit/cost ratio of 1.0 or higher).

The results of the economic potential forecasts are presented in Section 4.6 (residential), Section 5.6 (commercial), and Section 6.6 (industrial).

3.7 Market Potential Forecast Development

Market potential refers to the subset of the economic potential that is likely to be realized based on expected customer uptake. To be included in the market potential forecasts, customers must have the knowledge of various measures that are economically attractive to the utility and must have the willingness and means to adopt them.

The Low, Medium, and High market potential scenarios in this CPR estimate how customers' adoption rates would change as the simple customer payback varies based on varying incentive levels.

For this study, the market potential forecast was developed in two phases: first a Simplified Market Potential was developed using standard relationships between measure awareness, customer payback and measure uptake. Next, that simplified model was refined based on input from FortisBC staff, local market experts and other external stakeholders to develop a FortisBC-specific Market Potential.

Development of the market potential involved the following steps:

- Develop Simplified Market Potential.
  - At the measure level, this potential estimate was based on standard curves estimating the relationship between measure awareness, measure payback, and measure uptake consistent with the approach taken in the 2015 CPR.
  - Analysis included the development of a library of payback-acceptance and market diffusion curves, and their application to each measure based on attributes such as capital cost and reference market penetration.
  - These curves were then applied at three incentive levels: 25% 50%, and 100% of incremental cost to develop generic measure participation rates at the three spending levels.
- Market Potential Consultation and Workshops.

  This step consisted of two workshops for each sector:
  - Three sector-specific workshops engaging FortisBC Conservation & Energy Management program personnel, discussing and gathering input on the Simplified Market Potential participation rates based on prior program experience and known barriers and factors promoting uptake.
  - Three subsequent workshops attended by both FortisBC staff and members of Fortis BC's CPR Technical Advisory Committee[24] aimed at gathering external input on the Simplified Market Potential participation rates based on local market knowledge and capacity.

24 The Technical Advisory Group was made up of various external stakeholders including industry professionals, environmental nongovernmental organization representatives, and municipal/provincial government staff, and industry organization representatives.

- **Develop Market Potential.**
  - Based on the results of these consultations, updated measure uptake assumptions were developed and re-run through the model. This produced a Market Potential, meant to be the "expected" outcome from DSM programs at a typical incentive level (50% of incremental cost) and a sensitivity analysis at 25% and 100% of incremental cost.
  - The Low, Medium, and High market potential scenarios in this report assume that measure incentive levels will be 25%, 50% and 100% of incremental costs, respectively. For example, assume that a high-efficiency furnace may cost $200 more than a standard furnace, meaning the furnace would have an incremental cost of $200. In the medium scenario, this measure's hypothetical incentive from FortisBC would be $100. The other $100 would be paid by the end user.
  - In all scenarios, the non-incentive program costs are assumed to be 15% of the incentive cost.[25] In the example above, FortisBC's non-incentive spending would be $15. FortisBC's total cost for providing the measure to an end user would be $115.

25 Non-incentive program costs include activities such as program administration, communications, and research & evaluation. These costs have been estimated at 15%, a figure that is consistent with typical industry practice and the assumptions included in the 2017 CPR. Actual non-incentive program costs are dependent on several factors including program design, administrative structure, and evaluation requirements. For the purposes of this analysis, non-incentive spending that is not associated with specific measures or programs (including conservation education and outreach, and portfolio-level enabling activities) are not considered.

4 Residential Sector Results

This section presents the residential sector results and key findings, including:

- Base year (2019) natural gas use
- Reference case consumption forecast (2020-2040)
- Energy conservation measures evaluated in this CPR
- Technical potential savings
- Economic potential savings
- Market potential savings and scenarios

4.1 Residential Segments, End Uses, Vintages

The residential sector is divided into three segments, seven major energy end uses, and eight housing vintages. The residential domestic hot water (DHW) end use is subdivided into four as shown in Exhibit 7.

Exhibit 7 – Residential Sector Segments, End Uses, and Vintages

	Segments (3)	End Uses[26] (7)	Vintages[27] (8)

Residential Sector	• Single Family Detached/Duplexes
	• Single Family Attached/Row
	• Mobile/Other Residential
		• Clothes dryer
		• Cooking
		• Domestic hot water[28]
		  ○ Dishwasher DHW
		  ○ Washer DHW
		  ○ Shower DHW
		  ○ Other DHW
		• Fireplace
		• Other gas uses (outdoor fireplaces, patio heaters)
		• Pool & spa heaters
		• Space heating
			• Pre-1950
			• 1950-1975
			• 1976-1985
			• 1986-1995
			• 1996-2005
			• 2006-2015
			• Post-2015 (Existing)
			• New

26 All-electric end uses, such as clothes washer, lighting or plug loads, are not included in the reported results therefore are excluded from the end uses row of this table.
27 The residential sector has vintages to define time periods when residential dwellings are built. Existence Categories also apply to the residential vintages, as there is conversion of existing dwellings into new homes (i.e., renovations). 'New' residential dwellings do not appear until the first year of the reference case.
28 The DHW end use has been broken out into sub-end uses to facilitate CPR measure analysis. DHW can be reported at the end use or sub-end use level in the CPR.

4.2 Base Year Natural Gas Use

This section profiles the base year (2019) natural gas consumption for the residential sector. The following exhibits summarize how natural gas is used in the residential sector by segment, end use, vintage, and region, respectively.

Natural gas consumption in the residential sector base year is highest:

- In single-family detached (SFD)/duplex segment (~90% of consumption)
- For space heating end use (~62%)
- In the Lower Mainland excluding Vancouver region (~55%)
- In homes built between 1950 and 1975 (26%)

Exhibit 8 – Residential Natural Gas Consumption (GJ) in 2019 by Segment

Segment	Natural Gas Consumption (GJ)	% of Total
SFD/Duplex	69,593,368	90.3%
Attached/Row	5,609,684	7.3%
Mobile/other	1,888,575	2.4%
Total	**77,091,627**	**100.0%**

Exhibit 9 – Residential Natural Gas Consumption (GJ) in 2019 by End Use

Parent End Use	Natural Gas Consumption (GJ)	% of Total
Space Heating	48,159,206	62.5%
Domestic Hot Water (DHW)	13,800,150	17.9%
Fireplace	11,367,123	14.7%
Other Gas Uses	1,779,960	2.3%
Cooking	1,252,716	1.6%
Pool & Spa Heaters	509,960	0.7%
Clothes Dryer	222,511	0.3%
Total	**77,091,627**	**100.0%**

Exhibit 10 – Residential Natural Gas Consumption (GJ) in 2019 by Region[29]

Region	Natural Gas Consumption (GJ)	% of Total
Lower Mainland x Van	42,239,373	54.8%
Southern Interior	14,848,987	19.3%
City of Vancouver	9,339,690	12.1%
Vancouver Island	5,832,901	7.6%
Northern BC	4,564,223	5.9%
Whistler	266,452	0.3%
Total	**77,091,627**	**100.0%**

Exhibit 11 – Residential Natural Gas Consumption (GJ) in 2019 by Vintage [30]

Segment Vintage	Natural Gas Consumption (GJ)	% of Total
1950-1975	19,633,614	26.1%
1986-1995	12,634,000	16.8%
1976-1985	10,907,142	14.5%
1996-2005	10,070,375	13.4%
Pre-1950	9,196,994	12.2%
2006-2015	7,805,930	10.4%
Post-2015	4,954,997	6.6%

29 Recall that the 2019 actuals from FEI were based on FEI's billing system premise city and mapped by PG into the regions included in the study coverage.
30 "Mobile" has been excluded from the vintage results in this report; "mobile/other" appears in the segment results. The sample sizes for mobile dwellings in the REUS were too small to reliably divide the segment into vintages.

4.2.1 Accounts

Base year residential natural gas accounts are presented in Exhibit 12 by segment, region, and vintage. As shown in the table, the largest number of residential accounts in 2019 were:

- SFD / duplex type homes (806k out of 933k total)
- In Lower Mainland x Vancouver region (463k out of 933k total)
- Homes built between 1950 and 1975 (210k out of 933k total)

Exhibit 12 – Number of Residential Dwellings in 2019

Segment	City of Vancouver	Lower Mainland x Van	Northern BC	Southern Interior	Vancouver Island	Whistler	Total
SFD/Duplex	**80,641**	**395,571**	**40,486**	**180,309**	**106,270**	**2,527**	**805,804**
1950-1975	20,353	99,839	10,219	45,509	26,822	639	**203,381**
1986-1995	13,310	65,294	6,683	29,763	17,541	417	**133,008**
1976-1985	11,779	57,782	5,913	26,337	15,523	369	**117,703**
1996-2005	11,132	54,606	5,589	24,890	14,670	349	**111,236**
2006-2015	9,490	46,551	4,764	21,219	12,506	297	**94,827**
Pre-1950	8,780	43,065	4,408	19,630	11,569	275	**87,727**
Post-2015	5,797	28,434	2,910	12,961	7,639	181	**57,922**
Attached/Row	**11,638**	**57,086**	**2,949**	**10,017**	**8,677**	**140**	**90,507**
1986-1995	3,197	15,682	810	2,751	2,384	38	**24,862**
1996-2005	2,736	13,425	694	2,356	2,041	32	**21,284**
Post-2015	1,902	9,329	482	1,637	1,418	23	**14,791**
2006-2015	1,599	7,841	405	1,376	1,191	20	**12,432**
1976-1985	1,236	6,058	313	1,063	921	15	**9,606**
1950-1975	823	4,039	208	709	614	10	**6,403**
Pre-1950	145	712	37	125	108	2	**1,129**
Mobile/other	**2,024**	**9,928**	**8,459**	**12,764**	**2,706**	**179**	**36,060**
All	2,024	9,928	8,459	12,764	2,706	179	**36,060**
Total	**94,303**	**462,585**	**51,894**	**203,090**	**117,653**	**2,846**	**932,371**

4.2.2 Tertiary Load

Tertiary load is the useful energy delivered to an end use, or end use energy requirement: heat delivered by a furnace to a house, for example. This differs from natural gas consumption which is impacted by equipment efficiency: in the furnace example, consumption is equal to the tertiary load divided by seasonal efficiency of the furnace.

4.2.3 Unit Energy Consumption

As explained in Exhibit 3, unit energy consumption (UEC) is the end-use energy per unit (a "unit" in the residential sector is a dwelling). Fuel share is the percentage of the energy end use that is supplied by each fuel.

This section presents UEC by end use for dwellings that have gas as the predominant heating fuel and dwellings that have fuels other than gas as the predominant heating fuel[31] (referred to as "gas-heated" and "non-gas-heated" dwellings for simplicity). Tertiary loads for gas-heated and non-gas-heated dwellings are modelled identically for all end uses, except for space heating. Based on market research, non-gas-heated dwellings in FortisBC's service territory have been shown to have slightly lower space heating loads, meaning that they are somewhat smaller, better insulated, heated to a lower temperature, or some combination of these three.

This section also presents *stock average efficiency*, the average efficiency of equipment serving the tertiary load for that end use. UEC by end use is calculated by dividing unit tertiary load with stock average efficiency.

Exhibit 13 presents the 2019 modelled values for unit tertiary load, stock average efficiency and UEC values for all end uses (DHW sub-end uses are shown separately in Exhibit 14) for gas-heated and non-gas-heated SFD dwellings in the Lower Mainland excluding Vancouver region.

Exhibit 13 – 2019 Modelled UEC Values by End Use, Gas and Non-Gas-Heated SFD/Duplex Dwellings in the Lower Mainland

	Unit Tertiary Load (GJ/Dwelling/Yr.)	Stock Average Efficiency (%)[32]	UEC
Predominantly Gas-Heated Dwellings			
Clothes Dryer	3.9	86%	4.6
Cooking	2.9	51%	5.7
Fireplace	7.3	50%	14.5
Other Gas Uses	2.3	100%	2.3
Pool & Spa Heaters	23.7	86%	27.7

31 "Predominant heating fuel" represents if a building primarily uses gas for heat (>50% of the fuel share for space heating is from gas) or other fuels (>50% of fuel share for space heating is from fuels other than gas). In this report, we refer to this as 'gas-heated' and 'non-gas-heated' dwellings to simplify the text. Note that gas-heated dwellings can have other fuels supplying space heating, but gas is at least 50% of the fuel share.
32 Average stock efficiencies are only used to calculate tertiary load and are not used in the measure savings calculations or elsewhere in the modelling.

	Unit Tertiary Load (GJ/Dwelling/Yr.)	Stock Average Efficiency (%)[32]	UEC
Space Heating	59.1	85%	69.4
Domestic Hot Water	12.0	62%	19.5
Predominantly Non-Gas-Heated Dwellings			
Clothes Dryer	3.9	86%	4.6
Cooking	2.9	51%	5.7
Fireplace	7.3	50%	14.5
Other Gas Uses	2.3	100%	2.3
Pool & Spa Heaters	23.7	86%	27.7
Space Heating	55.8	85%	65.5
Domestic Hot Water	12.0	62%	19.5

Exhibit 14 presents the 2019 modelled values for unit tertiary load, stock average efficiency, and UEC values for the DHW sub-end uses. As DHW gas consumption does not vary by the predominant heating fuel in the dwelling, the table does not differentiate by gas versus non-gas-heated dwellings. The values are specific to the SFD/Duplex segment in the Lower Mainland excluding Vancouver ("LML") region.

Exhibit 14 – 2019 Modelled UEC Values for DHW Sub-End Uses, SFD/Duplex Dwellings in the LML

	Unit Tertiary Load (GJ/Dwelling/Yr.)	Stock Average Efficiency (%)	UEC
Other DHW	2.3	62%	3.7
Dishwasher DHW	1.4	62%	2.3
Shower DHW	6.5	62%	10.5
Washer DHW	1.8	62%	2.9

4.2.4 Average Natural Gas Use per Dwelling

The following exhibits present average annual natural gas consumption per account by end use. Included in the exhibits are:

- UEC: the amount of energy used by each end use per unit (the "unit" in the residential sector is typically a dwelling, with some minor exceptions described below).
- Fuel Share: the percentage of the energy end use that is supplied by each fuel (in this case, natural gas).
- Saturation: For most end uses, saturation reflects the extent to which an end use is present in a region, and segment. In the residential sector, cooking, space heating, DHW, and 'other gas uses' have a saturation of 100% as these end uses are assumed to be present in all residential dwellings.

  Three end uses – clothes dryers, fireplaces, and pool & spa heaters – are not present in every residential dwelling. In these cases, saturation is used to show the average number of appliances per dwelling supplying those end uses, and the "unit" referred to in the UEC is one equipment unit: a fireplace for example. In the exhibits below, saturation for these three end uses is not 100%: greater than 100% means that the average residential dwelling has more than one appliance related to that end use (e.g., fireplaces) and less than 100% means that the average residential dwelling has less than one (therefore no) appliances related to that end use (e.g., pool & spa heaters).

Average annual gas consumption per unit is calculated by multiplying these three variables together; therefore, they are included in the exhibits below.

Exhibit 15 presents the modelled average annual gas use per residential dwelling by end use (DHW sub-end uses are presented separately in Exhibit 16) for gas and non-gas-heated dwellings, respectively. Note that these values are specific to the SFD/Duplex segment and the Lower Mainland excluding Vancouver ("LML") region.[33]

Exhibit 15 – 2019 Modelled Average Annual Gas Use Per Dwelling by End Use, Gas and Non-Gas SFD/Duplex Heated Dwellings in the Lower Mainland

	UEC	Fuel Share	Saturation	Average Annual Gas Use (GJ/yr.)
Predominantly Gas-Heated Dwellings				
Clothes Dryer	4.6	6%	104%	0.3
Cooking	5.7	29%	100%	1.6
DHW	19.5	87%	100%	17.0
Fireplace	14.5	95%	110%	15.1
Other Gas Uses	2.3	100%	100%	2.3
Pool & Spa Heaters	27.7	26%	9%	0.7
Space Heating	69.4	93%	99%	63.8
Total Annual Consumption for an Average Residential Customer in LML				**100.8**
Predominantly Non-Gas-Heated Dwellings				
Clothes Dryer	4.6	7%	104%	0.4
Cooking	5.7	35%	100%	2.0
DHW	19.5	58%	99%	11.2
Fireplace	14.5	96%	121%	17.0
Other Gas Uses	2.3	100%	100%	2.3
Pool & Spa Heaters	27.7	10%	9%	0.2
Space Heating	65.5	17%	95%	10.8
Total Annual Consumption for an Average Residential Customer in LML				**43.9**

33 Note that the average annual natural gas use for all residential customers within FortisBC's service territory is approximately 90 GJ per year.

Exhibit 16 presents the modelled average annual gas use per residential dwelling by DHW sub-end use for gas and non-gas-heated dwelling, respectively. Note that these values are specific to the SFD/Duplex segment and the Lower Mainland excluding Vancouver region.

Exhibit 16 – 2019 Modelled Average Annual Gas Use Per SFD/Duplex Dwellings in the LML by DHW Sub-End Uses and Predominant Heating Fuel

	UEC	Gas Fuel Share	Saturation	Average Annual Gas Use (GJ/dwelling/yr.)
Predominantly Gas-Heated Dwellings				
Other DHW	3.7	87%	100%	3.3
Dishwasher DHW	2.3	87%	100%	2.1
Shower DHW	10.5	87%	100%	9.2
Washer DHW	2.9	87%	100%	2.5
Predominantly Non-Gas-Heated Dwellings				
Other DHW	3.7	58%	100%	2.2
Dishwasher DHW	2.3	58%	100%	1.4
Shower DHW	10.5	58%	100%	6.0
Washer DHW	2.9	58%	100%	1.7

4.3 Reference Case Natural Gas Use

This section profiles the reference case forecast (2020-2040) natural gas consumption for the residential sector.

Overall gas consumption is forecasted to decline by approximately 5% by 2040 (as shown in Exhibit 19) compared to 2020 consumption, with an average annual decrease of about 0.25%. While the forecast shows an increase in the number of residential accounts (as seen in Exhibit 18), the growth in accounts is less than the decrease in usage per account, so the net result is that consumption declines.

Exhibit 17 – 2020 vs 2040 Residential Gas Consumption (GJ) by Segment

Segment	2020	2040	Change
SFD/Duplex	69,263K	65,033K	-6%
Attached/Row	5,646K	6,046K	7%
Mobile/other	1,891K	1,927K	2%
Total	**76,801K**	**73,006K**	**-5%**

Exhibit 18 – Number of Residential Accounts, 2019 vs 2040, by Region, Segment, and Vintage

Region	City of Vancouver		Lower Mainland x Van		Northern BC		Southern Interior		Vancouver Island		Whistler		Total	
Segment	2019	2040	2019	2040	2019	2040	2019	2040	2019	2040	2019	2040	2019	2040
SFD/Duplex	**80,641**	**84,969**	**395,571**	**413,166**	**40,486**	**44,763**	**180,309**	**200,305**	**106,270**	**146,349**	**2,527**	**3,274**	**805,804**	**892,826**
1950-1975	20,353	13,358	99,839	65,502	10,219	6,788	45,509	30,366	26,822	21,015	639	445	**203,381**	**137,474**
1986-1995	13,310	8,736	65,294	42,838	6,683	4,439	29,763	19,859	17,541	13,743	417	290	**133,008**	**89,905**
1976-1985	11,779	7,731	57,782	37,910	5,913	3,927	26,337	17,574	15,523	12,163	369	257	**117,703**	**79,562**
1996-2005	11,132	7,306	54,606	35,826	5,589	3,713	24,890	16,608	14,670	11,494	349	243	**111,236**	**75,190**
2006-2015	9,490	6,229	46,551	30,541	4,764	3,164	21,219	14,159	12,506	9,799	297	207	**94,827**	**64,099**
Pre-1950	8,780	5,762	43,065	28,254	4,408	2,928	19,630	13,099	11,569	9,064	275	192	**87,727**	**59,299**
Post-2015	5,797	35,847	28,434	172,295	2,910	19,804	12,961	88,640	7,639	69,071	181	1,640	**57,922**	**387,297**
Attached/Row	**11,638**	**13,214**	**57,086**	**68,550**	**2,949**	**3,668**	**10,017**	**13,414**	**8,677**	**13,914**	**140**	**464**	**90,507**	**113,224**
1986-1995	3,197	2,098	15,682	10,289	810	538	2,751	1,836	2,384	1,868	38	26	**24,862**	**16,655**
1996-2005	2,736	1,796	13,425	8,807	694	461	2,356	1,573	2,041	1,599	32	23	**21,284**	**14,259**
Post-2015	1,902	6,824	9,329	37,219	482	2,029	1,637	7,822	1,418	8,226	23	383	**14,791**	**62,503**
2006-2015	1,599	1,049	7,841	5,144	405	269	1,376	918	1,191	933	20	14	**12,432**	**8,327**
1976-1985	1,236	811	6,058	3,974	313	208	1,063	709	921	722	15	10	**9,606**	**6,434**
1950-1975	823	541	4,039	2,650	208	138	709	473	614	481	10	7	**6,403**	**4,290**
Pre-1950	145	95	712	467	37	25	125	83	108	85	2	1	**1,129**	**756**
Mobile/other	**2,024**	**2,153**	**9,928**	**10,564**	**8,459**	**9,432**	**12,764**	**14,332**	**2,706**	**3,773**	**179**	**251**	**36,060**	**40,505**
All	2,024	2,153	9,928	10,564	8,459	9,432	12,764	14,332	2,706	3,773	179	251	**36,060**	**40,505**
Total	**94,303**	**100,336**	**462,585**	**492,280**	**51,894**	**57,863**	**203,090**	**228,051**	**117,653**	**164,036**	**2,846**	**3,989**	**932,371**	**1,046,555**

The following exhibits present how natural gas is forecasted to be used from 2020 to 2040 by segment, end use, and region, respectively. (Section 4.3.1 focuses on consumption from existing and new dwellings over the reference case). These exhibits illustrate forecasted trends in consumption over the reference case, including:

- Many consumption patterns evident in the base year are expected to persist throughout the reference case: natural gas is predominately used in the SFD/Duplex segment, in the Lower Mainland excluding Vancouver region, and for space heating throughout the study period.
- In 2020, post-2015 residential dwellings are forecasted to account for approximately 9% of consumption. By 2040, this vintage is projected to use about 38% of consumption.

Exhibit 19 – 2020 vs 2040 Residential Gas Consumption (GJ) by End Use

Parent End Use	2020	2040	Change
Space Heating	47,864K	43,877K	-8%
Domestic Hot Water (DHW)	13,680K	12,445K	-9%
Fireplace	11,407K	11,710K	3%
Other Gas Uses	1,844K	2,728K	48%
Cooking	1,268K	1,453K	15%
Pool & Spa Heaters	514K	556K	8%
Clothes Dryer	224K	238K	6%
Total	**76,801K**	**73,006K**	**-5%**

Exhibit 20 – 2020 vs 2040 Residential Gas Consumption (GJ) by Region

Region	2020	2040	Change
Lower Mainland x Van	41,954K	38,521K	-8%
Southern Interior	14,828K	14,406K	-3%
City of Vancouver	9,275K	8,502K	-8%
Vancouver Island	5,915K	6,830K	15%
Northern BC	4,557K	4,425K	-3%
Whistler	271K	322K	19%
Total	**76,801K**	**73,006K**	**-5%**

4.3.1 Reference Case Natural Gas Use: Existing versus New Residential Dwellings

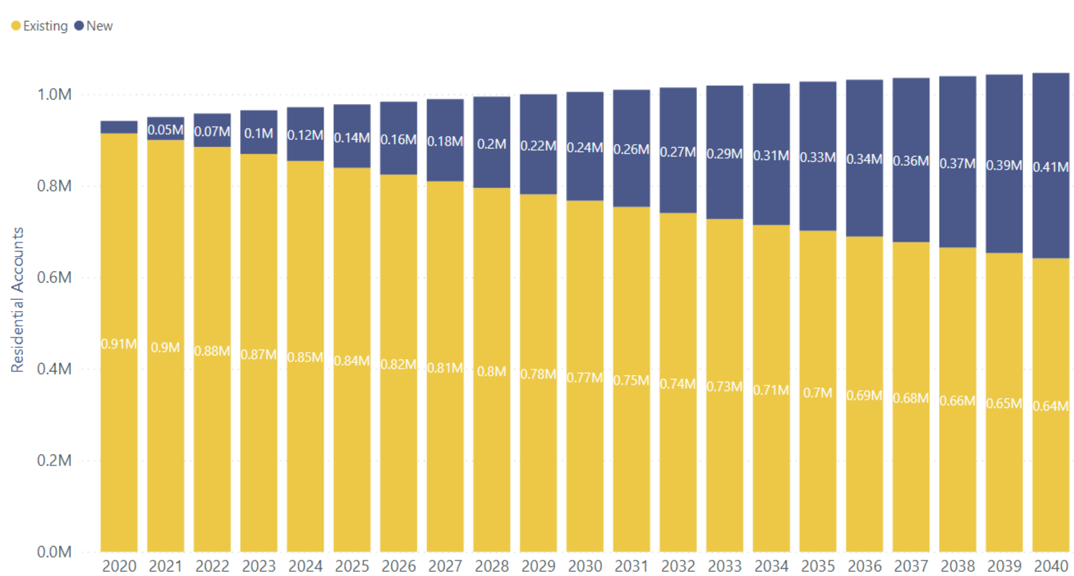
Exhibit 21 illustrates the expected increase in consumption from new residential dwellings over the reference case, from 2% in 2020 to approximately 33% in 2040, compared to existing dwellings.

Exhibit 21 – 2020-2040 Gas Consumption (GJ) by New and Existing and Segment

Existing/New	2020	2040	Change
Existing	**75,137K**	**48,621K**	**-35%**
SFD/Duplex	67,800K	43,427K	-36%
Attached/Row	5,462K	3,456K	-37%
Mobile/other	1,875K	1,737K	-7%
New	**1,664K**	**24,385K**	**1365%**
SFD/Duplex	1,464K	21,605K	1376%
Attached/Row	184K	2,590K	1305%
Mobile/other	16K	190K	1078%
Total	**76,801K**	**73,006K**	**-5%**

Despite the reference case showing a 5% decrease in residential sector gas use from 2020 to 2040, residential accounts are expected to grow by approximately 11% from 2020 to 2040, from 932,000 to 1,047,000. The portion of FEI accounts from new residential dwellings is forecasted to increase over the reference case from 3% in 2020 to almost 40% in 2040, with new construction contributing approximately 400,000 new accounts, and approximately 290,000 existing dwellings being demolished over the reference case period. This represents 30% of the existing dwellings being demolished between 2020 and 2040, a demolition rate of approximately 2% per year. Slightly countering this trend is the inclusion of some conversion customers, which are existing homes to which gas service is extended sometime after their construction. In most regions, conversion customers are a small fraction of new connections.

Exhibit 22 – 2020 vs 2040 Residential Gas Accounts Forecast by Existing and New Vintage



4.4 Measure Assessment

4.4.1 List of Measures

The list of residential measures that were included in this CPR are presented in Exhibit 23. The measures are divided into categories by end use and measure type.

Please see the MS Excel file entitled "Res_Measure Analysis Workbook" for a description of each measure and a full analysis.

Measures were classified in five measure type categories:

- Building Envelope (also referred to as "envelope measures")
- Equipment
- Controls
- Energy Management (including behavioral measures)
- New Construction – all new construction measures were placed in a separate category

New construction measures are analyzed using a whole-building approach, represented by the Step 3 - Step 5 BC Energy Step Code measures listed below. See Appendix M of the CPR method for the modelling approach used to assess residential Step Code measures.

Exhibit 23 – Residential Sector Conservation and Energy Management Measures

Space Heating – Building Envelope	Water Heating – Equipment
Attic Duct Insulation Attic Insulation Basement or Crawlspace Insulation Comprehensive Air Sealing Comprehensive Draft Proofing Exposed Floor Insulation High Performance Windows and Doors Manufactured Homes Duct Sealing Manufactured Homes Floor Insulation Wall Insulation	Connected Water Heater Controller Drain Water Heat Recovery Faucet Aerator Gas Heat Pump – Domestic Hot Water High-Efficiency Condensing Gas Tankless Water Heater High-Efficiency Condensing Gas Water Heater High-Efficiency Storage Gas Water Heater Low Flow Showerhead Pipe Wrap Solar Water Heating System Thermostatic Restrictor Shower Valve Water Heater Tune-Up
Space Heating – Equipment	**Appliances**
Boiler Early Retirement Boiler Reset Controls Boiler Tune-Up Communicating Thermostat Electric Air Source Heat Pump with Existing Gas Furnace Backup (Dual-Fuel Measure) Electric Air Source Heat Pump with New Gas Furnace Backup (Dual-Fuel Measure) Fireplace Timer Furnace Early Retirement Furnace Tune-Up Gas Heat Pump – Space Heating High Efficiency Boiler High Efficiency Boiler Dual Fuel-Gas Primary High Efficiency Fireplace High Efficiency Furnace High Efficiency Furnace Dual Fuel-Gas Primary High Quality Furnace Installation High-Efficiency Heat Recovery Ventilator HVAC Zoning	Convection Oven ENERGY STAR Dishwasher High Efficiency (ENERGY STAR®) Clothes Washer High Efficiency (ENERGY STAR®) Gas Clothes Dryer High Efficiency Gas Range **Pool & Spa Heaters – Equipment** HE Gas Pool Heater Outdoor Pool Cover Solar Pool Heater **New Construction** New Construction - Step 3 Homes New Construction - Step 4 Homes New Construction - Step 5 Homes
Space Heating & Water Heating - Equipment	**Other**
Combination System - Type 1 and 2 Combination System - Type 1 and 2 Early Retirement Combination System - Type 3 Gas Heat Pump Combination System – Type 1 and 2	Deep Energy Retrofits[34] ENERGY STAR Manufactured Home Home Energy Report

[34] Note that analysis that forms the technical, economic and market potential is based on individual measures rather than on "packages of measures" or program delivery approaches. Measures packaged in comprehensive programs such as FortisBC's Rental Apartment Efficiency program, Social Housing Retrofit Support program and deep energy retrofits were assessed within this analysis individually but not also collectively as a program package.

4.4.2 Results

Exhibit 24 shows measure-level results for the residential sector in order of decreasing cost effectiveness.

Measures were assessed based on their replacement type: **retrofit** (immediate replacement at full cost), **replace on burnout** (end of life replacement at incremental cost), or **new construction** (immediate installation at incremental cost).

The TRC and MTRC are presented at the measure-level and exclude program costs and free ridership.

Key findings of the measure assessment for the residential sector include:

- Of the 65 measures included in the analysis, only 14 pass the TRC screen. Substantially more, 54 measures, pass the MTRC screen.
- The most attractive water heating measures (i.e. measures with the highest TRC) include faucet aerators, pipe wrap and low flow showerheads.
- The most attractive space heating measures are certain building envelope (walls, attic duct, and basement) insulation measures, high-efficiency fireplaces, and communicating thermostats.
- Other building envelope measures, such as attic, floor insulation and air sealing measures do not pass the TRC (i.e. TRC is less than 1.0).
- Gas heat pumps combination systems and the mature market version of DHW gas heat pumps pass the MTRC. Neither pass the TRC.
- Most Step Code new construction measures pass the MTRC but neither pass the TRC.

Exhibit 24 – Residential Sector Results: Sector Averages (Sorted by High to Low MTRC)

#	Measure	Measure Type	Replacement Type	TRC	MTRC
1	Faucet Aerator	Equipment	RET	8.2	42.2
2	Pipe Wrap	Equipment	RET	7.7	38.5
3	Low Flow Showerhead	Equipment	RET	5	25.8
4	Combination System - Type 1 and 2	Equipment	ROB	10	10
5	ENERGY STAR Dishwasher	Equipment	ROB	10	10
6	Fireplace Timer	Equipment	RET	1.8	8.6
7	High Efficiency (ENERGY STAR) Clothes Washer	Equipment	ROB	1.7	8.5
8	Wall Insulation - Cavity (R-3 baseline)	Building Envelope	RET	1.7	7.6
9	High Efficiency (EnerChoice) Gas Fireplace or Vertically Direct Vented Fireplace	Equipment	ROB	1.5	7.4
10	Attic Duct Insulation	Building Envelope	RET	1.4	6.1
11	Communicating Thermostat	Controls	RET	1.2	5.2
12	Basement or Crawlspace Insulation	Building Envelope	RET	1.1	5
13	High Efficiency (ENERGY STAR) Gas Clothes Dryer	Equipment	ROB	1	4.8
14	Attic Insulation (R-12.6 Baseline)	Building Envelope	RET	0.9	4
15	GHP Combination System - Type 1 and 2	Equipment	ROB	0.7	3.6

16	Home Energy Report	Energy Management	RET	1.4	3.2
17	Air Source Heat Pump (Central) - Retrofit Existing Gas Furnace	Equipment	RET	0.6	3.1
18	Outdoor Pool Cover	Equipment	RET	0.6	3.1
19	Air Source Heat Pump (Central) - New Gas Furnace	Equipment	ROB	0.6	2.9
20	Comprehensive Air Sealing	Building Envelope	RET	0.6	2.8
21	Drain Water Heat Recovery	Equipment	RET	0.6	2.7
22	Attic Insulation (R-20 Baseline)	Building Envelope	RET	0.5	2.5
23	HVAC Zoning (HVAC Zone Control)	Equipment	RET	0.6	2.4
24	Exposed Floor Insulation	Building Envelope	RET	0.5	2.1
25	New Construction - Step 4 Homes - Electric DHW	New Construction	NEW	0.9	2.1
26	Wall Insulation - Cavity (R-10 baseline)	Building Envelope	RET	0.4	2.1
27	High Efficiency Furnace	Equipment	ROB	0.4	2
28	New Construction - Step 4 Homes	New Construction	NEW	0.4	2
29	Gas Heat Pump - DHW - Mature Market Costs	Equipment	ROB	0.4	1.9
30	Thermostatic Restrictor Shower Valve	Equipment	RET	0.3	1.8
31	Furnace Early Retirement	Equipment	RET	0.3	1.8
32	High-Efficiency Storage Gas Water Heater	Equipment	ROB	0.3	1.7
33	High-Efficiency Heat Recovery Ventilator	Equipment	RET	0.4	1.6
34	Boiler Reset Controls	Equipment	RET	0.3	1.6
35	Combination System - Type 3	Equipment	ROB	0.3	1.6
36	High-Efficiency (ENERGY STAR) Condensing Gas Tankless Water Heater - Mature Market Costs	Equipment	ROB	0.3	1.6
37	High Quality Furnace Installation - ENERGY STAR Verified	Equipment	ROB	0.3	1.6
38	Wall Insulation - Sheathing (R-7 baseline)	Building Envelope	RET	0.3	1.6
39	New Construction - Step 5 Homes - Mature Market Costs	New Construction	NEW	0.3	1.5
40	New Construction - Step 3 Homes - Electric DHW	New Construction	NEW	0.6	1.4
41	High Efficiency Furnace Dual Fuel-Gas Primary	Equipment	ROB	0.3	1.4
42	Combination System - Type 1 and 2 Early Retirement	Equipment	ROB	0.3	1.4
43	New Construction - Step 5 Homes - Electric DHW	New Construction	NEW	0.6	1.4
44	High Efficiency Boiler	Equipment	ROB	0.3	1.4
45	New Construction - Step 5 Homes	New Construction	NEW	0.3	1.3
46	Comprehensive Draft Proofing	Building Envelope	RET	0.3	1.3
47	New Construction - Step 3 Homes	New Construction	NEW	0.3	1.3
48	Solar Pool Heater	Equipment	RET	0.3	1.2
49	Boiler Early Retirement	Equipment	RET	0.2	1.1
50	Gas Heat Pump - Space Heating	Equipment	ROB	0.2	1.1
51	High Efficiency Boiler Dual Fuel-Gas Primary	Equipment	ROB	0.2	1

52	Manufactured Homes Duct Sealing	Equipment	RET	0.2	1
53	Manufactured Homes Floor Insulation	Equipment	RET	0.2	0.9
54	High Efficiency Gas Range	Equipment	ROB	0.2	0.8
55	Solar Water Heating System	Equipment	RET	0.1	0.7
56	Gas Heat Pump - DHW	Equipment	ROB	0.1	0.7
57	Convection Oven	Equipment	ROB	0.1	0.7
58	High-Efficiency (ENERGY STAR) Condensing Gas Water Heater	Equipment	ROB	0.1	0.5
59	Connected Water Heater Controller	Controls	RET	0.2	0.5
60	Boiler Tune-Up	Equipment	RET	0.1	0.3
61	Furnace Tune-Up	Equipment	RET	0.1	0.3
62	ENERGY STAR Manufactured Home	Equipment	RET	0.1	0.3
63	High Performance Windows and Doors	Building Envelope	ROB	0.1	0.3
64	Water Heater Tune-Up	Energy Management	RET	0	0.2
65	High Efficiency Gas Pool Heater	Equipment	ROB	0	0.2

4.5 Technical Potential

This section provides an overview of the technical potential savings results for the residential sector. Overall results are presented below, followed by measure level results and supply curves for the TRC and MTRC results.

As shown in Exhibit 25, almost half of the residential technical potential (24 PJ) would be available in 2021 and would increase to 43 PJ in 2040. This indicates that a large amount of the potential, approximately 19 PJ, would come from replace on burnout measures over the next two decades. The forecasted natural gas consumption for the residential sector is included for reference.

Exhibit 25 – Residential Technical Potential Savings (GJ)

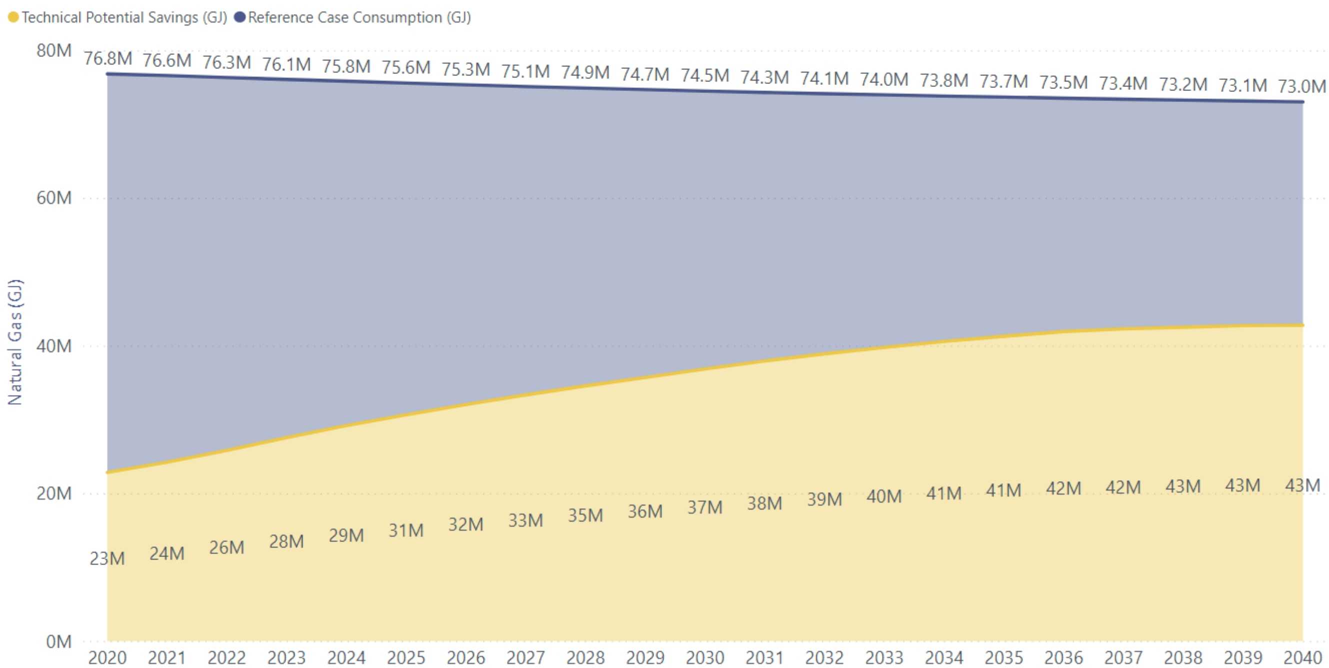
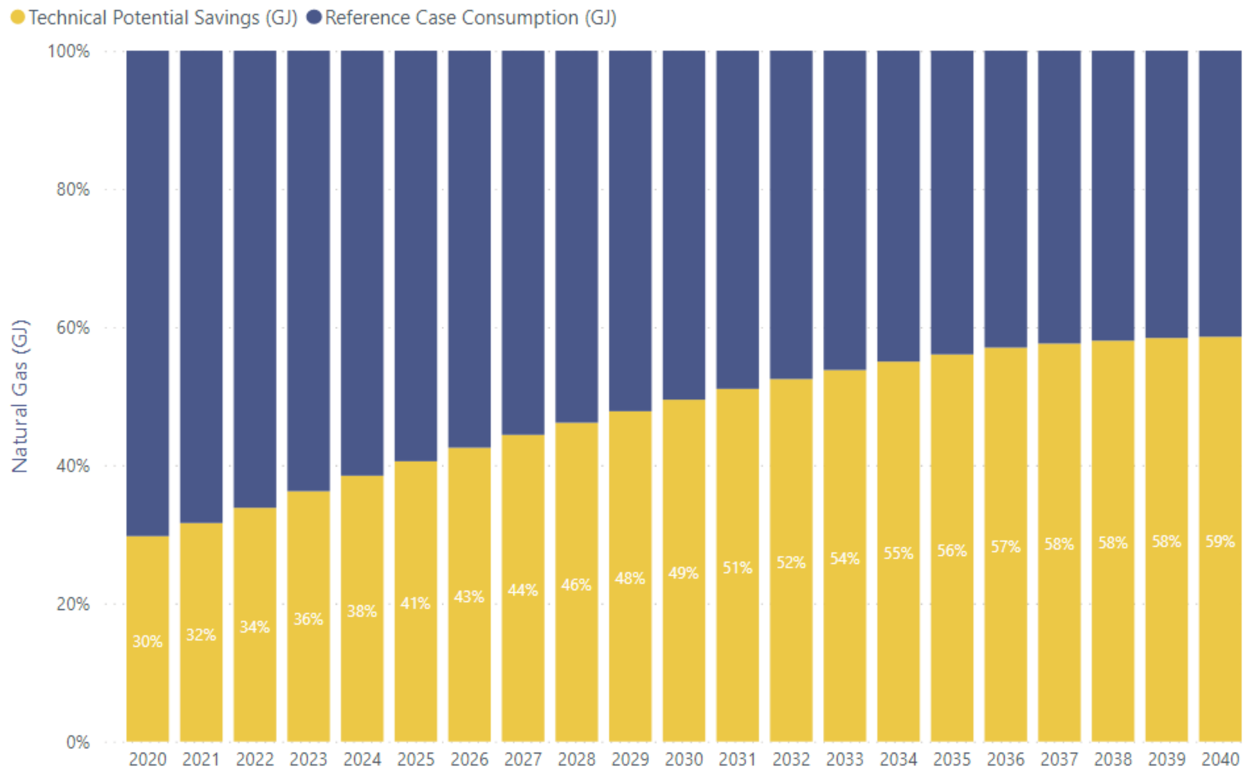


Exhibit 26 – Technical Savings Potential as a Percent of Residential Reference Case Consumption (%)



As shown in Exhibit 26, the technical potential savings is about 32% of residential reference case consumption in 2021 and increases to 59% by 2040, further indicating a that a substantial portion of the potential is expected to come from replace on burnout measures.

The technical potential savings by 2025 broken down by measure (only showing the top 25) are presented in Exhibit 27. The top three measures are all space heating measures (including gas heat pumps), followed by Step 4 new construction.

Exhibit 27 – Technical Potential – Annual Gas Savings from Top 30 Residential Measures in 2025 (GJ)

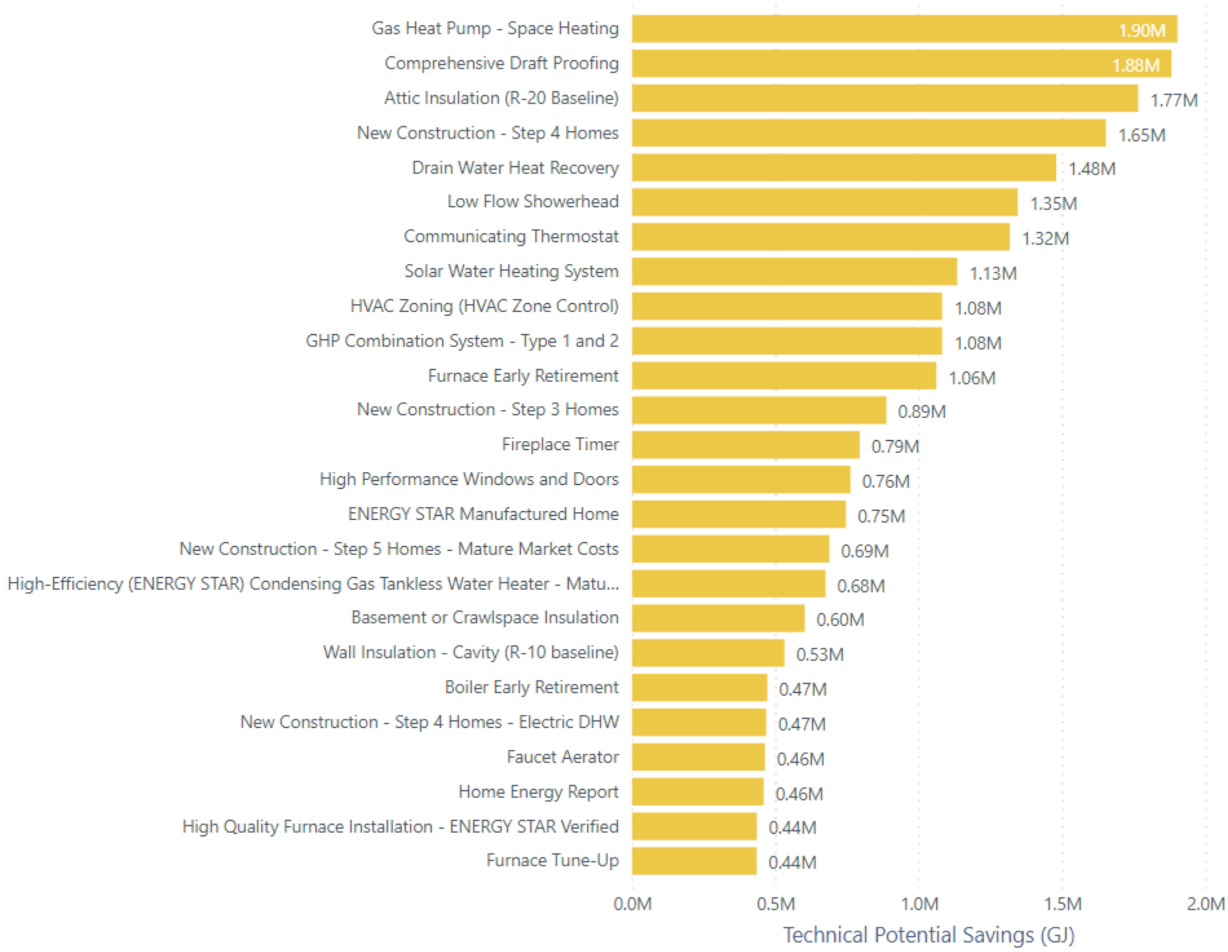


Exhibit 28 shows the cumulative residential sector technical potential savings in 2040 arranged as a supply curve, with measures ordered by decreasing TRC ratio from left to right. The graph shows that roughly 16% (around 7 out of 43 PJ) of the residential sector's technical potential by 2040, comes from measures with a TRC of 1.0 or higher. Approximately 1.5 PJ of savings come from measures with a TRC ratio of greater than 2. These are shown in aggregate.

Exhibit 28 – Residential Sector: Technical Potential Supply Curve – TRC

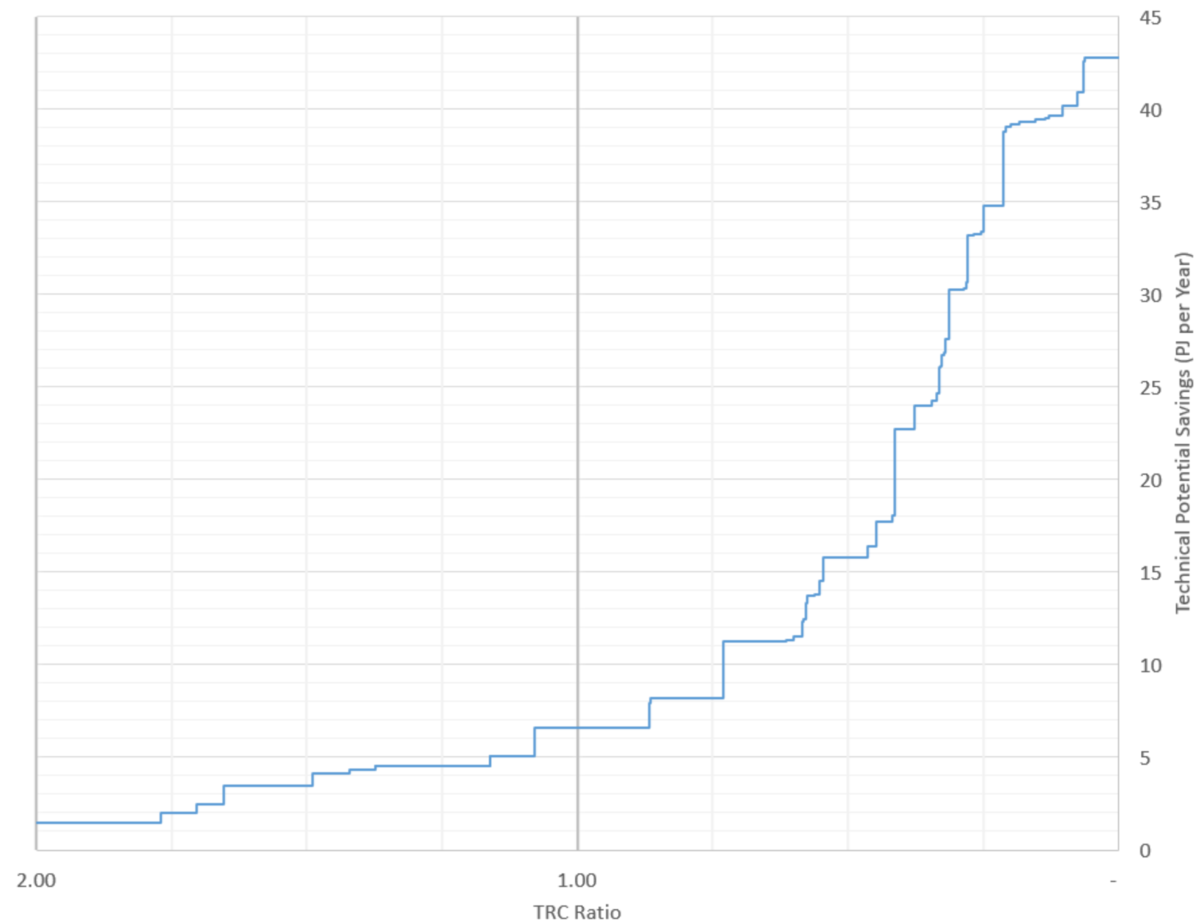
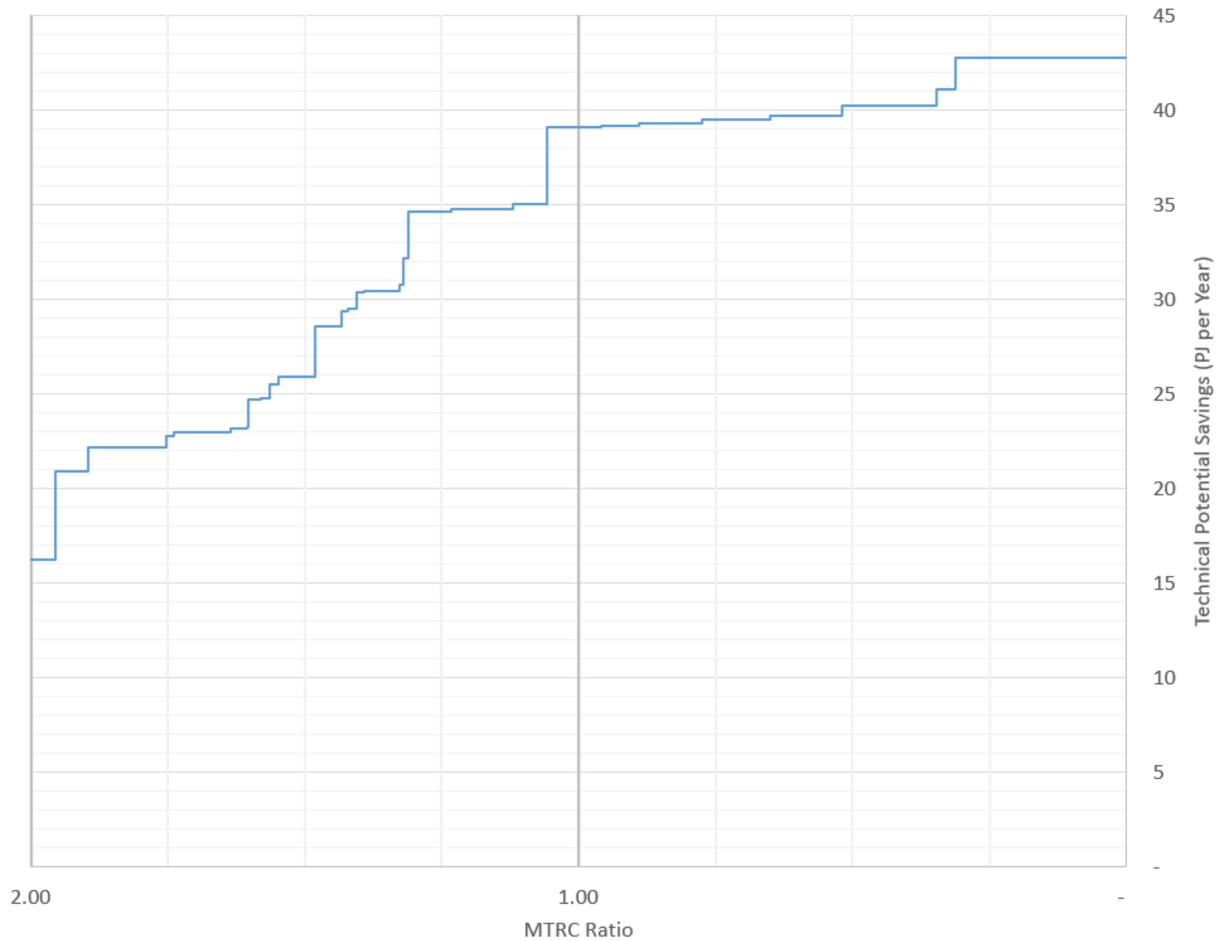


Exhibit 29 shows a similar supply curve, but with measures ordered by decreasing MTRC ratio from left to right. The graph shows that 90% (around 39 out of 43 PJ) of residential sector's technical potential by 2040 comes from cost-effective measures with an MTRC of 1.0 or higher. Approximately 16 PJ of savings come from measures with an MTRC ratio of greater than 2. These are shown in aggregate.

Exhibit 29 – Residential Sector: Technical Potential Supply Curve – MTRC

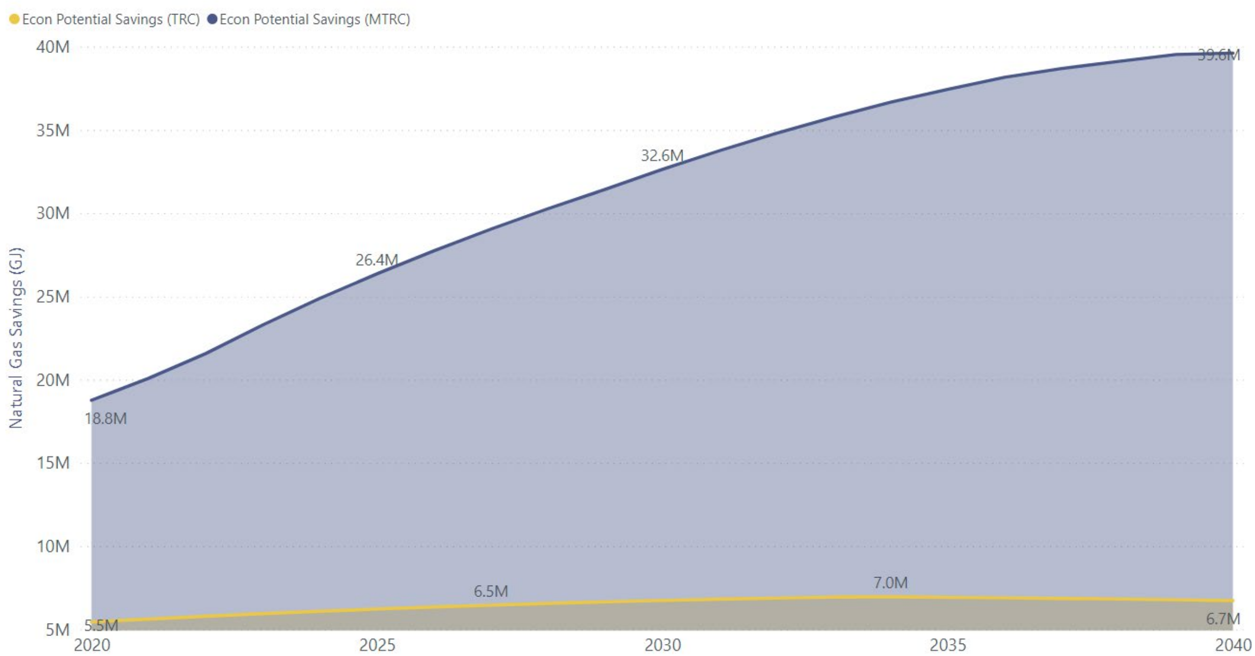


4.6 Economic Potential

This section provides the economic potential savings results for the residential sector from 2020 to 2040. We conducted two economic potential assessments: one using a TRC screen that includes measures with a TRC ratio of 1.0 and above, and one using an MTRC screen that includes measures with an MTRC of 1.0 and above. Outputs of both economic models are presented in this section.

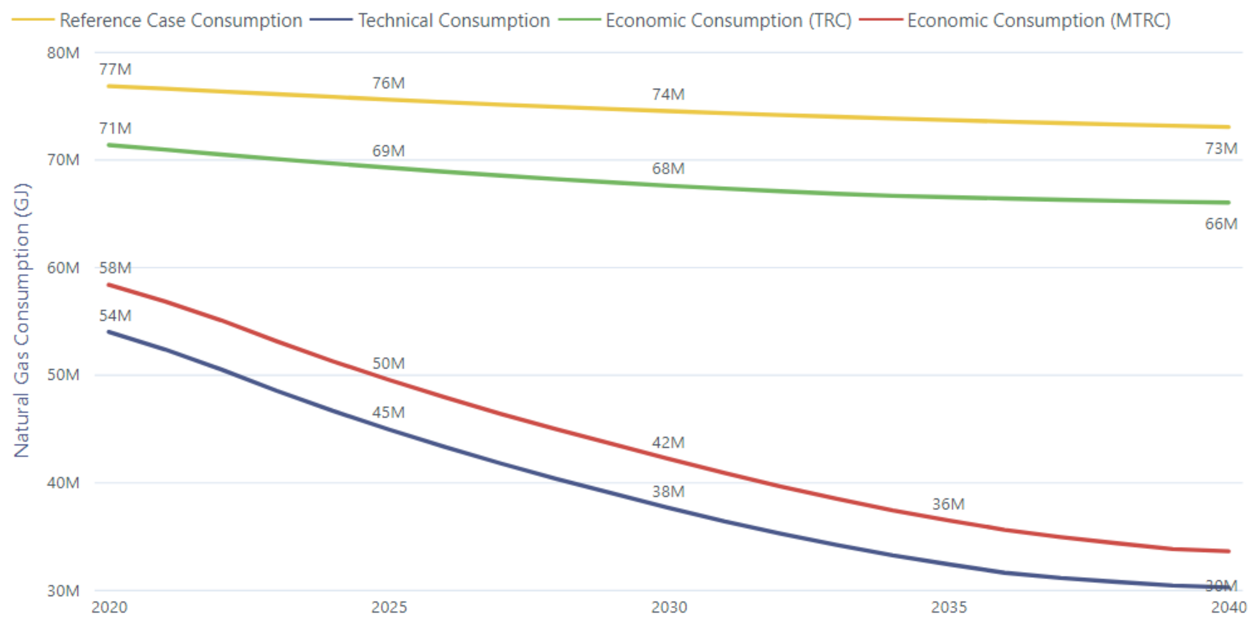
The residential sector economic potential savings with a TRC screen and with an MTRC screen are shown in Exhibit 30. As mentioned earlier, of the 65 measures included in the assessment, only 14 pass the TRC screen whereas 54 measures pass the MTRC screen. Those 40 measures that pass the MTRC but fail the TRC make up the difference between the two economic potential scenarios. This difference in economic potential in 2025 is roughly 20 PJ. In 2025, 24% of the MTRC economic potential comes from measures that pass the TRC as well. By 2040, that ratio is only 17%.

Exhibit 30 – Economic Potential Savings (GJ) – Residential, TRC and MTRC



The forecasted gas consumption under the technical potential, economic potential with a TRC screen, economic potential with an MTRC screen, and reference case scenarios for residential sector are shown in Exhibit 31.

Exhibit 31 – Economic Potential Consumption (GJ) Forecasts – Residential, TRC and MTRC



Results by Region

The TRC and MTRC economic potential savings in 2025 are presented by region in Exhibit 32 and Exhibit 33 respectively. The largest economic potential savings (3 PJ to 14 PJ depending on economic screen) are estimated to occur in the Lower Mainland outside of the City of Vancouver. The percentage of consumption captured by economic potential is uniform across all regions – around 8% under TRC screen and 34% under MTRC.

Exhibit 32 – Economic Potential Savings by Region in 2025 – Residential, TRC

Region	Ref Case Consumption (GJ)	Economic Potential Savings (GJ)	% of Consumption
Lower Mainland x Van	40,757K	3,303K	8%
Southern Interior	14,701K	1,343K	9%
City of Vancouver	9,007K	853K	9%
Vancouver Island	6,280K	421K	7%
Northern BC	4,517K	385K	9%
Whistler	290K	26K	9%
Total	**75,552K**	**6,331K**	**8%**

Exhibit 33 – Economic Potential Savings by Region in 2025 – Residential, MTRC

Region	Ref Case Consumption (GJ)	Economic Potential Savings (GJ)	% of Consumption
Lower Mainland x Van	40,757K	14,230K	35%
Southern Interior	14,701K	4,933K	34%
City of Vancouver	9,007K	3,150K	35%
Vancouver Island	6,280K	2,113K	34%
Northern BC	4,517K	1,522K	34%
Whistler	290K	87K	30%
Total	**75,552K**	**26,034K**	**34%**

Results by Segment and Vintage

The TRC and MTRC economic potential savings in 2025 are presented by segment and vintage in Exhibit 34 and Exhibit 35 respectively. As expected, older single-family dwellings present the most opportunities for economic potential under both economic screens. However, in the MTRC economic potential, the largest percentage of consumption is captured by the post-2015 vintage. This implies a sizeable potential contribution by Step Code new construction measures.

Exhibit 34 – Economic Potential Savings by Segment and Vintage in 2025 – Residential, TRC

Segment	Ref Case Consumption (GJ)	Economic Potential Savings (GJ)	% of Consumption
SFD/Duplex	**67,869K**	**5,854K**	**9%**
1950-1975	16,604K	1,731K	10%
1976-1985	8,892K	895K	10%
Pre-1950	7,885K	857K	11%
1986-1995	9,572K	830K	9%
1996-2005	7,606K	637K	8%
2006-2015	6,144K	509K	8%
Post-2015	11,166K	395K	4%
Attached/Row	**5,783K**	**381K**	**7%**
1986-1995	1,367K	99K	7%
1996-2005	1,115K	84K	8%
Post-2015	1,654K	69K	4%
2006-2015	619K	48K	8%
1976-1985	553K	40K	7%
1950-1975	397K	33K	8%
Pre-1950	77K	8K	10%
Mobile/other	**1,900K**	**97K**	**5%**
Total	**75,552K**	**6,331K**	**8%**

Exhibit 35 – Economic Potential Savings by Segment and Vintage in 2025 – Residential, MTRC

Segment	Ref Case Consumption (GJ)	Economic Potential Savings (GJ)	% of Consumption
SFD/Duplex	**67,869K**	**23,720K**	**35%**
1950-1975	16,604K	5,541K	33%
Post-2015	11,166K	5,048K	45%
1986-1995	9,572K	3,142K	33%
1976-1985	8,892K	2,931K	33%
Pre-1950	7,885K	2,642K	34%
1996-2005	7,606K	2,463K	32%
2006-2015	6,144K	1,954K	32%
Attached/Row	**5,783K**	**1,853K**	**32%**
Post-2015	1,654K	618K	37%
1986-1995	1,367K	418K	31%
1996-2005	1,115K	324K	29%
1976-1985	553K	172K	31%
2006-2015	619K	171K	28%
1950-1975	397K	126K	32%
Pre-1950	77K	24K	32%
Mobile/other	**1,900K**	**462K**	**24%**
Total	**75,552K**	**26,034K**	**34%**

Results by End Use

The TRC and MTRC economic potential savings in 2025 are presented by segment in Exhibit 36 and Exhibit 37 respectively. The largest amounts, in absolute savings, are expected to be captured under the space heating end use (2.7 PJ or 17.5 PJ depending on the economic screen). In terms of the percentage of reference case consumption captured by economic potential, domestic hot water captures the largest share in both economic screens (18% TRC, 51% MTRC). Although small in absolute savings, pool and spa heater end use has an economic potential ratio of 76% savings under the MTRC screen.

Exhibit 36 – Economic Potential Savings by End Use in 2025 – Residential, TRC

Parent End Use	Ref Case Consumption (GJ)	Economic Potential Savings (GJ)	% of Consumption
Space Heating	46,600K	2,710K	6%
Domestic Hot Water (DHW)	13,205K	2,347K	18%
Fireplace	11,549K	1,247K	11%
Clothes Dryer	229K	13K	5%
Cooking	1,328K	11K	1%
Pool & Spa Heaters	528K	5K	1%
Other Gas Uses	2,112K	0K	0%
Total	**75,552K**	**6,331K**	**8%**

Exhibit 37 – Economic Potential Savings by End Use in 2025 – Residential, MTRC

Parent End Use	Ref Case Consumption (GJ)	Economic Potential Savings (GJ)	% of Consumption
Space Heating	46,600K	17,569K	38%
Domestic Hot Water (DHW)	13,205K	6,784K	51%
Fireplace	11,549K	1,248K	11%
Pool & Spa Heaters	528K	403K	76%
Clothes Dryer	229K	19K	8%
Cooking	1,328K	11K	1%
Other Gas Uses	2,112K	0K	0%
Total	**75,552K**	**26,034K**	**34%**

The TRC and MTRC economic potential savings in 2040 are presented by end use in Exhibit 38. The difference is drastic – around 32 PJ. This is due to the large number of measures that pass the MTRC but fail the TRC. The biggest difference between the economic screens stem from measures that affect space heating.

Exhibit 38 – Economic Potential Savings by End Use in 2040 – Residential, TRC and MTRC

Parent End Use	Economic Savings (GJ) - TRC	Economic Savings (GJ) - MTRC	Difference (GJ)
Space Heating	3,382K	27,738K	24,356K
Domestic Hot Water (DHW)	2,009K	10,226K	8,218K
Pool & Spa Heaters	3K	301K	298K
Clothes Dryer	17K	28K	11K
Fireplace	1,312K	1,313K	1K
Cooking	8K	9K	0K
Other Gas Uses	0K	0K	0K
Total	**6,732K**	**39,615K**	**32,883K**

Results by Measure

The TRC economic potential savings by 2025 broken down by measure are shown in Exhibit 39, sorted by decreasing potential. The savings breakdown by end use is shown in Exhibit 40. Space heating savings make up 42% of the economic potential, domestic hot water 38% and fireplace measures 20% of the savings.

Exhibit 39 – Residential Economic Potential (TRC) – Annual Gas Savings from All TRC-Passing Measures in 2025 (GJ)

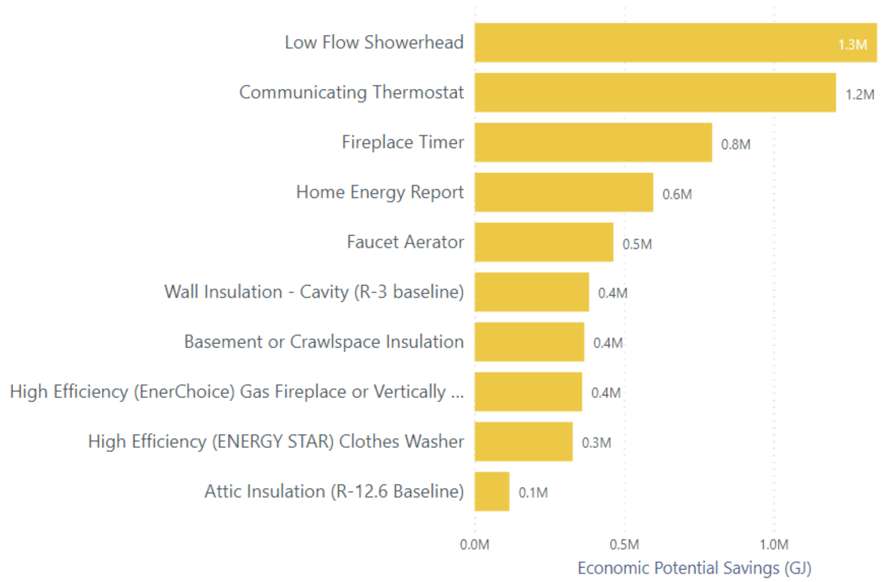
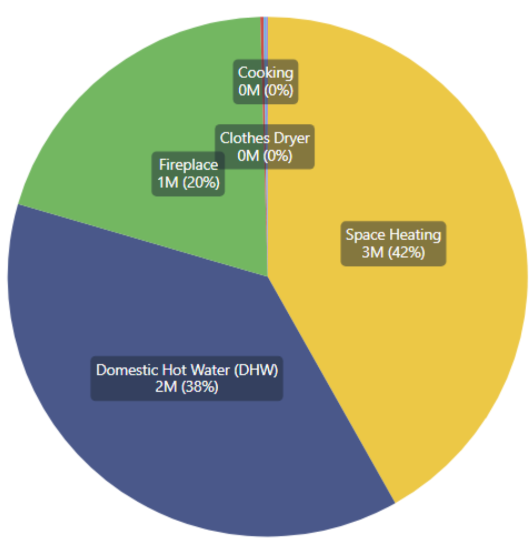


Exhibit 40 – Economic Potential in 2025 (GJ) By End Use – Residential, TRC



The economic potential savings by 2025 broken down by measure (showing only the top 25 measures) are presented in Exhibit 41. The savings breakdown by end use are presented in Exhibit 42. Space heating measures and their savings makes up the majority (68%) of the MTRC economic potential.

Exhibit 41 – Residential Economic Potential (TRC) - Annual Gas Savings from Top 25 MTRC-Passing Measures in 2025 (GJ)

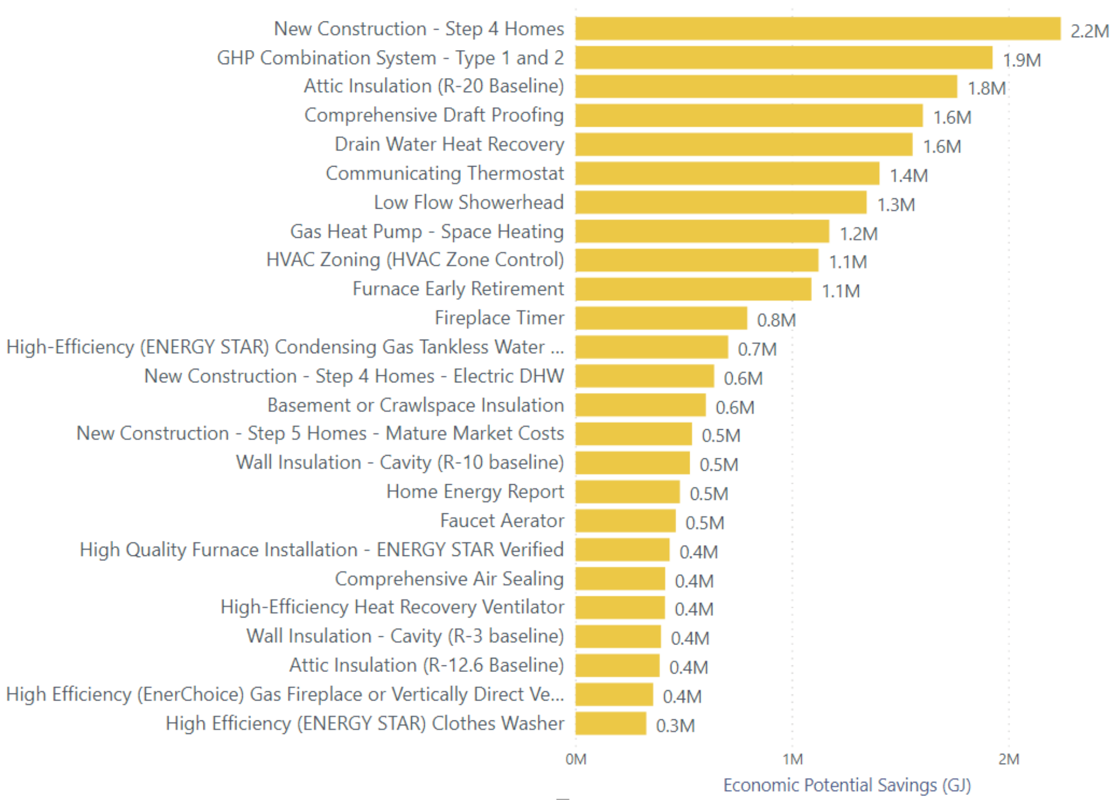
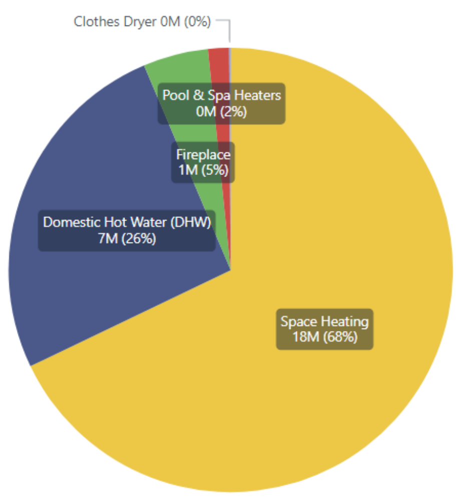


Exhibit 42 – Economic Potential (GJ) in 2025 By End Use – Residential, MTRC



4.7 Market Potential

This section provides an overview of the low, medium, and high market potential results for the residential sector.

Low, medium, and high scenarios assume that measure incentive levels will be 25%, 50% and 100% of incremental costs, respectively. For example, assume that a high-efficiency furnace may cost $200 more than a standard furnace, meaning the furnace would have an incremental cost of $200. In the medium scenario, this measure's hypothetical incentive from FortisBC would be $100. The other $100 would be paid by the end user. In all scenarios, the non-incentive program costs are assumed to be 15% of the incentive cost. In the example above, FortisBC's non-incentive spending would be $15. FortisBC's total cost for providing the measure to an end user would be $115.

The market potential savings results, with a TRC screen and with an MTRC screen, are shown in Exhibit 43 and Exhibit 44, respectively. The medium market potential using the MTRC screen is almost three times the market potential using TRC screen.

By 2040, the residential low, medium, and high market TRC potential savings are estimated to be 3 PJ, 3.4 PJ, and 4.3 PJ, respectively. By 2040, the low, medium, and high market MTRC potential savings are estimated to be 8.2 PJ, 9.9 PJ, and 14.2 PJ, respectively.

Exhibit 43 – Market Potential Savings (GJ) – Residential, TRC

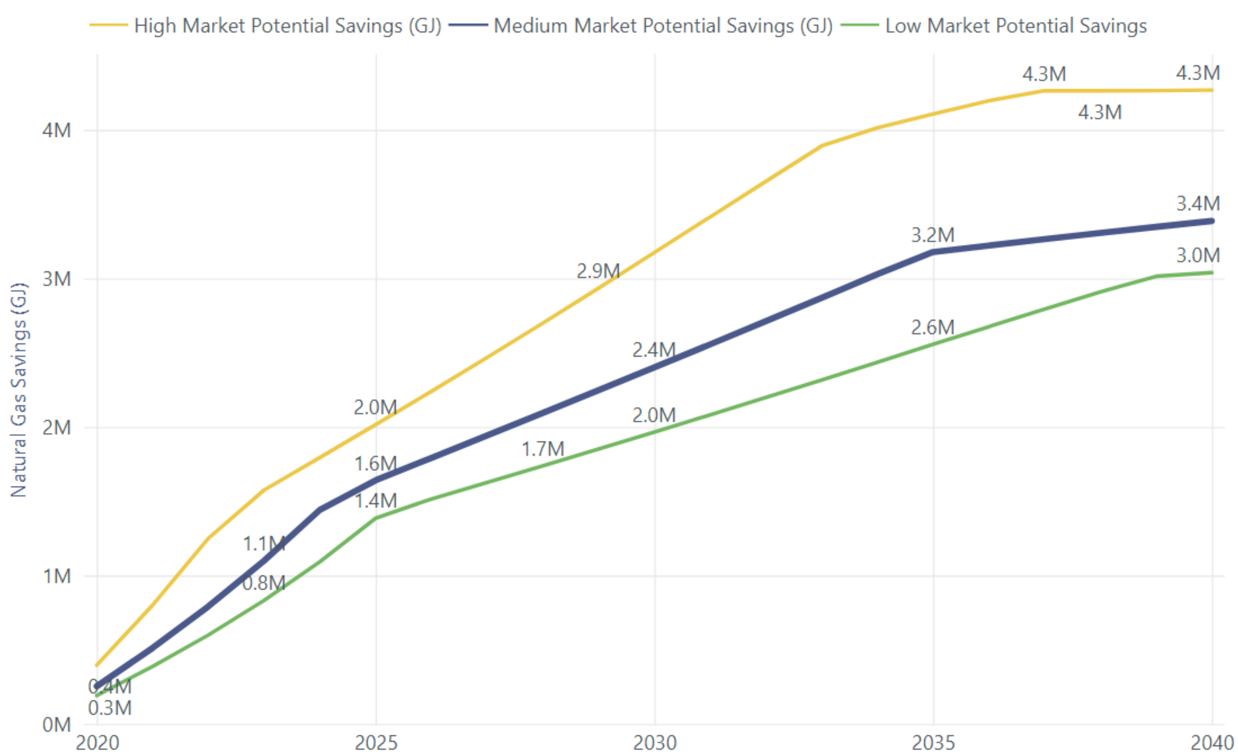
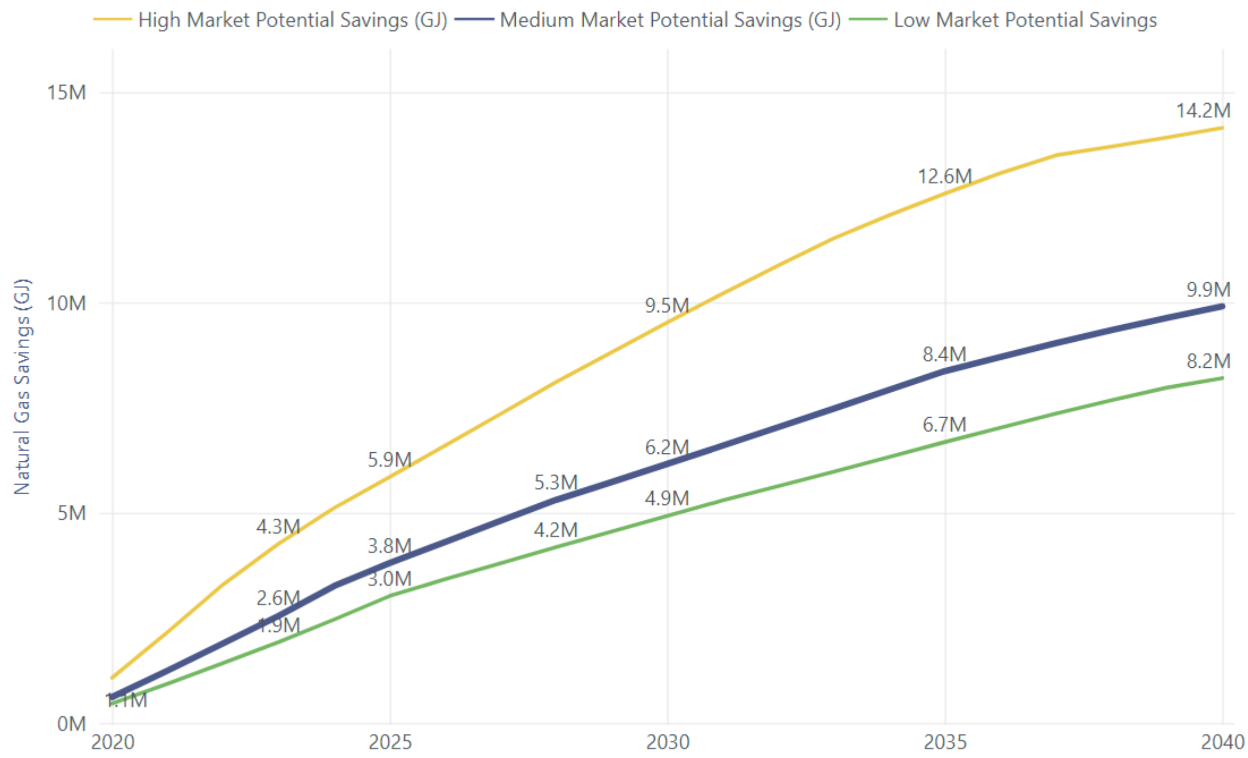


Exhibit 44 – Market Potential Savings (GJ) – Residential, MTRC



The forecasted residential gas consumption under the three market potential scenarios relative to reference case scenario is shown in Exhibit 45 (TRC) and Exhibit 46 (MTRC). The reference consumption is forecasted to drop to 73 PJ, from 77 PJ today. By 2040, the residential low, medium, and high market TRC potential consumption levels are estimated to be 70 PJ, 69.6 PJ, and 69 PJ, respectively. By 2040, the low, medium, and high market MTRC potential consumption levels are estimated to be 65 PJ, 63 PJ, and 59 PJ, respectively.

Exhibit 45 – Market Potential Consumption (GJ) Forecasts – Residential, TRC

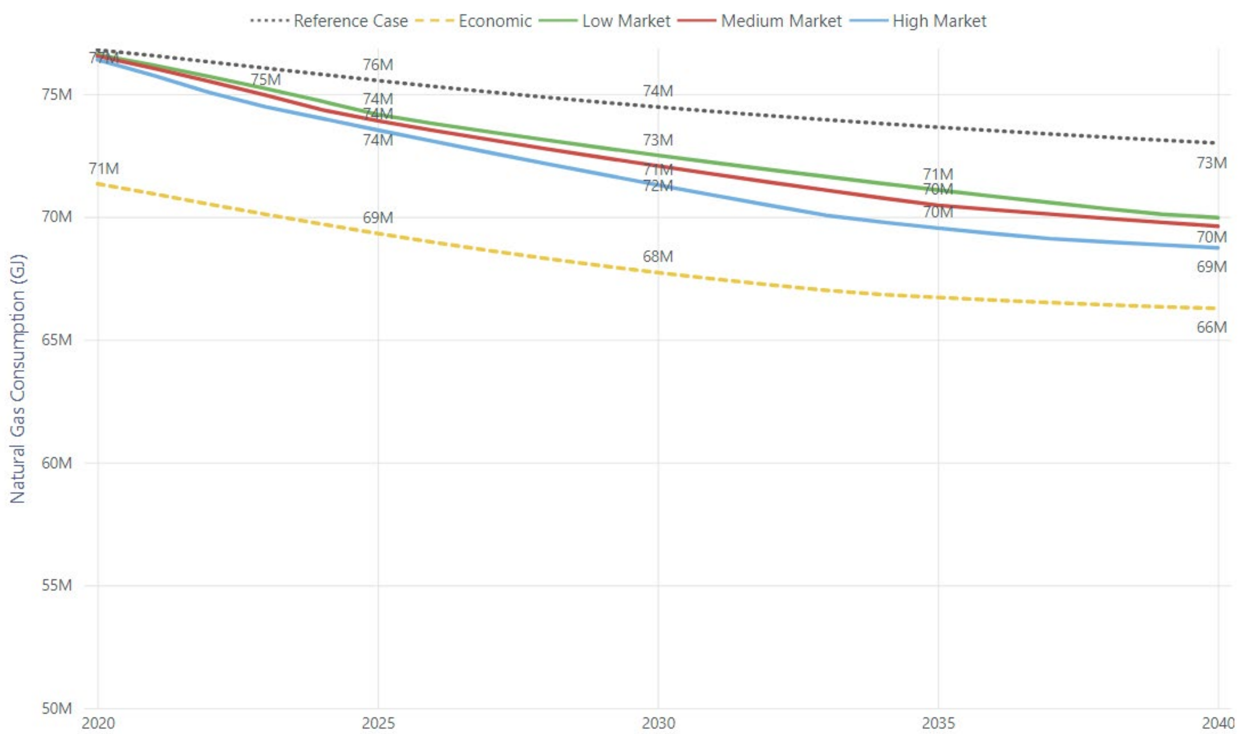
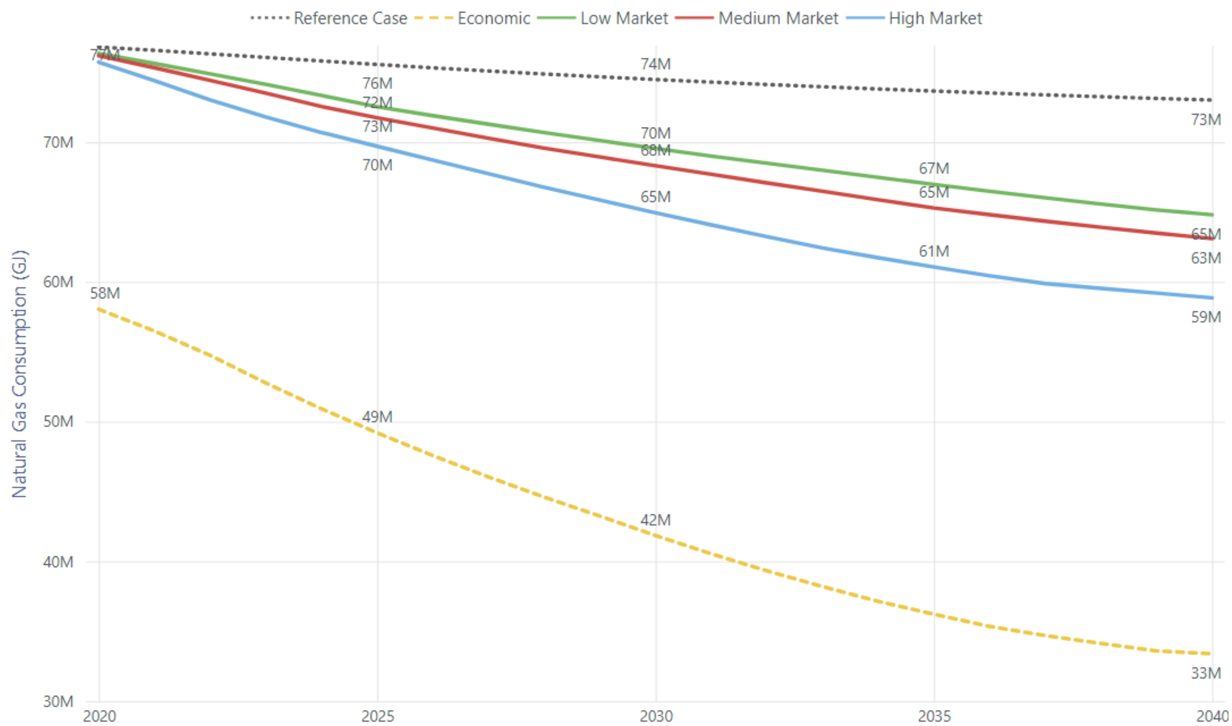


Exhibit 46 – Market Potential Consumption (GJ) Forecasts – Residential, MTRC



The remainder of this section presents detailed results of the medium market potential scenario only. Similarly detailed results of the low and high market potential scenarios can be found on the Power BI dashboard and the Excel workbooks.

Results by Region

The medium market potential savings for 2025 are presented by region in Exhibit 47 and Exhibit 48 using TRC and MTRC screen, respectively. Medium market potential savings in 2025 are estimated to be 2% of reference case consumption in all regions with TRC screen, and 5% with MTRC. The largest portion savings is expected to be in the Lower Mainland x Vancouver region.

Exhibit 47 – Medium Market Potential Savings by Region in 2025 – Residential, TRC

Region	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Lower Mainland x Van	40,757K	876K	2%
Southern Interior	14,701K	339K	2%
City of Vancouver	9,007K	202K	2%
Vancouver Island	6,280K	128K	2%
Northern BC	4,517K	92K	2%
Whistler	290K	6K	2%
Total	**75,552K**	**1,642K**	**2%**

Exhibit 48 – Medium Market Potential Savings by Region in 2025 – Residential, MTRC

Region	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Lower Mainland x Van	40,757K	2,054K	5%
Southern Interior	14,701K	767K	5%
City of Vancouver	9,007K	451K	5%
Vancouver Island	6,280K	301K	5%
Northern BC	4,517K	225K	5%
Whistler	290K	12K	4%
Total	**75,552K**	**3,810K**	**5%**

Results by Segment and Vintage

The TRC and MTRC economic potential savings in 2025 are presented by segment and vintage in Exhibit 49 and Exhibit 50 respectively. Single-family dwellings present the most market potential under both economic screens.

Exhibit 49 – Medium Market Potential Savings by Segment and Vintage in 2025 – Residential, TRC

Segment	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
SFD/Duplex	**67,869K**	**1,503K**	**2%**
1950-1975	16,604K	427K	3%
1986-1995	9,572K	233K	2%
1976-1985	8,892K	215K	2%
Pre-1950	7,885K	199K	3%
1996-2005	7,606K	187K	2%
2006-2015	6,144K	152K	2%
Post-2015	11,166K	91K	1%
Attached/Row	**5,783K**	**108K**	**2%**
1986-1995	1,367K	30K	2%
1996-2005	1,115K	25K	2%
Post-2015	1,654K	16K	1%
2006-2015	619K	14K	2%
1976-1985	553K	12K	2%
1950-1975	397K	8K	2%
Pre-1950	77K	2K	2%
Mobile/other	**1,900K**	**31K**	**2%**
All	1,900K	31K	2%
Total	**75,552K**	**1,642K**	**2%**

Exhibit 50 – Medium Market Potential Savings by Segment and Vintage in 2025 – Residential, MTRC

Segment	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
SFD/Duplex	**67,869K**	**3,472K**	**5%**
1950-1975	16,604K	935K	6%
1986-1995	9,572K	545K	6%
1976-1985	8,892K	505K	6%
Pre-1950	7,885K	438K	6%
1996-2005	7,606K	435K	6%
2006-2015	6,144K	351K	6%
Post-2015	11,166K	264K	2%
Attached/Row	**5,783K**	**262K**	**5%**
1986-1995	1,367K	74K	5%
1996-2005	1,115K	60K	5%
Post-2015	1,654K	41K	3%
2006-2015	619K	31K	5%
1976-1985	553K	30K	5%
1950-1975	397K	21K	5%
Pre-1950	77K	4K	5%
Mobile/other	**1,900K**	**75K**	**4%**
All	1,900K	75K	4%
Total	**75,552K**	**3,810K**	**5%**

Results by End Use

The TRC and MTRC medium market potential savings in 2025 are presented by segment in Exhibit 51 and Exhibit 52 respectively. In the TRC potential, the largest amount of absolute savings in 2025 are expected to be from domestic hot water (DHW) end use. These savings are roughly 6% of the DHW end use reference case consumption in that year. In the MTRC potential, the largest absolute savings in 2025 come from space heating end use, even though these savings amount to only 4% of the end use reference case consumption. When evaluating percentages, DHW has a larger potential (11% of the end use consumption in that year). Although small in absolute savings, pool and spa heater end use has the potential of capturing 17% savings under the MTRC screen.

Exhibit 51 – Medium Market Potential Savings by End Use in 2025 – Residential, TRC

Parent End Use	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Domestic Hot Water (DHW)	13,205K	757K	6%
Space Heating	46,600K	621K	1%
Fireplace	11,549K	246K	2%
Cooking	1,328K	11K	1%
Pool & Spa Heaters	528K	4K	1%
Clothes Dryer	229K	2K	1%
Other Gas Uses	2,112K	0K	0%
Total	**75,552K**	**1,642K**	**2%**

Exhibit 52 – Medium Market Potential Savings by End Use in 2025 – Residential, MTRC

Parent End Use	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Space Heating	46,600K	1,951K	4%
Domestic Hot Water (DHW)	13,205K	1,503K	11%
Fireplace	11,549K	252K	2%
Pool & Spa Heaters	528K	89K	17%
Cooking	1,328K	11K	1%
Clothes Dryer	229K	4K	2%
Other Gas Uses	2,112K	0K	0%
Total	**75,552K**	**3,810K**	**5%**

The TRC and MTRC medium market potential savings in 2040 are presented by end use in Exhibit 53. MTRC market potential is almost three times the TRC market potential. The biggest difference between the two economic screen scenarios comes from measures that affect space heating.

Exhibit 53 – Medium Market Potential Savings by End Use in 2040 – Residential, TRC and MTRC

Parent End Use	Medium Potential Savings (GJ) - TRC	Medium Potential Savings (GJ) - MTRC	Difference (GJ)
Space Heating	1,154K	5,049K	3,895K
Domestic Hot Water (DHW)	1,596K	3,981K	2,385K
Pool & Spa Heaters	3K	219K	216K
Fireplace	625K	643K	18K
Clothes Dryer	1K	9K	8K
Cooking	8K	9K	0K
Other Gas Uses	0K	0K	0K
Total	**3,388K**	**9,910K**	**6,522K**

Results by Measure

The medium market potential savings in 2025 of the top 15 residential measures are shown in Exhibit 54. The top measures in the TRC medium market potential are shown on the left and top measures in the MTRC scenario are shown on the right. Home energy reports and low flow showerheads top the list in both scenarios. More space heating measures contribute to savings in the MTRC screen, as evident from the measures list and the end use breakdown difference in Exhibit 55. The sixth measure on the MTRC list on the right side of Exhibit 54 is High-Efficiency (ENERGY STAR) condensing Gas Tankless Water Heater.

Exhibit 54 – Medium Market Potential (TRC on Left, MTRC on Right) - Top 14 Residential Measures in 2025 (GJ)

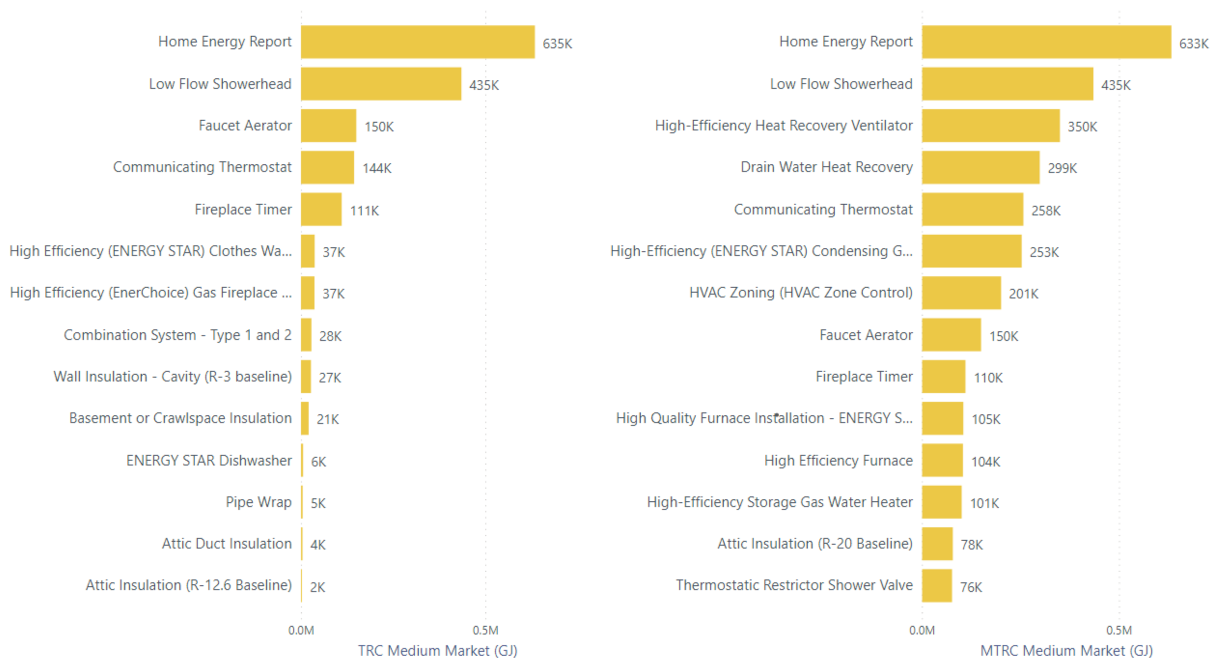
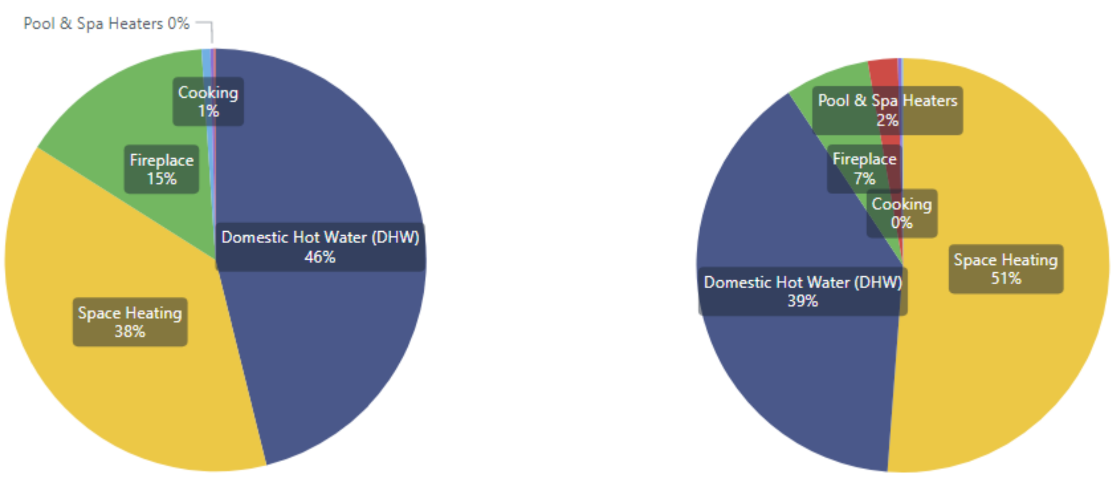


Exhibit 55 – Medium Market Potential (TRC on Left, MTRC on Right) – Savings by End Use in 2025 (%)



4.7.1 Incentive and Non-Incentive Spending

The incentive and non-incentive spending required to achieve the medium and high market potential are shown in Exhibit 56 (TRC) and Exhibit 57 (MTRC). Medium and high market incentives are assumed to be 50% and 100% of measures' incremental costs, respectively. In both medium and high scenarios, non-incentive costs are estimated to be 15% of incentive costs. The tables also show the total as well as incremental (that is, savings from new measures installed in a year) savings every year.

Exhibit 56 – Medium and High Market Incentive Costs and Natural Gas Savings – Residential, TRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$3.5M	$0.5M	$4.0M	255K	255K	$12.6M	$1.9M	$14.5M	397K	397K
2021	$3.6M	$0.5M	$4.2M	513K	258K	$13.0M	$2.0M	$15.0M	801K	405K
2022	$4.0M	$0.6M	$4.6M	793K	280K	$14.6M	$2.2M	$16.8M	1,251K	450K
2023	$4.5M	$0.7M	$5.2M	1,100K	307K	$10.9M	$1.6M	$12.6M	1,576K	325K
2024	$5.1M	$0.8M	$5.9M	1,442K	342K	$8.1M	$1.2M	$9.3M	1,794K	219K
2025	$3.0M	$0.4M	$3.4M	1,642K	199K	$8.3M	$1.2M	$9.5M	2,016K	221K
2026	$2.4M	$0.4M	$2.8M	1,792K	151K	$8.4M	$1.3M	$9.7M	2,240K	225K
2027	$2.5M	$0.4M	$2.8M	1,943K	151K	$8.6M	$1.3M	$9.9M	2,468K	228K
2028	$2.5M	$0.4M	$2.9M	2,095K	152K	$8.8M	$1.3M	$10.1M	2,700K	232K
2029	$2.6M	$0.4M	$3.0M	2,248K	153K	$9.0M	$1.3M	$10.3M	2,935K	236K
2030	$2.6M	$0.4M	$3.0M	2,401K	154K	$9.2M	$1.4M	$10.6M	3,175K	240K
2031	$2.7M	$0.4M	$3.1M	2,556K	155K	$9.1M	$1.4M	$10.5M	3,414K	239K
2032	$2.7M	$0.4M	$3.2M	2,712K	156K	$9.1M	$1.4M	$10.5M	3,653K	239K
2033	$2.8M	$0.4M	$3.2M	2,870K	157K	$9.1M	$1.4M	$10.5M	3,893K	239K
2034	$2.9M	$0.4M	$3.3M	3,029K	159K	$8.0M	$1.2M	$9.2M	4,015K	123K
2035	$2.9M	$0.4M	$3.4M	3,178K	149K	$8.0M	$1.2M	$9.2M	4,107K	92K
2036	$2.5M	$0.4M	$2.9M	3,222K	43K	$7.8M	$1.2M	$9.0M	4,196K	89K
2037	$2.5M	$0.4M	$2.9M	3,265K	43K	$6.7M	$1.0M	$7.7M	4,265K	69K
2038	$2.4M	$0.4M	$2.8M	3,307K	42K	$4.3M	$0.6M	$4.9M	4,264K	-1K
2039	$2.4M	$0.4M	$2.7M	3,347K	41K	$4.3M	$0.6M	$4.9M	4,265K	1K
2040	$2.3M	$0.4M	$2.7M	3,388K	40K	$4.4M	$0.7M	$5.1M	4,268K	4K

Exhibit 57 – Medium and High Market Incentive Costs and Natural Gas Savings – Residential, MTRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$41.2M	$6.2M	$47.4M	622K	622K	$152.3M	$22.8M	$175.1M	1,080K	1,080K
2021	$42.2M	$6.3M	$48.5M	1,250K	628K	$155.5M	$23.3M	$178.9M	2,170K	1,089K
2022	$43.1M	$6.5M	$49.6M	1,897K	647K	$159.7M	$24.0M	$183.6M	3,300K	1,130K
2023	$44.0M	$6.6M	$50.6M	2,556K	659K	$156.9M	$23.5M	$180.4M	4,267K	967K
2024	$45.2M	$6.8M	$51.9M	3,262K	706K	$148.8M	$22.3M	$171.1M	5,117K	850K
2025	$43.1M	$6.5M	$49.6M	3,810K	548K	$132.1M	$19.8M	$151.9M	5,855K	738K
2026	$43.3M	$6.5M	$49.8M	4,310K	500K	$135.8M	$20.4M	$156.2M	6,601K	746K
2027	$44.0M	$6.6M	$50.6M	4,811K	501K	$140.0M	$21.0M	$160.9M	7,355K	754K
2028	$44.5M	$6.7M	$51.2M	5,310K	499K	$142.9M	$21.4M	$164.3M	8,112K	757K
2029	$36.9M	$5.5M	$42.4M	5,735K	424K	$130.6M	$19.6M	$150.2M	8,822K	710K
2030	$38.0M	$5.7M	$43.7M	6,164K	429K	$130.4M	$19.6M	$150.0M	9,529K	706K
2031	$39.0M	$5.9M	$44.9M	6,598K	434K	$128.0M	$19.2M	$147.2M	10,214K	685K
2032	$40.2M	$6.0M	$46.2M	7,036K	438K	$125.9M	$18.9M	$144.8M	10,879K	665K
2033	$41.4M	$6.2M	$47.6M	7,479K	443K	$124.4M	$18.7M	$143.0M	11,527K	648K
2034	$42.7M	$6.4M	$49.1M	7,926K	448K	$121.6M	$18.2M	$139.9M	12,077K	550K
2035	$44.0M	$6.6M	$50.6M	8,370K	443K	$119.1M	$17.9M	$137.0M	12,589K	511K
2036	$41.9M	$6.3M	$48.2M	8,707K	337K	$116.2M	$17.4M	$133.6M	13,076K	487K
2037	$41.4M	$6.2M	$47.6M	9,038K	331K	$109.0M	$16.4M	$125.4M	13,502K	426K
2038	$39.5M	$5.9M	$45.4M	9,345K	307K	$89.6M	$13.4M	$103.0M	13,710K	207K
2039	$37.7M	$5.7M	$43.3M	9,633K	289K	$89.6M	$13.4M	$103.1M	13,923K	213K
2040	$36.9M	$5.5M	$42.4M	9,910K	276K	$91.9M	$13.8M	$105.7M	14,153K	230K

5 Commercial Sector Results

This section presents the commercial sector results and key findings, including:

- Base year (2019) natural gas use
- Reference case consumption forecast (2020 – 2040)
- Energy conservation measures evaluated in this CPR
- Technical potential savings
- Economic potential savings
- Market potential savings and scenarios

5.1 Commercial Segments and End Uses

In this CPR, the commercial sector is divided into 17 segments, five energy end uses, and two vintages.

Exhibit 58 – Definition of Commercial Sector Segments, End Uses, and Vintages

	Segments (17)	End Uses[35] (5)	Vintages (2)
Commercial Sector	• Apartments – Medium • Apartments – Large • Food Retail • Hospital • Hotel – Medium • Hotel – Large • Non-Food Retail – Medium • Non-Food Retail – Large • Nursing Home • Office – Medium • Office – Large • Other Commercial[36] • Restaurant • School – Medium • School – Large • University/College • Warehouse	• Cooking • Domestic Hot Water • Other[37] • Pools, Spas & Hot tubs • Space Heating	• Existing • New

35 All-electric end uses, such as clothes washer, lighting or plug loads, are not included in the reported results therefore are excluded from the End Uses row of this table.
36 The "other" segment includes facilities that do not fit into any of the other segments.
37 The "other" end use is a catch all for equipment that account for a small portion of consumption in the sector. In the commercial sector, examples of 'other' equipment are patio heaters and laundry dryers.

5.2 Base Year Natural Gas Use

This section profiles the base year (2019) natural gas consumption for the commercial sector. Please see Appendix A in the CPR Method Appendices document for how commercial NAICS codes were categorized into segments.

The following exhibits summarize how natural gas is used in the commercial sector by segment[38], end use, and region, respectively.

Natural gas consumption in the commercial sector base year is highest:

- In the apartment (31%), other (19%) and office (11%) segments
- In the space heating (56%) and water heating (31%) end uses
- In the Lower Mainland excluding Vancouver ("Lower Mainland x Vancouver") (48%) and the City of Vancouver (21%) regions

Exhibit 59 – 2019 Commercial Natural Gas Consumption (GJ) by Segment

Segment	Consumption (GJ)	%
Apartment	19,568K	31%
Other	12,201K	19%
Office	7,084K	11%
Restaurant	4,271K	7%
Warehouse	4,231K	7%
Nonfood Retail	3,587K	6%
Hospital	3,067K	5%
Hotel	2,553K	4%
School	2,271K	4%
University/College	1,987K	3%
Nursing Home	1,665K	3%
Food Retail	1,453K	2%
Total	**63,938K**	**100%**

38 Several commercial segments are further segmented by size (large or medium/small) including apartment, hotel, nonfood retail, office and school. The "other" segment includes facilities that do not fit into any of the other segments.

Exhibit 60 – 2019 Commercial Natural Gas Consumption (GJ) by End Use

Parent End Use	Consumption (GJ)	%
Space heating	35,556K	56%
Water heating	19,619K	31%
Food Service	4,800K	8%
Other	3,384K	5%
Pools; Spas & Hot Tubs	579K	1%
Total	**63,938K**	**100%**

Exhibit 61 – 2019 Commercial Natural Gas Consumption (GJ) by Region

Region	Consumption (GJ)	%
Lower Mainland x Van	30,920K	48%
City of Vancouver	13,507K	21%
Southern Interior	9,153K	14%
Vancouver Island	6,881K	11%
Northern BC	2,809K	4%
Whistler	667K	1%
Total	**63,938K**	**100%**

5.2.1 Accounts

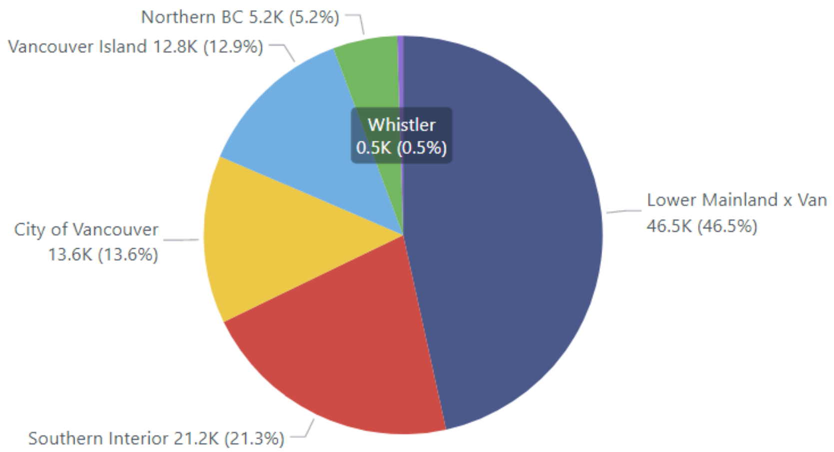
Base year commercial natural gas accounts are presented by segment in Exhibit 62 and by region in Exhibit 63. As shown in these exhibits, in 2019 the greatest number of commercial natural gas accounts were in:

- The other (30%), apartment (27%), office (13%), and nonfood retail (11%) segments
- The Lower Mainland excluding Vancouver region (47% of accounts)

Exhibit 62 – 2019 Commercial Natural Gas Accounts by Segment

Segment	Accounts	%
Other	29,520	30%
Apartment	26,813	27%
Office	13,359	13%
Nonfood Retail	11,211	11%
Restaurant	6,701	7%
Warehouse	4,289	4%
Food Retail	1,857	2%
School	1,713	2%
Hospital	1,640	2%
Hotel	1,534	2%
Nursing Home	660	1%
University/College	524	1%
Total	**99,821**	**100%**

Exhibit 63 – 2019 Commercial Natural Gas Accounts by Region



5.2.2 Tertiary Load

Tertiary load is the useful energy delivered to an end use. In the context of the CPR, tertiary load is the amount of energy required to be delivered as an end use *service*: heat delivered by a boiler to a square meter of office space, for example. This differs from consumption of natural gas which is impacted by the efficiency of the equipment: in the boiler example, consumption is equal to the tertiary load divided by the seasonal efficiency of the boiler.

5.2.3 Unit Energy Consumption

Recall that unit energy consumption (UEC) is the amount of energy used by each end use per unit (a "unit" in the commercial sector is square meter of floor area) and fuel share is the percentage of the energy end use that is supplied by each fuel.

This section presents a sample calculation of UEC for the space heating end use. Along with UEC values is *unit tertiary load*, which is the average tertiary load, by end use, per square meter, and *stock average efficiency*, which is the average efficiency of equipment serving the tertiary load for that end use. These values are included in the table because UEC by end use is calculated by dividing unit tertiary load with stock average efficiency. Values are presented for one segment, region and end use as an example.

Exhibit 64 presents unit tertiary load, stock average efficiency and UEC values for space heating in large offices in the Lower Mainland excluding Vancouver region.

Exhibit 64 – 2019 Space Heating UEC values by End Use, Large Offices in the Lower Mainland

	Unit Tertiary Load ($GJ/m^2.yr.$)	Stock Average Efficiency (%)	UEC ($GJ/m^2.yr.$)
Space heating	0.3	80%	0.3

5.2.4 Average Natural Gas Use per Building

The following exhibit presents average annual natural gas consumption per m^2 for space heating. Included in the exhibit is:

- UEC: the amount of energy used by each end use per unit. The "unit" in commercial sector is square meter of floor area.
- Fuel Share: the percentage of the energy end use that is supplied by each fuel (in this case, natural gas).
- Saturation: reflects the extent to which an end use is present in a region, and segment.

Average annual gas consumption per unit is calculated by multiplying these three variables together; therefore, they are included in the table below. Values are presented for one segment, region and end use as an example.

Exhibit 65 presents average annual gas use for space heating per large office in the Lower Mainland excluding Vancouver ("LML") region.

Exhibit 65 – 2019 Average Annual Space Heating Gas Use Per m^2, Large Offices, LML

	UEC	Fuel Share	Saturation	Average Annual Gas Use ($GJ/m^2.yr.$)
Space heating	0.3	75%	100%	0.25

5.3 Reference Case Natural Gas Use

This section profiles the reference case forecast (2020-2040) natural gas consumption for the commercial sector.

Overall gas consumption in the commercial sector is forecasted to increase over time: consumption in 2040 is expected to be approximately 26% higher than consumption in 2020, with an average annual increase of about 1% from 2020 to 2040. Consumption patterns from 2019 base year are expected to persist throughout the reference case. Natural gas is expected to continue to be used largely in apartments, other and office segments (as shown in Exhibit 66), for space heating (Exhibit 67) and in the Lower Mainland excluding Vancouver region (Exhibit 68).

The forecasted increase in commercial gas consumption can be explained by the following trends:

- There is a forecasted increase in the number of commercial accounts, as seen in Exhibit 69. The growth in accounts is somewhat counterbalanced by a decrease in usage per square meter. However, the decrease in usage per square meter is less than 0.5% per year on average while the increase in floor area due to account growth is more than 1.5% per year. The net result is consumption is forecasted to increase by about 1% per year.
- FortisBC has observed ongoing growth in commercial accounts in recent years with little change in usage per customer. The growth we have estimated is somewhat less than the historical trend, because of our assumed improvement in efficiency. We expect growth in commercial consumption to be further reduced by the future Step Code changes.

Exhibit 66 – 2020 vs 2040 Commercial Gas Consumption Forecast (GJ) by Segment

Segment	2020	2040	Change %
Apartment	19,968K	24,618K	23%
Other	12,440K	15,991K	29%
Office	7,205K	9,086K	26%
Restaurant	4,373K	5,743K	31%
Nonfood Retail	3,634K	4,701K	29%
Warehouse	4,215K	4,639K	10%
Hotel	2,540K	3,628K	43%
Hospital	3,082K	3,437K	12%
School	2,320K	3,319K	43%
Nursing Home	1,713K	2,608K	52%
Food Retail	1,478K	2,194K	48%
University/College	1,986K	2,009K	1%
Total	**64,953K**	**81,973K**	**26%**

Space heating and water heating end uses are expected to grow slower than other end uses, as shown in Exhibit 67. This also implies a slight decline in their ratio to overall building consumption by 2040. This decline is largely driven by:

- Improved new construction practices and more stringent equipment performance standards.
- Natural replacement of space heating and water heating equipment at the end of life. It is assumed that 50% of those replacing such equipment would adopt space heating equipment that was 85% efficient and water heating equipment that was 80% efficient. As a result, the average consumption per square meter for these two end uses was assumed to be declining slightly with time.

Exhibit 67 – 2020 vs 2040 Commercial Gas Consumption Forecast (GJ) by End Use

Parent End Use	2020	2040	Change %
Space heating	36,063K	45,300K	26%
Water heating	19,948K	24,552K	23%
Food Service	4,907K	6,780K	38%
Other	3,448K	4,557K	32%
Pools; Spas & Hot Tubs	587K	784K	34%
Total	**64,953K**	**81,973K**	**26%**

Exhibit 68 – 2020 vs 2040 Commercial Gas Consumption Forecast (GJ) by Region

Region	2020	2040	Change %
Lower Mainland x Van	31,574K	39,777K	26%
City of Vancouver	13,746K	16,815K	22%
Southern Interior	9,274K	13,076K	41%
Vancouver Island	6,877K	7,429K	8%
Northern BC	2,834K	3,975K	40%
Whistler	648K	901K	39%
Total	**64,953K**	**81,973K**	**26%**

Exhibit 69 – 2020 vs 2040 Commercial Gas Accounts Forecast by Segment

Segment	2020	2040	Change %
Other	29,862	37,176	24%
Apartment	27,174	33,437	23%
Office	13,492	16,116	19%
Nonfood Retail	11,320	13,503	19%
Restaurant	6,777	8,329	23%
Warehouse	4,330	5,168	19%
Food Retail	1,880	2,346	25%
School	1,740	2,319	33%
Hotel	1,556	2,010	29%
Hospital	1,656	1,973	19%
Nursing Home	672	971	44%
University/College	529	662	25%
Total	**100,988**	**124,010**	**23%**

5.3.1 Commercial Reference Case Natural Gas Use: Existing versus New Buildings

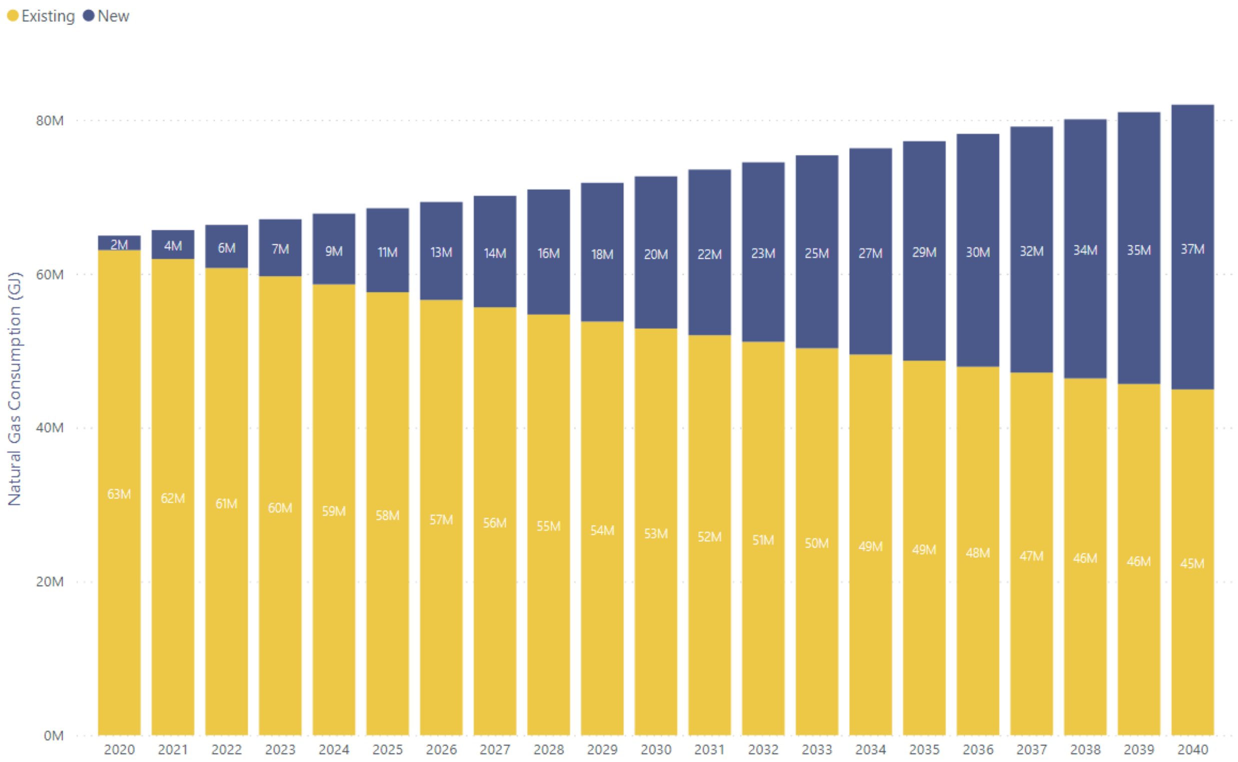
This section compares the consumption in existing versus new commercial facilities in the reference case forecast. Estimated new construction rates are drawn from rate-class level estimates developed by FEI and are applied by segment. Demolition rates are estimated at approximately 2% of floor area per year and held constant across segments. It is assumed that existing commercial buildings that are demolition are replaced by newly constructed buildings. This results in a forecasted commercial gas account increase of 23% by 2040, as shown in Exhibit 70.

In 2020, natural gas consumption from new buildings was roughly two million GJ, or 3% of the total commercial sector consumption. By 2040, new buildings are forecasted to use 37 million GJ (45% of total sector), as shown in Exhibit 71.

Exhibit 70 – 2020 vs 2040 Commercial Gas Accounts Forecast by Existing and New Vintage

Existing/New	2020	2040	Change %
Existing	97,844	65,843	-33%
New	3,144	58,167	1,750%
Total	**100,988**	**124,010**	**23%**

Exhibit 71 – 2020 vs 2040 Commercial Gas Consumption Forecast (GJ) by Existing and New Vintage



5.4 Measure Assessment

5.4.1 List of Measures

The list of commercial measures that were included in this CPR are presented in Exhibit 72. The measures are divided into categories by end use and measure type.

Please see the MS Excel file entitled "Com_Measure Analysis Workbook" for a description of each measure and a full analysis.

Measures were classified in five measure type categories:

- Building Envelope
- Equipment
- Controls
- Energy Management (including behavioral measures)
- New Construction – all new construction measures were placed in a separate category

New construction measures are analyzed using a whole-building approach, represented by the Step 2 - Step 4 BC Energy Step Code measures listed below. See Appendix O of the CPR Appendices document for the modelling approach used to assess these measures.

Exhibit 72 – Commercial Sector Conservation and Energy Management Measures

Appliances – Equipment Demand Control Kitchen Ventilation Efficient Pre-Rinse Spray Valve Efficient Commercial Cooking Equipment ENERGY STAR Dishwasher ENERGY STAR Clothes washer	**New Construction** Step 2 Level-of-Performance Step 3 Level-of-Performance Step 4 Level-of-Performance
Pool & Spa Heaters – Equipment Indoor Pool Cover Outdoor Pool Cover Solar Water Pool Heating	**Space Heating – Equipment** Advanced BAS Advanced Thermostats Air Curtains Condensing Boiler – Early/ROB Condensing MUAs – Early/ROB Condensing Unit Heaters Destratification Fans Dock Door Seals

Space Heating – Envelope

Deep Energy Retrofits[39]
High-Performance Air Sealing
High-Performance Window Upgrade
Low-e Window Film
Panelized Retrofit
Roof Insulation
Wall Insulation

Electric Air-to-Water Heat Pump with Existing Gas Furnace or Boiler Backup (Dual-Fuel Measure)
Electric Air-to-Water Heat Pump with New Gas Furnace or Boiler Backup (Dual-Fuel Measure)
Energy Recovery Ventilators
Gas Boiler/Furnace Tune-Up
Hydronic Additives
Heat Recovery – Waste Heat Chiller
Heat Recovery Ventilator
Infrared Heaters
Residential-Style Condensing Furnace – Early/ROB
Reverse Flow Heat Recovery Ventilator
Strip Curtains
Vertical Direct Vent Fireplaces

Controls

Advanced Remote Terminal Unit (RTU) Controls
Boiler Combustion Controls
Boiler Cycling Controls
Boiler Zoning Controls
DHW Recirculation Controls
Hotel Occupancy Controls
Return Water Temperature Optimization

Space Heating & Water Heating - Equipment

Gas Heat Pumps – Combination Systems

Water Heating - Equipment

Condensing DHW – On-Demand
Condensing DHW – Storage
Condensing DHW Supply Boilers
DHW Tank Insulation
Drain Water Heat Recovery
Faucet Aerators
Low-Flow Showerhead
Pipe Insulation
Solar DHW Preheat
Thermostatic Shower Restriction Valve

Energy Management and Other

Building Energy Report
Comprehensive Recommissioning
Heat Recovery – Health Care Sterilizers
Multi-Unit Gas Submetering
Occupant Behaviour
Refrigeration Waste Heat Recovery
Rink De-Aerator
Solar Air Preheating
Steam to Hot Water Conversion

[39] Note that analysis that forms the technical, economic and market potential is based on individual measures rather than on "packages of measures" or program delivery approaches. Measures packaged in comprehensive programs such as FortisBC's Rental Apartment Efficiency program, Social Housing Retrofit Support program and deep energy retrofits were assessed within this analysis individually but not also collectively as a program package.

5.4.2 Results

Exhibit 73 shows measure-level results for the commercial sector in order of decreasing cost effectiveness. Measures were assessed based on their replacement type: **retrofit** (immediate replacement at full cost), **replace on burnout** (end of life replacement at incremental cost), or **new construction** (immediate installation at incremental cost).

The TRC and MTRC are presented at the measure-level and exclude program costs and free ridership.

Key findings of the measure assessment for the commercial sector include:

- Of the 71 measures included in the assessment, 46 pass the TRC screen and 69 pass the MTRC screen.
- New Construction Step 2 and 3 pass the TRC screen and Step 4 does not.
- Gas heat pumps (Combination type) pass the TRC.
- Aerosol-applied air sealing passes TRC screen, with significant potential for energy savings in existing buildings (especially MURBs).

Exhibit 73 – Commercial Sector Measures with Average TRC and MTRC Results

#	Measure	Measure Type	Replacement Type	TRC	MTRC
1	ESTAR Dishwasher	Equipment	ROB	10	10
2	Boiler Cycling Controls	Equipment	RET	6.9	34.5
3	Steam Trap	Equipment	RET	5.3	28.1
4	DHW Tank Insulation	Equipment	RET	5.5	27.9
5	Efficient Cook Equipment	Equipment	ROB	5	25.1
6	DC Kitchen Vent	Energy Management	RET	4.9	24.6
7	Faucet Aerators	Equipment	RET	4.4	22.3
8	Boiler Zoning Controls	Equipment	RET	6	20.8
9	Occupant Behaviour	Energy Management	RET	3.6	20
10	BoilerFurnace Tune-Up	Equipment	RET	3.6	19.4
11	Efficient Pre-Rinse Spray	Equipment	RET	3.6	19
12	Refrigeration Heat Recovery	Equipment	RET	3.1	15.3
13	Low Flow Showerhead	Equipment	RET	2.8	14.5
14	Dock Door Seal	Equipment	RET	2.9	13.7
15	Lower Boiler Return Temp	Equipment	RET	2.5	11.9
16	Condensing Storage DHW	Equipment	ROB	2.1	10.6
17	Condensing Boiler (Early)	Equipment	RET	2	10.6
18	Direct Vent Fireplace	Equipment	ROB	2.1	10.2
19	Advanced Thermostat	Energy Management	RET	3.8	9.5
20	Air Curtain	Building Envelope	RET	1.9	9.4
21	Strip Curtains	Equipment	RET	1.8	9.4
22	Pipe Insulation	Equipment	RET	1.9	9.3
23	Condensing Boiler (ROB)	Equipment	ROB	1.9	9
24	Air Sealing	Building Envelope	ROB	1.7	7.8

25	Condensing On-Demand DHW	Equipment	ROB	1.6	7.8
26	Business Energy Report	Energy Management	RET	1.8	7
27	Condensing Make Up Air (ROB)	Equipment	ROB	1.4	6.9
28	Condensing Unit Heater	Equipment	RET	1.4	6.9
29	Solar Preheat	Equipment	RET	1.5	6.9
30	Recirculation Demand Control	Controls	RET	1.4	6.6
31	Reverse Flow Energy Recovery Ventilator	Equipment	ROB	1.3	6.5
32	Infrared Heaters	Equipment	RET	1.4	6.3
33	Boiler Combustion Controlss	Equipment	RET	1.2	5.9
34	Passive Drain Water Heat Recovery (DWHR)	Equipment	RET	1.1	5.3
35	Gas Heat Pumps - Combination	Equipment	ROB	1	5.1
36	Condensing Supply Boiler	Equipment	ROB	1.1	5
37	Heating Loop Additive	Equipment	ROB	0.9	5
38	Comprehensive Recommissioning (RCx)	Energy Management	RET	1.4	4.5
39	HRV	Equipment	ROB	0.9	4.3
40	NC Step 2 - Res	New Construction	NEW	1.9	4.3
41	NC Step 2 - Com	New Construction	NEW	2.1	4.3
42	NC Step 2 - Non-Step	New Construction	NEW	2.1	4.2
43	Hotel Controls	Equipment	RET	2	4.1
44	Steam to Hot Water	Energy Management	RET	0.8	3.9
45	Heat Recovery Chiller	Equipment	ROB	0.8	3.9
46	ERV	Equipment	ROB	0.8	3.9
47	NC Step 3 - Non-Step	New Construction	NEW	1.4	3.3
48	ESTAR Clothes Washer	Equipment	ROB	0.7	3.3
49	Window Film	Building Envelope	RET	2.2	3.3
50	NC Step 3 - Res	New Construction	NEW	1.3	3.2
51	NC Step 3 - Com	New Construction	NEW	1.4	3.2
52	Dual-Fuel-Electric Retrofit	Equipment	RET	0.6	3.1
53	Vortex De-Aerators	Equipment	RET	0.6	3
54	Dual-Fuel-Electric ROB	Equipment	RET	0.6	2.9
55	Indoor Pool Cover	Equipment	RET	0.5	2.8
56	Destratification	Equipment	RET	0.6	2.7
57	Advanced Building Automation System (BAS)	Equipment	RET	0.5	2.3
58	Condensing Make Up Air (Early)	Equipment	RET	0.4	2.2
59	RTU Controls	Equipment	RET	1.2	2.2
60	Roof Insulation	Building Envelope	ROB	0.5	2.2
61	Residential Furnace (ROB)	Equipment	ROB	0.4	2.1
62	Window Upgrade	Building Envelope	ROB	0.4	2.1

63	NC Step 4 - Non-Step	New Construction	NEW	0.7	1.7
64	Residential Furnace (Early)	Equipment	RET	0.3	1.7
65	NC Step 4 - Res	New Construction	NEW	0.6	1.6
66	Sterilizer Heat Recovery	Equipment	RET	0.3	1.5
67	Solar Water Pool	Equipment	RET	0.3	1.2
68	Submetering	Equipment	RET	0.2	1.2
69	Thermostat Shower Valve	Equipment	RET	0.2	1
70	Solar DHW Preheat	Energy Management	RET	0.2	0.8
71	Wall Insulation	Building Envelope	ROB	0.2	0.8

5.5 Technical Potential

This section provides an overview of the technical potential savings results for the commercial sector. Overall results are presented below, followed by measure level results and supply curves for the TRC and MTRC results.

As shown in Exhibit 74, the majority of the commercial technical potential (24 PJ) would be available in 2021 and would increase to 35 PJ in 2040. This indicates that a lot of the available potential (around 11 PJ) would come from replace on burnout measures over the next two decades. The forecasted natural gas consumption is included for reference.

Exhibit 74 – Commercial Technical Potential Savings (GJ)

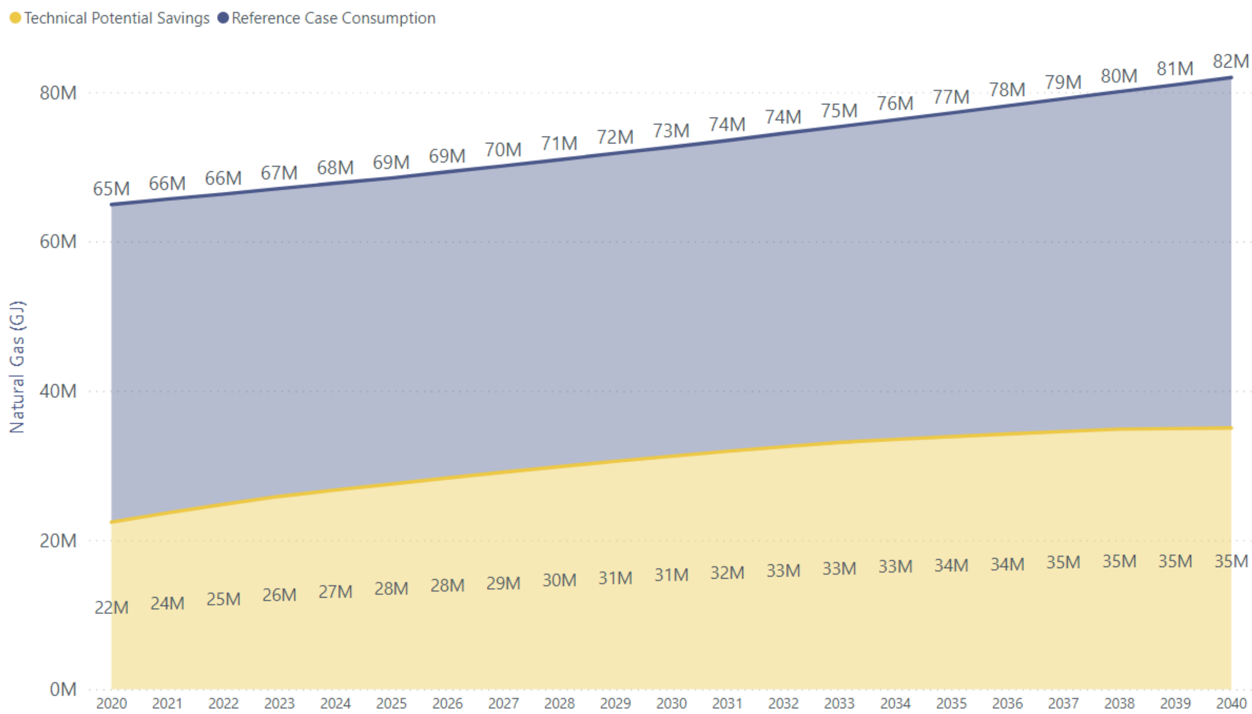
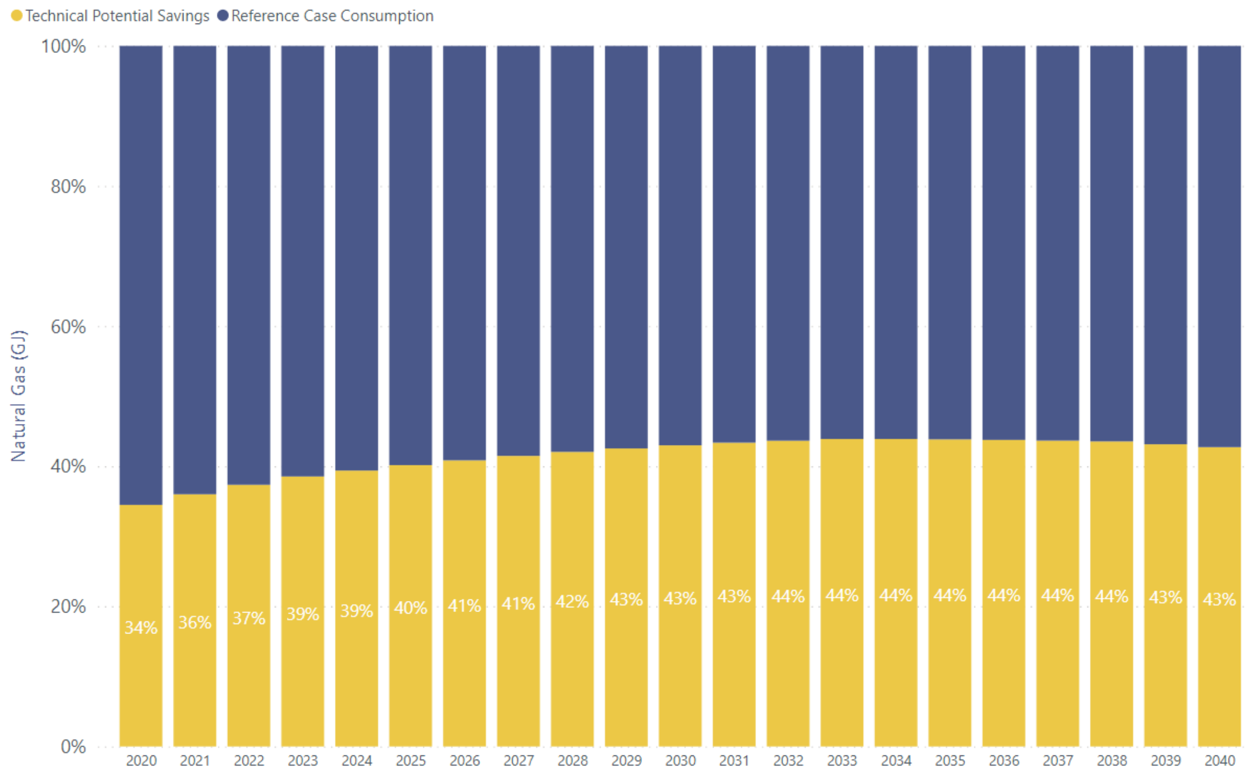


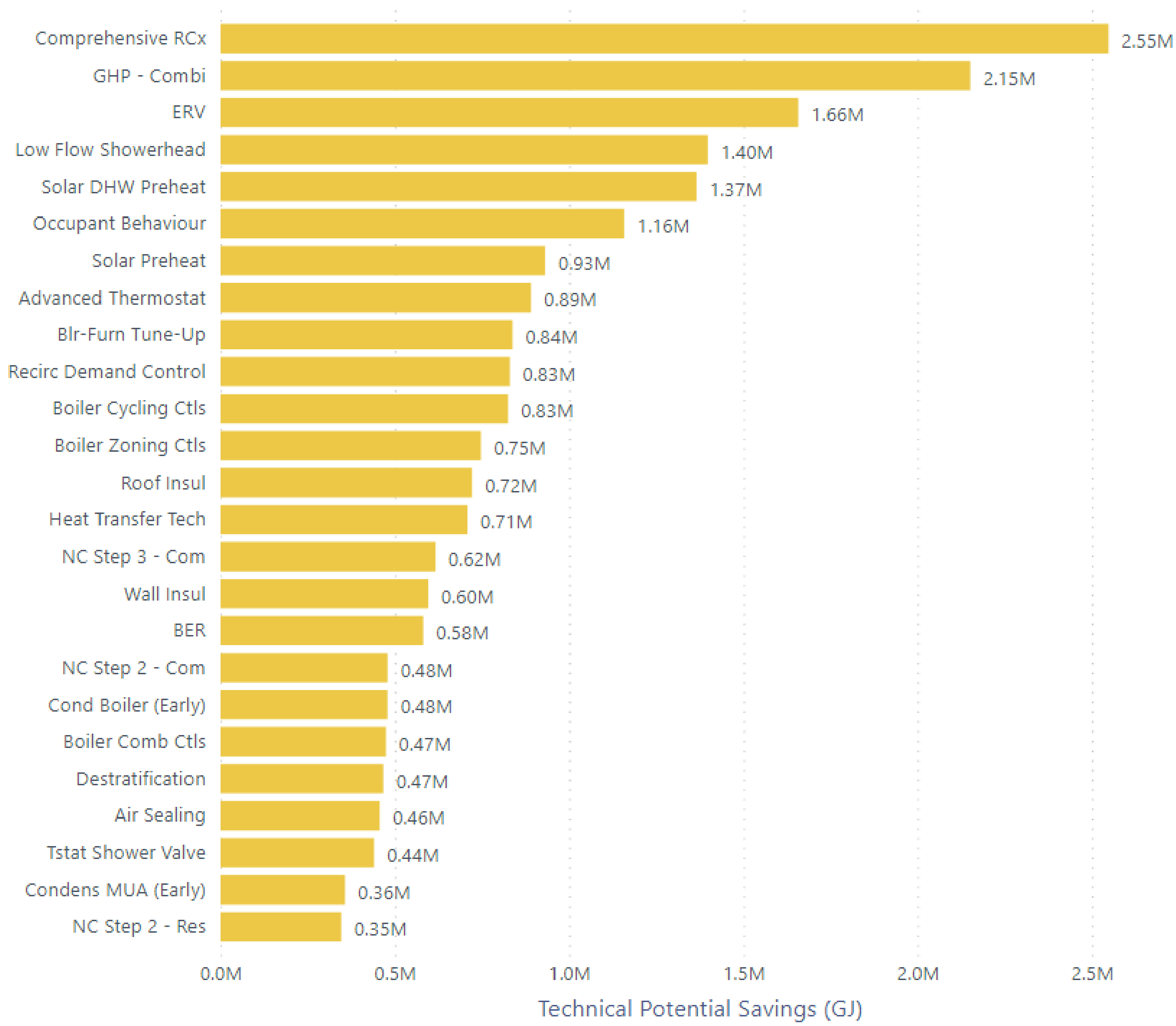
Exhibit 75 – Technical Savings Potential as a Percent of Commercial Reference Case Consumption (%)



As shown in Exhibit 75, the technical potential savings is about 36% of commercial reference case consumption in 2021 and increases to 43% by 2040, further indicating a fairly balance mix of potential from both retrofit and replace on burnout measures.

The technical potential savings in 2025 broken down by measure (only the top 25 measures are shown) are presented in Exhibit 76. From the top 5 measures that are expected to contribute the majority of the technical potential savings, only Solar DHW Preheat does not pass the TRC test. This means that the rest (the top 4) will also be expected to contribute largely to economic potential savings, as described in the following section.

Exhibit 76 – Technical Potential - Top 25 Commercial Measures in 2025 (GJ)

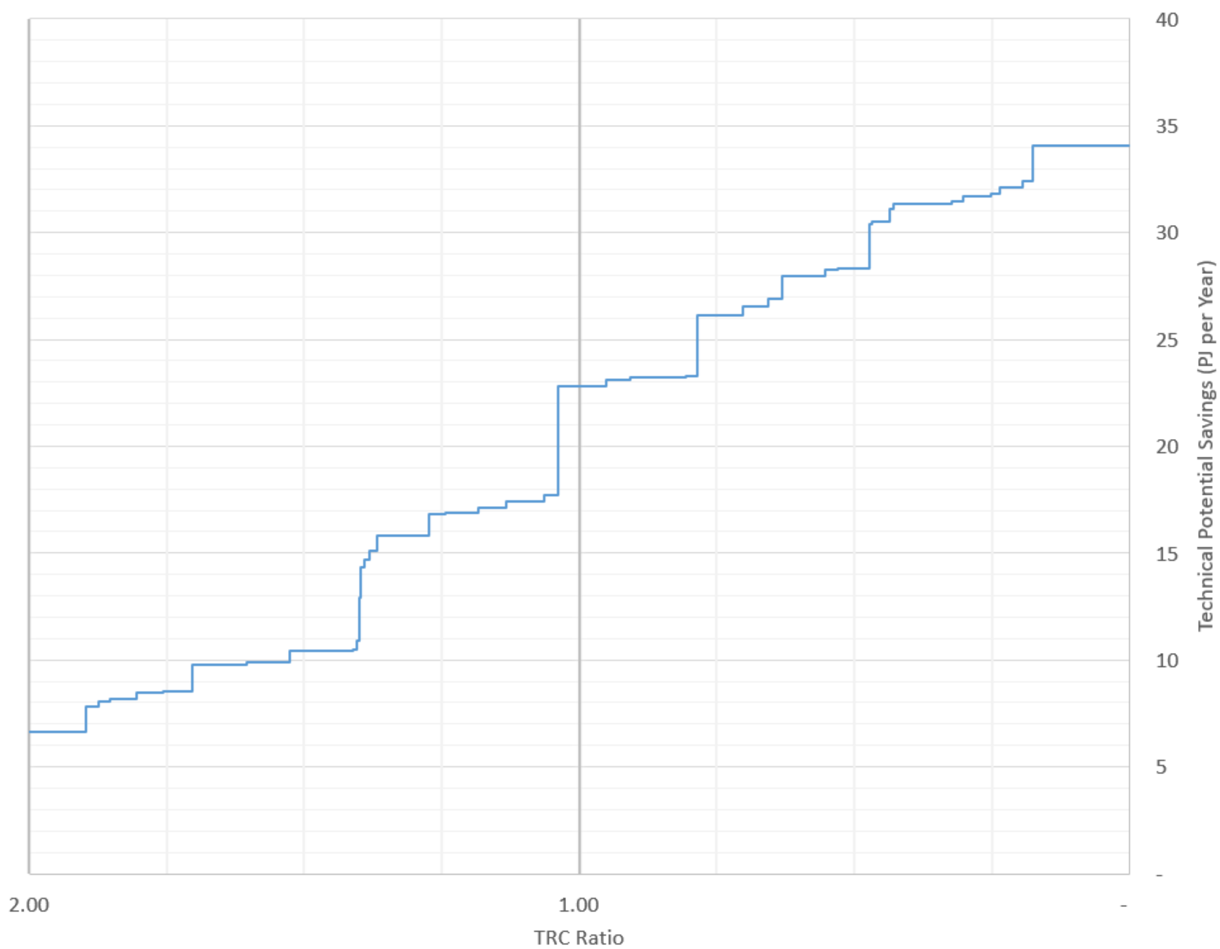


The cumulative commercial sector technical potential savings in 2040 are presented in Exhibit 77 as a supply curve, with measures ordered by decreasing TRC ratio from left to right.

As shown, approximately 68% of the commercial sector technical potential savings (approximately 23 of 34 PJ) comes from measures with a TRC of 1.0 or higher.

Approximately 7 PJ of savings come from measures with a TRC ratio of greater than 7. These are shown in aggregate.

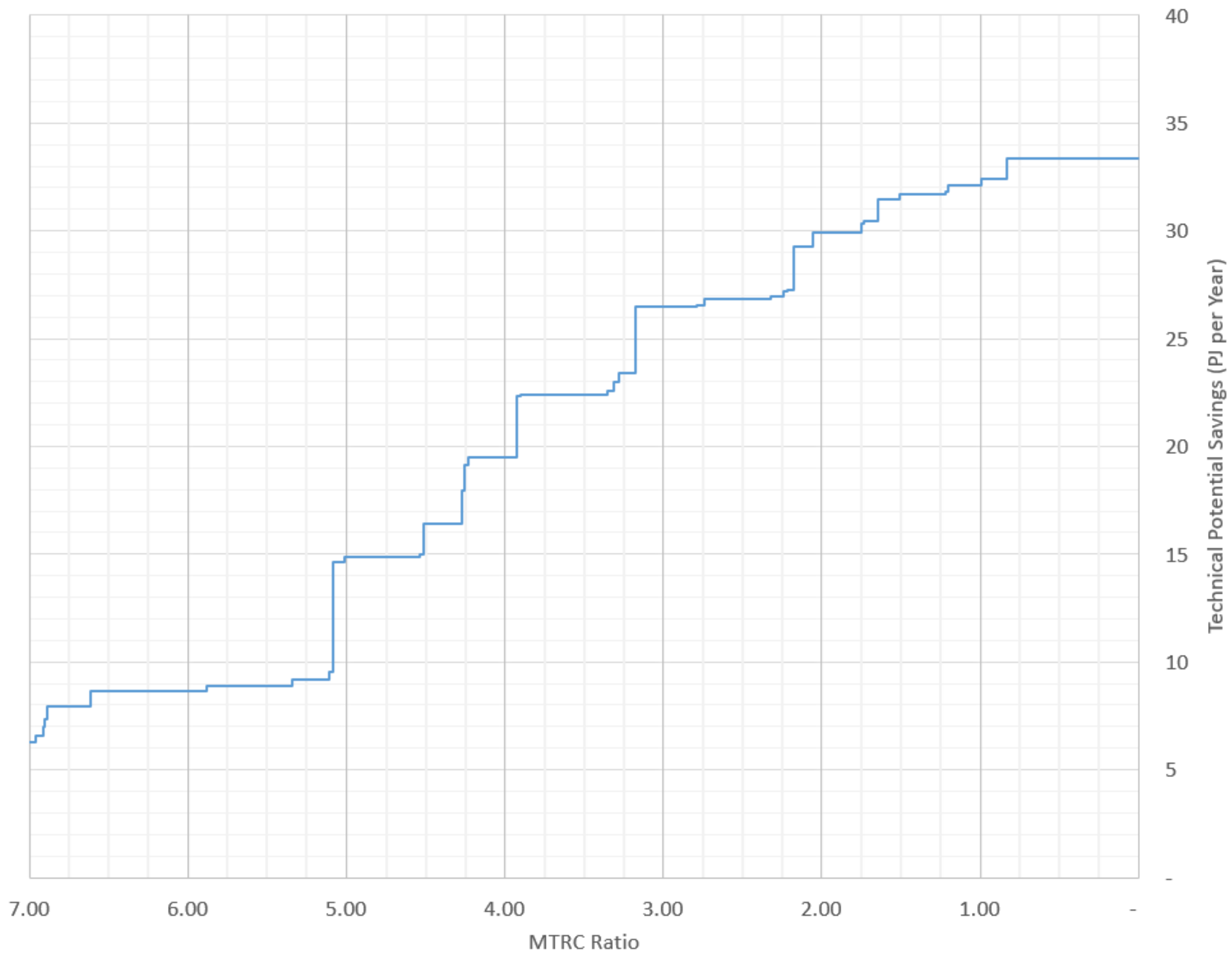
Exhibit 77 – Commercial Sector: Technical Potential Gas Supply Curve in 2040 – TRC Ratio



Similar to Exhibit 77, the cumulative commercial sector technical potential savings in 2040 are presented in Exhibit 78 as a supply curve, with measures ordered by decreasing MTRC ratio from left to right.

As shown, approximately 95% of the commercial sector technical potential savings (approximately 32 of 34 PJ) by 2040, comes from measures with an MTRC of 1.0 or higher. Approximately 6 PJ of savings come from measures with an MTRC ratio of greater than 7. These are shown in aggregate.

Exhibit 78 – Commercial Sector: Technical Potential Supply Curve – MTRC Ratio

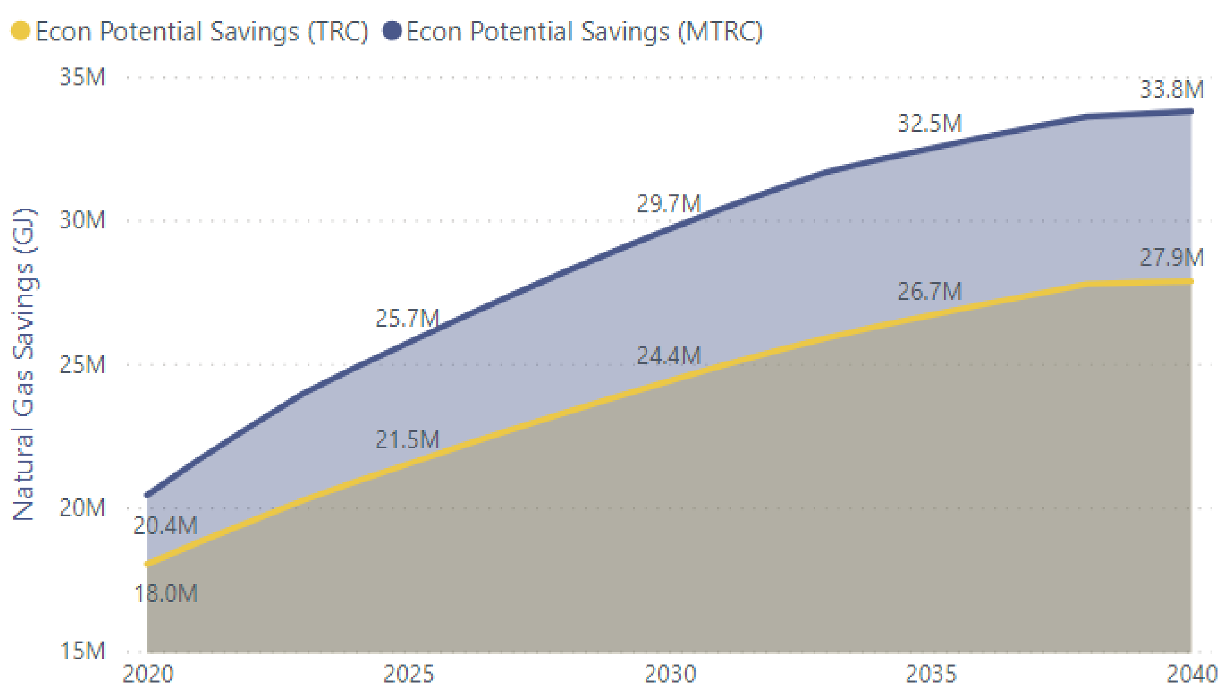


5.6 Economic Potential

This section provides the economic potential savings results for the commercial sector from 2020 to 2040. We conducted two economic potential assessments: one using a TRC Screen that includes measures with a TRC ratio of 1 and above, and one using an MTRC screen that includes measures with an MTRC of 1 and above. Outputs of both economic models are presented in this section.

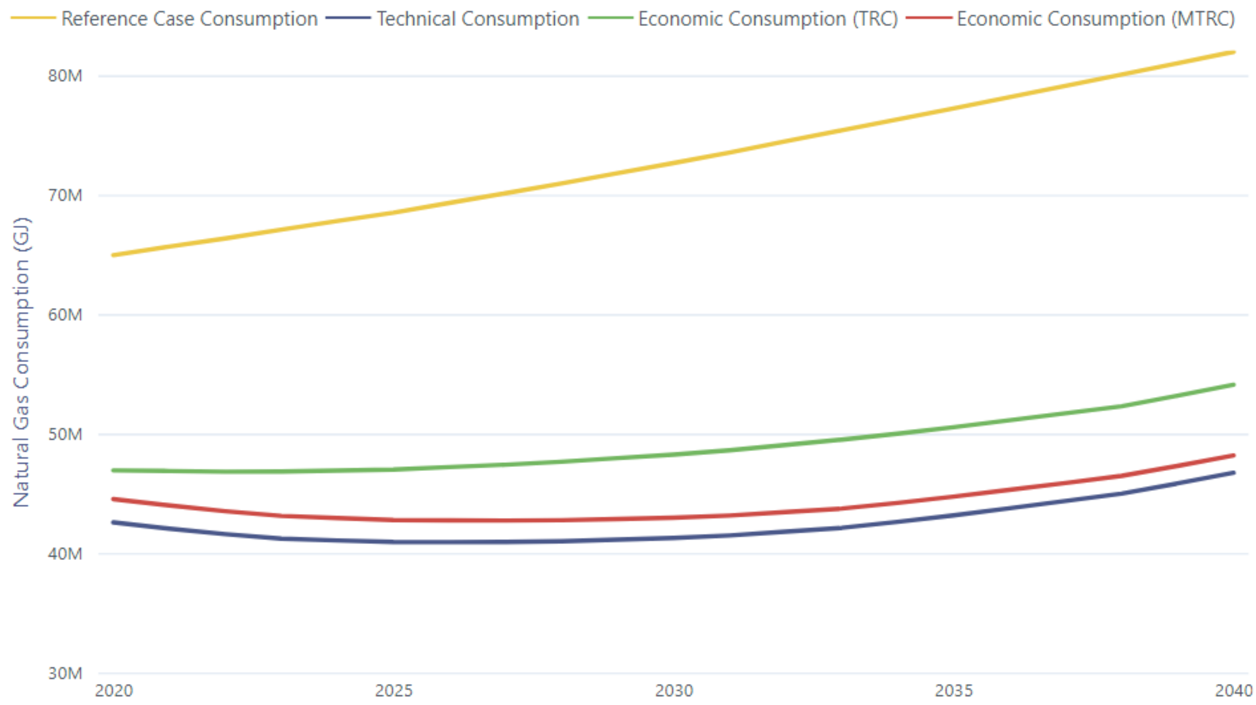
The commercial sector economic potential savings with a TRC screen and with an MTRC screen are shown in Exhibit 79. As mentioned earlier, of the 72 measures included in the assessment, 52 pass the TRC screen and 70 pass the MTRC screen. The 18 measures that that pass the MTRC but fail the TRC make up the difference between the two economic potential scenarios. The difference in economic potential in 2025 is around 4.2 PJ. Another way to look at it that the 84% of the MTRC economic potential comes from measures that pass the TRC as well.

Exhibit 79 – Economic Potential Savings (GJ) – Commercial, TRC and MTRC



The forecasted gas consumption under the technical potential, economic potential with a TRC screen, economic potential with an MTRC screen, and reference case scenarios for the commercial sector are shown in Exhibit 80. The slight uptick at the beginning of the curves is due to the implementation of the retrofit measures. The rest of the curves follow the shape of the reference case curve, as the replace on burnout measures are implemented at equipment end of life.

Exhibit 80 – Economic Potential Consumption (GJ) Forecasts – Commercial, TRC and MTRC



Results by Region

The TRC and MTRC economic potential savings in 2025 are presented by region in Exhibit 81 and Exhibit 82 respectively. The largest economic potential savings (10 PJ to 12.6 PJ depending on economic screen) are estimated to occur in the Lower Mainland outside of the City of Vancouver. Although small in absolute savings, the largest percentage of savings is expected to be captured in northern BC (more than 39% of reference case consumption).

Exhibit 81 – Economic Potential Savings by Region in 2025 – Commercial, TRC

Region	Consumption (GJ)	Economic Potential Savings (GJ)	Economic %
Lower Mainland x Van	33,493K	10,254K	31%
City of Vancouver	14,237K	4,418K	31%
Southern Interior	10,124K	3,322K	33%
Vancouver Island	6,863K	2,146K	31%
Northern BC	3,082K	1,200K	39%
Whistler	713K	171K	24%
Total	**68,513K**	**21,511K**	**31%**

Exhibit 82 – Economic Potential Savings by Region in 2025 – Commercial, MTRC

Region	Consumption (GJ)	Economic Potential Savings (GJ)	Economic %
Lower Mainland x Van	33,493K	12,634K	38%
City of Vancouver	14,237K	5,268K	37%
Southern Interior	10,124K	3,866K	38%
Vancouver Island	6,863K	2,470K	36%
Northern BC	3,082K	1,287K	42%
Whistler	713K	206K	29%
Total	**68,513K**	**25,731K**	**38%**

Results by Segment

The TRC and MTRC economic potential savings in 2025 are presented by segment in Exhibit 83 and Exhibit 84 respectively. The largest amounts of savings are expected to occur in apartments, other, and office segments. In both economic scenarios, the highest percentage of savings are expected to be captured offices, schools, university colleges.

Exhibit 83 – Economic Potential Savings by Segment in 2025 – Commercial, TRC

Segment	Consumption (GJ)	Economic Potential Savings (GJ)	Economic %
Apartment	20,961K	6,496K	31%
Other	13,284K	3,713K	28%
Office	7,633K	3,047K	40%
Warehouse	4,241K	1,361K	32%
Hospital	3,167K	1,198K	38%
Nonfood Retail	3,888K	1,124K	29%
School	2,549K	1,039K	41%
Hotel	2,800K	872K	31%
Restaurant	4,666K	859K	18%
University/College	1,752K	692K	40%
Nursing Home	1,940K	585K	30%
Food Retail	1,633K	525K	32%
Total	**68,513K**	**21,511K**	**31%**

Exhibit 84 – Economic Potential Savings by Segment in 2025 – Commercial, MTRC

Segment	Consumption (GJ)	Economic Potential Savings (GJ)	Economic %
Apartment	20,961K	7,683K	37%
Other	13,284K	4,306K	32%
Office	7,633K	3,710K	49%
Warehouse	4,241K	1,935K	46%
Hospital	3,167K	1,382K	44%
Nonfood Retail	3,888K	1,273K	33%
School	2,549K	1,268K	50%
Hotel	2,800K	1,038K	37%
Restaurant	4,666K	989K	21%
University/College	1,752K	879K	50%
Nursing Home	1,940K	718K	37%
Food Retail	1,633K	551K	34%
Total	**68,513K**	**25,731K**	**38%**

Results by End Use

The TRC and MTRC economic potential savings in 2025 are presented by segment in Exhibit 85 and Exhibit 86 respectively. The largest amounts, in absolute savings, as well as the highest percentage of savings relative to reference case consumption, are expected to be captured under the space heating end use (40% to 49% depending on the economic scenario).

Exhibit 85 – Economic Potential Savings by End Use in 2025 – Commercial, TRC

Parent End Use	Consumption (GJ)	Economic Potential Savings (GJ)	Economic %
Space Heating	37,973K	15,088K	40%
Water heating	20,913K	6,218K	30%
Food Service	5,322K	205K	4%
Other	3,674K	0K	0%
Pools; Spas & Hot Tubs	632K	0K	0%
Total	**68,513K**	**21,511K**	**31%**

Exhibit 86 – Economic Potential Savings by End Use in 2025 – Commercial, MTRC

Parent End Use	Consumption (GJ)	Economic Potential Savings (GJ)	Economic %
Space Heating	37,973K	18,543K	49%
Water heating	20,913K	6,707K	32%
Pools; Spas & Hot Tubs	632K	274K	43%
Food Service	5,322K	205K	4%
Other	3,674K	0K	0%
Total	**68,513K**	**25,731K**	**38%**

The TRC and MTRC economic potential savings in 2040 are presented by end use in Exhibit 87. The difference of almost 6 PJ is mostly a result of more space heating measures being included in the MTRC scenario. A small but interesting change is the pools, spas, and hot tubs end use, which contributed no savings under the TRC scenario, but has 219K GJ of economic potential under the MTRC.

Exhibit 87 – Economic Potential Savings by End Use in 2040 – Commercial, TRC and MTRC

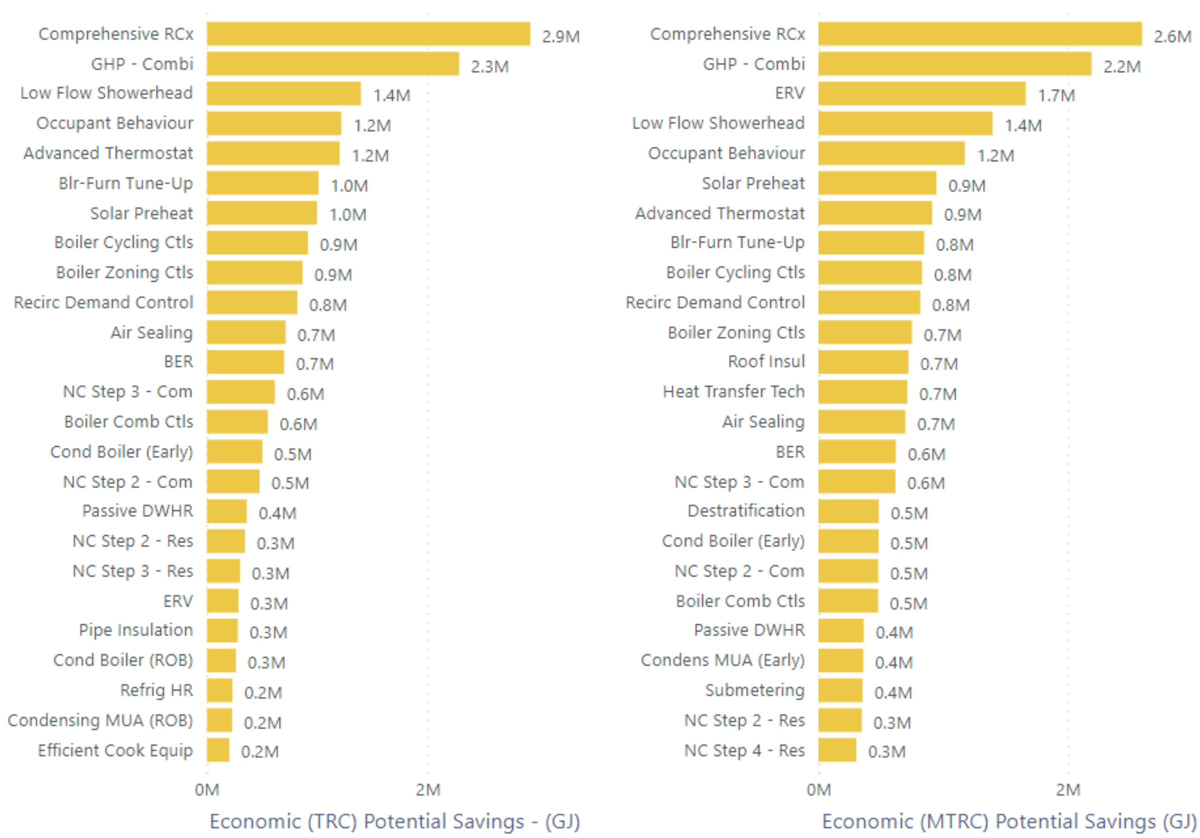
Parent End Use	Economic Savings (GJ) - TRC	Economic Savings (GJ) - MTRC	Difference (GJ)
Space Heating	19,735K	24,646K	4,910K
Water heating	7,822K	8,609K	787K
Food Service	313K	313K	0K
Pools; Spas & Hot Tubs	0K	219K	219K
Other	0K	0K	0K
Total	**27,870K**	**33,786K**	**5,916K**

Results by Measure

The economic potential savings in 2025 broken down by measure (only the top 25 measures are shown) are presented in Exhibit 88. The top measures in the TRC economic potential are shown on the left and on the MTRC scenario is shown on the right. Comprehensive recommissioning and combination gas heat pumps top the list in both scenarios. The MTRC scenario list on the right is almost similar to the top technical potential measures presented in Exhibit 76.

The main differences between the TRC and MTRC list are that the energy recovery ventilators (ERVs) become one of the top measures under MTRC. Other notable additions to the MTRC scenario include heat transfer technologies and roof insulation measures.

Exhibit 88 – Economic Potential (TRC on Left, MTRC on Right) - Top 25 Commercial Measures in 2025 (GJ)



5.7 Market Potential

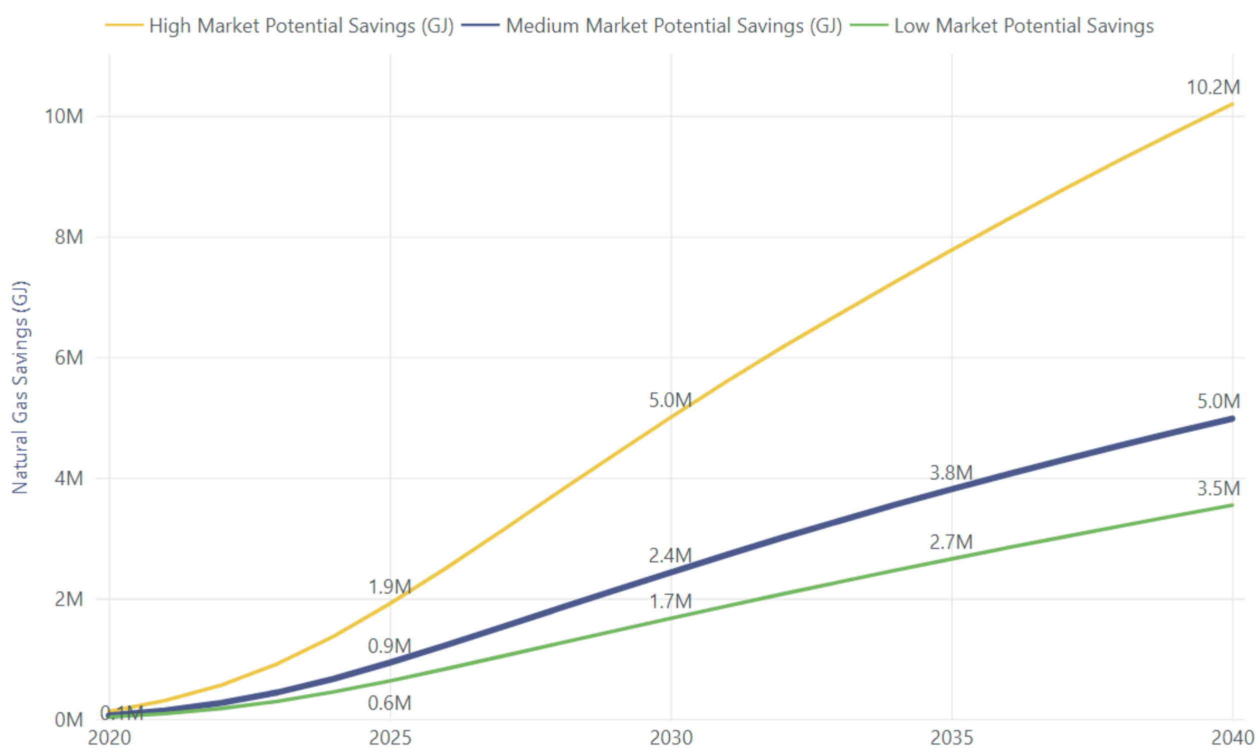
This section provides an overview of the low, medium, and high market potential results for the commercial sector.

Low, medium, and high scenarios assume that measure incentive levels will be 25%, 50% and 100% of incremental costs, respectively. For example, assume that a high-efficiency furnace may cost $200 more than a standard furnace, meaning the furnace would have an incremental cost of $200. In the medium scenario, this measure's hypothetical incentive from FortisBC would be $100. The other $100 would be paid by the end user. In all scenarios, the non-incentive program costs are assumed to be 15% of the incentive cost. In the example above, FortisBC's non-incentive spending would be $15. FortisBC's total cost for providing the measure to an end user would be $115.

The market potential savings results, with a TRC screen and with an MTRC screen, are shown in Exhibit 89 and Exhibit 90, respectively. The medium, or realistic, market potential scenarios under both economic screens are close, as the majority of the measures pass both screens.

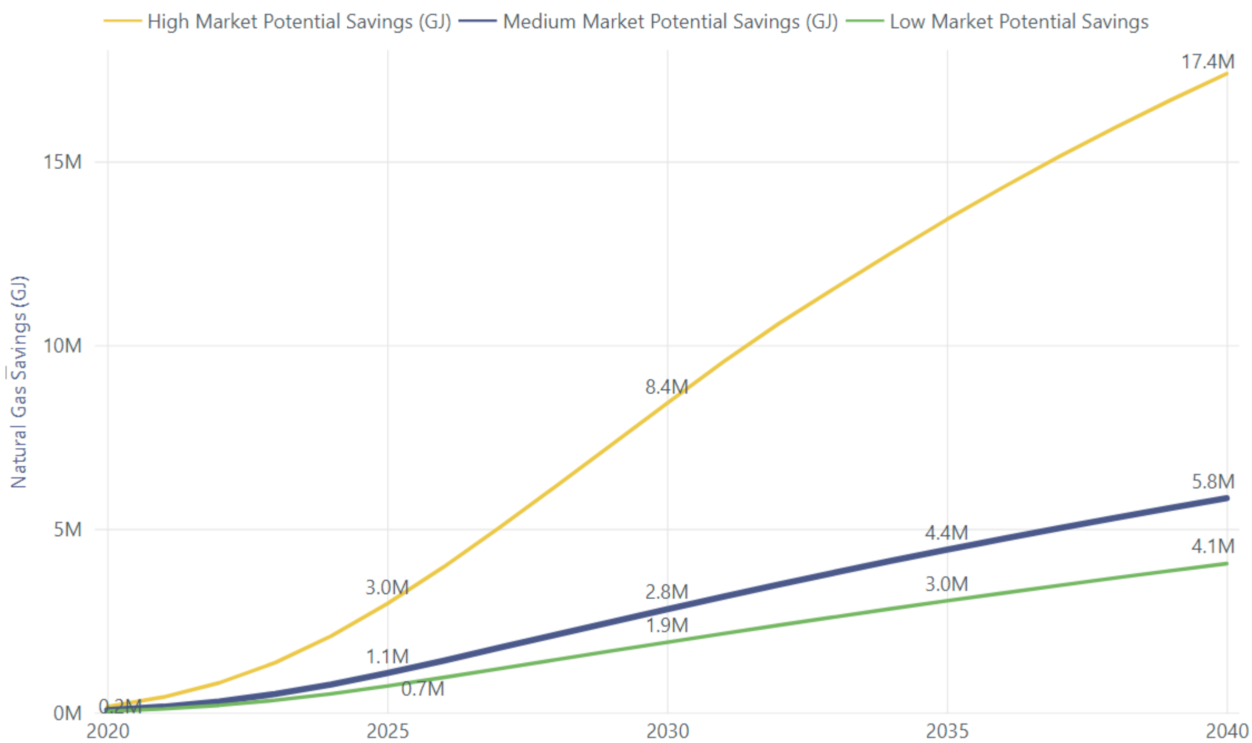
By 2040, the commercial low, medium, and high market TRC potential savings are estimated to be 3.5 PJ, 5 PJ, and 10.2 PJ, respectively.

Exhibit 89 – Market Potential Savings (GJ) – Commercial, TRC



By 2040, the commercial low, medium, and high market MTRC potential savings are estimated to be 4.1 PJ, 5.8 PJ, and 17.4 PJ, respectively.

Exhibit 90 – Market Potential Savings (GJ) – Commercial, MTRC



The high market potential scenario is much higher than the medium market potential in the MTRC scenario. By 2040, the difference in potential between the medium and high market MTRC scenarios is 11.6 PJ. In this case, gas heat pumps (GHPs) are a major factor contributing to the difference:

- For all measures, medium and high scenarios assume that measure incentive levels will be 50% and 100% of incremental costs, respectively.
- In addition to this, gas heat pumps were given different adoption curves in the two scenarios.
- In the medium market scenario, GHPs are modeled as an innovative technology with no current market penetration and low forecasted growth.
- In the high scenario, they are modeled as an innovative technology with no current market penetration, but with high forecasted growth, especially in the second half of the study period (2030-2040).

The difference in MTRC medium and high potential scenarios by 2040, broken down by measure, is shown in Exhibit 91. Only the top 10 measures that contribute to the difference are presented. Gas heat pumps top the list by a sizeable margin, but New Construction Step Code measures and energy recovery ventilators also influence the difference. For comparison, Exhibit 92 shows the difference in TRC medium and high potential scenarios - the absence of gas heat pumps is noticeable here.

Exhibit 91 – Top 10 Commercial Measures Contributing to Difference in Medium and High Market Potential Scenarios (Using MTRC Screen) by 2040

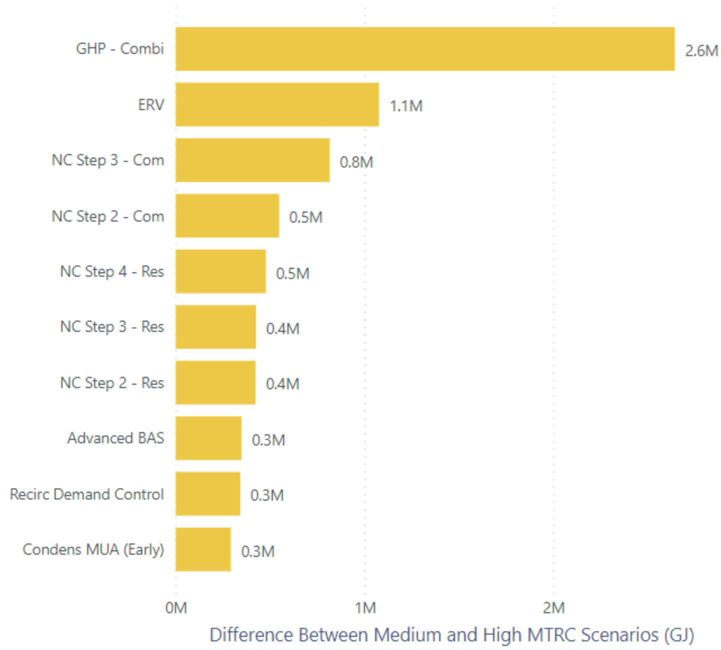
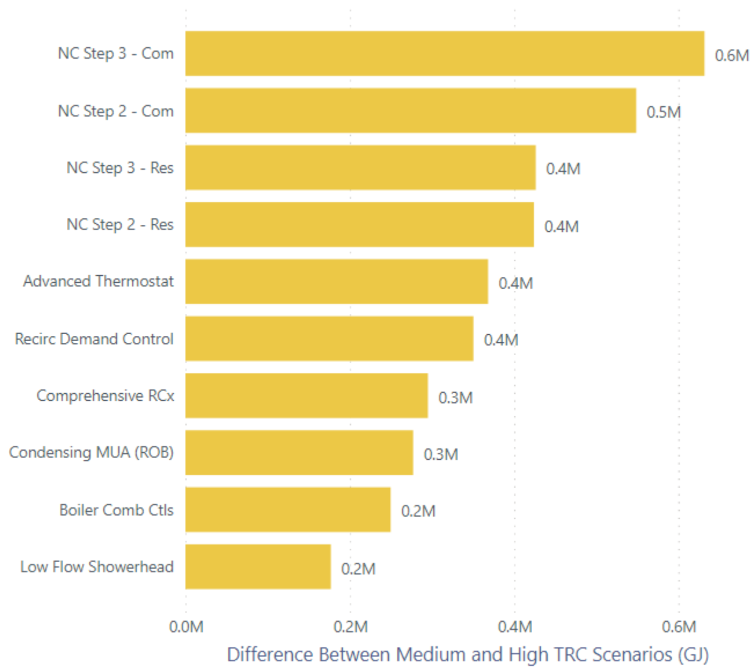


Exhibit 92 – Top 10 Commercial Measures Contributing to Difference in Medium and High Market Potential Scenarios (Using TRC Screen) by 2040



The forecasted gas consumption under the three market potential scenarios relative to reference case scenario for the commercial sector are shown in Exhibit 93 (TRC) and Exhibit 94 (MTRC). By 2040, the commercial low, medium, and high market TRC potential consumption levels are estimated to be 78 PJ, 77 PJ, and 72 PJ, respectively, while reference consumption is forecasted to reach 82 PJ. By 2040, the commercial low, medium, and high market MTRC potential consumption levels are estimated to be 78 PJ, 76 PJ, and 65 PJ, respectively, while reference consumption is forecasted to reach 82 PJ.

Exhibit 93 – Commercial Market Potential Consumption (GJ) Forecasts – Commercial, TRC

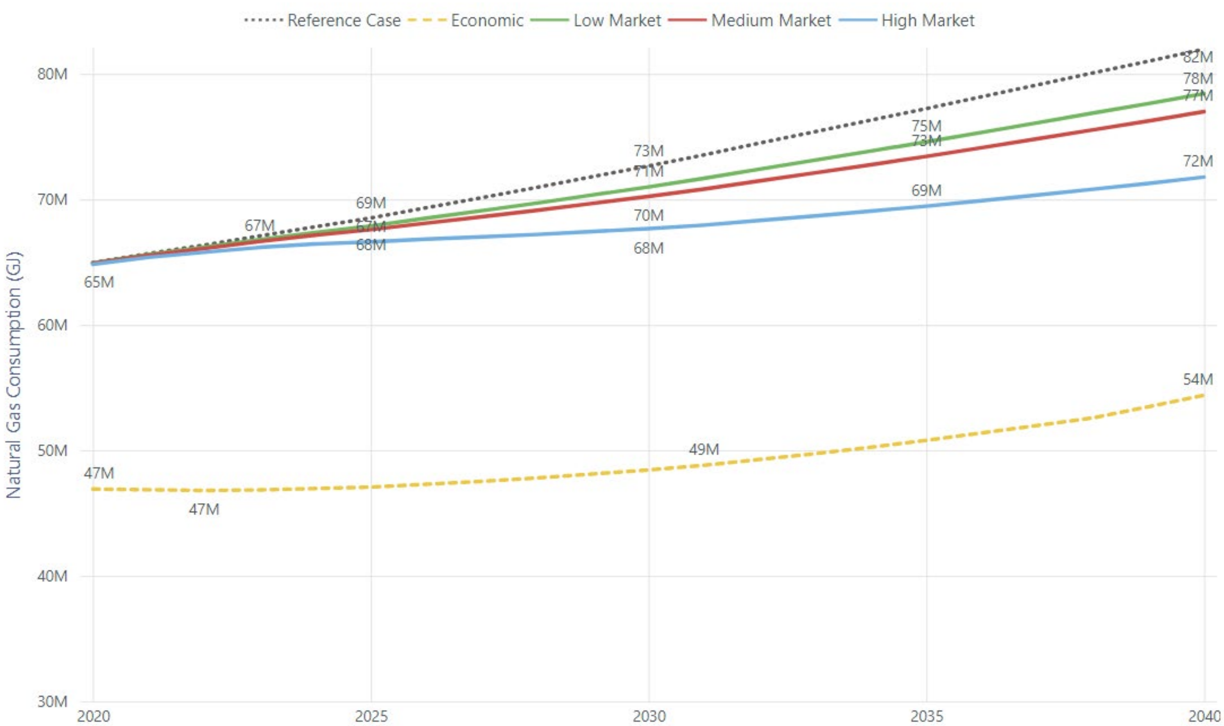
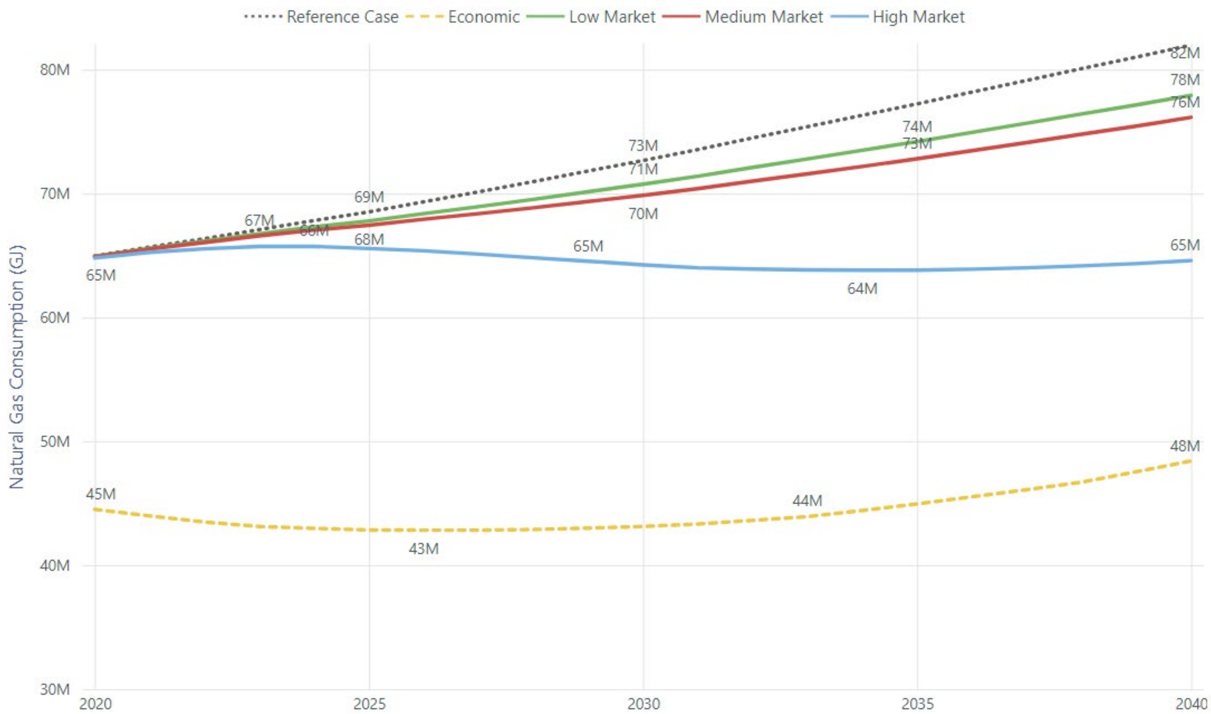


Exhibit 94 – Commercial Market Potential Consumption (GJ) Forecasts – Commercial, MTRC



The remainder of this section presents detailed results of the medium market potential scenario only. Similarly detailed results of the low and high market potential scenarios can be found on the Power BI dashboard and the Excel workbooks.

Results by Region

The medium market potential savings for 2025 are presented by region in Exhibit 95 and Exhibit 96 using TRC and MTRC screen, respectively. Medium market potential savings for 2025 are estimated to be between 1% and 2% of reference case consumption in all regions in both medium market scenarios.

Exhibit 95 – Medium Market Potential Savings by Region in 2025 – Commercial, TRC

Region	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Lower Mainland x Van	33,493K	425K	1%
City of Vancouver	14,237K	184K	1%
Southern Interior	10,124K	178K	2%
Vancouver Island	6,863K	103K	2%
Northern BC	3,082K	71K	2%
Whistler	713K	7K	1%
Total	**68,513K**	**969K**	**1%**

Exhibit 96 – Medium Market Potential Savings by Region in 2025 – Commercial, MTRC

Region	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Lower Mainland x Van	33,493K	498K	1%
City of Vancouver	14,237K	219K	2%
Southern Interior	10,124K	192K	2%
Vancouver Island	6,863K	113K	2%
Northern BC	3,082K	69K	2%
Whistler	713K	7K	1%
Total	**68,513K**	**1,099K**	**2%**

Results by Segment

The medium market potential savings for 2025 are presented by segment in Exhibit 97 and Exhibit 98 using TRC and MTRC screen, respectively. The largest amounts of medium market potential savings are estimated to occur in apartments, other, and office segments.

Exhibit 97 – Medium Market Potential Savings by Segment in 2025 – Commercial, TRC

Segment	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Apartment	20,961K	222K	1%
Other	13,284K	152K	1%
Office	7,633K	137K	2%
Restaurant	4,666K	98K	2%
Warehouse	4,241K	76K	2%
Hospital	3,167K	65K	2%
Nonfood Retail	3,888K	46K	1%
School	2,549K	46K	2%
Food Retail	1,633K	39K	2%
University/College	1,752K	36K	2%
Hotel	2,800K	31K	1%
Nursing Home	1,940K	22K	1%
Total	**68,513K**	**969K**	**1%**

Exhibit 98 – Medium Market Potential Savings by Segment in 2025 – Commercial, MTRC

Segment	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Apartment	20,961K	276K	1%
Other	13,284K	166K	1%
Office	7,633K	157K	2%
Restaurant	4,666K	102K	2%
Warehouse	4,241K	86K	2%
Hospital	3,167K	67K	2%
School	2,549K	51K	2%
Nonfood Retail	3,888K	48K	1%
University/College	1,752K	42K	2%
Food Retail	1,633K	40K	2%
Hotel	2,800K	37K	1%
Nursing Home	1,940K	26K	1%
Total	**68,513K**	**1,099K**	**2%**

Results by End Use

The medium market potential savings for 2025 are presented by segment in Exhibit 99 and Exhibit 100 using TRC and MTRC screen, respectively. More than two thirds of the savings come from the space heating end use.

Exhibit 99 – Medium Market Potential Savings by End Use in 2025 – Commercial, TRC

Parent End Use	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Space Heating	37,973K	652K	2%
Water heating	20,913K	257K	1%
Food Service	5,322K	60K	1%
Other	3,674K	0K	0%
Pools; Spas & Hot Tubs	632K	0K	0%
Total	**68,513K**	**969K**	**1%**

Exhibit 100 – Medium Market Potential Savings by End Use in 2025 – Commercial, MTRC

Parent End Use	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Space Heating	37,973K	776K	2%
Water heating	20,913K	260K	1%
Food Service	5,322K	60K	1%
Pools; Spas & Hot Tubs	632K	3K	0%
Other	3,674K	0K	0%
Total	**68,513K**	**1,099K**	**2%**

The TRC and MTRC medium market potential savings for 2040 are presented by end use in Exhibit 101. The scenarios under both economic screens are close, with a difference of 704 TJ, as the majority of the measures pass both screens.

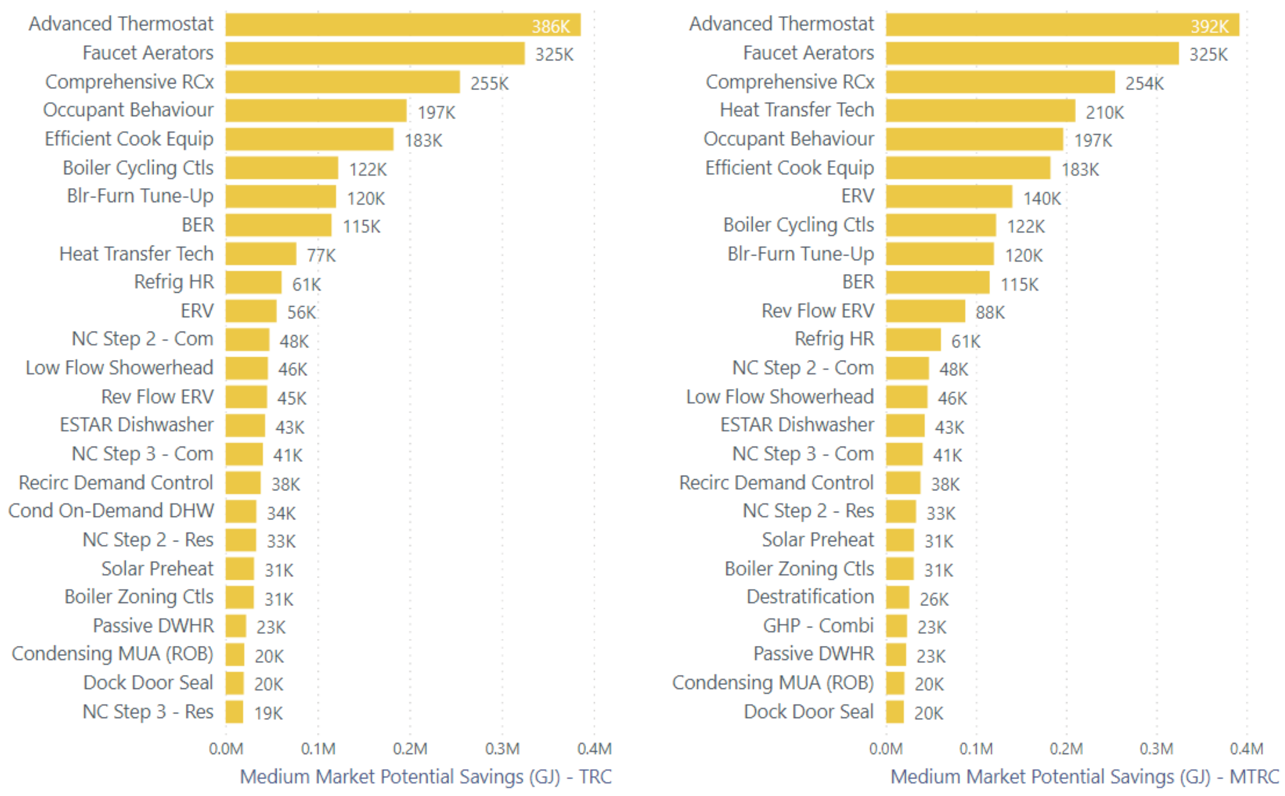
Exhibit 101 – Medium Market Potential Savings by End Use in 2040 – Commercial, TRC and MTRC

Parent End Use	Medium Potential Savings (GJ) - TRC	Medium Potential Savings (GJ) - MTRC	Difference (GJ)
Space Heating	3,702K	4,466K	764K
Water heating	1,072K	1,147K	75K
Pools; Spas & Hot Tubs	0K	13K	13K
Other	0K	0K	0K
Food Service	207K	207K	0K
Total	**4,981K**	**5,833K**	**852K**

Results by Measure

The medium market potential savings by 2025 of the top 25 commercial measures are shown in Exhibit 102, sorted by decreasing potential. The top measures in the TRC medium market potential are shown on the left and the top measures in the MTRC scenario are shown on the right. Advanced thermostats, faucet aerators, and comprehensive recommissioning (RCx) top the list in both scenarios. Occupant behavior measures, efficient cooking equipment, and heat transfer technologies have large potential in both scenarios as well. A major change in this top-measures list when compared with the economic potential list is the relatively small contribution of energy recovery ventilators (ERV) and gas heat pumps (GHP Combi).

Exhibit 102 – Medium Market Potential (TRC on Left, MTRC on Right) - Gas Savings from Top 25 Commercial Measures in 2025 (GJ)



5.7.1 Incentive and Non-Incentive Spending

The incentive and non-incentive spending required to achieve the medium and high market potential are shown in Exhibit 103 (TRC) and Exhibit 104 (MTRC). Medium and high market incentives are assumed to be 50% and 100% of measures' incremental costs, respectively. In both medium and high scenarios, non-incentive costs are estimated to be 15% of incentive costs. The tables also show the total as well as incremental (that is, savings from new measures installed in a year) savings every year.

Exhibit 103 – Medium and High Market Incentive Costs and Natural Gas Savings – Commercial, TRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$1.0M	$0.1M	$1.1M	57K	57K	$5.9M	$0.9M	$6.8M	124K	124K
2021	$1.6M	$0.2M	$1.9M	142K	85K	$9.9M	$1.5M	$11.4M	306K	183K
2022	$2.6M	$0.4M	$3.0M	267K	125K	$15.7M	$2.4M	$18.0M	563K	256K
2023	$3.9M	$0.6M	$4.5M	441K	174K	$24.1M	$3.6M	$27.7M	914K	352K
2024	$5.4M	$0.8M	$6.2M	667K	226K	$34.1M	$5.1M	$39.2M	1,370K	456K
2025	$6.8M	$1.0M	$7.8M	934K	267K	$43.9M	$6.6M	$50.5M	1,912K	542K
2026	$8.1M	$1.2M	$9.3M	1,223K	289K	$53.2M	$8.0M	$61.2M	2,501K	589K
2027	$8.9M	$1.3M	$10.2M	1,526K	302K	$59.1M	$8.9M	$68.0M	3,124K	623K
2028	$9.5M	$1.4M	$10.9M	1,830K	304K	$63.7M	$9.6M	$73.2M	3,757K	633K
2029	$9.7M	$1.5M	$11.2M	2,132K	302K	$65.4M	$9.8M	$75.2M	4,384K	627K
2030	$9.9M	$1.5M	$11.4M	2,430K	298K	$66.3M	$9.9M	$76.3M	4,999K	615K
2031	$9.9M	$1.5M	$11.4M	2,723K	293K	$67.0M	$10.0M	$77.0M	5,597K	599K
2032	$10.1M	$1.5M	$11.7M	3,009K	286K	$67.7M	$10.2M	$77.9M	6,170K	572K
2033	$9.7M	$1.5M	$11.2M	3,285K	276K	$64.9M	$9.7M	$74.6M	6,712K	542K
2034	$9.9M	$1.5M	$11.4M	3,555K	270K	$65.9M	$9.9M	$75.8M	7,249K	537K
2035	$9.6M	$1.4M	$11.1M	3,810K	255K	$64.6M	$9.7M	$74.2M	7,773K	524K
2036	$9.5M	$1.4M	$11.0M	4,058K	248K	$63.5M	$9.5M	$73.0M	8,283K	510K
2037	$9.5M	$1.4M	$11.0M	4,298K	240K	$64.0M	$9.6M	$73.6M	8,782K	498K
2038	$9.5M	$1.4M	$10.9M	4,534K	237K	$62.0M	$9.3M	$71.2M	9,269K	488K
2039	$9.1M	$1.4M	$10.5M	4,760K	226K	$58.1M	$8.7M	$66.8M	9,735K	466K
2040	$9.2M	$1.4M	$10.6M	4,981K	221K	$59.2M	$8.9M	$68.0M	10,197K	462K

Exhibit 104 – Medium and High Market Incentive Costs and Natural Gas Savings – Commercial, MTRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$1.2M	$0.2M	$1.4M	62K	62K	$10.8M	$1.6M	$12.4M	160K	160K
2021	$2.1M	$0.3M	$2.4M	159K	97K	$20.1M	$3.0M	$23.1M	422K	262K
2022	$3.4M	$0.5M	$3.9M	303K	144K	$32.7M	$4.9M	$37.6M	810K	388K
2023	$5.1M	$0.8M	$5.8M	505K	201K	$49.6M	$7.4M	$57.1M	1,359K	549K
2024	$6.9M	$1.0M	$7.9M	767K	262K	$70.0M	$10.5M	$80.5M	2,083K	724K
2025	$8.6M	$1.3M	$9.9M	1,075K	309K	$89.6M	$13.4M	$103.1M	2,961K	879K
2026	$10.3M	$1.5M	$11.8M	1,412K	336K	$109.6M	$16.4M	$126.0M	3,954K	993K
2027	$11.3M	$1.7M	$13.0M	1,762K	351K	$122.4M	$18.4M	$140.7M	5,027K	1,072K
2028	$12.1M	$1.8M	$13.9M	2,115K	352K	$132.5M	$19.9M	$152.3M	6,143K	1,116K
2029	$12.4M	$1.9M	$14.2M	2,465K	350K	$137.1M	$20.6M	$157.6M	7,280K	1,137K
2030	$12.6M	$1.9M	$14.5M	2,811K	345K	$140.6M	$21.1M	$161.6M	8,419K	1,139K
2031	$12.7M	$1.9M	$14.6M	3,151K	340K	$140.9M	$21.1M	$162.0M	9,541K	1,122K
2032	$12.9M	$1.9M	$14.9M	3,485K	335K	$142.3M	$21.3M	$163.7M	10,589K	1,049K
2033	$12.5M	$1.9M	$14.4M	3,810K	325K	$135.8M	$20.4M	$156.2M	11,557K	968K
2034	$12.6M	$1.9M	$14.5M	4,130K	319K	$135.8M	$20.4M	$156.1M	12,504K	946K
2035	$12.3M	$1.8M	$14.2M	4,431K	302K	$133.0M	$19.9M	$152.9M	13,422K	918K
2036	$12.3M	$1.8M	$14.1M	4,726K	295K	$131.3M	$19.7M	$151.0M	14,292K	870K
2037	$12.2M	$1.8M	$14.1M	5,014K	288K	$129.9M	$19.5M	$149.4M	15,127K	836K
2038	$12.2M	$1.8M	$14.0M	5,297K	283K	$124.3M	$18.6M	$143.0M	15,918K	790K
2039	$11.9M	$1.8M	$13.7M	5,568K	271K	$118.5M	$17.8M	$136.3M	16,673K	755K
2040	$12.0M	$1.8M	$13.8M	5,833K	266K	$116.1M	$17.4M	$133.5M	17,391K	718K

6 Industrial Sector Results

This section presents the industrial sector results and key findings, including:

- Base year (2019) natural gas use
- Reference case consumption forecast (2020 – 2040)
- Energy conservation measures evaluated in this CPR
- Technical potential savings
- Economic potential savings
- Market potential savings and scenarios

6.1 Industrial Segments and End Uses

In this CPR, the industrial sector is divided into 12 segments, 12 energy end uses, and two vintages.

	Segments	End Uses	Vintages
Industrial Sector	• Agriculture (includes greenhouses[40]) • Chemical • District energy providers • Fabricated Metal • Food & Beverage • Other Manufacturing (includes transportation[41] and other industrial) • Mining • Non-metallic Mineral (includes cement) • Pulp & Paper – Kraft • Pulp & Paper – TMP • Utilities • Wood Products	• Direct-fired heating • Direct Consumption of Gas in Process[42] • Heat Treating • Kilns • On-Site Power Generation[13] • Other[12] • Ovens • Petrochemical Refining and Process Heating • Process Boilers • Product Drying • Space Heating [includes HVAC air heating and HVAC boilers] • Water heaters	• Existing • New

40 Cannabis has been included in agriculture segment since there is not enough data at FEI to create a cannabis-specific forecast.
41 In the 2015 CPR, 'transportation' pertained to facilities that supported the transportation sector.
42 No CPR measures are applied to this end use; included for accounting purposes only.

6.2 Base Year Natural Gas Use

Base year (2019) industrial natural gas use is presented by segment in Exhibit 105, by end use in Exhibit 106, and by region in Exhibit 107.

Natural gas consumption in the industrial sector base year is highest:

- In the pulp and paper – kraft (31%), agriculture (13%), wood products (12%), and mining (12%) segments
- In the process boilers (36%), product drying (26%), and direct-fired heating (16%) end uses
- In the Lower Mainland excluding the Vancouver (33%), Northern BC (24%), and Southern Interior (26%) regions

Exhibit 105 – 2019 Industrial Natural Gas Consumption (GJ) by Segment[43]

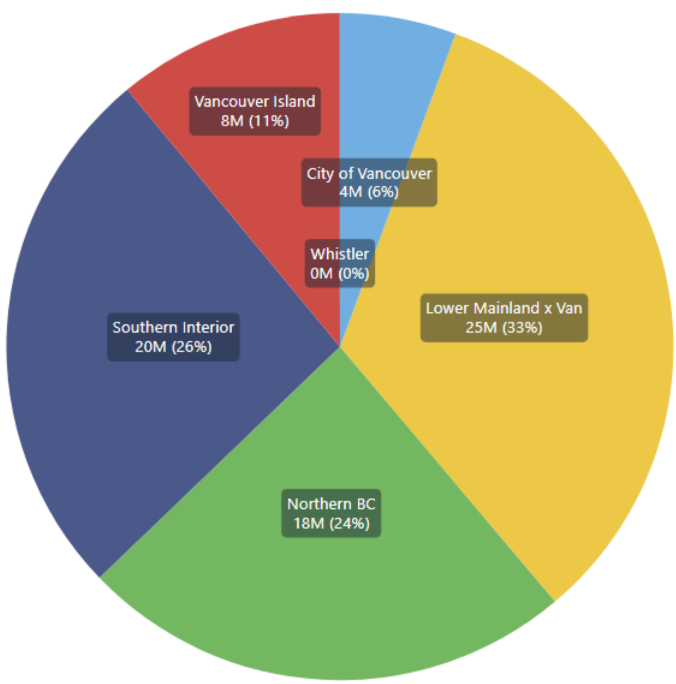
Segment	Natural Gas Consumption (GJ)	%
Pulp & Paper - Kraft	23,480K	31%
Agriculture	9,662K	13%
Wood Products	8,936K	12%
Mining	8,843K	12%
Non-metallic Mineral	4,657K	6%
Food & Beverage	4,548K	6%
Manufacturing	4,291K	6%
Chemical	4,014K	5%
Pulp & Paper - TMP	2,923K	4%
District Energy	2,555K	3%
Utilities	851K	1%
Fabricated Metal	526K	1%
Total	**75,286K**	**100%**

43 Please see Appendix B for how industrial sector NAICS codes were mapped into segments.

Exhibit 106 – 2019 Industrial Natural Gas Consumption (GJ) by End Use

Parent End Use	Natural Gas Consumption (GJ)	%
Process Boilers	27,045K	36%
Product Drying	19,465K	26%
Direct-fired Heating	11,817K	16%
Space Heating	5,737K	8%
Kilns	3,626K	5%
Direct Gas Use	1,553K	2%
Petrochem Refining	1,407K	2%
Other	1,209K	2%
Ovens	1,110K	1%
On-Site Generation	851K	1%
Water Heaters	823K	1%
Heat Treating	644K	1%
Total	**75,286K**	**100%**

Exhibit 107 – 2019 Industrial Natural Gas Consumption (GJ) by Region



6.2.1 Accounts

Base year industrial natural gas accounts are presented by segment in Exhibit 108 and by region in Exhibit 109. As shown in these exhibits, in 2019 the greatest number of industrial natural gas accounts were in:

- The manufacturing (37%), agriculture (21%), and food & beverage (13%) segments
- The Lower Mainland excluding Vancouver region (68%)

Exhibit 108 – 2019 Industrial Accounts by Segment

Segment	Accounts	%
Manufacturing	3,354	37%
Agriculture	1,930	21%
Food & Beverage	1,164	13%
Fabricated Metal	744	8%
Wood Products	701	8%
Chemical	437	5%
Non-metallic Mineral	247	3%
Utilities	201	2%
Mining	125	1%
Pulp & Paper - TMP	76	1%
Pulp & Paper - Kraft	26	0%
District Energy	18	0%
Total	**9,023**	**100%**

Exhibit 109 – 2019 Industrial Accounts by Region

Region	Accounts	%
Lower Mainland x Van	6,138	68%
Southern Interior	1,501	17%
City of Vancouver	680	8%
Northern BC	452	5%
Vancouver Island	247	3%
Whistler	5	0%
Total	**9,023**	**100%**

6.2.2 Tertiary Load

Tertiary load is the useful energy delivered to an end use. In the context of the CPR, tertiary load is the amount energy required to be delivered as an end use *service*: heat delivered by a furnace to a house, for example. This differs from consumption of natural gas which is impacted by the efficiency of the equipment: in the furnace example, consumption is equal to the tertiary load divided by seasonal efficiency of furnaces. Exhibit 110 provides 2019 tertiary load values.

6.2.3 Unit Energy Consumption

As explained in Exhibit 3, unit energy consumption (UEC) is the amount of energy used by each end use per unit. Defining "units" is challenging in the industrial sector. In the residential sector, consumption is typically analyzed per dwelling while in the commercial sector, consumption is analyzed per unit of floor area. In the industrial sector, consumption per unit of production capacity (kg of product, for example) would seem to be a useful approach. Unfortunately, the concept becomes inoperable when many different industries are included in the analysis. Nonetheless, it is desirable to have a way of representing growth in industries that is independent of changes in energy consumption caused by changes in fuel share or equipment efficiency. Therefore, 'units' in the industrial sector is used as a proxy of production capacity of different types of plants. The base year consumption is used as a proxy for the production capacity of different types of plants in each region and rate class.

Along with UEC values is *unit tertiary load*, which is the average tertiary load used by each end use in a dwelling, and *stock average efficiency*, which is the average efficiency of equipment serving the tertiary load for that end use. These values are included in the table because UEC by end use is calculated by dividing unit tertiary load with stock average efficiency.

Unlike the residential or commercial sectors, the end uses in the industrial sector are not common across the segments; rather, some end uses are specific to some segments. For example, the 'on-site generation' end use is only present in the 'utilities' segment. For the purposes of this report, UEC values are shown for one segment and region only, therefore UEC values are included only for the end uses that are present in that segment.

Unit tertiary load, stock average efficiency and UEC values for the pulp & paper – kraft segment in the Northern BC ("NBC") region are presented in Exhibit 110. This combination of segment and region was selected as the example because it A) is a significant consumer of gas, and B) has enough accounts to ensure consumption from one account cannot be determined through the information presented in this report, thereby protecting customer privacy.

Exhibit 110 – 2019 UEC Values by End Use, Pulp & Paper-Kraft Segment in Northern British Columbia

	Unit Tertiary Load (GJ/unit/yr)	Stock Average Efficiency (%)	UEC
Space Heating	0.02	0.62	0.03
Direct-fired Heating	0.38	1.00	0.38
Kilns	0.08	0.79	0.10
Product Drying	0.02	0.88	0.03
Process Boilers	0.34	0.67	0.51

6.2.4 Average Natural Gas Use per Account

Details on natural gas consumption per account by end use are provided in Exhibit 111 for an average Pulp & Paper – Kraft account in the Northern BC region. The following information is included in this exhibit:

- UEC: The amount of energy used by each end use per unit (a "unit" in the industrial sector is based on production capacity. Please see Section 6.2.3 for a discussion of a "unit" in the industrial sector.
- Fuel Share: The percentage of the energy end use that is supplied by each fuel (in this case, natural gas).
- Saturation: The extent to which an end use is present in a region, rate class and segment. In the industrial sector, saturation is either 100% or 0% because end uses are either used in a segment or are not.

Average annual gas consumption per unit would be calculated by multiplying these three variables. Similar to the UEC values presented in Section 6.2.3, only the end uses that are present in the segment and region are included.

Exhibit 111 – 2019 Average Annual Gas Use per Account by End Use, Pulp & Paper - Kraft Account in Northern British Columbia

	UEC	Fuel Share	Saturation	Average Annual Gas Use (GJ/Yr)
Space Heating	0.03	80%	100%	0.03
Direct-fired Heating	0.38	100%	100%	0.38
Kilns	0.10	93%	100%	0.10
Product Drying	0.03	93%	100%	0.02
Process Boilers	0.51	93%	100%	0.47
TOTAL				1.00[44]

44 Recall that "units" in the industrial sector is production capacity. In the base year, by definition, one industrial building unit uses 1 GJ, because base year consumption is the 'unit' for the base year.

6.3 Reference Case Natural Gas Use

This section profiles the reference case forecast (2020-2040) natural gas consumption for the industrial sector. The industrial production forecast, developed by FEI through survey of industrial customers, covers from 2020 to 2025. The first five-year period of the reference case forecast (2020 to 2025) incorporates how individual respondents expect their volume to change, and this five-year trend is extrapolated beyond 2025.

Reference case industrial natural gas consumption is presented by region in Exhibit 112, by segment in Exhibit 113, and by end use in Exhibit 114. These exhibits illustrate the following trends in consumption over the reference case:

- Overall gas consumption is forecasted to increase by approximately 7% between 2020 and 2040, but this increase is not evenly split between the regions, segments, or end uses. Some regions, segments, and end uses are forecasted to experience significant increases, while others are forecasted to remain stable or decrease.
- As shown in Exhibit 112, natural gas use in the Whistler region is forecasted to increase by 98%, while gas use in the Northern BC and Vancouver Island regions will remain relatively flat or decrease (1% decrease and 1% increase, respectively).
- As shown in Exhibit 113, natural gas use in the fabricated metal segment is forecasted increase by 39%, while gas use is forecasted to decrease in the non-metallic mineral and the pulp & paper – kraft segments (6% and 2% decrease, respectively).
- As shown in Exhibit 114, natural gas use in the heat-treating end use is forecasted increase by 28%, while gas use is forecasted to decrease by 4% in the kiln end use.
- Despite the differences in forecasted natural gas use, the same regions, segments and end uses as in the base year are expected to account for the largest shares of natural gas use in the industrial sector.

Exhibit 112 – 2020 vs 2040 Industrial Gas Consumption (GJ) by Region

Region	2020	2040	Change
Lower Mainland x Van	28,463K	31,860K	12%
Southern Interior	19,039K	20,907K	10%
Northern BC	18,892K	18,647K	-1%
Vancouver Island	8,235K	8,308K	1%
City of Vancouver	5,701K	6,511K	14%
Whistler	7K	13K	98%
Total	**80,335K**	**86,246K**	**7%**

Exhibit 113 – 2020 vs 2040 Industrial Gas Consumption (GJ) by Segment

Segment	2020	2040	Change
Pulp & Paper - Kraft	23,871K	23,487K	-2%
Agriculture	11,527K	13,858K	20%
Wood Products	9,960K	10,288K	3%
Mining	8,058K	8,861K	10%
Manufacturing	4,577K	5,418K	18%
Food & Beverage	4,696K	5,247K	12%
Non-metallic Mineral	5,132K	4,819K	-6%
District Energy	4,044K	4,657K	15%
Chemical	3,798K	4,578K	21%
Pulp & Paper - TMP	3,316K	3,341K	1%
Utilities	780K	890K	14%
Fabricated Metal	577K	802K	39%
Total	**80,335K**	**86,246K**	**7%**

Exhibit 114 – 2020 vs 2040 Industrial Gas Consumption (GJ) by End Use

Parent End Use	2020	2040	Change
Process Boilers	30,437K	32,987K	8%
Product Drying	19,680K	20,658K	5%
Direct-fired Heating	12,556K	12,760K	2%
Space Heating	6,179K	7,184K	16%
Kilns	3,864K	3,698K	-4%
Direct Gas Use	1,458K	1,778K	22%
Petrochem Refining	1,311K	1,606K	23%
Other	1,306K	1,548K	19%
Ovens	1,169K	1,250K	7%
Water Heaters	904K	1,004K	11%
On-Site Generation	780K	890K	14%
Heat Treating	691K	883K	28%
Total	**80,335K**	**86,246K**	**7%**

6.4 Measure Assessment

6.4.1 List of Measures

The list of industrial measures is presented in Exhibit 115 by industrial end uses.

Please see the MS Excel file entitled "Ind_Measure Analysis Workbook" for a description of each measure and a full analysis.

Measures were classified in four measure type categories:

- Building Envelope
- Equipment
- Controls
- Energy Management (including behavioral measures)

Exhibit 115 – Industrial Sector Conservation and Energy Management Measures

Process Boiler	Space Heating
Air Compressor Heat Recovery Boiler Right-Sizing Condensing Boiler Direct Contact Hot Water Heater Economizer Heat Recovery Systems Improved Condensate Return Pipe Insulation Process Boiler Load Control Process Boiler O_2 Control Steam to Hot Water Conversion (District Energy) Steam Traps Tank Insulation Venturi Steam Traps	Advanced Thermostat Air Comp Heat Recovery Air Curtains Condensing Make Up Air Units Condensing Unit Heaters Destratification Fans HE Rooftop Unit Controls HE Rooftop Units HVAC Boiler Tune-up HVAC Ventilation Optimization Loading Dock Seals Solar Walls
Other	**Greenhouse**
Combustion Testing Energy Management High-Efficiency Burners High-Efficiency Dryers High-Efficiency Furnaces High-Efficiency Kilns High-Efficiency Ovens Process Control Regenerative Catalytic Oxidizer Veneer Dryers Warm Mix Asphalt	Greenhouse Curtains Greenhouse Envelope Integrated Greenhouse Controls

6.4.2 Results

Exhibit 116 shows measure-level results for the industrial sector in order of decreasing cost effectiveness. Measures were assessed based on their replacement type: **retrofit** (immediate replacement at full cost) or **replace on burnout** (end of life replacement at incremental cost).

The TRC and MTRC are presented at the measure-level and exclude program costs and free ridership.

Some key findings of the measure assessment for the industrial sector include:

- Of the 39 measures included in the assessment, 34 pass the TRC screen and 38 pass the MTRC screen.
- The most attractive equipment replacement measure is boiler right-sizing, with a TRC of 167.7. This measure involves replacing an oversized boiler at equipment end of life, with a smaller, right-sized boiler. The measure TRC is exceptionally high because the incremental measure cost is either negligible or may even be negative in some cases.
- The most attractive energy management measure is process control, which has the potential for significant energy savings at a moderate capital cost.
- The most attractive building envelope measure is the greenhouse envelope measure (#7), which, as shown in Exhibit 115, only applies to the greenhouse end use. The most attractive building envelope measure that applies to the space heating end use is the air curtain measure (#14).
- Several measures that were included on the original list of measures were excluded from the analysis or modified. Please see the file called "Measure List Modifications.xlsx" for a list of changes.

Exhibit 116 – Industrial Sector Measures with Average TRC and MTRC Results

#	Measure	Measure Type	Replacement Type	TRC	MTRC
1	Boiler Right-Sizing[45]	Equipment	ROB	167.7	791.5
2	Process Control	Energy Management	RET	50.4	258.4
3	Furnace RET	Equipment	RET	11.7	56.6
4	Combustion Testing	Energy Management	RET	10.3	54.6
5	Energy Management	Energy Management	RET	10	54.3
6	Tank Insulation	Equipment	RET	10	50.9
7	Greenhouse Envelope	Building Envelope	RET	9.3	47.6
8	Regenerative Catalytic Oxidizer	Energy Management	RET	7.9	39.3

45 For the boiler right-sizing measure the incremental cost is negligible. A cost of $1,000 was used for this measure for the purposes of calculating the payback and TRC, to compare with other measures.

9	Integrated Greenhouse Environmental Controls	Energy Management	RET	6.8	34
10	Replace Steam Traps	Equipment	RET	5.3	28.1
11	Condensing Boiler	Equipment	ROB	5.7	26.9
12	Pipe Insulation	Energy Management	RET	4.8	24
13	High Efficiency Dryers	Equipment	ROB	4.7	22.9
14	Air Curtain	Building Envelope	RET	4.1	20.5
15	Boiler Tune-Up	Energy Management	RET	3.8	20.3
16	Condensing MAU Unit	Equipment	ROB	4.1	19.7
17	High Efficiency Ovens	Equipment	ROB	3.8	18.9
18	High Efficiency Burners	Equipment	RET	3.8	18.9
19	Direct Contact Hot Water Heater	Equipment	ROB	2.9	14
20	Process Boiler Load Control	Controls	RET	2.7	13.7
21	Heat Recovery Systems	Energy Management	RET	2.5	12.4
22	HVAC Ventilation Optimization	Energy Management	RET	2.3	12.4
23	Advanced Veneer Dryer	Equipment	ROB	2.3	11.3
24	Condensing Unit Heaters	Equipment	ROB	2.1	10.5
25	Improved Condensate Return (Retrofit)	Energy Management	RET	2	10
26	Venturi Steam Trap	Equipment	RET	1.8	9.3
27	Air Compressor Heat Recovery (Process Heating)	Equipment	ROB	1.7	8.7
28	Economizer	Equipment	RET	1.7	8.5
29	Advanced Thermostats	Energy Management	RET	2	7.4
30	Greenhouse Curtains	Building Envelope	RET	1.4	7.4
31	Air Compressor Heat Recovery (Space Heating)	Equipment	ROB	1.5	7.2
32	Solar Wall	Energy Management	RET	1.4	6.4
33	HVAC Boiler Tune Up	Energy Management	RET	1.1	6.1
34	Loading Dock Seals	Building Envelope	RET	1.2	5.9
35	High Efficiency Kilns	Equipment	ROB	0.9	4.3
36	High Efficiency RTU Controls	Energy Management	RET	0.9	3.9
37	Destratification Fan	Energy Management	RET	0.7	3.3
38	Steam to Hot Water Conversion (District Energy)	Energy Management	RET	0.5	2.5
39	Warm Mix Asphalt	Energy Management	ROB	0.1	0.5

6.5 Technical Potential

This section provides an overview of the technical potential savings results for the industrial sector. Overall results are presented below, followed by measure level results and supply curves for the TRC and MTRC results.

As shown in Exhibit 117, the majority of the industrial technical potential (15 PJ) would be available in 2021 and would increase slowly until reaching 19 PJ in 2040, indicating most of the available potential would be from retrofit measures as opposed to replace on burnout measures. The forecasted industrial natural gas consumption for the industrial sector is included for reference.

Exhibit 117 – Industrial Technical Potential Savings (GJ)

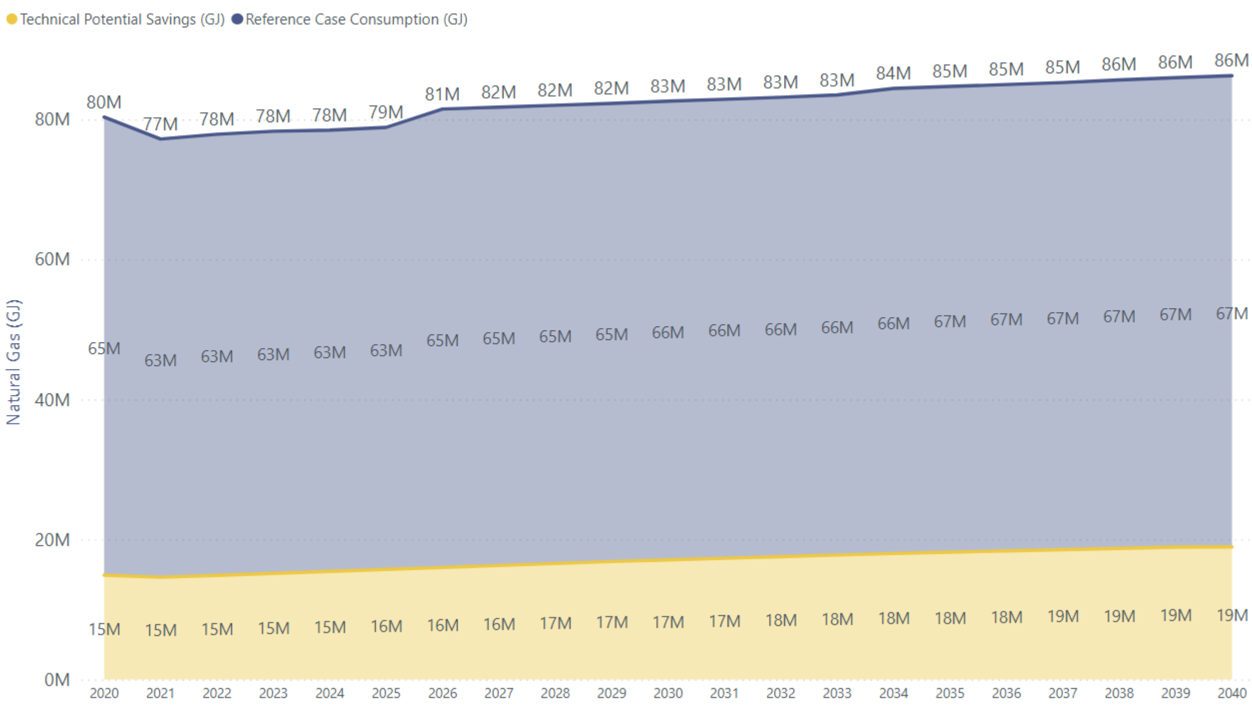
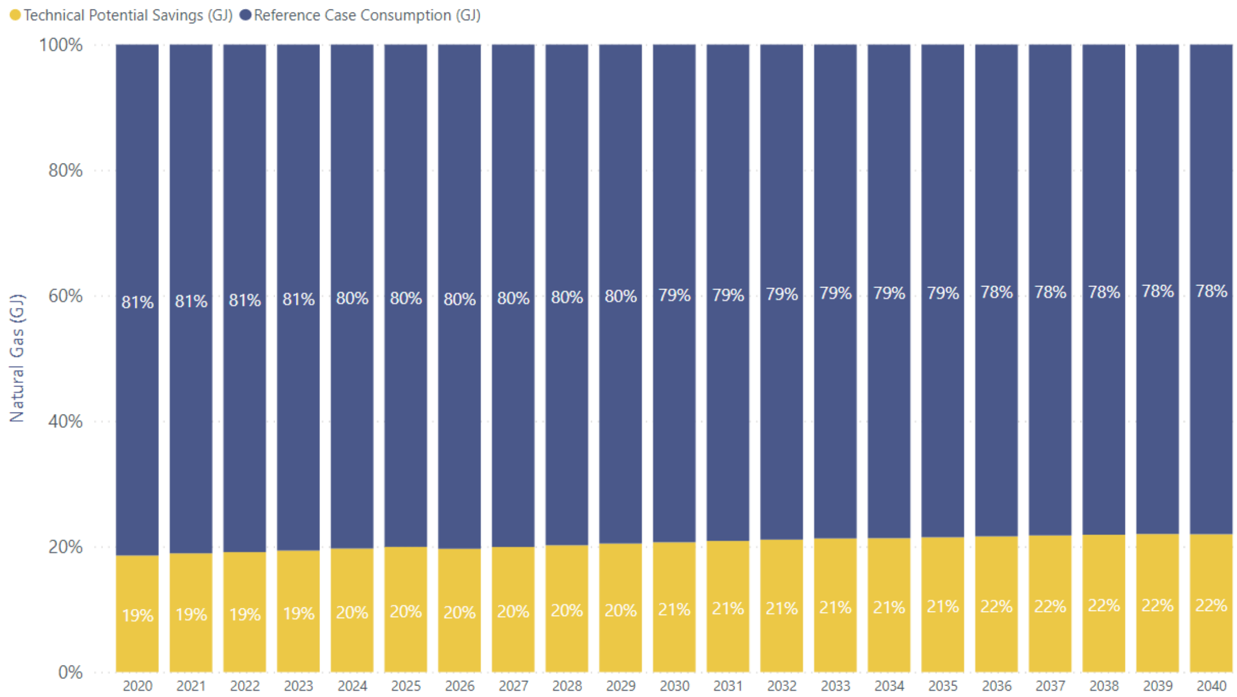


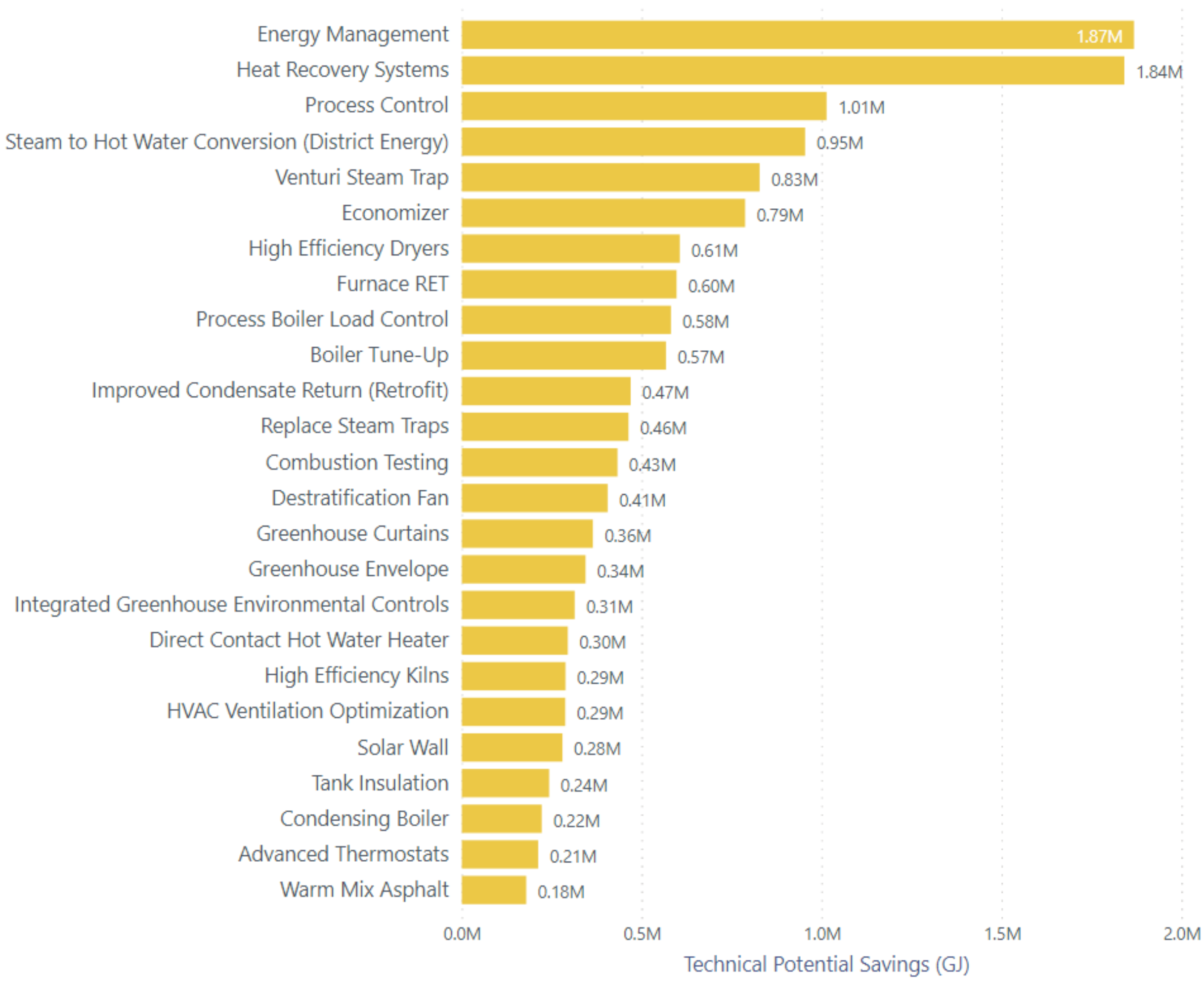
Exhibit 118 – Technical Potential Savings as a Percent of Industrial Reference Case Consumption (%)



As shown in Exhibit 118, the technical potential savings is about 19% of industrial reference case consumption in 2021 and increases to 22% by 2040, further indicating that most of the available potential would be from retrofit measures as opposed to replace on burnout measures.

The technical potential savings in 2025 broken down by measure (only the top 25 measures are shown) are presented in Exhibit 119. The top three measures (energy management, heat recovery systems, and process control) are expected to contribute substantially to technical potential savings (approximately 1.9 PJ, 1.8 PJ, and 1 PJ by 2025). As was shown in Exhibit 116, all three measures pass the TRC test, so they will also be expected to contribute to economic potential savings, as described in the following section. From the five measures that pass the MTRC but fail the TRC, Steam to Hot Water Conversion is the only one that has a large technical potential (#4 on the list below).

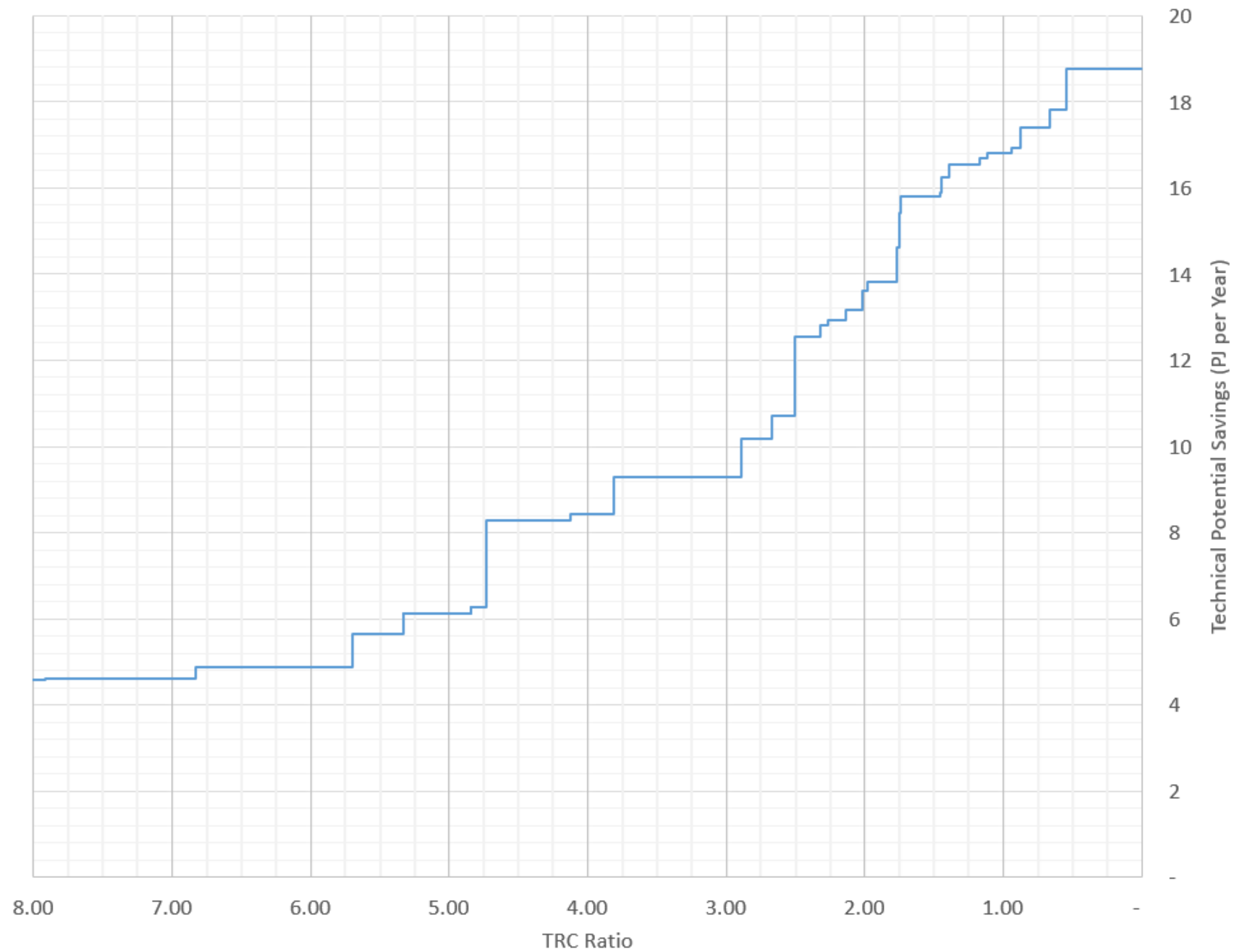
Exhibit 119 – Technical Potential – Top 25 Industrial Measures in 2025 (GJ)



The cumulative industrial sector technical potential savings in 2040 are presented in Exhibit 120 as a supply curve, with measures ordered by decreasing TRC ratio from left to right.

As shown, roughly 90% (17 out of 19 PJ) of the industrial sector technical potential savings by 2040 come from measures with a TRC of 1.0 or higher. Approximately 5 PJ of savings come from measures with a TRC ratio of greater than 8. These are shown in aggregate.

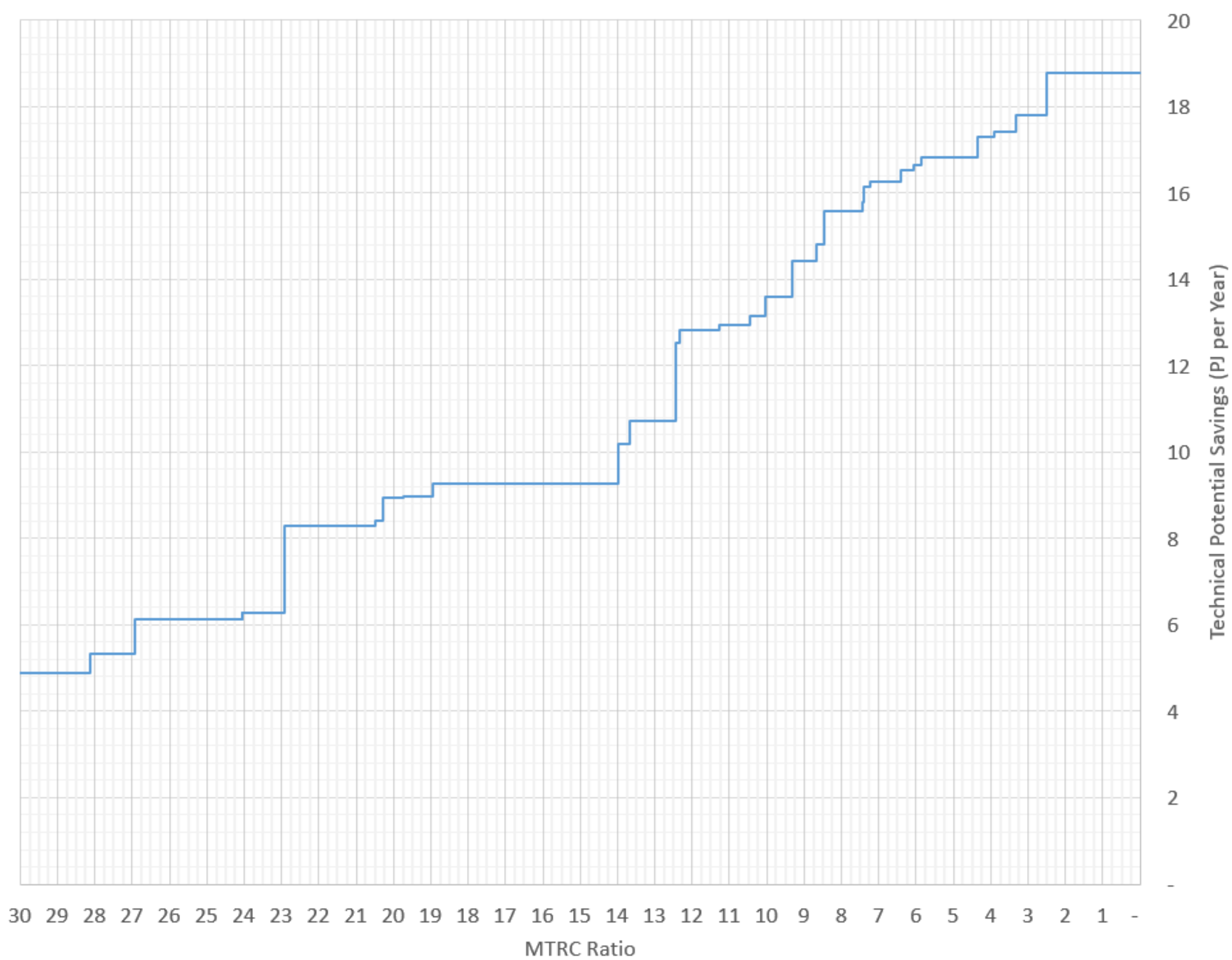
Exhibit 120 – Industrial Sector: Technical Potential Supply Curve, 2040 – TRC



Similar to Exhibit 120, the cumulative Industrial sector technical potential savings in 2040 are presented in Exhibit 121 as a supply curve, with measures ordered by decreasing MTRC ratio from left to right.

As shown, all of the industrial sector technical potential savings (approximately 19 PJ) by 2040, comes from measures with an MTRC of 1.0 or higher. Approximately 5 PJ of savings come from measures with an MTRC ratio of greater than 30. These are shown in aggregate.

Exhibit 121 – Industrial Sector: Technical Potential Supply Curve, 2040 – MTRC

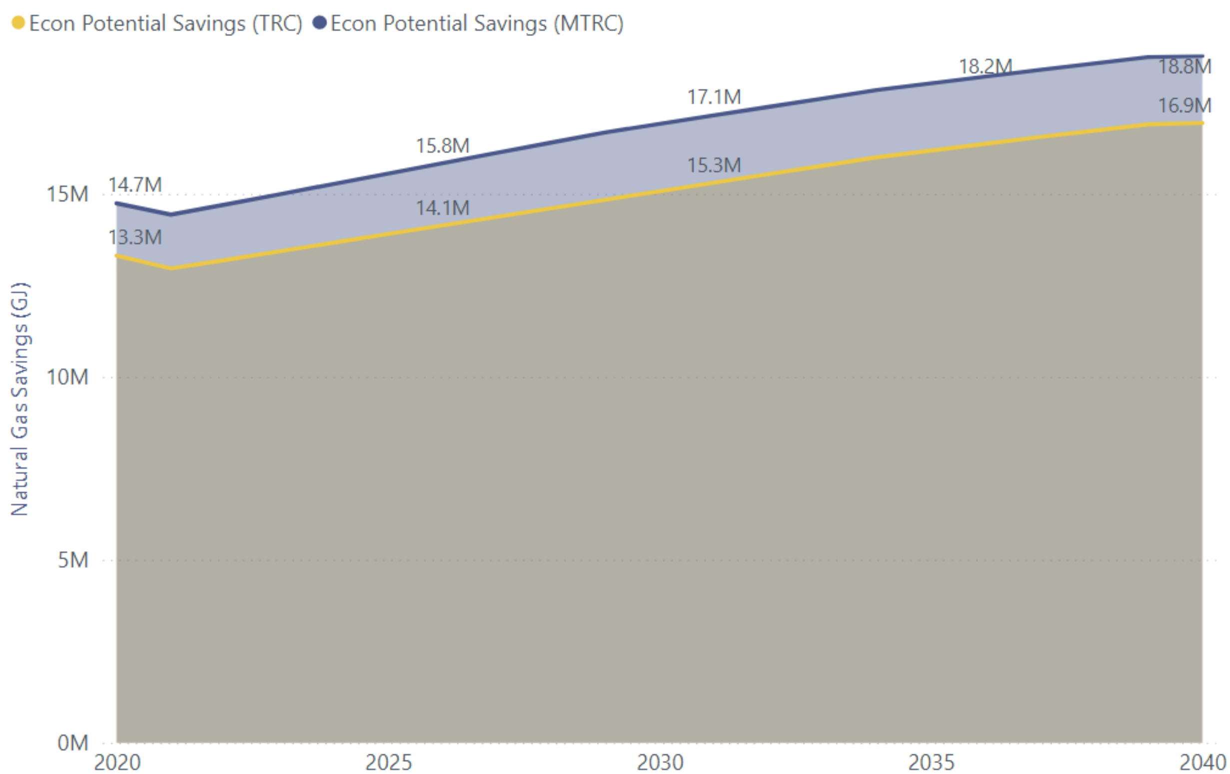


6.6 Economic Potential

This section provides an overview of the economic potential savings results. As was noted in section 6.3.2, 34 of the 39 measures examined have a TRC ratio over 1.0, so the difference between TRC and MTRC economic potential results for the Industrial sector is small.

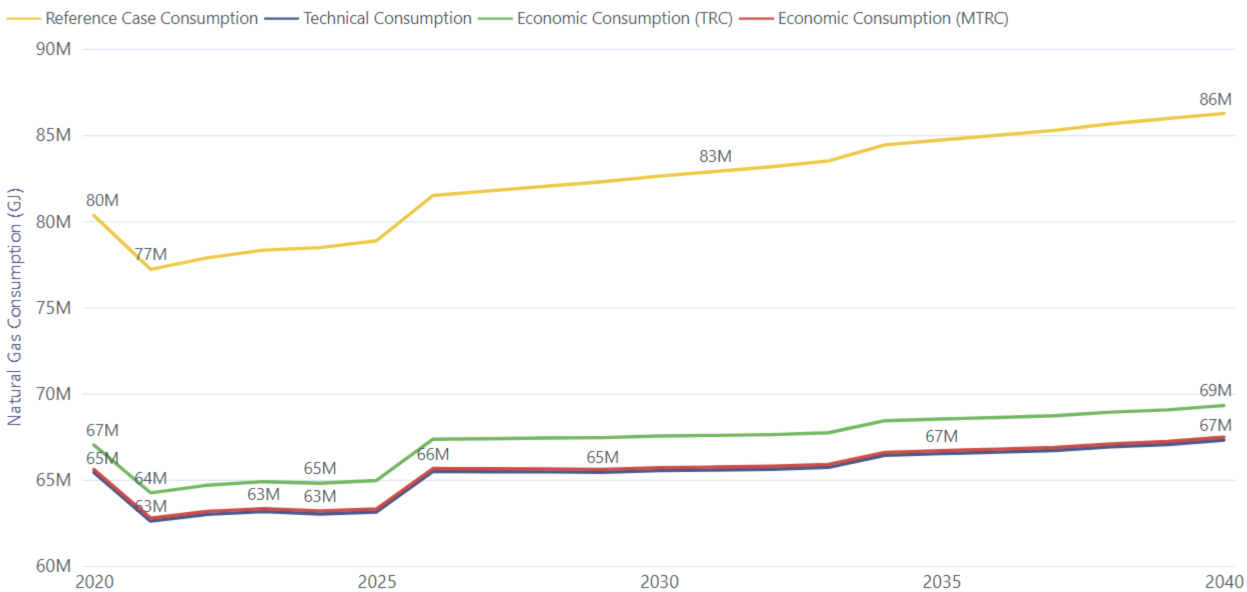
The industrial sector economic potential savings with a TRC screen and with an MTRC screen are shown in Exhibit 122. Although only four measures fail the TRC but pass the MTRC, the economic potential savings with an MTRC screen are roughly 1.7 PJ higher than with the TRC screen in 2025. This is mainly because one of those measures, steam to hot water conversion (district energy), represents the fifth largest technical potential (1 PJ) in 2025, as shown in Exhibit 119. Another way to look at it that the 92% of the MTRC economic potential comes from measures that pass the TRC as well.

Exhibit 122 – Economic Potential Savings (GJ) - Industrial, TRC and MTRC Screen



The forecasted gas consumption under the technical potential, economic potential with a TRC screen, economic potential with an MTRC screen, and reference case scenarios for the industrial sector are shown in Exhibit 123. The rapid decrease in technical and economic potential consumption in 2021 is a result of the implementation of the retrofit measures. The rest of the potential curve follows the shape of the reference case curve, as the replace on burnout measures are implemented at equipment end of life.

Exhibit 123 – Economic Potential Consumption (GJ) Forecasts – Industrial, TRC and MTRC



Results by Region

The economic potential savings in 2025 are presented by region in Exhibit 124 (TRC) and Exhibit 125 (MTRC). The highest level of economic potential savings (21% or 23% depending on the economic screen) is estimated to occur in the Lower Mainland outside of the City of Vancouver.

Exhibit 124 – Economic Potential Savings by Region in 2025 – Industrial, TRC

Region	Ref Case Consumption (GJ)	Economic Potential Savings (GJ)	% of Consumption
Lower Mainland x Van	28,893K	6,029K	21%
Southern Interior	19,995K	2,936K	15%
Northern BC	15,774K	2,793K	18%
Vancouver Island	8,407K	1,669K	20%
City of Vancouver	5,788K	477K	8%
Whistler	7K	0K	1%
Total	**78,864K**	**13,904K**	**18%**

Exhibit 125 – Economic Potential Savings by Region in 2025 – Industrial, MTRC

Region	Ref Case Consumption (GJ)	Economic Potential Savings (GJ)	% of Consumption
Lower Mainland x Van	28,893K	6,576K	23%
Southern Interior	19,995K	3,056K	15%
Northern BC	15,774K	2,887K	18%
Vancouver Island	8,407K	1,698K	20%
City of Vancouver	5,788K	1,339K	23%
Whistler	7K	2K	37%
Total	**78,864K**	**15,558K**	**20%**

Results by Segment

The economic potential savings in 2025 are presented by segment in Exhibit 126 (TRC) and Exhibit 127 (MTRC). The highest percentages of economic potential savings are estimated to occur in the agriculture, food & beverage, and fabricated metals segments. The largest absolute economic potential savings are estimated to occur in the pulp & paper – kraft segment.

Exhibit 126 – Economic Potential Savings by Segment in 2025 – Industrial, TRC

Segment	Ref Case Consumption (GJ)	Economic Potential Savings (GJ)	% of Consumption
Pulp & Paper - Kraft	20,542K	4,153K	20%
Agriculture	11,951K	3,503K	29%
Food & Beverage	4,966K	1,368K	28%
Mining	9,044K	1,121K	12%
Wood Products	10,195K	988K	10%
Manufacturing	4,877K	917K	19%
Pulp & Paper - TMP	3,291K	764K	23%
Non-metallic Mineral	4,856K	563K	12%
Chemical	3,627K	350K	10%
Fabricated Metal	643K	176K	27%
District Energy	4,029K	0K	0%
Utilities	842K	0K	0%
Total	**78,864K**	**13,904K**	**18%**

Exhibit 127 – Economic Potential Savings by Segment in 2025 – Industrial, MTRC

Segment	Ref Case Consumption (GJ)	Economic Potential Savings (GJ)	% of Consumption
Pulp & Paper - Kraft	20,542K	4,300K	21%
Agriculture	11,951K	3,610K	30%
Food & Beverage	4,966K	1,408K	28%
Mining	9,044K	1,137K	13%
Manufacturing	4,877K	1,086K	22%
Wood Products	10,195K	1,008K	10%
District Energy	4,029K	954K	24%
Pulp & Paper - TMP	3,291K	770K	23%
Non-metallic Mineral	4,856K	740K	15%
Chemical	3,627K	359K	10%
Fabricated Metal	643K	185K	29%
Utilities	842K	0K	0%
Total	**78,864K**	**15,558K**	**20%**

Results by End Use

The economic potential savings in 2025 are presented by end use in Exhibit 128 (TRC) and Exhibit 129 (MTRC). The highest percentages of economic potential savings are estimated to occur in the process boilers, space heating, and heat treating end uses.

Approximately two-thirds of the savings are attributable to the largest end uses: process boilers (distributed across all segments except utilities).

Exhibit 128 – Economic Potential Savings by End Use in 2025 – Industrial, TRC

Parent End Use	Ref Case Consumption (GJ)	Economic Potential Savings (GJ)	% of Consumption
Process Boilers	29,383K	8,353K	28%
Product Drying	20,665K	1,951K	9%
Space Heating	6,400K	1,540K	24%
Direct-fired Heating	11,270K	1,348K	12%
Kilns	3,428K	241K	7%
Heat Treating	755K	158K	21%
Ovens	1,204K	155K	13%
Petrochem Refining	1,219K	86K	7%
Other	1,382K	47K	3%
Water Heaters	942K	25K	3%
Direct Gas Use	1,376K	0K	0%
On-Site Generation	842K	0K	0%
Total	**78,864K**	**13,904K**	**18%**

Exhibit 129 – Economic Potential Savings by End Use in 2025 – Industrial, MTRC

Parent End Use	Ref Case Consumption (GJ)	Economic Potential Savings (GJ)	% of Consumption
Process Boilers	29,383K	9,307K	32%
Space Heating	6,400K	1,959K	31%
Product Drying	20,665K	1,951K	9%
Direct-fired Heating	11,270K	1,348K	12%
Kilns	3,428K	521K	15%
Heat Treating	755K	158K	21%
Ovens	1,204K	155K	13%
Petrochem Refining	1,219K	86K	7%
Other	1,382K	47K	3%
Water Heaters	942K	25K	3%
Direct Gas Use	1,376K	0K	0%
On-Site Generation	842K	0K	0%
Total	**78,864K**	**15,558K**	**20%**

The TRC and MTRC economic potential savings for 2040 are presented by end use in Exhibit 130. As only four measures pass the MTRC but not the TRC screen, most savings totals are the same, except for the process boilers end use (954 TJ higher in MTRC), the kilns end use (467 TJ higher in MTRC), and the space heating end use (416 TJ higher in MTRC).

Exhibit 130 – Economic Potential Savings by End Use in 2040 – Industrial, TRC and MTRC

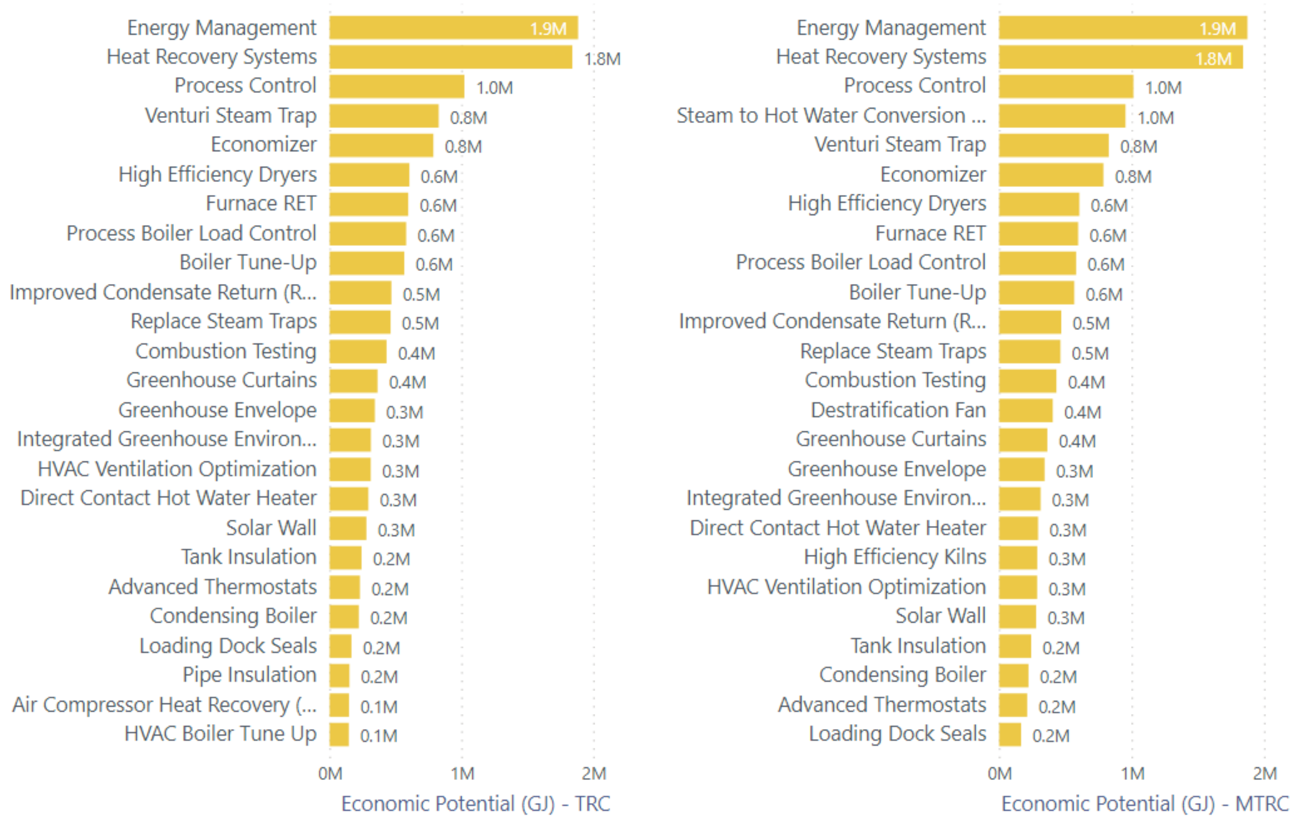
Parent End Use	Economic Savings (GJ) - TRC	Economic Savings (GJ) - MTRC	Difference (GJ)
Process Boilers	9,715K	10,669K	954K
Kilns	241K	708K	467K
Space Heating	1,712K	2,127K	416K
Direct Gas Use	0K	0K	0K
Direct-fired Heating	1,348K	1,348K	0K
Heat Treating	158K	158K	0K
On-Site Generation	0K	0K	0K
Other	47K	47K	0K
Ovens	269K	269K	0K
Petrochem Refining	86K	86K	0K
Product Drying	3,338K	3,338K	0K
Water Heaters	25K	25K	0K
Total	**16,938K**	**18,775K**	**1,836K**

Results by Measure

The economic potential savings in 2025 broken down by measure (only the top 25 measures are shown) are shown in Exhibit 131. The top measures in the TRC economic potential are shown on the left and the top measures in the MTRC scenario are shown on the right. As in the technical potential scenario, the top three measures (energy management, heat recovery systems, and process control) are expected to contribute substantially to economic potential savings (approximately 1.9 PJ, 1.8 PJ, and 1 PJ by 2025).

The main difference between the two lists is the large contribution of steam to hot water conversion (district energy) measure in the MTRC economic potential. Destratification fans and high efficiency kilns are the other two MTRC-only measures that appear on the list on the right.

Exhibit 131 – Economic Potential (TRC on Left, MTRC on Right) - Top 25 Industrial Measures in 2025 (GJ)



6.7 Market Potential

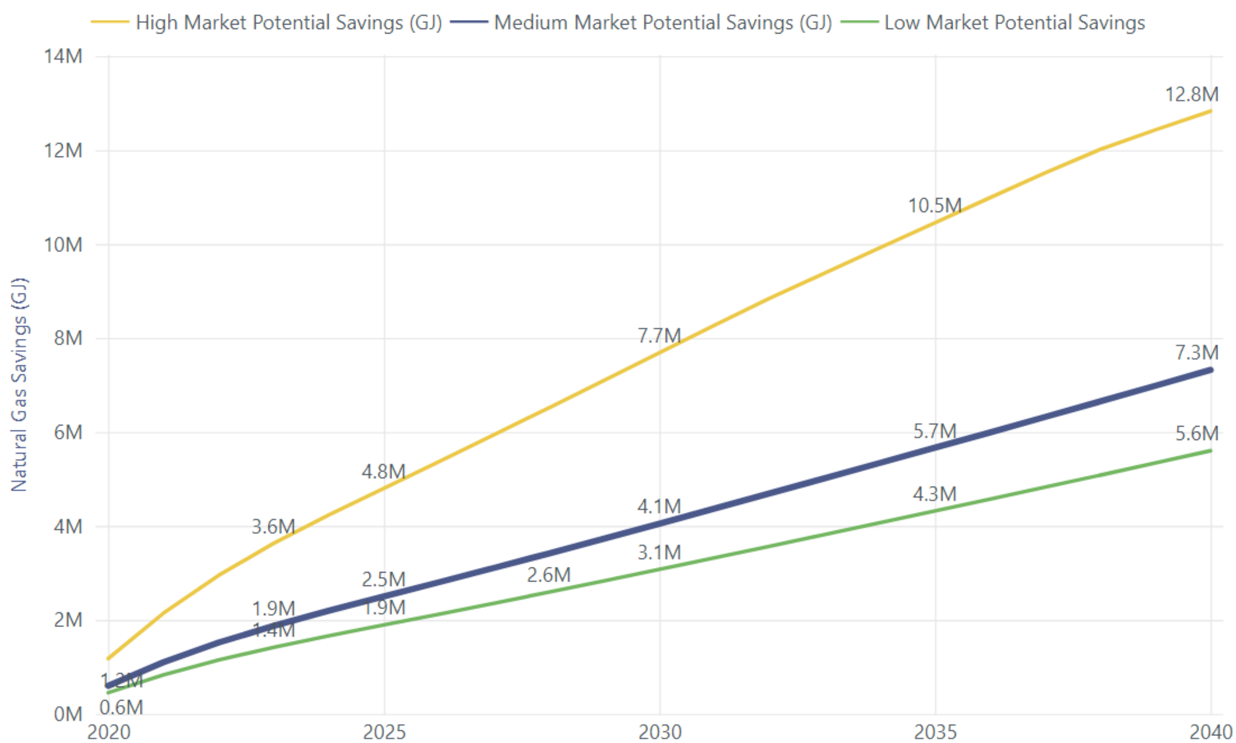
This section provides an overview of the low, medium, and high market potential results for the industrial sector.

Low, medium, and high scenarios assume that measure incentive levels will be 25%, 50% and 100% of incremental costs, respectively. For example, assume that a high-efficiency boiler may cost $10,000 more than a standard boiler, meaning the boiler would have an incremental cost of $10,000. In the medium scenario, this measure's hypothetical incentive from FortisBC would be $5,000. The other $5,000 would be paid by the end user. In all scenarios, the non-incentive program costs are assumed to be 15% of the incentive cost. In the example above, FortisBC's non-incentive spending would be $750. FortisBC's total cost for providing the measure to an end user would be $5,750.

The market potential savings results, with a TRC screen and with an MTRC screen, are shown in Exhibit 132 and Exhibit 133, respectively. These graphs are very similar because of the 39 measures included in the assessment, 34 pass the TRC screen and 38 pass the MTRC screen.

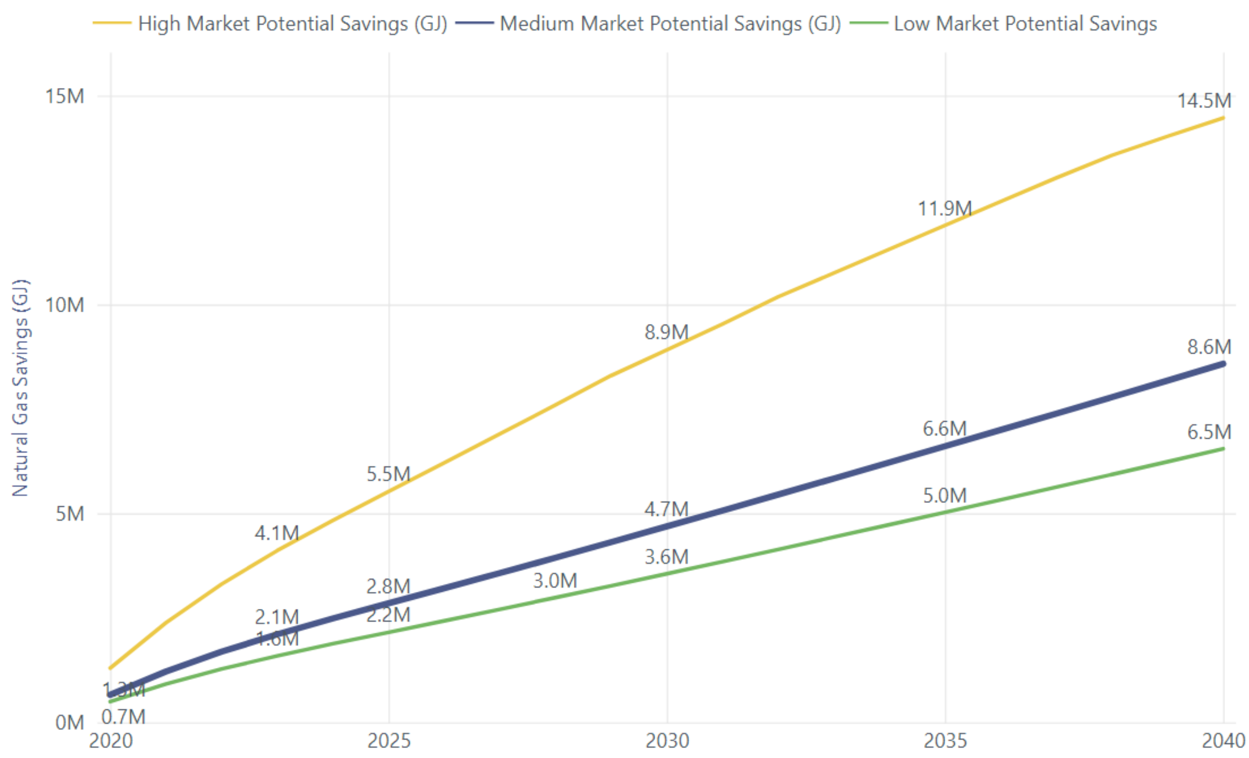
By 2040, the industrial low, medium, and high market TRC potential savings are estimated to be 5.6 PJ, 7.3 PJ, and 12.8 PJ, respectively.

Exhibit 132 – Market Potential Savings (GJ) – Industrial, TRC



By 2040, the industrial low, medium, and high market MTRC potential savings are estimated to be 6.5 PJ, 8.6 PJ, and 14.5 PJ, respectively.

Exhibit 133 – Market Potential Savings (GJ) – Industrial, MTRC



The market potential consumption results, with a TRC screen and with an MTRC screen, are shown in Exhibit 134 and Exhibit 135 respectively. These graphs are very similar because of the 39 measures included in the assessment, 34 pass the TRC screen and 38 pass the MTRC screen.

By 2040, the industrial low, medium, and high market TRC potential consumption levels are estimated to be 81 PJ, 79 PJ, and 73 PJ, respectively, while reference consumption is forecasted to reach 86 PJ.

By 2040, the industrial low, medium, and high market MTRC potential consumption levels are estimated to be 80 PJ, 78 PJ, and 72 PJ, respectively, while reference consumption is forecasted to reach 86 PJ.

Exhibit 134 – Market Potential Consumption (GJ) Forecasts – Industrial, TRC

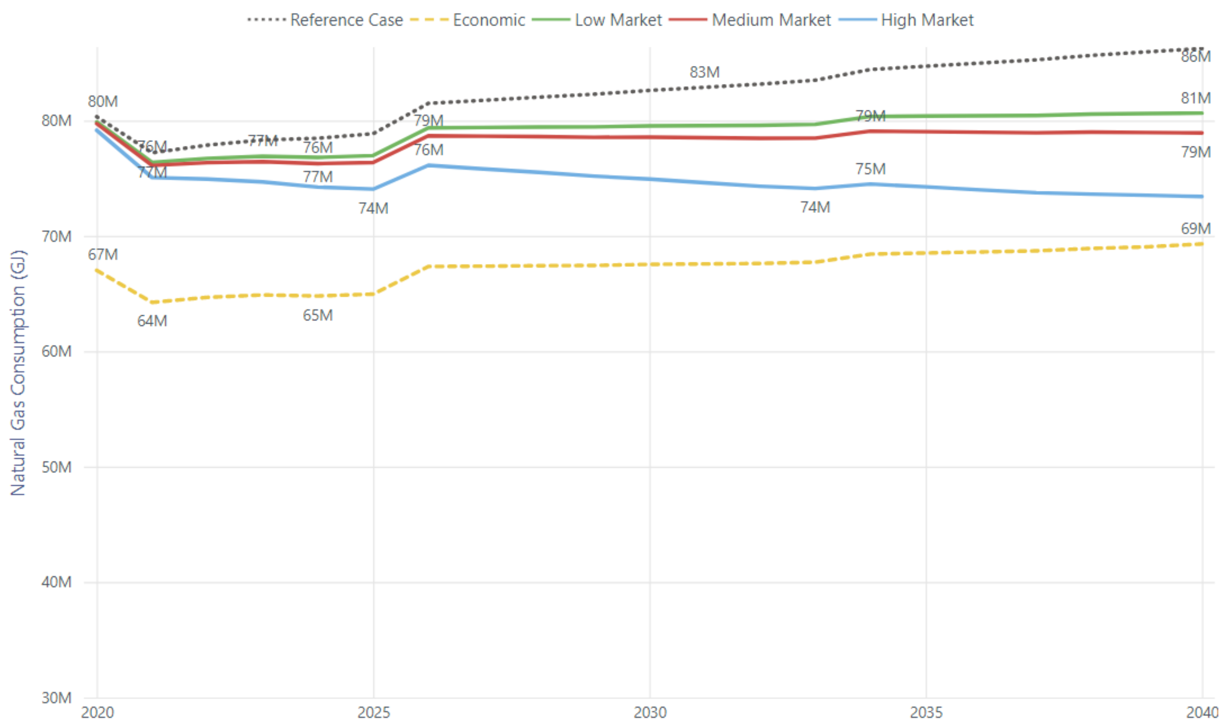
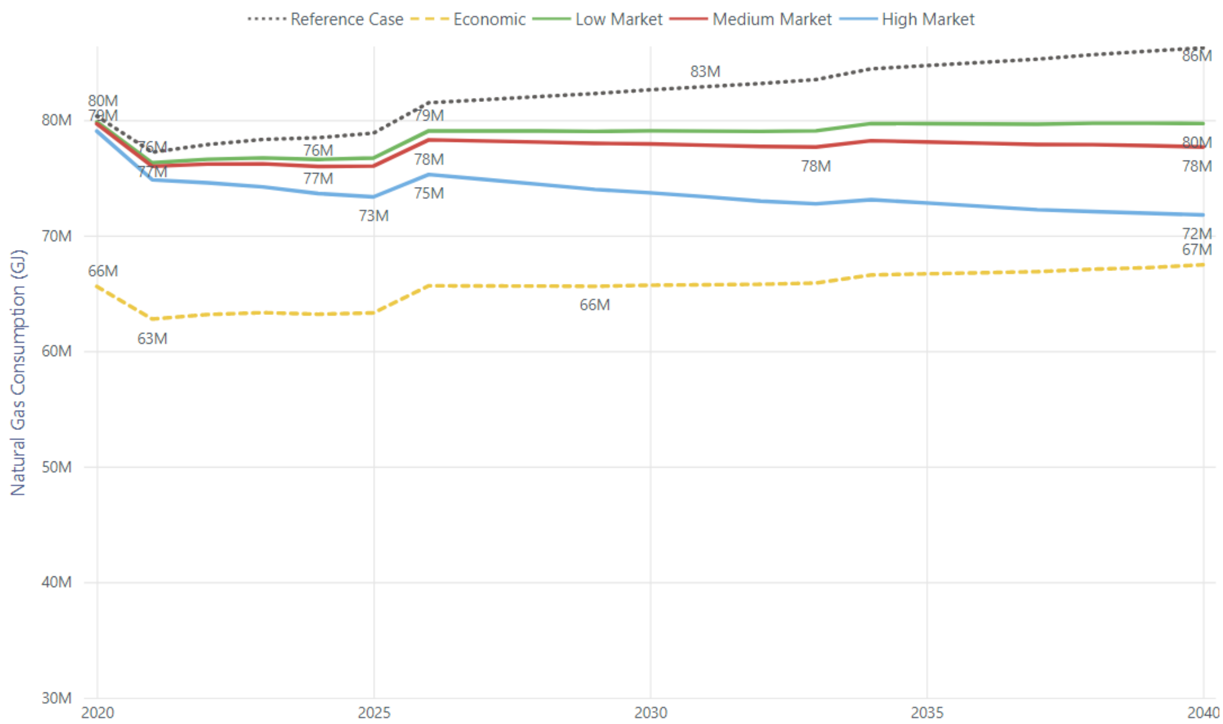


Exhibit 135 – Market Potential Consumption (GJ) Forecasts – Industrial, MTRC



The remainder of this section presents detailed results of the medium market potential scenario only. Similarly detailed results of the low and high market potential scenarios can be found on the Power BI dashboard and the Excel workbooks.

Results by Region

The medium market potential savings for 2025 are presented by region in Exhibit 136 (TRC) and Exhibit 137 (MTRC). TRC medium market potential savings for 2025 are estimated to be between 3% and 4% of reference case consumption in all regions, other than Whistler, where they are estimated to be less than 1%. MTRC medium market potential percentages are similar except in City of Vancouver (5%) and Whistler (11%).

Exhibit 136 – Medium Market Potential Savings by Region in 2025 – Industrial, TRC

Region	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Lower Mainland x Van	28,893K	1,108K	4%
Southern Interior	19,995K	535K	3%
Northern BC	15,774K	483K	3%
Vancouver Island	8,407K	299K	4%
City of Vancouver	5,788K	76K	1%
Whistler	7K	0K	0%
Total	**78,864K**	**2,501K**	**3%**

Exhibit 137 – Medium Market Potential Savings by Region in 2025 – Industrial, MTRC

Region	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Lower Mainland x Van	28,893K	1,186K	4%
Southern Interior	19,995K	547K	3%
Northern BC	15,774K	496K	3%
City of Vancouver	5,788K	317K	5%
Vancouver Island	8,407K	301K	4%
Whistler	7K	1K	11%
Total	**78,864K**	**2,848K**	**4%**

Results by Segment

The medium market potential savings for 2025 are presented by segment in Exhibit 138 (TRC) and Exhibit 139 (MTRC). In TRC medium market potential, the highest percentages savings are estimated to occur in the agriculture (5%) and fabricated metal segments (8%). The largest medium market potential savings (725 TJ) is estimated to occur in the pulp & paper – kraft segment. In MTRC medium market potential, the highest percentages savings are estimated to occur in the agriculture (5%), fabricated metal (8%) and district energy (7%) segments. The largest medium market potential savings (744 TJ) is still from the pulp & paper – kraft segment.

Exhibit 138 – Medium Market Potential Savings by Segment in 2025 – Industrial, TRC

Segment	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Pulp & Paper - Kraft	20,542K	725K	4%
Agriculture	11,951K	608K	5%
Food & Beverage	4,966K	220K	4%
Mining	9,044K	217K	2%
Wood Products	10,195K	206K	2%
Manufacturing	4,877K	158K	3%
Pulp & Paper - TMP	3,291K	134K	4%
Non-metallic Mineral	4,856K	112K	2%
Chemical	3,627K	71K	2%
Fabricated Metal	643K	50K	8%
District Energy	4,029K	0K	0%
Utilities	842K	0K	0%
Total	**78,864K**	**2,501K**	**3%**

Exhibit 139 – Medium Market Potential Savings by Segment in 2025 – Industrial, MTRC

Segment	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Pulp & Paper - Kraft	20,542K	744K	4%
Agriculture	11,951K	617K	5%
District Energy	4,029K	273K	7%
Food & Beverage	4,966K	223K	4%
Mining	9,044K	219K	2%
Wood Products	10,195K	208K	2%
Manufacturing	4,877K	171K	4%
Non-metallic Mineral	4,856K	137K	3%
Pulp & Paper - TMP	3,291K	134K	4%
Chemical	3,627K	72K	2%
Fabricated Metal	643K	51K	8%
Utilities	842K	0K	0%
Total	**78,864K**	**2,848K**	**4%**

Results by End Use

The medium market potential savings for 2025 are presented by end use in Exhibit 140 (TRC) and Exhibit 141 (MTRC). The highest percentages of economic potential savings are estimated to occur in the heat-treating end use (7% in both TRC and MTRC scenarios).

Under both economic screens, almost three quarters of savings are attributable to the Process Boilers end uses (1,500 TJ for TRC and 1,773 TJ for MTRC, distributed across all segments except utilities).

Exhibit 140 – Medium Market Potential Savings by End Use in 2025 – Industrial, TRC

Parent End Use	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Process Boilers	29,383K	1,500K	5%
Product Drying	20,665K	407K	2%
Direct-fired Heating	11,270K	231K	2%
Space Heating	6,400K	196K	3%
Heat Treating	755K	55K	7%
Kilns	3,428K	51K	1%
Ovens	1,204K	32K	3%
Petrochem Refining	1,219K	18K	1%
Other	1,382K	8K	1%
Water Heaters	942K	3K	0%
Direct Gas Use	1,376K	0K	0%
On-Site Generation	842K	0K	0%
Total	**78,864K**	**2,501K**	**3%**

Exhibit 141 – Medium Market Potential Savings by End Use in 2025 – Industrial, MTRC

Parent End Use	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Process Boilers	29,383K	1,773K	6%
Product Drying	20,665K	407K	2%
Direct-fired Heating	11,270K	231K	2%
Space Heating	6,400K	230K	4%
Kilns	3,428K	91K	3%
Heat Treating	755K	55K	7%
Ovens	1,204K	32K	3%
Petrochem Refining	1,219K	18K	1%
Other	1,382K	8K	1%
Water Heaters	942K	3K	0%
Direct Gas Use	1,376K	0K	0%
On-Site Generation	842K	0K	0%
Total	**78,864K**	**2,848K**	**4%**

The TRC and MTRC medium market potential savings for 2040 are presented by end use in Exhibit 142. As only four measures pass the MTRC but not the TRC screen, most savings totals are the same, except for the process boilers end use (954 TJ higher in MTRC), kilns end use (188 TJ higher in MTRC), and the space heating end use (117 TJ higher in MTRC).

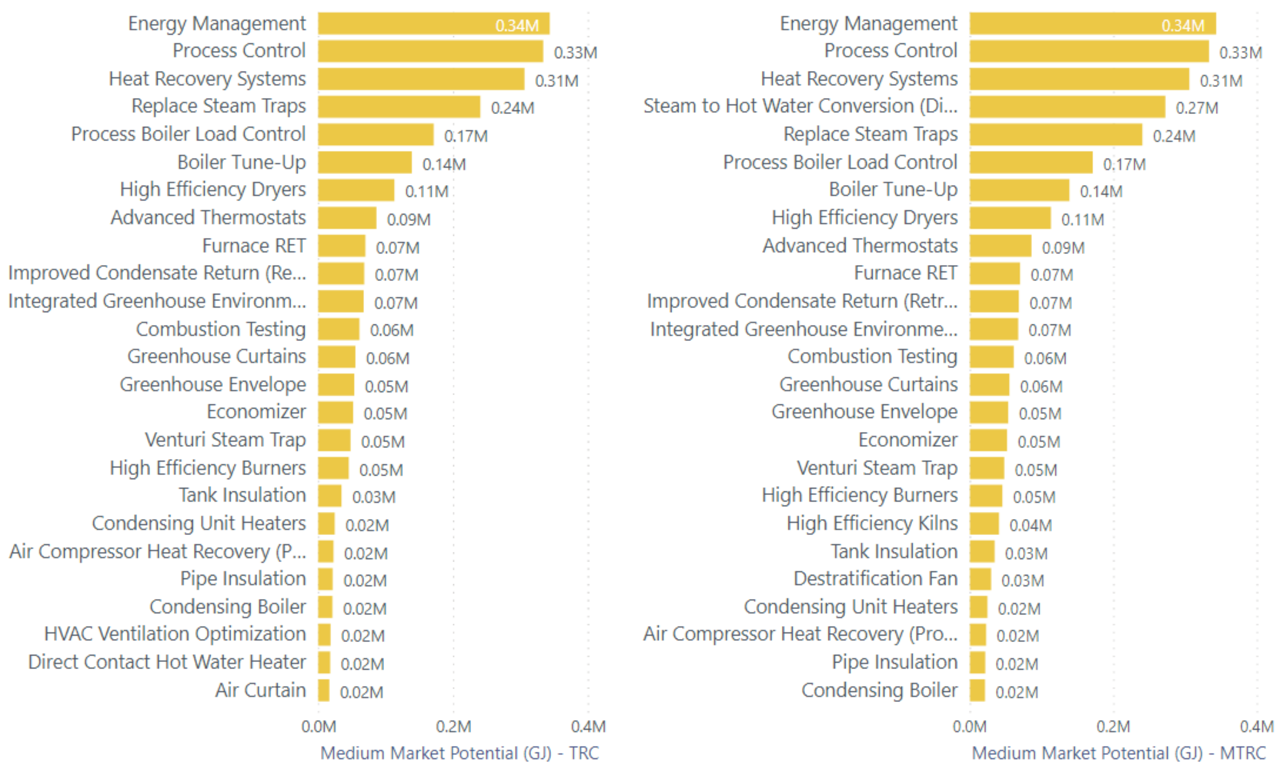
Exhibit 142 – Medium Market Potential Savings by End Use in 2040 – Industrial, TRC and MTRC

Parent End Use	Medium Potential Savings (GJ) - TRC	Medium Potential Savings (GJ) - MTRC	Difference (GJ)
Process Boilers	4,761K	5,716K	954K
Kilns	88K	276K	188K
Space Heating	522K	639K	117K
Direct Gas Use	0K	0K	0K
Direct-fired Heating	523K	523K	0K
Heat Treating	67K	67K	0K
On-Site Generation	0K	0K	0K
Other	15K	15K	0K
Ovens	118K	118K	0K
Petrochem Refining	31K	31K	0K
Product Drying	1,189K	1,189K	0K
Water Heaters	8K	8K	0K
Total	**7,323K**	**8,582K**	**1,259K**

Results by Measure

The total medium market potential savings (GJ per year) in 2025 of each of the top 25 industrial measures are shown in Exhibit 143, sorted by decreasing potential. As in the technical and economic potential scenarios, the top three measures (energy management, process control, and heat recovery systems) are expected to contribute a large portion of the medium market potential savings (approximately 0.34 PJ, 0.33 PJ, and 0.31 PJ in 2025).

Exhibit 143 – Medium Market Potential (TRC on Left, MTRC on Right) - Gas Savings from Top 25 Industrial Measures in 2025 (GJ)



6.7.1 Incentive and Non-Incentive Spending

The incentive and non-incentive spending required to achieve the medium and high market potential are shown in Exhibit 144 (TRC) and Exhibit 145 (MTRC). Medium and high market incentives are assumed to be 50% and 100% of measures' incremental costs, respectively. In both medium and high scenarios, non-incentive costs are estimated to be 15% of incentive costs. The tables also show the total as well as incremental (that is, savings from new measures installed in a year) savings every year.

Exhibit 144 – Medium and High Market Incentive Costs and Natural Gas Savings – Industrial, TRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$3.3M	$0.5M	$3.8M	600K	600K	$13.0M	$2.0M	$15.0M	1,178K	1,178K
2021	$3.3M	$0.5M	$3.8M	1,099K	499K	$12.9M	$1.9M	$14.8M	2,144K	966K
2022	$3.2M	$0.5M	$3.7M	1,518K	419K	$12.7M	$1.9M	$14.6M	2,949K	805K
2023	$3.1M	$0.5M	$3.5M	1,874K	356K	$12.1M	$1.8M	$13.9M	3,631K	681K
2024	$3.0M	$0.4M	$3.4M	2,196K	323K	$11.5M	$1.7M	$13.2M	4,234K	603K
2025	$2.9M	$0.4M	$3.3M	2,501K	305K	$11.3M	$1.7M	$13.0M	4,805K	572K
2026	$2.9M	$0.4M	$3.4M	2,804K	303K	$11.4M	$1.7M	$13.1M	5,373K	568K
2027	$3.0M	$0.5M	$3.5M	3,109K	305K	$11.6M	$1.7M	$13.4M	5,944K	571K
2028	$3.1M	$0.5M	$3.6M	3,419K	310K	$12.0M	$1.8M	$13.8M	6,520K	577K
2029	$3.2M	$0.5M	$3.7M	3,733K	315K	$12.5M	$1.9M	$14.4M	7,103K	583K
2030	$3.4M	$0.5M	$3.9M	4,051K	317K	$13.0M	$2.0M	$15.0M	7,689K	585K
2031	$3.5M	$0.5M	$4.0M	4,371K	320K	$13.4M	$2.0M	$15.4M	8,276K	587K
2032	$3.5M	$0.5M	$4.0M	4,694K	323K	$13.2M	$2.0M	$15.2M	8,848K	572K
2033	$3.5M	$0.5M	$4.0M	5,018K	324K	$12.7M	$1.9M	$14.6M	9,386K	538K
2034	$3.5M	$0.5M	$4.0M	5,343K	325K	$12.6M	$1.9M	$14.4M	9,924K	538K
2035	$3.5M	$0.5M	$4.0M	5,667K	324K	$12.4M	$1.9M	$14.3M	10,458K	534K
2036	$3.5M	$0.5M	$4.0M	5,994K	327K	$12.4M	$1.9M	$14.2M	10,990K	532K
2037	$3.5M	$0.5M	$4.0M	6,323K	329K	$12.4M	$1.9M	$14.2M	11,518K	528K
2038	$3.6M	$0.5M	$4.1M	6,653K	331K	$12.0M	$1.8M	$13.8M	12,020K	502K
2039	$3.6M	$0.5M	$4.1M	6,986K	333K	$9.1M	$1.4M	$10.5M	12,434K	414K
2040	$3.7M	$0.6M	$4.2M	7,323K	337K	$8.8M	$1.3M	$10.1M	12,833K	399K

Exhibit 145 – Medium and High Market Incentive Costs and Natural Gas Savings – Industrial, MTRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$8.8M	$1.3M	$10.2M	658K	658K	$35.2M	$5.3M	$40.5M	1,298K	1,298K
2021	$8.8M	$1.3M	$10.1M	1,215K	557K	$35.0M	$5.3M	$40.3M	2,384K	1,086K
2022	$8.8M	$1.3M	$10.1M	1,692K	477K	$34.9M	$5.2M	$40.1M	3,309K	925K
2023	$8.6M	$1.3M	$9.9M	2,105K	414K	$34.3M	$5.1M	$39.4M	4,110K	801K
2024	$8.5M	$1.3M	$9.8M	2,486K	381K	$33.7M	$5.1M	$38.8M	4,833K	723K
2025	$8.5M	$1.3M	$9.7M	2,848K	362K	$33.5M	$5.0M	$38.6M	5,524K	691K
2026	$8.5M	$1.3M	$9.7M	3,209K	361K	$33.6M	$5.0M	$38.7M	6,211K	687K
2027	$8.6M	$1.3M	$9.8M	3,572K	363K	$33.9M	$5.1M	$39.0M	6,901K	690K
2028	$8.7M	$1.3M	$10.0M	3,940K	367K	$34.3M	$5.1M	$39.4M	7,597K	696K
2029	$8.8M	$1.3M	$10.1M	4,313K	373K	$34.8M	$5.2M	$40.0M	8,299K	703K
2030	$8.9M	$1.3M	$10.3M	4,688K	376K	$15.2M	$2.3M	$17.5M	8,914K	615K
2031	$9.1M	$1.4M	$10.4M	5,067K	379K	$15.7M	$2.3M	$18.0M	9,532K	618K
2032	$9.1M	$1.4M	$10.5M	5,451K	383K	$25.7M	$3.9M	$29.5M	10,182K	649K
2033	$9.1M	$1.4M	$10.5M	5,835K	384K	$15.2M	$2.3M	$17.5M	10,753K	571K
2034	$9.1M	$1.4M	$10.5M	6,221K	386K	$15.1M	$2.3M	$17.4M	11,326K	572K
2035	$9.1M	$1.4M	$10.5M	6,607K	386K	$15.1M	$2.3M	$17.3M	11,895K	569K
2036	$9.2M	$1.4M	$10.5M	6,997K	389K	$15.1M	$2.3M	$17.4M	12,464K	569K
2037	$9.2M	$1.4M	$10.6M	7,389K	392K	$15.2M	$2.3M	$17.5M	13,030K	566K
2038	$9.3M	$1.4M	$10.7M	7,783K	394K	$14.9M	$2.2M	$17.1M	13,572K	542K
2039	$9.4M	$1.4M	$10.8M	8,180K	397K	$12.1M	$1.8M	$13.9M	14,026K	454K
2040	$9.5M	$1.4M	$10.9M	8,582K	402K	$11.9M	$1.8M	$13.7M	14,467K	441K

7 Portfolio Level Results

This section provides the results of the market potential savings on a portfolio (i.e. total of residential, commercial, and industrial sectors) level. It also presents estimated emissions reduction and job creation possibilities that can result from the energy savings in market potential scenarios.

7.1 Market Potential

Low, medium, and high scenarios assume that measure incentive levels will be 25%, 50%, and 100% of incremental costs, respectively. For example, assume that a high-efficiency furnace may cost $200 more than a standard furnace, meaning the furnace would have an incremental cost of $200. In the medium scenario, this measure's hypothetical incentive from FortisBC would be $100. The other $100 would be paid by the end user. In all scenarios, the non-incentive program costs are assumed to be 15% of the incentive cost. In the example above, FortisBC's non-incentive spending would be $15. FortisBC's total cost for providing the measure to an end user would be $115.

7.1.1 Results

The total market potential savings for all sectors, with a TRC screen and with an MTRC screen, are shown in Exhibit 146 and Exhibit 147, respectively. The medium market potential using the MTRC screen is 50% higher than the market potential using TRC screen.

By 2040, the total low, medium, and high market TRC potential savings are estimated to be 12 PJ, 16 PJ, and 27 PJ, respectively. By 2040, the low, medium, and high market MTRC potential savings are estimated to be 19 PJ, 24 PJ, and 46 PJ, respectively.

Exhibit 146 – Market Potential Savings (GJ) – All Sectors, TRC

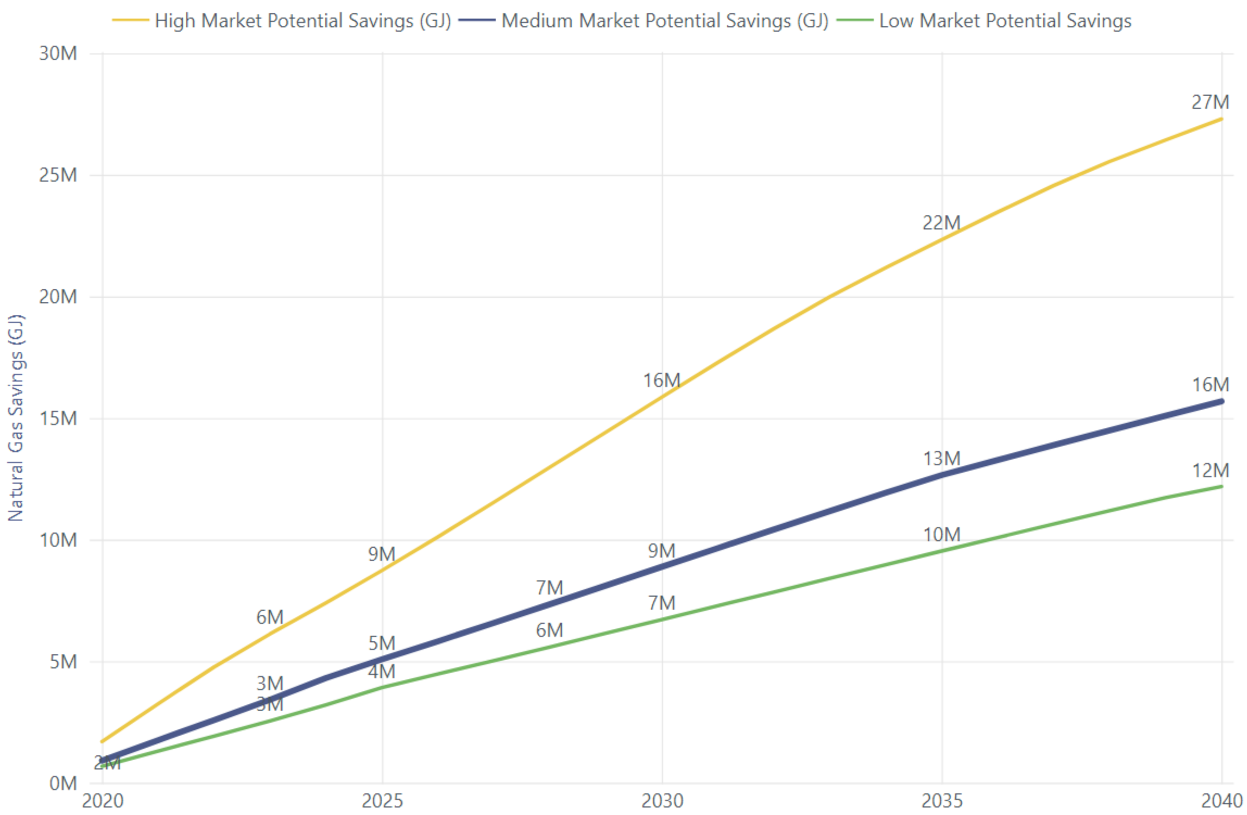
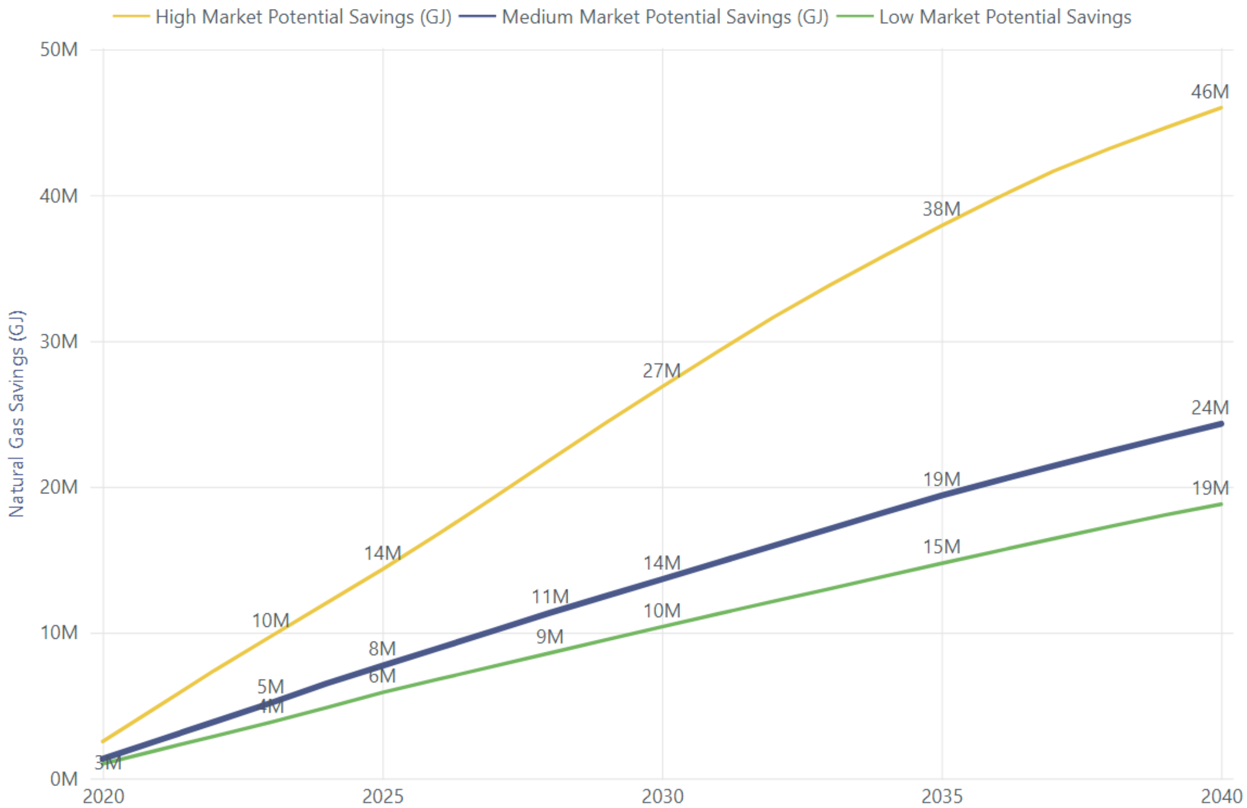


Exhibit 147 – Market Potential Savings (GJ) – All Sectors, MTRC



The forecasted total natural gas consumption under the three market potential scenarios relative to reference case forecast is shown in Exhibit 148 (TRC) and Exhibit 149 (MTRC). The reference consumption is forecasted to increase to 241 PJ – it is 222 PJ today. By 2040, the total low, medium, and high market TRC potential consumption levels are estimated to be 229 PJ, 226 PJ, and 214 PJ, respectively. By 2040, the low, medium, and high market MTRC potential consumption levels are estimated to be 222 PJ, 217 PJ, and 195 PJ, respectively.

Exhibit 148 – Market Potential Consumption (GJ) Forecasts – All Sectors, TRC

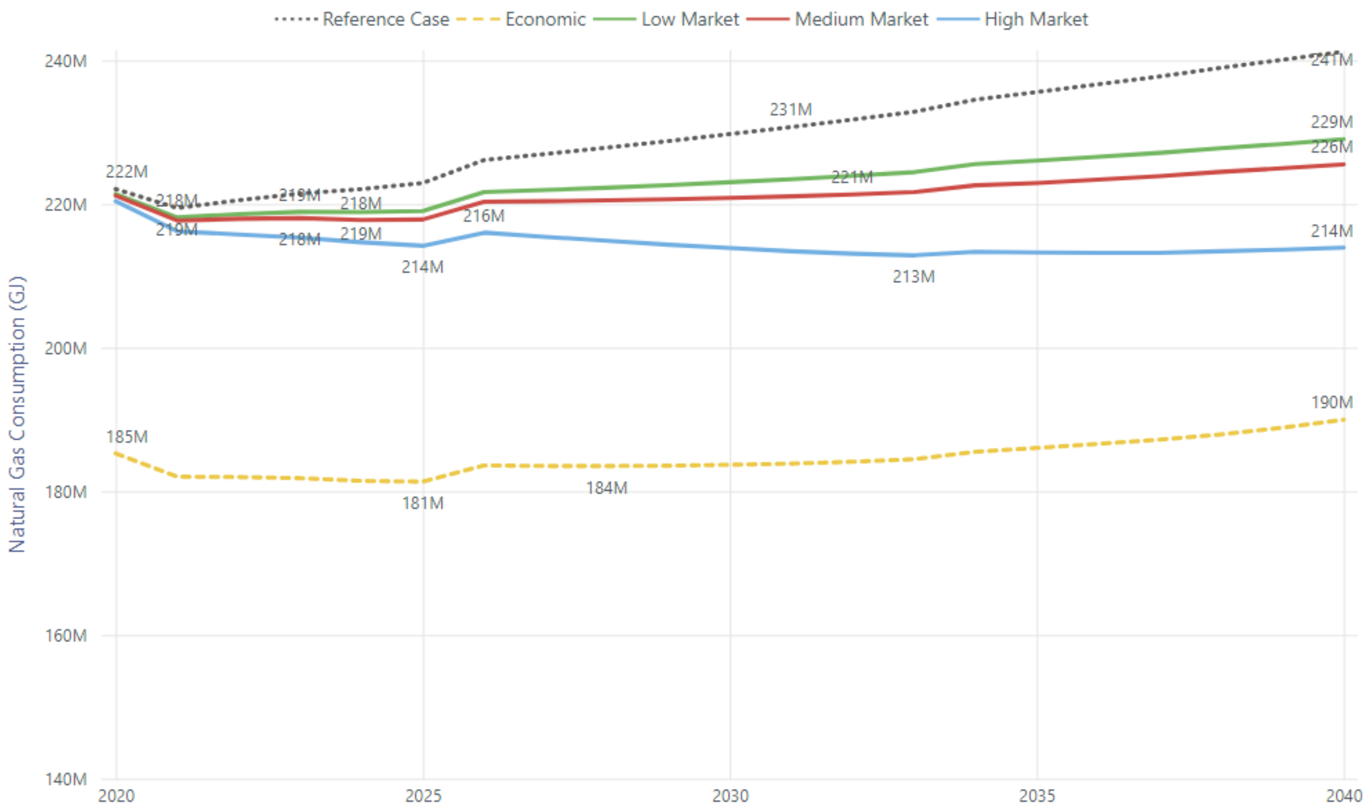
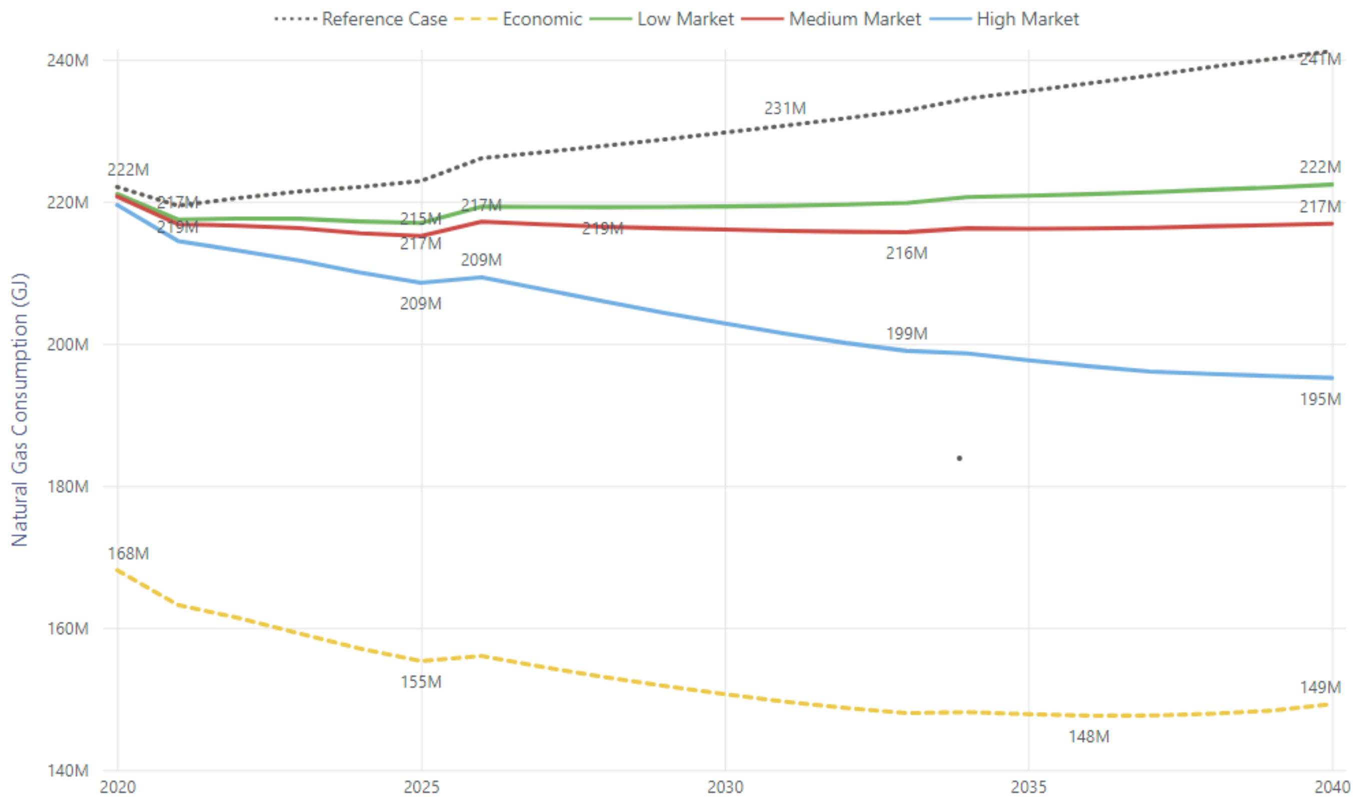


Exhibit 149 – Market Potential Consumption (GJ) Forecasts – All Sectors, MTRC



The medium market potential savings from the commercial, industrial, residential sectors are plotted together in Exhibit 150 (TRC) and Exhibit 151 (MTRC).

Under the TRC medium market scenario, by 2025, the industrial sector is estimated to have the most savings potential, followed by the residential and then commercial sectors. By 2030, the commercial sector overtakes residential. This is because there are only 14 residential measures that pass the TRC, and almost all of them are retrofit measures that can be implemented early in the study period. By 2040, potential savings from industrial, commercial, and residential sectors are estimated to be 7.3 PJ, 5.0 PJ, and 3.4 PJ, respectively.

Under the MTRC medium market scenario, the residential sector is estimated to have the most savings potential throughout the study period, followed by industrial and then commercial. By 2040, potential savings from residential, industrial, and commercial sectors are estimated to be 9.9 PJ, 8.6 PJ, and 5.8 PJ, respectively.

Exhibit 150 – Medium Market Potential Savings (GJ) – All Sectors, TRC

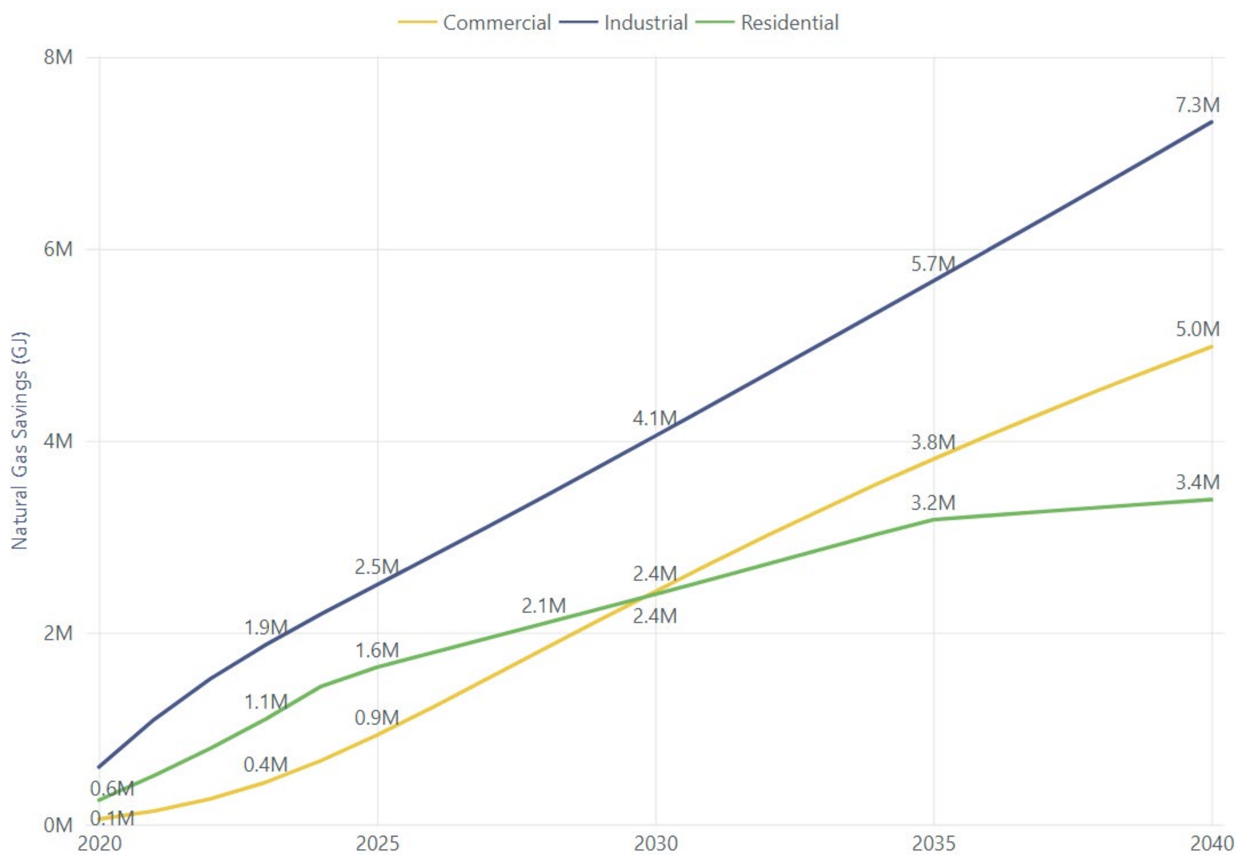
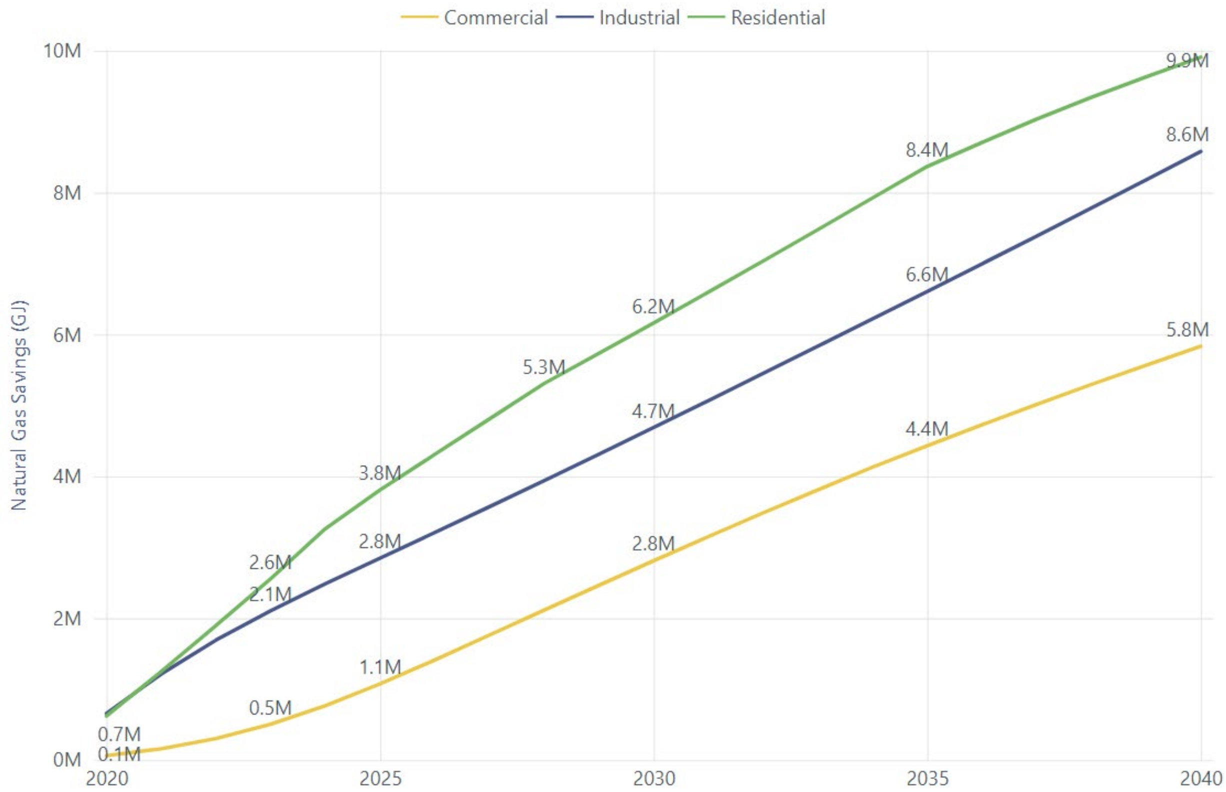


Exhibit 151 – Medium Market Potential Savings (GJ) – All Sectors, MTRC



7.1.2 Incentive and Non-Incentive Spending

The incentive and non-incentive spending required to achieve the medium and high market potential are shown in Exhibit 152 (TRC) and Exhibit 153 (MTRC). Medium and high market incentives are assumed to be 50% and 100% of measures' incremental costs, respectively. In both medium and high scenarios, non-incentive costs are estimated to be 15% of incentive costs. For each year, the tables show the total as well as incremental savings from new measures installed in each year.

Note that these costs and savings are not directly comparable to the costs and savings of FortisBC's current DSM portfolio for several reasons, including:

- Market potential includes a mix of measures that does not align exactly with the current DSM portfolio.
- The current DSM portfolio includes a mixture of measures that pass the TRC test and measures that pass the MTRC test only. This report presents TRC and MTRC analysis separately.
- Program-level incentive and non-incentive costs are estimated, and do not align exactly with current DSM costs.
- DSM spending includes portfolio-level non-incentive costs, whereas CPR modelling does not.

Exhibit 152 – Medium and High Market Incentive Costs and Natural Gas Savings – All Sectors, TRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$7.8M	$1.2M	$8.9M	912K	912K	$31.5M	$4.7M	$36.3M	1,698K	1,698K
2021	$8.5M	$1.3M	$9.8M	1,754K	842K	$35.8M	$5.4M	$41.2M	3,252K	1,554K
2022	$9.9M	$1.5M	$11.3M	2,578K	824K	$42.9M	$6.4M	$49.4M	4,763K	1,511K
2023	$11.5M	$1.7M	$13.2M	3,415K	837K	$47.0M	$7.1M	$54.1M	6,120K	1,357K
2024	$13.5M	$2.0M	$15.5M	4,306K	891K	$53.7M	$8.1M	$61.8M	7,398K	1,278K
2025	$12.6M	$1.9M	$14.5M	5,077K	771K	$63.5M	$9.5M	$73.0M	8,733K	1,334K
2026	$13.5M	$2.0M	$15.5M	5,819K	743K	$73.0M	$11.0M	$84.0M	10,114K	1,382K
2027	$14.4M	$2.2M	$16.5M	6,578K	759K	$79.3M	$11.9M	$91.2M	11,536K	1,421K
2028	$15.1M	$2.3M	$17.4M	7,344K	766K	$84.5M	$12.7M	$97.1M	12,976K	1,441K
2029	$15.5M	$2.3M	$17.9M	8,114K	770K	$86.9M	$13.0M	$99.9M	14,422K	1,446K
2030	$15.9M	$2.4M	$18.3M	8,882K	769K	$88.5M	$13.3M	$101.8M	15,863K	1,440K
2031	$16.1M	$2.4M	$18.5M	9,650K	767K	$89.5M	$13.4M	$102.9M	17,288K	1,425K
2032	$16.4M	$2.5M	$18.9M	10,415K	766K	$90.1M	$13.5M	$103.6M	18,671K	1,384K
2033	$16.1M	$2.4M	$18.5M	11,172K	757K	$86.7M	$13.0M	$99.7M	19,991K	1,320K
2034	$16.2M	$2.4M	$18.7M	11,926K	754K	$86.5M	$13.0M	$99.5M	21,189K	1,198K
2035	$16.0M	$2.4M	$18.4M	12,655K	729K	$85.0M	$12.7M	$97.7M	22,338K	1,149K
2036	$15.5M	$2.3M	$17.8M	13,273K	618K	$83.7M	$12.5M	$96.2M	23,469K	1,131K
2037	$15.5M	$2.3M	$17.9M	13,885K	612K	$83.0M	$12.5M	$95.5M	24,565K	1,095K
2038	$15.4M	$2.3M	$17.8M	14,494K	609K	$78.2M	$11.7M	$90.0M	25,554K	989K
2039	$15.1M	$2.3M	$17.4M	15,094K	599K	$71.6M	$10.7M	$82.3M	26,434K	880K
2040	$15.2M	$2.3M	$17.5M	15,692K	598K	$72.4M	$10.9M	$83.3M	27,299K	865K

Exhibit 153 – Medium and High Market Incentive Costs and Natural Gas Savings – All Sectors, MTRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$51.3M	$7.7M	$59.0M	1,343K	1,343K	$198.3M	$29.8M	$228.1M	2,538K	2,538K
2021	$53.1M	$8.0M	$61.1M	2,625K	1,282K	$210.7M	$31.6M	$242.3M	4,975K	2,437K
2022	$55.3M	$8.3M	$63.6M	3,892K	1,267K	$227.2M	$34.1M	$261.3M	7,418K	2,443K
2023	$57.7M	$8.7M	$66.3M	5,166K	1,274K	$240.8M	$36.1M	$276.9M	9,736K	2,317K
2024	$60.6M	$9.1M	$69.7M	6,514K	1,349K	$252.5M	$37.9M	$290.3M	12,032K	2,296K
2025	$60.2M	$9.0M	$69.2M	7,734K	1,219K	$255.2M	$38.3M	$293.5M	14,340K	2,308K
2026	$62.1M	$9.3M	$71.4M	8,931K	1,197K	$279.0M	$41.9M	$320.9M	16,766K	2,426K
2027	$63.9M	$9.6M	$73.5M	10,146K	1,215K	$296.2M	$44.4M	$340.6M	19,282K	2,516K
2028	$65.3M	$9.8M	$75.1M	11,365K	1,219K	$309.6M	$46.4M	$356.1M	21,852K	2,569K
2029	$58.0M	$8.7M	$66.7M	12,512K	1,147K	$302.5M	$45.4M	$347.8M	24,402K	2,550K
2030	$59.5M	$8.9M	$68.5M	13,663K	1,151K	$286.2M	$42.9M	$329.1M	26,862K	2,461K
2031	$60.8M	$9.1M	$69.9M	14,816K	1,153K	$284.5M	$42.7M	$327.2M	29,287K	2,424K
2032	$62.2M	$9.3M	$71.6M	15,972K	1,156K	$293.9M	$44.1M	$338.0M	31,650K	2,363K
2033	$63.0M	$9.5M	$72.5M	17,124K	1,152K	$275.4M	$41.3M	$316.7M	33,838K	2,188K
2034	$64.4M	$9.7M	$74.1M	18,277K	1,153K	$272.5M	$40.9M	$313.4M	35,907K	2,069K
2035	$65.4M	$9.8M	$75.3M	19,408K	1,131K	$267.1M	$40.1M	$307.2M	37,905K	1,999K
2036	$63.3M	$9.5M	$72.8M	20,430K	1,022K	$262.6M	$39.4M	$302.0M	39,832K	1,927K
2037	$62.9M	$9.4M	$72.3M	21,440K	1,011K	$254.1M	$38.1M	$292.2M	41,660K	1,828K
2038	$61.0M	$9.1M	$70.1M	22,425K	984K	$228.8M	$34.3M	$263.1M	43,199K	1,539K
2039	$58.9M	$8.8M	$67.7M	23,381K	957K	$220.3M	$33.0M	$253.3M	44,622K	1,423K
2040	$58.3M	$8.8M	$67.1M	24,325K	944K	$219.8M	$33.0M	$252.8M	46,010K	1,388K

7.2 Emissions

Reducing natural gas use results in lower greenhouse gas emissions. The estimated GHG emission reductions for the three sectors combined, in the medium and high market potential scenarios are shown in Exhibit 154 (TRC) and Exhibit 155 (MTRC).

These estimates use an emissions factor of 51.6 kg of CO_2e, or carbon dioxide equivalent, per GJ of natural gas saved.[46] The emissions reductions are shown in tCO_2e, or Tonnes of CO_2e.

Exhibit 154 – Estimated Greenhouse Gas Emissions Reduction (Tonnes of CO2e) – All Sectors, TRC

Year	Reference Case Emissions (tCO2e)	Medium Market Potential Emissions Reduction (tCO2e)	%	High Market Potential Emissions Reduction (tCO2e)	%
2025	11.5M	262k	2.3%	451k	3.9%
2030	11.8M	458k	3.9%	819k	6.9%
2035	12.1M	653k	5.4%	1.1M	9.5%
2040	12.5M	810k	6.5%	1.4M	11.3%

Exhibit 155 – Estimated Greenhouse Gas Emissions Reduction (Tonnes of CO_2e) – All Sectors, MTRC

Year	Reference Case Emissions (tCO2e)	Medium Market Potential Emissions Reduction (tCO2e)	%	High Market Potential Emissions Reduction (tCO2e)	%
2025	11.5M	399k	3.5%	740k	6.4%
2030	11.8 M	705k	5.9%	1.4M	11.7%
2035	12.1 M	1.0M	8.2%	1.9M	16.1%
2040	12.5 M	1.3M	10.1%	2.4M	19.1%

46 Lifecycle emissions factor derived from *Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007*, consistent with FortisBC practice.

7.3 Employment Impacts

Employment impacts from spending on energy conservation measures in the market potential are presented in this section. Using multipliers, this analysis illustrates the economic effect investing in energy efficiency can have on the labour market.

The literature defines three types of impacts on employment: direct, indirect, and induced. Details of the analysis approach for each employment category are provided below.

7.3.1 Direct/Indirect Jobs

Direct and indirect jobs are created by spending, as capital and labour are required to create and ship products, and conduct the work associated with an efficiency project.

The CPR includes a variety of measure types, each of which would have different employment impacts.[47] For the purpose of this analysis, impacts were estimated in aggregate using the following approach:

1. Estimate DSM spending: The total annual medium market incentive cost for all sectors, multiplied by two (as the incentive represents 50% of the incremental cost of implementing the measure). This value represents the spending injected into the economy from implementing the CPR measures.
2. Estimate direct and indirect employment impacts:
    a. Apply the multiplier for direct jobs – to estimate direct jobs supported by spending.
    b. Apply the multiplier for indirect jobs – to estimate indirect jobs supported by spending.
3. Sum results for the study period to derive the total estimated number of jobs supported by spending on CPR measures.

7.3.2 Induced Jobs

Induced jobs are created when people or businesses spend more money because they have lower fixed costs, such as energy bills.

Lower energy costs result in higher disposable income for households and people often spend disposable income in their local economy (going out for dinner or to the movies, for example). Similarly, businesses can become more competitive when lower energy costs reduce their operating expenses, creating more

47 Multipliers for job impacts may vary by measure type, as different measures involve different industries, and levels of labour and capital. For a more detailed analysis of employment impacts by measure type and sector, please see "Analysis of Job Creation and Energy Cost Savings from Building Energy Rating and Disclosure Policy" by the Institute for Market Transformation and the Political Economy Research Institute (2012) and "The Economic Impact of Improved Energy Efficiency in Canada" by Efficiency Canada (2018).

working capital. The Institute for Market Transformation estimates that 60% of net jobs created through energy efficiency projects are associated with the energy cost savings.[48]

The following steps were taken for the TRC and MTRC scenario to estimate induced jobs:

- Estimate cost savings: Annual retail rates by sector were multiplied by the medium market potential savings to generate an annual cost savings figure.
- Estimate employment impacts: Apply the multiplier for induced jobs to estimate induced jobs.

7.3.3 Summary of Employment Impacts

The analysis uses the following multipliers:[49]

- Direct jobs: 5 job-years[50] per $1 million CAD spent on energy efficiency measures.
- Indirect jobs: 4 jobs-years per $1 million CAD spent on energy efficiency measures.
- Induced jobs: 4 jobs-years per $1 million CAD saved, used to estimate induced jobs from bill savings resulting in energy efficiency measures.

Multipliers for direct and indirect jobs are net numbers, meaning they account for job losses in other sectors that may result from spending on energy efficiency.

Using the method described in the sections above, the following exhibits provide the cumulative incentive spending, total spending (double the incentive spending), direct and indirect jobs-years resulting from this spending, customer bill savings, induced jobs resulting from bill savings, and total employment impacts for the study period. Exhibit 156 and Exhibit 157 present results using spending and bill savings levels for the TRC and MTRC screens, respectively.

48 Institute for Market Transformation and Political Economy Research Institute. "Analysis of Job Creation and Energy Cost Savings." (2012).
49 Multipliers derived from Pembina Institute. "Deep emissions reductions in the existing building stock." April 11, 2017. (Online) Available at: http://www.pembina.org/pub/building-retrofits. Per dollar value multipliers were not converted from the source year to 2020 dollars.
50 A "Job-year" is defined as the resources to employ 1 person for 12 months.

Exhibit 156 – Annual and Cumulative Employment Impacts from CPR Measures, 2020-2040 - TRC Scenario

Year	Incentive Spending ($ Millions)	Total Spending ($ Millions)	Direct Job-years	Indirect Job-years	Bill Savings ($ Millions)	Induced Job-years	Total Job-years
2020	$7.8	$15.5	80	60	$13.5	55	195
2021	$8.5	$17.1	85	70	$27.0	110	265
2022	$9.9	$19.7	100	80	$40.7	165	345
2023	$11.5	$23.0	115	90	$54.8	220	425
2024	$13.5	$26.9	135	110	$73.3	295	540
2025	$12.6	$25.3	125	100	$90.3	360	585
2026	$13.5	$26.9	135	110	$104.5	420	665
2027	$14.4	$28.7	145	115	$118.7	475	735
2028	$15.1	$30.3	150	120	$133.3	535	805
2029	$15.5	$31.1	155	125	$148.3	595	875
2030	$15.9	$31.8	160	125	$163.9	655	940
2031	$16.1	$32.2	160	130	$179.9	720	1,010
2032	$16.4	$32.8	165	130	$196.4	785	1,080
2033	$16.1	$32.1	160	130	$213.4	855	1,145
2034	$16.2	$32.5	160	130	$230.8	925	1,215
2035	$16.0	$32.0	160	130	$248.3	995	1,285
2036	$15.5	$31.0	155	125	$263.9	1,055	1,335
2037	$15.5	$31.1	155	125	$279.8	1,120	1,400
2038	$15.4	$30.9	155	125	$296.1	1,185	1,465
2039	$15.1	$30.2	150	120	$312.8	1,250	1,520
2040	$15.2	$30.5	150	120	$330.1	1,320	1,590
TOTAL	$296	$592	2,955	2,370	$3,520	14,095	19,420

Exhibit 157 – Annual and Cumulative Employment Impacts from CPR Measures, 2020-2040 - MTRC Scenario

Year	Incentive Spending ($ Millions)	Total Spending ($ Millions)	Direct Job-years	Indirect Job-years	Bill Savings ($ Millions)	Induced Job-years	Total Job-years
2020	$51.3	$102.5	515	410	$21.4	85	1,010
2021	$53.1	$106.2	530	425	$43.0	170	1,125
2022	$55.3	$110.6	555	440	$65.4	260	1,255
2023	$57.7	$115.3	575	460	$88.0	350	1,385
2024	$60.6	$121.2	605	485	$116.0	465	1,555
2025	$60.2	$120.4	600	480	$142.8	570	1,650
2026	$62.1	$124.2	620	495	$166.7	665	1,780
2027	$63.9	$127.8	640	510	$190.8	765	1,915
2028	$65.3	$130.6	655	520	$215.4	860	2,035
2029	$58.0	$116.1	580	465	$239.1	955	2,000
2030	$59.5	$119.1	595	475	$263.8	1,055	2,125
2031	$60.8	$121.5	610	485	$289.1	1,155	2,250
2032	$62.2	$124.5	620	500	$315.3	1,260	2,380
2033	$63.0	$126.0	630	505	$342.3	1,370	2,505
2034	$64.4	$128.8	645	515	$370.2	1,480	2,640
2035	$65.4	$130.9	655	525	$398.4	1,595	2,775
2036	$63.3	$126.7	635	505	$425.1	1,700	2,840
2037	$62.9	$125.8	630	505	$452.4	1,810	2,945
2038	$61.0	$121.9	610	490	$479.7	1,920	3,020
2039	$58.9	$117.8	590	470	$507.3	2,030	3,090
2040	$58.3	$116.7	585	465	$535.6	2,140	3,190
TOTAL	**$1,267**	**$2,535**	**12,680**	**10,130**	**$5,668**	**22,660**	**45,470**

7.4 Findings and Conclusions

Readers are encouraged to use the CPR Data Visualization Tool to explore output data and draw their own insights for the purposes of DSM planning, program research and program design.

This section summarizes findings of this study at a high level:

- This study has found significant cost-effective and market achievable natural gas savings throughout the study period 2020-2040, and in all sectors and segments.

  Across all sectors, and using the MTRC screen, medium market potential savings are estimated at approximately 8 PJ, or 4% of reference consumption in 2025, rising to 24 PJ, or 10% of reference consumption in 2040.

  This estimated 24 PJ savings by 2040 includes potential savings from Residential, Industrial, and Commercial sectors of 9.9 PJ, 8.6 PJ, and 5.8 PJ respectively.

- In the ***residential sector***, only a small number of measures are cost-effective based on the TRC test, most being low-cost retrofit measures. Measures that pass the MTRC screen only become more important in the residential sector as the study period progresses.
  - The opportunities for equipment replacement measures, especially space heating measures, are much smaller relative to previous studies. This is primarily due to increasingly higher federal and provincial minimum energy performance standards (MEPS) for furnaces, which have caused DSM opportunities to become increasingly scarce.
  - In terms of percentage of reference case consumption forecast, more residential opportunities are available in the domestic hot water end use than the space heating end use throughout the study period. In absolute terms, savings potential for DHW measures (4 PJ by 2040 in the medium market potential scenario, MTRC screen) approaches that of space heating measures (5 PJ by 2040 in the medium market potential scenario, MTRC screen).

- ***Commercial sector*** savings show the most variance between the high and medium market potential scenarios. Using the MTRC screen, by 2040 the difference in potential between the medium and high market scenarios is 11.6 PJ.

  Gas heat pumps (GHPs) and efficient new construction are major contributing factors to this difference. These measures have high technical and economic potential, but future uptake is uncertain. For example, in the medium scenario, GHPs are modeled as an innovative technology with low forecasted growth. In the high scenario, they are modeled as an innovative technology with high forecasted growth, especially in the second half of the study period (2030-2040).

- The ***industrial sector*** is estimated to have the largest cost-effective savings potential on the TRC economic screen relative to other sectors. However, industrial customers require shorter payback periods relative to commercial and residential customers. Achieving savings from industrial measures that are cost-effective but have longer customer payback periods may be challenging and/or more expensive due to higher incentives and program costs.

- This CPR is the first to use a model that is fully compatible with the end use model developed for FortisBC's Long-Term Gas Resource Plan (LTGRP). The LTGRP provided the CPR's reference case, at a level of granularity not available to previous CPRs.

  Questions about the trends or assumptions in the reference case were easily answered by delving into the LTGRP model and the data upon which it was based. Furthermore, the results of the CPR will be provided to the LTGRP project for further analysis. Because the models are compatible, the LTGRP can easily explore variations in the CPR's potential estimates with different assumptions about economic conditions in the province or different budget envelopes for DSM programs.
- This CPR does not consider announcements related to the federal carbon tax made in 2021, which were made after modelling was complete for this project. Increases in the federal carbon tax are expected to positively impact the savings potential presented in this CPR: as natural gas costs rise, more measures will become cost-effective and pass the benefit/cost tests, and all measures will become more attractive financially to end users.

Appendix C-2

SUPPLEMENTAL INFORMATION FOR DEMAND SIDE RESOURCES – DSM ANALYSIS

APPENDIX C-2: SUPPLEMENTAL INFORMATION FOR DEMAND SIDE RESOURCES - DSM ANALYSIS

This appendix provides supplemental information to the DSM analysis results presented in Section 5 Demand Side Resources. Two separate analyses are provided. The first analysis provides the forecast long-term demand after DSM savings are applied for all sectors combined for the alternate future scenarios described in Section 5. The second analysis provides an overview of cost effectiveness test results for the residential, commercial and industrial sectors for (1) the Diversified Energy (Planning) Scenario with High DSM Budget Settings (DEP High Scenario), (2) the Reference Case, and (3) the Upper Bound Scenario.

For each of the residential, commercial and industrial sectors, a table is presented with an aggregate value for the sector over the planning horizon and the results for each year. FEI then presents four figures that compare DEP High to the Reference Case for each sector, illustrating the Total Resource Cost Test (TRC), Modified Total Resource Cost Test (MTRC), Utility Cost Test (UCT) and Cost of Conserved Energy (CCE) over the planning horizon. While the figures still show the Upper Bound scenario, there are no DSM settings considered in this scenario so the results for this scenario are nil.

1.1 Total Annual Demand After DSM Savings for Alternative Scenarios–Excluding LCT

Figure C2-1 and C2-2 below illustrates annual energy demand, excluding LCT[1], before and after estimated DSM energy savings for all sectors combined.

Figure C2-1 below, which is the same as Figure 5.5 discussed in Section 5.4.2, illustrates the following annual energy demand forecasts:

- Diversified Energy (Planning) – Pre-DSM
- Diversified Energy (Planning) – Post-DSM Medium (DEP Medium)
- Diversified Energy (Planning) – Post-DSM High (DEP High)
- Reference Case – Pre-DSM
- Reference Case – Post-DSM

[1] LCT in this case refers to LCT, Global LNG and the New Large Industrial Loads as they are all excluded from the DSM analysis.

Figure C2-1: Annual Demand Before and After Estimated DSM Savings (Excluding LCT) - All Sectors Combined

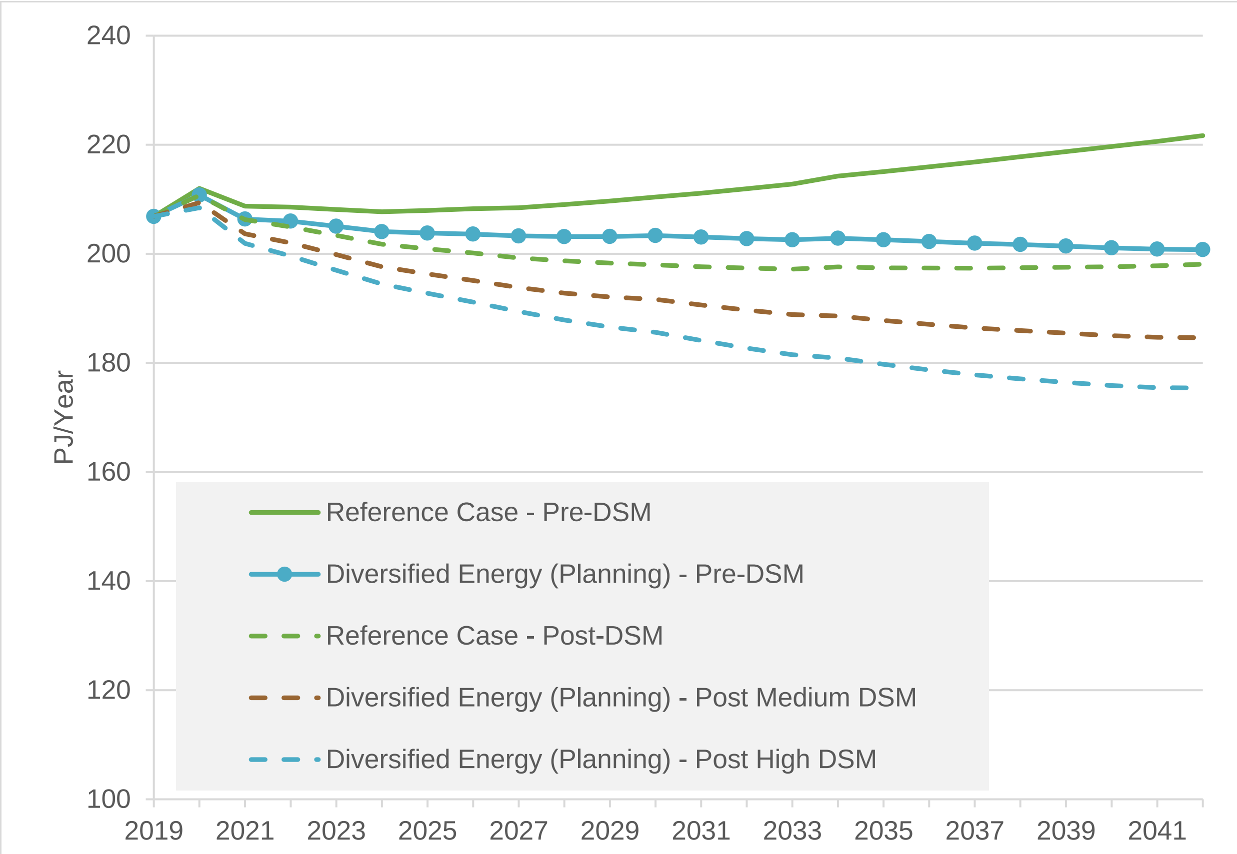
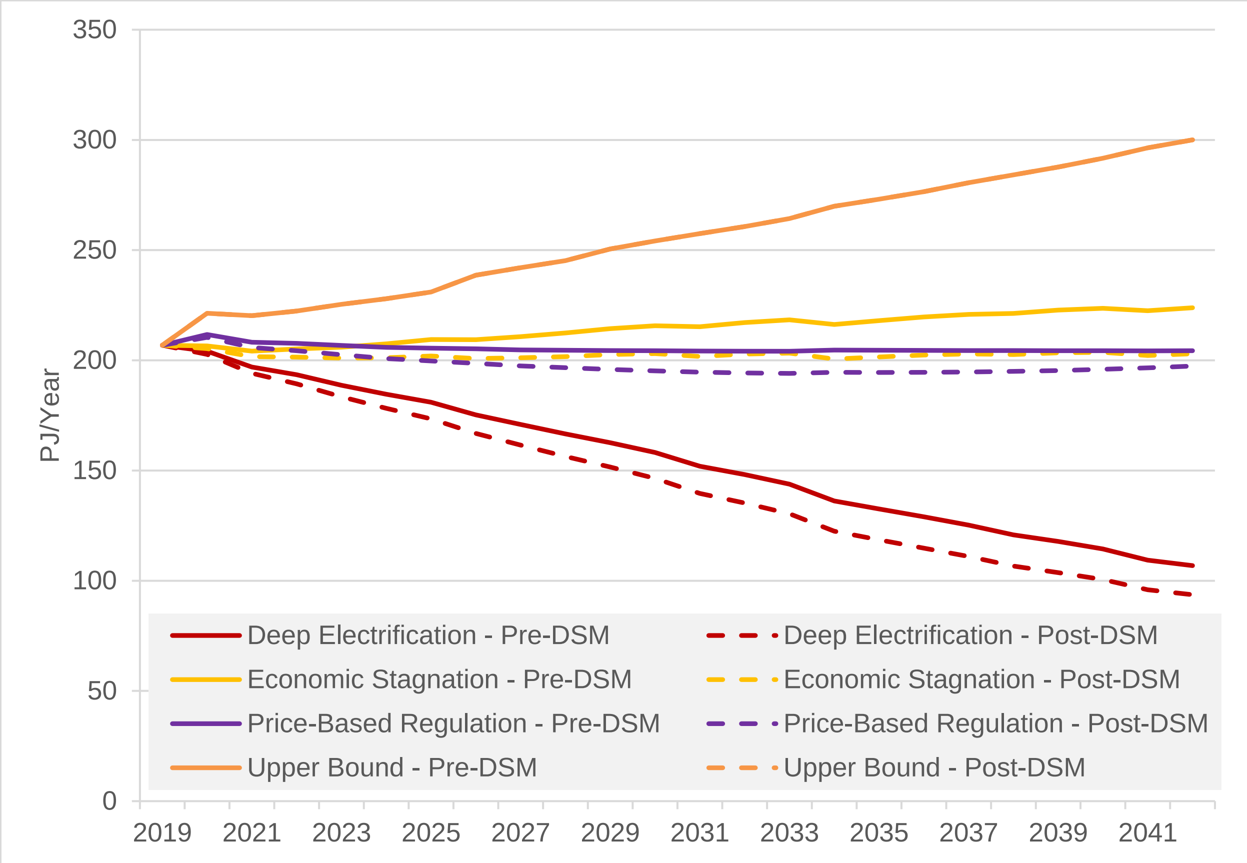


Figure C2-2 below compares the following annual energy demand forecasts:

- Deep Electrification-Pre-DSM
- Deep Electrification-Post-DSM
- Economic Stagnation-Pre-DSM
- Economic Stagnation-Post-DSM
- Price Based Regulation-Pre-DSM
- Price Based Regulation-Post DSM
- Upper Bound – Pre-DSM, which is equivalent to Upper Bound - Post-DSM

Figure C2-2: Annual Demand Before and After Estimated DSM Savings (Excluding LCT) - All Sectors Combined



In summary, annual energy savings for each of the six scenarios are as follows:

- DEP High annual energy savings are forecast to account for a 13 percent reduction in demand in 2042 while DEP Medium savings are forecast to account for an 8 percent reduction;
- Reference Case annual energy savings are forecast to account for a 11 percent reduction in Reference Case projected demand in 2042;
- Deep Electrification annual energy savings are forecast to account for a 12 percent reduction in Deep Electrification projected demand in 2042;
- Economic Stagnation annual energy savings are forecast to account for a 9 percent reduction in Economic Stagnation projected demand in 2042; and
- Price-Based Regulation annual energy savings are forecast to account for a 3 percent reduction in Price Based Regulation projected demand in 2042.

1.2 Cost Effectiveness Test Results for the Residential Sector

Table C2-1 below summarizes the DEP High cost effectiveness test results for the residential sector while Figures C2-3 to C2-6 illustrate how cost effectiveness test results vary across scenarios. The aggregate residential sector TRC ratio (1.5) and the aggregate UCT (1.4) are lower than the corresponding portfolio level results of 4.1 and 4.0, respectively. Aggregate residential CCE results are higher than the corresponding portfolio level CCE results, as is typical of the residential sector, and the results do decline over time. The Reference Case demonstrates higher cost-effectiveness test results, and this may partially be explained by the higher proportion of conventional natural gas in the fuel mix for the Reference Case.

Table C2-1: Estimated Diversified Energy (Planning) – High DSM Cost Effectiveness Test Results – Residential Sector

Year	TRC	MTRC	UCT	CCE ($/GJ)
Portfolio Aggregate	**4.1**	**14.2**	**4.0**	**11.3**
Residential Aggregate	**1.5**	**4.8**	**1.4**	**17.2**
2022	1.3	4.0	1.1	18.3
2023	1.3	4.1	1.1	18.4
2024	1.3	4.2	1.2	18.3
2025	1.4	4.3	1.2	18.2
2026	1.4	4.5	1.3	18.1
2027	1.4	4.6	1.3	17.9
2028	1.4	4.7	1.3	17.8
2029	1.5	4.8	1.4	17.7
2030	1.5	4.9	1.4	17.5
2031	1.5	5.0	1.4	17.4
2032	1.5	5.0	1.5	17.3
2033	1.5	5.0	1.5	17.2
2034	1.5	5.0	1.5	17.1
2035	1.6	5.1	1.5	16.9
2036	1.6	5.0	1.5	16.8
2037	1.6	5.1	1.5	16.6
2038	1.6	5.1	1.5	16.6
2039	1.5	5.0	1.5	16.5
2040	1.5	4.9	1.5	16.6
2041	1.5	4.8	1.5	16.5
2042	1.5	4.8	1.5	16.4

Figure C2-3: Estimated TRC Results by Scenario – Residential Sector

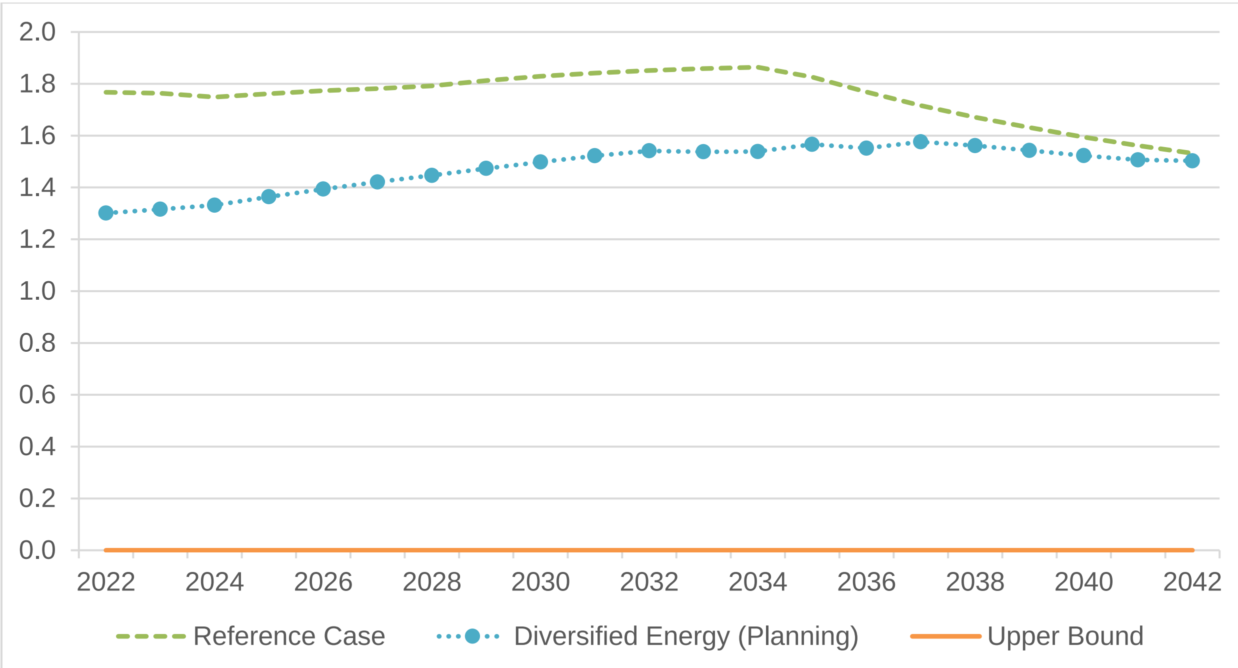


Figure C2-4: Estimated MTRC Results by Scenario – Residential Sector

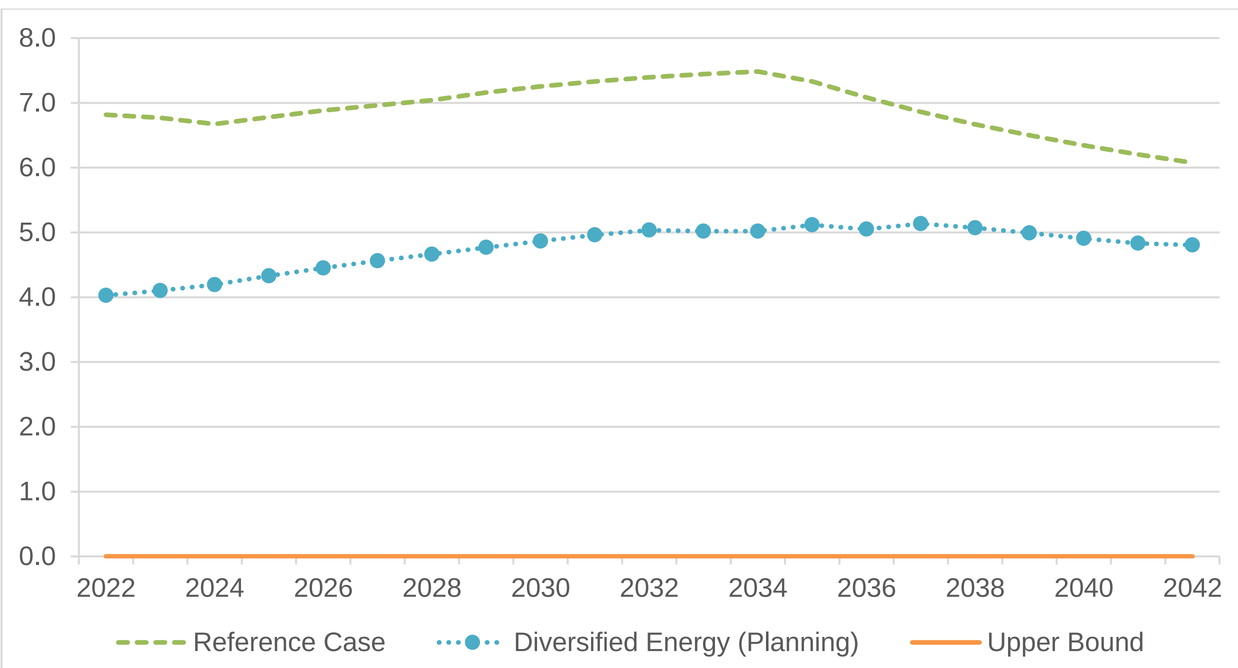


Figure C2-5: Estimated UCT Results by Scenario – Residential Sector

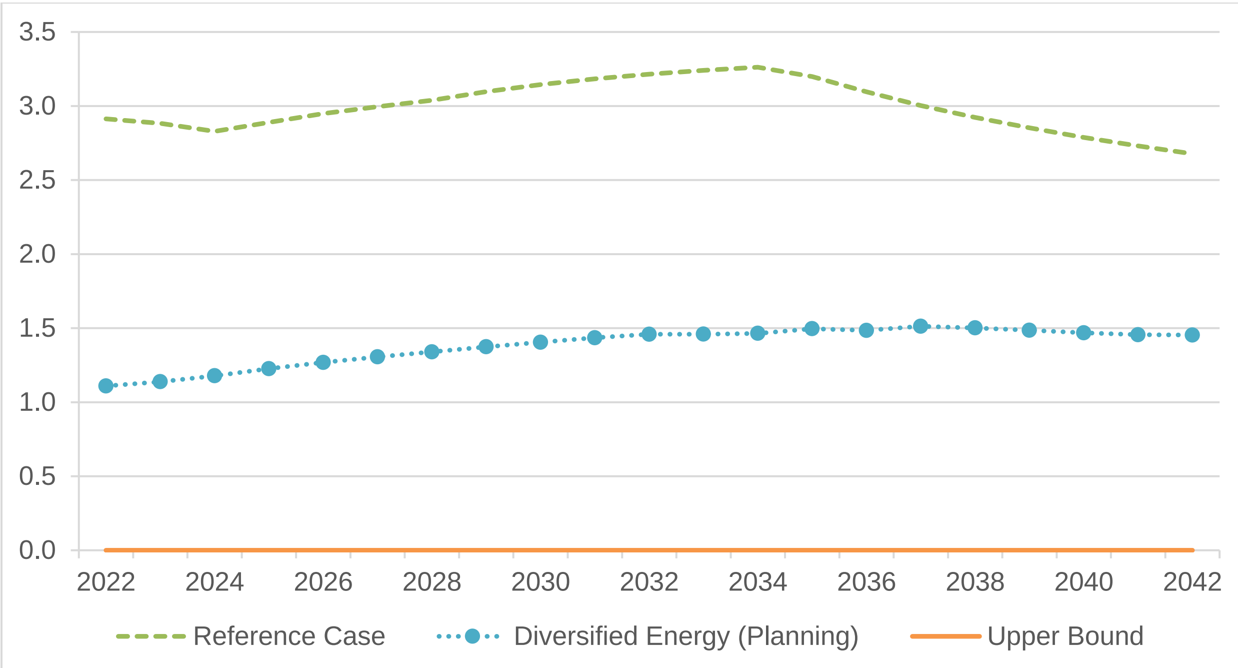
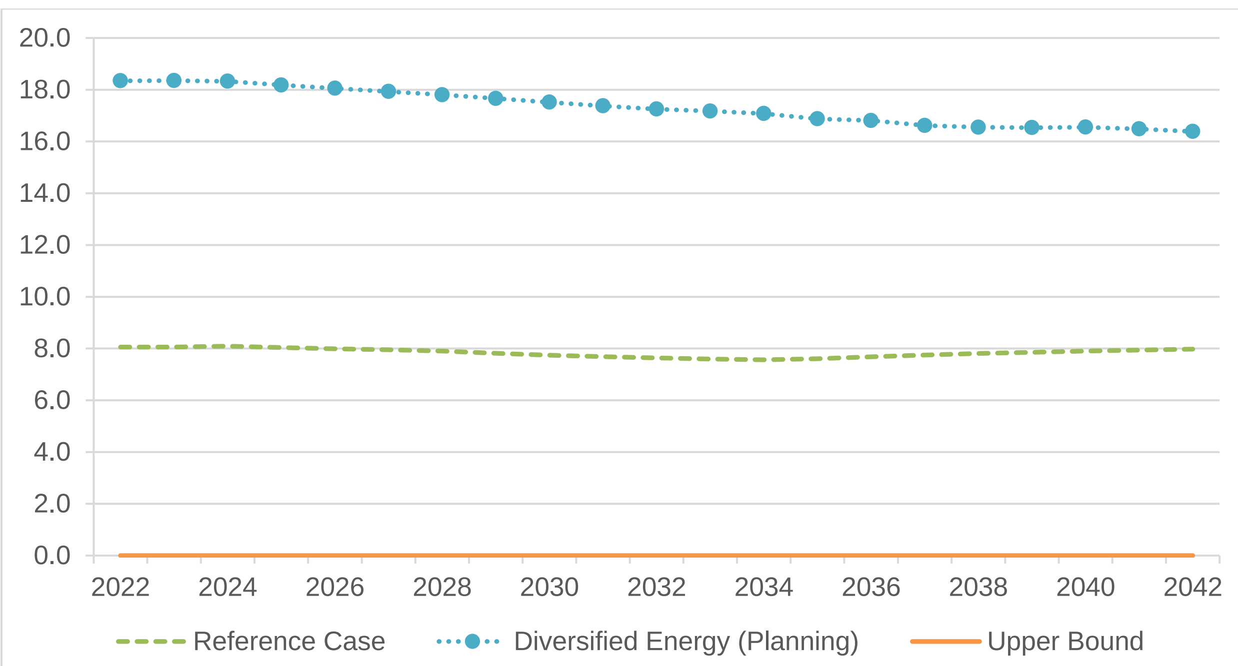


Figure C2-6: Estimated CCE Results by Scenario ($/GJ) – Residential Sector



1.3 Cost Effectiveness Results for the Commercial Sector

Table C2-2 below summarizes the DEP High cost-effectiveness test results for the commercial sector while Figures C2-7 to C2-10 illustrate how cost-effectiveness test results vary across scenarios. The aggregate commercial sector TRC ratio is lower and the aggregate UCT is lower than the corresponding portfolio level results. Aggregate commercial CCE results are somewhat lower than the corresponding portfolio level results and annual results increase slightly over time. The Reference Case demonstrates higher cost-effectiveness test results, and this may partially be explained by the higher proportion of conventional natural gas in the fuel mix for the Reference Case.

Table C2-2: Estimated Diversified Energy (Planning) – High DSM Cost Effectiveness Test Results – Commercial Sector

Year	TRC	MTRC	UCT	CCE ($/GJ)
Portfolio Aggregate	**4.1**	**14.2**	**4.0**	**11.3**
Commercial Aggregate	**2.1**	**6.3**	**1.9**	**10.7**
2022	2.2	6.6	1.9	10.0
2023	2.2	6.7	1.9	10.0
2024	2.2	6.8	1.9	10.0
2025	2.2	6.8	1.9	10.1
2026	2.1	6.7	1.9	10.2
2027	2.1	6.7	1.9	10.3
2028	2.1	6.6	1.9	10.4
2029	2.1	6.5	1.9	10.5
2030	2.1	6.4	1.9	10.5
2031	2.1	6.4	1.9	10.5
2032	2.1	6.3	1.9	10.6
2033	2.1	6.3	1.9	10.6
2034	2.1	6.3	1.9	10.7
2035	2.1	6.3	1.9	10.7
2036	2.1	6.2	1.9	10.8
2037	2.1	6.2	1.9	10.8
2038	2.1	6.2	1.9	10.8
2039	2.1	6.2	1.9	10.8
2040	2.1	6.2	1.9	10.8
2041	2.1	6.2	1.9	10.9
2042	2.1	6.2	1.9	10.9

Figure C2-7: Estimated TRC Results by Scenario – Commercial Sector

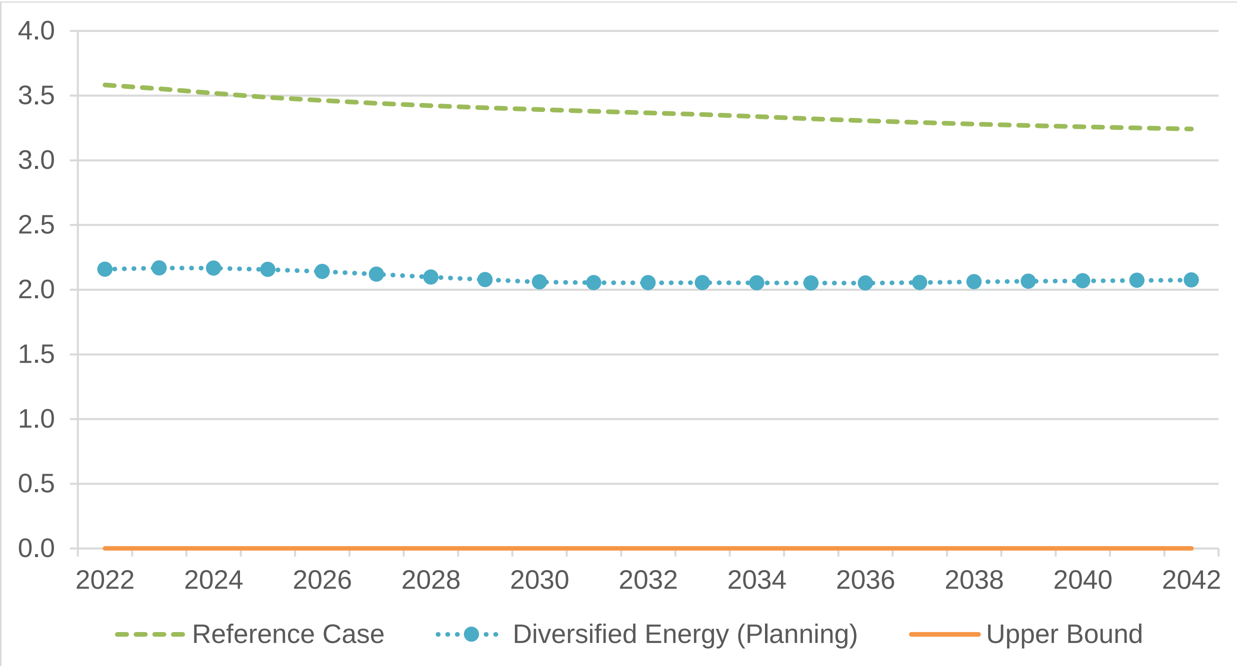


Figure C2-8: Estimated MTRC Results by Scenario – Commercial Sector

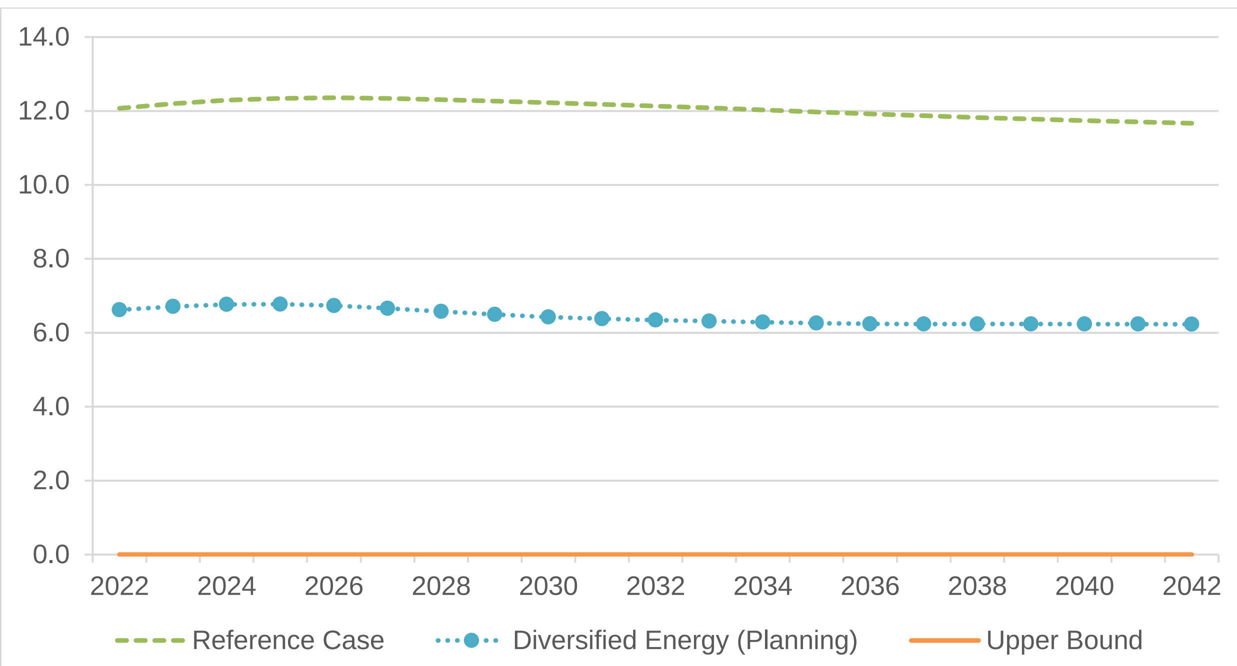


Figure C2-9: Estimated UCT Results by Scenario – Commercial Sector

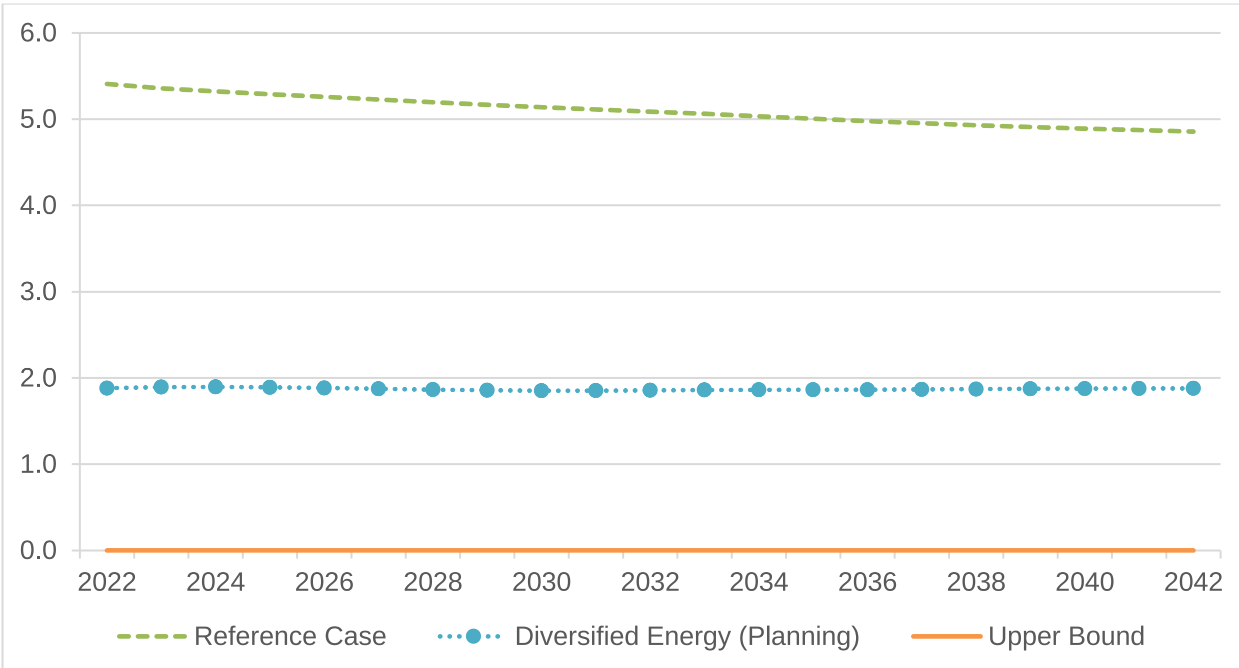
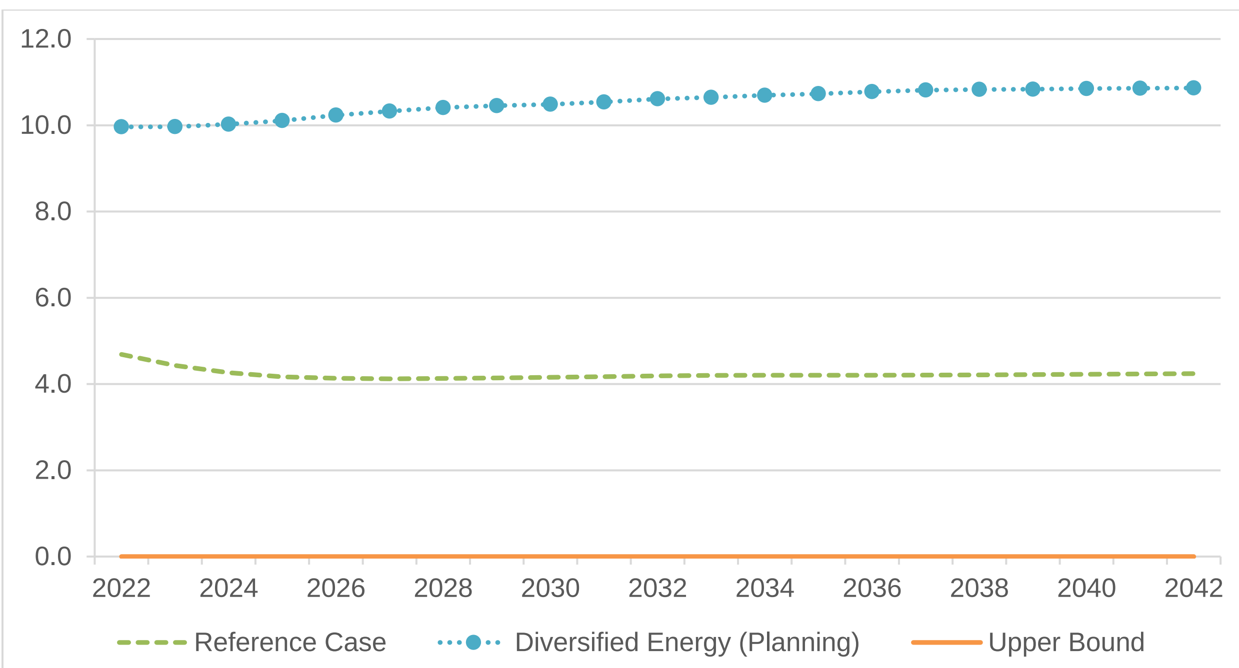


Figure C2-10: Estimated CCE Results by Scenario ($/GJ) – Commercial Sector



1.4 Cost Effectiveness Test Results for the Industrial Sector

Table C2-3 below summarizes the DEP High cost-effectiveness test results for the industrial sector while Figures C2-11 to C2-14 illustrate how cost-effectiveness test results vary across scenarios. The aggregate industrial sector TRC ratio and the aggregate UCT is higher than the corresponding portfolio-level results. Aggregate industrial CCE results are lower than the corresponding portfolio-level results. The results vary over the years but remain relatively flat over time. For the industrial program area, the Reference Case and DEP High scenarios are more closely aligned for the TRC and MTRC, but reflect larger differences for the UCT. This may be partially explained by the higher proportion of conventional natural gas in the fuel mix for the Reference Case as described in Section 5.

Table C2-3: Estimated Diversified Energy (Planning) – High DSM Cost Effectiveness Test Results – Industrial Sector

Year	TRC	MTRC	UCT	CCE ($/GJ)
Portfolio Aggregate	**4.1**	**14.2**	**4.0**	**11.3**
Industrial Aggregate	**10.7**	**38.5**	**10.8**	**3.8**
2022	14.9	56.1	15.0	3.4
2023	13.6	51.4	13.7	3.6
2024	12.7	47.6	12.8	3.7
2025	11.9	44.6	12.0	3.8
2026	11.3	42.2	11.4	3.9
2027	10.8	40.3	11.0	4.0
2028	10.5	38.8	10.6	4.1
2029	10.2	37.6	10.3	4.1
2030	10.1	37.0	10.3	4.0
2031	10.1	36.6	10.2	3.9
2032	10.1	36.4	10.2	3.9
2033	10.1	36.2	10.2	3.8
2034	10.1	36.2	10.3	3.8
2035	10.2	36.2	10.3	3.7
2036	10.2	36.1	10.3	3.7
2037	10.2	36.0	10.3	3.6
2038	10.3	36.0	10.4	3.6
2039	10.4	36.2	10.5	3.6
2040	10.5	36.3	10.6	3.6
2041	10.6	36.5	10.7	3.6
2042	10.7	36.7	10.8	3.6

Figure C2-11: Estimated TRC Results by Scenario – Industrial Sector

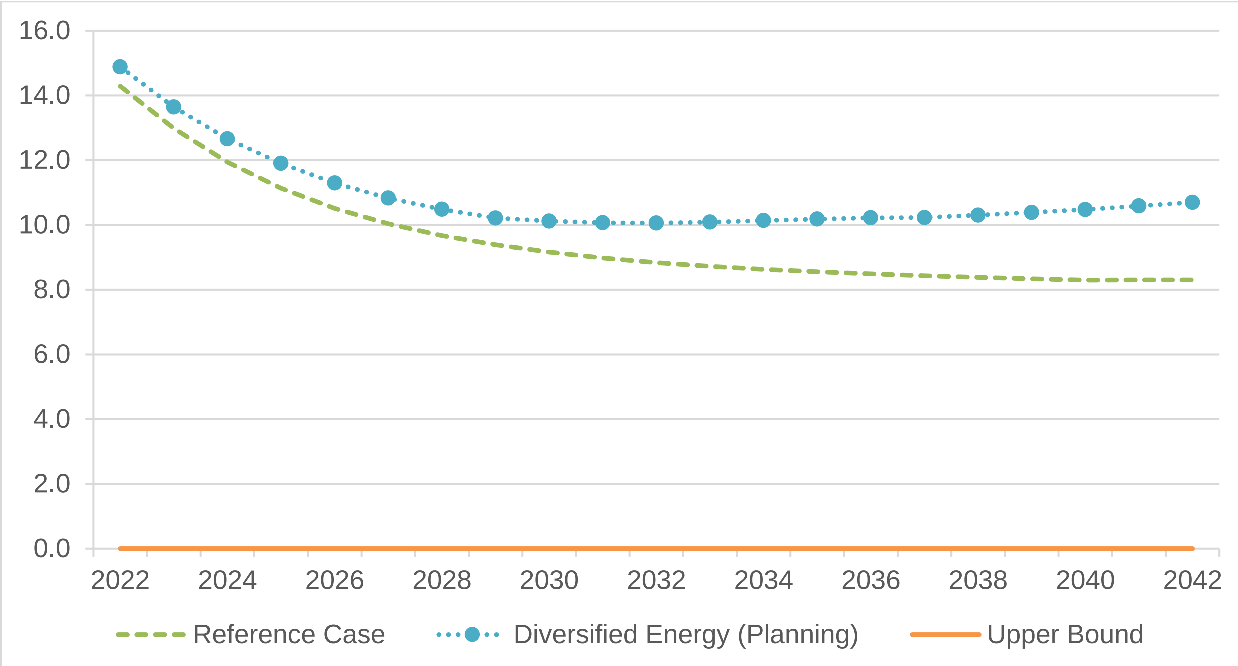


Figure C2-12: Estimated MTRC Results by Scenario – Industrial Sector

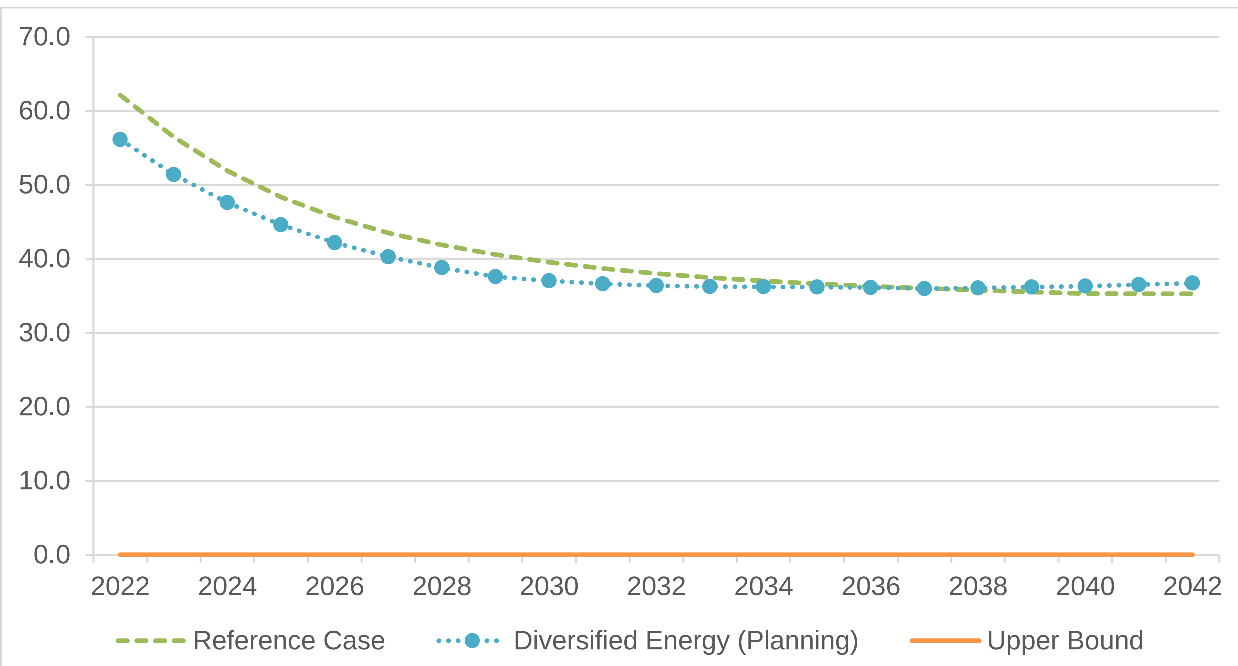


Figure C2-13: Estimated UCT Results by Scenario – Industrial Sector

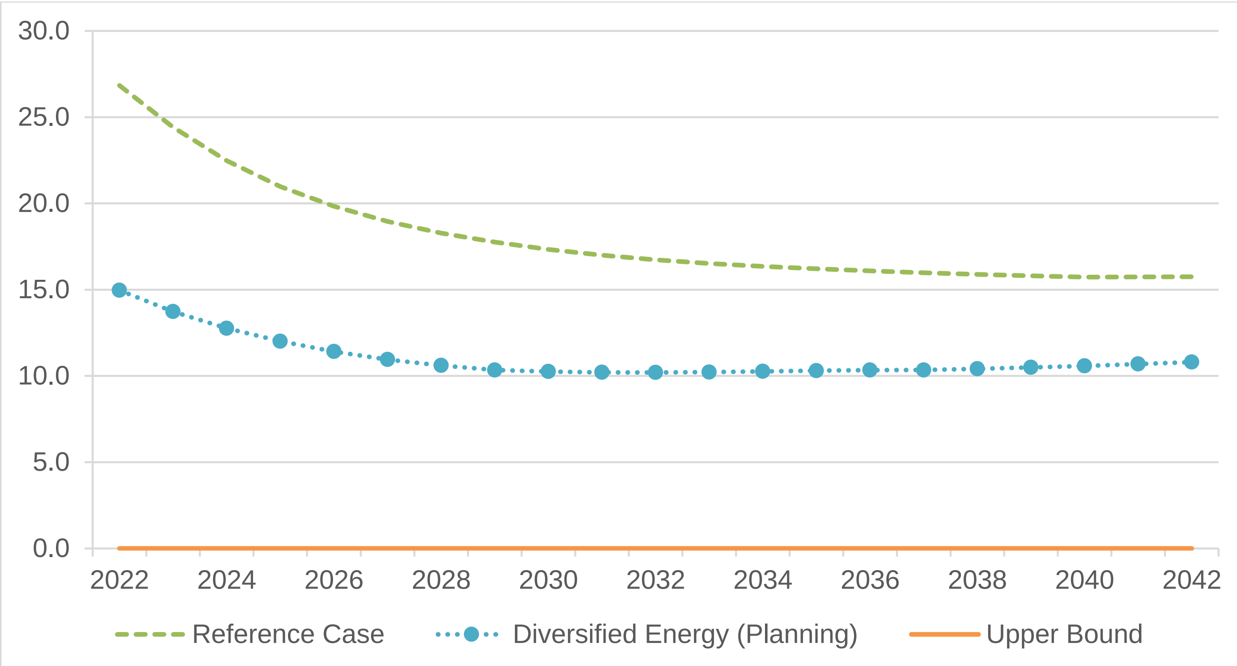
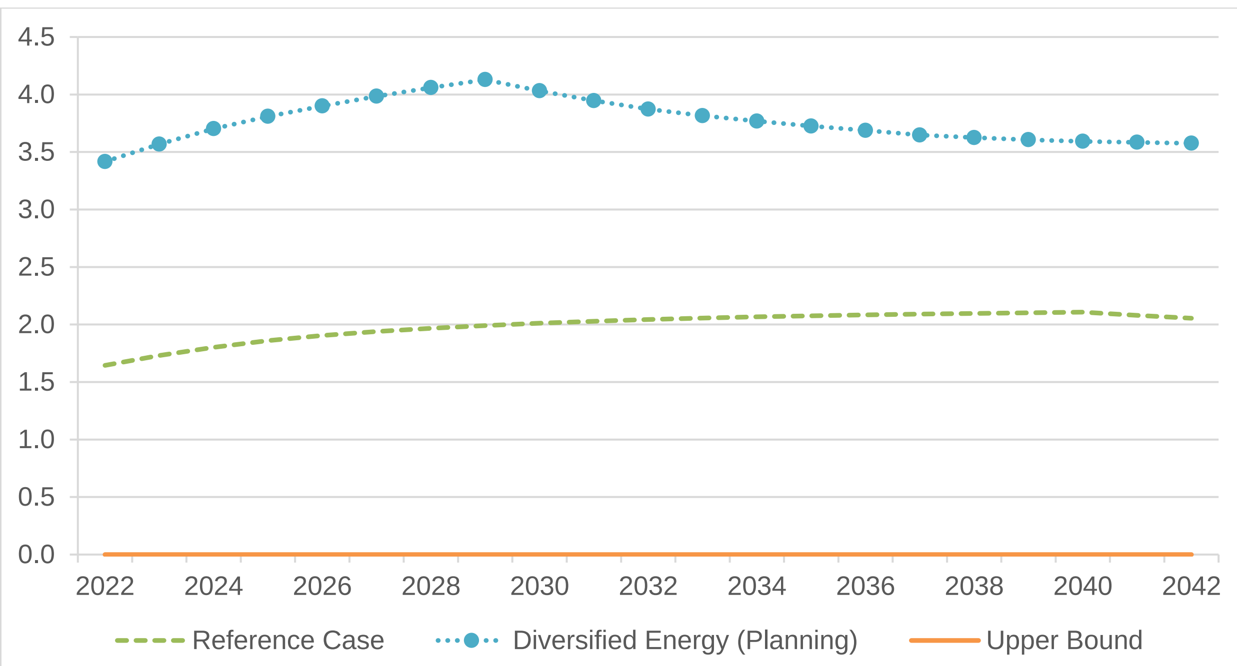


Figure C2-14: Estimated CCE Results by Scenario ($/GJ) – Industrial Sector



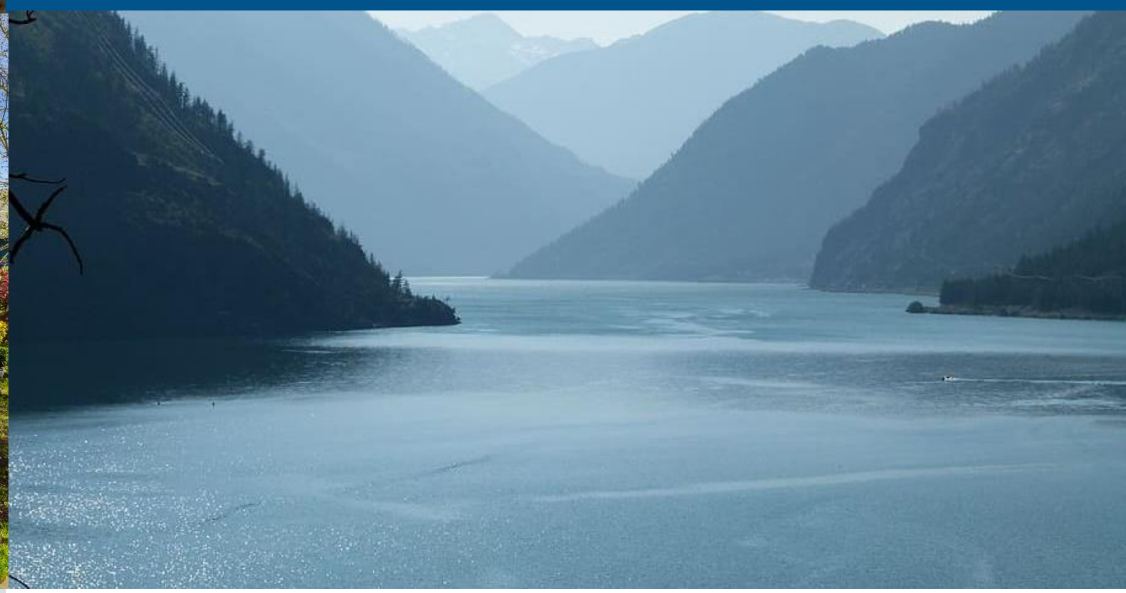
Appendix C-3

NON-PIPE SOLUTIONS FINAL REPORT



Non-Pipe Solutions Status Update

FINAL REPORT

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Acronyms

AMI	advanced metering infrastructure
ASHP	air-source heat pump
Btu	British thermal unit
C&I	commercial and industrial
CNG	compressed natural gas
DR	demand response
DSM	demand-side management
EE	energy efficiency
ETEE	enhanced targeted energy efficiency
ETO	Energy Trust of Oregon
FEI	FortisBC Energy Inc.
G2E	gas to electricity
GJ	gigajoule
GHG	greenhouse gases
GSHP	ground-source heat pump
IRP	integrated resource planning
IRPA	integrated resource planning alternative (Ontario equivalent for NPS)
LNG	liquefied natural gas
NESE	Northeast Supply Enhancement
NGDR	natural gas demand response
NPS	non-pipe solutions (also referred to as non-pipe alternatives (NPA))
NYSERDA	New York State Energy Research and Development Authority
OEB	Ontario Energy Board
PSC	New York Public Service Commission
PCT	participant cost test
REV	Reforming the Energy Vision
RIM	rate impact measure
RNG	renewable natural gas
SCADA	supervisory control and data acquisition
SCT	societal cost test
SPM	Standard Practice Manual (i.e. the California SPM, the National SPM)
TMA	Transportation Mode Alternative
TRC	total resource cost test
UCT	utility cost test

Executive Summary

FortisBC Energy Inc. (FEI) retained ICF Consulting Canada, Inc. (ICF) to research and report on the status of Non-Pipe Solutions (NPS) for natural gas distribution companies in North America. NPS are non-traditional and/or demand-side solutions that substitute for traditional capital investment in the gas distribution system infrastructure, including expansion of the gas network to new communities, reinforcement projects, or replacing older leak-prone pipes. Examples include energy efficiency, natural gas demand response, and electrification (i.e. gas to electricity) among others.

The potential for NPS to contribute to gas distribution system planning is largely based on the following:

- In some cases, NPS may be less expensive than traditional infrastructure investments, allowing natural gas customers to benefit from a downward pressure on transport and distribution rates
- Some NPS options may be more “modular” than traditional infrastructure investments, thus allowing for more “right-sized” solutions whose deployment is paced depending on need
- NPS may also reduce the risk of stranding gas distribution assets before the end of their book life, perhaps as a result of future carbon policies

In this report, ICF presents a review of NPS practices in a number of jurisdictions, with a particular focus on regions with relevant NPS activity. This report will be filed as part of FEI’s upcoming LTGRP submission to the BCUC and will partially fulfill the requirement “to provide an update of its analysis of opportunities for energy efficiency to be used to cost-effectively replace or defer infrastructure investments in its next LTGRP”, as per Decision and Order G-39-19.[1]

I. Definition of NPS

NPS can be used to address a range of different types of issues, based on the types and locations of the constraints and infrastructure investments faced by the utility. These issues include upstream constraints on pipeline capacity to the utility service territory, as well as existing and potential future infrastructure capacity constraints and investment requirements downstream of the city gate. This report focuses on distribution-level (demand side) NPS, which are located downstream of city gates.

[1] BCUC, ‘FortisBC Energy Inc. 2017 Long Term Gas Resource Plan: Decision and Order G-39-19’, 2019, p. Section 2.2.2, pp. 14–17 <https://www.bcuc.com/Documents/Proceedings/2019/DOC_53485_Decision-and-G-39-19-FEI-2017LTGRP.pdf> [accessed 12 November 2021].

Exhibit 1 summarizes the broad range of NPS options in two high-level categories:

Exhibit 1 Categorization of NPS Options

Distributed Infrastructure (Supply Side) Options

Liquefied Natural Gas (LNG)	Compressed Natural Gas (CNG)	Renewable Natural Gas (RNG) and Power to Gas (P2G)
Facility on land, on a barge or offshore with natural gas stored in cooled down liquid. The LNG must be delivered to the facility, and must then be gasified before being injected into the pipe network.	Facility on land with natural gas stored under high pressure in gaseous form. The CNG must be delivered, and is often trucked in. The CNG is decompressed before being injected into the pipe network.	Biomethanization facility that converts organic matter (often bio waste) into biogas. The biogas mainly contains methane but also other gases, some of them undesirable. The biogas is cleaned before injection into the pipe network. The RNG plant and the connection point to the network can be connected in an area of high constraint.

No-Infrastructure (Demand Side) Options

Enhanced Targeted Energy Efficiency (ETEE)	Natural Gas Demand Response (NGDR), and ***Enhanced Interruptible Rates***	Electrification (Gas to Electricity, G2E)
Gas consumption reduction in multiple buildings through a variety of technology upgrades and/or behavioural changes. Typically delivered in the form of an incentive, or a "kicker" adding to an existing franchise-wide program aimed at convincing multiple customers to implement the upgrades.	Curtailment of gas demand over a specific set of hours during peak demand periods through an automated system or a planned schedule. Gas DR can be used to alleviate day-long constraints at city gates or hourly constraints on the distribution system. Interruptible Rates are traditional gas utility resource akin to DR.	Conversion of space, water heating or even food service gas end-use to electrotechnologies on a geo-targeted basis to reduce peak day demand on parts of the natural gas distribution system. The electrotechnologies of choice to alleviate gas winter peak demand constraints are air-source and ground-source heat pumps. Although these technologies can help reduce natural gas peak demand, they generally contribute to electric peak demand.

Distributed infrastructure NPS options have a different risk profile than traditional distribution infrastructure because they can be generally be added in smaller and shorter-term capacity increments, reducing their risk of becoming stranded assets if the demand growth does not materialize as forecasted. However, distributed infrastructure NPS options are also typically more expensive than regular distribution infrastructure on a per unit capacity basis.

Nonetheless, CNG injection (CNG delivered by trucks) has been used to provide incremental natural gas capacity to the densely urbanized areas of New York City. Satellite LNG stations and propane-air stations have also been used for decades on nodes of the transmission pipeline network.

II. Jurisdictional Review

To date, there is limited experience with implementing NPS projects to address peak demand constraints. However, there have been significant developments with regards to NPS in the last few years. When ICF completed the 2018 IRP study for Enbridge Gas, it did not identify any natural gas utilities that were actively factoring in the impact of DSM programs on peak hour or peak day demand forecasts on their facilities planning. A few gas utilities had begun to consider these impacts, but their efforts were still in the early stages. ICF followed up twice with several of these utilities to document their progress since the 2018 IRP study to gain a better appreciation of the evolution of NPS. First, we consulted the utilities in 2020 as part of a study commissioned by Enbridge.[2] We then reached out to many of the same utilities in late 2021 as part of the present study. ICF consulted with Central Hudson (Upstate New York), Columbia Gas (Massachusetts), ConEdison (Downstate New York), NYSEG (Upstate New York), and NW Natural (Oregon).

In 2020, ICF identified several natural gas utilities that were considering the impact of their energy efficiency programs on the peak hour or peak day demand forecasts they use for their facilities planning. However, pilot projects related to NPS have been modest to date. As part of our current research and consultations, ICF identified several additional recent developments, not only in terms of new pilot programs but also with regards to NPS policy framework development.

NPS are being increasingly considered by gas utilities that are contemplating the modernization of long-term planning of their natural gas distribution systems in the context of decarbonization policies that include electrification.[3] For instance, New York, Colorado, Oregon, and California have started pursuing active electrification of their building sectors, leading to concerns over the adequacy of traditional utility infrastructure planning.

III. Long-Term Gas Capacity Planning and NPS Framework

In jurisdictions that have adopted a building electrification policy through legislation and rulemaking, gas utilities and utility commissions have started to pay greater attention to or even reform the approach to long-term gas capacity planning. Intervenors and stakeholders request better alignment of energy resources with climate policy direction in anticipation of reduced growth or even a potential decline in future natural gas demand, increasing the relevance of NPS options.

NPS can help address near-term natural gas demand growth that may be counter to the longer-term demand trajectory. Furthermore, NPS can help avoid issues with underutilized or abandoned pipes where demand is not guaranteed during the entire book life of the new pipe. NPS are only one instrument of a reformed long-term gas capacity planning approach in the context of a building electrification policy.

In anticipation of increased NPS activities, gas utilities seek the adoption of an NPS framework that can guide consideration and potential investments in NPS based on clear guidance from the utility commission. New York State and Ontario have both made progress towards adopting NPS frameworks. A NPS framework can, for instance, include:

- **A NPS process**, that is embedded in the natural gas infrastructure planning process. Steps of the NPS process can include steps such as: a characterization of the gas network needs or constraints requiring remedial action, a first-pass screening of these needs to remove traditional infrastructure projects that cannot be substituted by an NPS (e.g. a facility investment required to address a safety risk) and an evaluation process that includes but is not limited to technical feasibility within the timeline, and an economic assessment of NPS options.
- **Guidance on cost recovery, accounting treatment, and performance incentive for the utility,** which provides guidelines regarding how expenses related with NPS will be funded

[2] ICF, 'IRP Jurisdictional Review Report', *Completed on Behalf of Enbridge Gas Inc.*, 2020 <https://www.rds.oeb.ca/CMWebDrawer/Record/706445/File/document> [accessed 12 November 2021].
[3] With the notable exception of Ontario, jurisdictions that are working on implementing NPS pilots and developing an NPS framework have a decarbonization policy that includes building electrification.

through natural gas retail rates, and regarding how the natural gas utilities is to be rewarded for pursuing NPS.

- **Guidance on impact evaluation as well as reporting on progress.** The approach to impact evaluation and reporting should: (1) be flexible enough to adapt to the multiple types of NPS, and (2) strike the right balance between cost and rigour, thereby avoiding excessive reporting requirements. In the near-term, impact evaluation of NPS will generally not be able to leverage data from advanced metering infrastructure (AMI) meters for natural gas. Although this is not necessarily a barrier to implementing NPS, the absence of AMI data can impact the design of NPS projects[4] and the accuracy of impact evaluation results.
- **Guidance on how to perform economic assessment of the NPS solutions.** The economic assessment, or cost-benefit analysis, of the NPS solutions is largely grounded in a comparison between the cost of deploying NPS projects, and the avoided cost of the avoided traditional infrastructure project. These avoided costs include not only avoided cost of downstream capacity, reliability benefits, and/or avoided cost of obsolete pipe replacements, but also the avoided cost of upstream capacity, avoided cost of the natural gas commodity, and the valuation of net GHG abatement among other benefit streams. Developing a NPS cost-effectiveness testing approach based on the California Standard Practice Manual (SPM)[5] and/or on the National Standard Practice Manual[6] for Distributed Energy Resources is most appropriate.
- **Guidance on the approach to stakeholder engagement.** The recommended approach should strike the right balance between the overall flexibility of the process and the ability for stakeholders to add value by suggesting innovative solutions.
- **Guidance on the approach to implementation of the NPS projects and programs.** The framework should include recommendations on how, when, and from whom to source NPS. The recommendations should be commensurate with the size of the capital project to be substituted by an NPS.

Sufficient flexibility is a critical success factor for NPS frameworks. NPS projects can often be ramped up to address capacity needs, allowing gas utilities to react to observed impacts and evolving peak demand requirements.[7]

IV. NPS Pilot Projects and Programs

While ICF identified several NPS pilot projects, they remain relatively uncommon and constrained to a small number of jurisdictions.

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[4] The lack of AMI data can make it more challenging to "right-size" NPS projects. It can also impact the NPS options that are being considered.
[5] CPUC, *California Standard Practice Manual Economic Analysis of Demand-Side Programs and Projects*, *California Public Utilities Commission* (California, United States of America, 2001) <https://doi.org/10.1016/B978-1-85617-804-4.00018-5>.
[6] National Energy Screening Project, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, 2020 <https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf>.
[7] Unlike traditional infrastructure upgrades which typically result in the acquisition of one large "block" of capacity, NPS projects can often be modulated to address capacity needs.

The majority of the relevant pilots that ICF identified have been implemented by utilities in NY State. Exceptions include a NGDR pilot project in Southern California, an ETEE pilot project in Oregon, and a NGDR project in Colorado. Ontario has yet to implement any NPS pilot projects but Enbridge is in the early stages of identifying two pilot projects based on recent direction from the OEB to develop and implement two NPS pilot projects in sufficient time to collect measurement and verification results by winter 2022-2023.

ICF's research suggests that the majority of NPS pilots have tested NGDR technologies. This has included direct load control of smart thermostats to reduce space heating loads during peak demand periods. Some utilities have also piloted behavioural NGDR programs in large commercial and industrial buildings.

Three utilities in New York State have piloted or are in the process of piloting gas to electricity (G2E) conversion programs. There has only been limited additional activity with regards to ETEE pilot programs that are seeking to assess the magnitude of peak demand impacts related to the implementation of natural gas energy efficiency measures. Only one of these programs, which was focused on low-income weatherization, has yielded results to date.

ICF identified only one utility that used distributed infrastructure – a satellite CNG insertion station – for its NPS attributes, although this was not considered to be an NPS project by its respective regulator. RNG production facilities are becoming increasingly common infrastructure but reliability under peak demand conditions continues to be a challenge for these facilities and we have not found any that were deployed primarily for their NPS attributes. In addition, LNG facilities and propane-air facilities have been used for decades to alleviate transmission-level constraints.

V. Conclusions

The primary conclusions from this review include:

1) ICF identified some recent progress with regards to NPS both in New York State and in other jurisdictions, mostly as NPS are increasingly being considered as a novel component of reformed long-term natural gas infrastructure planning in the context of long-term decarbonization strategies. Jurisdictions that are planning for franchise-wide G2E in the medium or long term are considering NPS to solve local peak demand constraints or avoid obsolete pipe replacements without traditional gas infrastructure projects, which are typically amortized over 40+ years. The implications for electricity infrastructure needs as part of such wide-spread G2E are not assessed as part of this report.
2) Utilities in a small number of jurisdictions, such as New York State and Oregon, have made relevant progress in the development of NPS in terms of long-term capacity planning and analysis (e.g. National Grid Long-Term Capacity Planning reports) and pilot projects (ConEdison's NGDR pilot projects). In Colorado, NPS are being considered in the context of legislation encouraging widespread electrification of the building stock.
3) Recent and anticipated near-term developments with regards to NPS in New York State and Ontario are likely to provide useful examples and broader guidance on how to tackle many of the challenges associated with the broader implementation of NPS, such as:
    a. Treatment of issues related to utility remuneration and return on investment for different types of NPS
    b. Approaches to performance measurement and verification of NPS projects
    c. Transparency in the planning of NPS
    d. Minimizing the timeline for implementing and evaluating the impact of NPS

   e. Challenges associated with the sourcing of NPS

4) The lack of natural gas AMI meters is a challenge but not a barrier to NPS. Gas utilities have found workarounds to address the lack of AMI meters by using the interval data feeds from smart thermostats and water heater controllers, leveraging data from SCADA pipe pressure meters, and employing data feeds from electric AMI meters (e.g. using post G2E conversion electricity consumption to infer the baseline space heating gas demand). The resulting impact assessment may be less accurate, but there is also a reasonable amount of uncertainty with regards to long-term load growth forecasts, particularly for certain portions of the distribution network with fewer customers and less diverse energy use.

5) The timeline for NPS implementation is less of a hurdle if NPS decision and implementation is embedded in the capital project planning and decision process. If the NPS process was to overlap with the leave to construct application process, a three to five years lead time prior to forecasted capacity shortfall may be appropriate. It may be possible to implement smaller-scale NPS projects in a shorter timeline. Shorter timelines can generally be achieved by streamlining the approval and implementation process for NPS projects.

6) While GHG emission reductions are not the primary benefit utilities are seeking through NPS opportunities, decarbonization goals and policies are a key driver for adopting NPS. Not all NPS options lead to GHG emissions reductions, and the emissions abated by specific NPS projects are only ancillary to the policy goal of NPS. NPS are relevant to gas system decarbonization pathways since they can be used to avoid deploying new natural gas infrastructure whose medium- and long-term utilization may be significantly impacted by future decarbonization policies. This helps avoid potential issues with amortizing the cost of infrastructure over 40+ year timelines, during which it may become underutilized or obsolete.

1 Introduction

FortisBC Energy Inc. (FEI) retained ICF Consulting Canada, Inc. (ICF) to research and report on the status of Non-Pipe Solutions (NPS) for natural gas distribution companies in North America. NPS are non-traditional and/or demand-side solutions that substitute for traditional capital investment in the gas distribution system infrastructure, including expansion of the gas network to new communities, reinforcement projects, or replacing older leak-prone pipes. Examples include energy efficiency, natural gas demand response, and electrification (i.e. gas to electricity) among others.

Ongoing gas utility energy efficiency programs and interruptible rates have impacted the need for gas infrastructure investments for a number of years. However, this is different from the geo-targeted approach employed by NPS, where alternative options to replace or defer particular distribution infrastructure projects are considered.

The potential for NPS to contribute to gas distribution system planning is largely based on the following:

- In some cases, NPS may be less expensive than traditional infrastructure investments, allowing natural gas customers to benefit from a downward pressure on transport and distribution rates
- Some NPS options may be more “modular” than traditional infrastructure investments, thus allowing for more “right-sized” solutions whose deployment is paced depending on need
- NPS may also reduce the risk of stranding gas distribution assets before the end of their book life, perhaps as a result of future carbon policies

This report will be filed as part of FEI’s upcoming Long Term Gas Resource Plan submission to the BCUC and will partially fulfill the requirement “to provide an update of its analysis of opportunities for energy efficiency to be used to cost-effectively replace or defer infrastructure investments in its next LTGRP”, as per Decision and Order G-39-19.[8]

This study draws on a range of similar studies on NPS. For instance, FEI has been completing research and tracking developments with regards to NPS to determine if it could potentially use DSM to defer future natural gas infrastructure projects. As part of the regulatory process surrounding FEI’s 2017 Long Term Gas Resource Plan, FEI requested that ICF complete a report to respond to evidence from Energy Futures Group about the state of the industry regarding the use of NPS and the use of energy efficiency to defer or reduce the need for incremental infrastructure investments. This report was completed in 2018 and was submitted as expert witness testimony.

ICF’s report draws on research completed by ICF on behalf of Enbridge in 2018. ICF’s 2018 IRP study assessed the viability of employing targeted energy efficiency as an alternative to natural gas distribution system reinforcement infrastructure projects.[9] In addition to completing a jurisdictional review of NPS developments in other jurisdictions across North America and an assessment of distribution system planning and policy changes needed to facilitate NPS, the study included a detailed measure-level analysis of peak demand impacts and an assessment of a number of case studies.

[8] BCUC, p. Section 2.2.2, pp. 14–17.
[9] ICF, *Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment – Final Report*, 2018. Completed on behalf of Enbridge Gas Distribution and Union Gas Limited

In 2020, ICF updated the jurisdictional review portion of the IRP Study for Enbridge[10] as part of the OEB case EB-2020-0091, in which Enbridge requested that the OEB establish a framework to govern NPS activities in Ontario. ICF staff also testified as expert witnesses as part of this proceeding, which was completed in 2021.

[10] ICF, 'IRP Jurisdictional Review Report'.

2 Applicable Measures/Technologies

NPS are a set of non-traditional and/or demand-side solutions that can be used as substitutes to traditional capital investment in the gas distribution infrastructure. NPS are expected to generate additional benefit streams compared to traditional energy efficiency programs, including Avoided Cost of Downstream Capacity, Reliability Benefits, and Avoided Cost of Replacement of Obsolete Pipes (Often *Leak-Prone* Pipes).[11]

2.1 Purpose of NPS

NPS can be used to address a range of different types of issues, based on the types and locations of the constraints and infrastructure investments faced by the utility. These issues include upstream constraints on pipeline capacity to the utility service territory, as well as existing and potential future infrastructure capacity constraints and investment requirements downstream of the city gate.

This report focuses on distribution-level NPS, which are located downstream of city gates. Downstream (distribution-level) capacity constraints differ from upstream (transmission-level) constraints in that the investment needed to relieve the constraint is generally the responsibility of the distribution utility rather than an upstream pipeline. As a result, distribution-level NPS allow the distribution utility to both address capacity constraints and potentially reduce investments in long-lived infrastructure. In addition, the upstream capacity constraints that can be addressed by NPS tend to be based on peak day requirements for upstream pipeline capacity and peak day and seasonal requirements for upstream storage capacity.

At the distribution level, the constraints that can be addressed through NPS include daily requirements on parts of the system including transmission capacity, but are also driven by shorter term capacity requirements, down to the hourly or sub-hourly level as the distribution system gets closer to the end-user and as the distribution system piping becomes smaller in diameter. As a result, NPS at the distribution level can include measures and technologies that can reduce demand or shift demand away from peak periods for shorter periods of time relative to the upstream constraints. However, addressing distribution-level constraints requires a more thorough understanding of load growth and system capacity and customer characteristics, even in the low-diversity branches of the distribution system.[12]

NPS options can also be deployed to enhance distribution system reliability, potentially at a lower cost than traditional gas infrastructure options. Reliability benefits are focused on reducing the likelihood of low gas pressure in the distribution system during cold snaps and enhancing a natural gas utility's ability to react to unlikely yet impactful events such as extreme weather, accidents, fires, and terrorist incidents that cause supply and/or pressure disruption. For instance, over the past few years, extreme weather events, wildfires, and a pipeline explosion in FEI's service territory caused supply issues, prompting the utility to ask its customers to reduce their natural gas consumption. NPS options, such as gas DR or compressed natural gas

[11] The traditional benefit stream of energy efficiency programs includes avoided natural gas commodity costs, avoided upstream pipeline capacity (short-term contracting or building new pipelines), net greenhouse gas (GHG) abatement, and non-energy impacts.

[12] The level of diversity is defined and measured by the variety of end-uses and gas-using equipment, and the number of customers needing gas. A large population of heterogeneous customers has a high diversity level. A small population of homogeneous customers has a low diversity level. Low diversity level means more variability of the load and more challenging predictability of the load, both of which makes distribution infrastructure more challenging to plan for – especially in the long term.

(CNG), could have been used to either lower natural gas demand during these events or provide targeted supply to help alleviate demand constraints.

While GHG emission reductions are not the primary benefit utilities are seeking through NPS opportunities, decarbonization goals and policies can be a key driver for adopting NPS. However, not all NPS options lead to GHG emissions reductions. Nonetheless, NPS are relevant to gas system decarbonization pathways since they can be used to avoid deploying new natural gas infrastructure whose medium- and long-term utilization may be significantly impacted by future decarbonization policies. This helps avoid potential issues with amortizing the cost of infrastructure over 40+ year timelines, during which it may become underutilized or abandoned. However, some NPS options may impact electric peak demand, requiring additional electricity generation and investments to electric transmission and distribution infrastructure.

To date, there is limited experience with implementing NPS projects. However, as they become more common, NPS may sometimes be preferred over large gas infrastructure projects due to their modularity. NPS projects can often be ramped up to address capacity needs and their cost can generally be amortized over much shorter timelines. This enhances NPS' ability to avoid the potential for stranded gas infrastructure assets.

2.2 Categorization of NPS Options

The resources included in the definition of NPS vary depending on the utility and jurisdiction and have been evolving. For instance, in some parts of the United States, compressed natural gas (CNG) and liquefied natural gas (LNG) are considered important NPS options. In Ontario, where most of the NPS activity in Canada has been focused thus far,[13] NPS were first viewed as geo-targeted energy efficiency programs to reduce hourly gas peak demand. However, in its recent decision,[14] the Ontario Energy Board (OEB) has set a broader definition for NPS.

Exhibit 2 summarizes the broad range of NPS options in two high-level categories:

- **Distributed infrastructure:** Distributed infrastructure, as first formulated by National Grid,[15] represent natural gas infrastructure that are typically associated with the transportation or supply network. In the context of NPS, they are sited in areas of high constraint on the natural gas distribution network. In its recent decision, the OEB referred to this category of NPS as supply-side alternatives.
- **No-Infrastructure Options:** No-infrastructure options represent resources that are deployed behind the meter in the customers' premises. The OEB refers to this category as demand-side alternatives.

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[13] In Ontario, NPS have been referred to as Integrated Resource Planning Alternatives (IRPA). The IRPA terminology can be used interchangeably with NPS since both terms emphasize the local or geo-targeted nature of resource deployment to obtain maximum value. Ontario has also been using "Integrated Resource Planning" (IRP) to describe the integration of NPS in local distribution and transmission infrastructure planning, as opposed to franchise-wide gas planning as is the common usage of IRP terminology in British Columbia.

[14] Ontario Energy Board, *Decision and Order EB-2020-0091 Integrated Resource Planning Proposal* (Toronto, Ontario, Canada, 2021).

[15] National Grid, *Natural Gas Long-Term Capacity Report for Brooklyn, Queens, Staten Island and Long Island ("Downstate NY")* (New York City, NY, USA, 2020) <https://millawesome.s3.amazonaws.com/Downstate_NY_Long-Term_Natural_Gas_Capacity_Report_February_24_2020.pdf>.

Most of resources listed in Exhibit 2 can be deployed to seek benefits on a franchise-wise basis; however, they are considered as NPS when they are geo-targeted and considered as alternatives to distribution system infrastructure.

Exhibit 2 Categorization of NPS Options

Distributed Infrastructure (Supply-Side) Options

Liquefied Natural Gas (LNG)	Compressed Natural Gas (CNG)	Renewable Natural Gas (RNG) and Power to Gas (P2G)
Facility on land, on a barge or offshore with natural gas stored in cooled down liquid. The LNG must be delivered to the facility, and must then be gasified before being injected into the pipe network.	Facility on land with natural gas stored under high pressure in gaseous form. The CNG must be delivered, and is often trucked in. The CNG is decompressed before being injected into the pipe network.	Biomethanization facility that converts organic matter (often bio waste) into biogas. The biogas mainly contains methane but also other gases, some of them undesirable. The biogas is cleaned before injection into the pipe network. The RNG plant and the connection point to the network can be connected in an area of high constraint.

No-Infrastructure (Demand-Side) Options

Enhanced Targeted Energy Efficiency (ETEE)	Natural Gas Demand Response (NGDR), and ***Enhanced Interruptible Rates***	Electrification (Gas to Electricity, G2E)
Gas consumption reduction in multiple buildings through a variety of technology upgrades and/or behavioural changes. Typically delivered in the form of an incentive, or a "kicker" adding to an existing franchise-wide program aimed at convincing multiple customers to implement the upgrades.	Curtailment of gas demand over a specific set of hours during peak demand periods through an automated system or a planned schedule. Gas DR can be used to alleviate day-long constraints at city gates or hourly constraints on the distribution system. Interruptible Rates are traditional gas utility resource akin to DR.	Conversion of space, water heating or even food service gas end-use to electrotechnologies on a geo-targeted basis to reduce peak day demand on parts of the natural gas distribution system. The electrotechnologies of choice to alleviate gas winter peak demand constraints are air-source and ground-source heat pumps. Although these technologies can help reduce natural gas peak demand, they generally contribute to electric peak demand.

Distributed infrastructure NPS options have a different risk profile than traditional distribution infrastructure because they can be generally be added in smaller and shorter-term capacity increments, reducing their risk of becoming stranded assets if the demand growth does not materialize as forecasted. However, distributed infrastructure NPS options are also typically more expensive than regular distribution infrastructure on a per unit capacity basis.

A few jurisdictions are also exploring renewable natural gas (RNG) and power-to-gas as NPS. The role of these supply sources is currently relatively limited for practical reasons. The longer-term potential for these types of resources to serve constrained areas of a natural gas distribution system is limited by land occupation, population density, and the availability of locally-sourced feedstock. They would also only be considered as infrastructure alternatives in cases where the supply was highly reliable.

This study is focused on the demand-side resources: ETEE, NGDR and G2E. However, additional details on each of the NPS categories mentioned above, including distributed infrastructure are provide below.

2.2.1 Distributed Infrastructure

Distributed Infrastructure NPS options include geotargeted CNG, LNG, and RNG facilities, as well as commercial or market-based alternatives such as peaking supply, third-party assignments, or exchanges.

The utility regulator in Downstate New York established a precedent in 2019 by refusing CNG, LNG, and RNG as eligible NPS in a high-profile proposal made by ConEdison, the Smart Solutions Program.[16] The regulator took the view that using a performance incentive[17] to reward ConEdison for pursuing CNG, LNG, and RNG is inappropriate because these solutions must be considered as basic and urgent requirements to meet reliability requirements in ConEdison distribution license, and should not be rewarded in a similar fashion to other NPS options. Conversely, the OEB ruled that CNG, LNG and RNG are eligible to be considered as NPS options in Ontario.

Despite the ruling regarding distributing infrastructure in New York, CNG injection (CNG delivered by trucks) are increasingly being used to provide incremental natural gas capacity to the densely urbanized areas of New York City. Satellite LNG stations and propane-air stations have also been used for decades on nodes of the transmission pipeline network.

2.2.2 Natural Gas Demand Response (NGDR)

Demand response (DR) is widely applied in electricity markets. NGDR programs are starting to receive more attention as an NPS option. Exhibit 3 presents a typology of DR inspired by electricity DR.

Dispatchable NGDR solutions and programs attempt to lower demand by controlling the individual end-uses (e.g. space heating and water heating). In a dispatchable program, consumers agree to have their gas demand reduced when supply levels for the constrained area are in jeopardy (e.g., during a cold week in the winter). There are many methods to encourage participants to have their end-uses controlled remotely. For example, utilities can offer free devices, credits on gas bills, or lower gas rates, or they can leverage behavioural program approaches.

The gas industry has been implementing an approach to DR, using interruptible rates, for quite some time. Interruptible rates were originally designed to improve load factors, by "filling valleys" or increasing demand during off-peak periods. This allows gas utilities to amortize infrastructure costs over larger volumes of natural gas sales. It also reduces the need for high cost capacity during peak demand periods. Interruptible rates encourage customers to subscribe by offering lower rates in exchange for the ability for the gas utility to interrupt service during peak demand periods. Subscribers are typically required to shift to alternate fuels during interruptions – most often petroleum products.[18] The backup fuel equipment and storage capacity is an eligibility requirement for participation in many of these programs. Subscribers to interruptible rate programs may have to react to up to two dozen service interruptions per year.

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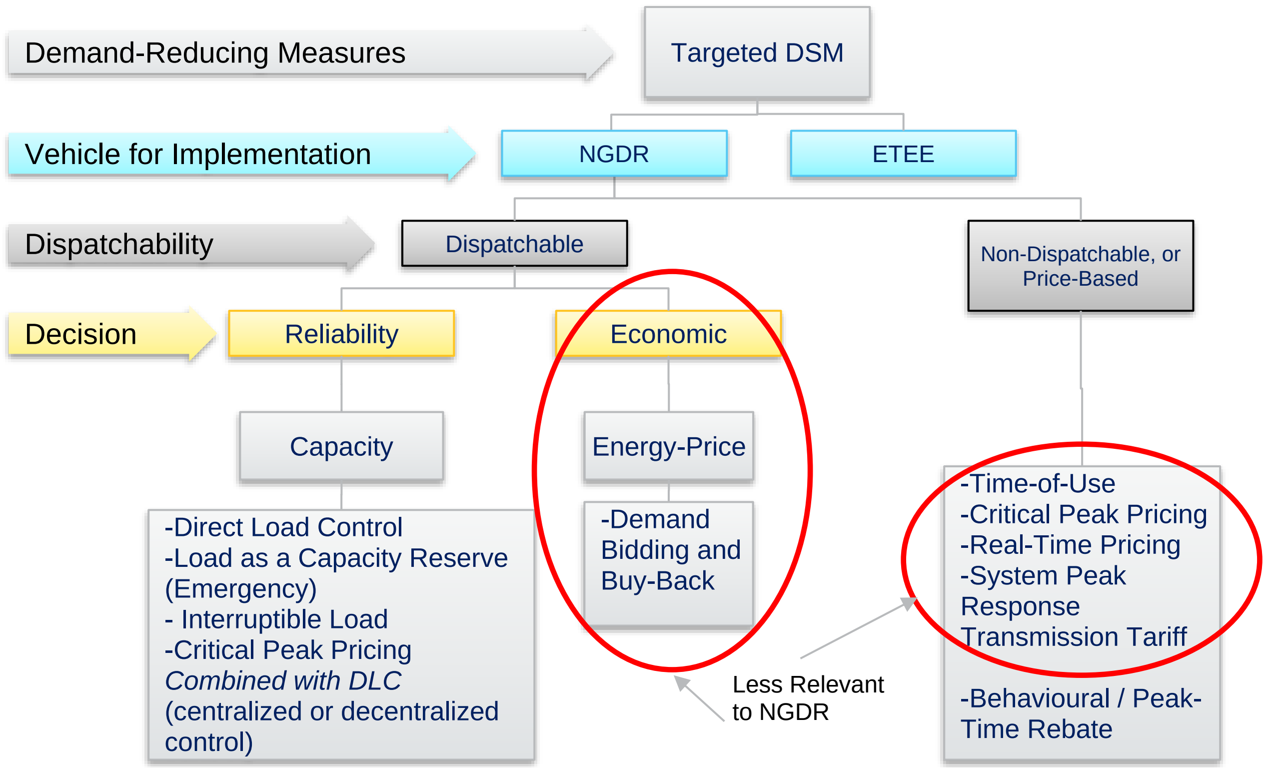
[16] NY Public Service Commission, *Case 17-G-0606 Order Approving with Modification the Non-Pipeline Solutions Portfolio*, 2019 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B64CE307C-4FD6-4043-8BE2-A5F04C5080E8%7D> [accessed 31 July 2020].

[17] ConEdison also requested a true-up to actual costs that would split overruns or underruns 50/50. A similar approach is used for electric non-wire solutions projects.

[18] The benefit of relying on a back-up fuel is that the gas service interruption can last for a large amount of time – i.e. a full day, or several days – with the only constraints being the size of the on-site fuel tank and delivery time for more fuel.

Exhibit 3 Suggested Typology for NGDR



Source: ICF expansion of a NERC industry-standard typology of electricity DR [19]

In addition to interruptible rates, utilities are starting to deploy novel NGDR options, such as those noted in Exhibit 3. They are starting to rely on a broader variety of technologies and/or price-based solutions such as advanced thermostats, behavioural programs, and direct load control (i.e. remotely-controlled curtailment). These approaches can help shift natural gas demand that has traditionally been served with firm service away from natural gas during peak periods. NGDR may prove to be more reliable at reducing peak demand since gas utilities can remotely dispatch during peak events.

A small number of gas utilities are also starting to deploy novel approaches to interruptible rates as they seek to expand the pool of customers that participate in these initiatives. For example National Grid's NGDR program in New York is offering its commercial and industrial building sector a "firm-service rate" with voluntary curtailment as opposed to mandatory interruption. Participants in this program have the right to firm service but are rewarded for curtailing their peak demand upon request. Conversely, a participant in a traditional interruptible rate does not have the right to a firm service and gets penalized for not participating in an event.

National Grid also required participants in its NGDR program to implement "clean DR". "Clean DR" is any NGDR approach that avoids the use of a fossil fuel-based back-ups during curtailment periods.[20] While the majority of traditional interruptible rates require a reliable fossil

[19] NERC, *Demand Response Availability Report* (Atlanta, GA, USA, 2011).

[20] "Clean DR" was introduced by the regulator of New York State at the start of a recent proceeding on gas planning that we will discuss in the remainder of this report. The regulator did not define it, however, except for mentioning that it would avoid the combustion of a petroleum product as a back-up energy source.

fuel-based back-up, a clean DR approach may see customers making use of biofuels, switching to resistive electric heating,[21] and/or relying on a thermal storage system.[22]

As we discuss in more detail in subsequent sections of this memo, some NGDR options have been pilot-tested by different utilities across North America. Although utilities are still assessing NGDR's potential to respond to their immediate needs, it may have growing relevance in NPS considerations given its ability to specifically curtail peak demand. However, the value of a DR program is dependent on the value of the peak demand reduction, which varies widely by jurisdiction.

2.2.3 Gas to Electricity (G2E) Conversion

G2E conversion (electrification from natural gas) is a relatively new concept in NPS. Electrification of gas-fired equipment be used to offset growth in natural gas requirements and investments in infrastructure. G2E programs have mainly focused on deploying air-source heat pumps (ASHPs), ground-source heat pumps (GSHPs), and heat pump water heaters (HPWHs). Any GHG emissions reductions from these technologies are dependent on the use of relatively "green" electricity. In addition, although these technologies can help reduce natural gas peak demand, they generally increase electric demand during peak winter periods, potentially increasing electric system capacity requirements.[23, 24] As a result, the assessment of G2E NPS needs to address the potential cost impacts on the electric grid, and on the customer, increasing the complexity of the NPS assessment.

Downstate New York has investigated G2E as a possible NPS; especially given the critical gas shortages in the area that have led to moratorium on new firm gas connections. However, the state regulator has not yet ruled on whether G2E programs can be employed as NPS in the state. Enbridge in Ontario also proposed that G2E conversion (e.g. electric ASHPs, geothermal systems, and district energy systems) be included as an option within its proposed NPS Framework. The utility acknowledged that these would be new activities that go beyond gas distribution and submitted that they should be considered a rate-regulated activity. However, the OEB ruled that "as part of this first-generation IRP Framework, it is not appropriate to provide funding to Enbridge Gas for electricity IRP alternatives" (i.e. G2E conversions).[25]

2.2.4 Enhanced Targeted Energy Efficiency (ETEE)

Energy efficiency (EE) includes a wide array of energy conservation measures that reduce natural gas consumption associated with space heating, water heating, food services, and industrial processes in residential, commercial, and industrial facilities. EE programs are mainly

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[21] Because interruption callups would likely happen during short periods of time, during cold snaps, electric resistance is probably the most technically and economically feasible solution from a customer standpoint. Heat pumps are more expensive than resistive heat, making economic viability challenging for so few hours of use. Heat pumps' performance and capacity is hampered during cold snaps while resistive heating equipment is not. However, it should be noted that using resistive electric heating during peak demand periods will contribute to electric system peak demand. Depending on the electric generation mix at this time, this may not result in net GHG emissions reductions.
[22] A gas-fired thermal storage solution would be a novel technology to be developed. To ICF's knowledge, mature thermal storage technologies are only electric.
[23] The impact of G2E NPS will depend on the nature of the local electric grid. A system that is currently summer peaking could absorb a certain amount of G2E without impacting overall system peak.
[24] End use facilities may also need to implement costly upgrades to their electric panels to accommodate the increase in electric load. In addition, mass adoption of electrification will require significant electric distribution and transmission infrastructure investments.
[25] Ontario Energy Board, *Decision and Order EB-2020-0091 Integrated Resource Planning Proposal*.

focused on reducing annual (or sometimes seasonal) volumes of natural gas consumption and they don't typically track or even estimate peak demand impacts of the EE measures.

ETEE has the following two characteristics that differentiate it from generic franchise-wide energy efficiency:

- **ETEE are "geo-targeted" in that they focus on specific areas of the distribution network:** Program administrators of ETEE programs can use a subset of the same conservation measures used franchise-wide to alleviate peak demand constraints downstream of city gates. In other words, ETEE is typically focused on specific branches of the distribution system. Geo-targeting generally requires additional promotion of some of the same EE technologies that are eligible to all customers in the distribution license. This can include additional marketing or increased incentives (sometimes called "incentive kickers"[26]). ETEE can also include incremental measures that are not eligible for rebates in the utility's broader EE programs.
- **ETEE focuses on reducing demand during specific hours:** Downstream constraints are often driven by hourly rather than daily peak demands and tend to be for a few hours at a time. The use of ETEE require a thorough understanding of the "load shape" of the gas savings, hour by hour. This is a critical aspect of ETEE because ICF's research suggests that relatively little data collection and analytical work has been completed to date to quantify the hourly demand profile from natural gas conservation measures.[27] Based on our current review of relevant pilot programs, this continues to be the case.

EETE programs can also be focused on alleviating peak demand constraints at the transmission level (i.e. upstream constraints), and they would then be focused on measures that reduce peak day demand rather than peak hour demand.

2.3 Peak Coincidence and Appropriateness of ETEE Measures

The ideal ETEE measure is one that scores well on the standard DSM benefit-costs tests (TRC, PCT, RIM, UCT), while also having a gas savings profile that coincides with peak demand. As such, cost-effective space heating measures (both HVAC equipment and thermal envelope improvements) tend to have the greatest potential as ETEE measures. However, any energy efficiency measure that reduces natural gas demand during the period of interest (e.g., peak day or peak hour) could provide potential benefits as an ETEE measure.

This phenomenon is demonstrated in Exhibit 4, which is based on the analysis ICF completed as part of its 2018 IRP Study for Enbridge.[28] Although these costs are not necessarily relevant to the FortisBC context, it is useful to discuss the relative differences between the measures included in this exhibit. The exhibit shows the costs and peak hour demand savings potential of an assortment of residential, commercial, and industrial EE measures. Here, it is evident that although space heating measures such as insulation, draft proofing, and high efficiency HVAC equipment are among the measures

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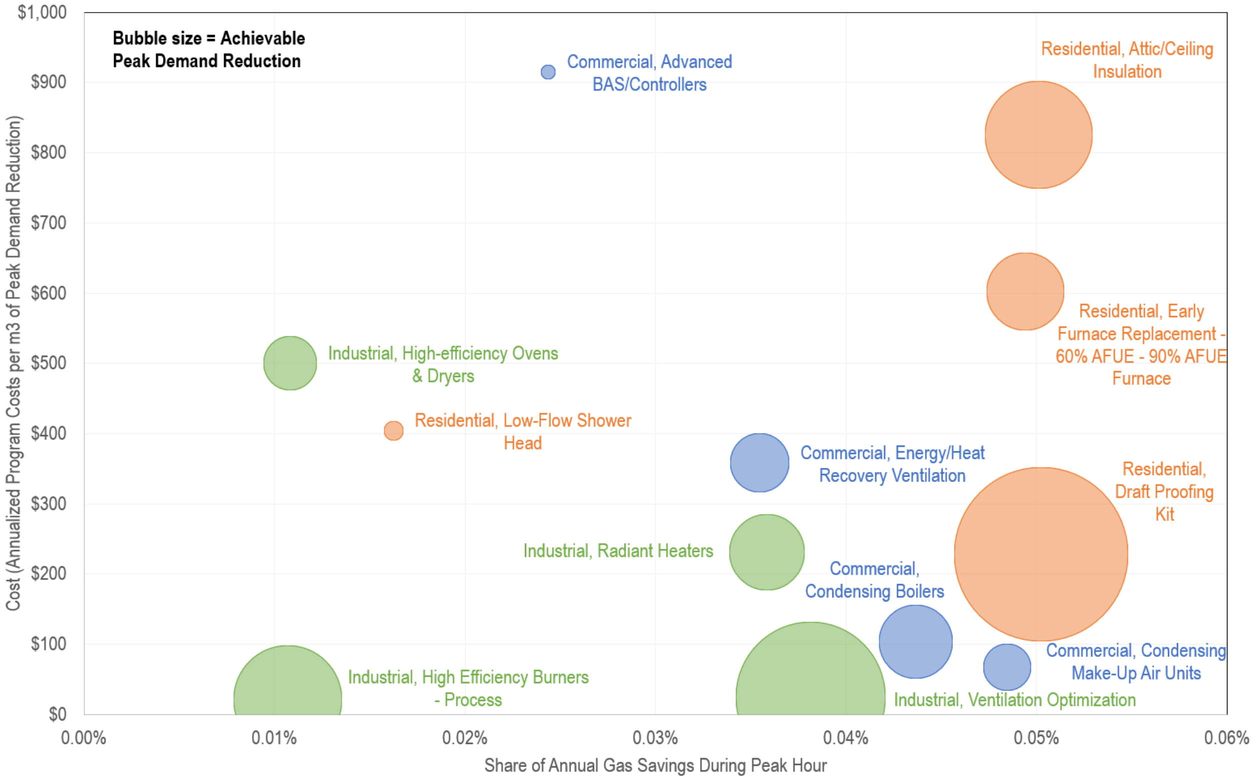
[26] "Incentive Kickers" are add-on to the franchise-wide EE incentive to induce more participation from a subset of customers.
[27] ICF, *Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment – Final Report*.
[28] As noted previously there is very limited data collection on the peak demand impacts of targeted energy efficiency measures. As such, ICF is not aware of any data to help validate the results of this analysis.

with the highest concentration of gas savings during the peak demand hour (furthest right along the x-axis), they are not necessarily the most cost-efficient measures in terms of reducing peak hour demand. For example, commercial condensing makeup air (MUA) units and residential attic/ceiling insulation both have gas savings that are highly coincident with the peak demand hour but the cost per unit peak demand savings is much lower for commercial condensing MUA units.

Exhibit 4 Relative Peak Hour Savings and Costs of Select Residential, Commercial, and Industrial DSM Measures

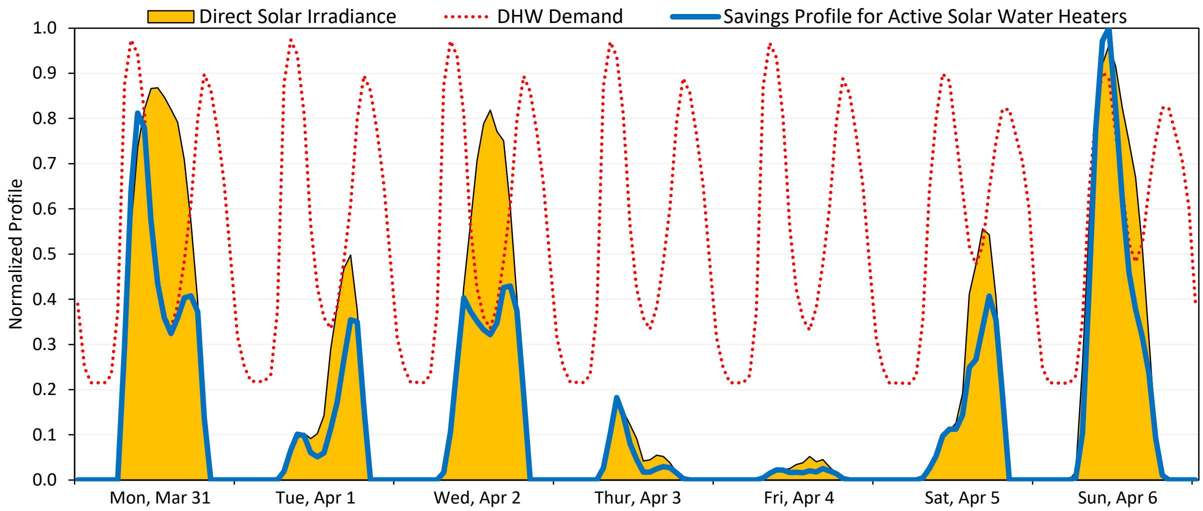


As part of our 2018 IRP Study for Enbridge, ICF developed hourly load profiles of the demand savings for a variety of energy efficiency measures. The approach for deriving measure-level load profiles fell broadly into the following categories:

- **Uniform savings profile:** For many measures, it was assumed that the savings profile matches the end-use profile to which it applies. For example, the distribution of energy savings resulting from a building envelope measure (e.g., attic insulation) was assumed to follow the space heating load profile.
- **Non-uniform savings profile:** For some measures, such as controls measures, the measure savings are not uniformly distributed and it is necessary to develop estimates of how the measure savings are distributed. This can be accomplished by developing custom load profiles for these measures. Although these measures may have non-uniform savings profiles, their savings may still be partially dependent on end-use load profiles coupled with variations in other parameters, such as building occupancy, control strategy, or solar irradiation. For such measures, customized approaches are necessary to generate hourly gas savings profiles. For example, Exhibit 5 shows how normalized DHW and solar irradiance profiles can be used to generate an hourly gas savings profile for residential active solar water heaters.

- **No impact on peak demand:** Certain measures do not coincide with peak (i.e., none of the savings occur during the peak). At the extreme, this includes measures such as high-efficiency pool heaters for the residential sector. For ETEE programs that are focused on winter peak demand, it may not be necessary to estimate peak demand savings from these measures.

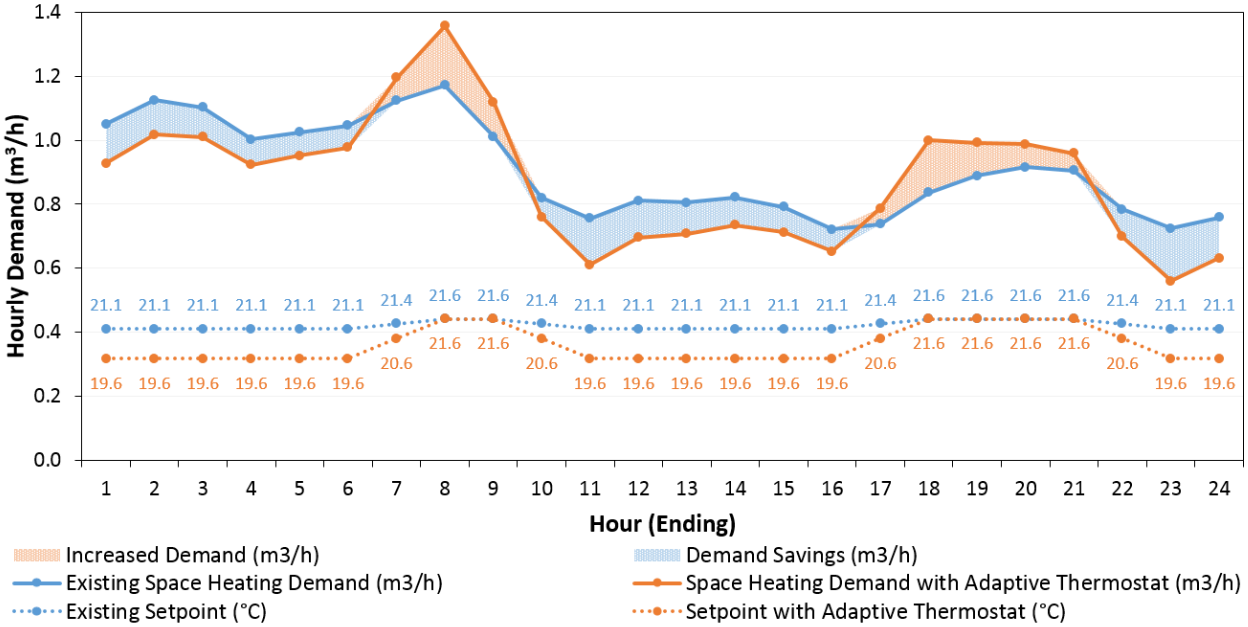
Exhibit 5 Savings Profile for Residential Active Solar Water Heaters



Among this group of DSM measures having more complex hourly gas savings profiles are two high-profile DSM measures: adaptive thermostats and tankless water heaters. Due to the prominence of these measures in current DSM portfolios across North America, ICF investigated their peak demand impacts in greater detail.

For adaptive thermostats, building performance simulations were conducted in EnergyPlus for two different temperature schedules. These schedules represent the reference and measure cases, the latter of which consists of more aggressive nighttime and daytime temperature setbacks, as would be expected with the implementation of an adaptive thermostat. The resulting gas demand profiles are also illustrated in Exhibit 6, where it can be observed that the early morning temperature recovery period induced by nighttime temperature setbacks is likely to lead to an increase in the winter peak hour demand that typically occurs between 7-9 am.

Exhibit 6 Residential Sector Hourly Demand Comparison for Adaptive Thermostats



ICF's analysis of tankless water heaters accounted for the fact that tankless water heaters typically achieve a uniform energy factor in the range of 0.9, while the uniform energy factor for storage water heaters typically falls in the range of 0.6. These higher efficiencies, which make tankless water heaters a cornerstone of many utility DSM programs, are made possible by the fact that hot water is only produced as it is needed. As such, tankless water heaters do not lose heat to the environment during periods of inactivity, as is the case for storage water heaters. Tankless water heaters do, however, require significantly higher heating capacities in order to produce hot water on demand (e.g., 180 kBtu/h compared to 40 kBtu/h for an equivalent storage water heater). This fact brings into question the impacts of tankless water heaters on peak hourly demand. These impacts are not obvious, as they depend greatly on the temporal diversity of hot water consumption among a larger population of consumers.

To further investigate these impacts, ICF used EnergyPlus to model and compare gas demand for both tankless and storage water heaters. This analysis leveraged publicly available residential hot water draw profiles with high temporal resolution (5 minutes).[29] In order to assess population level impacts, the draw profiles of profligate water consumers with different usage patterns (morning, evening, distributed) were superimposed upon one another to simulate the hot water demand of a community consisting of 129 households.

The modeled daily load profiles for tankless and storage water heaters are illustrated in Exhibit 7, where it can be seen that, even at a 5-minute resolution, gas demand from tankless water heaters rarely exceeds that of storage water heaters. ICF's analysis suggests that it is highly unlikely that widespread adoption of tankless water heaters will increase peak hourly demand (assuming storage water heaters as a baseline). However, this theoretical analysis does not necessarily confirm that tankless water heaters will lead

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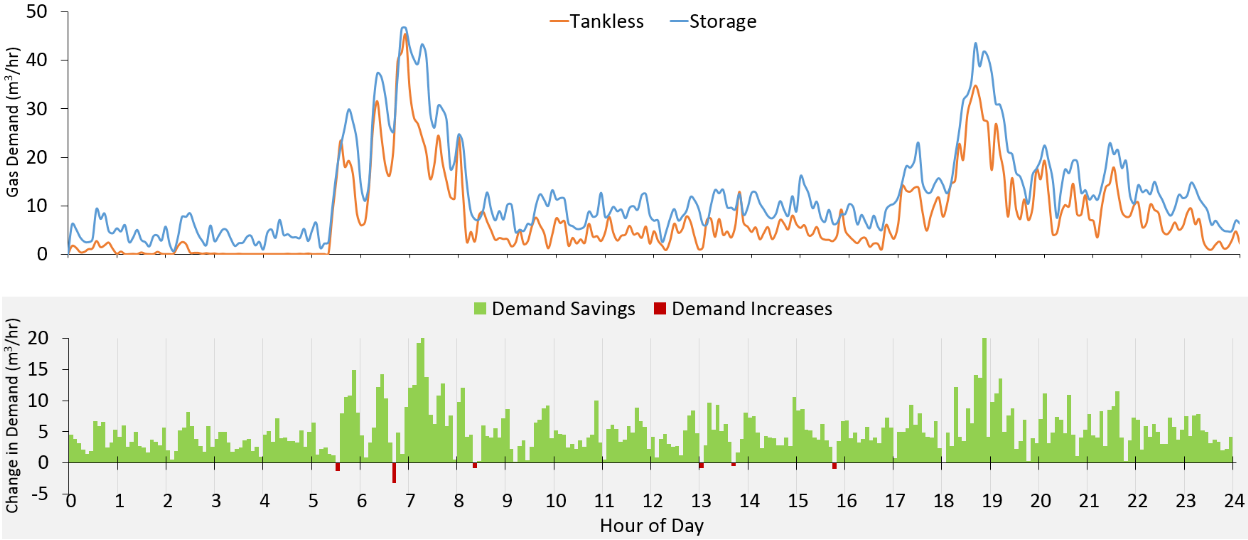
[29] Edwards, S. et al., *Representative Hot Water Draw Profiles at High Temporal Resolution for Simulating the Performance of Solar Thermal Systems*, Solar Energy (111) p. 43-52, 2015. https://carleton.ca/sbes/publications/hot-water-demand-profiles-downloadable/

to significant peak demand reductions.

Exhibit 7 Simulated Community-Level Gas Demand of Tankless and Storage Water Heaters, 5-Minute Resolution



3 NPS Developments Across North America

To date, there is limited experience with implementing NPS projects to address peak demand constraints. However, there have been significant developments with regards to NPS in the last few years. When ICF completed the 2018 IRP study for Enbridge Gas, it did not identify any natural gas utilities that were actively factoring in the impact of DSM programs on peak hour or peak day demand forecasts on their facilities planning. A few gas utilities had begun to consider these impacts, but their efforts were still in the early stages. ICF followed up twice with several of these utilities to document their progress since the 2018 IRP study to gain a better appreciation of the evolution of NPS. First, we consulted the utilities in 2020 as part of a study commissioned by Enbridge.[30] We then reached out to many of the same utilities in late 2021 as part of the present study. ICF consulted with Central Hudson (Upstate New York), Columbia Gas (Massachusetts), ConEd (Downstate New York), NYSEG (Upstate New York), and NW Natural (Oregon).

In 2020, ICF identified several natural gas utilities that were considering the impact of their energy efficiency programs on the peak hour or peak day demand forecasts they use for their facilities planning. However, progress on pilot projects related to NPS had been modest to date. As part of our current research and consultations, ICF identified several additional recent developments, not only in terms of new pilot programs (as described in Section 5) but also with regards to NPS policy framework development.

NPS are being increasingly considered by gas utilities that are contemplating the modernization of long-term planning of their natural gas distribution systems in the context of decarbonization policies that include electrification.[31] For instance, New York, Colorado, Oregon, and California have started pursuing active electrification of their building sectors, leading to concerns over the adequacy of traditional utility infrastructure planning.

3.1 FEI NPS Experience

FEI owns and operates approximately 50,000 km of natural gas transmission and distribution pipelines across BC, providing natural gas to over 1 million customers in the province. FEI has traditionally built regional peak demand forecasts based on a customer-by-customer analysis of the relationship between peak demand and weather based on historically observed trends, with current peak hour use per customer being held constant over the planning horizon. However, the utility has been exploring how peak hour demand per customer may vary at the end-use level based on load profile analysis.[32] This approach also translates consumption savings into peak demand impacts, allowing the utility to explore the potential impacts of broad based DSM programs upon peak hour demand.

Although FEI has investigated how end-use forecast modelling might be able to help inform peak demand forecasting, the utility has not assessed DSM or other non-pipe solutions as an alternative to infrastructure at a detailed level due to concerns related to the magnitude and reliability of peak demand impacts as well as the timelines associated with these projects. In addition, the results from their traditional peak demand forecast method remains FEI's base forecast for planning purposes since the exploratory end-use method is not based on metered FEI customer data. However, FEI is continuing to monitor potential metering solutions that may allow FEI to validate the results of the exploratory end-use forecasting method.

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[30] ICF, 'IRP Jurisdictional Review Report'.
[31] With the notable exception of Ontario, jurisdictions that are working on implementing NPS pilots and developing an NPS framework have a decarbonization policy that includes building electrification.
[32] FortisBC, 2017 Long Term Gas Resource Plan, Dec. 14, 2017, p.149.

FEI has been monitoring a small number of potential system constraints and studying a range of supply-side reinforcement options. However, FortisBC staff have indicated that there are no specific major gas infrastructure projects where DSM could be used as an alternative in FEI's service territory in the next several years. In addition, we understand that FEI continues to examine expanding its forecasting approach and the capacity impacts of franchise-wide energy efficiency. FEI has also indicated that it is starting to assess metering solutions that may enable further study into whether DSM can be used as a cost effective alternative to infrastructure spending.

3.2 NPS Framework

Ontario and the New York State are the two jurisdictions that have taken the lead with regards to developing formal frameworks for NPS.

In New York State, the driver behind the development of the framework was supply problems that were so acute that they forced the gas utilities to declare moratoriums on new customer connections. The pipelines serving the region are at capacity and their number has not increased despite significant growth in natural gas demand over the past decade due to a shift away from heating oil. The issue is so pronounced that parts of ConEd in Downstate New York imposed a moratorium on new customers connections. Moratoriums have also been declared in National Grid New York, National Grid Long Island, and Niagara Mohawk (Capital Region) service territories. NYSEG had to impose a moratorium as well.

In Ontario, Enbridge sought to be responsive to direction by the OEB to consider NPS as part of a leave to construct applications and sought to demonstrate that NPS could not be a replacement for the Dawn-Parkway System Expansion project.[33]

Both Ontario and the State of New York have thereby worked on policy frameworks to ensure that NPS are formally being considered as part of the long-term planning of the natural gas transmission and distribution networks. An NPS framework codifies how natural gas utility planners ought to consider NPS both in a systematic fashion when capital upgrades are being considered, and in comparison with each other based on a set of fair, pre-determined criteria.

The Ontario framework[34] was developed based on an application from Enbridge and an oral hearing with the Ontario Energy Board. The OEB ruled on Enbridge's application in an appendix to Decision and Order EB-2020-0091. The New York State NPS framework[35] was proposed by ConEd in 2020 as part of a rate case and is still being deliberated in front of the Public Services Commission (PSC).

The Ontario (OEB) framework and the New York framework (i.e. ConEd's proposed framework) have the following points in common:

- **A NPS process**, which entails a characterization of the gas network needs or constraints requiring remedial action, a first-pass screening of these needs to remove traditional infrastructure projects that cannot be substituted by an NPS (e.g. a facility investment required to address a safety risk) and an evaluation process that includes but is not limited to technical feasibility within the timeline, and an economic assessment of NPS options. In New York, there are three types of upgrades that trigger the consideration of NPS an

[33] The project has been withdrawn since then.
[34] Ontario Energy Board, *Decision and Order EB-2020-0091 Integrated Resource Planning Proposal*.
[35] ConEdison, *Proposal For Use Of A Framework To Pursue Non-Pipeline Alternatives to Defer Or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure. Case 19-G-0066*, 2020 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B2CCB0D2A-183A-483B-9F56-87878E0471FA%7D>.

alternative: load relief upgrades (i.e. installing a large main to support growth in peak demand), regulator station upgrades (i.e. upgrading the pressure regulator for continued reliability), and main pipe replacements (i.e. replacement of obsolete pipes, such as wrought irons pipes or unprotected steel pipes).

- **Guidance on cost recovery, accounting treatment and performance incentives for the utility,** which provides guidelines regarding how expenses related with NPS will be funded through natural gas retail rates, and regarding how the natural gas utilities is to be rewarded for pursuing NPS.
- **Guidance on impact evaluation as well as reporting on progress.** The New York framework provides guidance on how to assess avoided peak natural gas load rather than annual savings. Ontario provides guidance on frequency of reporting and nature of reporting about its NPS activities and portfolio to keep the OEB and stakeholder appraised of progress.
- **Guidance on how to perform economic assessment of the NPS solutions.** The economic assessment, or cost-benefit analysis, of the NPS solutions is largely grounded in a comparison between the cost of deploying NPS projects, and the avoided cost of the avoided traditional infrastructure project. These avoided costs include not only avoided cost of downstream capacity, reliability benefits, and/or avoided cost of obsolete pipe replacements, but also the avoided cost of upstream capacity, avoided cost of the natural gas commodity, and the valuation of net GHG abatement among other benefit streams. The proposed methods have many similarities.
  - The New York framework proposes a benefit-cost analysis handbook in appendix of the framework which aligns with the main principles that were set by the California Standard Practice Manual (SPM) for Demand-Side Energy Resources. The main decision test is the societal cost test (SCT), but New York Gas Utilities are also required to compute the utility cost test (UCT) and the rate impact measure test (RIM), which are three traditional economic tests that were originally described in the California SPM.
  - The Ontario framework proposes the use of the Discounted Cash Flow-Plus Test (DCF+). The DCF+ test has been the traditional test employed in Ontario to assess both transmission pipeline applications and to assess regular franchise-wide energy efficiency programs. In appearance, the DCF+ test seems to differ from New York's California SPM-inspired approach. In the details, however, it is similar because the final DCF+ test result, used to make decision, is akin to the SCT[36], which such tests as the RIM, the participant cost test (PCT) and the total resource cost test (TRC) also being computed as part of the interim steps prior to obtaining the final DCF+ cumulative result.

The New York framework differs from Ontario framework in that it has added details and guidance on how, when and from whom to source NPS. For instance, for large NPS, ConEd would be required to launch a public solicitation for solutions from third party suppliers. For smaller NPS projects, however, gas utilities benefit from more latitude on the implementation

[36] Just like cost-benefit analysis under the California SPM framework, the DCF+ test compared net present value of cost and net present value of benefits. The DCF+ test has three phases that are used separately and in combination. Each phase has a different set of benefits and cost being considered. The decision factor is the combination of all benefits and costs from the three phases. Phase 1 is akin to the RIM. Phase 2 is akin to the PCT with GHG emissions (abated or added) being valued and incorporated in the test. The cumulative of Phase 1 and 2 is akin to the TRC. The cumulative combination of Phase 1, 2 and 3 of the DCF+ is akin to the SCT.

approach. Gas utilities can, for instance, augment existing franchise-wide energy efficiency programs or heat pump programs by geo-targeting the marketing effort in the areas of high constraint, and/or top-off the franchise-wide incentive with an “incentive kicker.”

In the proposed framework, ConEd stressed the importance of flexibility of the framework in light of its experience with *non-wire* alternative projects; i.e. the equivalent of NPS but in the electricity sector. For instance, the demand growth for natural gas may not materialize as per the load forecast, canceling or reducing the need for NPS. Or else, the natural gas demand may increase unexpectedly, requiring quickness of intervention that can only be achieved by a traditional infrastructure upgrade. NPS projects can often be ramped up to address capacity needs, allowing gas utilities to react to observed impacts and evolving peak demand requirements.[37]

The Ontario framework is characterized by added details on approach to ensure the gas utilities plan NPS in a transparent manner, including the requirement to perform annual stakeholder engagement and NPS project-specific (targeted) stakeholder engagement events, the creation of a Technical Working Group to advise the OEB on the adjudication of future NPS projects, and requirements to make efforts to accommodate participation of Indigenous groups.

The Ontario framework requires Enbridge Gas to develop and implement two NPS pilot projects in 2022. Enbridge has not deployed NPS pilot projects to date. As presented in the next pages, New York gas utilities, including but not limited to ConEd, have implemented many pilot NPS projects and are in the process of implementing many more.

3.3 Jurisdictional Scan

As some jurisdictions such as New York State, Oregon, and California have implemented decarbonization policies and are starting to consider how they can electrify their building stock, NPS are being considered as options that gas utilities can deploy to replace or defer some future gas infrastructure investments.[38] NPS are increasingly being considered as an approach to meet isolated and temporary peak demand constraints in specific areas of the distribution network, and to avoid to the replacement of obsolete pipes.

The following sections provide an overview of relevant NPS developments in several jurisdictions.

3.3.1 New York

New York State (particularly Downstate New York) has seen a broad range of proposed NPS projects, including distributed CNG and LNG projects, as well as local RNG projects. ConEd, one of the large investor-owned natural gas utilities in the State, has proposed a framework for NPS to the PSC.[39] In addition, a few innovative NPS pilot projects based on EE, gas DR, and electrification programs have been implemented or proposed. More pilot programs and projects are underway. NPS are expected to become part of the routine long-term capacity planning

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[37] Unlike traditional infrastructure upgrades which typically result in the acquisition of one large “block” of capacity, it may be possible to modulate some NPS projects to address capacity needs.

[38] Regulatory Assistance Program (RAP), ‘Under Pressure: Gas Utility Regulation for a Time of Transition’, 2021 <https://www.raponline.org/wp-content/uploads/2021/05/rap-anderson-lebel-dupuy-under-pressure-gas-utility-regulation-time-transition-2021-may.pdf> [accessed 17 January 2022].

[39] ConEdison, *Proposal For Use Of A Framework To Pursue Non-Pipeline Alternatives to Defer Or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure. Case 19-G-0066*.

process for the NY utilities, and the State has been active in developing a set of best practices surrounding NPS, including ConEd's proposed NPS framework.

There are several drivers that have led to New York State being the pioneer and North American leader in NPS:

- **Precedent with Non-Wire Alternative in the Electricity Sector:** The State of New York is considered by many as one of the two states, along with California, that has pioneered and is leading the way in operationalizing Non-Wire Alternatives (i.e. using energy efficiency, and distributed energy resources to substitute for traditional electricity grid infrastructure.)
- **Strong Natural Gas Demand Growth Forecast (Prior to 2020):** When New York State started exploring NPS, they had been experiencing and were forecasting a long-term growth trend in natural gas demand, including both customer growth and consumption growth in certain areas of the State. This growth was driven by conversions from heating oil to gas, as well as new construction, primarily in the Downstate regions of the State. However, gas growth forecasts have been modest since then, at least partially due to the new Climate Leadership and Community Protection Act (CLCPA) legislation, the plan laid out in the New Efficiency: New York (NENY) report[40] by the NYSERDA, and, more importantly, as a result of the corresponding Accelerated Energy Efficiency Order.[41] State policies are encouraging a redoubling of efforts on energy efficiency and promotion of electric heat pumps. They are also contemplating widespread electrification of the building stock.
- **Constraints on the Development of Long Term Infrastructure:** The cancellation of several of the recent natural gas pipeline projects designed to bring new pipeline capacity into Downstate New York, including the Northeast Supply Enhancement (NESE) and Constitution Pipelines, is causing a perception that new interstate pipeline projects will become increasingly challenging to develop.
- **Public Concerns and Focus due to the Proliferation of Moratoria and the NESE Project Consultations:** The moratoriums on new connections in New York have created a challenging landscape that the gas utilities have had to navigate. These circumstances have resulted in the utilities launching innovative pilots and projects in order to demonstrate best efforts to solve their capacity constraints.
- **Strong Decarbonization Policies from the State Government:** NPS are in alignment with the formal state policies. Now that long-term natural gas growth forecast are more modest, NPS is being seen as an instrument to ensure reliability of the gas supply in isolated areas of the gas distribution network that are experiencing drops in gas pressure, and as alternatives to the replacement of leak-prone pipes.

In short, the significant supply shortage in the state, coupled with the experience with non-wire alternatives on the electric side, have led New York State gas distribution companies to consider NPS to alleviate constraints on pipeline capacity to the city gates (i.e. calling for intensifying EE, gas DR, and electrification over their entire service territories).

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[40] NYSERDA, *New Efficiency: New York*, 2018 <https://www.nyserda.ny.gov/-/media/Files/Publications/New-Efficiency-New-York.pdf> [accessed 20 August 2020].
[41] State of New York Public Service Commission, *Case 18-M-0084 ORDER ADOPTING ACCELERATED ENERGY EFFICIENCY TARGETS*, 2018.

However, over the course of the past two years, the focus in New York has shifted away from supply shortages at city gates towards New York State decarbonization policy and its impact on the future natural gas outlook. With lower overall growth on peak demand, New York gas utilities have started focusing on peak demand constraints on the distribution network (e.g. where customers are experiencing low gas pressure during cold snaps) and areas replacing obsolete pipes.

ConEd

ConEd delivers natural gas to approximately 1.1m customers in Manhattan and several boroughs of New York City. ConEd has been directly impacted by the cancelation of NESE, and has been first in launching NPS pilot projects. Furthermore, over the years, ConEd had become over-reliant on Delivered Services, short-term gas delivery contracts through existing pipelines.

In 2017, to address the growing concern of over-reliance on short-term contracts and the moratorium, ConEdison developed non-pipeline solution pilot projects with the long-term goal of reducing the need for new pipeline capacity. This effort is included as part of the Smart Solutions for Natural Gas Customers Program, including NGDR programs, a gas innovation program or renewable alternatives to natural gas heating, and a market solicitation for additional NPS.[42]

The 2017 public tender for NPS resulted in a portfolio of NPS projects that met cost-effectiveness requirements. However, the tendering process did not lead to sufficient cost-effective options to avoid or defer the need for NESE. Nevertheless, the effort resulted in a $412m ($305m USD) portfolio of projects, including a mix of EE and electrification as well as supply-side measures such as CNG and RNG. The portfolio was submitted to PSC for approval on September 28, 2018.[43] Only three solutions were accepted, only on a pilot basis and only for one year worth of funding. The delivered CNG solution was accepted, but deemed unacceptable as an NPS. The three pilot projects approved by the PSC included a targeted single-family residential G2E program (GSHPs), a low-income residential weatherization ETEE program, and a targeted multi-unit residential building G2E program (ASHPs).

Both with in its portfolio submission and with its proposed NPS framework, ConEd proposed a shareholder incentive approach to obtain a reward from pursuing NPS options based on a shared savings approach and the SCT (70% of net benefits under the SCT would go to ratepayers and 30% of the net benefits would go to the Company).

In order to complement its existing portfolio of NPS, ConEd issued a request for information in January 2020 with a submission deadline of April 2020.[44] ConEd's goal was to explore new options not previously examined as part of the earlier solicitation. The utility hoped to see proposals for DR enablement (i.e. installation of related equipment and/or controls) to allow greater participation in existing gas DR programs or new programs for smaller customers. The 2020 RFI also solicited hydrogen pipeline-injection proposals (i.e. Power-to-Gas).

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[42] ConEdison, *Gas Demand Response Pilot Implementation Plan, 2018-2021, Case 17-G-0606*, 2020 <https://www.coned.com/-/media/files/coned/documents/save-energy-money/rebates-incentives-tax-credits/smart-usage-rewards/gas-demand-response-implementation-plan.pdf> [accessed 31 July 2020].

[43] ConEdison, *Case 17-G-0606 – Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program*, 2018 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA7C3D0CD-E2B3-4B42-807C-82B553AE63F9%7D> [accessed 31 July 2020].

[44] ConEdison, *Request for Information (RFI) Non-Pipeline Solutions to Provide Peak Period Natural Gas System Relief*, 2020 <https://www.coned.com/-/media/files/coned/documents/business-partners/business-opportunities/non-pipes/non-pipeline-solutions-to-provide-peak-period-natural-gas-system-relief-rfi.pdf?la=en> [accessed 31 July 2020].

National Grid

National Grid provides natural gas to 1.9 million customers in Brooklyn, Queens, Staten Island, and Long Island. The utility has seen sustained growth in demand throughout its service territory.

National Grid was in a similar situation than ConEd was after the cancellation of the NESE pipeline and had to announce a moratorium on new gas hookups in 2019 in both its Long Island and New York service territories, which has since been lifted until September 2021. In 2020, National Grid published a Long-Term Capacity Report,[45] followed in May 2020 with a Supplemental Report[46] to present a comprehensive analysis of its capacity constraints and all available options for meeting its long-term demand. At that time, National Grid was contemplating a shortfall to meet demand growth over the course of 10 years.

National Grid's economic analysis, in the two reports, provides a useful illustration of the infrastructure investment challenges faced by utilities in jurisdictions with ambitious decarbonization targets like New York State. Natural gas is currently preferred by many customers for space and water heating, and new pipeline capacity may be needed to meet expected demand growth, but gas demand may plateau and begin to decline before these new assets are fully depreciated due to the pressure of decarbonization policies.

The approach used by National Grid assumes that EE, gas DR, and G2E can be deployed incrementally and almost on a just-in-time basis allowing the utility to throttle the amount of capacity and adapt quicker and more accurately to changes in the demand.[47] NESE was the least costly scenario in a "high demand growth future" (the upper bound of National Grid's demand forecast). However, NESE was also the costliest scenario under a low demand growth future (the lower bound) because the infrastructure would be underutilized while needing to be amortized in full. However, the "No-Infrastructure" scenario did not perform much better, even in a low-demand growth scenario. The least cost scenarios in the low demand future were mixes of distributed infrastructure solutions (CNG, LNG and smaller infrastructure upgrades), and no-infrastructure solutions (ETEE, NGDR and G2E).

Since 2020, National Grid has moved ahead with numerous NPS pilot projects including NGDR and improved interruptible rate programs.

Central Hudson

Central Hudson is a gas and electric utility that delivers gas to approximately 84,000 customers in New York State's Mid-Hudson River Valley. The utility has attempted to use beneficial electrification to avoid costly replacement of leak-prone pipes on its distribution system. They refer to the approach as a "transportation mode alternative". The initiative offers technical assistance and incentives to convince customers to fully electrify their space heating via ground-source heat pumps or air-source heat pumps and cut their gas connections. The initiative targets pipes that are scheduled for replacement due to obsolescence, particularly when the pipes connect to only a handful of customers.

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[45] National Grid, *Natural Gas Long-Term Capacity Report for Brooklyn, Queens, Staten Island and Long Island ("Downstate NY")*.

[46] National Grid, *Natural Gas Long-Term Capacity Supplemental Report for Brooklyn, Queens, Staten Island and Long Island* (New York City, NY, USA, 2020) <https://millawesome.s3.amazonaws.com/Downstate_NY_Long-Term_Natural_Gas_Capacity_Supplemental_Report_May_8_2020.pdf>.

[47] To be fair, EE, gas DR and G2E also have lead time as well as forecasting and performance uncertainties. So, the assumption that EE, gas DR and G2E can be throttled and reach target with accuracy is debatable.

To be successful in avoiding the replacement of a pipe, Central Hudson needs to be able to convince all the customers connecting to a particular pipe to switch off of natural gas. However, this has been challenging since in New York State the utilities have an obligation to provide gas service and customers have the right to retain their gas services. As noted in Section 5, this program has had some success but has also encountered situations where customers have been unwilling to electrify their equipment to allow for pipe retirements.

In a 2018 Order from the PSC establishing electric and gas rate plans, the PSC required Central Hudson to submit an implementation plan to identify NPS.[48] Central Hudson explored the opportunity of offering geo-targeted EE programs to high constraint areas of its distribution system due to intra-day drops in pressure on certain laterals of its system.

Central Hudson commissioned a study on the avoided cost of its distribution system.[49] The study was based on a novel approach based on probabilistic (as opposed to deterministic) load forecasting. The focus of the analysis was to value the avoidable distribution cost due to peak-coincident load growth. The analysis estimated location-specific patterns for individual gas systems (i.e. subsections of the gas distribution network). Because increases and decreases in load compound over time, the trajectory of the load can deviate substantially from a simpler deterministic load growth model. The analysis generated indexes measuring the likelihood of pressure drops – due to spikes in intra-day coincident demand – that would trigger the requirement for an upgrade.

Based on this study, Central Hudson identified three systems with a likelihood of triggering an upgrade over a 10-year time horizon. Two of them were unsuitable for NPS due to timeline issues. The third system (the Vassar Road (PN) System) was identified as relevant for an NPS project since analysis suggested that there was a 20% chance that an upgrade would be required in the next 10 years. Central Hudson followed through with an ETEE pilot that offered incremental incentives for smart thermostats.

NYSEG

There has been an active moratorium on new natural gas connections in the Lansing, New York area since 2017. In June 2021, NYSEG gained approval to implement the majority of its proposal to implement an NPS project in the Town of Lansing to improve its low-pressure situation during peak hours. The approved projects include G2E (residential ASHP, commercial GSHP, community GSHP), ETEE at two public authority buildings, ETEE (heat recovery) at industrial facilities, C&I building NGDR (using electric boilers as backup) and education & outreach program. None of these projects had started as of late 2021. Projects that were not approved included smart thermostat gas DR in the zone of highest impact (not cost-effective), LNG , CNG delivery and injection, and hydrogen generation and injection.[50,51]

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[48] NY Public Service Commission, *CASE 17-E-0459 and CASE 17-G-0460 ORDER ADOPTING TERMS OF JOINT PROPOSAL AND ESTABLISHING ELECTRIC AND GAS RATE PLAN*, 2018.
[49] Demand-Side Analytics, *2020 Central Hudson Location-Specific Avoided Gas Distribution Costs Using Probabilistic Forecasting and Planning Methods*, 2020 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA193B651-0944-48CC-86C5-945C70634191%7D>.
[50] NYSEG & RG&E, *Non-Pipes Alternative, 2021 Third Quarter Report*, 2021.
[51] NY Public Service Commission, *Case 17-G-0432, Petition of New York Electric & Gas Corporation for Authorization to Construct a Natural Gas Compressor Pilot Project in Tompkins County, NY - Order Approving Petition for Non-Pipe Alternative Projects, with Modifications*, 2021.

3.3.2 Ontario

In Ontario, the Ontario Energy Board (OEB) recently established an NPS framework that provides a basis for the consideration, design, planning, implementation, and monitoring of NPS pilots and projects in a transparent manner.[52] The framework also lays out requirements for annual stakeholder consultations, annual reporting on NPS progress, and project-specific stakeholder consultations to ensure that NPS options are considered where they are relevant. While Enbridge Gas has yet to implement NPS pilot projects, the OEB has established a Technical Working Group to advise on NPS pilots and Enbridge is required to select and deploy two NPS pilot projects by the end of 2022.

The process that led to the development of an NPS framework in Ontario is different from the process that led to a similar outcome in New York State. Enbridge was encouraged by the OEB in 2014 to examine whether Integrated Resource Planning (IRP) for natural gas infrastructure was warranted as part of three Leave to Construct applications by Enbridge Gas Distribution Inc. and Union Gas Limited in the Greater Toronto Area.[53] The applications were bound and adjudicated together by the OEB, as “GTA-Parkway” projects. In 2016, as part of mid-term review of the energy efficiency framework by the OEB, the OEB directed the utilities to work jointly on a transition plan to integrate energy efficiency into their infrastructure planning activities.[54]

In 2018, Enbridge Gas Distribution filed an IRP transition plan and a study from ICF Canada that was mainly focused on ETEE.[55] In 2019, as part of a Leave to Construct Application, the OEB found that Enbridge’s process for considering ETEE as an alternative to the Bathurst Reinforcement project had not been appropriate. Later that year, Enbridge proposed an NPS framework to:[56] (1) be responsive to the OEB’s encouragements and findings; (2) create the policy guidance to be successful in pursing NPS; and (3) demonstrate that NPS was not a viable alternative to the Dawn-Parkway Expansion pipeline project. This led to an oral hearing process with the OEB that culminated in the establishment of a formal NPS framework in the province.

3.3.3 Oregon

Headquartered in Portland, Oregon, NW Natural serves 750,000 natural gas customers in 140 communities in Oregon and Southwest Washington. NW Natural collaborates with the Energy Trust of Oregon (ETO) for the delivery of its broad-based DSM programs in Oregon. The utility contributes ratepayer-funding for DSM and provides assumptions that feed into the ETO’s planning. Programs, DSM forecasts, and targets are all set by the ETO, along with program delivery.

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[52] Ontario Energy Board, *Decision and Order EB-2020-0091 Integrated Resource Planning Proposal*.
[53] Ontario Energy Board, ‘Decision and Order on GTA-Parkway Project’, 2014 <http://www.rds.oeb.ca/HPECMWebDrawer/Record/424174/File/document> [accessed 17 January 2022].
[54] Ontario Energy Board, ‘Decision and Order on Applications for Approval of 2015-2020 Demand Side Management Plans’, 2016 <http://www.rds.oeb.ca/HPECMWebDrawer/Record/513656/File/document> [accessed 17 January 2022].
[55] Ontario Energy Board, ‘Report of the Ontario Energy Board, Mid-Term Review of the Demand Side Management (DSM) Framework for Natural Gas Distributors (2015-2020)’, 2018 <https://www.oeb.ca/sites/default/files/Report-of-the-Board-DSM-Mid-Term-Review-20181129.pdf> [accessed 17 January 2022].
[56] Enbridge Gas, ‘Integrated Resource Planning Proposal, EB-2019-0159’, 2019 <https://www.rds.oeb.ca/CMWebDrawer/Record/675587/File/document> [accessed 17 January 2022].

The NW Natural Gas IRP typically includes DSM as a key resource to meet forecasted load. Both latest IRP studies in 2018[57] and 2021[58] considered traditional storage, ETEE, NGDR, LNG, RNG, and blue hydrogen (hydrogen produced from natural gas with carbon capture, utilization and storage), and Power-to-Gas as options for meeting forecasted load. In 2021, in particular, the NPS solutions have been compared against the North Coast Feeder System Reinforcement Project. NPS solutions that were looked at included a new LNG plant, and an improved interruptible rate for C&I customers. The supply-side solutions was determined to be superior to LNG from a cost standpoint (net present value), and superior to the C&I interruptible rate due to the insufficiency of the capacity that could be freed up using the new program.

Over the years, NW Natural has been able to enhance its collaboration with the ETO and has streamlined the processes to develop more accurate DSM forecasts. For instance, during the 2019-2020 period, ETO achieved 97% of its target for the Oregon service territory and 101% for the Washington service territory. Avoided cost have significantly changed in 2021 compared with 2018 in alignment with state policy. NW Natural have updated its GHG compliance costs to align with societal cost of carbon, thereby increasing upstream avoided cost by approximately 40% for space heating end use (the increase varies depending on the end-use). The base case use, the EPA social cost of carbon, was $75 USD in 2021.

NW Natural continues to use an iterative method the utility developed as part of the 2018 IRP to determine the avoided cost of distribution infrastructure. In 2017, NW Natural indicated plans to collaborate with the ETO to include projections on the impact of peak savings. For the 2018 IRP, the ETO had projected the impact of peak savings both for a design day and for a peak hour over a time horizon of 20 years. The ETO estimated that 1.40% of annual gas consumption savings would overlap with peak day demand, and that 0.09% of the savings would overlap with peak hour demand. As such, annual savings of 100 GJ would results in a 1.4 GJ reduction in peak day demand and a 0.09 GJ reduction in peak hour demand.

NW Natural has expressed the need to address gaps related to the magnitude and ongoing reliability of targeted energy efficiency peak hour savings, the cost and timing at which the savings accrue, and the methodology for measurement of the savings.

NW Natural is currently an advanced stage of implementing its Geo-Targeted Energy Efficiency (GeoTEE) pilot project, in close collaboration with the ETO. The project is designed to obtain data on the peak demand impacts of geo-targeted energy efficiency measures. This will allow for the consideration of geo-targeted energy efficiency as a viable option for deferral and avoidance of future distribution system investments.

The GeoTEE pilot project includes three phases:

- **Phase 1:** Targeted marketing and customer engagement for a certain segment of NW Natural's distribution system to promote EE through existing broad-based EE programs.
- **Phase 2:** Targeted incentive kickers (i.e. adders) to top off incentives available through existing broad-based EE programs, within cost-effectiveness (UCT) bounds.
- **Phase 3:** Larger incentive kickers to top off incentives available through existing broad-based EE programs, beyond cost-effectiveness threshold.

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[57] NW Natural, *2018 Integrated Resource Plan*, 2018 <https://www.nwnatural.com/uploadedFiles/NW Natural 2018 IRP.pdf> [accessed 18 August 2020].
[58] NW Natural, '2018 Integrated Resource Plan Update 3, Docket No. LC 71/UG-170911', 2021 <https://webfrontend-sc-pd.azureedge.net/-/media/nwnatural/pdfs/nwnatural_2018_irp_update.pdf?la=en&rev=1f83206ac10d4312b92c171c3264fd8b&hash=370D028AA3F29C2805F590D0BC884B07> [accessed 17 January 2022].

It was critical to the experimental design of the project to select a loop of the distribution system that can be more easily isolated for the pilot. NW Natural installed a SCADA meter to monitor the hourly flow of gas at the entrance of the target area and they will compare daily and monthly data against the aggregated data from the SCADA meter.

Results from 2018/19 were delayed due to issues relating to a faulty meter. NW Natural is in the process of analyzing data from 2019/20, 2020/21, and 2021/22. They expressed concerns about the potential impact of COVID-19 on the dataset, but they have not yet confirmed whether this was indeed an issue of real concern. To date, no results have been made available from this pilot project.

NW Natural has also committed to file a study on NGDR options for residential and C&I customers in 2022.

3.3.4 Colorado

As part of a suite of state climate legislation passed in 2021, Colorado SB21-264[59] requires that gas distribution utilities file and obtain commission approval of a “clean heat” plan that shows how they intend to reduce GHG emissions associated with carbon dioxide and methane by at least 4% relative to 2015 levels by 2025, and 22% relative to 2015 levels by 2030. Possible "clean heat resources" allowed to be part of a clean heat plan include:

- Gas energy efficiency programs
- Recovered methane (such as biomethane; methane derived from solid waste, pyrolysis of municipal solid waste or biomass, or wastewater treatment; coal mine methane; or methane that would have been leaked without repairs of the gas distribution and service pipelines form the city gate to customer end use)
- Green hydrogen
- Beneficial electrification
- Pyrolysis of tires if the pyrolysis meets a recovered methane protocol
- Any technology that the Commission finds is cost-effective and that the division finds results in a reduction in carbon emissions from the combustion of gas in customer end uses or meets a recovered methane protocol approved by the air quality control commission

Utilities must also consider methane leakage from the transportation and delivery of gas from the gas distribution and service pipelines from the city gate to the customer end use, and from delivery of gas to other local distribution companies. The legislation allows the Colorado Public Utilities Commission to require that utilities evaluate NPS, noting that:

> *“To count toward a gas distribution utility’s compliance with the clean heat targets, the utility must quantify the actual methane reductions achieved by any leak repairs and the commission must find that the leak reductions are cost-effective. The commission may require the utility to evaluate non-pipeline alternatives.”*

Outside of legislation, Xcel Energy (the largest gas utility in the state) is currently running a pilot intended to better understand the roles that more frequent energy data and NGDR can play in supporting the gas system through its Heat Savers Mode Study.

[59] State of Colorado, ‘Adopt Programs Reduce Greenhouse Gas Emissions Utilities, SB21-264’, 2021 <https://leg.colorado.gov/bills/sb21-264> [accessed 17 January 2022].

The NGDR pilot is being implemented in Summit County, Colorado, a mountainous region with multiple ski resorts where pipeline expansion is particularly difficult and costly. Xcel is hoping the pilot results will help the utility better manage demand and avoid building out additional gas infrastructure going forward. In particular, the pilot involves the installation of wireless energy monitors that allow it to better understand localized load shapes and daily peaks in the overall gas consumption of individual homes to help improve system planning, and a NGDR component leveraging smart thermostats in conjunction with behavioral prompts through a customer-focused mobile app to reduce gas demand during peak periods.

3.3.5 California

California has been taking steps towards decarbonizing its economy for several years. In 2016, State Executive Order B-30-15[60] established an interim target of a 40% reduction in GHG emissions below 1990 levels by 2030. In 2017, the California Air Resources Board (CARB) issued a Scoping Plan[61] to identify measures to achieve this target. The least costly identified pathway calls for efficient electrification of up to 30% of space heating and water heating by 2030. In 2019, Executive Order N-19-19[62] mandated State government agencies to pursue California's climate targets in government buildings and government-funded infrastructure. In 2018, Senate Bill 100[63] stipulated that California's electricity grid must be decarbonized by 2045 and Executive Order B-55-18[64] adopted a target of carbon neutrality by 2045.

Key Californian agencies, including the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), and CARB, are increasingly adopting initiatives towards electrification and decarbonization, both in transportation and buildings. For instance, in 2021, CEC adopted a new building standard[65] that will come into effect in 2023 and will encourage electric heat pump technology and establish electric-ready requirements for new buildings.

Californian electric utilities are following suit, launching their own electrification programs and other initiatives. For instance, in 2021, Southern California Edison filed an electrification plan[66] targeting 250,000 heat pump installations and 65,000 electrical upgrades for households by 2030. Southern California Edison is calling for large-scale building electrification through the

[60] Office of Governor Edmund G. Brown Jr., 'Governor Brown Establishes Most Ambitious Greenhouse Gas Reduction Target in North America', 2015 <https://www.ca.gov/archive/gov39/2015/04/29/news18938/index.html> [accessed 25 March 2022].
[61] California Air Resources Board, 'California's 2017 Climate Change Scoping Plan', 2017 <https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/scoping_plan_2017.pdf> [accessed 25 March 2022].
[62] Executive Department State of California, 'Executive Order N-19-19', 2019 <https://www.gov.ca.gov/wp-content/uploads/2019/09/9.20.19-Climate-EO-N-19-19.pdf> [accessed 25 March 2022].
[63] California Energy Commission, 'SB 100 Joint Agency Report', 2022 <https://www.energy.ca.gov/sb100> [accessed 25 March 2022].
[64] Executive Department State of California, 'Executive Order B-55-18 to Achieve Carbon Neutrality', 2018 <https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf> [accessed 25 March 2022].
[65] California Energy Commission, 'Energy Commission Adopts Updated Building Standards to Improve Efficiency, Reduce Emissions From Homes and Businesses', 2021 <https://www.energy.ca.gov/news/2021-08/energy-commission-adopts-updated-building-standards-improve-efficiency-reduce-0> [accessed 25 March 2022].
[66] Southern California Edison, 'Testimony of Southern California Edison Company (U 338-E) in Support of Its Application for Approval of the Results of Its 2018 Local Capacity Requirements Request for Proposals (LCR RFP)', 2019 <https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1904016/2040/283296439.pdf> [accessed 25 March 2022].

replacement of natural gas appliances with electric heat pumps, heat pump water heaters, and electric cooktops.

In this policy context, natural gas utilities have to plan for a slower growth if not a reduction in demand. This will require a different approach to natural gas infrastructure planning. While natural gas demand may start declining overall, the natural gas utilities may still need to address peak demand growth in certain portions of their distribution networks. Some of their infrastructure investments may face increasing uncertainty in terms of their long-term volumes.

Starting in 2020, CPUC initiated a proceeding to address reliability standards[67] that reflects the challenges faced by natural gas utilities in the State. The utility commission is seeking to modernize the approach to natural gas infrastructure planning. The proceeding will assess the possible future role of NPS, an approach to balance the cost of replacement and repair against natural gas service reliability benefits, and an approach to determine which pipelines may be proactively decommissioned.

ICF identified an NPS pilot in California: the SoCalGas Smart Control Thermostat Program. SoCalGas' pilot program started in advance of the 2017/18 heating season. It is a NGDR program, utilizing thousands of residential smart thermostats to temporarily alleviate peak demand constraints. While the pilot program was not labeled as an "NPS project" at the time, it was deployed to test the ability to use demand-side resources to avoid the need for natural gas facility investments. More information on the pilot can be found in Appendix A.

The California experience provides valuable insight in to the potential for NPS to address gas capacity and environmental concerns. However, care needs to be taken when applying the California experience in other jurisdictions. The California climate in general is more conducive to the use of electric heat pumps than most other jurisdictions. There is significant incremental power capacity available during the winter to meet incremental load without requiring a major expansion of the electric system. In addition, the winter contribution from solar power in California is also more reliable than the jurisdictions further north.

3.3.6 New England

Considering that natural gas market conditions and other energy market conditions in New England States (i.e. Maine, Vermont, New Hampshire, Massachusetts, Rhode Island, and Connecticut) are similar to New York, as well as the prevalence of natural gas DSM programs in the region and the well documented lack of pipeline capacity into the region, ICF reviewed the information on NPS activities in the region, and reached out to several utilities in the region to discuss their experience with NPS.

The region has extensive experience with distributed sources of natural gas supply, including distributed CNG and LNG, both to provide natural gas to large consumers without access to the natural gas grid and to provide additional natural gas capacity in locations experiencing capacity constraints. However, ICF's research suggests that there is limited interest in NPS in the region, with no active NPS programs other than the existing broad-based DSM programs and the aforementioned distributed supply options.

ICF reached out to several gas utilities in the New England region, but was only able to consult with one. ICF spoke with Columbia Gas of Massachusetts in late 2020 to discuss the utility's experience with NPS. Columbia Gas staff indicated that the utility does not pursue any NPS or

[67] California Public Utilities Commission, 'Assigned Commissioner's Amended Scoping Memo and Ruling, Rulemaking 20-01-007', 2021 <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M415/K275/415275138.PDF> [accessed 25 March 2022].

geo-targeted EE or DR, despite supply constraints that have led to moratoria in adding new gas customers in Northampton and Easthampton. Columbia Gas also indicated that they view NPS as cost-prohibitive, and that the impacts of geo-targeted EE or DR would be insufficient to avoid new pipes in highly constrained areas of its distribution system.

Although ICF's research suggests that there is limited progress with regards to NPS in the New England States, we noted that Eversource was approved for cost recovery for three GeoMicroDistrict (networked geothermal) pilot programs in the greater Boston area. With construction scheduled to begin in mid-to-late 2022 and a three year pilot timeframe, this district energy system concept will employ "networked geothermal boreholes, connected by a shared loop in the current gas right-of-way that provides thermal energy to customer buildings".[68] This approach could represent an alternative role for gas utilities.

Electrification of space heating is being extensively discussed across the six New England States. For instance, Liberty Utilities in New Hampshire is planning a pilot project seeking to deploy ASHPs to substitute fossil fuel-fired heating appliances in a dual-fuel configuration and with integrated controls during the 2021-2023 period[69]. Another example includes Massachusetts' 2050 Decarbonization Roadmap, which was published in December 2020[70] by the state government. The roadmap suggests that the state will be pursuing state-wide electrification of buildings through ASHPs, GSHPs, and variable refrigerant flow heat pump systems. If these plans materialize, they may help address future natural gas peak demand constraints.

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4 NPS Pilot Projects and Programs

ICF compiled an inventory of NPS Pilot Projects and Programs across North America. The results of our work is summarized below. The complete list of NPS pilot projects along with details that ICF collected about these pilot projects can be found in Appendix A.

Based on our research, ICF identified two leading jurisdictions on the topic of codifying and establishing a formal framework around NPS; New York State and Ontario. Both jurisdictions have a framework. The framework is only proposed in New York State and is waiting for a final decision, but many utilities in New York State have already implemented NPS pilots. Enbridge, the largest utility in Ontario, has received a mandate from its regulator to pursue NPS. In both cases, the frameworks establish procedures and guidelines for a routine examination of NPS options. This process is embedded into the core infrastructure planning function of the relevant gas distribution companies in these jurisdictions, so that NPS can be considered early, systematically, and on an equal footing with traditional gas network infrastructure investments.

The majority of the relevant pilots that ICF identified have been implemented by utilities in NY State. Exceptions include a Natural Gas Demand Response (NGDR) pilot project in Southern California, an enhanced targeted energy efficiency pilot project in Oregon, and a NGDR project in Colorado. Ontario has yet to implement any NPS pilot projects. Rather, Enbridge is in the early stages of identifying two pilot projects, based on recent direction from the OEB to develop and implement two NPS pilot projects in sufficient time to collect measurement and verification results by winter 2022-2023.

4.1 NGDR Pilots

ICF's research suggests that the majority of NPS pilots have tested NGDR technologies. This has included direct load control of smart thermostats to reduce space heating loads during peak demand periods. These pilots have employed both a direct install approach and a bring-your-own thermostat model.[71] ConEd, National Grid, and SoCalGas have all deployed NGDR pilots focused on smart thermostats. Central Hudson is also utilizing smart thermostats, but has focused mostly on their energy efficiency attributes. When we spoke with them in 2021, they told us they are considering augmenting their program with NGDR events in the near future.

Some utilities have also piloted behavioural NGDR programs. For instance, ConEd, National Grid, and Niagara Mohawk ran behavioural pilot programs focused on large C&I customers, while National Grid is testing a behavioural program focused on its residential and small commercial customers. In behavioural NGDR programs focused on C&I facilities, customers are notified of a DR event and they must decide how to curb their natural gas consumption. For instance, they can decide to lower temperature setpoints for their space heating or water heating. Behavioural NGDR programs focused on residential and small commercial customers may instead rely on marketing via emails or other communication channels during cold weather events. Behavioural programs are better suited to commercial and industrial facilities since it is typically more challenging for gas utilities to automate responses to DR events, unlike the control signals that can be sent to smart thermostats in residential and small commercial applications.

In addition to behavioural programs, National Grid and Niagara Mohawk are piloting enhanced interruptible rates for C&I customers. Furthermore, ConEd tested direct load control, a form of NGDR, with advanced water heater controllers.

[71] In a "bring your own thermostat" model, customers purchase the smart thermostat, install the device themselves, enroll the device themselves, and sign up into the program through the platform.

There are several reasons for the popularity of NGDR NPS programs. For instance, direct load control of smart thermostats is of interest since they are a natural extension of existing electricity demand response thermostat programs (mostly focused on curbing the air conditioning load in the summer). In addition, the penetration of smart thermostats is high and they are relatively inexpensive compared to many other gas energy efficiency measures (e.g. high efficiency furnaces, water heaters, gas heat pumps, etc.). The devices and associated hardware and software also come with telemetric capabilities that facilitate the measurement and verification of peak demand impacts (e.g. temperature setpoint, indoor temperature, and duty cycle.)

Behavioural programs focused on larger buildings have also been of interest since the larger gas consumption for these facilities makes it easier to more accurately meter and justify the costs of the telemetric instruments to monitor peak demand impacts. Enhanced interruptible rates are a natural extension of existing interruptible rates, which gas utilities have used for decades to increase the utilization factors of their distribution networks. Furthermore, interruptible rates are dependable and do not have duration constraints due to the availability of backup heating systems. The availability of backup systems also means that there is typically no interruption of space or water heating service from a customer perspective. However, similar to traditional interruptible rate programs, customers have to assess the cost required to maintain back-up heating equipment and the required fuel compared to any monetary benefits associated with their participation in the program.

4.2 G2E Pilots

ConEd tested full electrification of suburban homes with ground-source heat pumps (GSHP) in an area of high constraint on a pilot basis. The fact that ConEd serves both electric and gas customers helped facilitate the implementation of this pilot. However, ICF did not assess the impact of the pilot on energy bills or rates. ConEd was also planning to test full electrification of multifamily buildings with ASHP but the pilot implementer failed to recruit a participating building.

Another relevant program that is being implemented by Central Hudson, its Transportation Mode Alternative (TMA) program, is focusing on avoiding the replacement of leak-prone pipes by converting all customers serviced by specific pipe segments to electrotechnologies (i.e. electrification). The program has been targeting pipe segments with very small numbers of customers (i.e. generally 1-3 customers but as many as 18 customers). Based on the latest update that they have filed with their regulator, Central Hudson has demonstrated success in converting customers to electrotechnologies and retiring certain pipe segments. However, there are several cases, with as few as two customers, where they have not been able to convince the customers to replace their gas-fired equipment.

While utilities in NY are promoting heat pumps of all kinds through a suite of generous incentive programs, these programs are not necessarily aimed at promoting G2E. Customers that use fuels such as heating oil, propane, and electric resistive heat are also eligible, and there is a stronger business case for these customers to implement heat pumps compared to customers with gas-fired space heating equipment. Furthermore, the incentives are available to customers across the entire state, as opposed to being geotargeted. National Grid has considered offering incentive kickers (incremental incentive on top of the licence-wide incentive) to customers in areas of high constraint but, to date, the utility has not followed with a pilot program.

4.3 ETEE Pilots

There has only been limited activity with regards to ETEE pilot programs that are seeking to assess the magnitude of peak demand impacts related to the implementation of natural gas energy efficiency measures. ICF identified four pilots focused on Enhanced Targeted Energy Efficiency (ETEE), including the following:

- **ConEd's low-income weatherization program:** ConEd's program used a direct install approach to implement weatherization measures in low-income households and it is the only ETEE program that has yielded results to date.
- **Central Hudson's non-DR smart thermostat pilot program:** Central Hudson's program is offering incremental (i.e. top-up) incentives on measures that are already incented through their broader programs to drive additional participation in a targeted area. However, Central Hudson also intends to leverage the smart thermostats' DR capabilities in the future.
- **NW Natural's multi conservation measure program:** NW Natural, in collaboration of Energy Trust of Oregon, is using enhanced marketing and direct outreach to boost participation in existing gas energy efficiency programs in a targeted area and is not offering any incremental incentives.
- **NYSEG's portfolio of non-pipe alternative projects:** NYSEG's program includes the installation of gas energy efficiency measures such as industrial heat recovery, G2E measures (ASHPs and a community loop GSHP project), and public education and outreach.

The complete list of NPS pilot projects along with details that ICF collected about these pilot projects can be found in Appendix A.

4.4 Distributed Infrastructure Options

While CNG and LNG are being discussed extensively as an NPS option by gas utilities in the United States, CNG has only been deployed as an NPS in New York City, and LNG was only one of many suggested options. Furthermore, CNG and LNG are considered as supply side options rather than NPS in New York State based on direction from the state regulator.

NY and Ontario are accepting RNG and P2G (hydrogen injection) as an NPS option. However, the role of RNG is relatively limited at the moment for a variety of practical reasons. For instance, the potential for RNG to serve constrained sections of a natural gas distribution system is limited by land space needs, population density, and the availability of locally-sourced feedstock. To be effective at curtailing peak demand, RNG and P2G would need to be coupled with a form of storage.

As for P2G, analysis and experimentation on hydrogen injection are occurring in some jurisdictions, such as Ontario. However, the technology is still in the process of development and is generally lagging behind other options in terms of its maturity.

5 Tracking Impacts

Gas utilities have much less experience than electric utilities with assessing the hourly profile of the impact of demand-side resources. This is challenge for NPS programs because the suitability of NPS to defer or avoid traditional gas infrastructure depends on the ability of NPS to influence gas demand during peak periods. Natural gas utilities have much less experience with assessing the hourly profiles of the impact of demand-side resources for the following main reasons:

- **Natural gas is easier to store:** In addition to some inherent storage capacity in the natural gas transmission and distribution infrastructure, gas utilities sometimes employ underground storage facilities or LNG storage. Gas utilities can also sometimes store additional natural gas within their pipeline network by pre-emptively boosting the pressure in the system in advance of an expected increase in demand.
- **Larger safety margins in natural gas systems:** Natural gas distribution systems are designed with a larger safety margin than electric distribution systems because the consequences of an interruption of the natural gas service in the middle of the winter are larger[72] and costlier[73] than that for an electricity outage. Moreover, the cost of over-sizing gas pipes is modest compared to the cost of replacing the pipes if supply capacity was to become prematurely insufficient.
- **Lower penetration of gas AMI meters:** The penetration of gas advanced metering infrastructure (AMI) is much lower than the penetration of electric AMI meters. This can be at least partially attributed to the aforementioned points, which have meant that it has historically been less critical to track natural gas demand on an ongoing basis. The cost of installing natural gas AMI meters is also higher compared with the monetary value of the commodity. The commodity cost of natural gas (the marginal cost) is lower than that of electricity, and does not vary as much on a temporal basis. AMI meters are more expensive to deploy because they require a source of electricity – whether it is a battery or a connection with an electric circuit. This either increases the cost of the devices or the cost of installation. As a result, the business case for natural gas AMI meters is not as attractive.

As part of ICF's previous related research for Enbridge in 2018 and 2020, the gas utilities that we consulted generally expressed concerns with the accuracy of the peak demand impacts in the absence of more and better data on hourly natural gas demand profiles that would come from natural gas AMI meters. Our current research suggests that this is still a concern for gas utilities. However, it has not prevented gas utilities from pursuing NPS pilots when policy, market circumstances, and/or public perception have created the necessary drivers to pursue NPS. As a result, NPS pilots have been selected and designed such that they account for the lack of gas AMI meters. The accuracy of the results from these pilots is still being assessed.

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[72] An outage may activate emergency actions, for instance, like distributing and installing portable electric heater, and/or moving people into warming centres. A large scale relight could take weeks rather than days or hours to resolve.

[73] Safely relighting a section of the distribution system requires a series of time-consuming steps, including: (a) Turning off service valves at every customer meter in the affected area; (b) Correcting the underlying issue that created the loss of system pressure; (c) Reintroducing gas into the affected mains and services; (d) Purging the affected mains and services to ensure that the pipes are filled with 100% natural gas; and (e) Unlocking customer meters and relighting customer appliance pilot lights on a customer by customer basis.

The granular data gathered during NPS pilots can and should be utilized to increase the accuracy of forward-looking NPS impact assessments. Piloting demand-side energy solutions is a preferred approach of utilities, electric or gas, prior to full scale deployment of most forms of programs, even for programs promoting energy efficiency measures that have been tried and tested in neighbouring service territories.

To ICF's knowledge, none of the NPS pilots or programs that have been implemented to date have employed AMI for measurement and verification (M&V) purposes. Gas utilities such as Enbridge have advocated for AMI to be recognized as an enabler of more wide-spread NPS, based on the fact that jurisdictions without AMI may have to overdesign their programs due to higher uncertainty regarding the peak demand impacts. As part of its recent Order and Decision, the OEB concluded that there was insufficient information to determine if AMI is an enabler of cost-effective NPS projects.[74]

ICF noted that NGDR pilots have been the most ubiquitous form of NPS pilot projects. This is at least partially due to the fact that NGDR pilot projects do not necessarily require AMI meters to evaluate their impacts. NGDR pilots can provide granular data that can be used to plan future NPS projects including but not limited to ETEE programs.

In the residential sector, NGDR programs have generally taken the form of a smart thermostat program or a smart domestic hot water controller program. The data feed coming from the devices at intervals (5, 10 or 15 minute intervals) through wireless communication solutions (i.e. duty cycle of the appliances, temperature setpoints, and current temperature) are used to assess the impact of the NGDR pilot projects. The same data feed can also be utilized to gain greater accuracy in the hourly load profiling of the residential space and water heating load profiles for "baseline" buildings.

NGDR programs in C&I buildings are not generally able to leverage this type of data. However, many C&I building meters are read more frequently than residential building meters – often daily compared with monthly for residential buildings. Alternatively, dedicated telemetric pulse-counting devices can be installed on the gas meters of larger facilities to track the impacts of NPS projects on a smaller interval. While telemetric instruments may not be a cost-effective solution for full-scale deployment of an ETEE or NGDR programs, the expense can be justified for pilot projects.

Assessing impacts from G2E pilots can rely on the data stream of electricity AMI meters (when they exist). Electric utilities can provide insights about the space heating and domestic water heating load profile from AMI data disaggregation analytics, particularly if isolating all-electric homes with resistive heat. There is an excellent correlation between the disaggregated electricity load and the space heating load for these buildings. The space heating load profile thereby obtained can then be utilized to forecast the baseline hourly gas load profile prior to the G2E conversion. Furthermore, the study of the data feed from an electric AMI meter on a given building prior and after G2E conversion can inform the determination of what the baseline space heating gas hourly load profile was prior to G2E conversion.

The greatest challenges remain with assessing impacts from ETEE programs. For the foreseeable future, ETEE will be more challenging than NGDR and G2E because existing metering infrastructure does not have the granularity to track impacts in smaller facilities, such as individual homes. Two strategies can help with tackling the M&V challenge with ETEE:

- Collaborating with electric utilities to refine the space heating and domestic hot water load profiles. More electric utilities have AMI meters than gas utilities. The data feed from electric AMI meters can be used to inform space heating and DHW load profiles by isolating homes

[74] Ontario Energy Board, *Decision and Order EB-2020-0091 Integrated Resource Planning Proposal*.

heated with resistive heating appliances and using AMI data disaggregation analytics to isolate the space heating and water heating load profiles.[75]

- Starting with NGDR pilot projects to get access to the data feed of smart thermostats and water heater controllers.

ICF also noted that two natural gas utilities, NW Natural and NYSEG, are using the natural gas pressure data feed from a Supervisory Control and Data Acquisition (SCADA) meter to track the impacts of NPS measures.

In conclusion, ICF's research suggests that the lack of natural gas AMI meters has not been a significant barrier to the deployment of G2E, NGDR, and ETEE pilot programs. However, it does require utilities to be more creative with how they track the impacts of their programs. While it does also increase the uncertainty band around the impact forecast, there are strategies to improve the overall accuracy. While an uncertainty band will remain in the absence of AMI meters, there is also a reasonable amount of uncertainty with regards to long-term load growth forecasts, particularly for certain portions of the distribution network with fewer customers and less diverse energy use.

[75] Electric AMI meter data disaggregation analytics provide excellent accuracy for space heating and domestic hot water load because these constitute the largest electricity end-uses in all-electric buildings. A challenge is that the building stock of resistive-heated buildings is different than that for natural gas-heated building, but calibrated building energy modeling can provide analytical solutions to make the necessary corrections to the load profile.

6 Timing Requirements

Large infrastructure projects have long implementation timelines, and regulated natural gas infrastructure projects are not exempt from this general rule. There is a risk that deployment of NPS may not be able to offset natural gas peak demand quickly enough to avoid a capacity shortfall, at which point it will be too late to build the regular pipe solution on time. This is particularly true for ETEE, NGDR, and G2E, which come in small increments and are dependent of the willingness of customers to subscribe to a program. It also highlights the importance of monitoring the impacts of NPS projects on an ongoing basis.

ICF's 2018 IRP Study and 2020 Study, which were both completed on behalf of Enbridge, suggest a utility would require up to 5 years to properly implement ETEE as an alternative to infrastructure investments. In other words, if a shortage is forecasted in less than five years, the pipe solution may be more dependable to avoid capacity shortfalls. Research completed as part of this study supports maintaining a meaningful lead time when determining whether a traditional infrastructure project can potentially be replaced by an NPS.

The lead time to implement NPS projects varies depending on the type of NPS, and depending on regulatory approval process. Traditional broad-based (i.e. franchise-wide) natural gas energy efficiency program filings are typically independent from leave to construct applications for new pipelines or compressor stations and also run on a different calendar. Gas utilities also often have some flexibility with regards to the scope and timing of their energy efficiency programs; especially if they are operating under multi-year DSM frameworks, similar to the approach used in BC. If the process to obtain regulatory approval for NPS projects is drawn out, this may lead to additional challenges with regards to timing.

Over the past two years, gas utilities in New York and California have been able to plan, implement, and obtain ex-post impact estimates from NGDR pilot projects and an ETEE pilot project (i.e. Central Hudson's "incentive kickers" for smart thermostats) in a relatively short timeframe. This included one year to launch and implement the pilot projects and a one-winter long measurement period.[76]

The amount of lead time to assess whether infrastructure projects can potentially be substituted by an NPS should thereby be dependent on whether the processes to obtain regulatory approval for the NPS is interlaced with the process to gain approval for traditional capital investments. If the NPS process is independent from the leave to construct application, a comfortable length of time of five years seems most appropriate for a large capital project. If the two are interlaced, perhaps starting immediately upon identifying the need for the new large capital project, it is conceivable to shorten the lead time down to 3 years with the first of the three years used to launch an NPS, monitor and report on impacts.

The timeline is also dependent on the size of the project. Less lead time is generally needed to implement smaller-scale NPS projects, which are generally focused on replacing or deferring lower capacity distribution infrastructure. Exhibit 8 is an example of capital project categorization based on ConEd's suggested NPS framework. ConEd has suggested that large projects require a three to five years of lead time, while smaller may require as little as 18 months of lead time.

[76] Although it is possible to assess the effectiveness of a program in this constrained timeframe, it is often challenging to do so and the results may be less reliable; especially if the weather is unusually warm or cold.

Exhibit 8 Suitability Criteria for NPA Consideration and Sourcing Approach as per ConEd Proposed NPS Framework[77]

Categorization	Timeline	Cost ($USD)
Large Project	>36-60 months	>$2 millions
Small Project	>18 months	≤$2 millions

The framework proposed by ConEd has two main attributes that enable the proposed timelines:

- It is presumed that NPS options are being considered and implemented as part of the routine, short- and long-term capital expenditure planning and capital project implementation. NPS are imbricated within the process, and are on the same calendar.
- The framework provides high-level guidelines on how the gas utility is procure NPS projects. For instance, large NPS projects must go through a public solicitation process to help ensure that the best technology solutions are brought forward by third-party developers at a competitive price. However, small NPS projects can leverage broad-based programs. For instance, ConEd may choose to provide incremental incentives and targeted marketing to boost program participation in a given area. This is an important option since it would be very challenging to implement NPS projects in a constrained timeline otherwise. If an NPS project is unable to generate sufficient peak demand impact, the utility needs enough time to proceed with the original capital infrastructure project.

Pursuing a variety of NPS projects may also help to mitigate timeline and performance risks associated with NPS. NGDR and residential G2E using ASHP have proven to be relatively fast to deploy, while some ETEE and G2E measures have longer lead times due to their costs and impact on building operations. For instance, building envelope retrofits, early replacements of furnaces and water heaters, GSHP deployment, and district heating systems may require longer lead times on average. All of these measures also have different risk profiles. Implementing a variety of measures with different lead times and risk profiles may increase an NPS program's chance of succeeding.

An example of large project employing a variety of NPS is NYSEG's NPS portfolio in its Lansing area near Ithaca. NYSEG pursued a public solicitation and received many C&I ETEE and G2E projects from a variety of project developers. The variety of NPS in the portfolio of projects pursued by NYSEG helped reduce the overall risk with regards to performance and timeline.

Two examples of small capital projects requiring a more nimble approach are the two NPS projects deployed by Central Hudson. Central Hudson's smart thermostat program used incentive toppers to bolster adoption of smart thermostat in a particular area. Central Hudson Transportation Mode Alternative also targets small portions of its distribution grid, thereby requiring an expedited process in each suitable area. The Transportation Mode Alternative program seeks to retire obsolete pipes servicing a very small number of customers. Time is of the essence because obsolete (leaky) pipe replacements are coordinated with road pavement replacement work. As such, the decision to either replace the pipe or retire it in place needs to be made quickly, so as not delay road pavement work.

More details on both NYSEG and Central Hudson's pilot projects are provided in Appendix A.

[77] ConEdison, *Proposal For Use Of A Framework To Pursue Non-Pipeline Alternatives to Defer Or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure. Case 19-G-0066*.

7 Conclusions

In this report, ICF presents a review of NPS practices in a number of jurisdictions, with a particular focus on regions with relevant NPS activity. ICF's research represents a targeted effort to update the jurisdictional review completed as part our 2018 IRP Study and 2020 NPS Jurisdictional Review Study, both completed behalf of Enbridge. ICF's research suggests that New York State and Ontario are currently at the forefront of innovation with regards to NPS, with a number of interesting developments in other jurisdictions such as California, Colorado, and Oregon.

The primary conclusions from this review include:

1) ICF identified some recent progress with regards to NPS both in New York State and in other jurisdictions, mostly as NPS are increasingly being considered as a novel component of reformed long-term natural gas infrastructure planning in the context of long-term decarbonization strategies. Jurisdictions that are planning for franchise-wide G2E in the medium or long term are considering NPS to solve local peak demand constraints or avoid obsolete pipe replacements without traditional gas infrastructure projects, which are typically amortized over 40+ years. The implications for electricity infrastructure needs as part of such wide-spread G2E are not assessed as part of this report.
2) Utilities in a small number of jurisdictions, such as New York State and Oregon, have made relevant progress in the development of NPS in terms of long-term capacity planning and analysis (e.g. National Grid Long-Term Capacity Planning reports) and pilot projects (ConEdison's NGDR pilot projects). In Colorado, NPS are being considered in the context of legislation encouraging widespread electrification of the building stock.
3) Recent and anticipated near-term developments with regards to NPS in New York State and Ontario are likely to provide useful examples and broader guidance on how to tackle many of the challenges associated with the broader implementation of NPS, such as:
    a. Treatment of issues related to utility remuneration and return on investment for different types of NPS
    b. Approaches to performance measurement and verification of NPS projects
    c. Transparency in the planning of NPS
    d. Minimizing the timeline for implementing and evaluating the impact of NPS
    e. Challenges associated with the sourcing of NPS
4) The lack of natural gas AMI meters is a challenge but not a barrier to NPS. Gas utilities have found workarounds to address the lack of AMI meters by using the interval data feeds from smart thermostats and water heater controllers, leveraging data from SCADA pipe pressure meters, and employing data feeds from electric AMI meters (e.g. using post G2E conversion electricity consumption to infer the baseline space heating gas demand). The resulting impact assessment may be less accurate, but there is also a reasonable amount of uncertainty with regards to long-term load growth forecasts, particularly for certain portions of the distribution network with fewer customers and less diverse energy use.
5) The timeline for NPS implementation is less of a hurdle if NPS decision and implementation is embedded in the capital project planning and decision process. If the NPS process was to overlap with the leave to construct application process, a three to five years lead time prior to forecasted capacity shortfall may be appropriate. It may be possible to implement smaller-scale NPS projects in a shorter timeline. Shorter timelines

can generally be achieved by streamlining the approval and implementation process for NPS projects.

6) While GHG emission reductions are not the primary benefit utilities are seeking through NPS opportunities, decarbonization goals and policies are a key driver for adopting NPS. Not all NPS options lead to GHG emissions reductions, and the emissions abated by specific NPS projects are only ancillary to the policy goal of NPS. NPS are relevant to gas system decarbonization pathways since they can be used to avoid deploying new natural gas infrastructure whose medium- and long-term utilization may be significantly impacted by future decarbonization policies. This helps avoid potential issues with amortizing the cost of infrastructure over 40+ year timelines, during which it may become underutilized or obsolete.

While ICF identified a significant number of relevant NPS pilot projects, few have yielded published results. Nonetheless, these pilot projects provide useful insights. ICF is recommending the following potential options as next steps for NPS pilots and/or research for FEI:

- **Enhanced smart thermostat NGDR pilot program:** NGDR using smart thermostats are relatively easy and fast to deploy, which explains why a relatively large portion of the pilot projects we identified focused on this technology. ICF noted that existing smart thermostat DR programs are focused only on curtailing the natural gas peak demand. FortisBC may want to consider a residential and small business smart thermostat DR program in coordination with BC Hydro and FortisBC's Electric Utility that focused on both summer peak load curtailment (AC) and winter gas peak demand curtailment.. A joint program will be more cost-effective since it can yield additional benefits. A smart thermostat NGDR pilot program would have the added benefit of yielding a wealth of data about the baseline load profile of space heating in British Columbia through analyzing the data feed from the smart thermostats (e.g. duty cycle, indoor temperature).
- **C&I ETEE pilot:** ICF's research suggests that there has been much less focus on ETEE as an NPS, including any M&V of the associated peak demand impacts of gas EE measures. FEI may want to consider an ETEE pilot focused on larger facilities, where it is simpler and more cost-effective to deploy the necessary telemetric equipment to measure peak demand impacts. FEI could employ a combination of incentive kickers and enhanced customer marketing and direct outreach.
- **G2E with ground-source heat pumps (GSHP):** GSHPs are significantly more efficient than air-source heat pumps. As an added benefit, GSHPs have a lower winter peak impact because they maintain their performance even during the worst cold snaps. ConEd has been testing the deployment of GSHPs as an NPS, and NYSEG is interested in pursuing community/ district heating-style geo-exchange loops. GSHPs and/or geo-exchange loops may be interesting for FEI to consider as well, since utilities are well-positioned to fund capital intensive projects that can be funded over an extended period.

While many of the challenges that were highlighted in the Enbridge 2018 IRP Study and the Enbridge 2020 study are being addressed, the industry is still a long way from a mature practice of NPS. New York State has a head start compared to other jurisdictions due to its unique circumstances, but there is limited relevant activity in other jurisdictions.

To help advance the consideration of NPS in BC, FEI may be interested in submitting an application to BCUC to formalize a framework for the consideration and deployment of NPS projects. Following the model of frameworks that have been developed in New York State and

Ontario, this would provide guidance and direction regarding important aspects such as the assessment process for NPS projects, the approach for cost-effectiveness analysis, the allocation of risk, monitoring and reporting requirements, timeline, sourcing, and cost recovery.

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Appendix A: Inventory of NPS Projects

The following section provides details on the NPS pilot projects that ICF identified as part of our jurisdictional scan of North American natural gas utilities. ICF identified only one “full scale” NPS program: Central Hudson’s Transportation Mode Alternative (TMA) program. All other pilot projects have self-imposed limitations on their applicability and were generally designed to test a variety of NPS options, using different strategies to assess the impacts.

Utility and NPS Pilot	Typology and Technologies	Research Questions	Status & Key Takeaways	Approach to M&V
ConEd – Smart Solutions (partially approved)	G2E with ground-source heat pumps in low-rise residential buildings; ETEE via residential low-income weatherization; G2E with air-source heat pumps in multi-unit residential buildings (accepted by commission but implementation was aborted); CNG/LNG (proposed but rejected as an NPS)	ConEd is investing in pilot projects and evaluation studies to ground future analysis and projections.	RFP for Whole Building Electrification Services was issued in July 2021 requesting proposals from experienced vendors with the capability to deliver innovative solutions	For large C&I customers, ConEd is in the process of installing AMI meters including encoder receiver transmitter (ERT) gas modules that get attached to the gas meters for provision of hourly interval readings on a once per day basis.
ConEd – Performance-Based Gas DR	NGDR Behavioural DR program in C&I building (Targets and call ups)	ConEd is investigating their customers' acceptance of NGDR programs and their value for gas utilities.	One event in 2019/2020 PY, achieved a demand reduction of 37,349 m^3 of gas from 156 participants, which was 54% of the pledged demand reduction.	Compared actual metered load on the event day to either an average day or weather-adjusted customer baseline load (CBL). ConEd used four different metering options for collecting of actual interval data – (1) AMI meters, (2) customer submitted consumption data from BMS, EMS, or other recording devices capable of recording hourly data, (3) annual meter reads from meters equipped with a volume corrector, and (4) Interface Management Unit data by upgrading the customer meter with an AMI Interface Management Unit.
ConEd – Thermostat DLC	NGDR, Advanced Thermostat DLC	ConEd is investigating their customers' acceptance of NGDR programs, their impact, and their value for gas utilities.	Two test events during the winter of 2019/2020 achieved a net average reduction of 1,529 m^3 per test event including the snapback effect, with about 19% of customers opting out.	The M&V approach focused on smart thermostats and was based on furnace runtime data from the thermostats. ConEd noted that it was challenging to establish the baseline for this program and that ERT meters would provide limited additional benefits in this regard.
ConEd – Water Heater Control	NGDR, Water Heater Controller	The energy efficiency and demand response potential of Aquanta's smart gas water heater controllers	Installed more than 200 Aquanta controllers in single family homes under this program. Impact evaluation for 2019 & 2020 PY are under process.	The M&V approach focused on comparing actual metered load on the event day to either an average day or weather-adjusted customer baseline load.
Central Hudson – Smart Thermostat Pilot	ETEE with Smart Thermostat incentive adders (2x the franchise-wide incentive)	Evaluating the impact of incentive adders on the adoption of smart thermostats	A total of 21 thermostats were purchased under this promotional program. Looking ahead, Central Hudson will set incentive adders from 2 to 4 time the franchise-wide incentive.	Central Hudson used a deemed savings approach (No measurement).

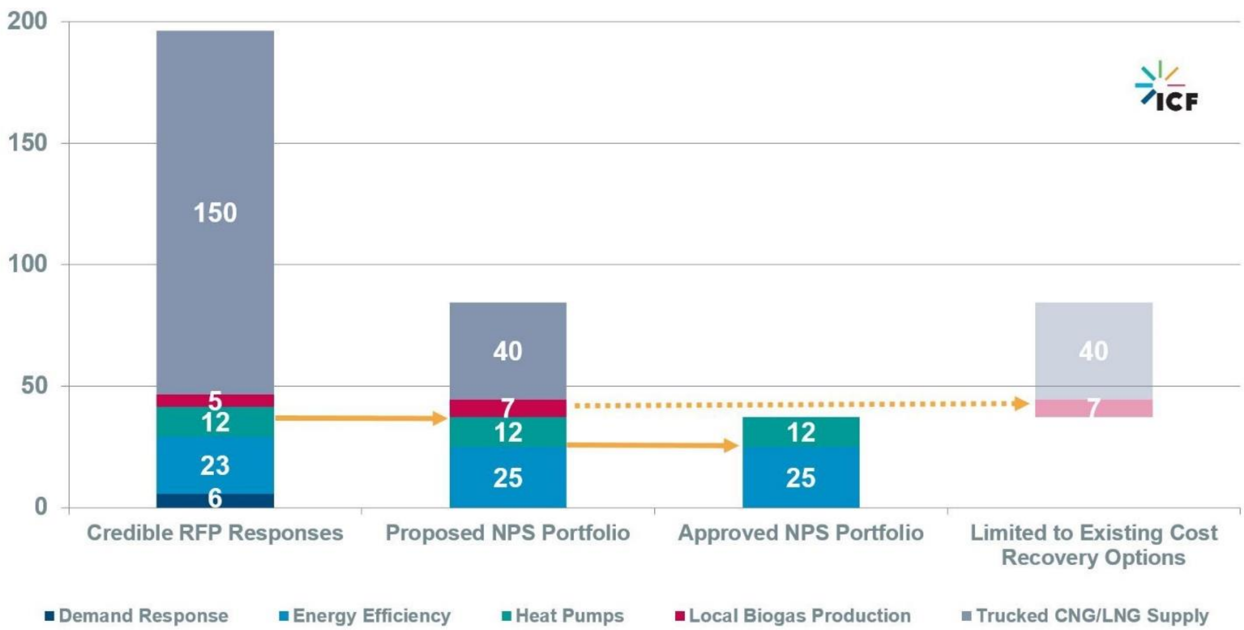
Utility and NPS Pilot	Typology and Technologies	Research Questions	Status & Key Takeaways	Approach to M&V
Central Hudson – Transportation Mode Alternatives	G2E – Full building electrification including space heating (heat pumps), electric or heat pump water heaters, and food service measures.	N/A (full-scale program)	Designed for radial mains with low customer saturation to facilitate strategic abandonment of leak-prone pipes. Currently underway in 11 identified locations.	Not applicable. By definition, no more natural gas is used in areas where this program is successful.
National Grid – Gas DR REV Demo Project	NGDR C&I Behavioural Program based on self-imposed targets; NGDR, C&I Enhanced Interruptible Rate approach with Non-Gas backup	Test the concept of NGDR and investigate the optimal ways to implement DR to generate value for both the utility and customers.	A total of 17 participants enrolled in the project, contributed 6,691 m^3/hr of peak demand reduction, which is indicative of a daily reduction of 133,820 m^3.	National Grid uses a device that reads pulses from their C&I customer meters to verify impacts from the C&I NGDR program. The utility is also accounting for the lack of AMI gas metering in the experimental design of its future pilots.
Niagara Mohawk – Commercial Gas DR	NGDR C&I Behavioural Program, based on self-imposed targets.	Test the concept of NGDR and investigate the optimal ways to implement DR to generate value for both the utility and customers.	A total of 5 participants enrolled in the project with a targeted reduction in demand of 3,610 m^3. Only one event called, achieved 110% of the target.	Niagara Mohawk uses a device that reads pulses from their C&I customer meters to verify impacts from the C&I NGDR program. The utility is also accounting for the lack of AMI gas metering in the experimental design of its future pilots.
National Grid – C&I Expanded DR	NGDR, Enhanced Interruptible Rate approach. Customers are required to have an alternate non-gas fuel source. Customers are rewarded for agreeing to interruption call-ups (a “reservation-based incentive”), rather than being penalized for not executing on interruption call-ups.	Expansion of Gas DR REV Demo	A total of 156 customers were enrolled, committed to a total of 493,890 m^3 of daily peak load reduction. Two 3-hour test events were called, with the portfolio performing at 83% of the weather-adjusted baseline.	Compared actual metered load on the event day to weather-adjusted customer baseline load (CBL).
National Grid – Non-Firm DR Rate	Legacy “Interruptible Rate” that has been re-named to differentiate it from the C&I Expanded DR, and slightly modified. Unlike the “C&I Expanded DR”, customers must switch over to a back-up system at a pre-determined temperature threshold, on an automatic basis in certain cases.	Test the effectiveness of voluntary peak reductions in terms of reducing intra-day demand and whether market-based credits will drive customer behavior to reduce consumption.	Two tiers: Tier 1 (fully automatic switchover of equipment at 16°F) service will have volumetric delivery rates set at 50% below the tail block volumetric rate, and Tier 2 (an automatic, semi-automatic, or manual switchover of equipment at 20°F) service will have volumetric delivery rates set at 60% below the tail block volumetric rate. No results are available to date.	National Grid installs a KYZ-pulse reader on the facility gas meter of participants to measure impacts, and an automatic, remote switching device as applicable.

Utility and NPS Pilot	Typology and Technologies	Research Questions	Status & Key Takeaways	Approach to M&V
National Grid – Bring Your Own Thermostat DR	NGDR, Smart Thermostat	Test case for estimating program potential and capability.	A total of 2,251 thermostats were enrolled for 2020-2021 PY. Four 4-hours long events were called, with average per event net savings (including snapback effect) per customer from 0.53 – 0.94 m^3.	National Grid used the data feed from the smart thermostats (15-minute interval runtime data). They developed a 'treatment and control' design for the 2020-21 BYOT program. Customer devices were randomly assigned to three different treatment groups, of which 1-2 groups could be dispatched during an event (treatment), with the non-dispatched group(s) serving as the control.
National Grid – Behavioural DR	NGDR, Residential and Small Commercial Behavioural	Investigate how customers react to messages notifying them of impending cold weather and suggesting ways to lower their gas consumption during peak hours.	Email alerts were sent to a total of 489,969 customers, out of which 2,894 customers (0.6%) committed to reducing their load.	
NYSEG – NPA Pilot (Proposal filed with NYPSC in Oct 2020)	ETEE including Industrial heat recovery and public education, G2E in buildings (ASHP and Community-Loop GSHP),	N/A	The projects are the results of two requests for proposals from developers.	M&V approach is being laid out on a project-by-project basis in collaboration with the project developer. Since the project is mostly focusing on large C&I buildings, daily reads are not out of the questions, and load profiles could be deemed and adjusted based on the heating degree days for a specific day. No M&V associated with the education component.
NW Natural – GeoTEE Pilot	EE, Geo-targeted energy efficiency. Three phases: geotargeted marketing, low incentive adder, high incentive adder.	Analysis of geo-targeted energy efficiency as an option for deferral and avoidance of future distribution system investments.	No results are available to date.	Selected a loop of the distribution system that can be easily isolated for the pilot and installed an AMI meter on the loop for measurements.
SoCalGas – Smart Thermostat Control Program	NGDR, Smart Thermostat	N/A	During the 2018-2019 PY, 43,103 customers were called for DR morning and evening events. Average event energy savings per participant were 0.311 m^3 for the morning event, leading to an aggregated event savings of 10,534 m^3 (15.1%), and 0.235 m^3 per participant for the evening event, leading to aggregated event savings of 2,152 m^3 (15.5%).	Gas load impacts (usage reductions) on event days were estimated by applying the best practices that have been developed for electric DR program measurement and evaluation in California. The M&V approach used the data feed received from the smart thermostat: duty cycle, indoor temperature, and setpoint.

ConEd – Smart Solutions (Partially Approved)

In December 2017, ConEd issued an RFP for market participants to provide NPS targeting peak-day relief in key areas. Based on the results of the solicitation, ConEd developed a portfolio of cost-effective NPS projects. However, the NPS suggested by the market participants did not lead to sufficient cost-effective options to avoid or defer the need for new pipeline capacity. Nevertheless, the effort resulted in a $412m ($305m USD) portfolio of projects, including a mix of ETEE and electrification as well as supply-side measures such as CNG and LNG. As shown in Exhibit 9, the portfolio was targeted at offsetting peak-day gas demand by 84,500 Dth. The portfolio was submitted to the New York Public Service Commission (herein PSC) for approval on September 28, 2018.[78]

Exhibit 9 Peak Day relief (1,000's of Dth/day) by Stage if NPS Process[79]



On February 7, 2019, the PSC ruled on the proposed NPS Portfolio, approving $300.5m ($222.6m USD) for the demand-side measures (energy efficiency & G2E) of the proposed portfolio with some conditions, while rejecting the rest $111.5m ($82.6m USD) portion of the proposal for the supply-side measures (CNG/LNG). PSC noted that these projects should instead be included within ConEd's existing capital program and/or the utility's upcoming rate filing.

While some of the intervenors were comfortable with the proposed LNG and CNG projects, arguing that these solutions would be preferable to a new pipeline due to their modularity and the reduced risk of stranded infrastructure assets, PSC ruled that the shared savings suggested by ConEd were inappropriate.[80] They argued that the proposed portfolio of NPS would fail to avoid the need for additional supply capacity to city gates and that the Petition lacked evidence that the proposed alternatives were an appropriate match to additional supply in terms of

[78] ConEdison, *Case 17-G-0606 – Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program*.
[79] ICF, 'What Can We Learn from New York's Non-Pipeline Solutions Ruling?', 2019 <https://www.icf.com/insights/energy/non-pipeline-solutions> [accessed 31 July 2020].
[80] ConEdison also requested a true-up to actual costs that would split overruns or underruns 50/50. A similar approach is used for electric non-wire solutions projects.

reliability (i.e. number of hours or days needed versus number of hours or days delivered by the NPS).

Though the PSC agreed to a $300.5m ($222.6m USD) budget for the specified demand-side measures, it directed that this funding should come from an expanded energy efficiency budget that had been announced previously. In April 2018, NYSERDA and the PSC published expanded energy efficiency targets for the state[81] and in December 2018 the PSC passed an order formally adopting expanded energy efficiency budgets and targets for utilities.[82] The PSC also instructed ConEd to include the ‘approved’ $300.5m ($222.6m USD) budget for NPS within the budget and plan it was scheduled to file in March 2019, as part of the separate proceeding for expanded energy efficiency budgets. Though PSC did not allow any new money, the NPS measures were approved since they aligned with the state’s existing plans to significantly increase funding to both improve energy efficiency and drive heat pump adoption.

Although most of the funding was tied up in additional cases, the PSC NPS order did allow ConEd to get started on some pilot projects, through the approval of $40.1m ($29.7m USD) for the first year of the demand-side initiatives. ConEd used the initial funding tranche to implement three one-year pilot programs:

- **Electrification program:** This pilot targeted residential customers in Westchester County for gas to ground-source heat pump conversions. ConEd reported results that exceeded targets, largely due to the higher than anticipated count of participating homes (i.e. 60 participants).
- **Residential sector weatherization program:** ConEd reported results that were lower than the targets for this program.
- **Electrification project:** This project was focused on a conversion to air-source heat pumps in a multi-unit residential building in the Bronx. The project was unsuccessful due to lack of suitable participants.

ConEd – Performance-Based Gas DR Pilot

ConEd’s Performance-Based Gas DR Pilot was launched in the winter of 2018/19. It is a behavioural NGDR Pilot targeting C&I customers and multi-unit residential buildings with centralized heating systems. This pilot is testing the effectiveness of incentivizing customers to provide net reductions in their natural gas demand during peak demand days (i.e. for a 24-hours period) on the coldest winter days. As part of the Performance-Based Gas DR pilot, building operators are asked to pledge daily savings on peak days and they are given advance notice of the need to curtail their demand on peak days. Participant incentives are based on their performance.[83] It is a behavioural program because it depends on actions taken by customers on the basis of utility notifications.

ConEd set participation limits of 500 customers in the first program year (2018/19), 750 customers in 2019/20, and 1,000 customers in 2020/21.[84] ConEd’s second status report for

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[81] NYSERDA.
[82] NY Public Service Commission, *CASE 18-M-0084 - In the Matter of a Comprehensive Energy Efficiency Initiative - Order Adopting Accelerated Energy Efficiency Targets, December 13, 2018*, 2018.
[83] ConEdison, *Gas Demand Response Report on Pilot Performance - 2019/2020, Case 17-G-0606 and Case 14-E-0423*, 2020.
[84] ConEdison, ‘Gas Demand Response Pilot Implementation Plan, 2021-2022, Case 17-G-0606’, 2021 <https://www.coned.com/-/media/files/coned/documents/save-energy-money/rebates-incentives-tax-credits/smart-usage-rewards/gas-demand-response-implementation-plan.pdf> [accessed 17 January 2022].

2019/2020 indicates that a total of 309 customers enrolled in the program and pledged 81,654 m^3 (2,886 Dth) of gas reductions. ConEd called one test during the 2019/2020 program year. The status report noted that the resulting impacts of 156 of the customers were measured and that they achieved demand reductions of 37,349 m^3 of gas (1,291 Dth) against a pledged quantity of 60,638 m^3 of gas (2,096 Dth) reduction. This translates to 54% of the pledged impact.[85]

During the 2020/21 program year, 590 customers enrolled in the program and pledged 107,330 m^3 (3,765 dth) of gas reductions. During the single test event, ConEd estimated a load reduction of 19,470 m^3 (683 dth) for customers who utilized curtailment of their gas-fired CHP equipment. However, they calculated an increase in net load of 18,670 m^3 (655 dth) for customers who curtailed gas-fired space heating and/or water heating equipment. ConEd is investigating these results further to determine if their approach to estimating demand impacts underpredicted customer consumption during the event day or if the methodology wasn't sensitive enough to capture customers' attempts to reduce load.

ConEd also noted that the temperatures experienced on the coldest days of the 2019/20 and 2020/21 program years were mild compared to gas system design temperatures. As such, the pilot provided limited insights into the ability to curtail peak demand at colder temperatures. This applies to both the performance-based pilot and the residential thermostat pilot that is discussed below.

ConEd – Residential Thermostat DLC

ConEdison's residential DLC Pilot was also launched in the winter of 2018/19. This program is deploying both ConEd's fleet of advanced thermostats that are also used for summer electricity peak curtailment and additional thermostats that were enrolled through a bring-your-own thermostat component. The advanced thermostats are used to control HVAC equipment and reduce natural gas demand during peak periods.

Over 2,800 thermostats were enrolled in the program in the 2019/20 program year. The program had two test events with an overall average reduction of 1,529 m^3 of natural gas (56.1 dth) per event including the snapback effect (i.e. incremental gas required to recover from temperature setbacks).[86] The average peak demand impact on a per-thermostat basis for the 4-6 hour events was 0.57 m^3 (0.020 dth), with higher average savings for longer setback periods and the morning test period. Snapback reduced the calculated load reduction by an average of 52%.[83] ConEd also found that around 19% of enrolled customers opted out during that program year.

ConEd carried out two additional events during the 2020/21 program year, with 5,014 participating customers and 4-6 hour temperature setbacks per event. They observed an average of 0.68 m^3 (0.024 dth) of gas load reduction per device including snapback and a higher out-out rate of 37%. This higher opt-out rate can be at least partially attributed to the testing of larger temperature setbacks (i.e. 3-4°F (1.7-2.2°C)). Based on its testing of different

[85] Con Edison, 'Performance-Based Gas Demand Response Pilot Guidelines, 2021/2022 Capability Period', 2021 <https://www.coned.com/-/media/files/coned/documents/save-energy-money/rebates-incentives-tax-credits/smart-usage-rewards/gas-demand-response-pilot-guidelines.pdf> [accessed 12 November 2021].

[86] The snapback effect is an increase in energy demand that happens due to the synchronization of a fleet of asset because of a DR event. In other words, the entire fleet of heating equipment that was curtailed start at the same time and operate at full capacity simultaneously to bring back the space temperature at its original setpoint. There are many DR strategies to minimize and soften the snapback.

temperature setbacks, ConEd's pilot has indicated that larger setbacks can result in higher average load reductions, even after accounting for opt-outs and snapback.

ConEd – Smart Gas Water Heater Controllers Pilot

ConEdison's Aquanta Smart Gas Water Heater Controllers Pilot was implemented from December 2018 to September 2020. This pilot program was designed to test the energy efficiency and demand response potential of Aquanta's smart gas water heater controllers. The pilot targeted residential customers in single family homes to install 300 Aquanta controls. The Aquanta controllers are Wi-Fi enabled, which allows customers to access them from any Wi-Fi enabled device. It also provided ConEd with a fleet portal for data gathering and DR event management. As part of this program, over 200 controllers were installed in single family homes in Westchester.[87]

Documentation suggests that ConEd and its EM&V contractor were performing the impact evaluation of the Aquanta Pilot for the 2019 and 2020 program years, with a report due to be released in Q2 2021. However, ICF was unable to verify that this work has been completed or gain access to the report to assess the results.

Central Hudson – Smart Thermostat Pilot program

In March 2018, NY's PSC ordered Central Hudson to assess natural gas demand-side solutions. Central Hudson's avoided gas distribution study didn't identify any constraints on its gas distribution system other than a portion of its system referred to as the PN Line, which serves in the southern portion of the Town of Poughkeepsie.

Central Hudson evaluated its six existing portfolios of energy efficiency and electrification technologies in conjunction with incentive kickers (i.e. adders) in a peak load management application focusing on the PN Line. To assess the use of kickers, Central Hudson performed a simplified analysis to compare the incremental costs of higher incentives and benefits associated with more concentrated load reductions.[88] Exhibit 10 summarizes the results for the locational benefits of the measures, indicating smart thermostats as the most cost-effective measure.

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[87] Con Edison, 'Verified Gross Savings Specification – Commercial & Industrial', 2021 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA1D97B04-2685-43EE-8217-FDA296374995%7D> [accessed 12 November 2021].

[88] Central Hudson Gas & Electric Corporation, 'Assessment of Natural Gas Demand-Side Load Management Solutions', 2020 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B1CB068E6-2DE6-490E-B5F1-1816192281F9%7D> [accessed 12 November 2021].

Exhibit 10 Simplified Benefit Cost Analysis of Kickers on Top of Broad-Based DSM Incentive for Central Hudson[89]

Measure	Locational Benefits	Locational Costs	Locational Net Benefits	Locational BC ratio	Avoided pipline capacity (CCFh-yr)
Smart thermostat	$ 371,344	$ 313,817	$ 57,527	1.18	74
Heat Pump Water Heater	$ 351,958	$ 1,589,387	$ (1,237,429)	0.22	75
ASHP - All-Electric Whole Home	$ 361,190	$ 1,067,952	$ (706,761)	0.34	60
ASHP - Dual-Fuel	$ 83,869	$ 270,449	$ (186,581)	0.31	14
Efficient Combi Boiler	$ 452,707	$ 2,323,269	$ (1,870,562)	0.19	73
Efficient Furnace	$ 539,779	$ 603,607	$ (63,828)	0.89	75

As a result of this analysis, Central Hudson implemented a “kicker incentive” to promote ENERGY STAR certified smart thermostats to customers served by the Vassar Road portion its PN Line. In November 2020, Central Hudson initiated its “Double the Rebates” marketing campaign to approximately 750 residential and commercial customers, with increased incentives available up until May 1, 2021. A total of 21 thermostats were purchased under this promotional program, representing approximately 3% buy-in from the targeted group. Central Hudson will implement this initiative on an as-needed basis and will set the incentive levels (i.e. anywhere from 2 to 4 times the regular incentive) based on consideration of existing portfolio budgets.[90]

Central Hudson – Transportation Mode Alternatives (TMA)

Central Hudson’s Transportation Mode Alternatives (TMA) program is designed to facilitate strategic abandonment of leak-prone pipes that are not otherwise integral to the distribution system. This opportunity is best suited for radial mains with low customer saturation. Under this program, each customer served by the targeted section must convert all of their current natural gas end uses to electricity. Central Hudson is using a direct install approach for this program, which includes efficient electric heat pumps and water heating systems, as well as ranges, dryers, and other appliances as needed.[91]

Based on the latest available results, 40 separate TMA project locations have been identified where it is potentially feasible and cost-effective to permanently retire sections of leak-prone pipe. These 40 project locations include approximately 100 customers. Out of the 40 projects, a total of 21 projects were included in the NPA Implementation Plans (2019, 2020 and 2021 Plan). Thus far, three projects involving a total of six customers have been completed and three more projects involving 24 customers are in progress. In addition, five projects have been found to be unsuitable upon further investigation and ten projects have been postponed due to lack of sufficient customer interest to proceed with an G2E solution.[92]

[89] Central Hudson Gas & Electric Corporation, *Cases 17-G-0459, et Al. Assessment of Natural Gas Demand-Side Load Management Solutions*, 2020 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B1CB068E6-2DE6-490E-B5F1-1816192281F9%7D>.
[90] Central Hudson Gas & Electric Corporation, ‘Non-Pipeline Alternatives Annual Report, Case 17-G-0460’, 2021 <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B46F78EB9-661D-41BB-AAF9-07E6F6D7F523%7D> [accessed 17 January 2022].
[91] Central Hudson Gas & Electric Corporation, ‘Central Hudson’s Demand Reducing Measures Status Report and Proposals. Case 20-G-0131’, 2020 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B6F5B0C7C-2D0F-48F9-8E65-0B8DBDDCFE90%7D> [accessed 12 November 2021].
[92] Central Hudson Gas & Electric Corporation, ‘Non-Pipeline Alternatives Annual Report, Case 17-G-0460’.

Central Hudson has partnered with ICF to deliver these projects. A direct install approach favouring ASHPs over GSHPs has been adopted considering the small number of customers, the requirement for 100% participation within each area, the cheaper and faster installation of ASHPs.

National Grid – Gas DR REV Demo Project

In 2017, National Grid launched a DR pilot for its large commercial firm customers with the goal of alleviating peak hour demand on its distribution system. This DR pilot program focused on expanding NGDR beyond interruptible or temperature-controlled customers who can perform fuel switching. The program has two options: Daily DR and Hourly DR. In the case of the Daily DR program option, participants must have the ability to reduce their gas consumption by shutting off non-heating gas equipment or switching to a non-gas heating backup. The Hourly DR program option is focused on customers who can only shift their gas loads to a different time period within the same day. In the case of the Hourly DR program option, customers are restricted from using a fossil-fuel backup during the DR events.[93]

This pilot project was designed and developed to test the concept of NGDR and to start exploring the optimal ways to implement DR to generate value for both the utility and its customers. A total of 17 large commercial facilities participated in the project over the course of three winter program period but the participation fluctuated, with a maximum of 16 participants. This project contributed 6,691 m^3/hr (241 Dth/hr) of peak demand reduction and this hourly reduction would be indicative of a daily reduction of 133,820 m^3 (4,820 Dth), which is equivalent to 2.5% of the reduction produced by National Grid's non-firm customers.[94]

National Grid – C&I Expanded DR

The C&I Expanded DR initiative is a program for large C&I customers capable of reducing peak day gas loads over a 6 or 8-hour period. The program depends on customers to completely curtail their gas loads over a 6-hour period by switching to an alternate, non-gas fuel source or completely shutting down their natural gas equipment. Participating customers were offered a reservation-based incentive at the beginning of the season. To receive 100% of the stated incentive, customers need to comply with all DR events. If they don't meet this condition, customers receive either 50% or none of the stated incentive, depending on the number of events called in the season.[95]

A total of 156 customers were enrolled for the 2020/21 expanded DR program that committed 493,890 m^3 (17,790 Dth) of daily peak load reduction. Over 90% of the participants in the 2019/20 program season returned for the 2020/21 program. Due to a mild winter, no DR events were called during the season. However, two 3-hour test events were called in December 2020 and almost all customers participated in one of the events. In aggregate, the participants

[93] National Grid, 'Reduce Your Natural Gas Usage and Earn Incentives, Natural Gas Demand Response Program for Firm Customers', 2021 <https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/demand_response_program.pdf> [accessed 12 November 2021].
[94] National Grid, 'Gas Demand Response Rev Demonstration Project - Final Report (Filed in Cases 16-G-0058 and Case 16-G0059)', 2020 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BC1EC8F5E-B383-4664-989A-1BE90C33FDE5%7D> [accessed 12 November 2021].
[95] National Grid, '2020-2021 Expanded Gas Demand Response Implementation Plan', 2020 <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B1043D93F-B2CD-4E27-86EF-FCCA68F2635D%7D> [accessed 12 November 2021].

reduced their daily load by 71,293 m^3 (2,568 Dths) for the sum total of both the events and the entirety of the 3-hours, with the portfolio performing at 83% of the weather-adjusted baseline.[96]

National Grid – Bring Your Own Thermostat DR

This is a residential and small commercial customer-focused program, which uses communicating thermostats to remotely lower temperature set points and shift peak hour gas loads. A total of 2,251 thermostats were enrolled at the end of 2020/21 heating season. To accurately measure the impact of the DR events, National Grid used a treatment and control approach, randomly dividing the enrolled participants into three groups for the DR events. They dispatched one or two groups and the other(s) served as the control group(s).[96]

A total of four separate 4-hour long events were called during the 2020/21 PY, including three morning events and one evening event. The average per event usage savings per customer ranged from 1.69-1.83 m^3 (0.061-0.066 Dth), while the net event savings (including snapback effect) ranged from 0.53-0.94 m^3 (0.019-0.034 Dth). These estimates are statistically significant at a 95% confidence level.[96]

Without access to interval metered data, National Grid utilized the 15-minute runtime data recorded from the participating thermostats. This runtime data was then transformed into Dths utilizing an estimated 80,000 BTU/Hour input assumption for the average customer heating equipment. National Grid is currently working to verify this input assumption using actual hourly data sampled from participating customers.

National Grid – Non-Firm DR Rate

In addition to the DR program for firm customers described above, National Grid has two non-firm rates as well, which are called "non-firm DR" in recognition of the reduction they provide during event hours. The non-firm DR rates are the former interruptible and temperature-controlled rates that were offered by National Grid. The non-firm DR program has two tiers: Tier 1 includes a fully automatic switchover of equipment at -8.9°C (16°F), and Tier 2 can have an automatic, semi-automatic, or manual switchover equipment at -6.7°C (20°F). National Grid installs KYZ-pulse readers on facility gas meters of participants to measure impacts, and an automatic, remote switching device as applicable.[97]

National Grid – Behavioral DR

This is a non-incentivized program that uses e-mails or mobile messaging to notify customers of impending cold weather and to suggest ways to lower their gas consumption during peak hours.[96] Two behavioral DR events were called during the 2020/2021 heating season, including a large event and a separate much smaller event that was focused on trying to measure impacts. The first event was conducted on the coldest day of the winter season and sent cold weather email alerts to 489,969 residential and small commercial customers. A total of 2,894

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[96] National Grid, 'Gas Demand Response 2020-2021 Annual Report', 2021 <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B401290B9-FE59-4F47-B886-CDE01A38522A%7D> [accessed 12 November 2021].

[97] National Grid, *Case 19-G-0309 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service and KeySpan Gas East Corp. d/b/a National Grid for Gas Service*, 2019 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BE11E743B-6CAF-4905-AA13-4807CE7A56B4%7D>.

customers committed to reduce their load but impacts could only be estimated due to the lack of hourly metering.

More recently, National Grid installed devices that are capable of reading hourly gas consumption from traditional drive-by meters on 900 select customers. Due to delays in the implementation of the metering and a small sample size, National Grid was not been able to more accurately assess impacts of its second behavioural NGDR program during the 2020/21 heating season. However, the utility is hoping to use these meters to measure impacts of behavioural NGDR events during the 2021/22 heating season.[96]

Niagara Mohawk (aka National Grid Upstate) – Commercial Gas Demand Response Project

This is a customer-centric, voluntary NGDR program targeting large commercial, firm gas customers in the Eastgate gas territory. The program launched in September 2019 and was scheduled to run over two winters. For Season 1, the project enrolled a total of five (5) participants, with a reduction target of 3,610 m^3 (130 Dth). Due to the mild winter, only one event was called on February 28, 2020. Out of the five participants, only one failed to meet their reduction target. The other four participants overperformed during the event, resulting in a 10% increase in total achievement (i.e. a total of 3,970 m^3 or 143 Dth).[98]

NYSEG – Approved Portfolio of NPS Projects

In October 2020, NYSEG filed a proposal with the NYPSC to implement an NPS project in the Town of Lansing, New York to improve its low-pressure situation during peak hours. The solution includes residential and non-residential heat pump installations, a community loop ground source heat pump project, the installation of gas energy efficiency solutions, industrial heat recovery, and a coordinated public education and outreach effort.[99]

In June 2021, the PSC approved procurement of seven NPS projects for a total estimated cost of $9.7 million with some modifications. Together, the projects do not pass the SCT test (although there was some debate regarding the valuation of GHG reductions). However, they do pass the UCT tests, which is why NYSEG is pursuing them and the PSC granted permission. These projects are expected to reduce the natural gas demand by approximately 56 MCF per hour. The approved projects include G2E (residential ASHP, commercial GSHP, community GSHP), ETEE at two public authority buildings, ETEE (heat recovery) at industrial facilities, NGDR at C&I buildings (i.e. using electric boilers as backup), and an education and outreach program. None of these projects had started as of late 2021.

The increase in electricity bills after G2E conversions will be higher than the reductions in their gas bills. The operators of participating buildings have agreed and are willing to pay higher energy bills. While NYSEG has agreed to an incentive amount to offset the cost of the G2E conversions, the amount is insufficient to make up for the incremental cost of ownership of all-electric HVAC.

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[98] National Grid, *Case 17-E-0238 & Case 17-G-0239 Report of Niagara Mohawk Power Corporation d/b/a National Grid on the Proposed Implementation of Advanced Metering Infrastructure*, 2018 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B5A9009BC-356F-4B0F-B3C7-F255EA8AA5A8%7D>.

[99] NYSEG News, 'NYSEG Files Plans for Industry Leading Non-Pipe Alternatives to Serve Natural Gas Customers, Among First of Its Kind', 2020 <https://electricenergyonline.com/article/energy/category/oil-gas/89/862079/nyseg-files-plans-for-industry-leading-non-pipe-alternatives-to-serve-natural-gas-customers-among-first-of-its-kind-.html> [accessed 12 November 2021].

Projects that were not approved include smart thermostat gas DR in the zone of highest impact (i.e. component not cost-effective), LNG and CNG delivery and injection, and hydrogen generation and injection.[100,101]

NW Natural – GeoTEE

NW Natural's Geo-Targeted Energy Efficiency (GeoTEE) pilot project is being implemented in close collaboration with Energy Trust Oregon (ETO). The project is designed to obtain measured data needed to more accurately consider geo-targeted energy efficiency as a viable option for deferral and avoidance of future distribution system investments.

The GeoTEE pilot project includes three phases:

- **Phase 1:** Targeted marketing and customer engagement for a certain segment of NW Natural's distribution system to promote EE through existing broad-based EE programs.
- **Phase 2:** Targeted incentive kickers (i.e. adders) to top off incentives available through existing broad-based EE programs, within cost-effectiveness (UCT) bounds.
- **Phase 3:** Larger incentive kickers to top off incentives available through existing broad-based EE programs, beyond cost-effectiveness threshold.

It was critical to the experimental design of the project to select a loop of the distribution system that can be more easily isolated for the pilot. NW Natural installed a SCADA meter to monitor the hourly flow of gas at the entrance of the target area and they will compare daily and monthly data against the aggregated data from the SCADA meter.

Results from 2018/2019 were delayed due to issues relating to a faulty meter. NW Natural is in the process of analyzing data from 2019/20, 2020/21, and 2021/22. They expressed concerns about the potential impact of COVID-19 on the dataset, but they have not yet confirmed whether this was indeed an issue of real concern. To date, no results have been made available from this pilot project.

Colorado Xcel Energy – Heat Savers Mode Study

The Heat Savers Mode Study is a NGDR pilot[102] that is being implemented in Summit County, Colorado, a mountainous region with multiple ski resorts where pipeline expansion is particularly difficult and costly. Xcel is hoping the pilot results will help the utility better manage demand and avoid building out additional gas infrastructure going forward. In particular, the pilot involves the installation of wireless energy monitors that will allow the utility to better understand localized load shapes and daily peaks over time to help improve system planning, and a NGDR component leveraging smart thermostats in conjunction with behavioral prompts through a customer-focused mobile app to reduce gas demand during peak periods.

SoCalGas Smart Control Thermostat Program

In the SoCalGas Smart Control Thermostat program, participants were granted access and control of the temperature settings over specific 4-hour events during the winter season in

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[100] NYSEG & RG&E.
[101] NY Public Service Commission, *Case 17-G-0432, Petition of New York Electric & Gas Corporation for Authorization to Construct a Natural Gas Compressor Pilot Project in Tompkins County, NY - Order Approving Petition for Non-Pipe Alternative Projects, with Modifications*.
[102] Xcel Energy, 'Heat Savers Mode Study', 2021 <https://co.my.xcelenergy.com/s/state-selector?return=%2Fs%2Fresidential%2Fheating-cooling%2Fheat-savers> [accessed 17 January 2022].

exchange for an economic incentive. The program started during the 2017/18 heating season showed impressive growth, reaching approximately 50,000 customers during 2018/19 program year. Customers signed up to receive smart thermostats and take advantage of existing advanced metering infrastructure (AMI). [103,104] The program is event-based and the load reductions are attained on event days from temporary temperature setbacks. The events are generally take place between the hours of 5-9 am or 6-10 pm.

During the 2018/19 program year, 33,895 customers were called for morning events (5-9 am) and 9,208 customers for evening events (6-10 pm). The average load reduction per participant during the morning event was 0.765 m^3/hr (0.027 CCF/hr or 15.1% average reduction), while evening event participants reduced their load by an average of 0.665 m^3/hr (0.020 CCF/hr or 15.5% average reduction). Average event energy savings per participant was 0.311 m^3 (0.110 CCF) during the morning event 0.235 m^3 (0.083 CCF) during the evening event.[105]

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[103] Nexant, '2018-2019 Winter Load Impact Evaluation of SoCalGas Smart Therm Program, CALMAC Study ID SCG0224', 2019 <http://www.calmac.org/publications/SoCalGas_2019_DR_Evaluation_Report_-_PUBLIC_FINAL.pdf> [accessed 12 November 2021].
[104] CISION PR Newswire, 'SoCalGas Smart Thermostat Program Offers Customers Up to $75 in Incentives to Conserve Natural Gas This Winter', 2018 <https://www.prnewswire.com/news-releases/socalgas-smart-thermostat-program-offers-customers-up-to-75-in-incentives-to-conserve-natural-gas-this-winter-300590568.html> [accessed 12 November 2021].
[105] Nexant.

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Appendix D

ENERGY SUPPLY PORTFOLIO

Appendix D-1

NATURAL GAS MARKET OVERVIEW

APPENDIX D-1: NATURAL GAS MARKET OVERVIEW

1.1 INTRODUCTION

This appendix provides a high level overview of the North American and regional natural gas marketplace which informs the LTGRP regarding the outlook on natural gas pricing, supply, and demand, however does not significantly impact the strategies implemented within the LTGRP. Some information in this appendix is provided by global energy market providers who prepare their own proprietary analysis (i.e. IHS Markit), while other information comes from some reports that are publicly available on Federal or Provincial websites.

The policy developments discussed in Section 2.2 that seek to address climate change and reduce GHG emissions will have an impact on the energy market, specifically the oil, natural gas, and electricity sectors. The natural gas and electricity markets have already seen impacts from such policies, as demonstrated through legislation in the early 2010's that resulted in coal plant retirements. Despite the urgency driving much of the recent policy initiatives, the nature of any impact they may cause on regional natural gas supply, demand, and infrastructure remains uncertain. The policies, targets and initiatives discussed in Section 2.2 illustrate that the conversation around the role of the gas system in decarbonizing Canada's GHG emissions is undefined.

The most recent supply and demand projections incorporate all known policies in the outlooks; however, an "evolving policies" or "fast transition" to net-zero scenario[1] is also provided to illustrate a pathway to achieving carbon net neutrality.

This section is organized as follows:

- **Section 1.2 – Natural Gas Prices –** This section provides an overview of North American and regional market prices (i.e., AECO/NIT);
- **Section 1.3 – Natural Gas Supply –** This section provides an overview of North American and regional supply (i.e., Western Canadian Sedimentary Basin);
- **Section 1.4 – Natural Gas Demand –** This section discusses North American demand, as well as regional LNG export and natural gas fired power demand.

1.2 NATURAL GAS PRICES

Henry Hub is the official pricing point for natural gas futures on the New York Mercantile Exchange (NYMEX) and is used as the benchmark for the North American natural gas market. The notable growth of shale gas supply since 2008 has resulted in a significant drop in natural gas prices. As illustrated below in Figure D1-1, prior to the shale gas revolution, Henry Hub prices in the "Pre-

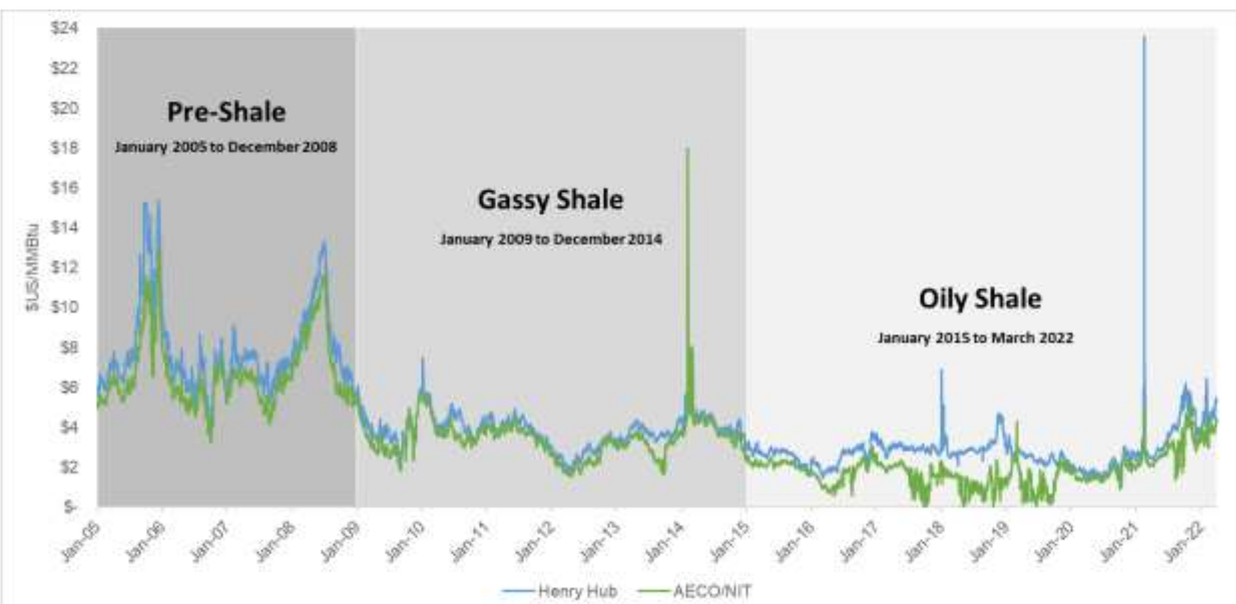
[1] The Canada Energy Regulator (CER) provides net-zero modelling for the first time in its "Evolving Policies" scenario, as part of its Canada's Energy Future 2021, released in December 2021. Additionally, IHS Markit provided a "Fast Transition" scenario as a pathway to net-zero carbon emissions in North America in May 2021.

Shale" era from January 2005 to December 2008 averaged $7.85 US/MMBtu[2] with market prices spiking over $12.00 US/MMBtu several times. During the "Gassy Shale" gas era from January 2009 to December 2014, Henry Hub had an average price of $3.84 US/MMBtu.

Currently, in the "Oily Shale" era from January 2015 to March 2022, Henry Hub prices have averaged $2.85 US/MMBtu. However, price volatility exists with price spikes above $23.00 US/MMBtu but also price dips below $2.00 US/MMBtu. The daily Henry Hub prices spiked to $23.45 US/MMBtu in February 2021 due to the Winter Storm Uri that affected much of the central part of the United States and disrupted energy systems, particularly in and around Texas. The daily Henry Hub prices dipped below $2.00 US/MMBtu for extended periods during the 2015/16 and 2019/20 winters, as well as the 2020 summer, this was due to an oversupply of gas and the global economic shutdown from the COVID-19 pandemic, respectively.

Recently, Henry Hub prices have become more interconnected with global markets, which has led to higher prices as well as increased pricing volatility; this is due to LNG exports helping to meet increased demand in tight global market conditions. Henry Hub prices have experienced greater connection to global markets beginning in 2021, as the insularity that once shielded North American prices from oversea turmoil disintegrates[3] due to LNG exports comprising a much larger portion of US demand. Natural gas demand also experienced a significant rebound in 2021, as the US and Canada began to recover from the economic downturn in 2020, and Henry Hub prices averaged $4.52 US/MMBtu for the 2021/22 winter (November 1 to March 31).

Figure D1-1: Henry Hub and AECO/NIT Historical Natural Gas Spot Prices[4]

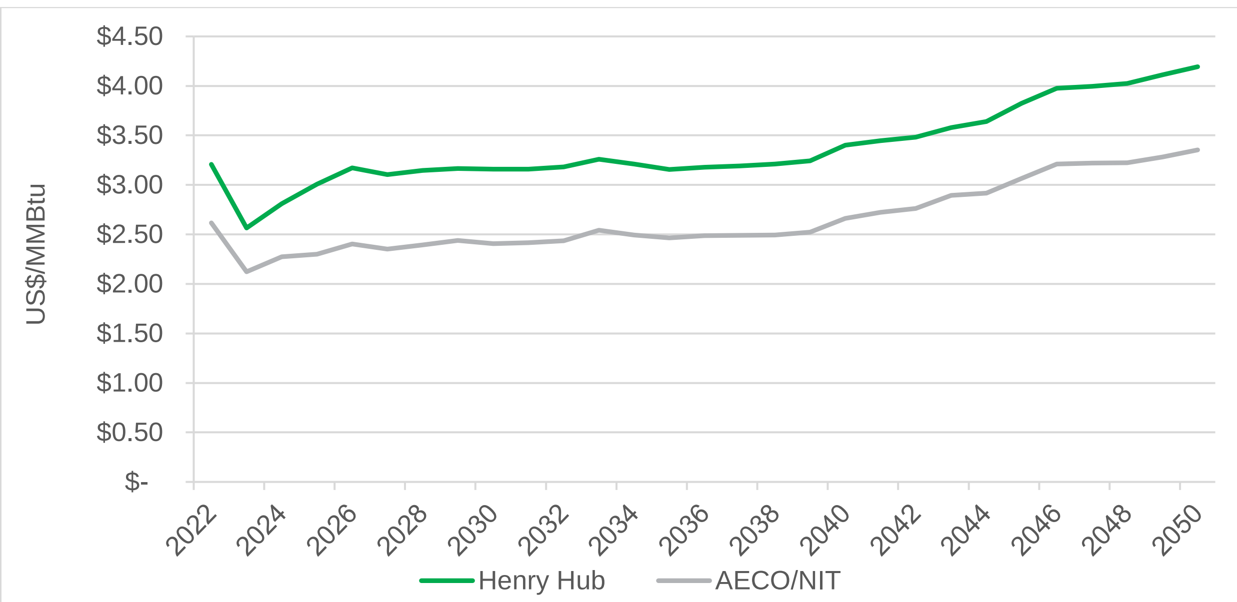


[2] MMBtu is defined as one million British Thermal Units.
[3] Bloomberg (January 2022). "U.S. Natural Gas Faces Wild 2022 as Foreign Crises Exert Pull."
[4] Platts. "Platts Gas Daily Market Fundamentals". https://www.platts.com/products/gas-daily.

As illustrated in Figure D1-1, AECO/NIT[5] prices trade at a discount to the Henry Hub price. This discount is driven primarily by the development of shale gas basins located much closer to key consuming markets in the US Northeast, such as the Marcellus and Utica shale gas plays. These basins do not face the costly transportation tolls that need to be paid by the more distant WCSB producers.

Figure D1-2 below shows IHS Markit's (S&P Global) long term natural gas price forecast, released in February 2022, for the Henry Hub and AECO/NIT markets in real 2021 dollars. In 2023, forecasted Henry Hub natural gas prices are expected to decrease due to increased production, however prices rebound the following year and remain flat over the long term, with prices above $3.00 US/MMBtu and steadily increasing from 2040 to 2050 to above $4.00 US/MMBtu. However, the forecasts do not include temporary price spikes or dips that can occur due to extreme weather events or other supply/demand imbalance events, as was shown in Figure D1-1. Additionally, this forecast was completed prior to the Russian invasion of Ukraine and thus does not include the impact of the current geopolitical climate and does not illustrate the current futures price market. IHS Markit has since noted[6] that they will be revising their outlooks to reflect "these new realities that we believe will endure over the next few years" which should be adjusted in their August 2022 long-term forecast.

Figure D1-2: Natural Gas Price Forecast (2021 Real Dollars)[7]



5 FEI procures most of its supply from the Station 2 and AECO/NIT supply hubs. After the TC Energy North Montney Mainline was placed into service in January 2020, Station 2 prices have strengthened relative to AECO/NIT and now typically trade at parity to AECO/NIT, and therefore only AECO/NIT is shown.

6 IHS Markit (April 2022). "Why North American natural gas prices have risen (and where do they go from here?)"

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1.2.1 Natural Gas Price Competitiveness to Other Fuel Sources

After the shale gas revolution, North American natural gas became more economically attractive relative to other fuel sources as it was significantly disconnected from other competing fuels. Figure D1-3 sets out prices (historical prompt month and futures, on a $US/MMBtu equivalent basis)[8] for West Texas Intermediate (WTI) crude oil, Japanese Korean Marker (JKM) LNG, and National Balancing Point (NBP) UK gas that compete with North American natural gas. As the figure below shows, prices for JKM and NBP are over $20 US/MMBtu higher than the Henry Hub price, as prices began to rise after the beginning of the COVID-19 pandemic due to the re-balancing of global supply and demand and a global energy shortage. More recently, natural gas prices in Europe and LNG prices continue to surge due to the Russian invasion of Ukraine.

Figure D1-3: Competing Fuel Prices[9]

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[8] Commodities futures are agreements to buy or sell a raw material at a specific date in the future at a particular price. Prompt-month prices refer to prices of the futures contract that is closest to expiration and is usually for delivery in the next calendar month; historical prompt-month data thus records the actual historical prices of these prompt-month contracts.

[9] US EIA & CME Group. (March 4, 2022).

1.3 NATURAL GAS SUPPLY

The North American natural gas market continues to be influenced by the abundance[10] of shale gas supply, which is a result of the rapid development of unconventional natural gas reserves. The rapid increase in domestic supply was enabled by efficient drilling technologies and associated gas from oil and natural gas liquid plays. Significant improvements have been made to two essential technologies, horizontal drilling and hydraulic fracturing, that are used to unlock natural gas trapped in shale formations. The use of horizontal drilling and hydraulic fracturing is critical for accessing the natural gas potential of North America's shale basins and to maintain production growth in the next decade.

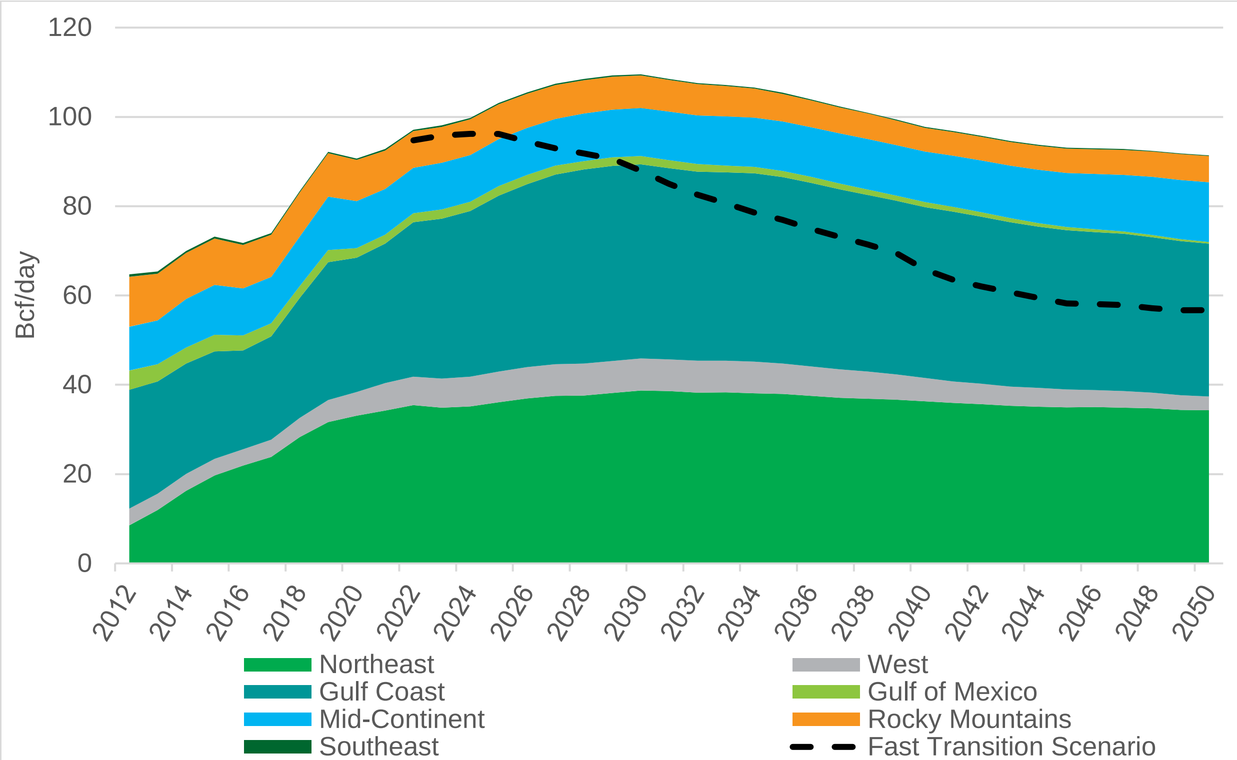
1.3.1 US Supply Forecast

In the US, supply growth will be driven by the low cost shale formations in the US Northeast, specifically the Marcellus and Utica basins, and the Gulf Coast, which includes the Permian basin. Figure D1-4 provides IHS Markit's latest long term supply forecast from February 2022, based on current or known policies, and shows production growing through 2030 then beginning to lower due to declining demand and increased solar and wind resources. In 2021, gas production within the US was 93 Bcf/day, which is 19 Bcf/day or 25 percent higher than production in 2017.

The figure below also provides what natural gas supply could be in a "fast transition" scenario with additional policies restricting production growth in a pathway to achieve economy wide carbon net neutrality by 2050 in the US.

[10] Gas market analysts currently predict that North America holds around 100 years of recoverable supply, based on current consumption levels. The total amount of supply is estimated at 2,926 trillion cubic feet (Tcf), compared to US dry gas production of 30 Tcf in 2020. https://www.eia.gov/tools/faqs/faq.php?id=58&t=8

Figure D1-4: US Natural Gas Production[11]



1.3.2 Regional Supply Forecast

The majority of Canada's natural gas supply originates within the Montney formation, located in the northwest of the Western Canadian Sedimentary Basin. The natural gas potential in the Montney shale formation is one of the largest and lowest cost upstream resources in North America, and is forecast to continue to be the significant driver of growth in Canadian natural gas production. This is illustrated through Figure D1-5 below, which is based on the CER's projected production growth in Canada based on current policies.

In 2021, gas production within BC was approximately 5.7 Bcf/day, which is 27 percent higher than the production in 2017. The CER expects this trend to continue, as illustrated in the figure above, as BC, and specifically the Montney basin, is expected to grow through 2040. Additionally, the CER expects that BC will surpass Alberta as Canada's biggest natural gas producing province, which is driven largely by LNG exports.

The below figure also provides what natural gas supply could be in the CER's "evolving policies" scenario, which is based on strengthening or expanding existing global and domestic policies to reduce GHG emissions. Notably, even under the "evolving policies" scenario, natural gas

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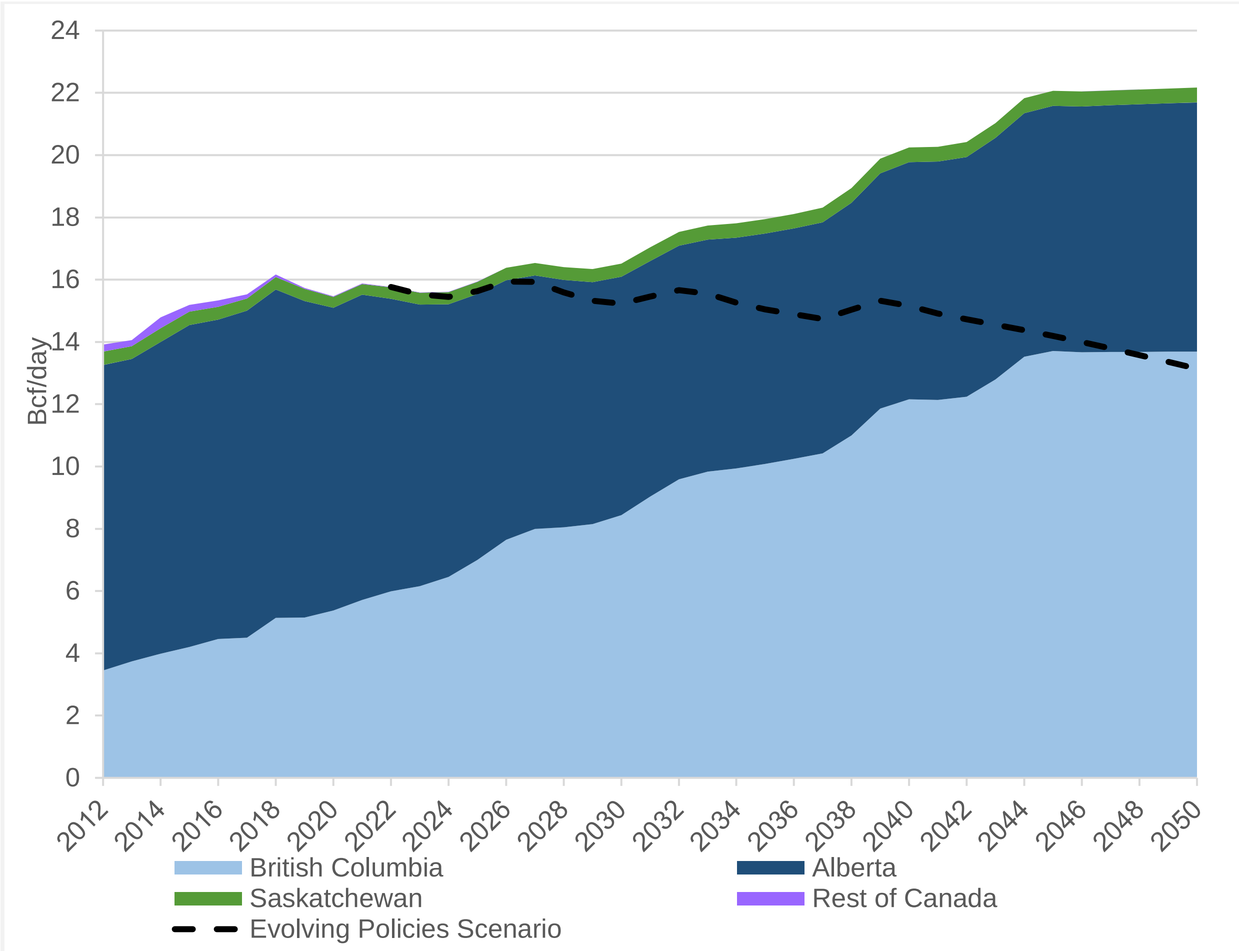
production remains near current levels for the next two decades, largely due to LNG export growth in BC.

Figure D1-5: Marketable Natural Gas Production by Province[12]



1.4 GAS DEMAND

The majority of demand growth in recent years has been from LNG exports, exports to Mexico, power demand, as well as industrial demand, specifically from the petrochemical sector. The market is also seeing increased natural gas demand from the power sector due to more switching from coal to natural gas electricity production, as well as from the retirement of coal plants. Furthermore, new incremental demand from US LNG being exported overseas will continue to drive the majority of the long-term demand growth. Lastly, the below subsections provide IHS Markit's gas demand forecast, this demand could be met in the future through a combination of natural gas and renewable gas, which includes RNG, biomethane, and other low carbon gas such

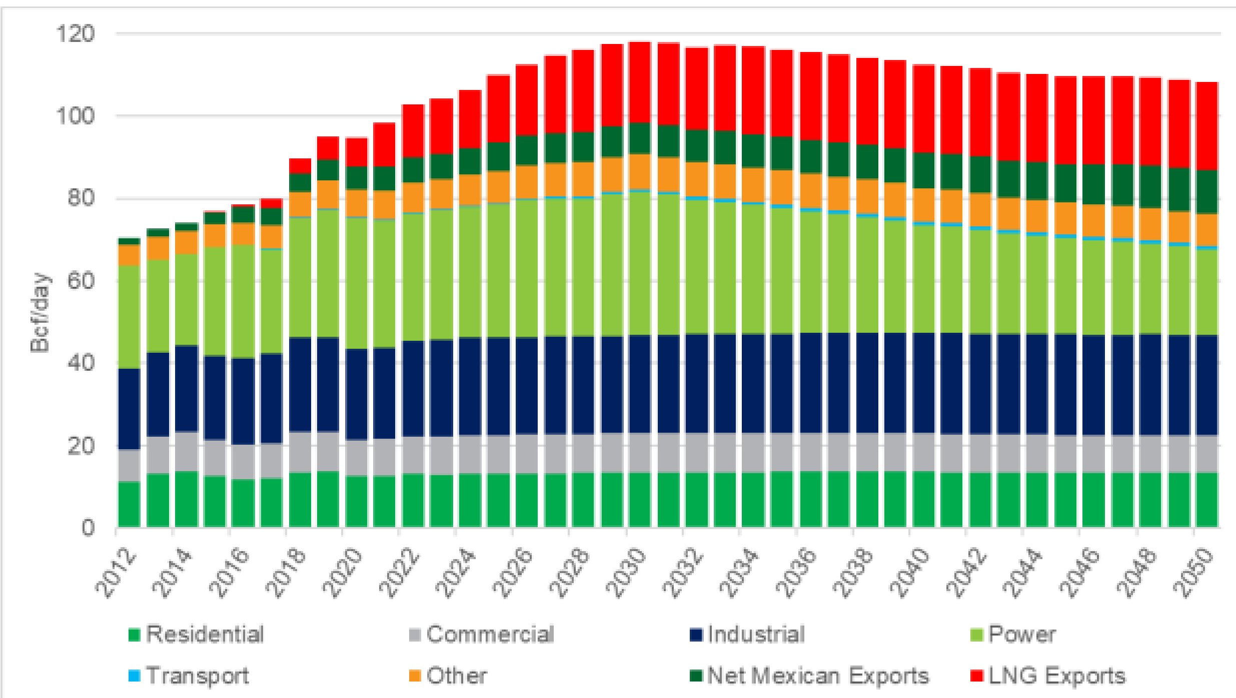
[12] CER (December 2021). "Canada's Energy Future 2021."

as hydrogen; however, demand will be also challenged with carbon policy initiatives and electrification across North America.

1.4.1 US Gas Demand

In the US, IHS Markit's latest long term outlook from February 2022 forecasts gas demand to peak in 2030 and decline thereafter to 2050, however, demand would still be higher compared to current levels with gas demand for LNG exports being the largest contributor to US demand. Figure D1-6 shows slight growth in power demand until 2030, and then a decline due to increasing renewables and battery storage. The development of the LNG export sector is expected to increase by 13 Bcf/day above current levels by 2040. In total, IHS Markit currently forecasts the US gas market will grow by 7 percent or about 6 Bcf/day above current levels by 2050.

Figure D1-6: US Gas Demand[13]



1.4.1.1 US Pacific Northwest (US PNW) Demand

In the US PNW, which is comprised of Washington, Oregon, and Idaho, IHS Markit expects regional demand to remain around approximately 2 Bcf/day until the late 2030's, as shown in Figure D1-7 below. In 2021, demand was 2.1 Bcf/day, which is 11 percent higher than in 2017 due to the power sector increasing its use of natural-gas fired generation, specifically through gas-fired plants along the I-5 corridor.

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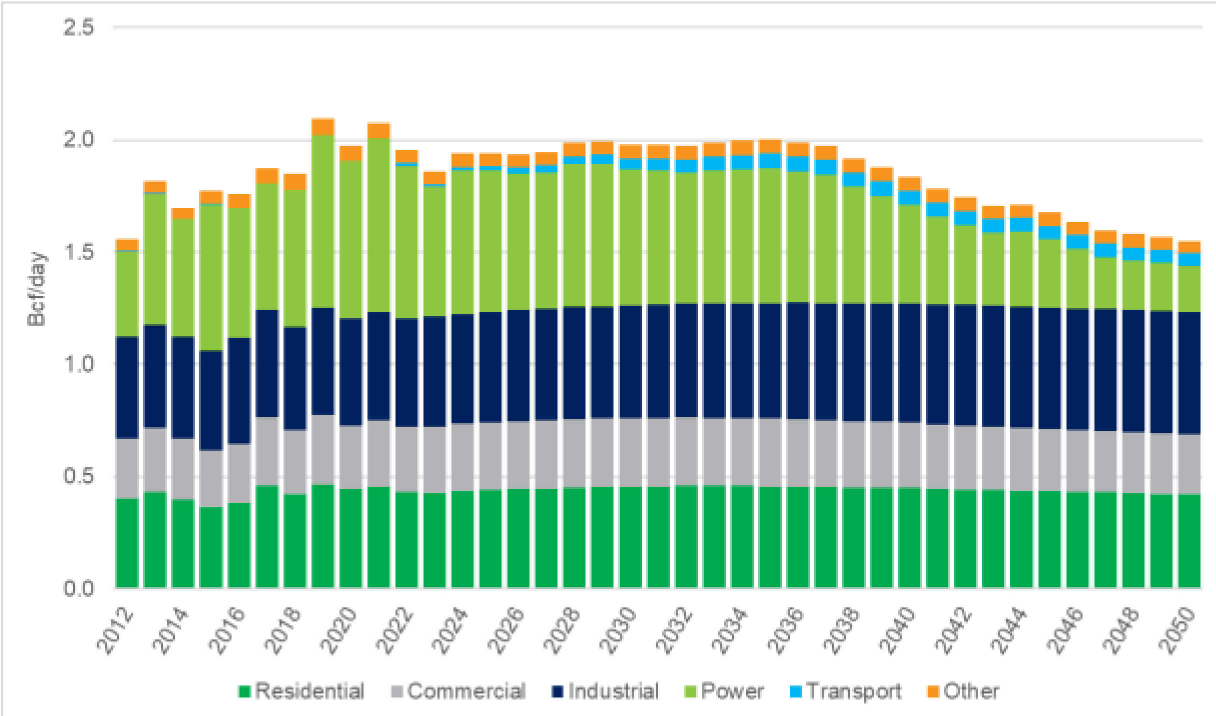
Figure D1-7: US Pacific Northwest Gas Demand[14]



The natural gas and power sectors are becoming increasingly interconnected in the PNW and California, especially as more coal-fired power generation plants retire. This development has resulted in increased demand for natural gas-fired power generation, in a region that is already constrained during the winter, which can cause pricing volatility at Sumas/Huntingdon depending on certain market conditions. The historical price volatility at the Sumas market hub, and forward prices for the next three years, was illustrated in Section 6 (Figure 6-4 and Figure 6-5), of the 2022 LTGRP.

In the region, government policies and renewable portfolio standards to reduce GHG emissions to meet state environmental objectives and targets have replaced the loss of coal-fired power generation with natural gas-fired generation and renewable resources. However, in peak periods when the renewable resource supply in the US PNW cannot meet demand, natural gas-fired power plants are relied upon as the marginal resource to balance the region's electricity supply. Further, even when the renewable resources are available, these plants may still consume natural gas, and export electricity to other states, specifically California.

This dynamic is expected to continue for at least the next five to ten years,[15] until the PNW region can build out adequate amounts of renewable resources and battery storage to relieve the increased annual dependence on natural gas as the balancing resource for the power utilities.

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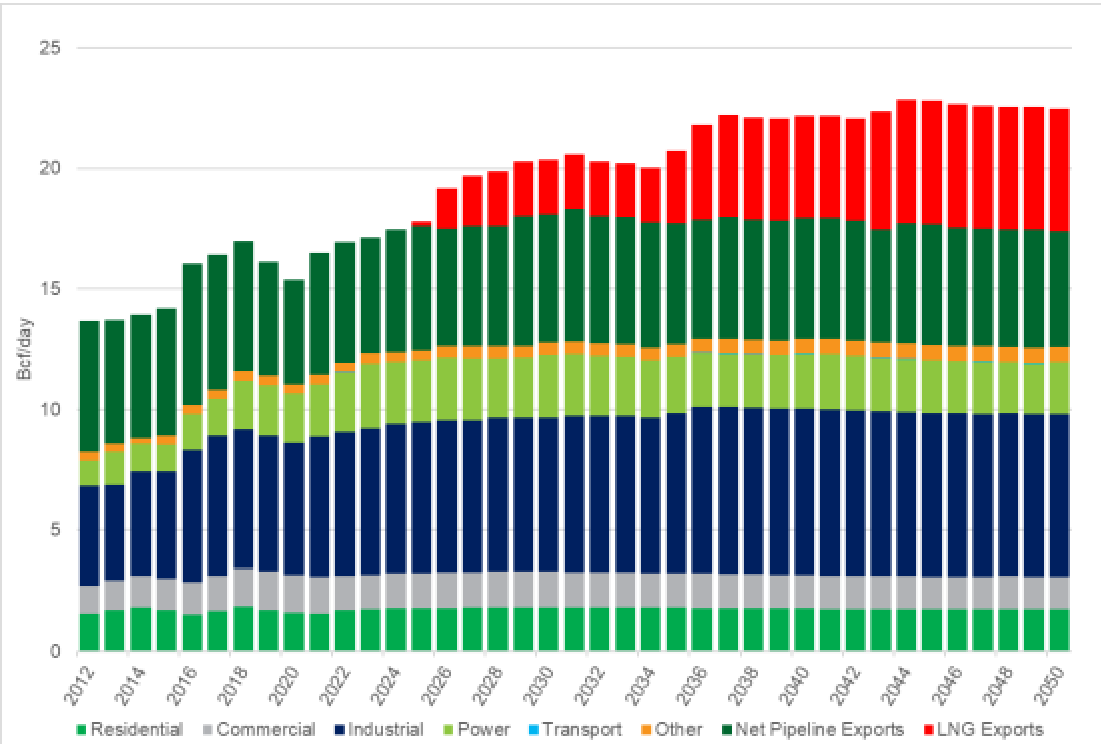
[15] This risk could continue even further than ten years, as electric utilities continue to need firm peaking reliable resources for ramping demand conditions.

However, reliance on natural gas as the marginal resource is expected to continue[16] as it is reliable and provides flexible generation during extreme weather events. This will continue to put a strain on peaking resources and peak winter demand, enhancing price volatility and the connection to power markets.

1.4.2 Canada Demand

Overall in Canada, demand in 2021 was approximately 16.5 Bcf/day, which is identical to the demand in 2017, as shown in Figure D1-8 below. Demand is expected to grow through 2050, largely driven by LNG exports increasing to 5.1 Bcf/day.

Figure D1-8: Canada Gas Demand[17]



A number of LNG export liquefaction terminals had been proposed on the west coast of BC, as well as large diameter pipelines to transport natural gas from new production basins in northeast BC to these terminals. The main driver of these projects had been the desire to take advantage of the historically lower North American natural gas prices compared to Asian natural gas prices. Moreover, Asian markets are seeking to diversify their sources of supply and are attracted by the political stability and mature market structure for accessing natural gas that Canada offers.

16 North American Electric Reliability Corporation (December 2021). "2021 Long-Term Reliability Assessment." https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf

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While the vast majority of these projects were able to receive their export licences from the NEB (now the CER), further development stalled soon after due to market conditions that included the substantial fall in oil prices in 2016, and the glut of LNG supply in 2017 that lead to a significant decline in global LNG prices. Not only did the projects have to deal with these challenging market conditions, they also faced ongoing considerable environmental and regulatory hurdles in BC. These factors caused many developers to cancel their LNG projects in BC; however, FEI continues to monitor the development of LNG export projects in BC, including two that remain active on the west coast of BC, LNG Canada and Woodfibre LNG, which are included in IHS Markit's forecast in Figure D1-8.

LNG Canada is a joint venture company comprised of five global energy companies (Shell, PetroChina, KOGAS, Mitsubishi Corporation, and PETRONAS). Construction on Phase One of LNG Canada (6.5 million tonnes per annum, or 1.8 Bcf/day) began in 2019, and is expected in service no earlier than 2025. LNG Canada is also considering the development of two additional trains that would double the output of LNG. FEI believes that the LNG Canada project may not have a significant impact on security of supply in the region, given that LNG Canada has contracted for the construction of a dedicated supply pipeline and that the majority of supply required by the project will come from proprietary production[18] by the project partners. FEI will continue to monitor the development of this project to ensure FEI retains access to gas supply at fair market prices.

Pacific Oil and Gas Limited, a Singapore based company, has formed a company called Woodfibre LNG Ltd. It is proposing to construct and operate a LNG export terminal, with a capacity of 2.1 million tonnes per annum (MTPA) (around 0.3 Bcf/day) located near Squamish. Development of the project has been ongoing, and Woodfibre LNG provided a Notice to Proceed and announced that pre-installation work is planned for 2022 with major construction beginning in 2023, and the facility in service in 2027. FEI will provide natural gas transportation service for the supply required by the facility, and will need to expand its existing system, which includes pipeline looping and adding compression[19].

Woodfibre LNG has already secured firm transportation capacity on Westcoast's T-South system for a significant portion of their demand requirements. Currently, that capacity is being used to serve existing market demand, and as discussed in Section 6.2.4.2, the regional gas supply infrastructure is already constrained during the critical winter heating season. Should Woodfibre LNG become operational, the supply available for customers in the Lower Mainland and along the I-5 Corridor would be reduced, which could cause more pricing volatility at the Huntingdon marketplace.

[18] The CER assumes in Canada's Energy Future 2020 that "75 percent of LNG feedstock will come from natural gas production dedicated to supplying LNG facilities".
[19] FortisBC: "Talking Energy." https://talkingenergy.ca/project/eagle-mountain-woodfibre-gas-pipeline-project

1.5 CONCLUSION

This Appendix first provided an overview of North American natural gas market prices, supply, and then discussed demand in the PNW region. The “evolving policies” and “fast transition” scenarios illustrate the uncertainty in conventional natural gas supply and demand in North America, and provides scenarios as additional policies are implemented over time.

Demand in BC is expected to increase through LNG export projects, including those that could be developed in the Lower Mainland, such Woodfibre LNG. Meeting the needs of such projects that require daily baseload gas volume can only be fulfilled by adding new pipeline capacity rather than other resources, such as storage. The development of new pipeline systems will only proceed if other parties are prepared to financially underpin any expansion.

All parties will need to work collaboratively in order to develop solutions that serve the interest of everyone concerned at large, ranging from project developers, pipeline companies, gas producers, Indigenous groups and local stakeholders, in order to ensure the successful advancement of large scale projects in the BC and PNW natural gas marketplace.

Appendix D-2

BC RENEWABLE AND LOW-CARBON GAS SUPPLY POTENTIAL STUDY

B.C. RENEWABLE AND LOW-CARBON GAS SUPPLY POTENTIAL STUDY

FINAL REPORT

Prepared for

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January 28, 2022

EXECUTIVE SUMMARY

Report Overview and Objectives

B.C. is a major producer and supplier of natural gas and the Government of B.C. is trying to decarbonize natural gas use and usher in the clean energy transition. Renewable and low-carbon gases can be used to decarbonise many sectors that are difficult to electrify, create new economic opportunities, and serve as tools to enable the transition towards a resilient, affordable, and low-emission energy system. BC Bioenergy Network (BCBN), the Government of B.C. and FortisBC commissioned this report to estimate the technical supply potential and production costs of renewable and low-carbon gases in B.C., Canada and the United States. This study uses the best information available to inform the supply outlook for renewable and low-carbon gases in B.C. The analysis, conclusions and recommendations in this report are those of the report authors, and do not necessary reflect the views of the report's sponsors.

Background and Objective

The Province of British Columbia (B.C.) has set ambitious greenhouse gas emission reduction targets, including becoming a net-zero jurisdiction by 2050. The CleanBC *Roadmap to 2030* (the Roadmap) includes plans to establish a greenhouse gas (GHG) emissions cap for natural gas utilities.[1] It would require natural gas utilities to reduce the carbon emissions related to their gas sales to approximately 6 Mt of CO_2e per year by 2030. It is anticipated that this cap will, in part, drive the production and acquisition of renewable gases as a key measure to displace fossil natural gas. The Roadmap also expands on an earlier commitment to a minimum of 15% (energy-based) renewable content retailed annually through the natural gas distribution system by 2030. The GHG Reduction Standard proposed in the CleanBC *Roadmap* will likely require an even higher percentage of renewable gas by 2030.

Additional regulatory action has been taken to kick-start the production and use of clean and renewable gases in B.C.'s natural gas distribution system. In 2021, the Province of B.C. amended the Greenhouse Gas Reduction Regulation (GGRR) in part to widen the scope of fuels gas utilities may use to reduce GHG emissions. The GGRR incentivises the production and utility purchase of low-carbon natural gas substitutes, including hydrogen, renewable natural gas (RNG), synthesis gas (syngas), and lignin. The cost of these clean resources will be recovered from the utilities' ratepayers.

The purpose of the report was to quantify the supply potential of renewable and low-carbon gases that could be used to lower overall GHG emissions from B.C. gas use. The study did not consider alternative options, such as switching natural gas heating to wood pellets, heat pumps, or increased energy efficiency.

This report examines four pathways to transition from fossil natural gas:

1. The production of hydrogen or methane from either renewable electricity or wood (pipeline injection).
2. The production of hydrogen from natural gas combined with carbon capture and sequestration or as a by-product of carbon black production, or the use of waste hydrogen (pipeline injection).
3. The production of syngas from wood to displace natural gas used in lime kilns at pulp mills.
4. The production of lignin from black liquor to displace natural gas used in lime kilns at pulp mills.

Technologies/Pathways

The report describes various technologies and resources used to produce the above types of low-carbon gas. Each technology relies on a supply chain, e.g., feedstock production or collection, pre-treatment, and

[1] The report was written based on the 2018 renewable gas commitment rather than the emission cap announced in the Roadmap.

gas processing. Gases injected into the pipeline system also require gas conditioning and compression. The resulting combination of processes is called a 'pathway'. Pathways can be grouped by the energy resource they rely on. Three main resources have been considered for a total of twelve pathways:

- **Organic waste:** Production of methane by fermenting of organics. These include agricultural waste, municipal organics, human waste collected at wastewater treatment plants, and gas generated in landfills.
- **Woody biomass:** Production of wood gas, also called syngas, through thermochemical means, such as gasification. Syngas may then be used as a gas at the point of production or upgraded to pure hydrogen or methane for pipeline injection.
- **Non-biomass resources:** Production of hydrogen via electrolysis or using fossil natural gas, including blue and turquoise hydrogen produced from fossil natural gas and green hydrogen produced from (green) electricity. The latter is commonly termed 'green hydrogen' as it can be produced from 'green' (renewable) electricity.

For each of these three groups, four specific pathways are described in Table 6. Lignin extracted from black liquor in kraft pulp mills is another wood-based resource. It can be used as a fuel in lime kilns but is technically more challenging and more expensive than using syngas from wood gasification. The value of lignin as a feedstock for non-energy application can also be expected to rise above the value as an energy source.

Table 1 Pathways for low carbon gas considered in this report

Organic Residue* (Anaerobic treatment)	Woody Biomass (Thermochemical pathways)	Non-Biomass Resources (Electrolysis and SMR)
Agricultural RNG: Digestion and gas conditioning using agricultural waste.	Syngas: Wood gasification to produce a gas used in lime kilns of kraft pulp mills.	Green hydrogen: Electrolytic production of hydrogen from water and clean electricity.
Municipal RNG: Digestion of source-separated organics (green bin) and industrial food waste.	Hydrogen from syngas: Syngas processed with water-shift reaction.	Blue hydrogen: Steam methane reforming of fossil methane with CO_2 capture and storage.
RNG from wastewater treatment plants: Digestion of water treatment sludge to produce RNG.	Methane from syngas: Syngas processed with water-shift and methanation step.	Turquoise hydrogen: 'Pyrolysis' of fossil methane, producing carbon black and hydrogen.
Landfill gas: Gas captured at landfills and conditioned to produce RNG.	Lignin as a replacement for natural gas in the pulp industry: Lignin extracted from black liquor to produce a dry lignin fuel.	Waste hydrogen: Hydrogen produced as a by-product in industrial processes.

* In reality, some of these feedstock types can be combined at any given plant; a strict separation is not possible but is used in the report to derive estimates for the potential of each waste type

Scenarios and Cost Curves

Potential by 2030 and 2050

The potential for producing renewable and low-carbon gases differs between the pathways, mainly due to the underlying resources available in B.C. The report compares and combines existing analyses to develop a comprehensive overview of resources available by 2030 and 2050.

The resource potential represents the theoretical availability of various biomass feedstock types, electricity, and fossil natural gas to produce renewable and low-carbon gases. The technical potential constrains the resource potential as it estimates the capacity for each pathway after accounting for geographic limitations, transport constraints, conversion efficiency and various system assumptions. This also includes technological readiness and realistically achievable implementation rates. The resulting potentials in the Maximum and Minimum scenarios for each pathway are further lowered as they consider timelines, harvesting practices and different outcomes with respect to resource availability and the speed of deployment. They represent the upper and lower bounds of renewable and low-carbon gas supply potential that can likely be achieved in B.C. by 2030 and by 2050, as shown in Figure 4. Some economic constraints, such as competing uses, price, or market developments, have not been considered in the estimation of these bounds.

The 2030 scenarios assume lower gas production levels than for 2050 as there are development cycles, learning curves and build-out rates for new or emerging technologies. More mature and lower-cost projects will likely be developed first. Most renewable and low-carbon gas production by 2030 lies with anaerobically produced RNG pathways (around 6 petajoules) and blue and turquoise hydrogen. The scenarios suggest that the 2018 CleanBC target of 15% renewable content in the natural gas system by 2030 cannot be met using provincial renewable resources alone. By 2050, blue and turquoise hydrogen make up most of the potential but wood-based pathways also represent a large share of the technical potential.

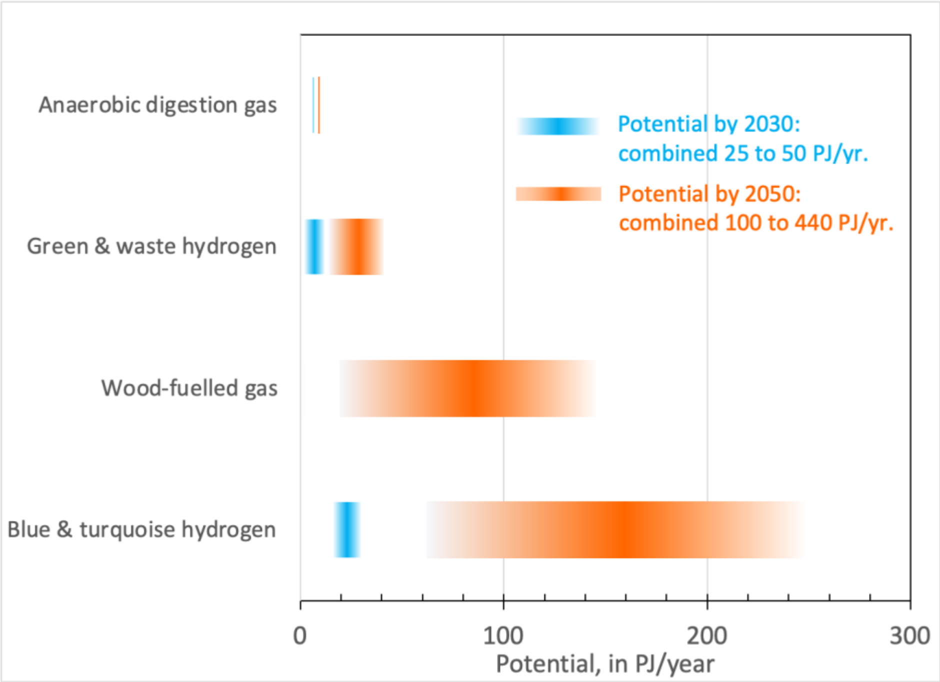


Figure 1 Minimum and Maximum Renewable and Low-Carbon Gas Production Scenarios for B.C. for 2030 and for 2050

Figure 4 shows:

1. By 2050, between 104 (Minimum) and 444 (Maximum) petajoules of renewable and low-carbon can be produced with in-province resources, i.e. between half and twice B.C.'s current natural gas use. Renewable gases alone could amount to produce between 42 and 195 petajoules annually, roughly a quarter to all of the natural gas currently retailed in B.C.
2. By 2030, between 25 (Minimum) and 50 (Maximum) petajoules can be produced with in-province resources; of the Maximum, only about 19 petajoules would be renewable gases.
3. Between 2030 and 2050, supply expands significantly in the Maximum scenario because the industry is built up quickly, and additional resources become available, such as new on-grid wind power, wood residue currently used for producing power or pellets, and the establishment of large-scale blue and turquoise hydrogen production.
4. Blue and turquoise hydrogen offer the highest technical potential. Renewable gases account for almost half of the gases produced by 2050. B.C. could replace almost all its current fossil natural gas use with renewable gas, mainly from woody feedstock.
5. Among renewable sources (as defined under the GGRR), wood-based pathways have the highest potential for renewable gas production under optimistic assumptions with respect to resource availability.
6. Traditional RNG from anaerobic digestion or biogas has lower potential (~10 petajoules by 2050). Other pathways will be crucial to achieve substantial decarbonization of the natural gas system.
7. Even with Site C being developed and the addition of 1,300 MW of new on-grid wind power, the availability of surplus electricity constrains the potential for producing green hydrogen in B.C. to about 27 petajoules by 2050 (40 petajoules when including off-grid production with wind power).

Cost curves

Each low-carbon gas has costs associated that are specific to the resource, technology, production process and various other parameters. The relation between potential and cost is illustrated in a cost curve (**Figure 3** below). The (horizontal) x-axis indicates the potential in petajoules of gas produced per year and the (vertical) y-axis indicates the production cost for each pathway, in 2021 Canadian dollars. The lowest-cost pathway is shown on the left, with the cost of respective pathways increasing to the right. Costs are determined by assumptions of initial capital expenditure, operational costs, including electricity and gas costs, and the cost of woody feedstock, where applicable.

The cumulative production potential increases as options with higher production costs are considered, resulting in a stepped graph. Eventually, costs surpass the $31 per gigajoule price limit[2] for natural gas utility acquisitions under the GGRR. The economic potential under the current regulatory framework is limited to the area outlined by a dashed black line.

Figure 2 and **Figure 3** shows that green hydrogen is expected to remain more costly than the $31 threshold (in 2021). By 2050, gases from (waste) woody biomass is projected to be available at a cost comparable to that of blue hydrogen. Production costs are estimated as sector averages; the body of the report provides more detailed cost curves for each pathway. The Maximum scenario represents an upper bound that would require very strong policies to achieve. It is unlikely that this scenario will come to pass but rather, that renewable and low-carbon gas production in B.C. will fall in-between the Minimum (104 petajoules) and Maximum (444 petajoules) scenarios by 2050. The scenarios are further elaborated in the body of the report.

[2] The threshold is indexed with inflation, so increases over time in nominal, but remains constant in 2021 dollars.

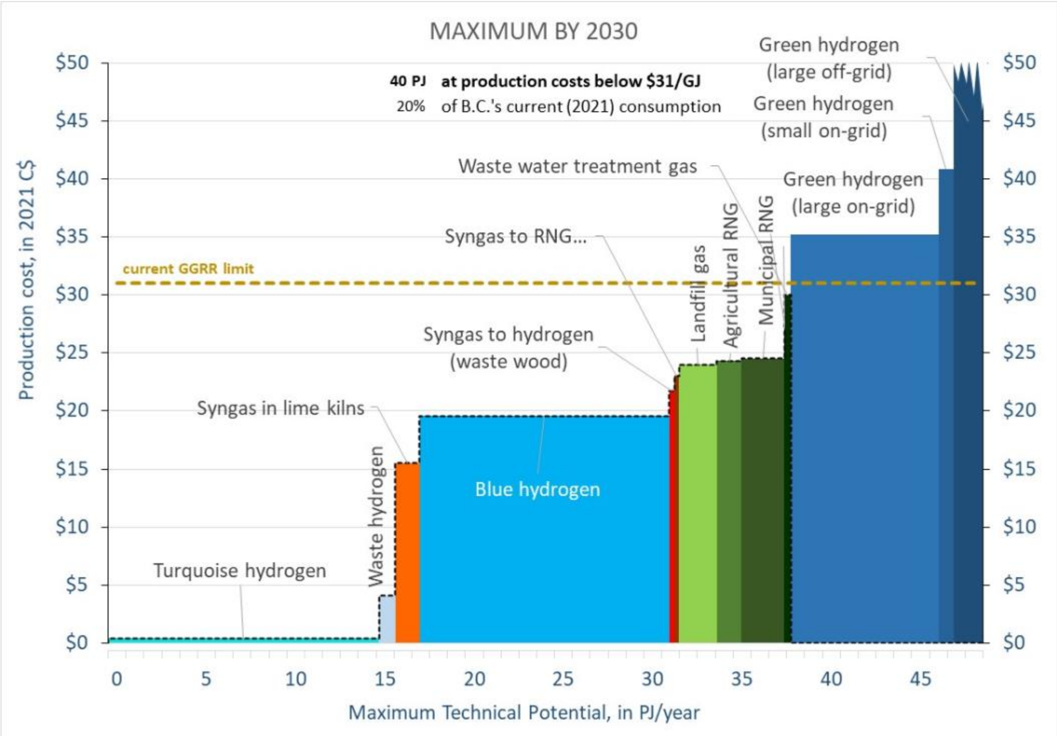
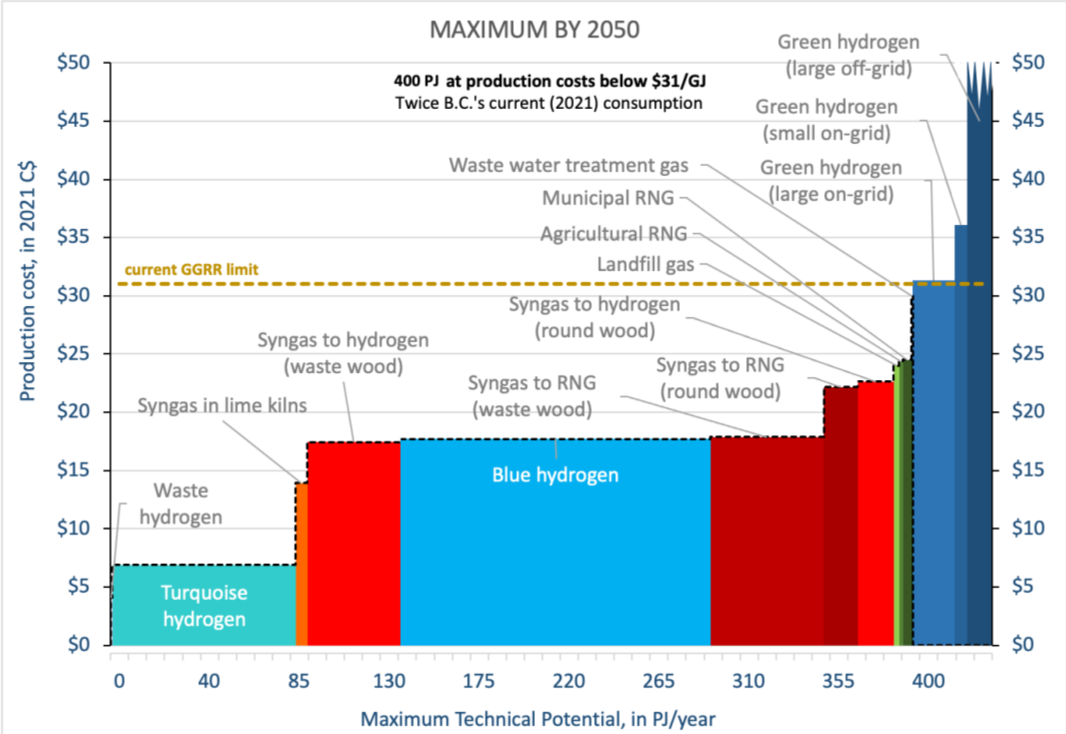


Figure 2 Production Cost and Technical Potential in the Maximum Scenario by 2030. Market prices may be higher than costs.



***Note*: For better readability, the scale of the x-axis (potential in PJ/year) is different for each graph**

Figure 3 Production Cost and Technical Potential in the Maximum Scenario by 2050. Market prices may be higher than costs.

Key Considerations

Cost Limits

In 2017, the Government of B.C. established the GGRR to require all natural gas utilities to purchase renewable natural gas up to a limit of 5% of their 2015 natural gas sales volumes, at a maximum price of $30 per gigajoule. In 2021, the regulation was further amended to:

- expand the volume limit to 15% of the utility's 2019 fossil natural gas sales;
- expand the range of resources that qualify under the initiative (i.e., to add green hydrogen, lignin, and syngas) and
- enable the maximum price to escalate each year with inflation (e.g., to $31 in 2021).

For a natural gas public utility to exceed these limits, and still recover the costs from their ratepayers, prior BC Utilities Commission approval would have to be obtained. The achievable economic potential would increase if natural gas utilities were enabled to pay higher prices for low-carbon gas. This would likely occur if the current renewable gas target were replaced with a carbon intensity target. Alternatively, the price limit could be defined as an average price, allowing for a mix of low and high-cost gas production.

Imports

Existing regulations allow gas utilities to acquire RNG from outside of B.C. Technically, there is enough potential in the rest of Canada to meet the 2030 target and when including the U.S., to replace all of B.C.'s retailed fossil natural gas by 2050. There is a trade-off between potentially lower costs for ratepayers when using out-of-province resources and socio-economic benefits when developing projects inside B.C.

Purchasing low-carbon and renewable gases outside of B.C. at low costs can hedge against higher gas costs while offering the option to sell any surplus gas later if sufficient gas can be sourced inside B.C. This could lower the cost for B.C. ratepayers but may at the same time reduce the impetus to develop projects inside B.C.

On the other hand, B.C. public natural gas utilities are unlikely to secure as much of this gas as they wish to due to competition. In the U.S., several jurisdictions have implemented renewable gas policies and have created lucrative markets for RNG certificates. Quebec has also enacted a RNG mandate. To take advantage of low-cost renewable gas supply from outside of the province, utilities will need to move quickly as competition for low-cost and low-carbon and renewable gas is likely to intensify.

GHG Reduction and Emissions

The technical potential established in this report is based on petajoules of renewable and low-carbon gas rather than tonnes of CO_2e displaced. A policy based on carbon abatement or carbon intensity of pipeline gas would have to look at a different metric to measure compliance.

Natural gas has a reported burner tip carbon intensity of 50 grams CO_2e per megajoule.[3] Another 6-12 grams need to be added for upstream emissions in B.C., according to current knowledge. The carbon intensities of renewable and low-carbon gases discussed in this report range from about 3 grams (wind-powered green hydrogen) to around 22 grams (blue hydrogen). Agricultural RNG can have negative carbon intensities due to avoided methane emissions.

The carbon intensity can vary significantly from one pathway to another, or even between projects within the same pathways. Some scientific sources claim that the additional energy needed to produce blue and turquoise hydrogen and the sequestration or conversion of carbon dioxide may result in higher carbon

[3] B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions, 2020. B.C. Ministry of Environment and Climate Change Strategy, Victoria, B.C., April 2021

intensity than fossil natural gas itself, especially when taking into account fugitive emissions related to hydraulic fracturing. The CleanBC *Roadmap to 2030* includes measures to regulate and reduce upstream emissions from natural gas production.

Building the Renewable and Low-Carbon Gas Industry in B.C.

The cost of building a renewable and low-carbon gas production sector to replace fossil gas use in B.C. could range between $5 billion and $20 billion for the 2050 Minimum and Maximum scenario, respectively. This is the same order of magnitude as recent foreign investments in the Kitimat liquified natural gas terminal and will take place over more than two decades. The critical next step is for governments, indigenous communities, utilities, and other industry participants to work collectively on policies and investments that will unlock and enable this potential. The report discusses several policy instruments to attract the required investment. These include R&D and demonstration support, policies favouring gas production inside B.C., the monetisation of social and environmental co-benefits, and low-interest financing and joint ventures between gas utilities and industry.

Conclusions

The Province of B.C. is rich in natural resources, including a resilient electrical system built almost exclusively on hydropower, vast lands covered by forest, and a prosperous agricultural sector. This suggests that renewable and low-carbon gases can play the prominent role that CleanBC has assigned them.

1. The potential supply of renewable and low-carbon gases combined is sufficient to reach CleanBC’s 15% target by 2030. The anticipated build-out rate of renewable gas production by 2030 will likely require either renewable gas imports from neighbouring jurisdictions and/or the use of low-carbon gas, such as blue or turquoise hydrogen, to reach the 15% target.
2. Provincially sourced renewable gases can displace 195 of the 200 PJ of natural gas by 2050 assuming, among other things, that the available agricultural, solid waste and forest residual feedstocks are used for this purpose.
3. Blue and turquoise hydrogen offer the highest technical potential, pending advancements in innovation and scaling-up.
4. Among renewable sources, i.e. excluding blue and turquoise hydrogen, wood-based pathways have the highest potential for renewable gas production under optimistic assumptions with respect to resource availability. These pathways still require research and demonstration to achieve the technical readiness required for a large roll-out.
5. Mature technologies such as anaerobic digestion can contribute most in the early stages of converting B.C.’s gas sector to renewable gas. Other pathways will be crucial to achieve substantial decarbonization of the natural gas system.
6. Based on the foreseeable cost of green electricity the production cost of green hydrogen is anticipated to be greater than $31 per gigajoule in the 2030 and 2050 scenarios. Green hydrogen production requires the installation of significant infrastructure such as wind turbines and related electrical transmission. The maximum potential to produce green hydrogen at a cost below $31 per gigajoule is 27 petajoules per year by 2050, even with the development of Site C hydroelectric dam and new wind-power generation.
7. Investment of up to $20 billion may be required to facilitate the transition from natural gas to renewable and low-carbon gases by 2050. This investment is comparable to other investments in

energy in B.C., such as LNG Canada, a $40 billion terminal for the liquefaction, storage, and loading of LNG in the port of Kitimat, B.C.

8. The price limit of $31 per gigajoule set by the GGRR will likely capture most of the technical potential in B.C. Yet, offering this gas price may not be sufficient to build this industry. B.C. will need a stronger regulatory framework conducive to significant investment in renewable and low-carbon gas production. Like in the renewable electricity sector, efforts will need to focus on providing stable investment climates, moderating risks, and providing adequate returns.
9. Importing RNG from outside B.C. can hedge against future high costs to keep BC's industry competitive and protect ratepayers but may diminish the overall investment in the renewable and low-carbon gas sector within B.C.
10. National and international competition for RNG will increase further with time. California's Low-Carbon Fuel Standard (LCFS) market provides higher financial gains than B.C.'s. While B.C. could import RNG there is also a risk that some renewable and low-carbon production will be exported from the province.

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Glossary

$ or C$	Canadian dollars; all costs in this report are given in CAD
AAC	Annual allowable cut, the maximum volume of timber available for harvesting each year from a specified area of land, usually expressed as cubic metres of wood per year
AD	Anaerobic digester, a plant for producing biogas
Adt	Air dry tonne (seasoned wood, counted as having 20% moisture)
ATR	Auto-Thermal Reforming - A method of converting natural gas into hydrogen or syngas where the heat needed to reform the hydrogen is generated internally.
BCBN	BC Bioenergy Network
BCTMP	Bleached Chemi Thermo Mechanical Pulp
BCUC	BC Utilities Commission
Biogas	A methane-rich gas created by the anerobic digestion process that is not compatible with the existing natural gas system without upgrading due to its high CO_2 content and/or other contaminants.
BPA	Biomethane Purchasing Agreement
BTU	British Thermal Unit, 1 BTU = 1.055 kJ
CAPEX	Capital costs (of a project)
CCU, CCS	Carbon capture, utilization or storage are processes used to prevent the CO_2 from reaching the atmosphere by either storing it in a geological formation or mineral or by using it in a product.
CFB	Circulating fluidized bed, a reactor type used for gasification
CH_4	Methane
CHP	Combined heat and power
CI	Carbon intensity of a fuel usually measured on a life-cycle rather than consumption (tailpipe) basis
CLD	Construction, land clearing and demolition waste
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent, a measure for GHG warming potential of a gas
EU	European Union
FICFB	Fast Internally Circulating Gasifier
FN	First Nation
FPI	FPInnovations, the research arm of the Canadian forest industry
FT or F-T	Fischer-Tropsch, a gas-to-liquid technology

g	Gram
GHG	Greenhouse Gas
GGRR	Greenhouse Gas Reduction Regulation
GIS	Geographic Information System
GJ	Gigajoule 1 GJ = 0.278 megawatt-hours (MWh) or 0.95 MMBtu 1 GJ is equal to the energy content of 28 litres of gasoline (at 20°C)
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen sulfide
ha	Hectare, an area of 100 x 100 m; 1 ha = 2.4 acre
HHV	Higher Heating Value - The heat set free from the complete combustion of a material, including condensation heat released by any water in the flue gas.
HTG	Hydrothermal gasification, a technology which uses water at supercritical or similar temperatures and pressures to form a syngas.
HTL	Hydrothermal liquefaction, a technology which produces a biocrude, and in some cases, some by-product syngas
IEA	International Energy Agency
IFS	Industrial Forestry Service Ltd, a forestry consulting firm
IPP	Independent Power Producer, a non-utility generator that is not a public utility but owns facilities to generate electric power for sale to utilities and/or end users.
kg	Kilogram, 1 kg = 2.2 lb
km	Kilometer
kW	Kilowatt
kWh	Kilowatt-hour
l	Litre
LCFS	Low-carbon fuel standard
LFG	Landfill gas captured from the natural breakdown of biodegradable materials in a landfill.
LHV	Lower heating value, same as net calorific value
MC	Moisture content or the percentage of the water in the biomass fuel. The moisture content can be measured on the dry basis which is the percentage of moisture relative to the dry mass or wet basis which considers the total mass including moisture and the dry matter. The wet basis is used unless otherwise stated.
MECCS	B.C. Ministry of Environment and Climate Change Strategy

MJ	Megajoule or 1/1000th of a gigajoule
MSW	Municipal solid waste
MW	Megawatt
MWe	Megawatt of electrical output
MWh	Megawatt-hour
NGV	Natural gas vehicle (a vehicle running on natural gas)
NRCan	Natural Resources Canada
O & M	Operation and maintenance
O_2	Oxygen
odt	Oven-dry tonne, same as bone dry tonne, the solid matter content of biomass. Referred to simply as “dry tonne” in the text of this report.
OPEX	Operational cost (of a project)
OSB	Oriented strand board, an engineered panel product made from stands of wood used as a plywood alternative
PJ	Petajoule; 1 PJ = 1 million GJ
PPA	Power purchase agreement
PSA	Pressure swing adsorption - a gas upgrading system that uses the differential capacity of CO_2 to be absorbed by a media to separate methane from CO2. It has the advantage of separating oxygen and nitrogen from a gas biogas source.
psi	Pounds per square inch; 1 psi = 6.9 kPa
PV	Photovoltaic
R&D	Research and development
RFS	Renewable Fuel Standard
RIN	Renewable Identification Number, a U.S. system for subsidizing renewable fuels.
RNG	Renewable natural gas (upgraded to pipeline quality from biogas, landfill gas or syngas)
ROI	Return on Investment: the amount of net revenue provided by a capital investment, usually on an annualized basis.
SMR	Steam Methane Reforming is a method of hydrogen or syngas production where natural gas or other fuel is reacted with steam to form a mixture of hydrogen and carbon oxides.
SPF	Spruce Pine Fir, standard coniferous lumber produced primarily in the interior.
SSO	Source-Separated Organics - Organic material such as food waste, garden waste, leaves and other organic material collected separately from other municipal solid waste, often using green bins placed on the curbside.
t	Metric tonne; 1 tonne = 1,000 kg = 2,204 lb

TFL	Tree farm licence, a license (area-based tenure) to harvest timber and manage a forest, recreation and cultural heritage values. TFLs exist within TSA boundaries.
TRL	Technology Readiness Level, a method to estimate technical maturity for commercial application
TSA	Timber supply area, a geographic area defined by the government for the purpose of organization and management; tenures of various types are auctioned off from within each TSA to allocate harvesting rights.
TSL	Timber sale licence
TWh	Terawatt-hour, 1 TWh = 1 million MWh
UBC	University of British Columbia
US	United States
WWTP	Wastewater treatment plant
Yr.	Year

1.0 BACKGROUND AND OBJECTIVE

In 2018 the Government of the Province of British Columbia (B.C.) released the CleanBC Plan, demonstrating leadership in climate change mitigation through ambitious greenhouse gas emission abatement targets.[4] This Plan set a target for 2030 of displacing a minimum of 15% natural gas with renewable gas. This was reiterated in the 2021 Clean BC Roadmap to 2030, which also refers to the intent of government to set an overall emissions cap on natural gas use in B.C. Currently (2021), about 200 petajoules of natural gas are retailed each year. It is the objective of this study to update previous estimates of the renewable and low-carbon gas supply potential and develop a growth strategy for increasing production in B.C. to 2030 and 2050. Other questions addressed in this report are the cost and carbon intensity of each gas and in what B.C. regions are resources most prevalent.

1.1 Previous Work and Political Context

The CleanBC Plan and Roadmap are a continuation and consolidation of various clean energy incentives, legislation and regulations that date back more than a decade. The provincial renewable gas target aims to decarbonize the natural gas grid and builds on FortisBC's voluntary renewable natural gas program that has been operating for over ten years.

The *Greenhouse Gas Reduction Regulation*[5] (GGRR) allows regulated utilities to acquire and/or produce renewable gases up to 15% total gas supply throughput and up to a cost of $31 per GJ. To better gauge how the target is likely to be met, the report quantifies locally available resources and the relative costs of gases and lignin displacing natural gas, and determines whether additional measures are necessary to enable a transition towards low-carbon gas. This study looks at the four possible energy types eligible under the GGRR (see Section 1.5) and integrates the results.

Previous reports and studies have dealt with the provincial bioeconomy and form the basis of the current work:

1. In 2010, the B.C. government commissioned a report on the provincial bioeconomy. This report suggested that the market potential for new bioproducts could reach $200 billion, exceeding the market for bioenergy ($170 billion).[6] The report strongly suggested that a comprehensive vision for B.C.'s bioeconomy be developed, followed by an effort to resolve issues around access to forest biomass, which currently prevents new industry entrants from easily accessing feedstock. Other recommendations involved technology, infrastructure and marketing roadmaps.
2. In 2016, the B.C. Government produced a report on the future of the forestry industry, which suggested that the sector maximize its value through the development of new bioproducts, biochemicals, and bioenergy – a biorefining approach that could lead to new employment and improved performance across the sector.[7] A similar report examining the B.C. pulp and paper

[4] B.C. Gov News, "CleanBC plan to reduce climate pollution, build a low-carbon economy." December 5, 2018. https://news.gov.bc.ca/releases/2018PREM0088-002338. [Accessed Sep 26, 2021].
[5] See amendment of May 25, 2021 (Order of the Lieutenant Governor no. 306).
[6] Province of B.C., *MLA Bio-Economy Committee Report*, 2010.
[7] B.C. Ministry of Forests, Lands, Natural Resource Operations and Rural Development, *Strong past, bright future: A competitiveness agenda for BC's forest sector*, August, 2016.

industry recommended an alliance between all B.C. pulp and paper companies to examine new bioproduct opportunities.[8]

3. In 2015, Industrial Forestry Services prepared a report for BC Hydro's Long-Term Planning Process on the potential for bio-based electricity in B.C. This report found that fibre supply would decline until 2026 due to the mountain pine beetle epidemic, after which it would stabilize. The report suggested that while 21 million m^3 of biomass was surplus to the industry shortly after the peak of the epidemic in 2015, this surplus would decline to 7.9 million m^3 in 2025 and remain at that level for the foreseeable future. The report also found that most of this wood is in the form of standing timber, and that harvesting this wood would be uneconomic, costing over $150 per dry tonne delivered.[9] Finally, this report highlighted the fact that while mill closures have left surplus wood behind, these closures have reduced the amount of easily accessed processing residues that have supported pellet production in the past.
4. The Resource Supply Potential for Renewable Natural Gas in B.C. (Hallbar Consulting, 2017).
5. The B.C. Hydrogen Study (Zen Clean Energy, 2019).
6. A pre-feasibility study for syngas and biomethane production at B.C. pulp mills (Tom Browne, 2019).
7. The confidential study, Revitalization of the B.C. Bioenergy Sector: Assessment of biomass feedstocks in B.C. (ENVINT, 2019).
8. Renewable Natural Gas (Biomethane) Feedstock Potential in Canada (Torchlight Bioresources, 2020).
9. An analysis conducted by Guidehouse Consulting and FortisBC demonstrated that using the existing gas system to distribute renewable and low carbon gases can achieve an 80% GHG reduction by 2050 and be a more affordable and resilient pathway for B.C. to reduce emissions.

1.2 Purpose of this Study

The purpose of this study is to evaluate and quantify the supply potential of renewable gases that could be used for decarbonization in B.C. The province possesses a provincial energy system supported by gas and electrical delivery infrastructure. The electrical system relies almost exclusively on hydropower. The gas system is supplied by B.C.'s abundant natural gas basins. Vast lands are covered by forest, and the Province has a prosperous agricultural sector. All of this suggests that renewable and low-carbon gases can meet or even exceed the limits that CleanBC has assigned to it. This report identifies diverse sources of supply within and out of B.C., their potential volumes and production costs. The data is based on previous work inside and outside of Canada and on calculations conducted by the authors of this study. Key objectives that this report addresses include:

- Establishing B.C.-wide supply potential and carbon intensity for all renewable and low carbon gas types

[8] B.C. Ministry of Forests, Lands, Natural Resource Operations and Rural Development, *British Columbia Pulp and Paper Sector Sustainability: Sector Challenges and Future Opportunities*, September, 2016. https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/forestry/competitive-forest-industry/pulp_and_paper_sept_2016.pdf

[9] Industrial Forestry Service Ltd, *Wood-based biomass in British Columbia and its potential for new electricity generation*, July, 2015. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/wood-based-biomass-report-201803-industrial-forestry-service.pdf

- Developing cost curves for provincially produced gases and cost analysis for imported renewable natural gas (RNG),
- Updating information from previous reports with new assumptions reflecting the changing resource availability,
- Identifying unique use-cases and end-uses such as evaluating the potential for required infrastructure in B.C. and using industrial consumers as host-sites for renewable and low-carbon gas production.
- Informing strategies to increase production capacity and deployment to achieve the province's GHG reduction targets.

This study's focus is the displacement of natural gas consumption delivered through the B.C. pipeline system with renewable and low-carbon gases. The use of these gases for transportation is not specifically considered, although the latter can be achieved using gas from pipelines. The goals and metrics used, however, refer to the approximately 200 petajoules of natural gas currently being delivered throughout B.C. for a variety of purposes, mainly for industrial use and space and water heating. Leaving aside strategies such as fuel switching (with the exception of using lignin and syngas in the forest products industry) and energy efficiency, the focus is on decarbonizing the gas coming to energy users through the natural gas grid.

1.3 Structure of this Study

This report has three main sections:

1. An analysis of pathways for renewable and low-carbon gas production or fossil gas displacement (Chapters 2, 3, and 4);
2. Supply portfolios or scenarios for the development of these pathways (Chapter 5);
3. A high-level deployment strategy (Chapter 6).

The pathways themselves are grouped by product (e.g., hydrogen versus syngas), by resource (e.g., forestry versus agricultural feedstock), and by technology (e.g., biochemical versus thermochemical):

- RNG from anaerobic digestion of agricultural and municipal waste streams (Chapter 2)
- Renewable gases from forest resources (Chapter 3);
- Hydrogen from non-biomass resources (Chapter 4);

Each of these chapters provides the technical supply potential and production costs for the pathways discussed. Apart from hydrogen derived from natural gas, all pathways are resource constrained and pathways based on woody biomass compete for the same resource. Market prices and the impact of competition for the resource, the final product, or the market value of renewable and low-carbon gas for sale to the U.S. are not taken into consideration to determine the technical potential. The technical potential should be taken as an upper bound of what would theoretically be possible if each resource were fully used. This is unlikely to occur, however, and a lower minimum resource potential has also been defined, based on less optimistic assumptions. Within these scenarios, the commercial potential is defined as the amount of gas that can be produced at no more than $31 per gigajoule.

1.4 Key Metrics Used

The cost analyses always refer to Canadian dollars, unless stated otherwise in the text or tables. Cost projections are made in 2021 dollars, i.e., inflation is assumed to occur but is not reflected in these numbers as the cost projections reflect a change with respect to today's costs, net of inflation. All gas potentials are based on the higher heating value (HHV) of the gases, given gas billing and transactions are generally based on HHV in B.C.

The cost of renewable and low-carbon gases purchased by B.C. utilities for the purposes of the GGRR is currently (in 2021) limited to $31 per gigajoule, indexed with inflation. As this report uses 2021 dollars, any future increases of the carbon purchasing price limit do not affect the results and estimates. This price is an upper limit for gas costs utilities may offer while still recovering their costs from the ratepayer base. It is possible, however, to contract for gas deliveries at higher prices if the BCUC approves of such contracts. The BCUC may do so if these purchases are deemed to be in the public interest. The price limit is nevertheless used as the current limit in this report as it reflects the desire of the regulator to limit overall costs to ratepayers, and the authors' interpretation is therefore that only limited amounts of renewable and low-carbon gases (e.g., from demonstration projects) would be offered higher pricing under the current regulatory regime.

1.5 Definitions

In this report, renewable gas refers to, in line with the GGRR, hydrogen, renewable natural gas (RNG), synthesis gas made from biomass (syngas), and lignin (used to displace natural gas). The report uses the term 'Renewable Natural Gas' (RNG) as an umbrella term for all gases made from renewable resources, including through anaerobic digestion, landfill gas, or syngas conversion to RNG. Gas produced from natural gas, such as blue and turquoise hydrogen, is referred to as 'low-carbon gas'.

Biogas is gas produced from organics generated at farms, from municipal organics (green bin and industrial or commercial organic waste), and by processing sludge from wastewater treatment plants. Gases emitted and collected in landfills is called landfill gas. RNG refers to methane produced from renewable resources. This include both anaerobic processes using organic waste and thermochemical processes that gasify solid biomass to produce RNG.

The report uses colour coding for hydrogen. Colours are attributed only to signify the pathway that the gas is created by. Hydrogen itself is a colourless gas: hydrogen produced from fossil fuels through steam methane reforming (SMR) is called blue if the associated carbon is not emitted to the atmosphere but sequestered in geological formations or otherwise used. 'Turquoise hydrogen' means that carbon contained in the fossil natural gas is stripped of, and converted into, a solid, 'carbon black.' 'Green hydrogen' is produced from 'green' electricity, i.e., renewable electricity.

Resource potentials determined in Chapters 2-4 are technical potentials, i.e. they are not limited by regulation or cost. They are smaller than the theoretical potential (100% of the resource) as they are limited by the available resource and resource recovery constraints. In the case of forest-based woody feedstock, recovery factors used assume that it is only possible to recover a portion of the theoretically determined resource, such as roadside residue. For RNG from anaerobic digestion, the potential determined in Chapter 2 considers that only sites near gas pipelines will be developed and that only a portion of the feedstock produced is available for digesters. The potential for blue hydrogen is limited by suitable geological formations where carbon dioxide stripped from natural gas can be securely sequestered.

The scenarios in Chapter 5 assume further restrictions, including build-out curves and technology readiness. They represent technically feasible outcomes whose realisation will depend on policies in B.C. and the interplay between markets in the province and in other jurisdictions. The achievable (as opposed to technical or theoretical) potential does likely lie in-between the Minimum and Maximum scenarios developed.

2.0 RENEWABLE GAS FROM ANAEROBIC DIGESTION

2.1 Description of Pathway

Inside air-tight tanks, naturally occurring microorganisms convert moist or liquid organic material into biogas and digestate. Biogas consists of methane (typically 55% – 65%), carbon dioxide (typically 35% – 45%), small amounts of water, hydrogen sulphide and other trace gases, such as nitrogen and oxygen. Biogas is upgraded to renewable natural gas (RNG) by removing carbon dioxide and other impurities. It is then injected into the local gas grid, or if there is no local grid, compressed and transported to a site where it can either be injected into the gas grid or used.

Digestate is the material removed from biogas plants after micro-organisms have finished converting most of the feedstock's dry matter into biogas. It contains most of the nitrogen, and all of the phosphorus and potassium of the input feedstock, and is considered a good fertilizer.

Biogas plants are most often categorised by the type of feedstock they digest. These categories are:

- Agricultural: biogas plants that digest livestock manure and other on-farm inputs, such as crop residues and energy crops. These plants may also digest some commercial and residential source separated organics (SSOs).
- Municipal: biogas plants that digest residential and/or commercial SSOs.
- Wastewater: biogas plants that digest sludge from wastewater treatment plants. These plants may also digest some commercial and residential SSOs.

RNG can also be produced from landfill gas (LFG). LFG, a mix of methane (typically 45 – 55%), carbon dioxide (typically 45 – 55%) and many impurities, is a by-product from decomposition of organic material buried in landfills. LFG (often classified as a type of biogas) is captured through a system of perforated pipes drilled into landfills. As with biogas, LFG can be upgraded to RNG by removing carbon dioxide and impurities. These impurities, including high levels of nitrogen and oxygen, make LFG more challenging than biogas to upgrade.

2.2 Technology Update

Biogas plants typically consist of four process stages, while LFG projects consist of only two process stages (i.e., the second and third process stage below). These are:

- Feedstock pre-treatment.
- Digester tanks or LFG capture.
- Biogas or LFG upgrading.
- Digestate management.

A multitude of mechanical feedstock pre-treatment technologies are commercially available. These technologies cut/shred feedstock into smaller pieces, or separate feedstock from non-organic material, such as plastic. Other feedstock pre-treatment technologies are rarely used, except in specific circumstance (e.g., thermal hydrolysis for specified risk material or highly contaminated feedstock). This is because pre-treating feedstock is often too costly, and/or biogas production from the feedstock is insufficient to justify the cost. There are no pre-treatment technologies near to commercialization (TRL 7/8) that could significantly increase biogas production from feedstock, or reduce pre-treatment costs.

Digester tanks are gas-tight, insulated tanks, placed below or above ground. While digester tanks differ in material (i.e., concrete or steel), shape and agitation (mixing of feedstock), they are all generally similar. No digester tank design is considered universally preferential or superior.

LFG is extracted from landfills using a series of wells and a blower/vacuum system. As with digester tanks, no LFG capture technology is widely considered to be better than others, nor are there any technologies near to commercialization (TRL 7/8) that could significantly increase LFG capture or reduce capture costs.

Upgrading biogas/LFG to RNG removes carbon dioxide and other impurities (such as hydrogen sulphide and water) to increase methane content from approximately 55 - 65% to > 95% or more. Several technologies are available for upgrading biogas/LFG to RNG, including membrane, water wash, chemical scrubbing, pressure swing adsorption and cryogenic upgraders. While the cost and performance of these technologies differ, the overall outcome (cost per gigajoule of produced RNG) is relatively similar. For this reason, all biogas/LFG upgrading technologies are considered similar in performance, and there are no technologies near to commercialization (TRL 7/8) that could significantly increase RNG production or reduce production costs.

In cases where nutrients in digestate are greater than needed in the immediate vicinity of biogas plants, nutrient recovery technologies are often used. Nutrient recovery technologies extract nutrients from digestate into a more concentrated form, reducing transportation costs. Dozens of nutrient recovery technologies are available, all designed to extract different types (nitrogen, phosphorus and/or potassium) and amounts of nutrients. Because different technologies are designed for different needs/purposes, no nutrient management technologies are deemed to be superior to others. Furthermore, there are no nutrient recovery technologies near commercialization (TRL 7/8) that could significantly reduce nutrient extraction costs.

Feedstock pre-treatment, digester, upgrading and nutrient recovery technologies have been commercially available for many years. During this time, small incremental improvements have been made to many of these technologies (such as lowering costs, improving performance and increasing durability). These improvements have resulted in very small increases in RNG production and/or lower production costs. There are no biogas technologies near commercialization (TRL 7/8) that could significantly increase the production of RNG (per unit of available feedstock), or significantly lower the cost of producing RNG ($ per gigajoule).

One pre-commercial technology that could significantly increase the production of RNG is ex-situ power to RNG.[10] This two-step process starts with the electrolytical production of hydrogen. The hydrogen is then combined with carbon dioxide from the exhaust stack of a biogas/LFG upgrader, and fed into a reactor tank with specialty microorganisms to convert hydrogen and carbon dioxide into RNG. However, because the use of electricity to produce hydrogen is considered below, the use of electricity to produce RNG through ex-situ power to RNG isn't considered in this study.

[10] Ex-situ power-to-RNG is different from in-situ power to RNG (which is TRL 5) because ex-situ power-to-RNG requires a separate reactor with specialty microorganisms in it. In-situ power to RNG feeds hydrogen and carbon dioxide into the same digester tank used for producing biogas from organic feedstock, where a wide range of non-specialty micro-organisms exist.

2.3 Feedstock Availability

For the purpose of this chapter, the following potential sources of feedstock were assessed:

- Agricultural: livestock manure, including dairy and beef cows, swine and poultry.
- Source-separated organics (SSOs): residential and commercial SSOs from food processors, grocery stores, etc., and homes (typically collected as part of a "green bin" program).
- Wastewater treatment plant: sludge from processing wastewater.
- Landfilled organics: organic material placed in landfills.

B.C.'s feedstock availability was estimated using the same assumptions that were used in the 2017 RNG Production Potential Study[11] (there called the short-term achievable potential).[12] To estimate feedstock availability for 2021, 2030 and 2050, estimated availability in the 2017 RNG Production Potential Study was extrapolated using predicted agricultural and population growth rates. The annual predicted agricultural growth rates used were 0% for beef, 1% for dairy, broilers and turkeys, and 2% for layers and hogs. Population growth rates for B.C., Canada and the U.S. were extrapolated using population data from the past 20 years. LFG potential was also based on the 2017 RNG Production Potential Study. This study used LFG model estimates from Golder Associates (2008).[13] It should be noted that while this approach is likely the most reasonable, estimating RNG potential into the future becomes less and less certain as feedstock availability and LFG production are calculated using predicted and historical growth rates.

2.4 Anerobic RNG production potential in B.C.

RNG production potential in B.C. for 2021 is estimated to be 8.9 petajoules per year (Table 2). This potential assumes that all wastewater treatment plants (WWTPs) and landfills flaring LFG or using biogas/LFG to produce heat or heat and electricity switch to RNG production.

Due to its high dry matter and energy density, food waste (unlike livestock manure and WWTP sludge) can be transported up to 150 km or more to a biogas plant. This means that food waste can be digested in agricultural, municipal or WWTP biogas plants, regardless of where it is produced. In the RNG potential estimates shown in Table 2, it is assumed that most food waste is digested in municipal biogas plants. This assumption was used because in theory, municipal biogas plants should be closer to food waste than agricultural and WWTP biogas plants.

However, food waste could just as easily go to agricultural or WWTP biogas plants. Therefore, while the following agricultural, municipal and WWTP production estimates for B.C. assume an RNG division of approximately 40% from agricultural, 50% from municipal and 10% from WWTP biogas plants, in reality this division could be 70% from agricultural, 10% from municipal and 20% from WWTP biogas plants (or any other combination therein). RNG from LFG is different, as these estimates are based on estimated methane production from food waste already in B.C. landfills. The potential for 2050 assumes that organic waste is still landfilled over the coming decade; landfill gas production will decrease eventually (after 2050) if organics are more and more diverted and used for anaerobic digestion.

[11] Hallbar Consulting, *Resource Supply Potential for Renewable Natural Gas in B.C. Public Version,* 2017.

[12] The only changes were that plant operating capacity was increased from 80% to 90%, while residential and commercial SSO availability was increased from 60% and 80% to 70% and 85% respectively. These changes were made to reflect growing maturity of B.C.'s biogas industry and greater participation in organics source separation.

[13] Golder Associates, Report on Inventory of Greenhouse Gas Generation from Landfills in British Columbia (2008).

In a 2012 B.C. RNG study,[14] theoretical RNG potential for FortisBC's Service Areas 1 and 2 (covering approximately 90% of B.C.'s population) from agricultural, residential and commercial SSOs was estimated to be 5.4 petajoules per year. This is only 0.6 petajoules lower than the 6.0 petajoules estimated in Table 2 (when LFG is excluded). Realistic RNG potential was estimated to be 1.93 – 2.38 petajoules per year. One possible reason that this study estimated much lower RNG potential than shown in Table 2 is because it assumed a maximum RNG sale price of $15.28 per gigajoule. If a higher price had been assumed, realistic RNG potential may have been much closer to the theoretical potential.

RNG production potential in B.C. for 2030 is estimated to be 9.5 petajoules per year. This is approximately one-third of FortisBC's 15% renewable gas target. The 8% growth in B.C.'s RNG potential between 2021 and 2030 is entirely due to industry (agricultural feedstock) and population (SSOs and WWTP sludge) growth estimates, and LFG production models.

RNG production potential in B.C. for 2050 is estimated to be 11.2 petajoules per year. As in 2030, the 27% growth in B.C.'s RNG potential between 2021 and 2050 is entirely due to industry (agriculture feedstock) and population (SSOs and WWTP sludge) growth estimates, and LFG production models.

Table 2 B.C. RNG Potential, in Petajoules (PJ) per Year

	Agricultural	Municipal	WWTP	LFG	Total
2021	2.4	3.1	0.48	2.9	**8.9**
2030	2.5	3.5	0.55	3.1	**9.5**
2050	2.8	4.6	0.69	3.1	**11.2**

2.5 Anerobic RNG Production Potential in All of Canada

RNG production is constrained by feedstock availability. As such, the challenge with estimating RNG potential is that provincially-aggregated feedstock data (e.g., tonnes of manure or SSOs) can provide false perceptions. To estimate RNG potential with any level of confidence, detailed regional and municipal-level spatial feedstock data is required. This data must be overlayed with information known to impact biogas plant development.

For example, liquid manure (i.e., dairy and hog) cannot be transported far before transportation costs are greater than revenue from RNG production. Liquid manure is therefore unlikely to be available for biogas plants greater than 10 – 15 km away. Other feedstock, such as SSOs, may have competing uses (e.g., animal feed). Therefore, it may not be available for RNG production. Biogas plants also require power (a rough ballpark estimate is 1-2 kWh per cubic metre of RNG). As such, even a 100,000 gigajoules per year biogas plant requires ~300 – 600 kW of electricity. If three-phase power isn't available locally it can be very challenging to build a biogas plant.

Furthermore, biogas plants typically inject RNG into the gas pipeline. Biogas plants also produce digestate which must be managed (ideally spreading on nearby fields). While RNG can be compressed and transported for grid injection elsewhere, and while nutrient extraction technology can be used to transport nutrients to fields further away, the unavailability of a local gas grid and the requirement for nutrient extraction technology adds cost and can severely impact biogas plant economics.

Finally, while biogas plants are environmentally beneficial, they can still face community resistance if built too near communities (due to concerns with traffic, noise, odour, safety, etc.). Finding locations for biogas

[14] CH Four Biogas, Inc., *Biomethane Potential in FortisBC Service Areas 1 and 2,* December 2012.

plants that are sufficiently near feedstock (much of which comes from residential and commercial sources), yet far enough away from homes and businesses to avoid public opposition can be challenging.

The B.C. RNG production estimates above have been calculated using regional and municipal-level spatial feedstock data overlayed with information known to impact biogas plant development (including localised feedstock availability and competition, infrastructure and digestate management requirements). As such, they represent a realistic estimate of RNG production potential based not only on feedstock availability, but also on constraints known to impact biogas plant development.

Canada's livestock sectors are relatively evenly distributed across the country,[15] and B.C. and Canada's per capita commercial and residential SSOs and WWTP sludge production and capture rates are comparable. Population densities in all but the smallest provinces and territories are similar. Therefore, the above B.C. RNG production estimates have been extrapolated, with a moderate level of confidence, for the rest of Canada based on population size.

In 2021, RNG potential in Canada (including B.C.) is estimated in Table 3. Of Canadian RNG potential, 39% is estimated to be in Ontario, with 23%, 14% and 12% estimated to be in Quebec, B.C. and Alberta, respectively. All other Canadian provinces and territories account for the remaining 13% of RNG potential. As with RNG production potential in B.C., it is important to note that estimated RNG production between three of the sources (agricultural, municipal and WWTPs) in Table 3 is somewhat arbitrary. Because food waste is the greatest producer of RNG and can be transported up to 150 km or more to a biogas plant, the division of RNG between agricultural, municipal and WWTP biogas plants could be very different from that presented below.

Table 3 RNG Potential in Canada, in Petajoules per Year

	Agricultural	Municipal	WWTP	LFG	Total
2021	17.4	22.9	3.6	21.3	65.2
2030	18.2	25.2	4.0	22.3	69.7
2050	20.0	33.2	4.9	22.5	80.7

In 2030, RNG potential in Canada is estimated to be 69.7 petajoules per year. Of Canadian RNG potential, 39% is estimated to be in Ontario, with 22%, 14% and 13% estimated to be in Quebec, B.C. and Alberta respectively. All other Canadian provinces and territories account for the remaining 13% of RNG potential. The 7% growth in Canadian RNG potential between 2021 and 2030 is entirely due to industry (agriculture feedstock) and population (SSOs and WWTP sludge) growth estimates, and LFG production models.[16]

In 2050, RNG potential in Canada is estimated to be 80.7 petajoules per year. Of RNG potential, 40% is estimated to be in Ontario, with 20%, 14% and 15% estimated to be in Quebec, B.C. and Alberta respectively. All other Canadian provinces and territories account for the remaining 12% of RNG potential. As with 2030, the 24% growth in Canadian RNG potential between 2021 and 2050 is entirely due to industry (agriculture feedstock) and population (SSOs and WWTP sludge) growth estimates, and LFG production models.[16]

[15] While Quebec and Ontario have more dairy cows per capita, B.C. has a higher number of poultry, Manitoba a higher number of hogs, and Alberta a higher number of beef cattle per capita. The concentration of grains and oilseeds in the prairie provinces isn't relevant as crop residues and energy crops are excluded from this study.
[16] B.C. agricultural growth estimates and LFG production models were used to estimate national increases in agricultural feedstock and LFG availability, while provincial population growth estimates were used to estimate increases in national residential and commercial SSOs.

Other studies have also attempted to estimate Canadian RNG potential. For example, according to the 2010 Alberta Innovates Technology Futures study,[17] Canadian RNG potential from manure, SSOs, WWTPs and LFG is 165 petajoules per year (68.8 petajoules per year from manure, 5.6 petajoules per year from municipal SSOs, 7.2 petajoules per year from WWTP and 83.8 petajoules per year from LFG). This estimate is for technically feasible RNG potential, and doesn't take into account actual feedstock availability, location, etc. If these RNG estimates were assessed through a more realistic lens, taking into account actual rather than theoretical feedstock availability, estimated RNG potential would likely be 50% lower at 82.5 petajoules per year.

In 2013, the Canadian Biogas Association (CBA) released a biogas study[18] that estimated Canada's RNG potential to be 92 petajoules per year. While this estimate is significantly higher than the 65 petajoules per year estimated above, it includes crop residues, which are not included in the present estimate.[19] If crop residues are removed, and only 50% of livestock manure is considered to be available (a realistic assumption identified in the CBA study), RNG potential falls to 62.5 petajoules per year.

While RNG pathway potentials in the 2013 CBA study differ significantly from those estimated in this study(for example, the 2013 CBA study estimates 6.8 and 11 petajoules per year from WWTPs and landfills, respectively), the reason for this is due to assumed feedstock end use. Most feedstocks can be used in multiple RNG pathways. For example, SSOs can be digested in agricultural, municipal or WWTP biogas plants, or can be landfilled to produce LFG. Therefore, assumptions on where feedstock is used significantly impacts how much RNG is estimated from each pathway.

In a more recent study, Torchlight Bioresources estimated the Canadian RNG potential from livestock manure, biosolids, WWTP, urban organics and LFG to be 111.5 petajoules per year.[20] However, as the study notes, this is theoretical not realistic potential. Technical RNG potential, which would require an assumption that only '40-70% of potential feedstock' is available for RNG production, is estimated to be 44.6 – 78.1 petajoules per year. Table 4 compares the results of the above-mentioned studies. Discounting the Alberta study, the results are very similar in each.

Table 4 Canadian RNG Potentials Compared, in Petajoules per Year

	This Study	Alberta Innovates	CBA	Torchlight Bioresources	Range of All Studies
Current RNG Potential	65.2	82.5*	62.5	61.4**	61.4 – 82.5

* Deemed to be 50% lower than this theoretical potential identified in the Alberta study.
** Average taken from 44.6 – 78.1 petajoules per year range estimated by Torchlight.

[17] Salim Abboud et al., *Potential Production of Methane from Canadian Wastes,* 2010.
[18] Canadian Biogas Association, *Canadian Biogas Study: Benefits to the Economy, Environment and Energy - Technical Document*, 2013.
[19] Crop residues have been excluded for several reasons. To reduce soil erosion and/or build-up organic matter, crop residues are often incorporated into the soil or, as with straw, used elsewhere (e.g., animal bedding or in mushroom production). For these reasons crop residues are often unavailable. Crop residues often have low spatial energy density and high fiber content. This means they can be costly to collect and transport, and require expensive pre-treatment. Finally, crop residue availability is highly variable, depending upon weather, crop rotation and seasonal variation, while they are also only available once or at certain times of the year. This makes them challenging to use because biogas plants require year-round feedstock availability and long-term storage is expensive.
[20] TorchLight Bioresources Inc., *Renewable Natural Gas (Biomethane) Feedstock Potential in Canada*, 2020.

2.6 Anerobic RNG Production Potential in the United States

B.C. RNG production estimates in this study were used to estimate RNG potential in Canada. This was done with a moderate level of confidence due to similarities in livestock distribution (and therefore manure production), SSOs production and capture rates, WWTP sludge production rates, and population densities across Canadian provinces.

Using the above B.C. RNG potentials to estimate U.S. RNG production potential is much less straightforward. Unlike in Canada, U.S. populations and livestock densities vary greatly. For example, California has 254 people, 4.4 dairy and 12.8 beef cows per km^2, while Wisconsin and Oregon have 44 and 109 people, 9.1 and 0.5 dairy cows and 24.6 and 5.0 beef cows per km^2 respectively.[21,22,23] This means that unlike Canada, availability of agricultural and SSO feedstocks for RNG production will vary greatly between U.S. states. Those with high populations and/or animals per km^2 will be able to collect and use a lot more feedstock than others (i.e., those with low populations and few animals per km^2).

Unlike in Canada, per capita SSOs capture rates in U.S. states are vastly different. Wisconsin and California, for example, have 0.6 and 1.9 composting facilities per 1,000 km^2, while Idaho and Texas have 0.02 and 0.05 per 1,000 km^2, respectively.[24] This means that some U.S. states (those with more compost facilities per square kilometre) will be able to collect much more SSO feedstock than others (those with less compost facilities per square kilometre). Despite this, and due to lack of available data elsewhere, the above B.C. RNG production estimates for 2021, 2030 and 2050 have been extrapolated, based on population size, to estimate RNG potential in the U.S. However, as just noted, this has been done with a low level of confidence.

Current RNG potential in the U.S. is estimated in Table 5. The 5% growth in U.S. RNG potential between 2021 and 2030 is entirely due to industry (agriculture feedstock) and population (SSOs and WWTP sludge) growth estimates, and LFG production models.[25] The 12% growth in U.S. RNG potential between 2021 and 2050 is also entirely due to industry (agriculture feedstock) and population (SSOs and WWTP sludge) growth estimates, and LFG production models.[25]

Table 5 RNG Potential in the U.S., in Petajoules per Year

	Agricultural	Municipal	WWTP	LFG	Total
2021	150	197	31	184	561
2030	154	213	34	189	590
2050	156	259	38	176	630

Other studies have also attempted to estimate U.S. RNG potential. For example, in 2011 the American Gas Foundation[26] estimated U.S. RNG potential (not including food waste) under non-aggressive and aggressive scenarios. Under the non-aggressive scenario, manure, WWTPs and LFG were estimated to

[21] Iowa State University: *Milk Cows in the United States*.

[22] Beef2Live: *Ranking of States with The Most Cattle,* September 26, 2021.

[23] U.S. Census Bureau, *Historical Population Density Data (1910-2020)*, April 26, 2021.

[24] BioCycle: *The State of Organics Recycling*, October 2017.

[25] B.C. agricultural growth estimates and LFG production models were used for estimating national increases in agricultural feedstock and LFG availability, while population growth estimates were used to estimate increases in national residential and commercial SSOs.

[26] American Gas Foundation, *The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality,* September 2011.

have RNG potential of 156.1, 4.2 and 192 petajoules per year, respectively. These estimates are very similar to those presented above in Table 5.

In 2013, the National Renewable Energy Laboratory[27] estimated U.S. RNG of 110.4 petajoules per year from manure, 67 petajoules per year from commercial SSO, 135 petajoules per year from WWTP, and 142 petajoules per year from LFG. While the distribution of RNG potential is different from other estimates (likely due to the assumption that more commercial SSO will be sent to WWTPs then municipal biogas plants), total estimated RNG potential is again similar.

In 2019, the American Gas Foundation published an update to their 2011 study.[28] It estimated U.S. RNG potential under non-aggressive and aggressive scenarios in 2040. The non-aggressive scenario, which is 857.5 petajoules per year, is one-third greater than the RNG estimate for 2050 made here.

Table 6 US RNG Potential Compared, in Petajoules per Year

	This Study	American Gas Foundation (2011)		NREL	American Gas Foundation (2019)		Range of Studies
		Aggressive	*Non-Aggressive*		*Aggressive*	*Non-Aggressive*	
Current RNG Potential	561	352.4 (No food waste)	917.9 (no food waste)	455.2			352.4 – 461*
Future RNG Potential	630 (2050)				1,503.7 (2040)	857.5 (2040)	630 – 857.5*

* Using American Gas Foundation's non-aggressive scenarios.

2.7 Anerobic RNG Production Cost Curves for B.C.

2.7.1 Key Considerations

Estimating RNG production costs can be very challenging for three reasons. First, unlike renewable energy technologies that either require no biomass (e.g., wind, solar and hydro) or purchase homogenous feedstock (e.g., wood pellets), biogas plants accept a wide array of feedstock with varying quality (i.e., level of contamination) and characteristics (size, dry matter, viscosity, etc.). As such, biogas plants can require very different feedstock reception, handling, storage and processing equipment.

Second, unlike renewable energy technologies that have an established energy output per unit of technology or feedstock (e.g., kilowatts per square metre of solar panel or gigajoules per tonne pellets), biogas production of feedstock varies greatly. Some feedstocks produce ten times or more biogas per tonne than others. As such, biogas plants that are similar in size and scope can produce very different amounts of RNG.

Finally, unlike renewable energy technologies that produce no by-product (e.g., wind, solar and hydro) or very little by-product (e.g., ash from biomass plants), biogas plants produce digestate. Digestate is a low-nutrient concentration liquid (or solid if produced by a dry-batch biogas plant). If digestate cannot be used locally (e.g., spread on nearby fields), nutrient extraction technology or transportation (trucking) is often required. Both of these can add significant costs.

[27] National Research Energy Laboratory, *Energy Analysis: Biogas Potential in the United States*, October 2013.
[28] American Gas Foundation, *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*, December 2019.

No public data is available for RNG production costs in B.C. (biogas plants and landfills in B.C. don't make their production costs public). For this reason, estimated B.C. RNG production costs are based on the 2017 RNG Production Potential Study.[29] The 2017 RNG Production Potential Study estimated the total feedstock availability in B.C. and used realistic assumptions to determine what percentage of this feedstock could be available to biogas plants, and how much biogas this feedstock could produce.

It then looked at the size of municipalities and farms near available feedstock to determine how much feedstock would go to what type of biogas plant (municipal or agricultural), and how much RNG these plants would produce. All SSOs were assumed to go to municipal or agricultural biogas plants, while WWTPs were assumed to only digest sludge.

Once the type (municipal or agricultural) and size (gigajoules of RNG per year) of biogas plant was established, production costs ($ per gigajoule) were estimated using an industry cost-curve. This cost-curve, created using data from hundreds of biogas plants in Europe, provides an estimated cost of RNG production based on biogas plant size. As biogas plants increase in size (digest more feedstock), they are anticipated to benefit from economies of scale, and the cost of RNG production decreases. To fully understand all of the assumptions and methodology used to estimate RNG production costs, the reader is referred to the 2017 RNG Production Potential Study.[11]

Tip fee (or avoided cost) for SSOs is assumed to be $0 per tonne[30] because to meet all, or at least a high percentage of, estimated RNG potential, all available feedstock must be used. Therefore, while biogas plants are currently able to receive a tip fee of around $20-40 per tonne, it is expected that a significant increase in food waste demand will drive down the fee biogas plants are paid to take it. For 2030 and 2050, there are expectations that RNG equipment costs will come down by 5% and 10% respectively as a result of a more mature biogas sector.

2.7.2 B.C. Production Costs in 2021

Estimated B.C. RNG production costs in 2021 are shown in Figure 4. The reason there is no RNG potential for ≤$18 per gigajoule from agricultural and municipal biogas plants is due to digestate management costs assumed in populated areas (i.e., Lower Mainland and Vancouver Island). The difference in RNG potential between ≤$50 per gigajoule and the technical potential is because some biogas plants are assumed to be unable to secure SSOs. If SSOs were available , RNG production costs for these plants would decrease significantly, while technical RNG potential would increase.

RNG potential from WWTPs and landfills is much lower in cost than agricultural and municipal RNG because digester tanks, LFG capture equipment, etc. are not included in the RNG production cost estimates (this equipment is assumed to exist as WWTPs and landfills require this equipment even if they do not produce RNG). Therefore, the only cost included for RNG production for WWTP and landfills is the cost of biogas/LFG upgrading. If the cost of digester tanks, LFG capture equipment, etc. were included, WWTP and landfill RNG production costs would be significantly higher.

[29] Hallbar Consulting, *Resource Supply Potential for Renewable Natural Gas in B.C. Public Version,* 2017.

[30] Tip fee typically accounts for <15% of biogas plant revenue, so an assumption of a $0/tonne tip fees doesn't significantly impact RNG production costs.

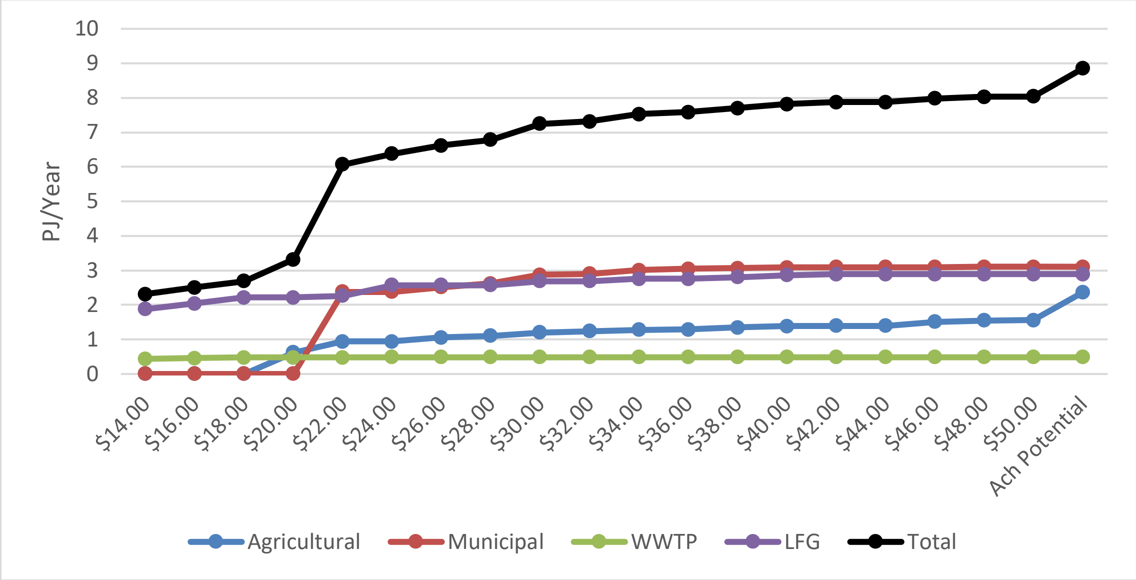


Figure 4 B.C. RNG Production Costs (2021)

2.7.3 B.C. Production Costs in 2030

Estimated B.C. RNG production costs in 2030 are shown in Figure 5.

- **Agricultural RNG** potential remains low, due to the assumption that most SSOs will be used in municipal biogas plants. As in 2021, there is no RNG potential for ≤$16 per gigajoule due to digestate management costs, while the difference in RNG potential between ≤$50 per gigajoule and technical potential is due to lack of SSOs.
- **Municipal RNG** potential is zero under $18 per gigajoule but increases to 3.3 petajoules per year for ≤ $31 per gigajoule. Technical RNG potential is 3.5 petajoules per year. As in 2021, there is no RNG potential for ≤$18 per gigajoule due to digestate management costs.
- **WWTP RNG** potential is small, even though some will be available for less than $16 per gigajoule.
- **Landfill RNG** potential is an important low-cost resource, with 2.2 petajoules available at $16 or less, and 2.9 petajoules per year for ≤ $31 per gigajoule. As in 2021, production costs for WWTP and landfill RNG only includes the cost of biogas/LFG upgrading.

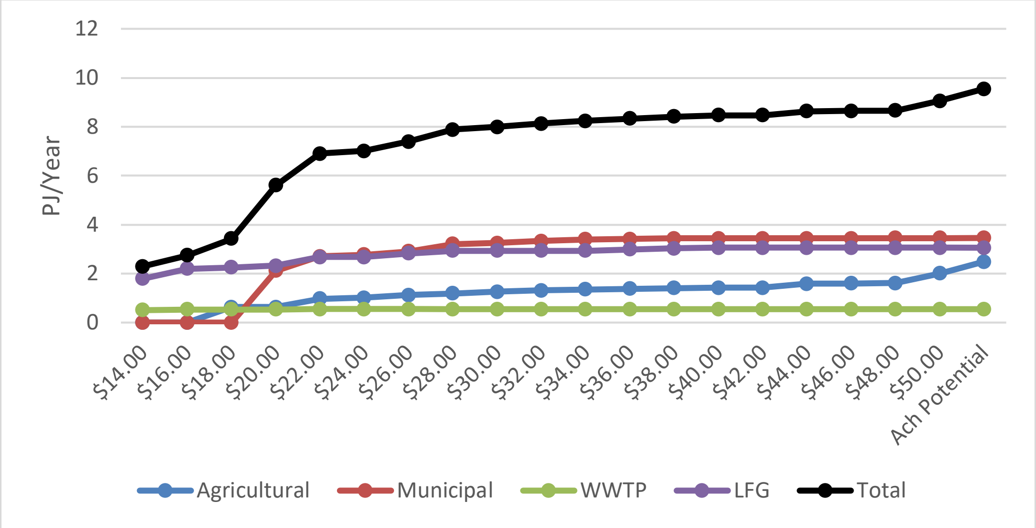


Figure 5 B.C. RNG Production Costs (2030)

2.7.4 B.C. Production Costs in 2050

Estimated B.C. RNG production costs in 2050 are shown in Figure 6.

- **Agricultural RNG** potential increases to a maximum of 2.2 petajoules for ≤50 per gigajoule. As before, there is no RNG potential under $16 per gigajoule due to digestate management costs, while the difference in RNG potential between ≤$50 per gigajoule and technical potential is due to lack of SSOs.
- **Municipal RNG** potential is significant, at 4.5 petajoules for ≤ $31 per gigajoule. There is no RNG potential for less than $14 per gigajoule due to digestate management costs.
- **WWTP RNG** potential is only slightly higher than in previous years.
- **Landfill RNG** potential is only slightly higher than in 2030, at 3.0 petajoules under $31 per gigajoule. As before, production costs for WWTP and landfill RNG only includes the cost of biogas/LFG upgrading.

Figure 7 combines the above data into a single graph that shows estimated RNG production costs for 2030, for the various sub-categories defined above. About 8 petajoules are available for ≤$30 per gigajoule. This represents the majority of the technical potential. Only a relatively small amount can be added by paying more for the RNG. Also, only a small additional amount becomes available by 2050, adding up to the total potential of 11 petajoules shown in Table 2 above.

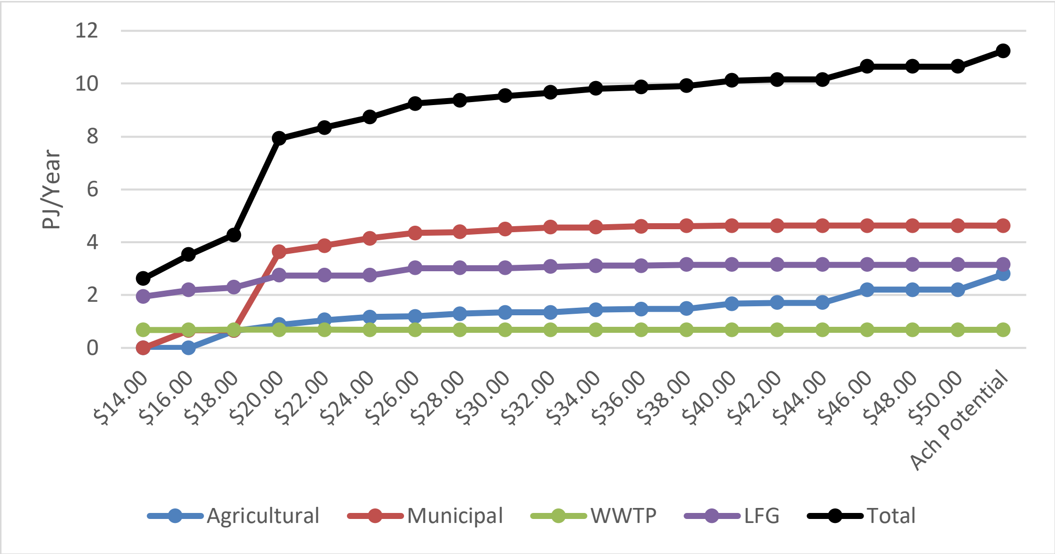


Figure 6 B.C. RNG Production Costs (2050)

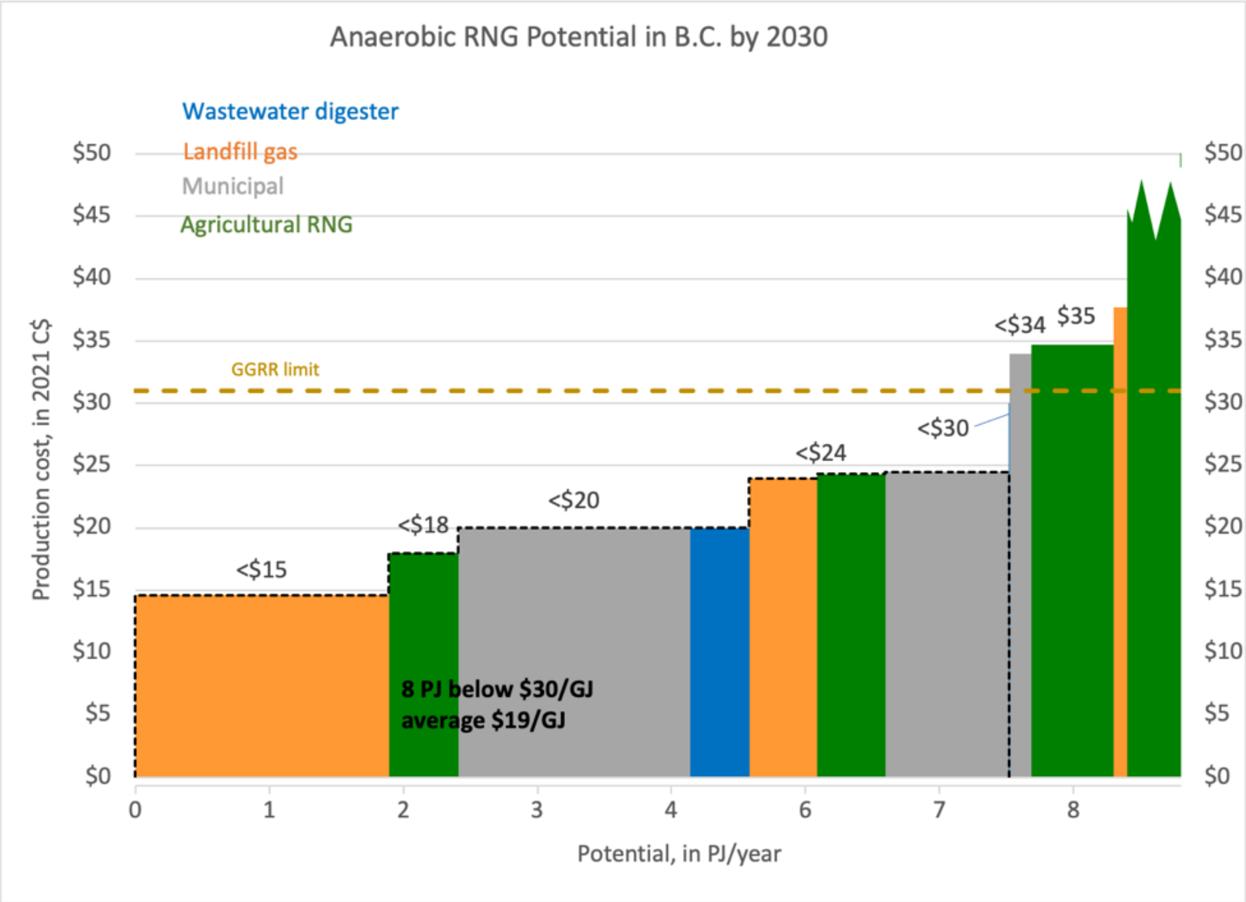


Figure 7 B.C. RNG Cost Curve for RNG from Anaerobic Digesters (in 2030)

2.8 Anerobic RNG Production Cost Curves in Canada

2.8.1 Key Considerations

The B.C. RNG production potential estimates above were used to estimate Canadian RNG potential. This was possible because Canada's livestock sectors are relatively evenly distributed, B.C. and Canada's per capita SSO and WWTP sludge production rates are the same, and population densities in all but the smallest provinces and territories are similar.

Using the B.C. RNG production cost estimates to calculate Canadian RNG production costs is more challenging. Typically, as biogas plants digest more feedstock or landfills capture more LFG (i.e., are larger), production costs per gigajoule of RNG decrease. This is because larger plants can benefit from economies of scale. Because Ontario and Quebec have significantly more feedstock than B.C., while Manitoba, Saskatchewan and the Atlantic provinces have significantly less feedstock, estimating Canadian RNG production costs using B.C. cost estimates may over- or under-estimate actual production costs.

Furthermore, the B.C. RNG production cost estimates were calculated by overlaying spatial feedstock data with local natural gas infrastructure. Gas infrastructure plays a key role in RNG production as it connects biogas plants and landfills with demand centres and end-users. The distribution of feedstock relative to the natural gas infrastructure in B.C. is not necessarily the same as in the rest of Canada. While RNG can be compressed and transported for grid injection elsewhere, doing so can increase RNG production costs by \$3 – \$6 per gigajoule or more.

Finally, different Canadian provinces have different policies and regulations that affect RNG production. Obstructive policies, whether intentional or not, can delay project development and result in the need for additional equipment, both of which affect RNG production costs. While this impact is less significant to production costs than project size and gas infrastructure availability, it can still be impactful.

2.7.5 Canadian RNG Production Costs in 2021, 2030 and 2050

Despite the challenges of unknown project size, gas infrastructure availability and provincial regulations, the following are Canadian RNG production cost estimates for 2021, 2030 and 2050. While these cost curves may not be as accurate as those for B.C., they still provide a good indication of Canadian RNG production costs (Figure 8).[31]

Of Canadian RNG potential in 2021, 2030 and 2050, > 65% of production for ≤\$18 per gigajoule is from WWTPs and LFG. This is because estimated production costs for WWTP and LFG RNG only include the cost of biogas/LFG upgrading. In 2021, 2030 and 2050, 85% of Canadian RNG potential is for ≤\$34 per gigajoule, ≤\$32 per gigajoule and ≤\$30 per gigajoule, respectively. From 2021 to 2050 the cost of RNG decreases due to both expectations that equipment costs will decrease (as the biogas/LFG market grows) and economies of scale will increase as a result to greater feedstock availability.

[31] Digestate management costs for agricultural biogas plant were only assumed for plants in B.C.'s Lower Mainland and Vancouver Island. Agricultural biogas plants in all other areas of Canada were assumed to have no digestate management costs.

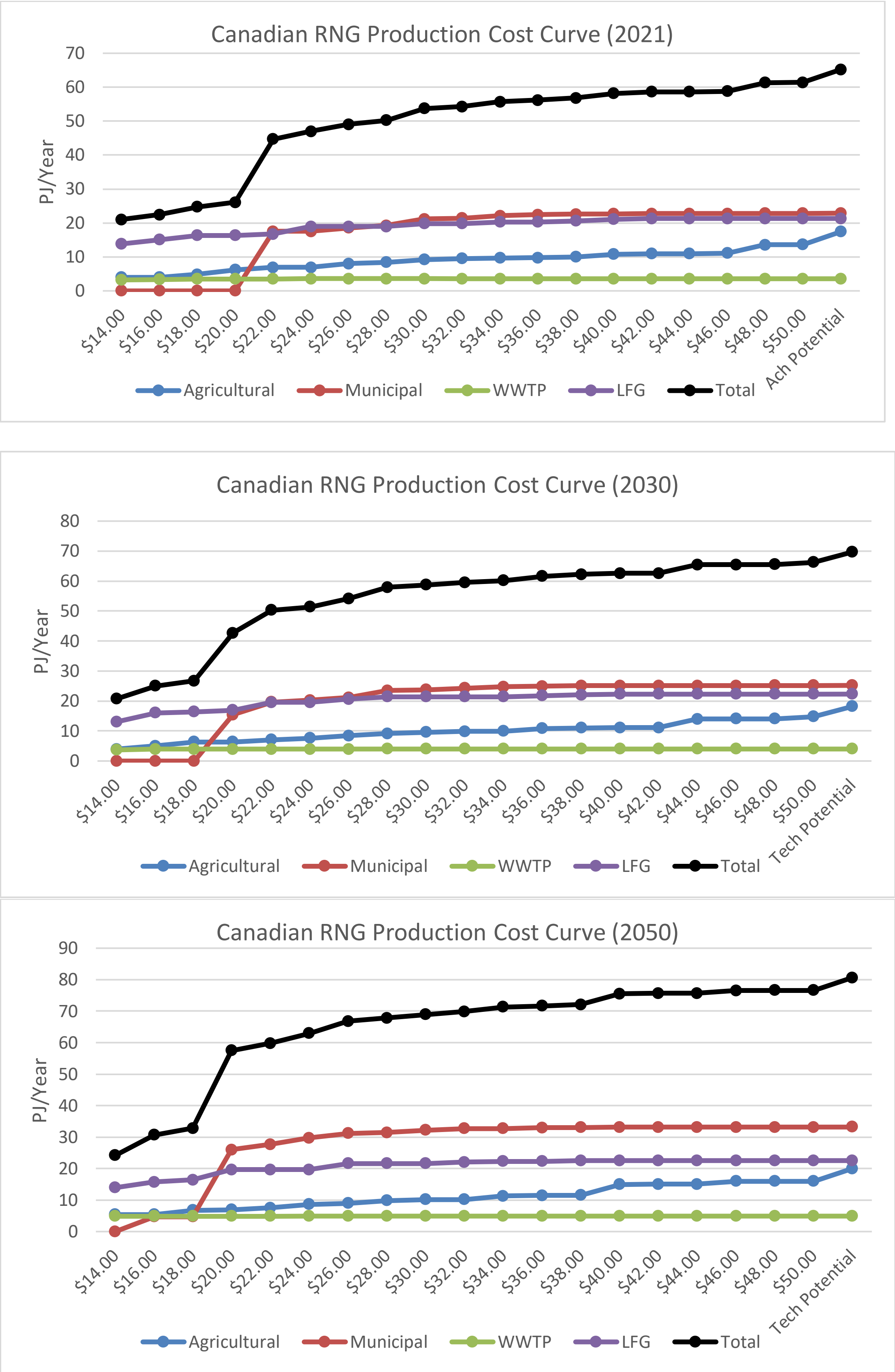


Figure 8 Canadian RNG Production Costs (2021, 2030 and 2050), in $/GJ

Other studies have also attempted to estimate the cost of Canadian RNG production. For example, the Torchlight Bioresources study[32] estimated RNG production costs ranging from $6 per gigajoule to almost $55 per gigajoule. RNG from a 0.1 petajoules per year biogas plant digesting hog manure and SSO was estimated to cost $53.90 per gigajoule, while RNG from LFG was estimated to cost $6.10 per gigajoule (best case) and $15.60 per gigajoule (most likely). While the estimated cost of $53.90 per gigajoule for agricultural RNG seems extremely high, the cost of $15.60 per gigajoule for LFG RNG is similar to that estimated above (70% of Canadian RNG from LFG is estimated to cost ≤$16 per gigajoule).

A study by Guidehouse[33] estimated current European RNG production costs to be €0.65 - €0.9 per cubic metre (~$26 - $36 per gigajoule), with RNG costs in 2050 estimated to be €0.47 - €0.57 per cubic metre (~$19 - $23 per gigajoule). While current RNG costs estimated by Guidehouse are slightly higher than the estimates above, this is likely for two reasons. First, the Guidehouse study considered the cost of biogas tanks and LFG capture equipment at WWTPs and landfills. Second, land availability in Europe is limited. Therefore, many European biogas plants require nutrient extraction technologies.

2.9 Anerobic RNG Production Cost Curves in U.S.

Using B.C. or Canadian RNG production cost estimates to estimate U.S. RNG production costs isn't possible. Canadian and U.S. agricultural sectors (both scale and density), population densities, policy structures and per capita commercial and residential SSOs capture rates aren't comparable. Furthermore, the U.S. currently has no standard market price for RNG. Instead, price is largely driven by the value of environmental commodities associated with the RNG from participating in the federal Renewable Fuel Standard and/or LCFS programs (see below). For this reason, the following RNG cost estimates were taken from previous studies by the American Gas Foundation.

The American Gas Foundation's 2011 study[34] estimated RNG production prices under a non-aggressive scenario state by state. RNG from animal manure was estimated to cost anywhere from C$8.1 – C$105.3 per gigajoule in Delaware and Alaska respectively, with an average cost of C$14.6 per gigajoule. RNG from WWTPs was estimated to cost anywhere from C$14.1 – C$40.8 per gigajoule in Illinois and Louisiana respectively, with an average cost of C$25.3 per gigajoule. RNG from LFG was estimated to cost anywhere from C$7.0 – C$18.8 per gigajoule in New York and Utah, respectively, with an average cost of C$9.7 per gigajoule.

In the American Gas Foundation's 2019 study,[35] RNG production cost ranges were again estimated, this time between C$24.4 – C$43.2 per gigajoule for biogas from animal manure, C$25.8 – C$37.6 per gigajoule from food waste, CD$9.8 – C$34.7 per gigajoule from WWTPs, and C$9.6 – C$25.4 per gigajoule from LFG. These ranges are somewhat comparable to the RNG production cost estimates above for both B.C. and Canada.

Table 7 Estimated RNG Production Costs (American Gas Foundation), in C$ per Gigajoule

	Agricultural		Food Waste		WWTP		Landfill	
Year	Low	High	Low	High	Low	High	Low	High
2011	$8.1	$105.3	N/A	N/A	$14.1	$40.8	$7.0	$18.8
2019	$24.4	$43.2	$25.8	$37.6	$9.8	$34.7	$9.6	$25.4

[32] TorchLight Bioresources Inc., *Renewable Natural Gas (Biomethane) Feedstock Potential in Canada*, 2020.
[33] Guidehouse, *Gas Decarbonization Pathways 2020-2050: Gas for Climate*, April 2020.
[34] American Gas Foundation, *The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality,* September 2011.
[35] American Gas Foundation, *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*, December 2019.

2.10 Competition for Anerobic RNG

The above work was carried out to estimate technical RNG production potential in B.C., Canada and the U.S. today, in 2030 and 2050. Work was also carried out to estimate how much this RNG would cost to produce. However, there can be a very large difference between costs (expenses incurred producing RNG) and prices (the amount RNG is sold for). This is because RNG isn't valued based on its energy content, but on environmental benefits generated through federal and provincial/state programs.

For example, B.C. has a Low Carbon Fuel Standard (LCFS), while Canada has the proposed Canadian Clean Fuel Standard. The U.S. has the federal Renewable Fuel Standard, and the California and Oregon LCFSs, with many more under development. Most of these programs[36] assign RNG a Carbon Intensity (CI) score. The lower (more negative) the CI score, the more RNG is sold for. This is because a smaller amount of highly negative CI RNG is needed to reduce a producer's overall fuel supply CI score.

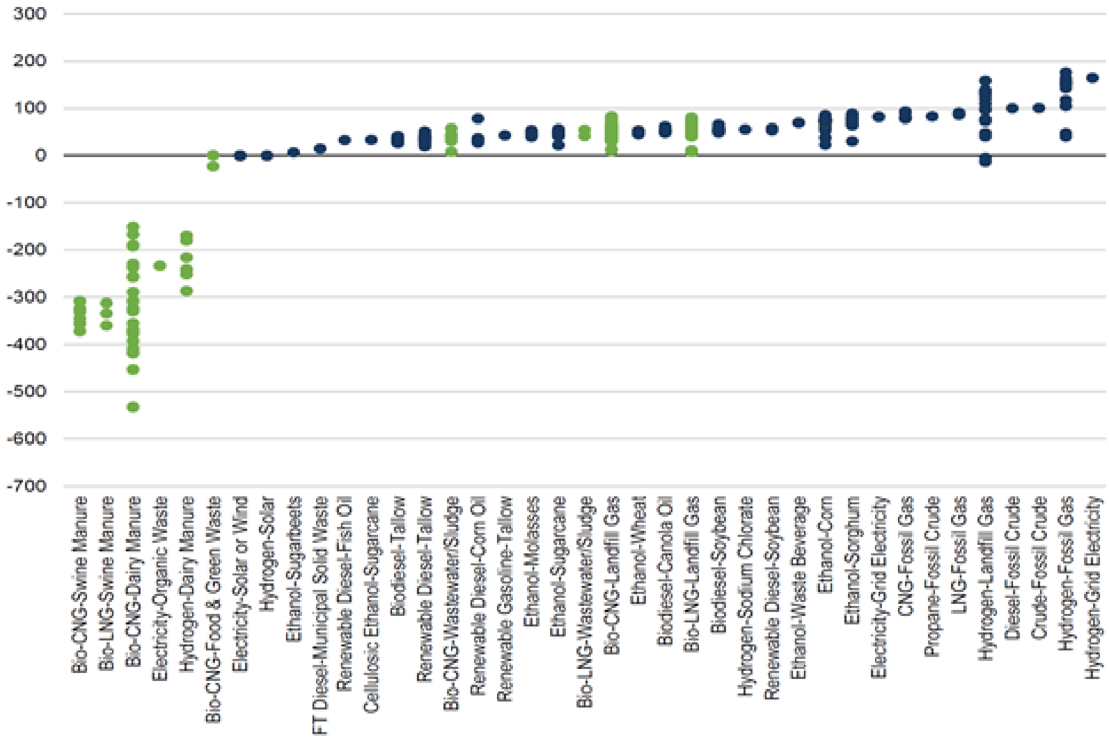
Furthermore, because most LCFS programs use a lifecycle accounting framework methodology where upstream emissions are included, two similar biogas plants can have very different CI scores. For example, Farm A and Farm B both digest 200,000 tonnes per year of manure and consume similar energy inputs. As a result of these biogas plants, both farms prevent 10,000 tonnes per year of carbon dioxide equivalent being emitted into the atmosphere from manure storage (baseline emissions).

However, because Farm A has a longer retention time and superior agitation, it produces 100,000 gigajoules per year of RNG, while Farm B only produces 75,000 gigajoules per year. The outcome is that Farm B's RNG has a more negative CI score and will attract a higher price than Farm A's RNG (this is because the 10,000 tonnes per year of carbon dioxide equivalent not emitted from manure storage is divided by the number of megajoules of RNG produced). The price that Farm B receives for its RNG could be 30+% higher compared to the price Farm A receives.

If Farm A were to add food waste feedstock to the biogas plant, RNG production would increase significantly, while the tonnes per year of carbon dioxide not emitted from manure storage would stay the same. This means that the 10,000 tonnes per year of carbon dioxide equivalent would be divided by a much larger number of megajoules, and the farms' CI score would become even less negative, resulting in an even lower price for the RNG.

In 2021 Stifel Equity Research[37] estimated that over the past few years RNG from dairy manure and LFG has sold for an average price of C$129.1 per gigajoule and C$39.9 per gigajoule, respectively. This price is potentially up to three times higher than the production cost of the RNG. For example, the American Gas Foundation[38] estimated the maximum dairy manure and LFG RNG production costs to be <C$45 per gigajoule and <C$26 per gigajoule, respectively. Figure 9 shows typical CI scores for different types of renewable energy sold into the Californian LCFS market, with green dots denoting all types of compressed RNG, including manure, food waste, WWTPs and LFG. This means that due to its highly negative CI agricultural and to a lesser degree, municipal RNG can potentially be sold for several times what they actually cost to produce.

[36] The exception being the U.S. Renewable Fuel Standard, which creates renewable identification numbers which are purchased by those needing to meet their EPA-specified renewable volume obligation.
[37] Stifel Equity Research, *Energy & Power – Biofuels: Renewable Natural Gas. A game-changer in the race for net-zero*, March 8, 2021.
[38] American Gas Foundation, *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*, December 2019.



Note: Values determined based on the California LCFS methodology. Values for use in vehicles, based on high electricity use for gas compression, and adding emissions from truck transport.

Figure 9 Carbon Intensity Values of Certified Pathways, in in Grams per Megajoule[37]

To date, all B.C.-produced RNG has been contracted to FortisBC. This is likely for two key reasons. First, FortisBC is the largest local utility. This means injecting RNG into the local gas grid is relatively easy and more straightforward than selling RNG to another entity. Second, FortisBC offers up to 20-year (for agricultural projects) and 25-year (for municipal projects) biomethane purchase agreements (BPAs). Having a long-term BPA is often necessary to secure project financing. For these reasons, it is realistic to assume that, in the short-term, a very high percentage of RNG produced in B.C. could be available to FortisBC at or near production costs.[39] However, and depending upon the price of carbon, this percentage may decrease in the long term as the B.C. LCFS, Canadian Clean Fuel Standard and other programs mature, creating competing demand for B.C.-produced, low-carbon RNG.

Across Canada, FortisBC is successfully purchasing RNG. While FortisBC isn't the local utility for these projects, it can offer long-term BPAs. As a result, a high percentage of RNG produced in Canada could be available to FortisBC at or near production costs in the short-term. However, this percentage could fall drastically in the long-term if other Canadian utilities start offering BPAs similar to those offered by FortisBC. Furthermore, and as in B.C., the price of RNG could increase drastically when the Canadian Clean Fuel Standard or other provincial or state-based LCFS regulations are created.

Estimating the percentage of U.S. RNG that could be available at cost rather than at price is incredibly challenging. Within the U.S., FortisBC isn't the local utility but it does offer long-term BPAs. Despite this,

[39] While Pacific Northern Gas (PNG) is also able to offer long-term BPAs for RNG, the PNG natural gas lines are in Northern B.C. where livestock and population densities are low. The amount of B.C. RNG that could be produced in areas where PNG has a gas line is relatively small compared to where FortisBC has gas lines.

and as shown in Figure 9, agricultural and municipal biogas plants are typically able to achieve highly negative CI scores. This makes it unlikely that FortisBC will acquire much agricultural or municipal RNG from the U.S. at or near production costs. According to Section 2.6 above, up to two-thirds of U.S. RNG is estimated to come from agricultural and municipal biogas plants.

For these reasons, it is realistic to assume that in the short-term a medium to low percentage of RNG produced in the U.S. could be available to FortisBC at or near production cost. In the long-term, this percentage could fall if U.S. utilities start offering BPAs similar to those offered by FortisBC, while changes to the federal Renewable Fuel Standard and California and Oregon LCFS, and/or introduction of new state LCFSs could cause this percentage to fall even further.

2.11 Markets

Currently the main buyer of RNG in Canada is FortisBC (although other utilities and companies are also starting to purchase RNG). Other markets for RNG do, however, exist. These markets, which may attract RNG from projects within, and more likely, outside of B.C., include:

- The U.S. RNG certificate market is an opportunity that offers high pricing, especially for low CI agricultural and municipal RNG, and is already attracting projects development in the U.S.
- RNG can be used as a transportation fuel. This is a lucrative market, though it is often restricted to fleets running locally on RNG.
- As soon as the federal Clean Fuel Standard is enacted, demand from other gas retailers will follow. Quebec is also mandating its gas retailers to buy 10% renewable gas by 2030 and Energir is therefore buying LFG for pipeline injection.[40]

2.12 Infrastructure Needs

The equipment and technology necessary to build and operate biogas plants/LFG capture systems are all commercially available. Despite this, and at times, the existing gas infrastructure can be a limiting factor. If certain feedstock is concentrated in an area unserved by natural gas,[41] or if the existing natural gas infrastructure isn't able to accept RNG (especially during summer months, when natural gas demand is low), RNG must be compressed and transported for grid injection elsewhere. Compression and transportation can increase RNG production costs by $3 – $6 per gigajoule or more (depending upon project size and distance RNG must be transported). As Figure 10 shows, many landfills and WWTP are close to the gas pipeline. This is also true for most large urban areas, but isn't true for all farms that produce feedstock for RNG production.

Therefore, developing the full potential of RNG production with B.C., Canada and the U.S., will require expansion of the natural gas infrastructure to areas currently too far from the grid to inject any gas. Alternatively, and as done in Sweden where many biogas plants are located well away from any natural gas infrastructure, greater emphasis and support is needed to reduce the cost of RNG compression and transportation.

[40] https://www.ledevoir.com/economie/632010/le-gaz-naturel-renouvelable-dans-la-mire-d-energir-et-de-waste-management (Accessed September 1, 2021).

[41] Especially liquid, low dry matter feedstock, such as manure (i.e., dairy and hog), which typically cannot be transported far before transportation costs are greater than revenue from RNG production.

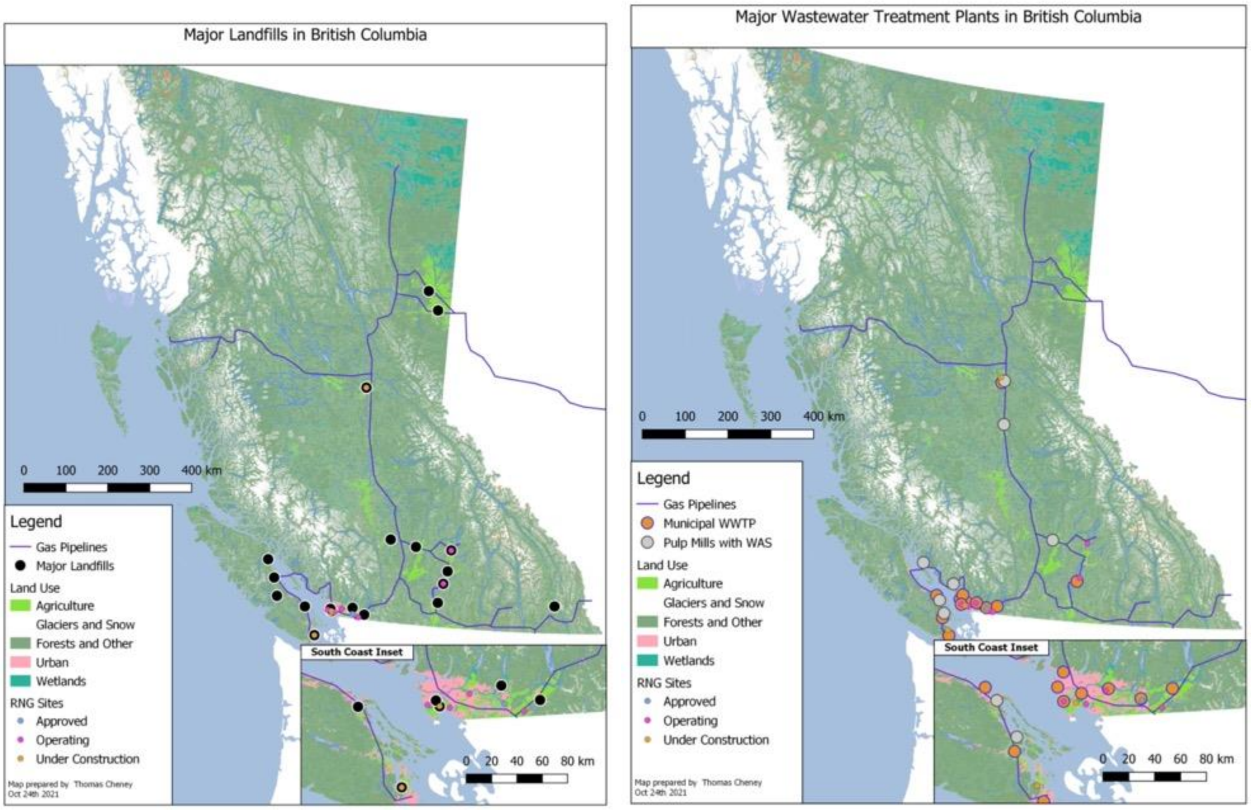


Figure 10 Locations of Major Landfills and WWTP in British Columbia

2.13 Recommendations

FortisBC is the first natural gas utility in Canada and one of the first in North America to purchase RNG. FortisBC also offers long-term BPAs. Having a long-term BPA is often necessary to secure project financing. For these reasons, FortisBC is able to purchase RNG across North America, and compete with federal and provincial/state fuel standards. However, as other Canadian and even U.S. gas utilities start offering BPAs similar to those offered by FortisBC, the 'first-mover' advantage that FortisBC currently has will start to erode.

Furthermore, as more fuel standards are developed, or as existing fuel standards mature, the attractiveness of these markets for RNG producers may increase (e.g., price stability and trust may increase, and/or fuel suppliers or intermediary companies may start offering long-term contracts). As such, FortisBC should leverage their current 'first-mover' advantage by procuring as much RNG as they can in the short-term, before the level of competition and the cost of RNG increases.

When it comes to procuring RNG, the choice for type (e.g., agricultural, municipal, WWTP or LFG) will depend upon a multitude of factors. The most important of these factors currently is cost. However, if/when there is a transition from requiring FortisBC to acquire 'renewable content' to acquiring gases with a certain CI score, the choice of RNG will depend upon CI calculations used. If a life cycle accounting methodology is used where credit is given for avoided methane from manure storage or food waste landfill diversion, then agricultural and municipal RNG will likely be the most attractive. Aligning these methodologies between jurisdictions is important to prevent that different GHG accounting methods may create higher value for a RNG type outside of B.C., leading to out-of-province sales.

3.0 THERMOCHEMICAL CONVERSION OF FOREST RESOURCES

This chapter deals with thermo-chemical conversion such as gasification of woody biomass. The gas generated may be upgraded to be injected into the pipeline or may be used directly at the point of production, replacing natural gas. We assume that all forest biomass available can be used by the various gasification and other technologies. It is understood that woody biomass comes in different dimensions and qualities (see Appendix C). For example, hog fuel may have higher ash content than other wood but this can be dealt with by using more potent syngas cleaning technologies. Salt contamination in coastal areas can be a problem for some processes and may then require salt removal (e.g., pre-washing) in order to use such material. Emerging technologies, such as supercritical water processing, may remove the need to pre-treat feedstock in. the future (see Appendix A).

3.1 Forest Biomass Resource Assessment

3.1.1. *Total Available Woody Biomass*

The estimates in this section are taken from the report *'Revitalization of the B.C. Bioenergy Sector*,' produced for BCBN in 2019. They are based on a commercial fibre supply model that uses the Annual Allowable Cut (AAC), mill activity, imports, and exports of fibre between regions, and estimates surplus residue at mills and in the forest. The main conclusions from this work were:

Based on the analysis in Appendix C,

combines availability data on the various wood feedstock types that have been quantified, adding typical cost ranges (see also Section 3.1.3). About half the long-term resource would come from standing trees (roundwood) at elevated pricing. The most significant low-cost resources include feedstock potentially becoming available from expiring contracts with BC Hydro for power production and feedstock currently used for wood pellet production. At the same time, these streams remain highly speculative as it is not certain that they will become available. Unused mill residue – a low-cost resource – provides a small amount throughout. Harvesting residue is one resource that is not yet fully exploited but also has limited availability unless harvesting rates increase above current levels.

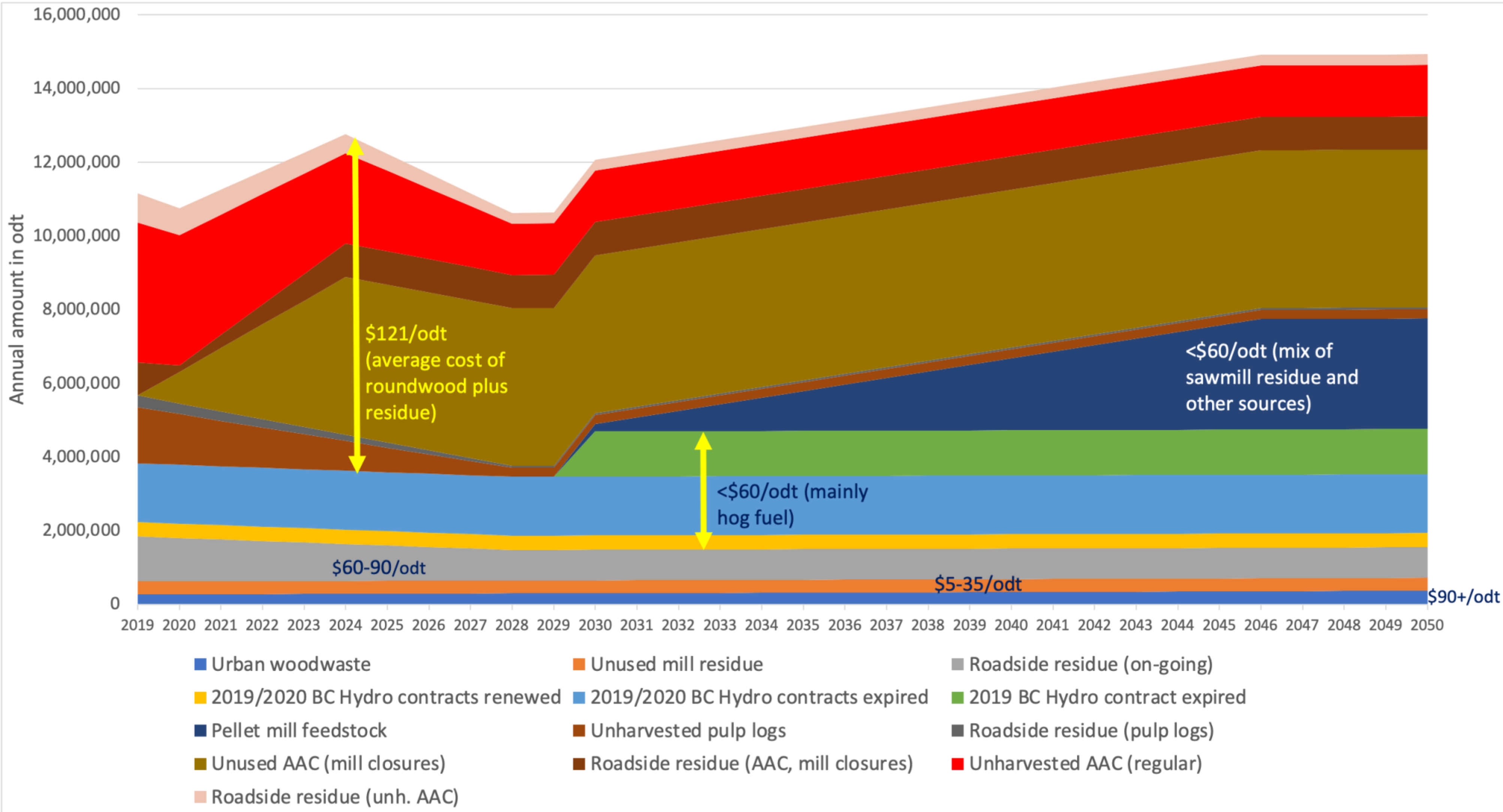


Figure 11 Assumed Amounts and Changes in Availability of Wood Fibre between 2019 and 2050

Table 8 summarizes the graph above in numbers. The largest amounts of wood available are also the most expensive to retrieve, i.e., standing trees from unused AAC. Together with the roadside residue generated from harvesting additional trees, the estimated cost of this biomass in the model is $121 per dry tonne – about twice the amount assumed for the low-cost fibre resources.

The inclusion of residue currently used for pellet production implies a conversion of this industry towards renewable gas production for local use instead of pellet exports. Such changes may be very gradual and may remain incomplete. Only some of this potential may be available.

The AAC may be further reduced due to beetle kills or wildfires, or conservation issues, such as the desire to protect old-growth forests. This would affect both AAC and residue production. Previously mentioned caveats also apply, such as how much harvesting residue may be available. It is not entirely clear if BC Hydro contracts with mills exporting excess power will be extended in 2028. Some of these uncertainties are expressed as different scenarios in the next chapter.

Converting the total amount of wood available in 2030 (217 petajoules) to hydrogen at an efficiency of 66% would result in about 143 petajoules of gas. This amount does not consider alternative uses for this biomass, either from new sawmills, for chemicals production, or pellet production. The use of lignin is not included because there are more effective ways of using biomass. Not counting the most expensive resource, i.e., unharvested AAC (and related roadside residue), the total gas production potential is then only 60 petajoules in 2030.

Table 8 Total Available Forest Biomass (Technical Potential) in B.C. and Gas Production Potential

	2021-2023		2030		2050	
Source	**Million odt**	**PJ**	**Million odt**	***PJ***	**Million odt**	***PJ***
Unharvested AAC	3,792,151	69	1,394,417	26	1,394,417	26
Roadside residue related to above	796,352	15	292,828	5	292,828	5
AAC from mill closures	4,282,789	78	4,282,789	78	4,282,789	78
Roadside residue related to above	899,385	16	899,385	16	899,385	16
Unharvested pulp logs	1,519,373	28	246,751	5	246,751	5
Roadside residue related to above	319,068	6	51,818	1	51,818	1
Unused roadside residue	1,223,419	22	831,315	15	831,315	15
Unused mill residue	349,080	6	346,199	6	346,199	6
Conversion of pellet plants	0	0	0	0	*>3,000,000*	>55
Expiring BC Hydro contracts	387,856	7	3,212,437	59	3,212,437	59
Urban wood waste (CLD)	270,000	5	300,000	5	*364,000*	7
TOTAL	**13,839,473**	**253**	**11,857,939**	**217**	**>13,839,473**	**>273**

Assumptions: Harvesting continues at recent levels, only adjusted by known and expected mill closures. Mills will continue to use residue at current amounts to sustain their operations. Nothing from BC Hydro contracts will be available before 2029.

Pellet mills have long-term contracts and are only deemed to transition towards renewable gas production after 2030. Population growth in B.C. is about 1% per year (for estimating urban wood waste).

Unused roadside residue is conservatively estimated. A higher amount may be available based on sources discussed above. Additional roadside residue from new activities is estimated as 21% of the mass of round logs.

Grey numbers identify the most expensive resource (standing trees).

3.1.2. *Conclusions on Wood Fibre Availability*

Large amounts of wood fibre are, or may become, available in B.C., including unharvested trees (most), harvesting residue, and mill residue. Yet, only limited amounts are easily accessible and currently available at low pricing (see next section). As already found in 2019, almost no mill residue is currently available for new projects. The pellet and pulp and paper industries are focusing on harvesting residue to obtain additional residue. This residue is being recovered in only a few areas, partly because of the difficulties of retrieving fibre beyond a certain distance from the road. Other reasons are the costs of recovering fibre after the primary harvest. Finally, there are legal constraints with tenure holders restricting third-party access to waste fibre. The 2019 estimate of around 1.2 million tonnes is still deemed accurate, although recovered amounts have recently started to increase and will therefore soon reduce the remaining potential. On the other hand, improved and integrated harvesting approaches may increase the availability of such residue over the coming decade.

Accessing more residual fibre will require improved supply chains that integrate tree harvesting and residue recovery and use best available technologies to reduce the cost of residue recovery. Some opportunities may exist where no pulp or pellet mills currently exist to recover additional harvesting residue for new energy projects. Costs may then be affordable, given the shorter transport distances.

Another element that would increase fibre availability are clearer regulations regarding the allocation of forestry residue and the responsibilities of the tenure holder versus the residual fibre user. If a third party is given access to a tenure holder's harvesting area, using the same logging roads, liabilities should remain with the third party and not the license holder. Failing to resolve such issues increases risk for sawmills and has led to unnecessary red tape and difficulties in accessing residue. Continued funding through e.g., the Forest Enhancement Society is needed to develop and improve related supply chains.

Another new mechanism, currently being tested in the Fort Nelson area, is the takeover of abandoned TSAs, where sawmills or other mills have been shut down. This can open access to large sources of fibre but also requires a complete business concept that makes use of both non-merchantable and merchantable wood to maximize revenue and allow projects to become bankable and operate profitably.

Summarizing thoughts on availability, it is important to understand that:

- Little unallocated mill residue is available throughout B.C. and only one or two new projects may be able to rely mainly on such resources.
- The mill residue previously used for excess power production at pulp and paper mills until 2019 is unlikely to become available for new projects. Sawmill closures have created a shortage of residuals. This biomass will likely be redistributed among existing users.
- Roadside residue appears to be the main opportunity for new projects but is already partially being used by pulp and pellet mills. Estimates of its availability vary by about a factor of two between models. Recovery becomes costly as the terrain becomes more rugged and distances to the user increase. Its availability is linked to harvesting techniques, such as skidding (most residue left in the forest) versus forwarding (more residue taken to the roadside). Changes in harvesting practices may be necessary to increase recoverable amounts.
- New stand-alone facilities to produce RNG or hydrogen will likely have to rely on more than one resource, such as some mill waste and some roadside residue, to secure their feedstock. This limits opportunities for locating such plants.

- Whole-tree harvesting, including non-merchantable wood, on abandoned TSAs where sawmills are no longer active may be a new opportunity as long as there is a high enough share of sawlogs in the stands to be cut that can be cost-effectively sold to sawmills. This concept is being tried in Fort Nelson but may not be directly transferable to other regions with limited pulp markets.
- Whole-tree harvesting for energy production may lead to a backlash from environmental groups – the scientific consensus is that harvesting is sustainable as long as a portion (usually around 20-30%) of the non-stemwood is left on the cut block but the B.C. community may still not accept large-scale operations of this type for fear of its impact on landscape and biodiversity.

3.1.3. *Feedstock Cost*

Typical feedstock costs, or the ability to pay, varies with industries. Pulp mills will pay up to about $100 per dry tonne for wood residue - possibly more for marginal amounts. Pellet mills produce a product of much lesser value and mainly rely on residue, only using small amounts of roundwood. They have typical feedstock costs of $50 per dry tonne but may also pay more for marginal amounts. Power plants usually use low-cost feedstock that costs no more than $35 per dry tonne.

Table 9 provides an overview of feedstock costs in 2015. Since then, harvested costs have increased around 30%, especially in the B.C. Interior. Stumpage fees were at about $0.25 per cubic metre in 2014 but have since increased to $20 (end of 2019).[42] Wildfires and beetle kills have reduced the resource to such a degree that longer hauls are necessary to obtain the same amount of wood. Standing timber would therefore likely cost in the area of $225 per dry tonne (delivered) today. During the second quarter of 2021, Interior sawlog pricing was reported as $128 per cubic metre for spruce-pine-fir (SPF) species and $50 ($123 per dry tonne) for pulp logs.[43]

The 2019 CFS report indicates costs of $5-15 per dry tonne for hog fuel, around $100 for residual wood chips ($120 on the coast), $40-55 per cubic metre ($98-134 per dry tonne) for pulp logs, $25-40 for sawdust. And $70-90 per dry tonne for delivered roadside residue (2018 pricing).[44]

Table 9 2015 Estimated Feedstock Procurement Costs in B.C.[45]

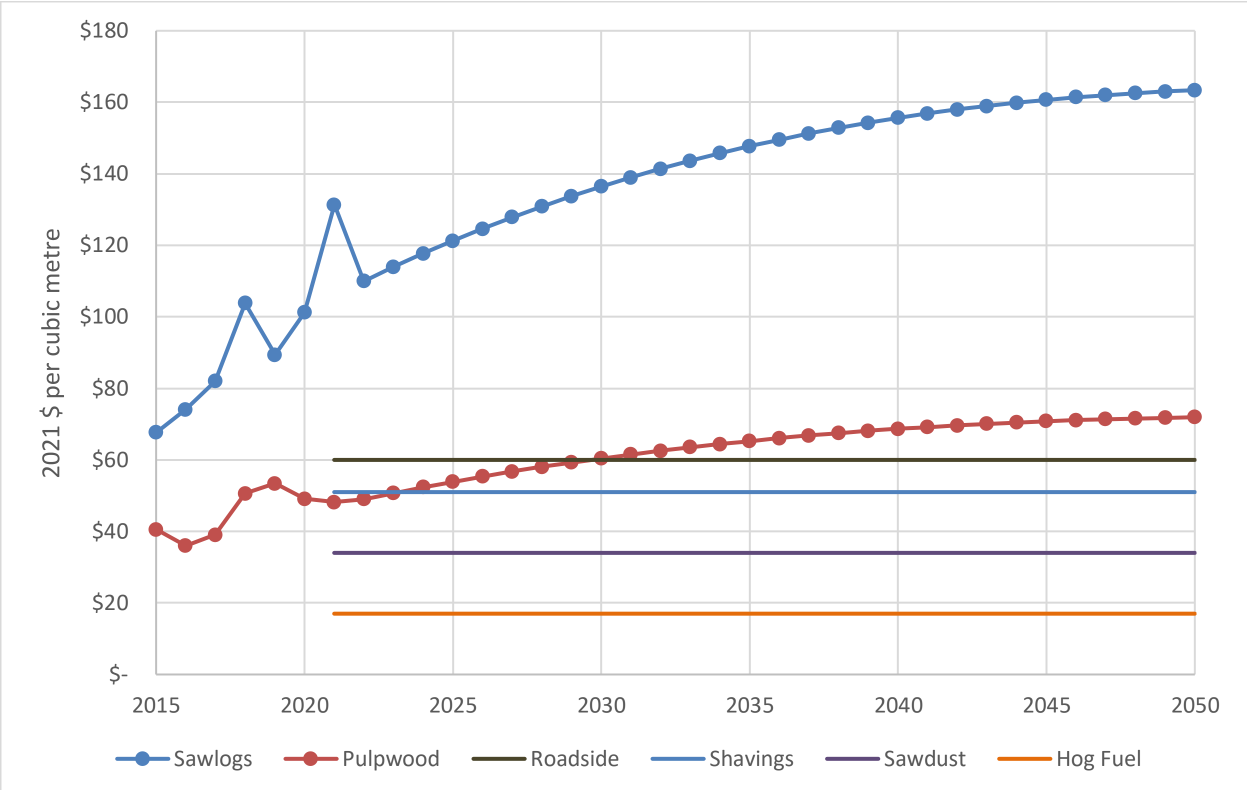
Fibre supply by source		Dry shavings	Saw-dust	Roadside residue	Hog fuel	Standing timber	Total/ average
	% supply	5%	5%	35%	5%	50%	100%
Regional fibre cost	in $/odt	$35	$20	%5	$5	$113	$61.25
Average delivery cost	in $/odt	$10	$10	$50	$10	$60	$49
Total delivered cost	**in $/odt**	**$45**	**$30**	**$55**	**$15**	**$173**	**$110.25**
	in $/m³	**418**	**$12**	**$22**	**$6**	**$71**	**$45.00**

[42]Jim Girvan and Russ Taylor (Fall 2020) "Can Stumpage Reform Save the B.C. Interior Forest Industry). *Truck Loggers*. from https://issuu.com/truckloggers/docs/truckloggerbc_fall_2020_final_lowres/s/11119030 (Accessed September 8, 2021).
[43] B.C. Interior Log Market Report for the three-month period of April 1, 2021 to June 30, 2021. Timber Pricing Branch, Ministry of Forests, Lands, Natural Resource Operations and Rural Development, Province of British Columbia, July 2021.
[44] B.C. Regional Surplus Biomass Fibre Supply Forecast. Industrial Forest Service Inc., March 2019.
[45] Wood Based Biomass in British Columbia and its Potential for New Electricity Generation. Industrial Forest Service Inc., July 2015.

The actual delivered cost of biomass depends on both harvesting and transport costs, plus any treatment at the plant that may be necessary (grinding, milling, de-barking, drying). No general cost can therefore be determined without taking the location and pre-processing requirements into account. Generally, roadside residue costs increase with distance and only a portion will be economically available. FPInnovations set the maximum cost at $60 per dry tonne and determined for various TSAs the amount deemed to be available at that cost, assuming a specific processing site. More can be recovered at a higher cost. The Forest Enhancement Society of B.C. provides one way of bringing down the delivered cost and increasing recovery rates. They contribute an average of $14 per dry tonne, allowing for a delivered cost of about $74 per tonne on average, for an amount of around 1.25 million cubic metres per year.[233]

Figure 12 shows the cost curves for woody feedstock in B.C., based on past trends, in 2021 Canadian dollars, not considering inflation. We assume that:

- Sawlog costs are based on SPF costs (Interior), although slightly lower costs are reported for other species, such as hemlock. Pricing includes logging road construction and replanting and has increased from $66 in 2014 to $128 per cubic metre in 2021 (average of $92 in 2014 to $166 in coastal TSAs), according to the Timber Pricing Branch. Some of the costs will also relate to increases in stumpage, which increased by 75% in the province's interior between 2020 and 2021. Cost increases in our model start at 5% per year in 2016, and decrease to a more modest 2% per year by 2050. Mill closures may reduce competition for logs and therefore lead to lower pricing. This cost represents the case where new facilities would access unharvested stands on their own account, as opposed to buying residue. Some economies can be expected due to whole-tree harvesting and are not accounted for in this cost.
- The cost of pulp logs increased from $40 to $50 per cubic metre since 2014, i.e., over seven years. This is about twice the 2% historical inflation rate, i.e., a 2% cost increase for pulp logs is presumed based on 2021 dollars. Cost increases in our model mirror the recent cost increases for sawlogs.
- Roadside residue costs rise with inflation. They are expected to remain constant in real dollars, at $60 per dry tonne on average. Yet, cost reductions due to supply chain improvements will lead to higher total amounts recovered.
- The cost of other residue is inflated at 2% per year to 2021 pricing from the 2015 pricing shown in Table 9, and deemed to continue to increase with inflation.



Note: Costs are expected to increase with inflation. This chart shows developments net of inflation

Figure 12 Expected Increases in Delivered Fibre Cost by Category, 2021-2050, in 2021$

3.2 Allocation of Resources

The forestry resources quantified above can be used for several of the technology pathways discussed below. Some of them therefore stand in direct competition for the same resources. Either one technology will win out over others, they will share the resource, or a staggered transition from one to another will occur. In any case, the total potential for each cannot be greater than the total wood resource. A brief outline describes the most likely outcomes:

- Lignin may be removed from black liquor to de-bottleneck recovery boilers but, once removed, higher-value markets are likely to be sought for this product. Although the energy value of lignin is fairly high at $30 per gigajoule, its use in lime kilns would require major modifications that deter its use. Recovery boilers will have to replace lignin with alternative fuels, such as hog fuel, to maintain an energy balance.

- Syngas will likely be produced at most B.C. mills using natural gas in lime kilns. This technology is deemed commercially available, even though it is still new. It is expected to be deployed gradually, starting with demonstration projects in the coming two years.[64] The scope of these gasifiers will be limited to the lime kilns and will therefore only consume a portion of the woody feedstock available, and only replace a portion of natural gas use at mills. Once established, it will likely continue for many years, possibly through 2050. Gasifiers could be used at cement kilns, veneer plants and others but we do not explore this in this report.

- Hydrogen from wood is a pre-commercial technology not yet proven at scale. It is not expected to be implemented before 2030 except for demonstration projects. It is considered to be less complex and cheaper than RNG production from wood and is therefore allocated the remaining resources not used up by syngas production. It is possible that hydrogen production may replace syngas production at some mills, or that stand-alone or separate hydrogen production will occur.

- RNG is not expected to be produced from wood due to the higher complexity of the technology and its very high capital costs. This may change after 2030 as new technologies mature, at which time it would compete with hydrogen production from wood. These dynamics are difficult to predict and hydrogen and RNG production may then be interchangeable alternatives. This is less relevant to this analysis, given the similar energy conversion efficiencies of these technologies.
- Alternative uses of forestry resources may occur but are not considered here. The production of platform chemicals or the continued or additional use for pellet production, for example, may affect the total resource available for renewable gas production.

3.3 Syngas Production from Solid Biomass

3.3.1 *Description of pathway and technology*

Syngas is the primary product of gasification (carried out at temperatures between 800-1000°C), and a co-product of pyrolysis (carried out at temperatures between 300-500°C). Gasification is a thermochemical process that uses a partially oxidized environment to generate syngas, which a mixture of H_2, CO, CO_2, and CH_4, as well as other small hydrocarbons. Oxidizing agents used in the gasification process include steam, oxygen, and air. While air is a cheap oxidizing agent, it produces syngas with lower LHV and HHV values - for biomass, HHV typically ranges between 4-7 megajoules per cubic metre.[46] The use of different oxidizing agents can deliver syngas with significantly higher HHVs - 10-18 megajoules per cubic metre for steam, and 12-28 megajoules per cubic metre for oxygen.[47]

The process of gasification of solid biomass requires the material to be dried (generally below 30% MC), reduced in size to particles or chips, combusted in the absence of oxygen (pyrolyzed), and oxidized to produce syngas. Of approximately 250 gasification facilities operating worldwide, only 10% use solid biomass as a feedstock.[47] While gasification technology itself is proven and operational (i.e. technology readiness levels (TRLs) of 7+), recent work by Binder et al. suggests that across total process chains TRLs are much lower, between TRL 5 (for dual fluidized bed technology) and TRL 3 (sorption enhanced reforming technology).[48] This is due to the lack of operational demonstrations which link all aspects of biomass recovery, processing, gasification, and gas product recovery. As such, lower TRLs would apply to new greenfield construction rather than adding gasifiers to existing pulp and paper mills. An overview of current technologies and their technology status is provided in Appendix A.

[46] Kitzler et al. (2011). Pressurized gasification of wood biomass - variation of parameter. Fuel Process Technology 92:908-914. https://doi.org/10.1016/j.fuproc.2010.12.009

[47] Solarte-Toro et al. (2018). Evaluation of biogas and syngas as energy vectors for heat and power generation using lignocellulosic biomass as raw material. Electronic Journal of Biotechnology 33:52-62. https://doi.org/10.1016/j.ejbt.2018.03.005

[48] Binder et al. (2018). Hydrogen from biomass gasification. IEA Bioenergy Task 33, December 2018.

3.3.2 *Cost Curves*

Syngas has multiple applications. Relatively few reports focus on syngas as a primary product, as most gasification processes are being optimized for hydrogen or for RNG production. Table 10 provides several sources informing about costs related to syngas from wood.

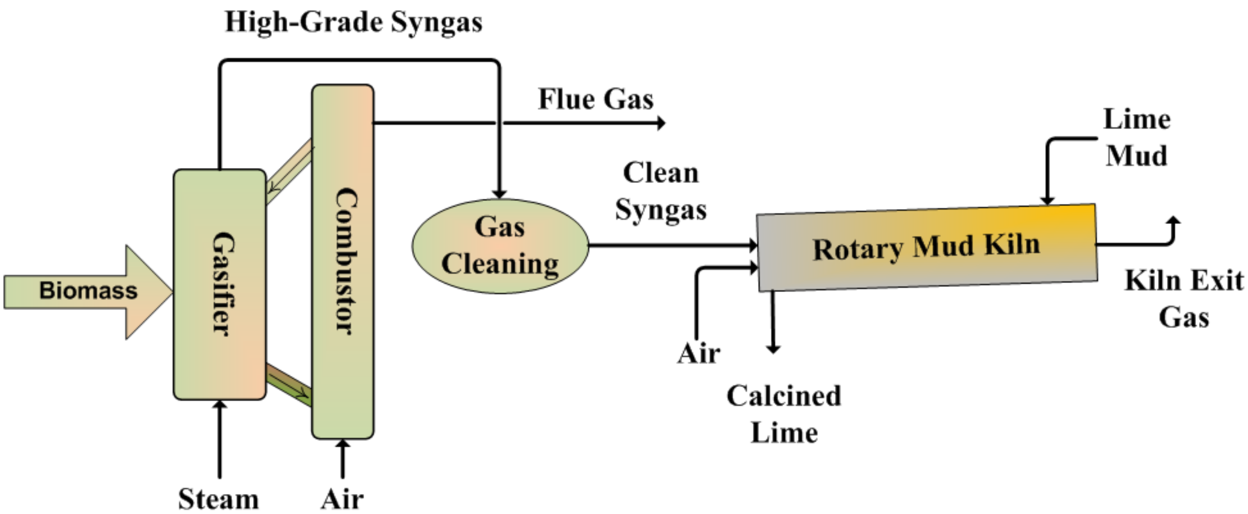
Table 10 Previous Cost Estimates on Syngas Production

Facility	Technology	Size	Energy yield	Gas cost	Capital cost	Source
Conceptual	Dual fluidized bed steam gasification	17.5 tpy		$1.22/m³ $17/GJ	$12.5 M US	Kim et al. 2011
Conceptual	Single-step air-steam gasification	600 ktpy	12 PJ/y	$6.45/m³ $92/GJ	n.d.	Nakyai and Seabea 2019.
Conceptual	Downdraft fixed bed gasification	27 ktpy	0.26 PJ/y		$13.82 M US	Mustafa et al. 2017
Lime kiln	Conventional circulating fluidized beds, or novel fixed bed	50 ktpy	0.8 PJ/y		$40-50 M US	Browne et al. 2019[227]

Capital costs for syngas production are variable, but seem to range between $1-2 million per 1,000 tonnes of material processed. Capital costs drop as plant size increases, so doubling plant size from about 25,000 to 50,000 results in a decrease of 50% in CAPEX. The capital costs used in this report are taken from Browne et al. because this reflects the B.C. situation and because they reflect the slightly lower costs associated with larger throughput.

This chapter describes the use of syngas in lime kilns of kraft pulp mills. Lime kilns are the last stage of recovering spent chemicals. To create the chemical calcination reaction with lime, kilns need to be operated at high temperatures. This is achieved by burning natural gas directly into the kilns. Across B.C., almost 6,000 gigajoules of natural gas are used in lime kilns.

Syngas can be a substitute for natural gas, more so than solid biomass, because its physical and chemical properties require little modification upstream and downstream of the existing lime kilns. In fact, medium calorific syngas could likely be used in parallel to natural gas, providing increased redundancy and a reduced conversion risk compared to other fuels, such as lignin (see chapter 3.6 below). The pathway is illustrated in Figure 13 below.



Source: Highbury Energy

Figure 13 Process Flow for the Production and Use of Syngas in Lime Kilns of Kraft Pulp Mills

Table 11 presents the default input parameters used to model gas costs. The capital cost was developed above. Operating cost parameters are based on Browne (2019.)[227] Capital costs are assumed to decrease over time due to technology improvements; the technology is fairly well understood and costs will likely drop in a fairly linear fashion. The default cost of wood is $60 per dry tonne but it is important to note that these costs could rise. While investment costs are substantive, feedstock costs are critical to the cost of these operations.

Table 11 Default Cost Parameters, Syngas from Wood for Use in Lime Kilns, in 2021$

Cost parameter	Value	Share	Comments
Annual biomass input	50,000 odt		Commercial-scale plant
Feedstock cost	$60/odt		Minimum scenario and first block of Maximum scenario
Gas yield	75%		Based on feedstock input, HHV
Capital cost	$50 million		In 2021
Capital cost	$35 million		In 2030 (-30%)
Capital cost	$25 million		In 2050 (-50%)
Amortization	$5.6 million	45%	20 years, 9.2%
Feedstock cost	$3.0 million	24%	
Personnel cost			
Labour, 9 FTE	$0.5 million	4%	
Management, 3 FTE	$0.3 million	2%	
Electricity	$0.5 million	4%	7.5 GWh/year (estimated value)
Natural gas	$0.02 million	0%	2,000 GJ/year (estimated value)
Other costs	2.5 million	20%	5% of CAPEX
TOTAL OPEX	$13 million	100%	
Gas production cost	$18/GJ		In 2021

Figure 14 depicts modelled syngas costs for use at B.C. lime kilns. We base our initial assumptions on Browne's 2019 report on syngas options for B.C. These costs evolve over time with reductions in capital offset in part by increases in feedstock costs. The primary cost of syngas systems is the cost of biomass used in the process, while capital costs are substantively lower. We use an average conversion efficiency of 70% on an energy input-output basis. The efficiency for syngas from biomass in the literature ranges between 0.42 to 0.88 gigajoules per gigajoule, so these efficiencies reflect the median conversion efficiency of systems available.

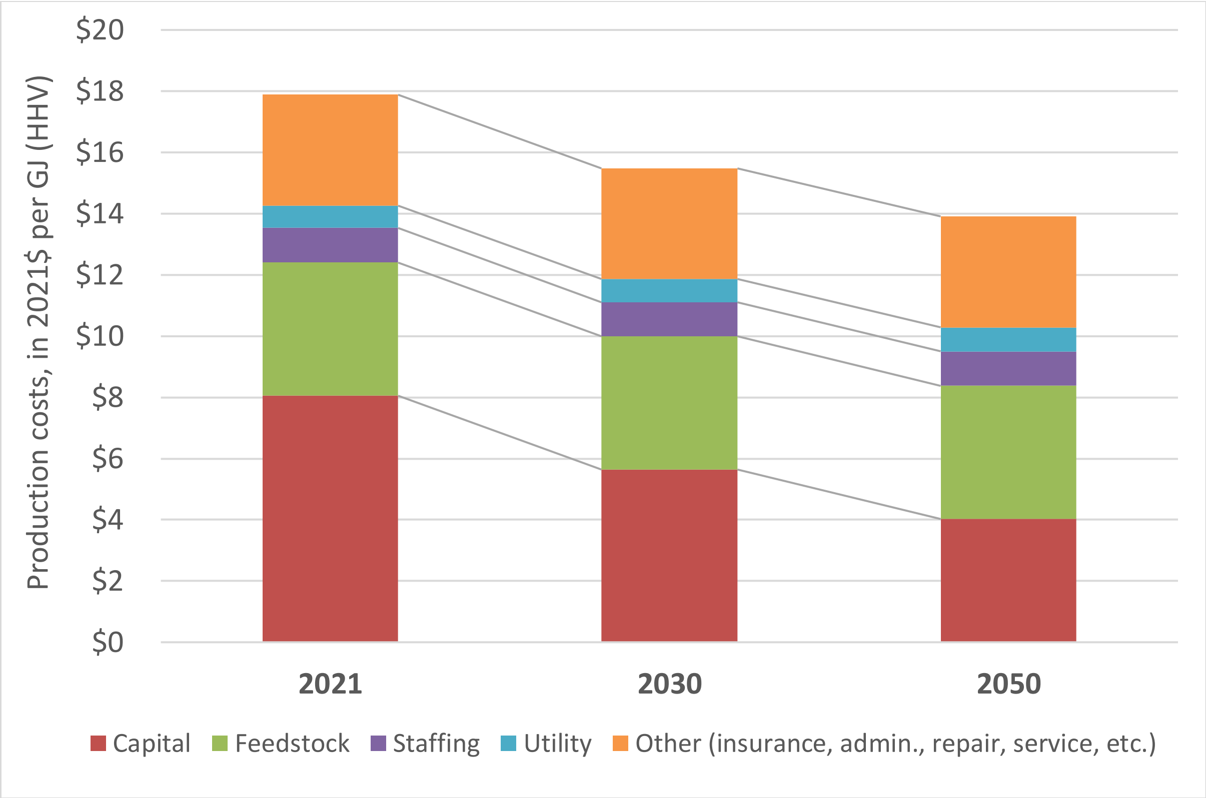


Figure 14 Modelled Cost for Syngas Use in a Pulp Mill's Lime Kiln

3.3.3 *Carbon intensity of syngas from biomass*

The use of syngas in energy production provides significant reductions in CO_2 emissions compared to natural gas on a life-cycle basis. Use of fossil fuels in the harvest and transport of biomass, and in the plant itself, contributes to emissions. Browne estimates that production of 0.8 petajoules per year of syngas would reduce GHG emissions associated with natural gas use by 41 kilotonnes CO_2e per year, in B.C.[227] Based on the model used to estimate the production costs above, B.C. values for natural gas-, electricity-, and feedstock-related GHG emissions for the production of syngas result in a CI of 3.2 grams per megajoule.

3.3.4 *Markets*

Producing syngas at existing pulp and paper facilities provides an opportunity to reduce natural gas consumption in lime kilns within these facilities. Browne estimated the impact of converting the three largest lime kilns in the province to syngas. He suggested that approximately 150,000 dry tonnes of biomass would be required per year to displace 2.4 petajoules per year of natural gas. He found that with a capital cost of US$40-50 million per conversion, and with variable operating costs of between US$5-10 per gigajoule, payback periods could be as low as 3-5 years (at $30 per gigajoule). Browne assumes that many of the capital costs for gasifiers are fixed.[227] Assuming this to be true, the market for syngas in B.C. is limited to a short list of facilities, and would consume about 150,000 dry tonnes per year. Browne considered the smaller kilns (nine in total) to be too small for economically feasible conversion. In total, these mills could consume up to 225,000 dry tonnes per year of biomass, and displace a total of 3.65 petajoules per year. Thus, the full potential of lime kiln substitution is 6.05 petajoules and would consume 475,000 dry tonnes per year of biomass.

3.3.5 *Infrastructure Needs*

Developing syngas for use in lime kilns will result in substantive savings, particularly with larger kilns. The technology is well understood and the economic feasibility for the three largest plants (150,000 dry tonnes per year in total) is strong. Expanded use of this technology with smaller lime kilns is more problematic as the capital costs are high, even for small facilities, and thus the cost of syngas goes up on a per unit basis. The best use case will focus on the largest plants and allow other biomass to be used for other renewable gas applications as discussed in following sections.

3.4 Hydrogen Production from Solid Biomass

3.4.1. *Description of Pathway and Technology Update*

As described in the previous section, gasification (or pyrolysis) produces hydrogen and CO among other gas species. These gases can be recovered through adsorption or via membrane separation.[49] CO can be further combined with H_2O via a water-gas shift reaction to produce additional hydrogen, CO_2, and a small amount of heat. The water-gas shift reaction is used to clean up syngas and produce a clean mix of CO_2, CO, and hydrogen (syngas) which can then be separated to provide a pure hydrogen stream. Key technological challenges common to most platforms include the production of better membranes to separate the gases, process simplification and high biomass costs. Commercial projects are now being planned using plasma-enhanced thermal catalytic technology, as pioneered by SGH2. An overview of current technologies and their technology status is provided in Appendix A.

3.4.2. *Cost Curves*

Examples of cost estimates in the literature are shown in Table 12. Capital costs for hydrogen-producing gasification systems are highly variable as a number of new technologies are being explored. In this study, we chose recent figures published by Binder for a large-scale dual fluidized bed gasifier, with throughput of approximately 50 tonnes per day, which reflects recent cost estimates for an established technology. We expect that capital costs for a 140,000 dry tonnes year facility will be approximately $160 million.

Table 13 presents the default input parameters used to model gas costs. The capital costs are developed above. Operating cost parameters are based on Binder et al. (2018). Capital costs are assumed to decrease over time due to technology improvements, especially after 2030. The default cost of wood is $60 per dry tonne, representing low costs. In this model, feedstock is the dominant cost, as the technology is scaled to a very large size. Note that the large plant size would suggest that transport of feedstock may become a substantive cost, which would be reflected in higher feedstock costs on a per-tonne basis.

[49] DOE Hydrogen and Fuel Cell Technologies Office. "Hydrogen Production: Biomass Gasification". Accessed August 18th, 2021 from https://www.energy.gov/eere/fuelcells/hydrogen-production-biomass-gasification

Table 12 Previous Cost Estimates for Hydrogen Production from Biomass

Facility	Technology	Size	Energy yield	Gas cost	Capital cost	Source
Conceptual	Dual fluidized bed steam gasification	218 ktpy	61% (LHV)	US$1.88/kg	US$71 M	Müller (2011)
Conceptual	Generic gasifier	700 ktpy	70-80 kg/odt	US$4.8-6.1/kg	US$214 M	Ruth (2011)
Conceptual	Generic gasifier	294 ktpy	78%	Not determined	n.d.	Meramo-Hurtado (2020)
Conceptual	Dual fluidized bed gasifier	12.5 ktpy		US$3.13/kg	US$75.3 M	Binder et al. (2018)
Conceptual	Sorption enhanced reforming	0.25 ktpy		US$6.37/kg	US$6.4 M	Binder et al. (2018)
Conceptual	Taylor Energy gasifier	700 ktpy	38.4%	US$2.49/kg	US$112 M	Raju (2019)
Sweetman Renewables	Unknown	30 ktpy			US$14M	Peacock (2021)
SGH2 Hydrogen	Plasma-enhanced thermal catalytic	42 ktpy	60% (LHV)	US$2/kg	US$55M [50]	SGH2 (2021), recycled waste

Table 13 Default Cost Parameters, Hydrogen from Wood, in 2021$

Cost Parameter	Value	Share	Comments
Annual biomass input	140,000 odt		Commercial-scale plant
Feedstock cost	$60/odt		
Gas yield	67%		Based on feedstock input, HHV
Capital cost	$160 million		In 2021
Capital cost	$144 million		In 2030 (-10%)
Capital cost	$80 million		In 2050 (-50%)
Amortization	$17.8 million	45%	20 years, 9.2%
Feedstock cost	$8.4 million	21%	
Personnel cost			
Labour, 18 FTE	$1.4 million	4%	
Management, 3 FTE	$0.5 million	1%	
Electricity		10%	60 GWh/year
Natural gas		1%	45,000 GJ/year
Other variable costs	$1.6 million	4%	1% of CAPEX
Other costs	$5.6 million	14%	4% of CAPEX
TOTAL OPEX	$29.4 million	100%	
Gas cost	$23/GJ		In 2021

Figure 14 depicts modelled hydrogen costs in B.C. The recent ZEN/BCBN report estimates the cost of hydrogen from biomass to be $2.14 per kilogram, based on a $180 per tonne feedstock cost and incorporating carbon capture and storage costs, which are included to offset non-biogenic emissions.[93] Incorporating all costs, this is about $8-12 per gigajoule. Although the assumed feedstock cost is much

[50] Ellingson (2020). World's largest green hydrogen project coming to Lancaster. https://www.bizjournals.com/losangeles/news/2020/05/19/worlds-largest-green-hydrogen-project-lancaster.html

lower, the model used for the present report shows somewhat higher costs per gigajoule, though still lower than those for RNG (see next section). Initial costs are predicated on high capital costs associated with early-stage plants, with related utility and operating costs (about $22 per gigajoule in total). The cost estimates towards 2050 bring capital costs closer to the Zen figures, at about $18 per gigajoule. An average conversion efficiency 0.67 gigajoules per gigajoule (feedstock input to gas output) was used. Efficiency ranges for hydrogen in the literature cited in this section range from between 0.56 and 0.67 gigajoules per gigajoule so we have opted for the most efficient conversion technology we are aware of.

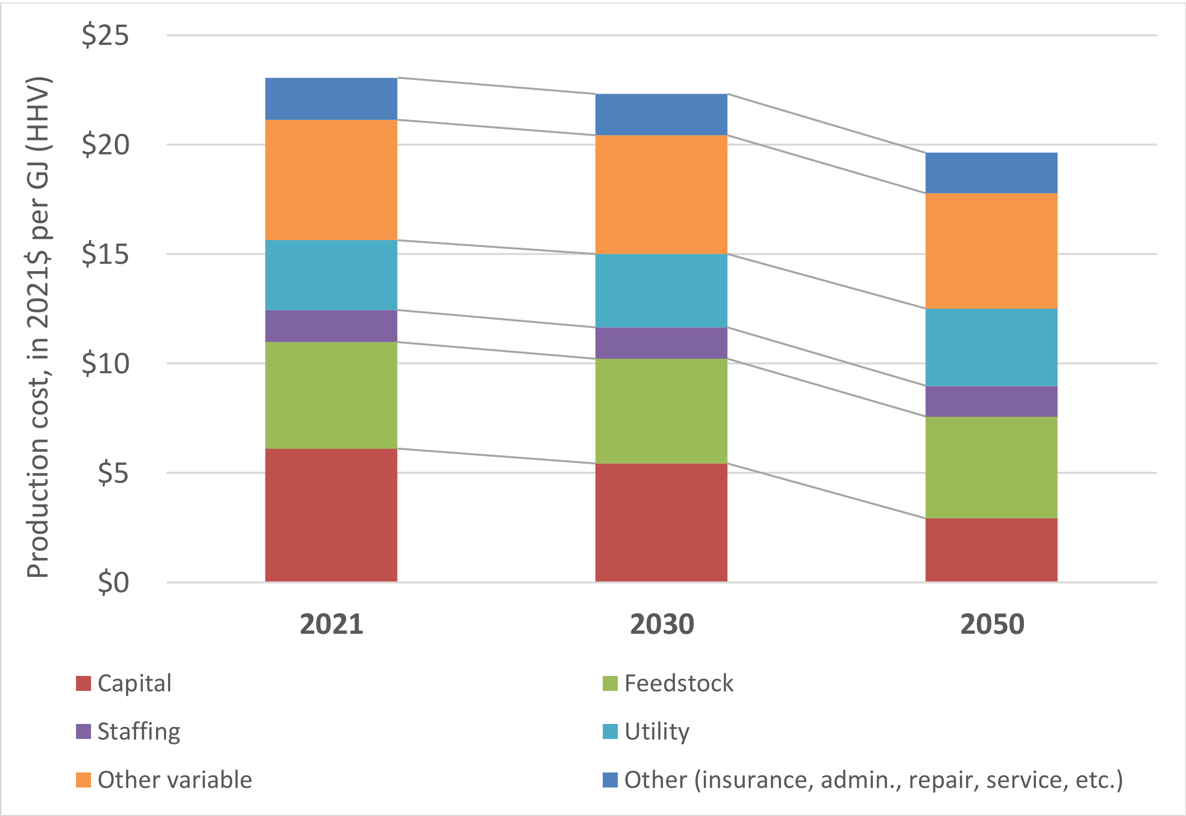


Figure 15 Modelled Hydrogen-from-Biomass Production Costs

3.4.3. *Carbon Intensity of Hydrogen from Wood*

Hydrogen from biomass has significant challenges. The very low hydrogen content in biomass itself (5-10%, tending to the lower end of this spectrum), means that most hydrogen produced is actually sourced from the water used in steam reformation. Conversely, the energy efficiency of steam reformation can be very high (56%).[51]

Biomass-sourced hydrogen has no direct GHG footprint. GHGs are still generated during the harvest and transport of biomass, and through the use of grid electricity and some natural gas in its production. Note that some technologies (e.g. SGH2) claim avoided (negative) GHG emissions of -188 grams CO_2e per megajoule H_2 (likely because of avoided landfilling).[52] The Hydrogen Council estimates the CI of hydrogen

[51] Milne et al. (2001) Hydrogen from biomass: State of the art and research challenges. IEA Hydrogen Task 16.
[52] SGH2 (2021). Technology. https://www.sgh2energy.com/technology/#hic

from wood as 1.7 kilograms per kilogram of hydrogen (12 grams per megajoule), which is the value assumed for this report.[53]

3.4.4. *Markets*

Sales of hydrogen into the gas network will depend on both updated policy targets and the cost of hydrogen produced from woody feedstock. As with other renewable gases from biomass, there is competition for wood feedstock, including cogeneration in mills, pellet production, and potentially renewable liquid fuels. By 2030, and possibly in subsequent years, several syngas projects are expected to be implemented and given priority over the more expensive and less mature hydrogen production technologies (see Section 3.2). Most hog fuel and roadside residues are likely to be used for syngas production by then, resulting in a theoretical total of up to 6 petajoules per year.

A large portion of the readily available woody biomass is currently used in power boilers of pulp mills. The power is partly used by the pulp mill and excess is fed into BC Hydro's grid under power purchase agreements that will expire before 2030. If this feedstock currently bound up in BC Hydro contracts for power exports to the grid (see Table 69 in Appendix A) becomes available and if there is a transition from pellet production to gas production in B.C., sufficient additional material will become available to also produce substantial amounts of hydrogen (see Chapter 5.0). A policy that reserves a certain amount of renewable gas for woody resources may create a captive market for hydrogen and/or RNG from wood (see Section 3.5).[227]

3.4.5. *Infrastructure Needs*

Developing hydrogen from biomass using gasification followed by a water-shift reaction will require significant development of new gasification infrastructure in B.C. Browne's report suggests that gasifiers capable of processing about 150,000 dry tonnes of biomass per year can be cost-effective, which in turn suggests that about eight facilities across the province would be sufficient to handle the 1.2 million tonnes of available biomass that we estimate from roadside residue. Facility locations would be determined via analysis of the gas grid and proximity to wood supply. Work also needs to be carried out on carbon capture and sequestration technologies to maximize the benefit of these processes.[93]

3.5 RNG from Woody Feedstock

3.5.1. *Description of pathway and technology overview*

The production of RNG from wood generally follows a stepped process that first gasifies the wood, cleans the syngas and then subjects it to a water-shift reaction (addition of steam) to add more hydrogen. Once the molar CO-H_2 ratio is about 1:3, a methanation reaction turns the syngas into a mixture with a high share of methane. Subsequent purification and compression provide pipeline-grade gas. Although these processes by themselves are all commercial, their combination is still pre-commercial. As opposed to syngas production to displace natura gas on-site, producing methane from woody feedstock requires some economies of scale. A much larger and more costly process will be needed to replace all natural gas used at a pulp and paper mill, and to insert additional gas into the pipeline system.

Appendix A identifies key technology providers for each of the main process steps (gasification, water-shift, methanation, and gas cleaning). The technologies from Sweden (GoBiGas/Valmet), the Netherlands (ECN) and the Austrian FICFB gasifier concepts are currently considered to be the best contenders for

[53] Hydrogen decarbonization pathways: A life-cycle assessment. Hydrogen Council, January 2021

gasification and gas cleaning. Methanation units can be provided by Haldor Topsoe, BASF or WOOD (Vesta). The University of Karlsruhe and ECN have also developed such technologies.

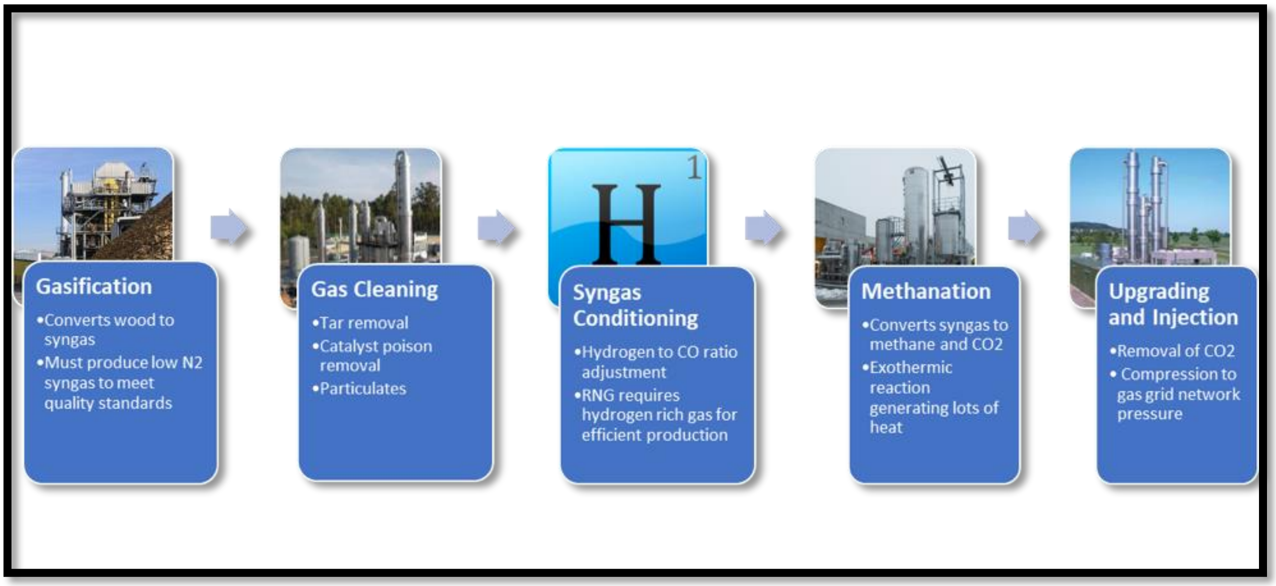


Figure 16 Generic Syngas to RNG Process

Biological methanation is an emerging technology that may soon replace the need for a chemical methanation step. Biological methanation occurs at low temperatures and pressures, similar to conventional anerobic digestion, rather than the high pressures and temperatures needed for conventional methanation.[54] Furthermore, biomethanation of syngas can yield significant savings as some contaminants, such as sulphur, do not need to be removed, meaning that the tar removal, water gas shift and guard beds can be avoided.[55] Tar removal, although likely to a lesser extent, is still necessary for biological syngas methanation. Challenges with biomethanation processes include the low solubility of syngas and the relatively low production rate.[56] The efficiency, at 50-65%,[57] is lower than catalytic methanation, which has a biomass-to-RNG efficiency of 65%-70%. Typically, syngas with high hydrogen content is best for biological methanation. Vancouver-based Highbury Energy is investigating biological methanation as a wood-to-RNG pathway. A small slipstream project testing biomethanation of syngas occurred at the gasifier in Güssing (Austria). The technology does not appear to be commercially proven with syngas but developments should be monitored.

[54] Grimalt Alemany, A., Skiadas, I. V., & Gavala, H. N. (2018). Syngas biomethanation: state-of-the-art review and perspectives. Biofuels, Bioproducts and Biorefining, 12(1), 139–158. https://doi.org/10.1002/bbb.1826

[55] Lorenzo Menin et al (2020). Techno-economic modeling of an integrated biomethane-biomethanol production process via biomass gasification, electrolysis, biomethanation, and catalytic methanol synthesis. *Biomass Conversion and Biorefinery*. DOI :10.1007/s13399-020-01178-y

[56] Sanjay Shah et al. (2017), "Methane from Syngas by Anaerobic digestion." Conference: Proceedings of the 58th Conference on Simulation and Modelling (SIMS 58) Reykjavik, Iceland, September 25th – 27th, 2017. Accessed September 23rd 2021.

[57] Seemann M, Biollaz S, Stucki S, Schaub M. (2005). Bio-SNG from Wood – New Insight from a 10 KW Scale Test. U.S. DOE Office of Scientific and Technical Information, 2 pp. https://www.osti.gov/etdeweb/servlets/purl/20671613

Another potential paradigm changer is the pre-commercial process from G4 Insights. This Vancouver-based company proposes a simplified tar-free methane production process called hydropyrolysis that has considerably lower capital costs than the conventional gasification concept and is thought to be able to reduce the costs of methane production from woody feedstock. The process works by heating the biomass in a hydrogen atmosphere into char and a pyrolysis gas, the latter of which is then catalytically reacted to form methane. The mixture of methane, H2, syngas, water and carbon dioxide are separated. The methane is injected into the grid or used on-site. Some of the mixture is fed back to a char-fired reformer & PSA to generate and purify the necessary hydrogen.

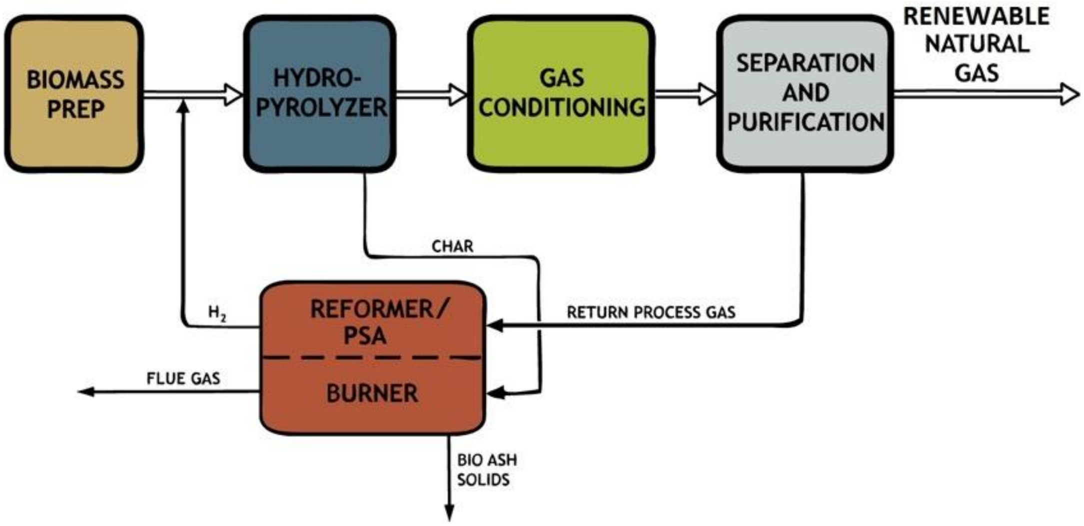


Figure 17 Pyrocatalytic Hydrogenation Wood to Methane Process

Emerging technologies around supercritical water may also open new avenues in wood methanation. Supercritical water uses the special solvent capacity of water with organic feedstocks when it is heated to a temperature greater than 374°C and pressurized above 22.1 megapascal.[58] Key advantages of supercritical water gasification include a higher carbon conversion capability and the ability to use wet feedstocks such as sewage sludge and other slurries without a significant energy penalty while Hydrothermal gasification or liquefaction can complement AD plants that have biosolids or digestate disposal issues as microplastics, some heavy metals, and pathogens are reduced or eliminated. Struvite, a desirable form of fertilizer can also be produced, aiding the nitrogen and phosphorous control benefits of the technology.[59] The efficiency is estimated to be 60-70%. Process heat recovery and conventional plant sizes are expected to be in the range of 2-3 tonnes dry mass per hour and to operate at temperatures of 600-700°C.[60]

As for the syngas produced, supercritical water gasification produces methane. The syngas can be fed into an anaerobic digester or be upgraded like conventional biogas.[61] Treatech's technology can generate

[58] ScienceDirect (n.d). "Supercritical Water Gasification". Accessed September 30, 2021 from https://www.sciencedirect.com/topics/engineering/supercritical-water-gasification
[59] Hyflex fuel (n.d) The HyFlexFuel process. Accessed September 30th 2021 from https://www.hyflexfuel.eu/technologies/
[60] GRTgaz March 2020). Hydrothermal Gasification (HTG)Converting liquid biomass into renewable gas https://www.igu.org/wp-content/uploads/2019/09/SG1.2-Hydrothermal-Gasification.pdf
[61] SINTEF Norway.(May 7th, 2021). "BioSynGas - Next generation Biogas production through the Synergetic Integration of Gasification"

around 150% more methane than anaerobic digestion. RNG can also be produced from a similar hydrothermal liquefaction process as a by-product, with 3.6 gigajoules being produced per tonne of dry feedstock. HTL plants are being developed in Vancouver and Prince George and could represent an additional RNG source as well as being a liquid fuel generator. The TRL of this technology is around 3-7 according to GRTgaz, the largest and most advanced appearing to be with SCW systems having a 2 tonnes per hour demonstrator in the Netherlands.[62]

3.5.2. *Production Cost Parameters*

For the production of RNG from wood, both capital and feedstock costs are key parameters. Table 14 summarizes the estimates made in a previous report for an RNG plant with a wood input of 200,000 dry tonnes per year, assuming a 67% energy yield based on wood input. The design includes a Carbona gasifier and a Halder Topsoe methanation unit. For operating costs (leaving out debt service), feedstock represents about a quarter, with other variable costs accounting for almost a third of OPEX. The payback determined with these costs is over 60 years. According to the study, an RNG gas price of $50 per gigajoule would be required to bring this to ten years unless subsidies can be obtained. Capital costs have a great impact on the economic performance of the plant: a 30% cost increase means the ROI at a gas price of $50 per gigajoule would drop from 19% to 15%.

Table 14 Cost Structure of Biomass-to-RNG Conversion,* as per Browne (2019)[227]

CAPEX	Million C$ (2018)	OPEX	Million C$ (2018)
Gasification	117	**Wood ($61.2/odt)**	12
Methanation	85	**Other variables**	15
Construction	184	**Labor & maintenance**	8.7
EPC fee	15	**Fixed**	10
Engineering	8		
Permits & consulting	4		
Commissioning & start-up	17		
General & administrative	4.7		
TOTAL	**410**	**TOTAL**	**46**

* 200,000 odt per year feedstock intake

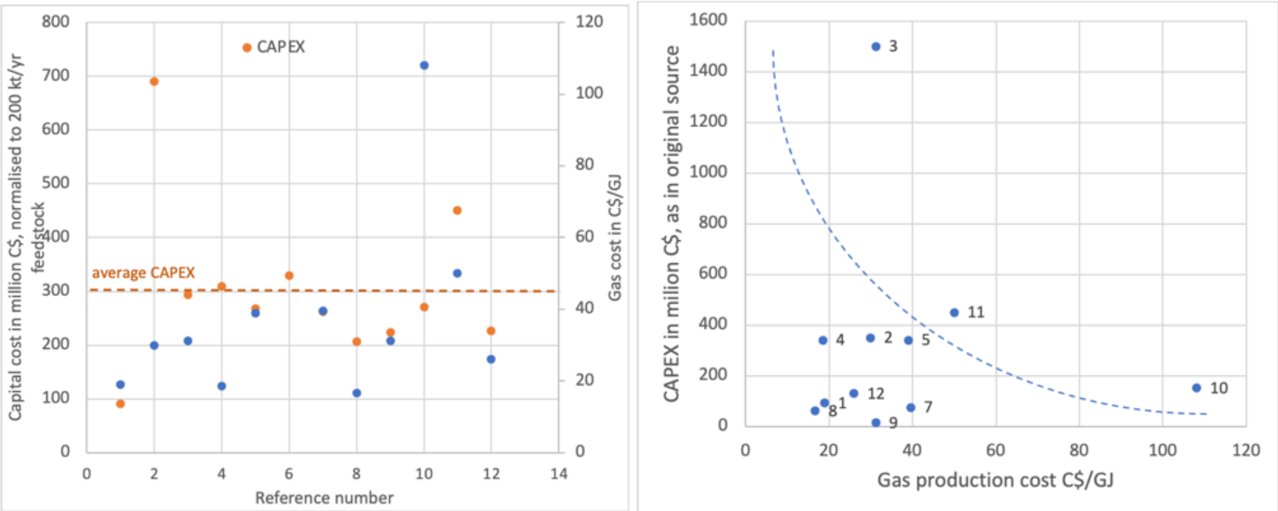
Since the methanation step is exothermic, this energy can be used as process energy. In theory, it could be used to dry pulp or lumber (depending on the site). RNG production will also increase power consumption at the mill considerably. To simplify the challenge, the approach followed here assumes that excess heat is used to produce additional power to reduce power imports from the grid.[65]

3.5.3. *Capital and Production Costs*

Figure 18 shows cost estimates for RNG production from wood. The sources for the figure are identified in Appendix B, by number (Table 60). The left graph normalises the literature values to 200,000 dry tonnes of wood input, making some assumptions about wood energy values and economies of scale for each plant (scale factor 0.8). The graph shows a wide spread of results, with capital costs varying by a factor of seven and gas costs varying from $20 to more than $100 per gigajoule. Gas cost estimates for the GoBiGas, ECN and two conceptual estimates concur with the estimate in Appendix B: at between C$30-40 per gigajoule. The REN Energy facility planned for Fruitvale, B.C. seems to be an outlier as it would only cost $130 million.63 It would use over 100,000 tonnes of wood waste, and produce about one petajoule of RNG.

[62] https://www.igu.org/wp-content/uploads/2019/09/SG1.2-Hydrothermal-Gasification.pdf (October 12th, 2021).
[63] https://www.canadianbiomassmagazine.ca/a-first-for-north-america-fortisbc-ren-energy-to-produce-rng-from-wood-waste/ (Accessed September 16, 2021).

Presumably, it would produce RNG at under $31 per gigajoule to qualify for a purchasing agreement with Fortis. The large spread of cost estimates indicates that the uncertainty regarding production costs of RNG from wood remains very high. The right graph plots the original CAPEX numbers of each source against the resulting gas costs. However, no logical cost curve showing economies of scale can be derived from this data.



Note: See Table 60 in Appendix B for sources of each data point. Data normalised to 200,000 odt per year

Figure 18 Normalized Cost Estimates for CAPEX and Gas Cost (RNG from Wood)

Capital cost estimates seem to converge around 200 to 400 million dollars for a plant with 200,000 dry tonnes of annual input. The cost estimate from the previous section therefore seems very conservative. For this report, $300 million in capital costs has been assumed. This is in line with the numbers developed for syngas and for hydrogen production in the previous sections. For 2030, no material change in capital or production costs is expected. After 2030, assuming that emerging technologies such as G4 Insights may become commercialized, a capital cost decrease of about 50% can be postulated. Because little is known about the G4 Insights process, the other operating parameters were not changed for this estimate. This may lead to a high cost estimate as the one-step process can be expected to have lower utility and personnel costs.

Based on the above, Table 15 presents the default input parameters used to model gas costs. The capital cost was developed above. Operating cost parameters are based on Browne (2019).[227] Capital costs are assumed to decrease over time due to technology improvements, especially after 2030. The default cost of wood is $60 per dry tonne but higher costs have also been modelled. High amortization costs clearly dominate operating costs, even with the somewhat generous assumption of a 20-year payback. Feedstock is the second most important cost but is considerably less important than amortization.

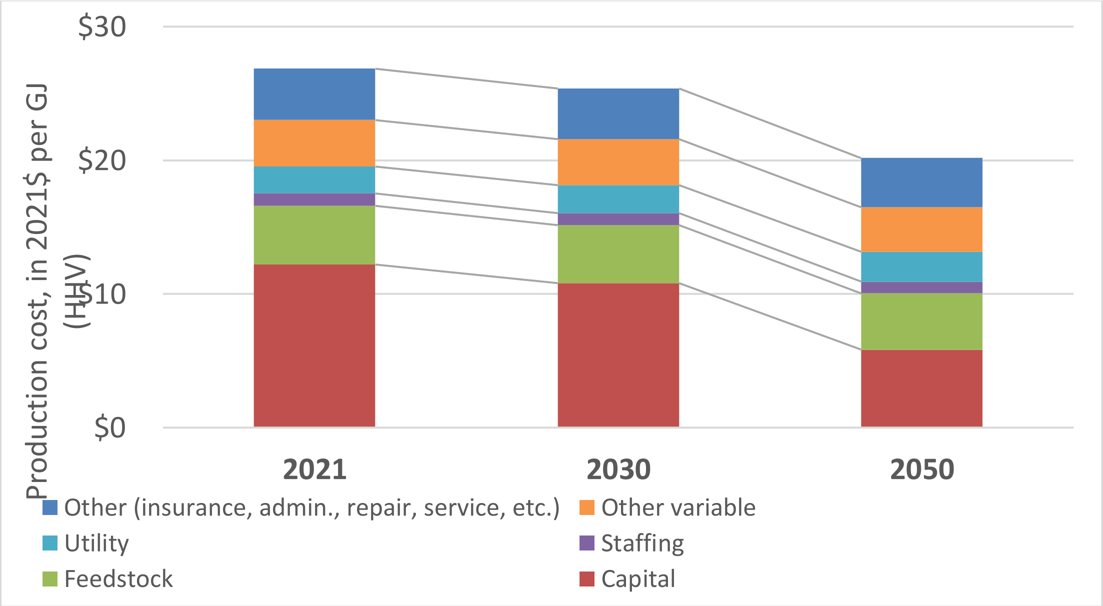
Figure 19 is the model output for RNG production costs from wood today and over the coming three decades. Capital costs are the main cost factor initially. Capital subsidies or better borrowing terms can positively influence gas production costs. The 20-year amortization period assumed is not acceptable to the forest products industry, which is known to seek amortization periods of only a few years for any investment.[64] This implies that subsidies or third-party financing (e.g., through a gas utility) would be required to implement such projects. Although feedstock is an important factor, it is only responsible for about 10% of production costs. Somewhat higher feedstock costs will therefore not have a strong impact on RNG cost.

[64] Bob Lindstrom, BC Pulp and Paper Alliance, in a conversation on Sep 27, 2021

Larger mills would likely implement syngas production during the first decade, removing around 150,000 dry tonnes from the available resource. With increased recovery of harvesting residue, about 1.2 million tonnes of this material would be available for new RNG production. This is sufficient for six facilities with an annual input of 200,000 dry tonnes, each producing 2.55 petajoules of gas per year (12.76 gigajoule per dry tonne.)[227]

Table 15 Default Cost Parameters, RNG from Wood, in 2021$

Cost parameters	Value	Share	Comments
Annual biomass input	200,000 odt		Commercial-scale plant
Feedstock cost	$60/odt		Minimum scenario and first block of Maximum scenario
Gas yield	67%		Based on feedstock input, LHV
Capital cost	$300 million		In 2021
Capital cost	$270 million		In 2030 (-10%)
Capital cost	$150 million		In 2050 (-50%)
Amortization	$33,333,633	45%	20 years, 9.2%
Feedstock cost	$12,000,000	16%	
Personnel cost		4%	
Labour, 26 FTE	$2,080,000		
Management, 3 FTE	$450,000		
Electricity	$5,124,600	7%	78,840 MWh per year
Natural gas	$376,631	1%	47,328 GJ per year
Other variable costs	$9,498,769	13%	
Other costs	$10,500,000	14%	4% of CAPEX
TOTAL OPEX	$73,363,633	100%	
Gas cost	$27/GJ		In 2021



* Feedstock cost at $60/odt

Figure 19 Anticipated Production Cost Development for RNG from Wood

3.5.4. *Carbon Intensity of RNG*

Counting wood feedstock as carbon neutral because it does not contain any fossil carbon, the feedstock procurement and process emissions still lead to emissions that need to be accounted for to arrive at a carbon intensity for RNG made from wood. For the Stockton site in the U.K., a GHG intensity of 16.8 grams per megajoule was determined.[65] This calculation took into account grid electricity emissions but also provided emission credits for the excess electricity produced in this case. These would likely cancel each other out in B.C. Another result assessed a process using the WoodRoll technology and arrived at 12 to 15 grams per megajoule for facilities of 4.8 and 18 MW capacity, respectively.[66] This includes credits for district heating that would rarely be available to a plant in B.C. Leaving out this credit but removing emissions from electricity use would lead to a very similar outcome as in the previous study. G4 Insights determined the GHG intensity of methane made from wood in California to replace motor vehicle fuels and arrived at 14 grams per megajoule.[67] The latter would imply that the GHG emission intensity will not be impacted in a major way by the technology used, since G4 Insights may be an emerging technology replacing the more conventional gasification approach. Any reductions are likely to be incremental, due to overall lower GHG emissions from transport and other sectors.

3.5.5. *Markets*

Total demand for renewable gases for injection into the provincial pipeline network is at least 15% (on a gigajoule basis) by 2030, based on the current renewable gas target set out in the CleanBC Plan. Additional potential could exist for local projects, where the gas produced would be used directly, or for exporting RNG through certificate trading, e.g., with the Californian LCFS market.

For renewable methane, the market after 2030 is theoretically equal to the total natural gas use in B.C. but actual sales into the gas network will depend on both updated policy targets and the cost of RNG produced from woody feedstock.

There is also competition for the woody feedstock itself. Alternative markets for woody feedstock exist in the power generation sector, including cogeneration at mills, which may become more attractive after 2032, when BC Hydro expects electricity production to start facing shortfalls. Competition may also come from pulp mills (for roadside residue), wood pellet mills and new concepts around producing renewable liquid fuels for direct use in vehicles or for sale to B.C. refineries. The markets that will ultimately develop and the ability of producers to pay for the woody feedstock will determine how additional feedstock will be allocated.

3.5.6. *Infrastructure Needs*

The existing 15 pulp and paper mills, where some of the feedstock will be available as hog fuel, are prime sites for the installation of RNG production facilities. They are generally close to the natural gas grid (see Figure 45 in Appendix C) and offer colocation benefits in terms of lower personnel requirements and shared infrastructure with existing mills. The estimated cost per facility is $300 million. With 26 new facilities for the Maximum scenario (Section 5.4), the total investment would come to $7.8 billion. These costs do not include additional pipeline or transport costs to take the RNG produced to an injection point. If any of the plants were to be situated at a distance from the pipeline network, additional costs would ensue.

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[65] Low-Carbon Renewable Natural Gas (RNG) from Wood Wastes. GTI, February 2019.

[66] Held, Jörgen and Olofsson, Johanna: LignoSys - System study of small-scale thermochemical conversion of lignocellulosic feedstock to biomethane. Renewable Energy Technology International AB, 2018.

[67] http://www.g4insights.com/environmentalbenefits.html (Accessed September 17, 2021).

3.6 Lignin as a Replacement Fuel for Natural Gas in the Pulp Industry

3.6.1. *Description of pathway and technology overview*

The GGRR has been amended to enable the gas utilities to work with pulp mills to displace natural gas used at their sites. Lignin is a by-product of the chemical pulping process and when extracted, can be used as a fuel in lime kilns at kraft mills. Wood fibre consists of cellulose, hemicellulose, and lignin. Cellulose is the main component used for pulp. Lignin has been traditionally burned, partly as a fuel, partly to get rid of an unwanted by-product, and to recover the pulping chemicals. Instead of burning lignin as black liquor in recovery boilers it can also be extracted from the spent chemicals.

Because lignin has a high calorific value it can be used to replace natural gas used in a pulp mill's lime kiln. Even though many kraft pulp mills produce surplus steam, lime kilns are typically fuelled by natural gas. This final stage of recovering the original chemical (NaOH) is done in direct-fired rotary kilns that cannot be heated by steam. Dried and ground to a fine powder, lignin can be injected into the kiln just like natural gas, even though the sulfur content of untreated lignin is generally high, derating the kiln capacity and causing corrosion and unwanted effluents.

Lignin can be further processed and sold to offsite markets as a high-grade solid fuel or as a feedstock for bioplastics, resin, etc. Onsite and offsite use as a natural gas replacement is discussed below. Both pathways compete with using lignin as a feedstock for various chemical processes that generally fetch higher market prices than when used or sold as a fuel.

Lignin extraction also has impacts on a pulp mill's energy balance and output capacity. These implications can be understood by looking at the various processes involved. In the chemical pulping process, cellulose is extracted by 'cooking' the wood fibre in caustic chemicals called 'white liquor.' The white liquor turns black as lignin is dissolved in it. By evaporating the water and burning the resulting 'black liquor,' the original chemicals are recovered and, after calcining in the lime kiln, can be reused. Many of these processes require steam or natural gas (Figure 20).

Most chemical pulp mills use lignin as a fuel to heat and power various processes.[68] Extracting lignin creates a fuel shortage that needs to be made up for by additional biomass. The energy balance of the specific pulp mill determines how much lignin can be extracted before lower-cost wood fuel needs to be brought in to fuel a power and steam boiler. A mill would have to have a proper heat / mass balance done to determine the impact and benefits of lignin extraction.[69] Looking only at one of the two pathways would neglect the overall systemic impact of lignin extraction (Figure 21).

Pathway 1 - Lignin replacing natural gas in a lime kiln:
To create the chemical reaction with lime and for maintenance reasons, lime kilns need to be operated at high temperatures and are typically heated by natural gas burners. Wood cannot not be used as a fuel, unless it is completely dried and finely ground or gasified. Dry lignin, however, can be burned in injection burners with the flame injected directly into the kiln. Stora Enso in Finland fires kraft lignin as a fuel in its lime kiln to reduce natural gas use by 70%.[70]

Pathway 2 - Lignin replacing natural gas in other undetermined energy producing processes:

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[68] Wells, K. *et al.* 2015. CO_2 Impacts of Commercial Scale Lignin Extraction at Hinton Pulp using the LignoForce Process & Lignin Substitution into Petroleum-based Products.

[69] Lindstrom, Bob; Personal communication. B.C. Pulp and Paper Coalition, in an email on Sep 16, 2021

[70] Pulp & Paper Canada. 2013. Stora Enso upgrading Sunila mill to produce lignin.

Because lignin has a high calorific value (26 gigajoules per tonne, HHV), it is a denser and more valuable fuel than conventional woody biomass (17 to 19 gigajoules per tonne, HHV). Like the onsite lime kiln, it can be burned with some technical modifications in the secondary wood processing industry, e.g., in direct-fired lumber drying kilns, veneer dryers or as a supplemental fuel in wood-burning processes of the paper industry.

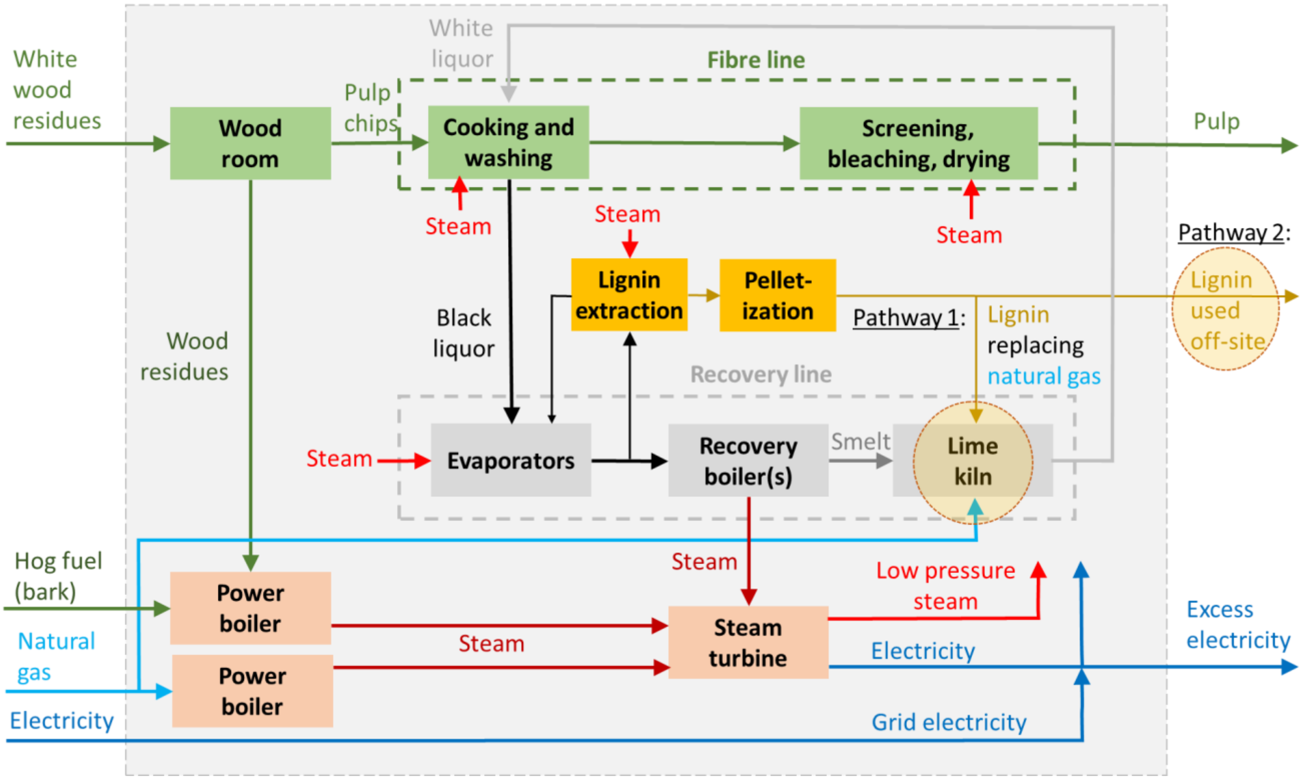

Figure 20 Processes and Energy Flows in a Pulp Mill[71]

The capacity of a kraft pulp mill is typically limited by the size of its recovery boiler, the most expensive part of a kraft mill.[72] Extracting lignin requires that <u>less</u> black liquor be burned in the recovery boiler, thereby allowing increased pulp output. This lignin, then, is no longer available as a fuel to heat other processes. Typically, no more than 15% of lignin can be extracted before additional heat sources are needed, such as low-value bark burned in a power boiler.[68] At a market value of $800 per tonne,[80] equivalent to $31 per gigajoule (HHV), it would be more profitable to sell lignin as a chemical feedstock and purchase additional natural gas at $8 per gigajoule than to burn lignin on site. Instead of burning high-value lignin, low-value biomass may be gasified to heat lime kilns.

[71] Graph based on: Hamaguchi M *et al.* 2012. Alternative Technologies for Biofuels Production in Kraft Pulp Mills—Potential and Prospects. *Energies* 53390:2288-2309 DOI. 10.3390/en5072288.
[72] Bruce Process Consulting for Alberta Environment. 2008. Technical and Regulatory Review and Benchmarking of Air Emissions from Alberta Kraft Pulp Mills.

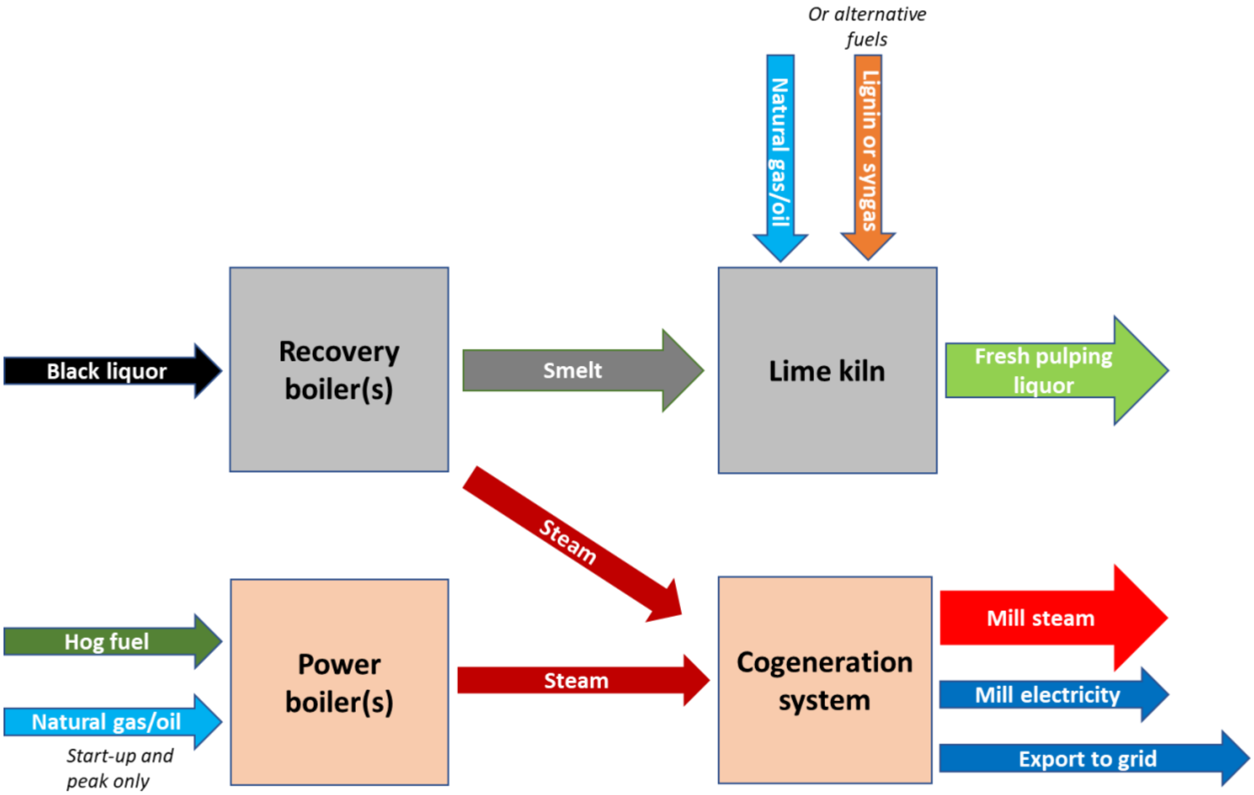

Figure 21 Energy Systems in Kraft Pulp Mills

Typically, around 1.5 tonnes of black liquor solids, consisting of lignin, hemicellulose and pulping chemicals, are created per tonne of pulp (cellulose) produced. Of the black liquor, around 15% to 25% of lignin (roughly 0.18 tonnes of lignin per tonne of pulp, at 10% moisture content)[73] can be extracted without compromising the operation of the recovery boiler. An average-sized kraft pulp mill in B.C. with a daily capacity of 1,100 tonnes of pulp can thus produce around 45,000 tonnes of lignin a year.[74]

The basic process of extracting lignin from black liquor is acidifying the caustic liquor and thereby precipitating the lignin contained in it. Washing, filtration and pelletization are downstream process steps. FPInnovations, combined with NORAM Engineering, refined the process by first oxidizing the liquor to prevent the release of hydrogen sulfate (H_2S), a toxic and foul-smelling gas. Secondly, the oxidation process reduces alkali content and thereby the need for carbon dioxide and sulfuric acid. Heat exchangers recover the heat created from the oxidation of the black liquor.

A competing technology is the LignoBoost system developed in Sweden.[75] A key difference between the LignoBoost and the LignoForce systems is that the latter oxidizes some of the reduced sulphur compounds. Oxidized black liquor has lower ash content and increased particle size of the precipitated lignin, making it easier to be filtered out. The LignoBoost system claims to have lower capital and operational costs. The LignoBoost system is marketed by Valmet and is commercially deployed at the

[73] Wells, K. et al. 2015. CO2 Impacts of Commercial Scale Lignin Extraction at Hinton Pulp using the LignoForce Process & Lignin Substitution into Petroleum-based Products.
[74] Hamaguchi, M. *et al.* 2012. Alternative Technologies for Biofuels Production in Kraft Pulp Mills. *Energies.* 53390:2288-2309. DOI. 10.3390/en5072288.
[75] Tomani, P. 2006. The LignoBoost Process. *Cellulose Chem. Technol.* 44 (1-3), 53-58 (2010).

Domtar Pulp plant in Plymouth, N.C. and Stora Enso's Sunila mill in Finland, producing 25,000 and 50,000 tonnes of lignin a year, respectively.[76]

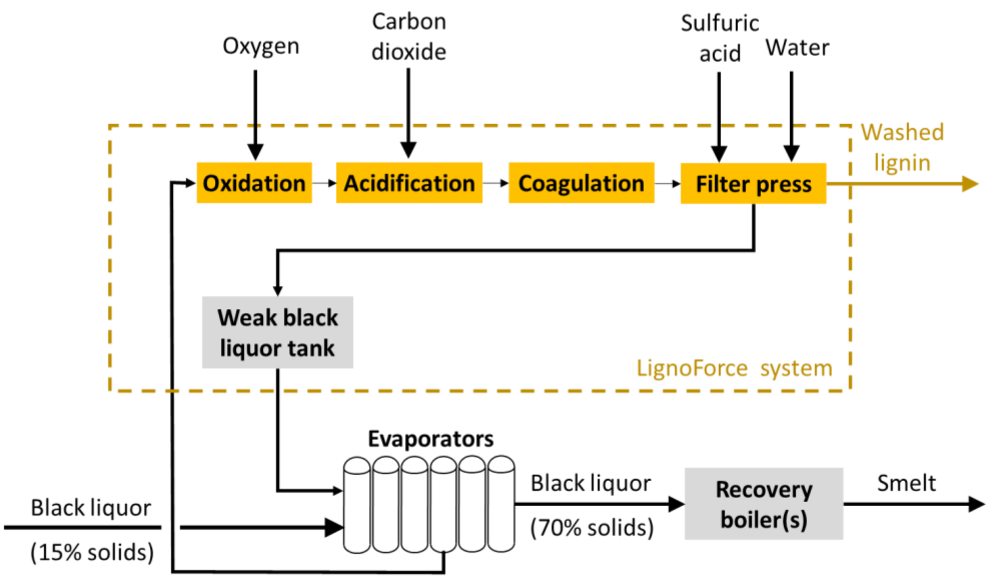

Figure 22 Schematic of the *LignoForce* Technology

One promising pre-commercial approach to producing lignin in a stand-alone plant comes from Pure Lignin Environmental Technology based in Kelowna, B.C. The process produces three separate products: cellulose, lignin and sweet liquor that can be used in the production of cellulosic ethanol. This nitric acid process increases yields compared to the traditional kraft process. A key advantage of the technology is its ability to use any type of biomass, including grasses, husks and waste wood, as feedstock. There is no commercial-scale plant in operation yet. A 50-tonne-per-day plant is said to yield a return on investment of 35%.[77] The company still appears to be at the demonstration stage with a one-vessel portable unit.[78]

3.6.2. *B.C. Potential for Excess Lignin Use*

Currently, no lignin extraction exists at any pulp mill in B.C. West Fraser operates four pulp mills in B.C. and Alberta. The company employed the LignoForce technology at its kraft mill in Hinton, AB. The technology could be replicated at other kraft mills in B.C. Each pulp mill would have the potential to produce more than twice the amount of lignin required to fuel their respective lime kilns. Theoretically, B.C. kraft mills could replace approximately 5.1 petajoules of natural gas and export the remaining 264,000 tonnes of surplus lignin off-site (Table 16).

[76] Valmet. 2017. The next generation LignoBoost – tailor-made lignin production for different lignin bioproduct markets.
[77] Pure Lignin Environmental Technology. 2020. Pure Lignin Environmental Technology (PLET) https://www.purelignin.com/ (Accessed June 11, 2020).
[78] Pure Lignin Environmental Technology. 2020. PLETS Demo Plant, https://purelignin.com/plet%E2%80%99s-plant's (Accessed Nov 27, 2021).

Table 16 Potential for Using Lignin as a Replacement for Natural Gas in Lime Kilns

Location of mill / name	Ownership	Annual capacity	Estimated potential for lignin extraction		Lime kiln natural gas use	Surplus lignin
		tonnes of pulp/year[79]	*tonnes/year*	*containing GJ/year*	GJ/year	*tonnes/year*
Prince George Intercontinental	Canfor Ltd.	329,000	41,100	945,000	461,000	18,000
Prince George Northwood	Canfor Ltd.	568,000	71,000	1,633,000	795,000	32,000
Prince George	Canfor Ltd.	316,000	39,500	909,000	442,000	18,000
Quesnel	West Fraser	349,000	43,600	1,003,000	489,000	19,000
Crofton	Paper Excellence	347,000	43,400	998,000	486,000	19,000
Kamloops	Domtar	343,000	42,900	987,000	480,000	19,000
Port Mellon	Howe Sound Pulp & Paper Corp.	372,000	46,500	1,070,000	521,000	21,000
Cedar	Nanaimo Forest Products	356,000	44,500	1,024,000	498,000	20,000
Mackenzie (closed)	Paper Excellence	0	0	0	0	0
Skookumchuk	Skookumchuk Pulp Inc	255,000	31,900	734,000	357,000	14,000
Castlegar	Zellstoff Celgar LP	461,000	57,600	1,325,000	645,000	26,000
TOTAL		**3,696,000**	**462,000**	**10,628,000**	**5,174,000**	**206,000**

Pulp mills do not produce more steam than they need for internal purposes. Removing lignin from this balance requires that an equivalent amount of energy is replaced, e.g., in the form of biomass. Instead of burning lignin in the recovery boiler, additional 'hog fuel' needs to go into the power boiler. That hog fuel needs to be imported, preferably from the region or area that the mill is located in. Additional fibre, however, may not be available. The forecast of fibre availability changes depending on the fibre model used or the region or area or zone the mill is located in. Some forecast a deficit for 2029 in certain areas and a surplus in other areas. Trucking woody residue from one area to another is an option and has been done in the past, albeit at a cost. Transportation and handling costs may exceed the value of the fibre, especially if the distance exceeds 200 kilometers one-way. The model underlying the cost projections below assumes that no import or export of fibre is done within assigned regions, areas or zones.

The theoretical potential shown in Table 16 is then constrained by the availability of fibre in the area or region that the mill is located in. Instead of 6 petajoules, the technical or resource potential is only 1.4 to 2.2 petajoules, i.e., a fraction (22% to 47%) of the theoretical potential. Figure 23 below shows the technical potential depending on the fibre model used.

[79] B.C. Ministry of Forest, Lands and Natural Resource Operations (2020). *2019 Major Timber Processing Facilities in British Columbia.* Victoria, B.C.

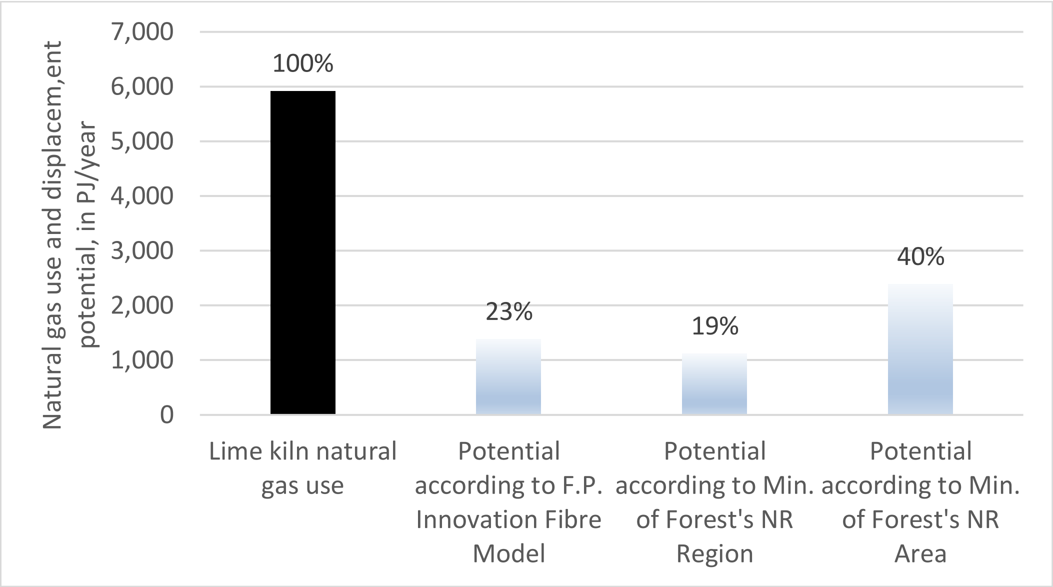

Figure 23 Technical or Resource Potential for Displacing Natural Gas in B.C. Kraft Mills

3.6.3. *Cost Curves*

The cost model shows that assuming the same feedstock costs, heating a pulp mill's limekiln with lignin is more expensive than heating it with syngas ($19 instead of $14 per gigajoule in 2030). This would apply even more when using lignin as a fuel off-site when transport costs are added in. Wherever lignin can be used as a fuel, syngas or even wood pellets likely achieve lower production costs. Moreover, lignin is likely to fetch higher prices when sold as a feedstock for non-energy markets. Current (2021) market prices for sulfate lignin are around $800 per dry tonne (Adt)[80], equivalent to $35 per gigajoule (LHV). Lignin, even in its unrefined form, is too valuable a product to use as a fuel (Figure 24).

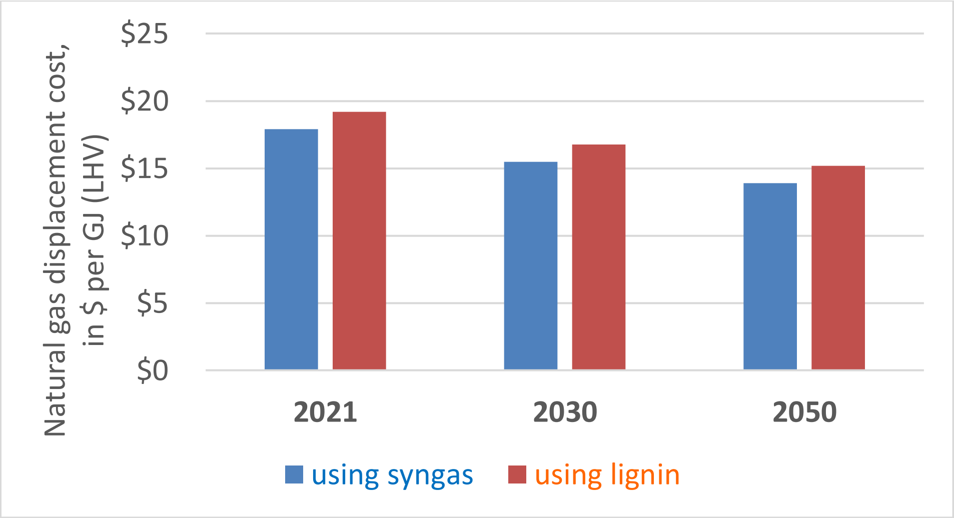

Figure 24 Cost of Replacing Natural Gas in Lime Kilns with Syngas and Lignin

80 https://www.forest2market.com/blog/more-rd-activities-open-up-lignins-feedstock-potential (Accessed September 1st, 2021).

3.6.4. *Carbon Intensity of Lignin Fuel*

Extracting lignin from a pulp mill's energy balance requires replacing it with biomass with an equivalent calorific value. Because lignin has a higher energy density (23 gigajoules per ADt, 26 gigajoules per dry tonne) compared to waste wood or hog fuel (10 gigajoules per green tonne, 18.3 gigajoules per dry tonne), a larger volume of wood fuel needs to be imported than the lignin extracted. Additionally, grid electricity has a small carbon footprint. Using the B.C. grid emission factor, less than 3 kilograms per gigajoule of calorific value would be emitted, 5% of the burner tip emissions of natural gas. Total carbon abatement would range between 54,000 and 118,000 tonnes of CO_2e per year, depending on the fibre availability model used.

Figure 25 Impacts of Lignin Diversion on Kraft Mill Energy Demands and GHG Emissions

Fuel	Amount		GHG emission factor[81]		Annual GHG emissions	
Feedstock (*wood to offset steam losses*)	45,000	odt/year	40.32	kg CO_2e/odt	1,814	t of CO_2e
Electricity	2,500	MWh/yr.	10.80	kg CO_2e/MWh	27	t of CO_2e
Avoided carbon emissions	n/a					
TOTAL			**2.67**	**kg CO_2e/GJ (HHV)**	**1,841**	**t of CO_2e**

3.6.5. *Markets*

Markets for lignin can be separated into energy use and non-energy use. The former is marginal in Canada. Beyond fuel, lignin has a wide variety of uses and applications, including opportunities to displace traditional fossil-based chemicals and products. There has been significant investment in lignin over the past 20 years. Historically, the lignin market for commercial application has been around 60,000 tonnes per year. Major markets for lignin include:[82]

- Adhesives
- Plastic/packaging materials
- Insulation
- Carbon fibre

Different lignin applications have various levels of commercialization. Thermoplastic and packaging applications are the most mature. Resins are an emerging application explored by West Fraser. Currently, lignin can replace up to a quarter of the polyurethane in foams. For carbon fibre applications, lignin-based materials can substitute for 50% to 100% of the fossil-fuel-based material used for carbon fibre[82] and is being investigated as an alternative way to reduce battery weight for lithium ion batteries.[83] Opportunities also exist to use lignin to replace the carbon black used for tires and other reinforced rubber products.[68]

[81] Factors published by B.C. Ministry of Environment: "B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions", 2020, Accessed on Sep 26, 2021.
[82] Xiaofei Tian et al. (2016) "Properties, Chemical Characteristics and Application of Lignin and Its Derivatives" in Zeng and Smith eds. *Production of Biofuels and Chemicals from Lignin Biofuels and Biorefineries*. Singapore: Springer Science and Business Media.
[83] KTH Institute of Technology. 2014. Battery design could reduce electric car weight. https://phys.org/news/2014-06-battery-electric-car-weight.html (Accessed May 18, 2020).

3.6.6. *Infrastructure Needs*

Lignin has the potential to be used as a high-grade fuel where flame temperatures matter. Replacing natural gas in lime kilns is a potential niche application. Converting the existing gas burner with a solid fuel suspension burner is technically more challenging than burning syngas in the same kiln. The burner would have to be exchanged and the flame might have a different shape, resulting in spatially different temperature gradients inside the kiln. This might affect the chemical reaction time, the wear of the refractory, maintenance, and downstream flue gas volumes. The flue gas treatment system, especially the particulate precipitators, would likely have to be changed. This is notably more expensive than using a medium calorific gas, such as syngas from a wood gasifier that would keep the existing equipment in place.

Currently, suspension burners are used where finely ground wood fibre is available, e.g., sander dust at particle board plants. The fine particles instantly ignite as they are injected into the hot combustion chamber, dryer or kiln. Start-up of suspension burners generally requires fossil fuel to heat up the refractory beyond the flash point of the solid fuel used, generally above 300°C. Suspension burners are best used in applications that operate 24/7 without interruption. This tends to be the case in large-scale applications, such as in the pulp and paper industry, the cement industry or petrochemical industry. These operate continuously throughout the year. The sheer amount of lignin that would be needed to fuel these industries and the associated need for fuel storage, however, makes heavy industry an unlikely candidate for using lignin as a fuel.

For transport, lignin is usually compressed into pellets, see Figure 26 below. The material can then be transported in the same vessels as pellets of grain. 'Black pellets' made with, or entirely of, lignin have been used as a fuel in other parts of the world, for example in Russia where lignin is abundant as a by-product of wood alcohol production.[84]

In the Canadian context, the authors of this report consider lignin to be too valuable a product to use as a fuel. An exception may be adding lignin to enhance the calorific value and improve the physical properties of wood or herbaceous pellets used as a fuel. Wood is a sturdy material because lignin is the natural binder. In wood pellets, lignin is the material that creates dense, durable pellets. To get the same quality from pellets produced using plants with lower lignin content, such as straw, a binder must be added during the process. Lignin is a natural resin that can also be used to improve the quality of biomass pellets. Pellets without binding agent may decompose during conveying and storage, forming hazardous gases such as carbon monoxide and hexanal. Adding lignin to pellets may reduce safety concerns and occupational health problems such as wood dust exposure, fire and explosion risks. However, the increase in fuel value has to be balanced with the cost of adding lignin.

[84] Bioenergy International, "Lignin Pellets – from residual product to valuable biofuel," May 2020, Accessed on September 26, 2021 at https://bioenergyinternational.com/pellets-solid-fuels/lignin-pellets-from-residual-product-to-valuable-biofuel

Figure 26 Lignin Pellets[85]

3.7 Recommendations on the Use of Woody Feedstock

While B.C. is a largely forested province, the amount of accessible and attainable woody feedstock has declined in the past year, partly as a consequence of drawing down mountain pine beetle-killed stands and partly due to disturbances, including wildfires. The Ministry of Forests has reduced the Annual Allowable Cut to approximately half the amount available before the infestation. With the projected mill closures, the amount of mill and forestry waste will be reduced further.

In the near term, the best strategy to displace fossil methane in the forest resources industry is to use syngas for use in lime kilns. This can only displace a portion of natural gas use by the industry but still has considerable potential. It will require less feedstock (around 50,000 dry tonnes per year for the largest kilns) and considerably less investment. The gas is also likely to be produced at a lower cost than pipeline-grade methane or hydrogen. These still require technology development to become commercial.

In the longer term, hydrogen or RNG production from solid biomass is an option that can potentially displace large amounts of fossil gas. Just six full-scale RNG plants may displace more than five petajoules of demand, and recovery and use of all available biomass (an unlikely scenario) could deliver as much as 145 petajoules in the form of hydrogen or methane. Although the required technologies to achieve this exist, they are not proven technologies so demonstration and further refinement are required. Based on previous work on the GoBiGas plant and other such ventures, the most suitable technologies need to be combined and operated at a smaller scale. Once this is achieved and the process has been shown to operate successfully on a continuous basis, a full-scale plant could be built. Given the high capital cost of these plants, utility and/or government partnerships are likely necessary to realize this potential. As the technology matures and, possibly, more advanced technologies with lower capital costs become available after 2030, gas costs from these pathways are expected to decrease.

[85] https://newsroom.domtar.com/lignin-pellets-plastic-bioalternative/

4.0 HYDROGEN FROM NON-BIOMASS RESOURCES

4.1 Description of Pathways: Blue, Green, Turquoise and Waste Hydrogen

4.1.1 The Hydrogen Opportunity

Approximately 70 million tonnes per annum of hydrogen are currently manufactured globally. The vast majority is used for industrial purposes, namely the manufacture of ammonia and the upgrading of liquid fuels in refineries. It is estimated that 95% of global hydrogen produced comes from steam methane reformation (SMR) of natural gas, resulting in a relatively high carbon intensity for the hydrogen generated. Multiple pathways exist to produce low carbon intensity hydrogen. An introduction to nomenclature that has been adopted follows.

4.1.2 Green Hydrogen

The most common description of green hydrogen is its production by the electrolysis of water, using emission-free power generation sources. Other green hydrogen manufacturing technologies exist, such as the production of hydrogen in nuclear reactors. These generally have low TRLs. The term 'green hydrogen' usually presupposes the use of renewable electricity from wind, photovoltaic, geothermal and hydro power as the energy sources for the electrolysis. These energy sources have low carbon intensities, in some cases close to zero.

4.1.3 Blue Hydrogen

The production of grey hydrogen via steam methane reforming (SMR) technologies is currently the most cost competitive and common hydrogen production process used globally. This hydrogen is used mainly for the production of ammonia for fertilizers and the upgrading of petroleum products in refineries and has high carbon intensity. When the CO_2 stream from grey hydrogen production is captured, and sequestered or used, the resulting hydrogen is called blue hydrogen. The sequestration, capture and use of CO_2 can occur through a number of pathways that include the injection of the CO_2 deep into the Earth's crust. An example is the Shell Quest Project.[86] This report will only assess the potential for blue hydrogen and not grey hydrogen.

Autothermal reforming (ATR) is a technology used to produce hydrogen for methanol and ammonia production. It is being proposed as a way to produce low carbon intensity blue hydrogen from natural gas because it allows carbon capture at higher rates than conventional SMR, and at a lower cost.[87]

4.1.4 Turquoise Hydrogen

Turquoise hydrogen is a more recent addition to the description for hydrogen that is produced by breaking down methane within a natural gas stream into hydrogen and solid amorphous carbon. The process is called pyrolysis and has the potential to produce a relatively low carbon intensity hydrogen. This is because most of the carbon by-product in the process is solid (black) carbon that mainly displaces carbon produced from other fossil sources. There are a number of natural gas pyrolysis technologies. Pyrolysis hydrogen production technologies use electricity to drive the processes and would be of benefit in B.C. given BC Hydro's low CI electricity. The use of amorphous black carbon is relatively common within industries around the world for applications such as the manufacture of rubber for tires, the use as pigment blacks in polymers and in printing blacks.

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[86] Shell Quest Project. https://www.shell.ca/en_ca/about-us/projects-and-sites/quest-carbon-capture-and-storage-project.html (Accessed September 7, 2021).

[87] Pembina Institute. Carbon intensity of blue hydrogen production. August 2021 revised.

4.1.5 Waste Hydrogen

Waste hydrogen is produced at two plant locations in B.C. The North Vancouver Chemtrade plant is a chloralkali facility that focuses on the production of chlorine for numerous applications. Chemtrade has sodium chlorate production facilities, based in Prince George. Approximately 18,500 kilograms of hydrogen per day, for both plants together, is produced as a by-product. Hydra Energy has partnered with Chemtrade to use some of the waste hydrogen to power dual-fuel Class 8 trucks.[88]

Pipeline injection of any waste hydrogen would potentially require increased natural gas use to replace the hydrogen that is not emitted into the atmosphere but is used to produce heat for the Chemtrade plants. Thus, minimal or no GHG reduction benefits would accrue when using all the waste hydrogen produced. Only a portion may be available as low-carbon hydrogen for pipeline injection.

4.2 Technology update

Table 17 provides a brief overview of hydrogen production technologies. Essentially, all elements of blue and green hydrogen production are commercial, with only incremental improvements expected in the near term. Some new technologies, such as plasma pyrolysis, are expected to contribute to turquoise hydrogen production in the coming decade. More detail can be found in Appendix A.

Table 17 Overview of Hydrogen Production Technologies

Technology	Improvements/Benefits	Limitations/Challenges	Key players and Game Changers
Electrolysis: PEM	Improvement in membrane current density and lowering platinum loadings. Capex and efficiency improvements. The benefit is the fast dynamic response capability for demand-side response grid stabilisation opportunities.	Efficiency not significantly improved and thus Opex. Electricity costs are the largest component of the total cost of ownership. Capex would be negatively affected as well	Suzhou Jingli, Siemens, Areva H2gen, ITM Power, Erredue SpA , H2B2, Elchemtech, CUMMINS, NEL Hydrogen, Plug Power
Electrolysis: Alkali membrane	Improvements in Capex reduction. Alkali membrane electrolysis is a mature technology. Benefit is the low Capex per MW	Insignificant cost reduction improvements. No further dynamic response improvements.	CUMMINS, NEL Hydrogen, Teledyne Energy Systems, McPhy, Yangzhou Chungdean Hydrogen Equipment, Asahi Kasei, Verde LLC, ThyssenKrupp, Toshiba
Electrolysis: SOEC	The benefits of SOEC include the high efficiency: 30% above incumbent technologies.	SOEC is not yet commercialised. TRL of ~6. Operates at high temperatures of around 700°C and in a steady stage mode.	Haldor Topsoe, Ceres Power, Toshiba

[88] Hydra Energy. https://hydraenergy.com/news/chemtradepressrelease. (Accessed September 7, 2021).

Technology	Improvements/Benefits	Limitations/Challenges	Key players and Game Changers
ATR - CCUS	Improvement in CO_2 capture in ATR plants versus SMR technology and potential cost reduction according to a Pembina Institute report.	Not as common in the marketplace as SMR plants. GHG reduction benefits are marginal.	Air Products. New plant in Alberta planned for 2024
SMR - CCUS	Improvement in CCUS is key to the successful deployment of blue hydrogen. Both higher capture and sequestration percentages and associated costs are developing. Large SMR plants are deployed globally and produce hydrogen at a low cost of under US$2/kg. Increased efficiencies of small units that can provide smaller modularity benefits related location.	According to the Global CCS Institute[89] there are 25 technologies in various TRL stages. Which of these succeed is still unknown.	There are 26 CCUS plants in operation around the world[90]
Partial Oxidation	Shell Gas Partial Oxidation (SGP). High TRL. More than 100 plants globally. Claimed 22% lower levelised cost of hydrogen for SGP technology compared with ATR.	Past market focus for this technology has not been on hydrogen production but to monetise low-value refinery residues, asphaltenes, heavy oils, gas or biomass by converting them into syngas	Shell
Methane pyrolysis	The various pyrolysis technologies offer a low cost of H_2 and opportunities to use and sell the solid carbon by-product	Mostly low TLR. Some have a high TRL.	

4.3 Feedstock and resource availability

4.3.1 B.C. Potential for Green Hydrogen Production

The primary parameters determining the potential for green hydrogen production via electrolysis include:

- The availability of renewable electricity. Focusing on BC Hydro's most recent draft 2021 Integrated Resource Plan (IRP)[91] that addresses both demand-side efficiency improvements and demand response programs, additional capacity needs are not foreseen until 2032 (however, a high electrification ['accelerated'] scenario indicates a need for power imports as early as 2025 and new power plants being added as of 2029, despite the commissioning of the Site C hydro facility, as per Table 18 in the plan's appendix). No mention is made in this draft report about the use of electricity

[89] Global CCS Institute, Technology Readiness and Costs of CCS (2021).
[90] Global CCS Institute, Global Status of CCS 2020.
[91] BC Hydro and Power Authority DRAFT 2021 Integrated Resource Plan. BC Hydro, June 2021

for the electrolytic hydrogen production. Transmission from electricity production sites or large sub-stations will play a role in site selection.

- Availability of potable water as an electrolyser feedstock. Each megawatt of electrolyser load capacity requires about 1.4 million litres of water per annum. This subject was addressed for a number of sites up to 300 MW plants.[92] Water availability was not an issue. The addition of a potable water filtration plant was the only requirement identified.
- Hydrogen injection into the natural gas grid is faced with a number of challenges and barriers that include:
    - Critical pipeline system components including embrittlement of steel.
    - End-user equipment tolerances and operating considerations.
    - Engineering assessments that would examine the safety, integrity and reliability of the gas company and end-user-owned assets.
    - Updates to pipeline standards and policy.
    - The establishment of mixed (hydrogen/methane) gas tariffs and insurance (the gas blend still needs to meet tariff requirements).
    - Pipeline capacity (including locating hydrogen-producing facilities near major pipelines to inject it into the B.C. grid).
    - Hydrogen separation technology.
    - Gas metering for blended gases, purity and requisite specifications.[93]
    - Finally, the upper hydrogen concentration limit in the B.C. grid needs to be determined.

The above leads to three possible concepts for implementing new green hydrogen production in B.C.:

1. One or more centralized on-grid facilities: BC Hydro indicated the ability to support 300 MW of electrolyser load capacity for green hydrogen production.[92.] According to recent discussions with BC Hydro, this can be increased if power demand is close to the new Site C dam or other large power generation plants. Beyond a few hundred megawatts of demand, BC Hydro could not to guarantee power deliveries for new plants in the coming decade. It may be possible to wheel electricity from other jurisdictions, but this may again depend on plant location and transmission capacities.
2. Wind or solar PV-generated electricity. Figure 28 indicates wind farm and gas network overlapping regions that may provide opportunities to build large (100-150 MW nameplate capacity) off-grid wind farms and electrolysers. Potential for consideration includes the B.C. mainland and offshore wind generation west of Vancouver Island. Off-shore wind farms may be very large, in the range of 300-700 MW. The limitations are then dictated both by the potential amount of hydrogen that can be injected into the natural gas grid and by the time required to get such facilities permitted, built and production commissioned.
3. A third opportunity is decentralized hydrogen production using large- and small-scale facilities such as the one being developed in Chetwynd[94] or the HTEC/Mitsui 5-megawatt project.[95] Grid-

[92] Centralized Renewable Hydrogen Production in B.C. – Final Public Report. G&S Budd Consulting Ltd., July 2019.
[93] BC Hydrogen Study. ZEN Clean Energy Solutions, July 2019.
[94] https://biv.com/article/2020/01/green-hydrogen-plant-project-has-investor (Accessed September 8, 2021).
[95] https://www.htec.ca/htec-has-partnered-with-mitsui-co-canada-ltd-to-develop-electrolytic-hydrogen-production-project-in-british-columbia-that-will-provide-fuel-to-htecs-network-of-fueling-stations-and-hel/ (Accessed September 8, 2021).

connected facilities of this or a smaller size can rely on both hydro power from the grid, and solar or wind power from a nearby facility, putting less strain on the power grid. They could be developed in various regions and inject into the local grid, albeit at somewhat higher costs because of lower economies of scale.

Table 18 outlines the resulting estimates for new green hydrogen production potential in B.C. by 2030 and by 2050 (cumulative). The current (2021) BC Hydro draft Resource Plan extends to the year 2041 and does not consider any major new power production for hydrogen consumption. The addition of large amounts of demand would likely require adapting the resource plan. The possibility of wheeling electricity from other jurisdictions is not considered here but could potentially allow for the construction of additional electrolyser capacities. About 700 MW of electrolyser capacity is required to reach the provisional volumetric variable of 5% hydrogen in the pipeline network. Note that some power plants, such as wind-based generators, have nameplate capacities that are considerably larger than their average output. For example, 100 MW of average electrolyser output from wind will likely require wind farms of at least 250 MW nameplate capacity.

The 2030 technical potential for centralized grid-connected hydrogen production is based on opportunities to use grid electricity at locations that are relatively near BC Hydro power plant sites and major sub-stations. By 2050, BC Hydro can contract for new generation capacities (or import more power) and will then be able to connect additional green hydrogen plants. The exact amounts would depend on Utilities Commission approval and direct negotiations with BC Hydro.

The estimate for total resource potential considers information provided in the ZEN Hydrogen Study that estimates 5.4 GW of wind potential.[93] With the sites tentatively indicated in Figure 28, several large off-grid wind farms seem feasible in the Interior, along the gas pipeline network. Also considering offshore locations for very large wind farms (300-700 MW), this would amount to a total of 1450 to 2000 MW of installed wind power capacity. This would result in up to 800 MW of net average power output,[96] using a 40% capacity factor. Some of this potential may also be developed as on-grid facilities. Given long lead times, only one or two on-shore and no off-shore wind farms are deemed feasible by 2030. Beyond 2030, the potential for on-grid electrolyser farms will ultimately be determined by policy and Utilities Commission directives since BC Hydro or the private sector could add considerable new renewable generation. This may increase overall power pricing and therefore needs regulatory support. Five hundred MW of new electrolyser net capacity (about 1250 MW of wind farms) between 2030 and 2050 is deemed to be a reasonable estimate in this respect. Wheeling of low-carbon electricity from other jurisdictions may also be a possibility to increase on-grid electrolyser capacities. This option is not explored here but the technical potential depends on both legal constraints and transmission and interconnection hub capacities.

For small-scale, decentralized on-grid hydrogen production, the estimate assumes a plant size of 10 MW with up to five sites being developed by 2030 and up to 30 sites by 2050. Decentralized facilities may be built near the gas distribution grid, with lower input pressures. They could be linked to local renewable energy generation to supply some of the electricity needed. Larger facilities elsewhere may feed power into the grid commensurate with increased local demand. They may be close to hydrogen users in the Lower Fraser Valley. These potential estimates can be modified based on cost evaluations and the establishment of potential sites intended for the injection of hydrogen into the natural gas grid.

[96] Real output will fluctuate with the wind resource. In an off-grid situation, this would require either adding battery storage to ensure stable power supplies at the average level or otherwise, building electrolyser farms with capacities close to the maximum output of the wind farm in order to minimise curtailment. In an on-grid situation, the grid can serve as a "battery", thus reducing the capital investment required.

Table 18 Estimated Green Hydrogen Production Potential in B.C. (Electrolyser Capacity)

Concept	By 2030	By 2050 Technical potential	Total Resource potential
Centralized grid connected	300 - 500 MW*	1000 MW	2100 MW net** (from wind) Additional potential exists from e.g., geothermal, photovoltaic
Centralized off-grid	60 MW	600-800 MW	
Decentralized grid connected	10 - 50 MW	300 MW	
Total	**370 – 610 MW**	**~1900 MW**	**>2100 MW**

* Current limit for new on-grid demand by 2030; ** assuming an average capacity factor of 40%.

Figure 27 indicates five areas where large off-grid wind power plants could be implemented, including an off-shore site that would need to be linked to Kitimat and two areas along the northern section of the Westcoast Energy Pipeline System. In addition, offshore wind power plants west of Vancouver Island could be implemented. As Vancouver Island requires a gas pipeline upgrade to increase capacities delivered, the upgrade could be used to install a larger pipeline that can carry hydrogen produced on the Island back to the mainland. This could occur in a reversed flow if production capacities are large enough or through a parallel hydrogen pipeline. A large (500 MW) offshore wind farm could provide the electricity for electrolytic hydrogen production. The areas indicated appear to be good candidates, but this high-level overview does not replace the need for detailed resource assessments and an examination of siting conditions and other requirements to determine suitable locations. For example, the gas flow currently goes to Vancouver Island and Kitimat. Hydrogen injected may then either be used locally or may cause the flow to be inverted, which may pose engineering and cost challenges not considered here.

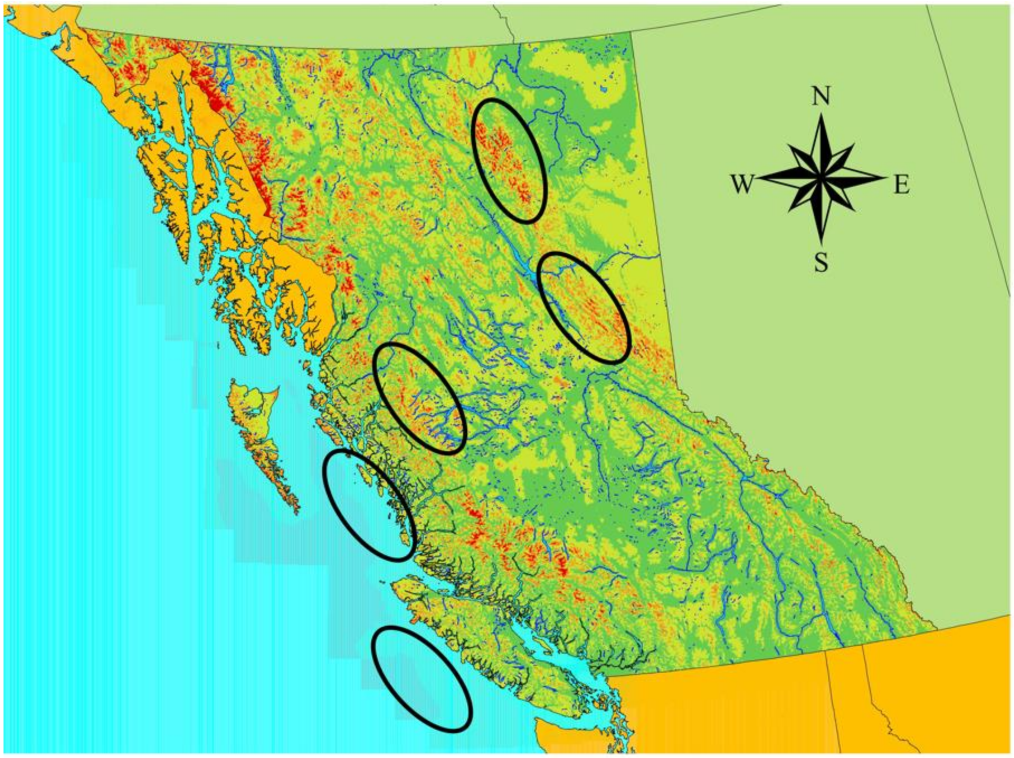


Figure 27 Promising Regions for New Wind Farms Supporting Large-Scale Green Hydrogen Production

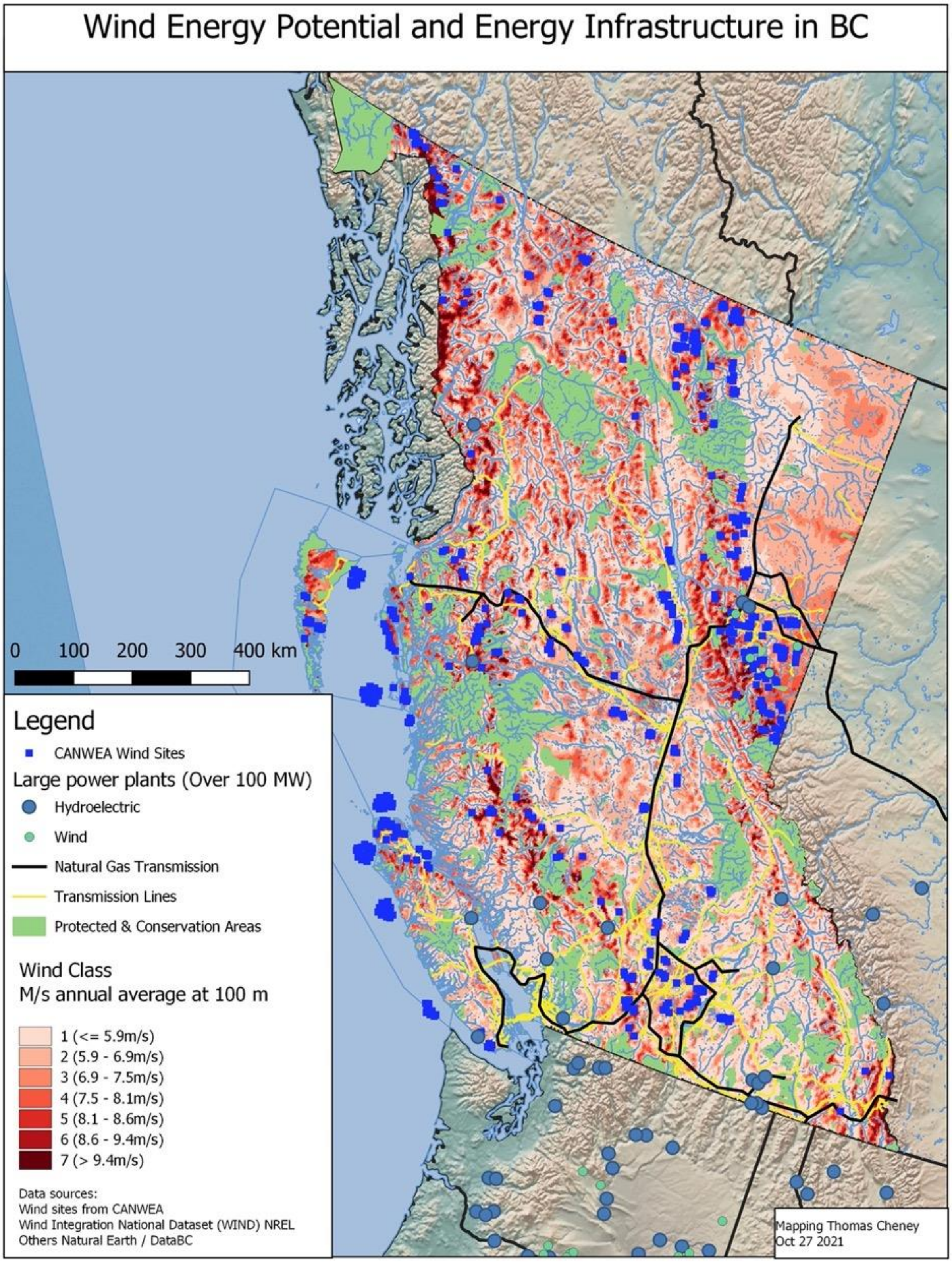


Figure 28 B.C. Predicted Wind Speeds and Potential Locations for Large Wind Farms Near the Gas Pipeline Network

For grid connected, large-scale hydrogen production, locations near large hydro facilities in the province's north appear to be ideal, in line with the regions identified for larger wind farms in Figure 27. In addition, larger facilities could also produce for industrial (direct) use and for grid injection, capturing additional economies of scale. They could produce for use in other applications that include, by way of example, fuel cell powered mobility (not within the scope of this study). Opportunities to capture and sell the by-product electrolytic oxygen need to compete with a cost of less than US$50/t from air separation plants. Colocation opportunities may exist that could use either the hydrogen or any by-product oxygen, or both. The two refineries (Burnaby and Prince George) could provide opportunities as they use large amounts of hydrogen and may continue operating if they were to move towards biofuels, using plant-based lipids and possibly biocrude. The latter, however, would stand in competition to gas production from the same resources. Although most of ground transportation may no longer use liquid fuels by 2050, air and marine transport may still rely on renewable liquid fuels.

4.3.2 B.C. Potential for Blue Hydrogen Production

The two primary feedstock types required for the production of hydrogen using SMR or ATR technologies are natural gas and water. The potential for the production of blue hydrogen is dependent on a number of factors, including:

- Carbon capture and sequestration is required to meet the proposed B.C. carbon intensity threshold for low-carbon gases of 36.4 g CO_2e per megajoule. This will require that at least 60% of the CO_2 is sequestered or used, based on a carbon intensity of 90 g CO_2e per megajoule for grey hydrogen. Geological sequestration capacity in B.C. is deemed large, as suitable sites exist close to where gas production is taking place (Figure 29). Overall estimated sequestration capacities have been used to derive the blue hydrogen potentials in the ZEN report.
- The adoption of ATR technology instead of SMR offers a simpler production stream, with a high concentration of carbon dioxide, which allows a higher percentage of carbon emissions to be captured. Capture efficiency is estimated at 90 to 95% in the conversion process and at its best, a carbon intensity of 11 kilograms CO_2e per gigajoule of hydrogen is projected.[106] It is potentially a more cost-competitive solution. However, unlike SMR, ATR requires the supply of oxygen as a feedstock. This may offer co-location benefits for green hydrogen production using the by-product oxygen as feedstock for ATR blue hydrogen production.
- The cost of the CO_2 captured and sequestered needs to be considered. For every kilogram of hydrogen produced via SMR, approximately 9.5 kilograms of CO_2 is produced. If the cost to capture and sequester the CO_2 were US$60 per tonne, an additional cost of US$0.57 per kilogram results for the cost of hydrogen produced.
- In terms of hydrogen injection into natural gas pipelines, one limitation is the amount of hydrogen the pipeline can technically tolerate unless the pipeline is converted to transport high hydrogen blends or 100% H_2. The total amount of gas that can be injected at any particular site will have to be determined and is site-specific. Given that 90% of natural gas produced in B.C. is exported, any target for the B.C. market will only have a minor impact on the renewable gas content in the main transmission lines. It is, however, possible that decentralised production of hydrogen on the gas distribution grid may lead to high hydrogen concentrations near the point of injection and would then need to include variable hydrogen flow rates to maintain the target injection percentage, especially in the summer when gas consumption may be three to four times lower than during some winter days.
- The size of the SMR plant and location along any of the natural gas pipe branches influences potential. Large plants may be limited in terms of where and how much hydrogen can be injected into the grid. Potential locations must allow either the use of CO_2 or its injection into geologic formations underground. The capacity to sequester the CO_2 below the Earth's surface in northern B.C. must

therefore be considered and may become a limiting factor. Numerous smaller high-efficiency SMR units and small CCUS modular technologies that capture CO_2 are being developed (see Section D.2 in Appendix A). These units can be placed in locations that would avoid the limitations associated with the use of large SMR and CCUS.

The overall potential for blue hydrogen production is very high. All current gas production in B.C. could theoretically be replaced with blue hydrogen, since production is about ten times larger than provincial demand. It is, however, unrealistic to expect that this will happen. By 2030, few plants will likely have been constructed. This is because the technology is relatively new and because lengthy permitting periods expected for the first B.C. CO_2 injection projects. The scenarios therefore only include limited blue hydrogen production by 2030. After this date, the industry is more likely to grow and may then obtain a large market share for low-carbon gas. The scenarios assume that up to 30 full-scale facilities may be built in the two decades between 2030 and 2050. Total potential by 2050 is based on the ZEN Hydrogen report.[93]

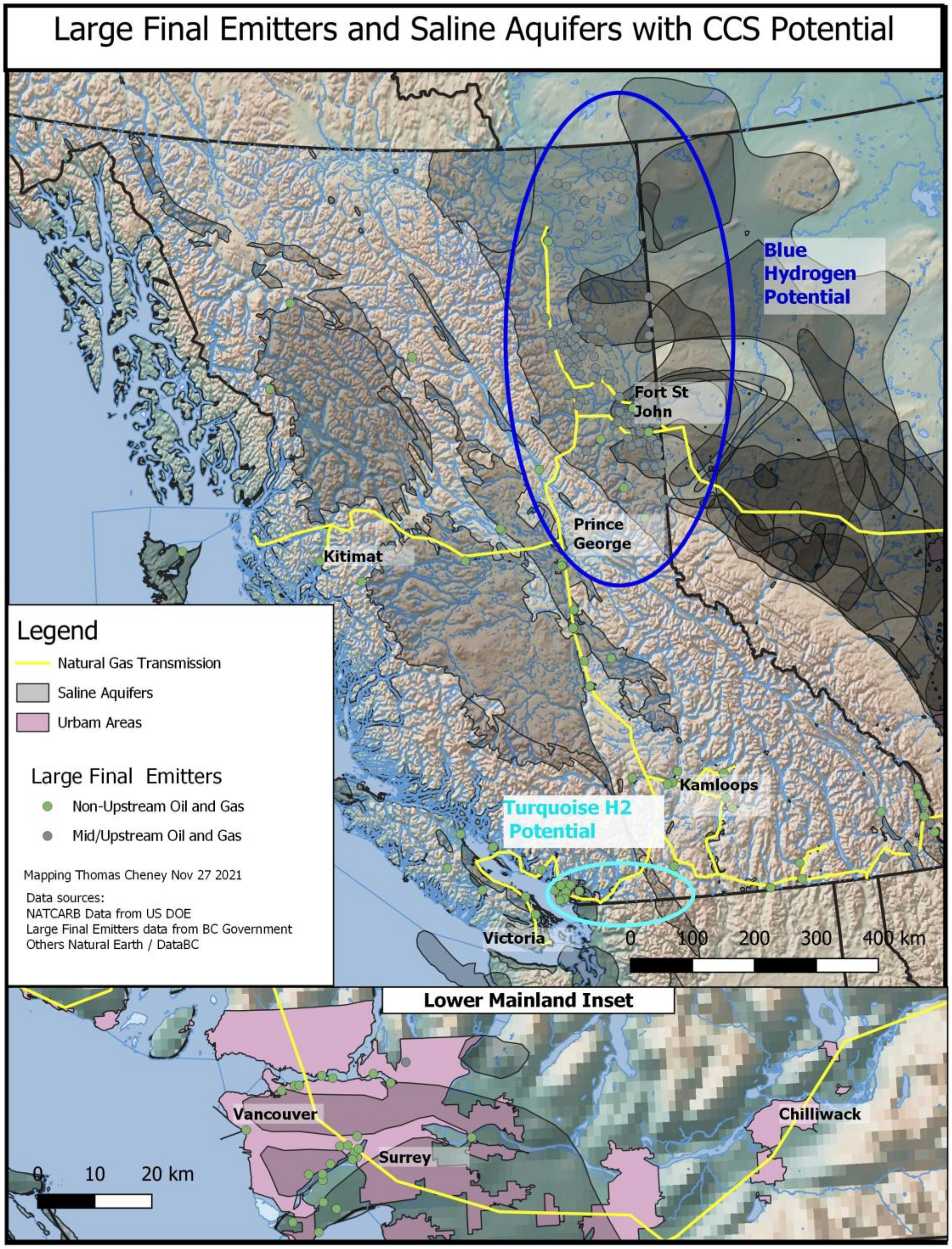
Figure 29 shows the northern area around Fort Nelson, where natural gas is produced, as the obvious region where blue hydrogen could be produced and injected, and where captured CO_2 could be injected into the ground. Turquoise hydrogen production, also indicated on the map, would more likely happen more downstream along the gas pipeline, near strategic export hubs (Kitimat, Vancouver) or near potential users of hydrogen or carbon black. This suggests that locations near refineries, where the hydrogen could be used directly, are also attractive.

4.3.3 B.C. Potential for Turquoise Hydrogen Production

A number of pyrolysis technologies have been considered in this report (Appendix A). These include plasma, fluidised bed, moving bed, molten salt and pulse methane pyrolysis. All technologies require natural gas as a prime feedstock. Using RNG would be a more costly alternative but could at the same time result in a negative-emission pathway if the carbon black produced is used in long-lived products. This section will focus on two technologies, Plasma Pyrolysis (Monolith Materials) and Pulse Methane Pyrolysis (EKONA Power). The former is chosen as this technology appears to be more advanced in terms of its TRL (see Appendix A). The potential to produce low-carbon-intensity hydrogen using a turquoise pathway depends on a number of factors, including:

- Similar to blue hydrogen, the location, plant size and allowable amount of hydrogen that can be injected into the grid, used in industrial hubs, or distributed through gas infrastructure and converted to 100% hydrogen are key.
- Methane pyrolysis yields solid carbon (high-value production output if sold as carbon black) with hydrogen as a (lower-value) by-product, which adds a revenue stream opportunity to sell the carbon as a pigment or rubber black. No CO_2 capture is necessary.
- The market for black carbon is large (US$18 billion per year and increasing[97]) so there is considerable potential for B.C. to produce this material while also making hydrogen. The projected market growth can be estimated as about 8 million tonnes by 2026. One facility in B.C. may only produce around 100,000 tonnes per year.
- The production cost of this process is close to zero once black carbon sales are factored in. Hydrogen could likely be sourced at no more than $10 per gigajoule from this source.

[97] https://www.alliedmarketresearch.com/carbon-black-market (Accessed September 30, 2021).



Promising regions for **blue hydrogen** and **turquoise hydrogen** production marked by ovals.

Figure 29 Potential CO_2 Sequestration Sites in B.C.

The potential for turquoise hydrogen, as with blue hydrogen, is very large. This resource could provide a large share of the low-carbon gas required to help achieve BC's 2030 and 2050 GHG reduction targets. In the ZEN report,[93] its potential is estimated at 92 petajoules – almost half the current B.C. gas consumption. As with green hydrogen, however, the realization of this potential will depend on the ability to source enough electricity – unless thermal pyrolysis is used as the production method. One plasma pyrolysis plant may use around 40-50 megawatts of power; 90 petajoules of hydrogen output per year would require the construction of 18 such plants, amounting to additional power demand of around 800 megawatts. Since the technology is new, the scenarios in Chapter 5.0 assume that few plants can be built by 2030. After that date, the potential is based on the ZEN Hydrogen study.

4.4 Cost Curves

4.4.1 Green Hydrogen

Figure 30 shows the cost curves resulting for electrolytic hydrogen. Costs are higher than C$31 per gigajoule throughout, and incremental cost reductions and efficiency improvements are cancelled out by expected increases in electricity pricing. Producing hydrogen off-grid will entail considerably higher costs. The latter vary greatly between on-shore (around US$1.5 million per megawatt) and off-shore wind farms (around US$5 million per megawatt). Since both are envisaged for B.C. to obtain sizeable numbers, a cost of around US$3 million per megawatt was used. The very high CAPEX for wind turbines and oversized electrolyser farms combined with the intermittent output of wind turbines (capacity factor assumed to be 40%) lead to very high costs of hydrogen produced off-grid, despite independence from grid electricity. For on-grid hydrogen production, electricity costs are the most important cost factor and changes in electricity pricing will heavily influence hydrogen costs. For off-grid, the power generation assets are owned by the producer and the capital costs for these assets and the electrolyser farm become the most important cost element, yet maintenance and operating costs are also significant. The predicted cost scenarios for green hydrogen are based on an electricity price of C$65 per megawatt-hour, including demand charges (see Section 5.1). Lower electricity costs will cause a significant reduction in the unit cost estimation for the green hydrogen produced. Future green hydrogen cost improvements will be due to developments in:

- Electrolyser Capex reduction,
- Improvements to electrolyser stack and system efficiencies,
- Decreases in operating and maintenance costs,
- Longer durability, and electrolyser system operational lifetime.

Table 19 Key Cost Impacts, On-Grid Green Hydrogen Production

Year	Status and improvements	Challenges
2021	The electrolyser capex (incl. balance of plant but excl. storage) is estimated at C$1,400/kW	Cost of electricity
2030	For this period, it is expected that further improvements will be made to the cost associated with the list above.	Inadequate supply of available renewable electricity. Cost of electricity.
2050	For this period, further improvements are expected to be made to the costs associated with the list above. PEM electrolyser target costs have been studied in the UK for a planned mega electrolyser production facility.[98]	Inadequate supply of available renewable electricity.[91] Cost of electricity.

For capital costs, the assumptions from the ZEN report were retained for 2021. Future cost reductions may be significant. A U.S. source predicts costs of only US$400 per kilowatt.[99] Strong capital cost

[98] Gigastack Bulk Supply of Renewable Hydrogen Public Report. February 2020.

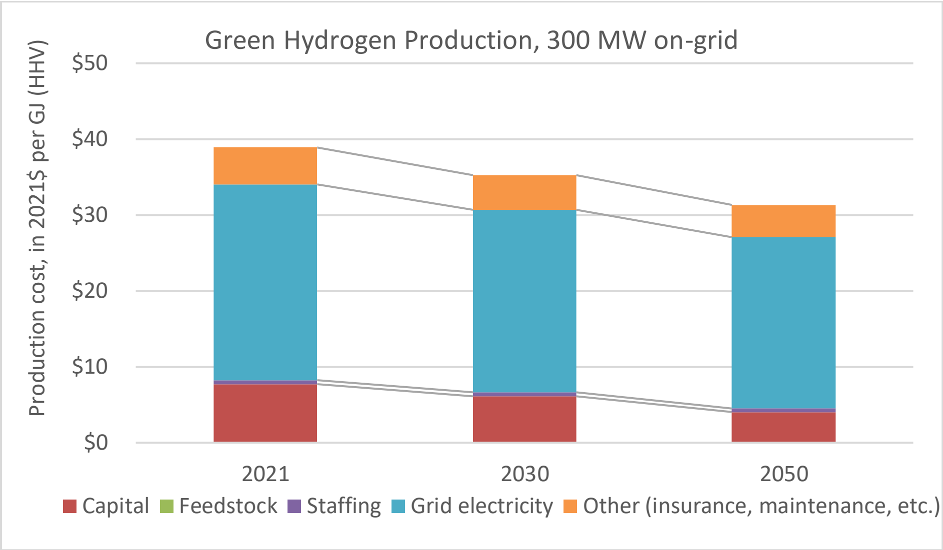
[99] Roadmap to the U.S. Hydrogen Economy – Reducing Emission and driving growth across the nation. Fuel Cell and Hydrogen Energy Association, March 2020.

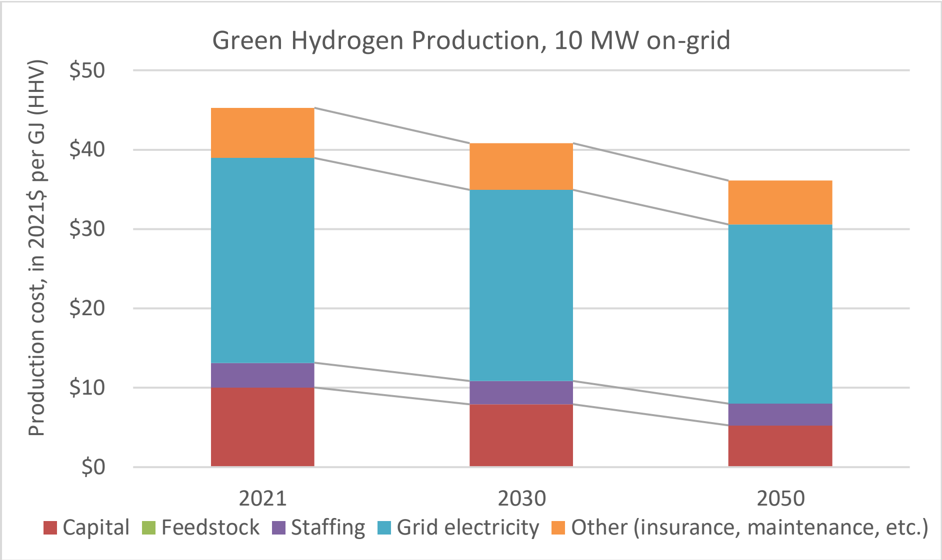
reductions for 2030 (15%) and 2050 (40%) were therefore assumed. Another important variable is electrolyser efficiency. Currently, PEM electrolysers can achieve a power-to-hydrogen conversion efficiency of up to 72%.[100] Default assumptions are 70% for 2021, 75% for 2030 and 80% for 2050. Additional assumptions for a small (10 MW) and off-grid plant can be found in the Excel model.

Table 20 Default Cost Parameters, On-Grid Green Hydrogen, in 2021$

Cost parameter	Value	Share	Comments
Electrolyser plant	300 MW		Very large
Conversion efficiency	70%		Electricity to hydrogen, GJ/GJ
Gas yield	6.48 PJ		
Capital cost	$420 million		In 2021
Capital cost	$357 million		In 2030 (-15%)
Capital cost	$252 million		In 2050 (-40%)
Amortization	$46.7 million	20%	20 years, 9.2%
Opex personnel costs		1%	
Labour, 36 FTE	$2.90 million		
Management, 2 FTE	$0.30 million		
Opex electricity	$156.00 million	66%	2,400,000 MWh per year at $65/MWh
Opex other costs	$29.40 million	12%	7% of CAPEX for maintenance, insurance, etc.
TOTAL OPEX	$235.25 million	100%	
Gas cost	$39/GJ		In 2021

[100] Hydrogen Program Plan. U.S. Department of Energy, November 2020 (footnote 80).





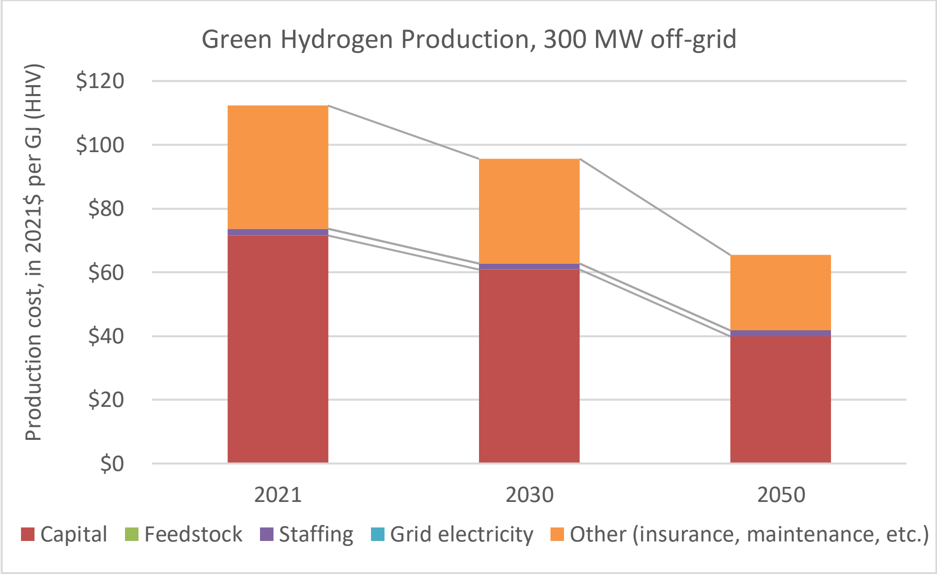


Figure 30 Cost Curves for Electrolytic Hydrogen Production

4.4.2 Blue, Turquoise and Waste Hydrogen Cost Curves

For blue hydrogen, the natural gas price is key after the cost of carbon sequestration. Presuming these plants will be built at the well, where natural gas costs are lowest and sequestration opportunities exist, any increases in natural gas pricing will negatively affect hydrogen costs. This is buffered by the expectation that sequestration costs will fall over time. Capital costs are the most important cost factor, due to the need to implement both SMR reactors and the carbon capture, compression, and sequestration infrastructure. Other models, such as the use of CO_2 in tertiary oil and gas fields, or other uses of CO_2, would strongly reduce the sequestration cost but are not likely going to be sufficiently available for the large amounts of blue hydrogen anticipated.

The conversion efficiency of natural gas to hydrogen is assumed to increase to 85% by 2050.[101] Carbon capture costs are modelled as decreasing from $75 a tonne of CO_2 in 2021, by 10% by 2030 and 25% by 2050. Capital costs will decrease more slowly at 9% by 2030 and 20% by 20% by 2050. Gas costs at the well are deemed to increase only with inflation. No carbon tax applies since natural gas is (mainly) used as a feedstock. The resulting cost of $3 per kilogram (US$2.30 per kilogram), although somewhat higher than in the ZEN study ($2.14 per kilogram), lies within the range of previous estimates.[102] The plant size of 100 tonnes per day has been retained from the ZEN report and was chosen to compare to turquoise hydrogen production; actual projects may be considerably larger.

Table 21 Default Cost Parameters, Blue Hydrogen, in 2021$

Cost parameter	Value	Share	Comments
Conversion efficiency	75%		Methane to hydrogen, GJ/GJ
Gas yield	100 tonnes/day		As hydrogen (5 PJ per year)
Capital cost	$300 million		In 2021
Capital cost	$273 million		In 2030 (-9%)
Capital cost	$240 million		In 2050 (-20%)
Amortization	$33.3 million	32%	20 years, 9.2%
Opex personnel costs Labour, 42 FTE Management, 2 FTE	 $3.4 million $0.3 million	3%	
Opex electricity	$2.3 million	2%	35,000 MWh per year at $65/MWh
Opex natural gas	$25.6 million	25%	6.6 PJ of natural gas at $3.87/GJ
Carbon capt./sequestr.	$23.6 million	23%	$75 per tonne of CO_2[103]
Other OPEX	$15 million	14%	5% of CAPEX
TOTAL OPEX	**$103.5 million**	**100%**	
Gas cost	$21/GJ		In 2021 ($2.96/kg)

For turquoise hydrogen, feedstock costs (natural gas) remain the most important factor. No capture or sequestration is required, making the process easier to locate and operate. Yet, the conversion efficiency is lower than with SMR, which increases overall production costs. Carbon black sales may, however, almost entirely compensate for the cost of production. Producing the correct grade of carbon and establishing sales channels will be key. Given the carbon in the feedstock is not emitted but turned into carbon black, likely displacing fossil carbon black sources, turquoise hydrogen production is not impacted by increasing carbon taxes (methane use as a feedstock is not subject to the carbon tax). If on the

[101] Hydrogen in a low-carbon economy. Committee on Climate Change (UK), November 2018
[102] GLOBAL STATUS OF CCS 2020. Global CCS Institute, November 2020 (Table 3)
[103] See https://www.iea.org/commentaries/is-carbon-capture-too-expensive (Accessed October 29, 2021)

distribution grid, facilities would, in theory, be affected by increasing gas pricing as is anticipated with increasing amounts of renewable and low-carbon gases being injected (see Section 5.1). It is, however, presumed here that a low gas price is offered to turquoise hydrogen producers that will only change with inflation. This is estimated by taking the current Rate 5 commodity charge plus storage and transportation charges, resulting in a gas price of only $4.70 per gigajoule. Whereas the hydrogen conversion efficiency is deemed to remain constant over time, the increasing amount of hydrogen in the gas pipeline will lead to lower rates of carbon black output, although somewhat more hydrogen is then injected into the pipeline by 2050. Alternatively, the development of hydrogen at scale in B.C. could include dedicated natural gas pipelines to deliver methane feedstock to processing facilities such as these.

Table 22 Default Cost Parameters, Turquoise Hydrogen, in 2021$

Cost parameter	Value	Share	Comments
Conversion efficiency	57%		Methane to hydrogen, GJ/GJ
Gas yield	5 PJ/year		As hydrogen
Capital cost	$153 million		In 2021
Capital cost	$139 million		In 2030 (-9%)
Capital cost	$122 million		In 2050 (-20%)
Amortization	$17.0 million	18%	20 years, 9.2%
Opex personnel costs		3%	
Labour, 30 FTE	$2.40 million		
Management, 2 FTE	$0.30 million		
Opex electricity	$22.8 million	25%	350,000 MWh per year at $65/MWh
Opex natural gas	$41.2 million	46%	8,769,600 GJ of natural gas at $4.7/GJ
Other OPEX	$7.6 million	8%	5% of CAPEX
TOTAL OPEX	$91.3 million	100%	
Carbon black revenue	-$89.6 million	-98%	112,000 tonnes at $800 per tonne
Gas cost	$0.3/GJ		In 2021

Turquoise hydrogen is a special case due to the co-production of carbon black. Depending on its exact texture and quality, carbon black can fetch considerable value in the market. It has been conservatively assumed that a value of C$800 per tonne is attainable.[104] This is sufficient to cancel out almost all of the operating cost of a new plant, leading to very low hydrogen production costs. Natural gas is the main cost parameter but somewhat higher pricing could be absorbed.

One concern with turquoise hydrogen is the anticipated change of gas composition in pipelines. If significant amounts of hydrogen will be injected, turquoise hydrogen facilities will not be able to generate the same amount of carbon black as before, which may affect their financial viability. A detailed technical analysis of this problem would be beyond the scope of this study, but it is assumed that with moderate amounts of hydrogen, the process would simply become somewhat less efficient and would produce more hydrogen as a by-product. Increasing amounts of hydrogen in the gas distribution network could also affect other industries using natural gas as a feedstock but no such industries, such as fertiliser production, were identified during the research for this report. For the cost estimate, it has been assumed that hydrogen in pipelines will amount to 2% by 2030 and 40% by 2050. This leads to somewhat less carbon black revenue but also to increased hydrogen sales. It is assumed that the hydrogen in pipeline gas would simply be injected back into the same after processing, together with the hydrogen produced by the

[104] Pricing was around US$800 in 2021, see https://www.chemanalyst.com/Pricing-data/carbon-black-42 (Accessed October 28, 2021)

process. Alternatively, plants could be situated on gas transmission pipelines where the hydrogen content may be lower than at locations on the distribution grid.

Waste hydrogen is produced at several facilities in B.C. but is generally already being used for plant process heat and as an energy vector for heavy duty truck applications, a Hydra Energy Chemtrade project. Therefore, only a small portion may be available for pipeline injection. If the gas is currently vented, the costs of harnessing the resource are fairly small (some conditioning and compression). It is the most cost-effective resource but also very limited in its potential.

Although the production costs for turquoise and waste/by-product hydrogen are estimated as less than $10 per gigajoule, it is deemed unlikely that this hydrogen would be offered on the market for less than $10. For the cost curves in Chapter 5.0, the calculated amounts were used but it is not expected that this would be the actual cost of purchasing this hydrogen.

Table 23 Default Cost Parameters, Waste Hydrogen, in 2021$

Cost parameter	Value	Share	Comments
Gas yield	0.9 PJ		All figures used based on ZEN (2019)
Capital cost	$19.3 million		In 2021 (no change for later years since no more potential)
Amortization	$2.1 million	57%	20 years, 9.2%
TOTAL OPEX	$3.7 million	43%	Labour and maintenance
Gas cost	$4/GJ		In 2021

Figure 31 shows the gas cost estimates for the present year, 2030, and 2050. The cost is lowest for turquoise hydrogen (due to the revenue generated from selling carbon black), followed by waste hydrogen and then, blue hydrogen

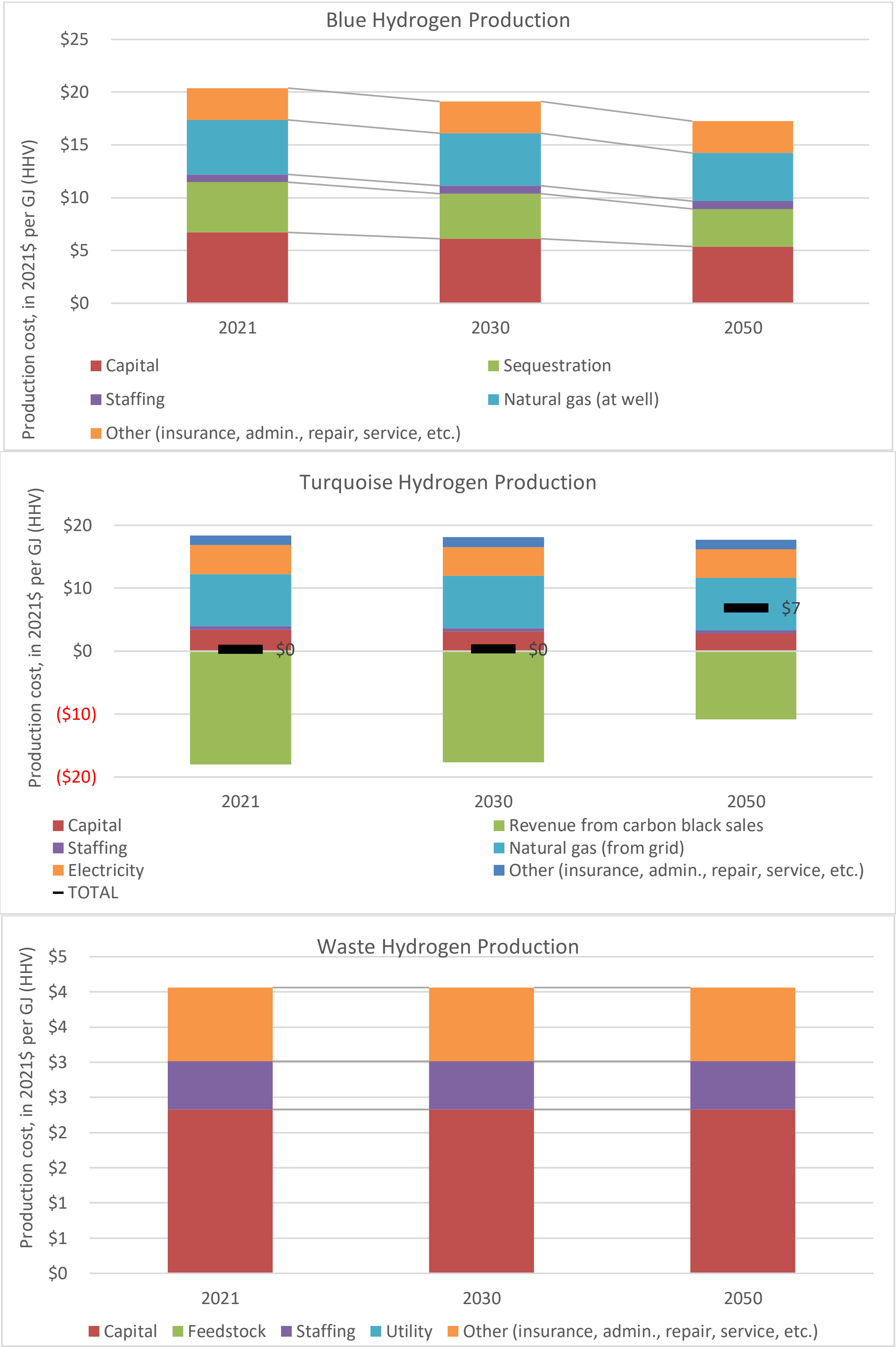


Figure 31 Cost Curves for Non-Electrolytic Hydrogen Production

4.5 Carbon Intensity of Hydrogen from Non-Biomass Sources

Table 24 shows additional values for the four types of hydrogen available in B.C. For blue hydrogen, the actual value will depend on the carbon capture efficiency. The value shown here indicates about 80% of CO_2 being captured, i.e., lower values may be achieved with more efficient technology. The life-cycle emission value for natural gas with and without carbon capture remains contested, however, as indicated in Section 5.5 below.

Table 24 Literature Values for Hydrogen Carbon Intensity

Type	Value	Source
Green	15.6 g CO_2e/MJ	Based on GHGenius[105]
	0.0 g CO_2e/MJ	ZEN (2019), off-grid
	3.3 g CO_2e/MJ	Pembina (2021)[106], wind electricity. Only plant construction
	27.4 g CO_2e/MJ	ZEN (2019), on-grid
Blue	22.4 g CO_2e/MJ	ZEN (2019), 80% capture efficiency
	14.0 g CO_2e/MJ	Pembina (2021), SMR, high performance
	10.6 g CO_2e/MJ	Pembina (2021), ATR, high performance
	26.3 g CO_2e/MJ	BC Hydrogen Strategy, 90% capture eff.[107]
	50 g CO_2e/MJ	Timmerberg (2020)[108]
Turquoise	12.5 g CO_2e/MJ	ZEN (2019), Plasma pyrolysis
Waste	10.5 g CO_2e/MJ	ZEN (2019)

4.6 Markets

The primary markets in B.C. for renewable hydrogen are:

- Pipeline injection to reduce the carbon intensity of retailed natural gas in B.C. To attain (a theoretical) 5% hydrogen by volume in the B.C. natural gas grid, 100,000 tonnes of hydrogen need to be produced and injected into the grid. If this were green hydrogen, it would require an approximate total of 700 MW of electric output to operate the electrolysers.
- The second segment is the transportation market and includes light-, medium- and heavy-duty on-road vehicles, city buses and ferries, to name a few. The Zen Hydrogen Study recommended transportation as second on their list of future demand for hydrogen, albeit over a longer period of time. The focus of this study does not include the transportation market.
- Large industrial users may buy or produce renewable and low-carbon hydrogen. This could include oil refineries and other industries that are large hydrogen users. They could produce hydrogen for on-site use and possibly for export, or a third party could produce for both markets.
- A national or interprovincial strategy to create dedicated hydrogen transport infrastructure could allow for the sale of pure hydrogen across larger portions of Canada, as well as internationally through B.C. ports, or to Western U.S. jurisdictions through pipelines. Market dynamics would then no longer be constrained by the B.C: market but would be driven by large-scale U.S: and overseas demand. Such

[105] GHGenius501d-5, www.ghgenius.ca. Numbers are for BC Hydro's integrated grid. Electricity and green hydrogen produced in the Fort Nelson grid has a much higher carbon intensity.
[106] Gorski, Jan *et al.*: Carbon intensity of blue hydrogen production - Accounting for technology and upstream emissions. Pembina Institute, August 2021.
[107] B.C. Hydrogen Strategy - A sustainable pathway for B.C.'s energy transition. CleanBC, July 2021.
[108] Timmerberg, Sebastian et al.: Hydrogen and hydrogen-derived fuels through methane decomposition of natural gas – GHG emissions and costs. Energy Conversion and Management: X Vol 7, September 2020.

infrastructure could also allow for long-term storage of hydrogen in order to stabilise the electricity grid and provide more seasonal flexibility with hydrogen delivery. In the absence of dedicated hydrogen pipelines, liquid organic hydrogen carriers (e.g., methyl cyclohexane) or liquefied hydrogen could be exported by ship to U.S. or Asian markets from B.C. Physical export or the sale of hydrogen certificates into extra-provincial markets represents a potential threat to the ability to use the gas locally if pricing is higher outside of B.C.

4.7 Infrastructure Needs

The main infrastructure for low-carbon hydrogen use is already in place: the natural gas grid. The limit to hydrogen content in the gas pipeline is currently undetermined. B.C. exports 90% of its natural gas production. Even if all B.C.'s natural gas consumption was converted to hydrogen, the average hydrogen content in the main transmission lines would be only 10% or less.

The co-location of hydrogen production at other industrial sites that could potentially use hydrogen – for example near cement plants and refineries – offers infrastructure benefits. Section 6.3.5 of this report also notes this. Additional infrastructure needed includes electrolysers, power generation assets, and other production assets linked to blue and turquoise hydrogen, as indicated in Table 25.

Table 25 Infrastructure and Planning Requirements to Increase Hydrogen Production

Requirements	Status
Additional renewable electricity production assets	BC Hydro currently developing a new integrated resource plan.
Electrolyser farms	Installation of large-scale production sites on-grid or off-grid. For off-grid sites, additional investment is required to generate electricity (PV, wind). Off-shore sites will potentially require long cable connections to the mainland.
Site local water feed for electrolysers	Filtration plants will need to be invested in.
BC Environmental Management Act. Site and plant environmental assessment and permitting will need to be undertaken for large electrolyser plants	Electrolysers use integrated water purification including ion exchange and reverse osmosis filtration processes. Feed water and grey waste water effluent will need to be addressed.
Steam methane reforming facilities	Commercial technology that needs to be financed and deployed in several locations, often near proven sites for carbon sequestration.
Carbon sequestration infrastructure	CO_2 capture units (amine-based or other technologies), compression and injection into the ground.
Methane pyrolysis plants	Production of carbon black and hydrogen near hydrogen users and/or the natural gas grid.

4.8 Recommendations

The cost curves can inform the best strategy for procuring renewable and low-carbon hydrogen from B.C. or elsewhere. Generally, hydrogen from outside the province is not expected to be cheaper, given the low electricity and gas costs in B.C. The exception would be any waste hydrogen that is currently vented, or turquoise hydrogen. If the aim is to keep costs low, available sources of waste and turquoise hydrogen should be secured first. A strategy should be developed to attract investors to B.C. who will demonstrate and then commercially produce turquoise hydrogen and by-product carbon that could be sold into the carbon black markets. The production of green and turquoise hydrogen should preferably be situated near large consumers, such as the refineries in Prince George and Burnaby. This can make use of existing infrastructure and possibly, personnel, will maximise the value of the hydrogen as it can be delivered in its pure form, and offers possibilities to better manage pipeline injection of surplus hydrogen produced that is not used on-site, thus reducing impacts on the local gas distribution pipelines.

For blue hydrogen, incentives may be needed to construct a first production site by 2030. Since carbon sequestration is likely required, permitting is expected to take several years. This may be a demonstration facility or a full-scale facility. Alternatively, the effort could focus on building a CCUS facility if a market for the CO_2 can be identified. This would avoid the need for sequestering the CO_2 and would improve economics through sale of CO_2.

The production cost of green hydrogen is currently above the GGRR price limit of $31 per gigajoule. This may change if the price ceiling is modified so that an *average* price can be used that allows more than $31 per gigajoule for some projects to be paid, or if the current policy is changed towards a carbon intensity-based target which allows for higher pricing. Green hydrogen may also become more competitive if power tariffs are implemented that reflect the ability of large-scale electrolysis to balance the power market, use constrained wind, and provide long-term (seasonal) energy storage opportunities. Given the very high potential for blue hydrogen, green hydrogen is only deemed competitive if it is incentivised through a portfolio standard approach. Implementing electrolytic hydrogen production where the by-product, oxygen, can be used will slightly improve economics. At an estimated value of $50 per tonne of oxygen, hydrogen costs could be reduced by about $2.80 per gigajoule. This is insufficient to achieve a cost of below $31 per gigajoule for green hydrogen but niche opportunities may exist where this is possible if oxygen costs are higher.

The high cost of off-grid hydrogen production strongly suggests that on-grid wind farms or other renewable electricity production technologies should be given preference for green hydrogen production. Strongly increasing green hydrogen production will require an adjustment to the BC Hydro Resource Plan to accommodate large new sources of intermittent power production and large-scale green hydrogen production.

Time-of-use electricity prices would offer benefits as hydrogen could be produced when wholesale grid pricing is zero or negative, for load balancing. Current electricity pricing structures provide no incentive for energy storage, and there is no need for such grid balancing in B.C. at this point in time as it can be handled by adjusting hydro output. This may, however, change after 2030 if large amounts of intermittent renewable power production is added to the B.C. grid.

5.0 SUPPLY PORTFOLIOS

This chapter develops scenarios that model the cost and availability of a portfolio of renewable and low-carbon gas production pathways described in the chapters above. These scenarios are not to be confused with, or taken as, a forecast. Rather, they are models that represent a possible outcome based on a set of criteria. The underlying Excel-based model considers possible factors or drivers, the interactions between pathways, and their relative contribution to the targets by 2030 and by 2050.

The model is simplistic and high-level and would need to be refined to achieve specific goals and milestones. The scenarios are based on several assumptions, mainly related to costs and the availability of resources, build-up rates, and technology readiness of each pathway.

5.1 General Assumptions

General assumptions apply to all pathways and were made to model the cost of the various renewable and low-carbon gases in 2030 and 2050, as depicted in Table 26. These cost assumptions can be modified in the model to determine their relative impact on the cost of production. The amounts are given in 2021$ – i.e., inflation is not considered but costs reflect changes above the inflation level. For natural gas, future costs were based on the "Diversified" scenario developed in the Guidehouse report. For users on the distribution grid, the Fortis Rate 5 (Lower Mainland/Southern Interior) was used. The retail cost accounts for increasing amounts of renewable and low-carbon gases in the distribution grid. For electricity costs, BC Hydro's latest Revenue Requirements Application to the BCUC indicates a bill decrease of 1.4% in 2022, then an increase of 2% in 2023 and another increase of 2.7% in 2024. In 2025, due to Site C being commissioned, another 5-6% rate increase is expected. After that, assuming that rates grow with inflation, these assumptions reflect price increases in line with 2% inflation for the entire decade. After 2030, an annual increase commensurate with inflation is assumed to continue.

Table 26 Default Cost Assumptions, in 2021$

Cost Factor	2021	2030*	2050*
Electricity	$65/MWh	+0%	+0%
Natural gas, retail (Rate 5)**	$7.96/GJ	$14.09/GJ	$21.43/GJ
Natural gas, at the well	$3.68/GJ	$3.68/GJ	$3.68/GJ
Natural gas retail demand in B.C.	200 PJ/year	200 PJ/year	186 PJ/year[109]
Renewable and low-carbon gas share in B.C. gas grid[109]	0%	15%	73%
Pipeline gas carbon intensity	49.9 g/MJ	42.4 g/MJ	20 g/MJ
Capital costs, non-biomass hydrogen	100%	-9 to -15%	-19 to -40%
Capital costs, gas from biomass	100%	-10 to -30%	-50%
Capital costs, anaerobic RNG	100%	Incremental	Incremental
WACC	9.2%	9.2%	9.2%
Loan term	20 years	20 years	20 years
Carbon tax	$45/t	$130/t***	$130/t
Wood feedstock cost (residue, average)	$60/odt	$60/odt	$60/odt
Wood feedstock cost, add. harvest	-	-	$121/odt

* In relation to 2021; ** Incl. carbon tax; *** Corresponds to $170/t in 2021, at 3% inflation

[109] Pathways for British Columbia to Achieve its GHG Reduction Goals. Guidehouse, August 2020 (Diversified Pathway).

Electricity costs include demand charges but do not consider BC Hydro's lower CleanBC Industrial Electrification Rates,[110] which are deemed to benefit the project developer and investors, but not the purchaser of renewable gases.

The B.C. carbon tax does not apply when natural gas is used as a feedstock, as opposed to a fuel.[111] This means that for turquoise and blue hydrogen production, where natural gas is the feedstock, no carbon tax applies on any volumes of CO_2 emitted at the production stage. On the other hand, wood gasification and steam reforming using natural gas are subject to the tax since the gas is used as a process fuel.

An important assumption relates to feedstock costs for gas production from wood. In line with Section 3.1.3, the cost of residue is assumed to increase with inflation, whereas the costs of pulp and sawlogs continue to increase above the inflation rate. $60 per dry tonne is taken as a conservative number for residue costs - an average between mill residue and increasing amounts of harvesting residue. This cost is also applied to any wood residue currently used for either power production for BC Hydro or for pellet manufacturing.

Additional wood could be harvested but would then require the use of standing trees within the AAC limit. This has been estimated to roughly double feedstock costs for gas production, as an average between pulp quality logs and the resulting roadside residue, also assumed to be available at a cost of $60 per dry tonne. Only about 30% of new stands harvested this way are assumed to be used for renewable gas production; most of the harvested volumes would be sold as sawlogs.

5.2 Technology Readiness

The pathways discussed in this report vary in technology readiness (see also Appendix A). The build-out rate of mature pathways will be faster than of those with little or no commercial-scale implementations. Precommercial technologies is unlikely to be mature by 2030. Unless enormous resources are poured into decarbonization, their full technical potential is likely to be reached only by 2050. With respect to the three major pathways, the following can be said:

- **Anaerobic digestion:** By and large, RNG from anerobic digestion is a well-developed technology that could grow quickly.
- **Woody biomass:** Renewable gas production from woody feedstock is not commercial technology. Technologies need to mature, with demonstration projects being built and evaluated before full technical potential can be realized. We assume a slower build-out for these pathways, with only demonstration projects producing hydrogen or RNG from wood happening before 2030. Syngas for lime kiln projects could proceed more rapidly.
- **Hydrogen from non-biomass resources:** While electrolysis is a well-known technology, large industrial-scale applications are only just being deployed. Blue hydrogen (carbon capture and sequestration) and turquoise hydrogen have to mature even further.

5.3 Resource Potential

Previous chapters describe the technical resource potential of each of the three main renewable and low-carbon gas sources: anaerobic digestion, wood gasification, and non-biomass hydrogen production. The

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[110] https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/electrification-rates.html (Accessed November 26, 2021)

[111] https://www2.gov.bc.ca/gov/content/taxes/sales-taxes/motor-fuel-carbon-tax/business/exemptions (Accessed October 14, 2021

numbers provided in these chapters are technical potentials that need to be translated into what is realistic or desirable for B.C. Consequently, two scenarios reflecting a maximum and a minimum resource potential are developed below. What is actually achievable in B.C. with appropriate policies and investment may lie in-between these two extremes. Ultimately, the criteria to gauge potential for in-province renewable and low-carbon gas production must also consider the cost of each pathway and the relative availability of each resource. Other criteria, such as carbon intensity values for different gases or fuels, may also be taken into account.

For anaerobically produced RNG, resource potential has been assessed in detail and is well known. Scenarios for 2030 and 2050 are mainly a function of the cost associated with each pathway. For anaerobically produced RNG, the Minimum scenario only considers projects that cost less than $31 per gigajoule, the current threshold the GGRR has set to protect ratepayers from excessive rate increases. Also, only a portion of the technical potential can be realized. The Maximum scenario allows for projects that are up to $50 per gigajoule.

The potential for green hydrogen largely depends on the availability of (green) electricity. BC Hydro's long-term resource planning suggests that around 300-500 MW may be available for low-carbon fuel production. Additional or alternative sources may include on-grid power production from renewables, such as wind power.

The potential for blue hydrogen is mainly constrained by the availability of suitable geological features and abandoned wells that could be used to sequester CO_2. Turquoise hydrogen produces carbon black and can only be produced cost effectively where there are markets for this by-product. The market for carbon black is large and growing. Sufficient natural gas is available within B.C. to supply both pathways. Currently, only 10% of B.C.'s natural gas production is used provincially; the rest is exported.[112]

The supply potential of renewable gas from wood biomass is constrained by resource availability and its distribution within the province. The demand for syngas in a particular area might not match feedstock supply. Trucking woody feedstock from parts of the province that have surplus fibre may not be viable or even desirable as the energy contained in it is rather low, and trucking costs would be high. Only the Maximum scenario makes use of whole logs (beyond some unharvested pulp logs used in both scenarios). Only low-cost residue is used in the Minimum scenario. In the Maximum scenario, we assume that low-cost resources from expiring BC Hydro contracts and transitioning of mill waste from wood pellet to gas production takes place.

The numbers used for the two scenarios for wood resources are made explicit in Table 27. Both scenarios have time horizons for 2030 and 2050. The amount of wood has been converted to gas production potential using an input-output (feedstock/gas) calorific conversion rate of 67%, representative of the main technologies to be used.

[112] https://www.capp.ca/explore/natural-gas-and-the-lng-opportunity-in-british-columbia/ (Accessed October 6, 2021).

Table 27 Renewable Gas from Woody Biomass Produced in B.C. in Each Scenario (PJ per year, HHV)

Wood Resource	MINIMUM SCENARIO		MAXIMUM SCENARIO	
	2030	2050	2030	2050
Unharvested AAC	-	-	4.6	4.6
Roadside residue related to above	-	-	2.1	4.0
AAC from mill closures	-	-	14	14
Roadside residue related to above	-	-	6.5	11
Unharvested pulp logs	3.6	3.6	4.0	4.0
Roadside residue related to above	0.4	0.6	0.4	0.6
Unused Roadside residue	6.0	10	5.9	10
Mill residue not used	4.8	4.8	4.8	4.8
Conversion of pellet plants	-	-	-	44
Expiring BC Hydro contracts	-	-	47	47
Urban wood waste (CLD)	-	-	-	-
TOTAL	**15**	**19**	**89**	**143**

The table above shows that in the Minimum scenario, insufficient wood is available to reach a 15% renewable gas target (equivalent to about 30 petajoules) with wood alone. On the other hand, there are, in theory, sufficient resources overall to reach the 15% renewable gas target in 2030 and to produce up to 143 petajoules of gas in the Maximum scenario. Table 28 summarizes the assumptions underlying the subsequent tables.

Table 28 Assumptions on Wood Availability for Minimum and Maximum Scenarios

Minimum Scenario	Maximum Scenario
- BC Hydro power purchase agreements with pulp mills extended, limiting availability of mill residues for renewable and low carbon gas production - All lime kilns converted to syngas by 2050. - No whole-tree harvesting for energy occurring due to high cost or difficulty harvesting. - Demonstrations for hydrogen and possibly RNG at pulp mills by 2030. - Urban wood waste already used by others. - 50% of unused roadside residue recovered by 2030, 85% by 2050. - Pellet plants continue to operate and export after 2030.	- Substantial amounts of lower-cost biomass transitioning from BC Hydro power purchase agreements and pellet mills will buffer costs from increased use of roundwood. - All kraft mill lime kilns converted to syngas by 2050. - Hydrogen and RNG production are implemented at almost all mills, possibly some stand-alone facilities. - Max. about 30% of standing trees on a cutblock used for energy, the rest for sawmills or new uses (bioproducts). - Mixed cost of roundwood and associated roadside residue is $121 per dry tonne by 2050. - Max. 75% of unused AAC can be accessed by 2050 (remoteness, terrain, etc.). - Max. 85% of unused roadside residue recovered. - Pellet plant feedstock transitioned to gas production after 2030. - BC Hydro power purchase agreements expire around 2029 and Hydro sources electricity from wind and solar. - Urban wood waste already used by others.

Based on the above assumptions, Table 29 and Table 30 lay down the resource potentials assumed to exist in each scenario, for the years 2030 and 2050. This includes assumptions about demonstration and build-up of new gas production facilities.

Table 29 Assumptions for Gas Production in 2030 and 2050, in PJ/yr (Minimum Scenario)

Gas Type	2030	2050	Rationale
Green hydrogen (large on-grid)	0.0	8.3	Slower ramp-up than Maximum scenario
Green hydrogen (small on-grid)	0.8	1.9	Slower ramp-up than Maximum scenario
Green hydrogen (large off-grid)	0.0	2.4	A single 300 MW off-grid wind farm after 2030
Blue hydrogen	14.2	46.8	Limited by permitting and regulatory restraints
Turquoise hydrogen	1.5	15.4	Slower ramp-up than Maximum scenario
Waste hydrogen	0.9	0.9	Identical to Maximum scenario
Syngas in lime kilns	1.4	5.9	Identical to Maximum scenario
Lignin in lime kilns	0.0	0.0	Lignin a more expensive fuel than syngas
Syngas to hydrogen	0.3	13.4	No change to forestry practices. BC Hydro PPAs are extended. No use of wood pellet feedstock. Only low-cost residue used.
Syngas to RNG	0.0	0.0	Technology not advancing as expected
Agricultural RNG	0.9	1.2	Potential for production cost below \$31/GJ; 70% of 2030 technical potential (90% of 2050 potential).
Municipal RNG	2.3	4.0	
Waste water treatment gas	0.4	0.6	
Landfill gas	2.1	2.7	
TOTAL	**24.7**	**103.8**	

Table 30 Assumptions for Gas Production in 2030 and 2050, in PJ/yr (Maximum Scenario)

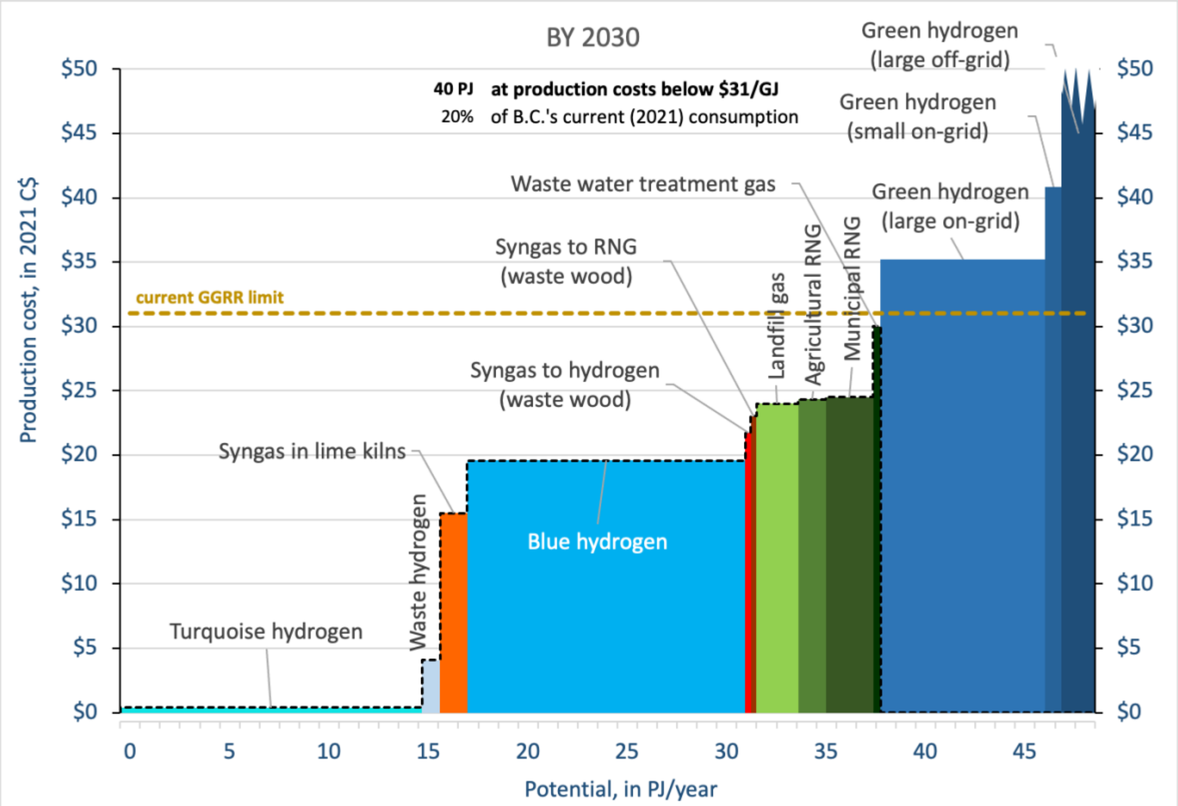
Gas Type	2030	2050	Rationale
Green hydrogen (large on-grid)	8.4	21.0	Converted to petajoules from Table 18
Green hydrogen (small on-grid)	0.8	6.3	Converted to petajoules from Table 18
Green hydrogen (large off-grid)	1.7	12.6	Converted to petajoules from Table 18
Blue hydrogen	14.2	156	From ZEN (2019) report, Figure 28 (in 2050)
Turquoise hydrogen	15.4	92.2	From ZEN (2019) report, Figure 28 (in 2050)
Waste hydrogen	0.9	0.9	From ZEN (2019) report, Figure 28
Syngas in lime kilns	1.4	5.9	100% of lime kilns are converted to syngas by 2050. BC Hydro contracts are not extended.
Lignin in lime kilns	0.0	0.0	Lignin a more expensive fuel than syngas
Syngas to hydrogen	0.3	64.9	Increased forest residue recovery. BC Hydro contracts are not extended. Pellet feedstock transitions towards gas production. 36 plants (or less if larger plant size), also using standing trees
Syngas to RNG	0.3	74.2	One demo by 2030. 26 full-size plants by 2050. Use of some roundwood
Agricultural RNG	1.4	2.0	Potential for production cost below \$50/GJ. 70% of 2030 technical potential (90% of 2050 potential).
Municipal RNG	2.4	4.2	
Waste water treatment gas	0.4	0.6	
Landfill gas	2.1	2.8	
TOTAL	**49.7**	**444**	

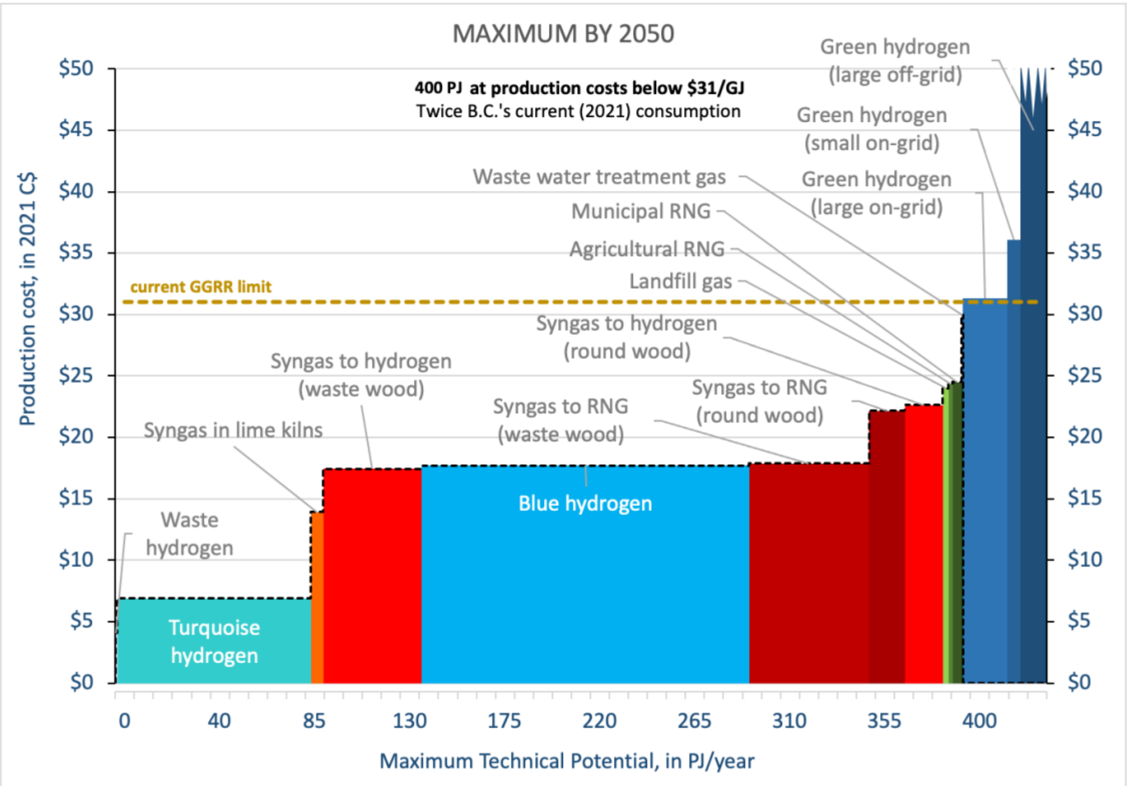
The potentials shown above result in the cost curves displayed in Figure 32 and Figure 33. The (horizontal) x-axis indicates the potential in petajoules per year and the (vertical) y-axis shows the production cost for each pathway. The lowest-cost pathway is shown on the left. The potential increases as higher-cost options are considered, resulting in a stepped curve. Eventually, the costs per gigajoule surpass the $31 threshold that the GGRR requires. The viable potential under the current regulatory framework is limited to the area in the graph that is outlined by a dashed line. Note that, to keep the graphs legible, the size of the x-axis is not the same.

There would be a gradual increase in production over time, which for some pathways only begins after 2030. For anaerobically produced RNG, the potential for 2030 developed in Section 2.4 has been reduced to 70% (90% by 2050) as developing the total potential is not realistic. Syngas production from woody feedstock is assumed to continue through 2050 even if new hydrogen or RNG production is added to mills.

Maximum scenario: the 2030 target of 15% renewable gas can be reached using only in-province resources if low-carbon gas becomes eligible. The target would be reached with a mix of gases, mainly blue hydrogen (construction of about 300 tonnes of blue hydrogen production capacity before 2030) and anaerobically produced RNG. By 2050, 100% of natural gas currently retailed in B.C. could be replaced with provincial renewable and low-carbon gas, still remaining within the $31 (2021$) cost threshold. The resulting gas mix includes a large share of blue hydrogen, high biomass use, and also the construction of carbon black production facilities that produce turquoise hydrogen. For gases from woody biomass, production sites exceed the number of existing mills, suggesting that some greenfield plants would have to be built and substantial amounts of roundwood would be used. More than the current provincial demand could be produced with provincial resources, possibly allowing for exports.

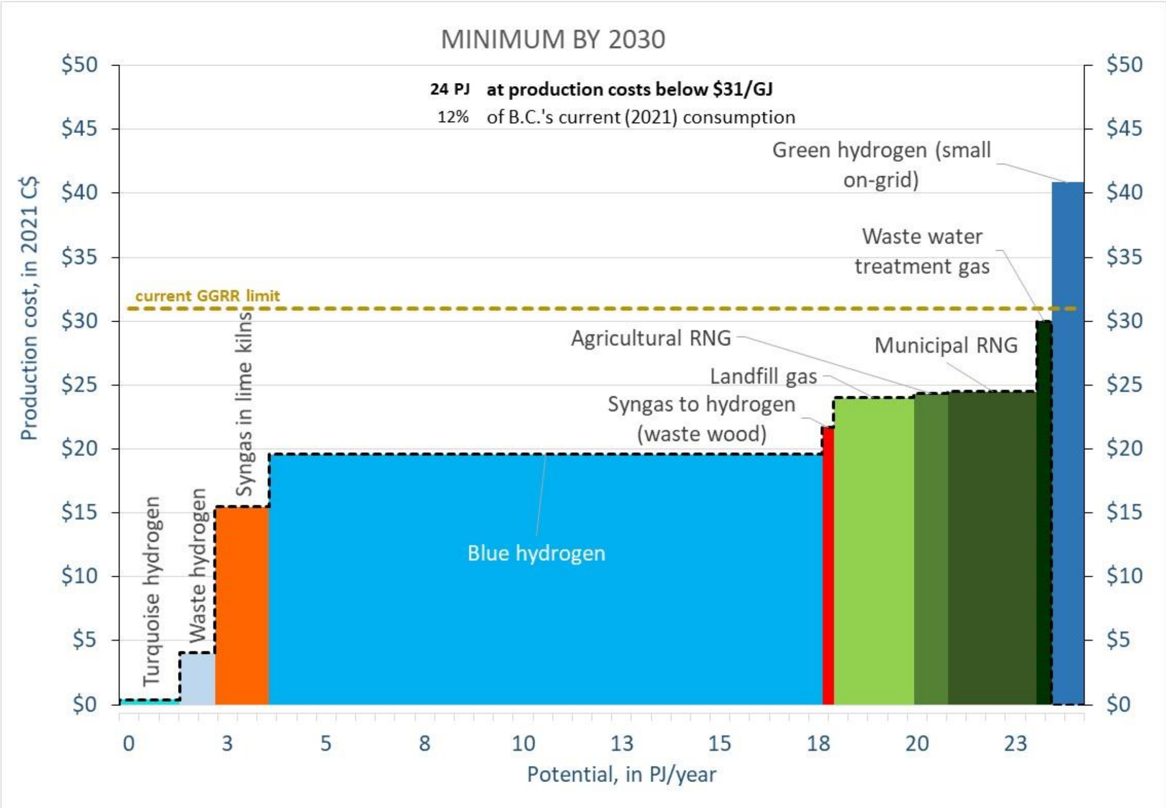
Minimum scenario: compared to the Maximum scenario, the 2030 target cannot be reached with provincial resources. If low-carbon gases are eligible and if action is taken now to implement blue hydrogen production, only 24 out of 30 petajoules per year required are produced in province. B.C: gas utilities would have to purchase 6 gigajoules a year of RNG from out-of-province resources. By 2050, the total available renewable and low-carbon gas levels off at around 100 petajoules, i.e. only about half of current natural gas distributed through pipelines can be displaced. Renewable and low-carbon gas imports would be necessary to fully decarbonize provincial gas usage unless B.C. gas consumption is reduced drastically. The lower gas production levels in this scenario are due to more pessimistic assumptions with respect to woody feedstock availability and built-out rates, as well as technology development (e.g., no RNG production from wood).

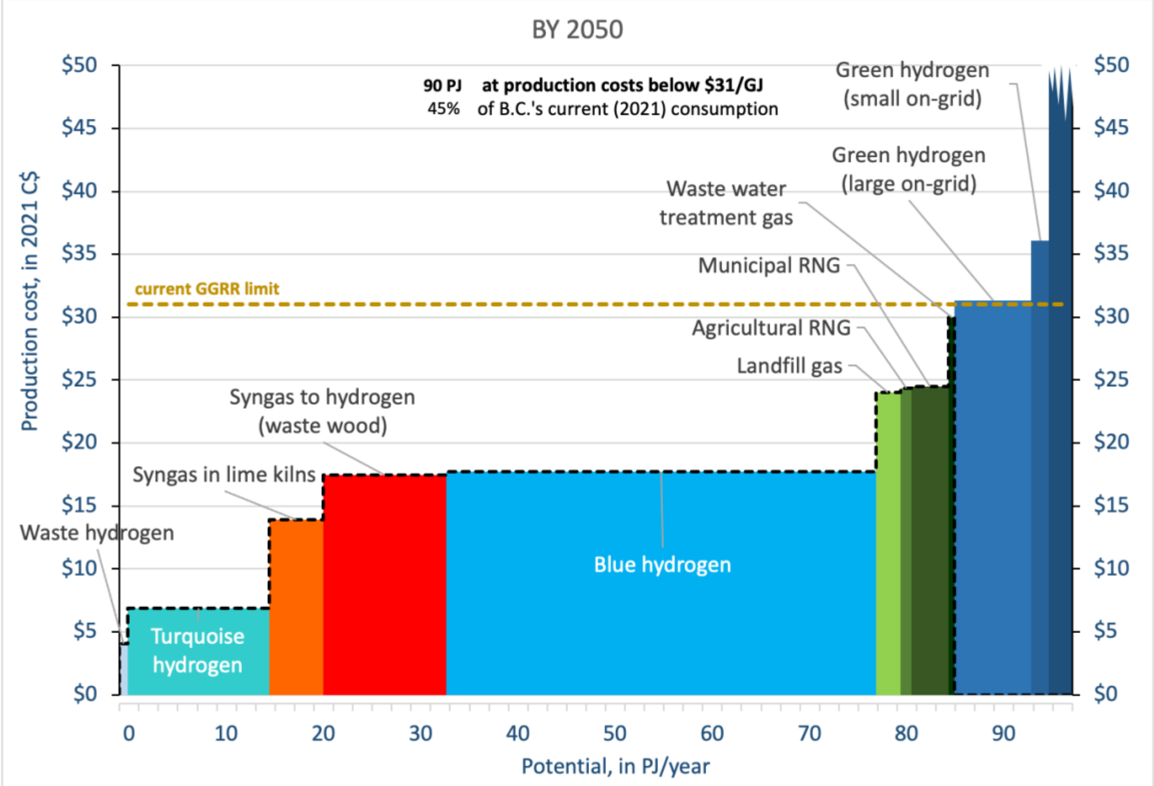




Note: To keep the graphs legible the size of the x-axis for 2030 are not the same as for 2050

Figure 32 2030 and 2050 Cost Curves for Renewable and Low-Carbon Gas Production (Maximum Scenario)





Note: To keep the graphs legible the size of the x-axis for 2030 are not the same as for 2050

Figure 33 2030 and 2050 Cost Curves for Renewable and Low-Carbon Gas Production (Minimum Scenario)

5.4 Supply Portfolios

5.4.1 Criteria for developing portfolios

The cost curves above show both costs and potential. These numbers are, in part, based on predictions and are subject to changes such as technology development and resource availability. The cost curves can be used to gauge the contribution that each pathway may make, and at what cost. Apart from the cost threshold of $31 per gigajoule (indexed with inflation), other criteria policy makers might want to consider include:

- **Geographical origin:** Gas produced outside B.C. will not have the same provincial social and economic benefits as gas produced within the province.
- **GHG footprint:** The government might set a minimum life cycle carbon intensity for gas to qualify for displacing natural gas. This could give preference to gases that have much lower – even negative – carbon intensities than others, possibly accelerating GHG reductions (Section 5.5).
- **Industry sector:** Renewable and low-carbon gas production may be promoted depending on the potential and need for job creation and how competitive the industry is.
- **Co-benefits**: Some pathways create co-benefits in addition to renewable gas. These co-benefits, which can include local employment, rural diversification and odour and nutrient management, may be considered when choosing which renewable and low-carbon gases to acquire.
- **Social acceptance:** Some pathways may be more acceptable than others. For example, social acceptance may be lower for carbon sequestration projects than for green hydrogen, or for large-scale wood gasification projects versus small-scale digesters. Buyers need to weigh the advantages of each and may have to engage in education efforts to defend purchasing decisions if they are faced with critiques in the media.
- **Speed of development:** As discussed above, some types of projects may require much longer lead times. This would apply to off-shore wind projects used to power electrolysers, or to blue hydrogen projects that need to inject carbon dioxide into the ground. Other types of projects may be developed more easily and quickly, especially to meet the 2030 targets.
- **Investment needs:** Some pathways require substantial investments for project development. A full-scale RNG production facility using woody feedstock may cost more than $300 million to build, which is more difficult to realize than smaller projects under $100 million, such as syngas production, or under $30 million, such as anaerobic digestion.
- **Technology status:** Pre-commercial pathways need to be supported with further R&D. Demonstration projects should be realized before 2030, possibly with public support, but near-term solutions lie in technologies that are already fully commercial today.
- **Diversity and hedging:** It may be advantageous to diversify the production portfolio, including several sources of renewable and low-carbon gases. This will reduce the risk of relying on a single source that may become more expensive or may even cease to exist over time, and will support the parallel development of new industries in several sectors.
- **Potential and replicability:** Some pathways have more potential than others in terms of how much gas can be produced.

5.4.2 Possible Supply Portfolios

Table 31 qualitatively compares the renewable and low-carbon gas pathways. Some clear messages can be derived:

- Green hydrogen remains too expensive for immediate consideration.
- Turquoise hydrogen is of great interest but not yet commercial.
- Waste hydrogen is also of great interest but very limited in terms of its resource potential.
- Syngas production from wood is the most achievable and lowest-cost option for using woody biomass.
- Wood-based pathways offer more social benefits than those based on electrolysis or blue hydrogen.
- Agricultural RNG is attractive based on several parameters but has limited potential.
- Anaerobic pathways are the most developed technologically and also relatively easy to develop.

Table 31 Qualitative Comparison of Renewable and Low-Carbon Gas Pathways

Pathway	Gas Cost	Invest-ment	GHG	Sector	Co-Benefits	Social	Speed	TRL	Poten-tial	Overall score
Green hydrogen (large on-grid)	--	-	+	o	o	+	+	+	+	**o**
Green hydrogen (small on-grid)	--	o	+	o	o	+	+	+	+	**o**
Green hydrogen (large off-grid)	---	--	+	o	+	+	--	+	++	**-**
Blue hydrogen	+	-	o*	+	-	-	--	+	++	**o**
Turquoise hydrogen	++	+	o*	++	-	+	-	-	+	**o**
Waste hydrogen	++	++	o	o	-	+	+	++	--	**++**
Syngas in lime kilns	o	+	+	+	o	+	o	+	+	**+**
Syngas to hydrogen	-	-	o	+	o	o	--	-	++	**o**
Syngas to RNG	-	--	o	+	o	o	--	-	++	**o**
Agricultural RNG	o	+	++*	+	++	o	+	++	+	**+**
Municipal RNG	o	+	+*	o	+	o	+	++	+	**+**
Wastewater treatment gas	+/o	+	+*	o	o	+	+	++	o	**+**
Landfill gas	+	++	+*	o	o	+	+	++	o	**+**

---- extreme; -- very bad; - bad; o neutral or small impact; + good; ++ very good

* Exact carbon intensity is disputed; see Section 5.5

In combination with the cost curves developed above, the supply portfolios for 2030 and 2050 could be structured as shown in Table 32. Options to facilitate these outcomes will be discussed in Chapter 6.0.

Another question is what role imported gases will play. This is discussed in the following section. As mentioned above among the criteria, a portfolio approach is desirable both in terms of creating more opportunities inside B.C. and offering more resilience for gas retailers that need to comply with government mandates. The breadth of this diversity will depend on the ability to pay for the gas – i.e., whether the $31 per gigajoule threshold is hard or flexible – to accommodate some of the more expensive sources. It is presumed below that such flexibility may not occur before 2030 and/or that more expensive sources may become more affordable after that date.

Table 32 Potential Supply Portfolios of Renewable and Low-Carbon Gases

	2030	2050
Primary sources	Waste hydrogen Anaerobically produced RNG Syngas in lime kilns Blue hydrogen	Turquoise hydrogen Syngas in lime kilns Hydrogen (or RNG) from wood Anaerobically produced RNG Waste hydrogen
Secondary sources	Turquoise hydrogen Hydrogen from wood (demonstration)	Blue hydrogen Green hydrogen

5.4.3 In-Province Versus Out-of-Province Supplies

FortisBC is currently buying RNG produced outside of B.C. (e.g., Lethbridge, AB and Des Moines, Iowa) for an existing voluntary market.[113] This option is in line with other jurisdictions, such as California, that use a certificate trading system to 'move' RNG between jurisdictions by separating and selling the environmental benefits of these gases. Buyers can then claim these benefits for their own gas use whereas, at the injection point, the RNG is treated as if it was generic natural gas. The green benefits therefore accrue where the buyer uses natural gas, not where the producer injects it, geographically decoupling RNG production and use.

While avoiding trade barriers, this system may leave most of the socio-economic benefits from renewable and low-carbon gas production outside of B.C. However, it can be harnessed to obtain low-cost RNG (e.g., from landfill gas sites) or hydrogen to protect B.C. ratepayers from exposure to high renewable and low-carbon gas pricing. It may also enable sourcing RNG with very low, or even negative, carbon intensities. This would be an advantage for reaching provincial and corporate GHG targets more quickly. Yet, sourcing all, or a large portion of, gases from outside B.C. will economically benefit producers in other jurisdictions, rather than keeping ratepayers' money inside the province. Some balance between imports and local production is therefore desirable.

As outlined in Chapter 2.0, the potential for anaerobic RNG production in the rest of Canada and the U.S. is large enough to cover all of B.C.'s gas needs. Both qualify as vendors of renewable gas because they are connected to B.C. through the continental gas grid. The Canadian potential (including B.C.) is deemed to be about 70 petajoules by 2030 and 80 petajoules by 2050. U.S. potential is deemed to be close to 600 petajoules in 2030 and about 630 petajoules in 2050. This means the entire 2030 B.C. target could, in theory, be procured inside Canada and any 2050 target could be complied with using Canadian and U.S. sources.

B.C. utilities are unlikely to secure as much of this gas as they wish to due to competition. In the U.S., several jurisdictions have implemented renewable gas policies and have created lucrative markets for RNG certificates (see Section 5.5). In Canada, Quebec is currently seeing uptake of RNG from landfill gas. Any first-mover advantage that B.C. gas utilities currently have may therefore disappear soon. Table 33 provides a comparison between the advantages and limitations of importing renewable and low-carbon

[113] https://www.fortisbc.com/services/sustainable-energy-options/renewable-natural-gas/meet-our-renewable-natural-gas-suppliers#tab-7 (Accessed October 5, 2021).

gases. The choice mainly relates to sourcing lower-cost, assured gas production outside B.C. versus creating more social and economic benefits inside the province.

Table 33 Renewable and Low-Carbon Gas Procurement in B.C. versus Imports

	Aspect	Purchase gas certioficates outside British Columbia	Develop renewable and low-carbon gas projects inside British Columbia
0.	Potential	Currently far in excess of required targets.	Sufficient to meet 15% by 2030 CleanBC target within $31/GJ threshold. Can theoretically replace entire B.C. gas consumption by 2050.
1.	Cost	Reduced cost to ratepayers if credits are purchased soon and for a long period.	Some of the gas purchased will cost more than out-of-province.
2.	Project portfolio	'Low-hanging fruit' will be developed first – mainly RNG from anaerobic digestion and landfills.	Range of pathways will be developed because B.C. offers better conditions than many other jurisdictions.
3.	Competition	Competition with other utilities and venture capital.	Less competition due to Fortis predominance as a gas utility in B.C.
4.	Control	Limited control over resources outside B.C. Credits may go to other bidders after initial contracting period.	Good control of biomass and electricity-based projects, some control over organic waste.
5.	Resilience to high price carbon markets	Some resilience if B.C. utilities are 'early movers'. High exposure to markets as regulatory framework is developed in other jurisdictions.	High resilience because B.C. utilities have right of first refusal.
6.	Impact on competing resource users	Low	Industries such as the pellet industry will see increased competition for 'energy wood.'
7.	Technology development	Limited incentives for technology development.	Developers and venture capital have incentive to develop and mature technologies.
8.	Compatibility with other B.C. government policies	Incompatible with desire to strengthen forest products industry and develop provincial renewable and low-carbon gas production.	Demand for electricity from B.C. Hydro will increase. Low-grade wood waste may be used for energy rather than higher-value products.
9.	Demand side management	Low gas prices discourage energy savings.	Increased gas prices will foster demand-side management.
10.	Cash flow	Net outflow of ratepayer money.	Ratepayer money stays inside B.C. Potential inflow of capital from out-of-province.

Table 34 takes a conservative approach for the potential of imported gases. A portion of RNG may be secured in the coming years as other jurisdictions ramp up their own renewable and low-carbon gas policies. After 2030, possibly, earlier, the first-mover advantage may cease to exist, and only incremental amounts may be secured. This is especially true in the U.S., where very high RNG certificate pricing has been observed together with rapidly increasing sales volumes.[114] This may price RNG out of reach for Canadian utilities. There is also the question of renewing RNG sales contracts after the 20-year procurement contract ends. A 20-year term is reasonable for the life expectancy of most RNG plants. At renewal, pricing is likely to adjust to market conditions, which may feature higher prices than at the start of such projects.

For hydrogen, low-cost resources such as waste hydrogen will likely be quickly secured by U.S. buyers. Turquoise hydrogen and other electricity-based gases would likely cost more in the U.S. than in B.C., and no imports are assumed. This leaves mainly blue hydrogen potential for imports. Since there is great potential inside B.C. for such gas, import needs are limited. They may still occur if B.C. production is slow to commence or if costs are lower outside of B.C. (e.g., where good sequestration opportunities exist). For the table, it is assumed that two large sources (100 tonnes per day) may be secured outside B.C. by 2030 and another two by 2050. The current wording of the GGRR does, however, not appear to allow for hydrogen imports as it requires that the gas must be delivered through the B.C. gas distribution system or directly used by a client to replace natural gas.[5]

Table 34 Anaerobic RNG and Hydrogen Import Potential

	Technical Potential, 2030	Achievable, 2030		Achievable, 2050	
Rest of Canada	60 PJ	10%	6 PJ	15%	10 PJ
U.S.	590 PJ	5%	30 PJ	7%	44 PJ
Blue hydrogen	Very large		8.4 PJ		17 PJ

The above assumptions are conservative and a more aggressive approach may deliver different results. Yet, even with these conservative assumptions, the resource outside B.C. will be more than sufficient to comply with the 2030 target. For 2050, an aggressive strategy would have to be in place to secure enough renewable and low-carbon gas production in competition with other jurisdictions. However, if certificate pricing remains high or increases, this may not be a profitable strategy.

With pricing of environmental credits over US$200 per tonne of CO_2 in recent years,[115] the value of renewable and low-carbon gases can be very high in the U.S. Table 35 provides a range of market values for different renewable and low-carbon gases, based on their carbon intensities (Cis). The higher CI value is typical for blue hydrogen, for example, whereas low positive values may apply to gases derived from solid biomass, and negative values refer to agricultural and municipal RNG. With a carbon intensity for natural gas of 60 kilograms per gigajoule (see next section), a gas that has an intensity of 30 kilograms per gigajoule would displace 30 kilograms per gigajoule. At C$260 per tonne of CO_2 under the California LCFS, this would reflect a value of $7.80 per gigajoule. Renewable Identification Number (RIN) pricing for R3 RINs (for RNG) have been about US$2.50 per RIN since 2020.[116] This corresponds to about C$38 per gigajoule – well above the current B.C. threshold of $31.[117]

[114] https://www.naturalgasintel.com/renewable-natural-gas-potential-just-scratching-the-surface-but-obstacles-remain/ (Accessed October 5, 2021).
[115] https://ww2.arb.ca.gov/resources/documents/lcfs-credit-clearance-market (Accessed October 5, 2021).
[116] https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information (Accessed October 5, 2021).
[117] https://www.waste360.com/gas-energy/where-renewable-natural-gas-moving-forward-and-what-will-mean-industry-and-states-part-2 (Accessed October 5, 2021).

Table 35 Current U.S. RNG Certificate Pricing, in C$*

Gas Carbon Intensity	RIN Value	LCFS Credit Value**	Total
30 g/GJ	$38	$7.8/GJ	$46/GJ
5 g/GJ		$14.3/GJ	$52/GJ
-100 g/GJ		$41.6/GJ	$80/GJ
-400 g/GJ		$117/GJ	$155/GJ

* Converted from US$ at a rate of C$1.3/US$

** Depends heavily upon the California Low-Carbon Fuel Standard Credit price, which has been as low as US$71/tonne in June 2017 and as high as US$217/tonne in February 2020. The price in October 2021 was US$158/tonne.[118]

The important takeaway from this table is that at current pricing levels, it is impossible for B.C. utilities to buy even gases with a comparatively high CI through certificate trading as pricing is higher than the C$31 per gigajoule threshold. This may change in the future but the best strategy is to source the gas from projects through long-term purchasing agreements at the investment stage. This implies high transaction costs and a limitation to greenfield projects or projects that have previously sold their gas into different markets (e.g., using biogas for power generation). Blue hydrogen does not fall under the RIN system but would earn LCFS credits in the U.S.

A strategy for gas utilities in B.C. is to secure renewable and low-carbon gas supplies outside the province to hedge against the risk of insufficient resources below the ceiling price in B.C. by 2030. This is a no-regrets strategy since utilities can sell surplus credits into the gas credit market later if there are enough low-cost gas sources in the province. If credit pricing remains high, this may mean that profits can be obtained from such activity, which could in turn reduce the cost of gas for B.C. ratepayers. Sourcing renewable and low-carbon gases provincially should still be a priority as it creates the support structures that establish this industry in B.C.

5.5 Carbon intensity and emission reductions of supply portfolios

The potential that this report has established is based on petajoules of renewable and low-carbon gas rather than tonnes of CO_2e displaced. A policy switch away from energy and towards carbon abatement as a measuring parameter would have to look at a different metric to measure compliance with GHG targets. This section assesses the carbon mitigation that can be achieved with the existing potential.

The various pathways differ in their use of resources and thereby in the amount of greenhouse gases (GHG) emitted. The spreadsheet model factors in carbon credits from the displacement of GHGs that would occur in the absence of the project. Using GHG emission factors published by the B.C. Ministry of Environment and Climate Change Strategy (MECCS)[119] and other data, the model determines the carbon intensity of each pathway. Literature values are also used to determine the reported range of carbon intensities. The carbon intensity can vary significantly from one pathway to another, or even between projects within the same pathways, especially when methane is emitted, a powerful GHG with a high global warming potential.

Carbon emissions of <u>agricultural and municipal RNG</u>: Most pathways described in this report have a GHG footprint lower than that of natural gas. Agricultural RNG, especially from projects involving liquid manure (such as dairy and hog farms), even has a strong negative carbon intensity as it captures methane that

[118] Source: California Low Carbon Fuel Standard Credit price | Neste.

[119] BC Ministry of Environment and Climate Change Strategy, « B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions, 2020 », Victoria, B.C., April 2021.

would have escaped from manure stored in open pits.[120] Some of the carbon intensities reported do not include GHG emissions that happen outside the digester. Digestate is removed from the digester while anaerobic reactions continue to produce uncaptured methane for a while. Many life-cycle analyses include some emissions from digestate in the actual facility and some from spreading digestate on the land. The 'GHG Genius' model used by the government may not include the latest data and may exclude some emissions associated with digestate.[121]

Carbon emissions of RNG from landfill gas and WWTPs: At times, landfill gas and WWTP RNG projects reportedly have higher CI scores than natural gas in B.C. This is because most CI data for landfill gas and WWTP RNG projects comes from the California LCFS, which counts GHG emissions during RNG production and from the transportation and compression of RNG to approximately 3,600 PSI (248 bar) for use as vehicle fuel. As such, if landfill gas and WWTP RNG projects are built in U.S. states with high CI electricity, the CI of the RNG can be quite high.

Carbon emissions of natural gas: Similarly, fugitive emissions from the extraction of natural gas, especially related to hydraulic fracturing, may result in significantly higher GHG emissions than stated. The burner tip emission intensity of natural gas (close to 50 kg per gigajoule) needs to be augmented with upstream emissions, currently estimated at between 6 and 12 kilograms per gigajoule for B.C. natural gas.[122] Recent remote measurements indicate that this may still be an underestimation by a factor of two as some fugitive emissions have not been captured in previous ground surveys.[123] Any uncertainties with respect to natural gas also apply to natural gas-derived low-carbon gases.

Carbon emissions of blue hydrogen: Converting methane into hydrogen is an overall endothermic process, that is, heat/steam must be supplied to the process for the reaction to proceed. This steam is usually produced using natural gas as a fuel. The CO_2 emissions from the steam boiler may or may not be captured and sequestered. Powerful compressors are used to inject and sequester the captured CO_2 into geological formations. These pumps may be fuelled by green electricity or by natural gas. Hydrogen has a lower calorific value than natural gas (12.7 gigajoules per standard cubic metre as opposed to 39 gigajoules per standard cubic metre) requiring more pump energy per gigajoule to deliver gas through the pipeline to the end user. Most natural gas compressor stations are powered by gas-powered combustion engines,[124] which vent exhaust emissions into the atmosphere.

Blue hydrogen merits a closer look due to the uncertainties and technology pathways that can lead to significant differences in carbon intensities. The Pembina Institute evaluated the carbon intensity of blue hydrogen produced with different technology pathways. In that they found that existing steam methane reforming (SMR) technologies employed like at the Quest upgrader in Alberta leads to a modest reduction in carbon intensity.[125] Other studies suggest even higher GHG emissions for blue hydrogen than for natural

[120] This is considered for the California LCFS but currently not for the B.C. LCFS, which may lead to very different carbon credit values from the same source.
[121] Fusi et al., "Life Cycle Environmental Impacts of Electricity from Biogas Produced by Anaerobic Digestion," March 2016, Front. Bioeng. Biotechnol., Accessed on October 8, 2021 at https://doi.org/10.3389/fbioe.2016.00026
[122] Liu, Ryan *et al.*: Greenhouse Gas Emissions of Western Canadian Natural Gas: Proposed Emissions Tracking for Life Cycle Modeling. *Environ. Sci. Technol.* 2021, 55, 14, 9711–9720
[123] Tyner, David and Johnson, Matthew: Where the Methane Is - Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data. *Environ. Sci. Technol.* 2021, 55, 9773–9783
[124] Enbridge, "Transporting Natural Gas", accessed on Dec 4, 2021 at https://www.enbridge.com/about-us/natural-gas-transmission-and-midstream/natural-gas-101/transporting-natural-gas/compressor-stations
[125] Gorsky et al., Pembina Institute, "Carbon intensity of blue hydrogen production", Aug 2021, accessed on Jan 28, 2022 at https://www.pembina.org/pub/carbon-intensity-blue-hydrogen-production

gas.[126,127] Pembina's report states that "*there are a wide range of carbon intensities for blue hydrogen, depending on the choice of technology (SMR or ATR), carbon capture rate, emissions associated with imported electricity, and the emissions from natural gas production (which vary by production basin).*"

A robust regulatory framework that addresses upstream GHG emissions sources like fugitive methane and supports best available technologies is important to ensuring that blue hydrogen production pathways are as low-carbon as possible to align with long-term GHG reduction goals.

Carbon emissions of wood-fuelled gas: Using roundwood for energy purposes accelerates the emission of carbon contained in the wood, and creates a carbon dept that must be paid back through regrowing felled trees over time. This is because there is essentially no residence time for carbon in the final product (i.e. the fuel) before energy is created, as opposed to lumber which might remain in solid form for decades or centuries before disposal. For mill and harvesting residue, convention typically attributes the majority of emissions to the harvested wood products, such as dimensional lumber or pulp. The residue is then counted as close to carbon neutral. In the Maximum scenario, some roundwood is harvested to produce RNG or hydrogen. The initial carbon removal that is reported as a loss in the Canadian GHG inventory when a tree is cut would then be attributable to this portion of the feedstock. RNG made from wood then has a similar carbon footprint as natural gas, since the carbon in the RNG produced is counted as an emission. Unlike with natural gas, however, trees regrow over time and the carbon debt is then paid off as the same amount of CO_2 is sequestered as harvested stands are renewed. The B.C. carbon stock accounting system is not yet set up to capture these processes fully. Over a 50-to-100-year timeframe, roundwood is also carbon neutral. It will be a policy decision as to how temporary emissions from roundwood for energy are accounted for, and whether and how the repayment of carbon debt enters the equation.

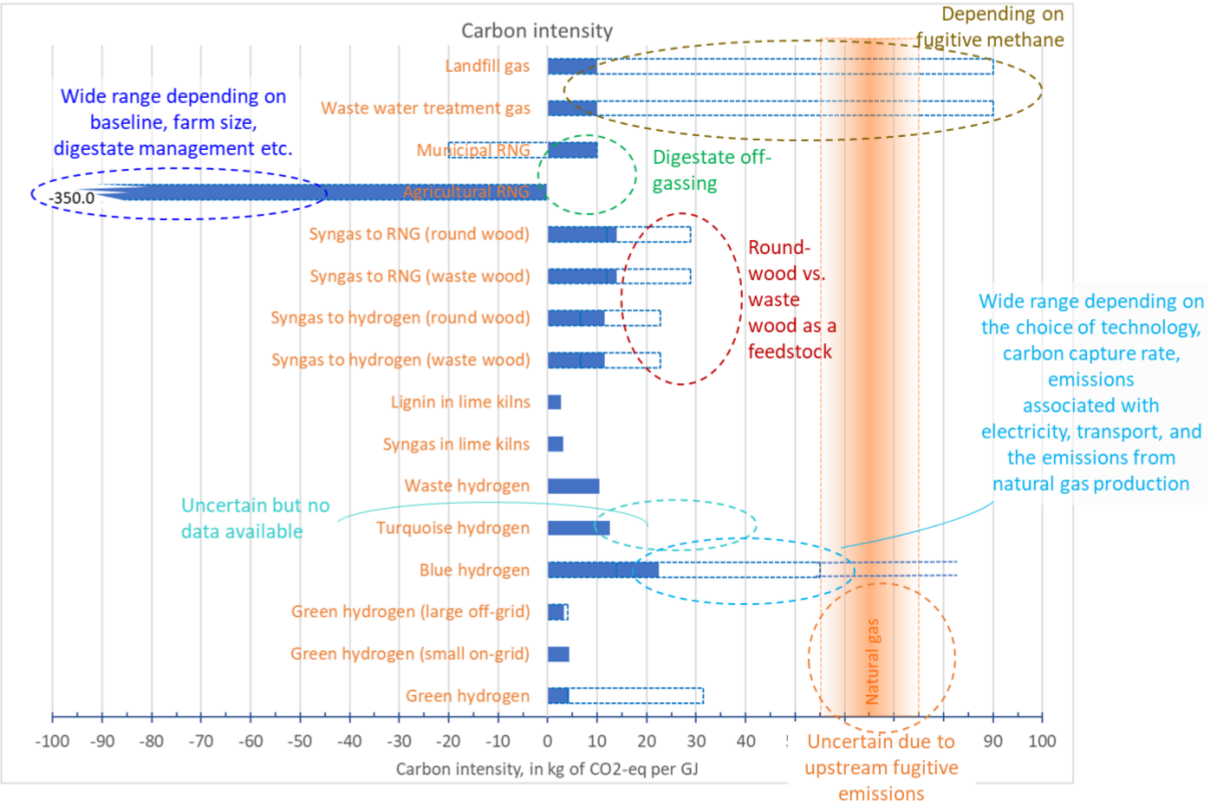
The examples above show that refining emission factors and quantification protocols is still on-going and substantial uncertainties exist with the GHG profile of some of the pathways discussed in this study. The factors published by MECCS, largely used in this study, may reflect neither the latest science on the full upstream emissions of natural gas exploration nor the downstream emissions of biogas production. As science improves, carbon accounting protocols will change. MECCS updates its "B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions" on an annual or bi-annual basis.

A climate change strategy that is largely based on blue and turquoise hydrogen or on anaerobic digestion might be at risk of having to correct the carbon intensities of these pathways over time. This may become important as the Government of B.C. is contemplating switching from targets pegged to energy production to those related to GHG intensity. Figure 34 provides the carbon intensities used in this report (solid green bar) and the range that could be gleaned from some published studies.

[126] Bauer et. al., "On the climate impacts of blue hydrogen production", Sustainable Energy and Fuels journal, Issue 1, 2022, accessed on Jan 28, 2022 at https://pubs.rsc.org/en/content/articlelanding/2022/se/d1se01508g

[127] Robert W. Howarth, Mark Z. Jacobson, "How green is blue hydrogen?" *Energy Science and Engineering*, August 2021, accessed on on Jan 28, 2022 at https://onlinelibrary.wiley.com/doi/full/10.1002/ese3.956

Figure 34 Carbon Intensities of Renewable and Low-Carbon Gas Pathways as reported in literature



Notes:

- Dashed bars indicate the range of factors stated in various publications.
- Error bars represent uncertainty with respect to life-cycle GHG emissions for various pathways.
- For anaerobic RNG, uncertainty arises with both accounting methodologies (including avoided emissions from lagoons in the agricultural sector, consideration of methane off-gassing from digestate), fugitive emissions (e.g., leakage from repeated gas transfers), as well as indirect emissions (compression to high pressures for use in transportation using more or less green electricity).
- Different conversion technologies and energy types used for gas production from wood will result in different CI values.
- For green hydrogen, the CI of the electricity used determines the CI of the hydrogen produced.
- For both natural gas and or turquoise and blue hydrogen, upstream emissions from gas production, conversion, sequestration and transport, as well as CO_2 leakage from geological storage can have impacts.
- No data is available for turquoise hydrogen but uncertainties will likely be in the same range as for natural gas.

6.0 CREATING THE B.C. RENEWABLE AND LOW-CARBON GAS INDUSTRY

6.1 Key considerations and Desired Outcomes

As discussed in Section 5.4.1, there are many considerations for the choice of renewable and low-carbon gas pathways for B.C. The B.C. Government wants to weigh three main considerations:

(a) Achieve the CleanBC *Roadmap to 2030* goals, including a minimum of 15% renewable being retailed in B.C. by 2030, reducing emissions while supporting a strong economy, supporting innovation, and implementing a cap on emissions for natural gas utilities.

(b) Keep the cost of pipeline gas affordable. Low gas prices are important to keep energy costs affordable in the province. Increasing energy costs disproportionately affects the poor and energy-intensive industries. Changes must be gradual and must occur in a considered way to be socially acceptable.

(c) Develop a bioeconomy within B.C., maximizing socio-economic benefits for the province. The renewable and low-carbon gas should be made in-province. Producing gas from local biomass can increase local benefits over the current situation, especially if wood fuel exports were redirected towards provincial renewable gas production. It could also stabilise the forest product industry if BC Hydro contracts expire without renewal around 2029. In addition, the gases produced should have a low (or negative) carbon intensity.

These considerations lead to the question of how best to support a transition towards renewable and low-carbon gas use in B.C. and what types of policies should be implemented, above and beyond those currently in place.

6.2 Best Policy Pratices in Other Jurisdictions

6.2.1 Main Policy Approaches

The promotion of anaerobic RNG and other renewable and low-carbon gas types, takes place across a broad spectrum of policy areas ranging from agricultural/forestry, waste, energy, climate, and general environmental policy. As illustrated in Figure 35, the RNG value chain can be affected and enhanced at several stages, including facilitating feedstock acquisition, creating a demand-pull using incentives or mandates, and a regulatory environment that supports RNG deployment.

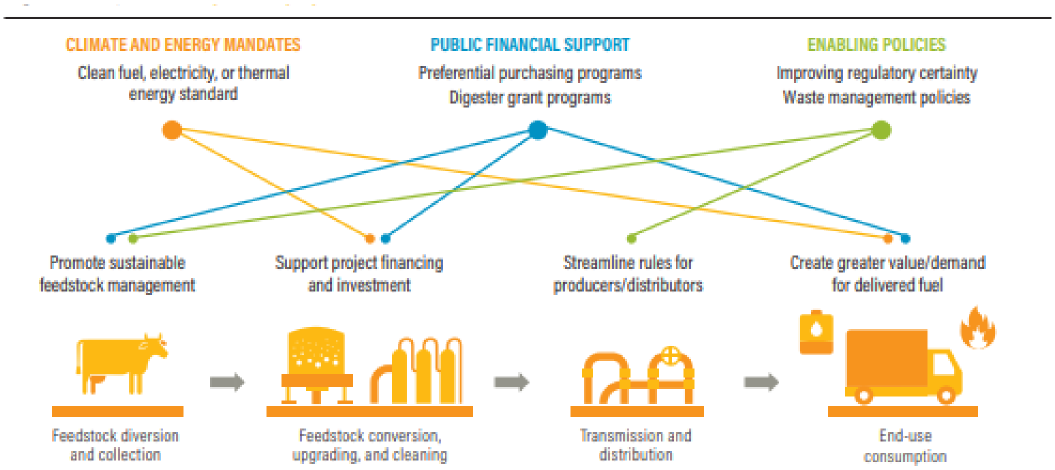


Figure 35 Policies Promoting the Development of RNG[128]

[128] Cyrs, Tom, John Feldmann, and Rebecca Gasper. 2020. "Renewable Natural Gas as a Climate Strategy: Guidance for State Policymakers." World Resources Institute. https://doi.org/10.46830/wriwp.19.00006.

Countries and states have created legislation regarding renewable energy to diversify their energy resources, promote provincial energy production and encourage economic development. Three approaches to promoting renewable energy have evolved over the last decades.

1. Renewable Portfolio Standards (RPS) or Clean Energy Standards (CES) are quantity-based schemes in which the regulator requires a specific amount or proportion of gas to come from renewable or 'clean' low-carbon sources. A carbon intensity standard is a variation of this approach.
2. Feed-in tariffs (FIT) guarantee all eligible producers a fixed price per gigajoule of gas fed into the grid. The tariffs are linked to standardized and simplified interconnection rules.
3. Public tenders: A certain amount (in gigajoules per year) or value (in $ of investment) for renewable or low-carbon gas is publicly tendered and sold to the lowest bidder or bidders with the highest volume.

Table 36 outlines key features of each instrument. All of them have been tried and tested in the electricity sector over the last decades. There are variations of, and supplementary policies for, each of them used in various jurisdictions. These are described below.

Table 36 Policy Instruments for Promoting Renewable and Low-Carbon Gas Production

	Renewable Portfolio Standard, Clean Energy Standard or LCFS	Feed-in tariff or premium system	Public tenders or auctions
Approach	Quota for renewable or low carbon gas or quota for maximum GHG intensity.	Set price for renewable or low-carbon gas fed into the grid, or premium/ bonus paid on top of fossil natural gas price.	Individual tenders for a certain type of renewable or low carbon gas. Reverse auction mechanism.
Mechanism	Volume-based	Incentive-based, can be restricted by total target volume.	Either volume or price-based.
Technology	Technology neutral. Only eligible technologies.	Technology specific. Carve-outs for specific technologies.	Technology-specific
Control of portfolio	Investors and producers decide which pathway/technology is used.	Government controls tariff for each pathway/ technology.	Tender specifies type and volume of gas, typically large projects only.
Target control	Penalty for not reaching target(s).	Markets and tariff decide uptake. Cap and floor for premiums	Penalty for winning and then not implementing capacity.
Certificate trading	Possible	Not possible.	Not possible.
Investment security	No investment security.	Stable cash flow insulates investors from revenue risks.	Binding investment limit. High risk for investors.
Adminis-trative effort	Low	Medium	High
Build-out / installed capacity	Build-out rate dependent on target.	Robust short-term growth and high build out if incentives adequate.	Many bids end up being too low and projects fail.

	Renewable Portfolio Standard, Clean Energy Standard or LCFS	Feed-in tariff or premium system	Public tenders or auctions
Local development	Certificate trading may not encourage local development.	Incentives for selective technologies can promote local and specific local development	Frequently larger bidders from out-of-province.
R&D	Lowest price technologies succeed. Little R&D.	Stimulates R&D input to reduce costs.	Lowest-price technologies succeed. Little R&D.
Cost-effective-ness	Least-cost instrument. Competition between technologies. Self-corrects. More efficient to reduce GHG emissions and cost to ratepayers.	Lack of competition leads to higher cost than RPS. Requires continual adjustment by government/utility board Low transaction cost and low risk leads to low financing cost.	Strong push for low costs but some projects then fail due to often higher than expected cost. High transaction costs.
Impact on ratepayers	Lower social risk than feed-in tariff.	Cost to ratepayer may be volatile.	Typically, lower than feed-in tariff
Key challenges	Low build-out pace.	Social acceptance might decline with increased costs to ratepayer.	Top-down approach often does not meet with reality on the ground. Monopolizes production. Political insecurity.
Compatibility with existing B.C. policies	15% renewable gas commitment Low-carbon fuel standard.	Eligible CI can be defined. Maximum cap for total or per category and per year can be defined.	BC Hydro approach to buying power from third parties.

6.2.2 Current B.C. Policy

B.C. currently has a favourable policy framework for RNG development, including market support. Both pipeline gas and vehicle fuel are supported by B.C.'s Renewable Portfolio Allowance and the LCFS. The B.C. commitment to source 15% of renewable gas in gas sales is currently the most ambitious in Canada, higher than the current 10% by 2030 target for renewables gases in Quebec, which has very similar natural gas retail demand to B.C.[129] The carbon tax of $45 per tonne of CO_2e is among the highest in North America and is scheduled to rise to $50 in 2022,[130] then to increase at least in line with federal rates. However, the

[129] https://www.quebec.ca/en/government/policies-orientations/plan-green-economy (accessed November 22, 2021)

[130] https://www2.gov.bc.ca/gov/content/environment/climate-change/clean-economy/carbon-tax (Accessed October 11, 2021).

LCFS and voluntary purchase program have been the key drivers of growth in RNG. Under the 2018 CleanBC Plan and the 2021 *Roadmap to 2030*,[131] several targets related to RNG were announced:[132]

- Minimum 15% renewable gas target by 2030.
- Increase in the Carbon Tax to $50 per tonne by 2022, then to meet or exceed federal tax levels,
- Tripling the LCFS from a 10% reduction in carbon intensity in 2020 to a 30% reduction by 2030.
- Aiming to get to 95% organic waste division and capturing 75% of landfill gas by 2030.
- A GHG emissions cap of approximately 6 Mt of CO_2e per year for 2030 for gas utilities.

Follow-up policies have included purchases of CNG buses which can easily be switched to RNG, and an Organic Infrastructure Fund, which provided $30 million of funding from various sources to improve organic waste management. Also, the Organic Matter Recycling Regulation Intentions paper calls for stricter environmental assessments and controlled atmosphere composting (negative air pressure, biofilters, leachate control for all composting facilities that consume over 15,000 tonnes of food waste or biosolids per year).[133]

At the local level, some municipalities are interested in reducing and perhaps eliminating residential natural gas use as part of their climate action strategy. Such jurisdictions include the City of Vancouver, which has the power to control its building code, and the City of North Vancouver, which allows a less strict step code adoption for natural-gas-free buildings.[134]

6.2.3 Canadian Clean Fuel Standard and Other Federal Policies

While originally planning to have separate streams for solid, gaseous and liquid fuels, the Canadian Government announced in 2020 that the Clean Fuel Standard will only apply to liquid fuels,[135] however RNG used in vehicles can be used to generate compliance credits. The Clean Fuel Standard will require a 13% reduction in fuel carbon intensity below 2016 values by 2030.[136]

The federal carbon tax is currently (2021) at $40 per tonne of CO_2e and will increase to $50 in April 2022. The government's intent is to increase it further, to $170 (nominal) per tonne in 2030.[137] This will apply to fossil natural gas in the pipeline, thus reducing the price differential between renewable and low-carbon gases and natural gas. This will also increase costs for renewable and low-carbon gas production where natural gas is used for process heat (some of the wood gasification processes).

6.2.4 U.S. Policies

Policies at the state level vary between states, with California having the most comprehensive set of policies. Most RNG policies have centred around its use as a vehicle fuel. This is primarily through its use in compressed natural gas vehicles, which currently have a 40% RNG market share in the U.S.

[131] B.C. Ministry of Environment (2021) CleanBC: Roadmap to 2030
[132] B.C. Ministry of Environment (2018) CleanBC: Our Nature, Our Future, Our Power.
[133] B.C. Ministry of Environment (2018) OMRR Policy Intentions Paper.
[134] https://www.nsnews.com/local-news/north-vancouver-district-probes-gas-free-future-3123997 (Accessed October 5, 2021).
[135] https://gowlingwlg.com/en/insights-resources/articles/2021/canadian-clean-fuel-regulations/ (Accessed October 18, 2021).
[136] https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-standard/about.html (Accessed October 11, 2021).
[137] https://www.cbc.ca/news/politics/carbon-tax-hike-new-climate-plan-1.5837709 (Accessed October 11, 2021).

Some states have made significant changes, with Washington, Oregon, California and Nevada developing either voluntary or system-wide RNG policies. The combined Federal Renewable Fuel Standard credits (called 'Renewable Indentification Numbers' or 'RINs') and California's LCFS credit value adds up to around C$21 to C$107 dollars per gigajoule (see also Table 35), with most RNG being over C$31 per gigajoule. California's population and economy are larger than all of Canada and several other states have also implemented RNG policies. Considerable demand could be generated in these jurisdictions and B.C. utilities may only compete with difficulty. On the other hand, enhanced electrification and other low-carbon fuels may limit demand for RNG in the U.S. market. Nonetheless, with RNG being the first mass-produced advanced biofuel, competition with the U.S. is likely to increase in the long-haul trucking sector.[138]

LCFS programs are under discussion in the U.S. northeast and mid-Altantic[139] (Transportation and Climate Initiative). Minnesota, Colorado, Iowa, South Dakota and others are considering LCFS policies , which may significantly increase demand for low-carbon and renewable fuels. When all the proposed and existing LCFS policies are considered, demand for low-carbon-intensity fuels should increase significantly. This is noteworthy, as the Californian LCFS alone has sparked considerable RNG development across the continent, with RNG being purchased from as far away as Quebec. With increasing demand for renewable and low-carbon fuels, prices are expected to rise, particularly for very low and negative carbon intensity projects RNG. Any first-mover advantage that B.C. utilities may currently have when securing supplies of low-cost RNG will likely disappear over the coming years.[140]

State-level policies are also driving RNG demand for the natural gas utility sector. California, Washington, Oregon and Nevada are all developing either voluntary or mandatory procurement of RNG by their natural gas utilities. Other noteworthy policies include organics diversion mandates in some states (California, Connecticut and Massachusetts)[141] and low-interest loans for RNG projects in Iowa.[142] California also has a program to extend infrastructure to large clusters of dairy farms.[143] Wisconsin and Washington State have funded agricultural digesters to reduce agricultural impacts on lands and water. Finally, watershed nutrient trading is considered, which allows farmers to trade nutrient permits and thus provides economic support to solutions such as anerobic digestion.[128]

Table 37 provides an overview of the most relevant U.S. policies affecting renewable and low-carbon gas production and markets. One can cnoclude that competition for RNG and RNG certificates will increase further with time. Especially California's LCFS market provides higher financial gains than B.C.'s. Quebec also recently announded renewable gas portfolio targets that are comparable to those of B.C. There is a risk that provincially produced RNG will leave the province.

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[138] EBA/WBA (2021) Smart CO2 Standards for Negative Emissions Mobility.
[139] https://www.transportationandclimate.org/ (Accessed October 11th, 2021).
[140] https://thejacobsen.com/news_items/states-considering-lcfs/ (Accessed October 11th, 2021).
[141] https://www.biocycle.net/organic-waste-bans-recycling-laws-tackle-food-waste/ (Accessed October 11, 2021).
[142] https://www.legis.iowa.gov/docs/publications/BL/1207158.pdf (Accessed October 11, 2021).
[143] https://www.act-news.com/news/massive-rng-supply-boost-in-california-dairy-digester/

Table 37 Current U.S. Policies Pertaining to Renewable and Low-Carbon Gas[144,128]

State	Low-Carbon Fuel Standard	RNG Pipeline Sales	Infrastructure/Other
California	• State LCFS[145]	• Biomethane target under development. • Utilities' (Southwest Gas, SoCalGas and SDG&E) RNG purchases including eliminating price caps for the last two (voluntary program).	• Clusters for Dairy RNG, including infrastructure funding. • Organics landfilling regulations • Cap and Trade program at state level • Short-lived Climate Pollutants plan. • Ability for developers to establish grid connection and requirement for reasonable time period for utility. • Standardised interconnection procedures among gas utilities to facilitate RNG production • Dedicated pipelines to large, industrial dairy farm clusters
Washington	• State LCFS under development[146]	• Under development to allow either voluntary or system-wide RNG sales.[147]	
Oregon	• LCFS under development with a target of 25% below 2015 levels by 2030	• Target for 5% RNG with thermal energy credits under development. Some integration with state LCFS.	• Cap-and-reduce program for RNG to reduce GHG intensity of gas distributedin state.
Iowa			• Low-interest bonds for farm RNG development.
Nevada	• LCFS envisaged[148]	• Utilities allowed to sell RNG. Encourages RNG to be in supply portfolio.	

6.2.5 Recommendations for B.C.

B.C. has a robust framework for the development of RNG with strong price support for deployment. One threat to this leadership is competition from the California market due to the very lucrative combination of the federal Renewable Fuels Standard and state-level LCFS revenues. Acquiring RNG from out-of-province could become increasingly difficult, particularly for low or negative-carbon intensity RNG

144 https://www.rngcoalition.com/policies-legislation (Accessed October 11th, 2021).
145 https://energynews.us/2021/05/13/california-clean-fuel-standard-sparks-renewable-gas-boom-in-midwest/ (Accessed October 11th, 2021).
146 https://ecology.wa.gov/Air-Climate/Climate-change/Greenhouse-gases/Reducing-greenhouse-gases/Clean-Fuel-Standard
147 http://biomassmagazine.com/articles/15172/inslee-signs-bill-to-promote-rng-in-state-of-washington
148 https://www.argusmedia.com/en/news/2165860-nevada-includes-lcfs-in-climate-strategy (Accessed October 12, 2021).

products. B.C.'s first-mover advantage can be used to procure RNG from projects where it can be secured with 20-year contracts. This hedges against stronger than expected costs from locally produced gas. If locally-produced gas can then be procured, any excess gas credits can be sold into the open market. The following areas should also be addressed to expand renewable and low-carbon gas production in B.C.:

Feedstock:

1. Continue working on improving the ability to recover harvesting residue through subsidies (Forest Enhancement Society programs) and the supply chain, using better methods and technologies.
2. Implement meaningful cost mechanisms to motivate forest product companies to recover most of the harvesting residue.

Financial:

1. Low-interest financing could be provided for agricultural digesters (and other types of gas production), as done in Iowa.
2. Provide funding to support the additional cost of RNG deployment over composting or other organics/wastewater solids disposal options.
3. Work with agricultural organizations to promote cooperatively-owned or operated centralized RNG plants, including a possible sustainable agriculture payment scheme for digestate use and soil carbon enhancement.
4. Financially recognize the broader social and ecological benefits of anaerobic RNG production, as AD with nutrient management can play an important role in preventing nutrient overload on lands and waters, increasing soil carbon, reducing methane emissions, and providing a low-carbon fuel for the gas grid and NGVs.
5. Continue to support R&D and demonstrationand first commercial-scale facilities to produce low-carbon gas.
6. Create mechanisms to support renewable and low-carbon gas production at larger scales from woody feedstock, such as higher gas rates being paid during the first years of operation to shorten payback periods, or low-cost, long-term financing for capital-intensive projects.

Infrastructure:

1. Work within B.C. and with neighbouring jurisdictions to make the gas system hydrogen-ready.
2. Proactively plan for network meshing, reverse flows and other measures to integrate renewable and low-carbon gas.
3. Work with BC Hydro to ensure that enough new power generation capacity is available after 2029 to enable green and turquoise hydrogen production in B.C. Electrolytic hydrogen production could be linked to on-grid power production commensurate with new demand and based on facilitated grid access for new renewable power generation linked to, but not necessarily in close proximity to hydrogen production hubs.

Regulatory:

1. Prioritize AD over composting when treating separately collected organic waste.

2. Allow for an average renewable and low-carbon gas cost of $31 per gigajoule, instead of the $31 ceiling, to facilitate demonstration projects and green hydrogen at higher costs (without requring BCUC approval each time), as was proposed in a previous study.[227] This would enable increased provincial production during the initial years; the cost cap could then be reduced over time.
3. Consider a renewable gas feed-in tariff that assigns cost thresholds depending on the pathway used, similar to feed-in tariffs in the electricity sector. Mature low-cost pathways may have lower thresholds than technologies under development. These cost caps should be reduced over time as prices come down.
4. If the current percentage target is retained, define five-year carve-outs for each pathway that require gas utilities to buy gas from several different sources rather than only the lowest-cost ones.
5. Alternatively, a carbon cap that requires utilities to account for the life-cycle carbon intensity of renewable and low-carbon gases fed into the pipeline could lead to a more diversified mix where more expensive sources may still be preferred if they have low or negative CIs.
6. In the longer term, consider coupling green hydrogen production with grid balancing and for energy storage to remunerate such services with revenue created from hydrogen production and release on demand, to create incentives to add green hydrogen production.

Climate:

1. Examine means to incorporate climate benefits from lower nitrogen fertilizer use and increased soil carbon due to the use of digestate from anaerobic RNG production.
2. Align international GHG quantification protocols to better compete in the international market.
3. Review the carbon footprints of blue and turquoise hydrogen and the anaerobic pathways to ascertain their impacts in terms of GHG emission reductions.

Demand-side management and technology switching:

This study focuses on the supply potential for renewable and low-carbon gas production pathways. Pathways beyond renewable and low-carbon gas are outside the scope of this report. A more comprehensive approach would compare primary energy use of various pathways in a 'well-to-heat' manner. Currently, 45% of natural gas consumed in B.C. is used by the residential and commercial sector.[149] The residential sector alone uses around 48 petajoules per year of natural gas for low-temperature space heating.[150] This need for low-temperature heat can be met more effectively by pathways other than low-carbon gas.

For example, green hydrogen can be produced with a conversion efficiency of 65% to 75% of the electricity used. Methanation of syngas to produce RNG is expected to have 95% conversion efficiency. A downstream household may use renewable gas in its furnace or boiler at a seasonal efficiency of 80% to 85%. The total system efficiency multiplies to 46% to 61% of the electricity input. In comparison, an air-source heat pump used in the climate of southern coastal B.C., where most of the population is located,

[149] https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-british-columbia.html (Accessed October 17, 2021).
[150] https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=bc&rn=8&page=0 (Accessed October 17, 2021).

can achieve a coefficient of performance (equivalent to an efficiency) of 300% to 350% of the electricity used, i.e. it is six to eight times more efficient than heating with gas.

The life expectancy of residential buildings in Canada ranges from 42 years for apartment buildings with less than five storeys to 65 years for single detached and row houses and 80 years for large apartment buildings.[151] Assuming an average age of the residential housing stock of 36 years[152] (in 2021), a large share of B.C.'s building stock will be replaced within the 29 years between 2021 and 2050. This offers opportunities to switch from natural gas to alternative forms of heating. The goal of 15% renewable gas may be achieved more easily by switching technologies than by switching to low-carbon gas.

6.3 Infrastructure, Innovation and Technology

6.3.1 A comprehensive approach

Summarizing the issues discussed above, several measures should be considered to fully enable a transition towards renewable and low-carbon gas that relies to a large degree on provincial resources. This includes:

- **Feedstock:** One key resource is forest harvesting residue. More than a million tonnes are available at an affordable cost today and more could be sourced with better technologies and supply chains. Whereas Scandinavian harvesting models may not be directly transferable to B.C. conditions, subsidies (or penalties) to enhance residue recovery and better approaches to recovering the material, such as integrated harvesting, are needed.
- **Electricity:** B.C. has significant potential for wind farm development, a resource that could be used for hydrogen production. Major investment in wind farms and related transmission infrastructure would be required if green hydrogen is to form a substantial part of a low-carbon, gas-production strategy.
- **Technology development:** Several technologies are still pre-commercial. Demonstration and further R&D are necessary to enable the production of hydrogen and/or RNG from woody feedstock. Further refinement and cost reductions are also necessary for green hydrogen. Turquoise hydrogen represents another interesting pathway that needs development support.
- **Pipeline infrastructure:** Continuing work is required to upgrade the existing natural gas pipeline network to accommodate increasing amounts of hydrogen. This should be started near hydrogen users, such as oil refineries in Burnaby and in Prince George or the ammonia plant in Trail.
- **Financing:** Capital costs to produce renewable and low-carbon gas can be very high. The forest products industry cannot accommodate long-term amortization of large investments. Systems to reduce these cost parameters through low-cost loans or other means could accelerate demonstration and deployment (see also Section 6.2.5).
- **Demand-side management and fuel switching**: The 15% renewable gas target for 2030 can be achieved easier and likely at a lower cost by reducing the demand for fossil natural gas. In the moderate climate of southern and coastal B.C., electric heat pumps can achieve GHG reductions more effectively than renewable and low-carbon gases. Similarly, pellet production and heating with pellets has a higher overall efficiency than the biomass-syngas-hydrogen-methane pathway. Switching natural gas use for low-temperature applications, such as building heat, to other fuels will reduce costs for achieving CleanBC targets. This applies especially to new construction. Vancouver City Council has

[151] https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=4610000801 (Accessed on Nov 27, 2021)

[152] https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=HB&sector=res&juris=00&rn=11&page=0 (Accessed on Nov 27, 2021)

approved a bylaw that bans fossil fuel appliances for low-rise buildings as of 2022.[153,154] Fossil natural gas will be phased out completely by 2050.[155] This approach could be extended to all of B.C.

6.3.2 *Investment needs*

Table 38 illustrates the investment required to realize the envisaged transition. Investment needs are around $5 billion by 2050 in the Minimum scenario and around $20 billion in the Maximum scenario. This does not include expansions or upgrades to the gas distribution network, or new power generation sources (apart from the off-grid green hydrogen pathway). Most early investment would be for anaerobic digestion, a pathway that is commercially more mature than other technologies.

Results shown in the table are taken from an Excel model that includes the cost parameters shown in Chapters 2 to 4. The corresponding amount of gas produced can be read from Figure 32 and Figure 33 in Chapter 5. This model can be used to simulate different input parameters and to model sensitivity towards varying assumptions.

Table 38 Investment Requirements, in Million Dollars (Minimum scenario)

Pathway	CAPEX per plant, 2030	Number of new plants, 2030	Total cost, 2030	CAPEX per plant, 2050	Number of new plants, 2050	Total cost, 2050	Cumulative cost, 2030 + 2050
Green hydrogen (large on-grid)	$357	1	$476	$252	1	$280	$532
Green hydrogen (small on-grid)	$15	4	$62	$11	5	$55	$66
Green hydrogen (large off-grid)	$155	0	$0	$109	1	$109	$218
Blue hydrogen	$273	3	$780	$240	7	$1,57 7	$1,817
Turquoise hydrogen	$139	0	$43	$122	3	$341	$463
Waste hydrogen	$19	1	$19	$19	0	$0	$19
Syngas in lime kilns	$35	2	$70	$25	7	$164	$189
Syngas to hydrogen	$144	0.1	$23	$80	8	$619	$699
Syngas to RNG	$270	0	$0	$150	0	$0	$150
Anaerobic RNG		*5.6 PJ*	$280 – 684		*3 PJ*	$150 – 375	$430 – 1,059
TOTAL			**$1,753 - 2,157**				**$4,584 – 5,213**

* Plant sizes vary between sites. Cost estimations based on total gas production potential.

[153] www.homebuildercanada.com/news/news201214-Natural-gas-outlawed.htm (Accessed October 9, 2021).
[154] City of Vancouver, "Zero Emissions Buildings Plan" (2016).
[155] https://globalnews.ca/news/2958288/city-of-vancouver-votes-to-ban-natural-gas-by-2050/ (Accessed October 9, 2021).

Table 39 Investment Requirements, in Million Dollars, Maximum Scenario

Pathway	CAPEX per plant, 2030	Number of new plants, 2030	Total cost, 2030	CAPEX per plant, 2050	Number of new plants, 2050	Total cost, 2050	Cumulative cost, 2030 + 2050
Green hydrogen (large on-grid)	$357	1	$476	$252	3	$840	$1,316
Green hydrogen (small on-grid)	$15	4	$64	$11	31	$341	$405
Green hydrogen (large off-grid)	$155	1	$102	$109	5	$540	$642
Blue hydrogen	$273	3	$780	$240	29	$6,857	$7,637
Turquoise hydrogen	$139	3	$431	$122	15	$1,894	$2,324
Waste hydrogen	$19	1	$19	$19	0	$0	$19
Syngas in lime kilns	$35	2	$70	$25	7*	$164	$234
Syngas to hydrogen	$144	0.1	$23	$80	36	$2,880	$2,903
Syngas to RNG	$270	0.1	$27	$150	26	$3,900	$3,927
Anaerobic RNG		*6.3 PJ*	$315 – 770		*3.3 PJ*	$165 – 413	$480 – 1,183
TOTAL			**$2,308 - 2,763**				**$19,889 - 20,592**

* Because of the large size assumed for a syngas plant, the total is smaller than the number of kraft mills in B.C.

Investment needs are large, and vary by a factor of four between the minimum and maximum scenarios, by 2050. The $20 billion of the Maximum scenario correspond to 6.7% of the annual provincial GDP of around $300 billion, or about ten times the annual investment in the B.C. building sector.[156] Asia-Pacific countries invested about $30 billion in B.C. between 2018 and 2020, a large portion of which was dedicated to the LNG terminal in Kitimat.[157] As such, the cost of conversion to renewable and low-carbon gas production lies within the bounds of past energy infrastructure investments.

[156] https://www.saanichnews.com/news/building-investments-rose-81m-in-b-c-while-falling-across-canada/ (Accessed November 26, 2021)
[157] https://investmentmonitor.ca/insights-reports/investment-monitor-2021-report-post-covid-recovery-and-foreign-direct-investment (Accessed November 26, 2021)

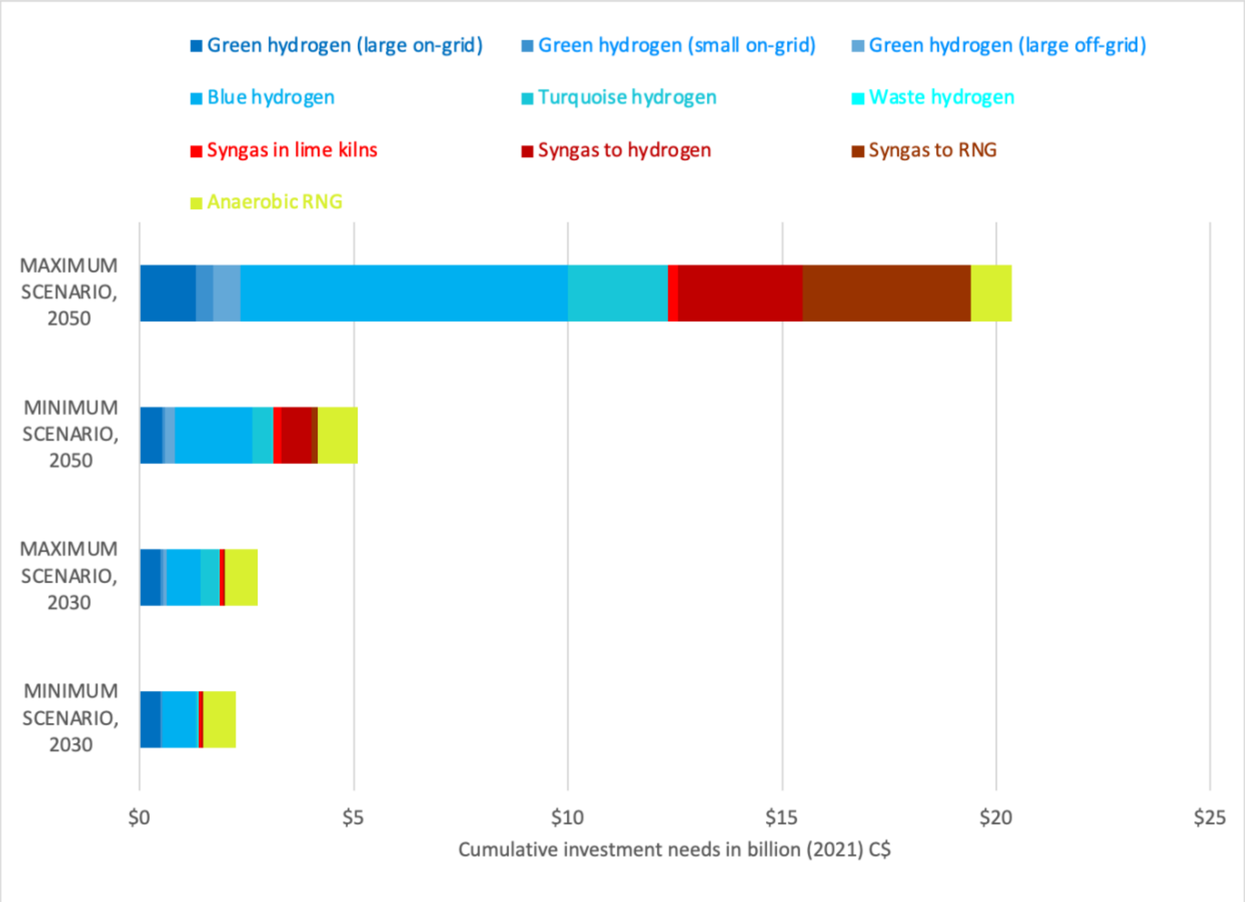


Figure 36 Cumulative Investment Needs by 2030 and 2050 in the Two Scenarios

6.3.3 Accounting for the Dynamics of a Changing Gas Production Industry

As the gas network transitions towards renewable and low-carbon gases, several aspects are changing at the same time:

- The average cost of gas from the pipeline will increase since the cost of renewable and low-carbon gases is higher than that of fossil natural gas.
- Carbon taxes are expected to increase over time, which will reduce the cost advantage of natural gas over renewable and low-carbon gases.
- The costs of renewable and low-carbon gases will decrease over time due to better and cheaper technologies.
- The carbon intensity of pipeline gas will decrease over time, as more renewable and low-carbon gases are injected – the share of fossil natural gas is expected to decrease, reducing the carbon intensity and amount of carbon tax to be paid per gigajoule.
- The pipeline gas composition will change as more hydrogen is added. This affects gas users (e.g., changed Wobbe index) and especially users that use methane as a chemical feedstock. This also concerns turquoise hydrogen production, which transforms natural gas into carbon black and hydrogen.

- Gas demand may be reduced as prices increase and if provincial strategies favour different heating technologies.

These developments have been considered at least in part in the cost model but can only be predicted with low certainty. The related uncertainties indicate the need for periodic review of the assumptions made. The latter can be modified in the Excel cost model, such that new developments can be integrated to model different outcomes.

6.3.4 Caveats With the Results of This Report

Several assumptions have gone into the preparation and underlying model of this report. These assumptions need to be verified and adapted. For users of this report, it is important to understand significant assumptions that were made for some of the pathways:

- **Anaerobic biogas:** The uncertainties are fairly minor and previous work has allowed for a fairly precise assessment of potentials, costs, and future developments. An important question is how much RNG produced in B.C. may be exported and how much RNG produced outside B.C. may be imported. This mainly depends on policies in B.C. and competing jurisdictions, and the RNG market value resulting from these policies. There is also some uncertainty about the true carbon intensity of anaerobically produced RNG, which may affect its future market potential. Any newly required technologies to reduce its carbon intensity could increase its cost. Finally, the potential by 2030 may not be realized unless there is a capital cost subsidy or other mechanism to deploy more production sites. Although the gas price offered is sufficiently high, it has not succeeded in motivating large numbers of farmers or municipalities to enter into purchase agreements with gas utilities.
- **Syngas:** The main assumption is that almost all mills can implement this technology, which is close to commercial. The potential is well understood and corresponds to current mill kiln energy demand. The main variable is the real cost of producing syngas and the reliability of the technology, which is improving quickly.
- **Wood resource:** This assessment relies on a set of assumptions, at least two of which can have major impacts on pricing and availability. These are: a) the amounts that will be available from BC Hydro PPAs expiring around 2029. It is unknown whether existing PPAs will be extended beyond this date. If they are extended, less low-cost material will become available and thus a strategy relying on large amounts of renewable gas from wood will have to account for much higher feedstock costs, including the use of some non-merchantable roundwood. Similarly, the assumption that after 2030, wood residue currently used to produce wood pellets for export may be redirected towards renewable gas production is uncertain. This material is fairly low-cost, at generally less than $60 per dry tonne, and if it does not become available, feedstock costs for future hydrogen and RNG plants will increase. Furthermore, uncertainties exist around future feedstock impacts from beetle infestations, fire damage, policy decisions impacting the AAC, and future mill closures or reopenings. At the time of writing, the treatment of old-growth forests in B.C. was under discussion and political decisions may significantly affect future AAC. All of this can have significant impacts on fibre availability and cost.
- **Hydrogen and RNG from wood:** These technologies are pre-commercial, so there is considerable risk with respect to both technology performance and related costs. Especially for RNG from wood, cost estimates vary widely.
- **Green hydrogen:** Whereas the cost parameters for green hydrogen are well understood, the future price of electricity is uncertain. Hydrogen production costs could fall after 2030 in 2021 dollars if power pricing does not increase with inflation. However, BC Hydro may need to buy more new renewable power after that date at higher costs to respond to increasing electrification demand and new users. This would leave electrolytical hydrogen one of the most expensive renewable and low-carbon gas

sources. Similar impacts would apply for turquoise hydrogen but to a much lesser degree, since this pathway has better economics than green hydrogen.

- **Blue hydrogen:** Significant uncertainty remains with respect to this pathways' carbon intensity. Future research may reveal that energy requirements for SMR, and fugitive emissions are more significant than current quantification protocols account for, which would decrease the value of blue hydrogen.
- **Turquoise hydrogen:** Similar concerns as with blue hydrogen apply to turquoise hydrogen. The technology is not mature yet and a GHG protocol needs to be developed that allocates carbon emissions between the carbon black and hydrogen products.
- **Future gas demand:** The B.C. retail market for pipeline gas beyond 2030 will depend on various developments in the industrial and building sectors, including annual growth, regulations, energy efficiency, and fuel switching. These developments may lead to shrinking pipeline gas sales in B.C. and other jurisdictions, changing the need for renewable and low-carbon gas production to reach the set targets.
- **New projects and industry changes:** Any new projects that compete for the same resources may have material impacts on the potentials identified above. For example, the CCU project announced by Huron Clean Energy will use over 300 MW of power from BC Hydro by 2025,[158] jeopardizing the addition of new electrolyser capacities through 2030 or longer. Similarly, closures of pulp and paper mills could reduce the potential for sourcing mill residue or for integrating hydrogen production plants with existing industrial operations.
- **Amortization periods:** The model uses a 20-year amortization period. This is not the usual approach for many projects. It also presupposes that a large portion of financing is provided through low-interest, long-term loans, to shorten paybacks for private equity investment. If such mechanisms are not functional, projects may not go ahead or gas pricing may be considerably higher than modelled.
- **Ownership:** The model assumes that plants are owned and operated by a private developer or an existing company, depending on the application. Each pathway has its own assumptions regarding staffing costs based on the most likely ownership model. Different ownership models may require different gas prices as they may have different cost structures.

6.3.5 Building the Renewable and Low-Carbon Gas Production Infrastructure

The transition towards renewable and low-carbon gas sources requires infrastructure upgrades. A strategy specific to infrastructure upgrades should be developed in collaboration with industry. This strategy needs to consider resource potential and related costs, as determined in the present study. Other factors to consider are geographic constraints, stakeholder interests, ratepayer impacts, regulatory issues, questions around gas imports versus provincial gas production, technical restraints to accommodate hydrogen into the gas network and competing uses for electric power and biomass resources.

This section highlights some basic considerations that can serve to inform such a strategy. This report does not recommend or suggest a 'winning' or preferred technology. Rather, actions are recommended that foster the development of all pathways considered (Table 40).

[158] https://www.alaskahighwaynews.ca/fort-st-john/carbon-capture-biofuel-plant-planned-for-bc-4514944 (Accessed October 22, 2021).

Table 40 Roadmap for Renewable and Low-Carbon Gas Pathways

	Phase 1: Develop Supply & Infrastructure 2020–2026	**Phase 2:** Commercial Expansion 2026–2030	**Phase 3:** Commercial Mainstream 2030–2050
Forestry & Feedstock	50% of roadside residue used for bioenergy.	85% of roadside residue used for bioenergy.	Integrated harvest of roundwood and residue in B.C.
Green Hydrogen	Continue R&D and observe technology developments.	Develop pilot demonstration project.	Focus on on-grid applications using new renewable energy generation.
Blue Hydrogen	Research fugitive methane emissions. Clarify hydrogen limits for existing pipelines.	Support the construction of first commercial production site near a refinery or sequestration site.	Source a portion of retailed gas from blue hydrogen.
Turquoise Hydrogen	Continue R&D and piloting of technology. Observe market developments for black carbon.	Support the construction of commercial production sites.	B.C. to become a major international player in terms of black carbon production linked to turquoise hydrogen.
Anaerobically produced RNG	The primary source of RNG in Phase 1. Continue to source RNG inside and outside B.C.	Landfill gas from all sites >1000 t/year is beneficially used. 70% of provincial potential is developed.	70% of all provincial landfill gas emissions captured and used. 90% of provincial potential is developed.
Syngas from wood	1-2 demonstration projects realised.	50% of lime kiln energy displaced by syngas.	100% of lime kiln energy displaced by syngas.
Syngas to Hydrogen or RNG	Continue R&D.	2+ demonstration projects implemented.	20-40 commercial sites developed in B.C.

Key questions to be answered for a strategy are: i) what is the timeline for recommended actions, and ii) where should new infrastructure be situated? A Geographic Information System (GIS) could be established that identifies resources, infrastructure capacities and demand from major consumers. This system will help identify the need for infrastructure upgrades. Table 41 highlights some of the elements to be considered in this GIS system.

Table 41 Development Considerations for Renewable and Low-Carbon Gas Resources in B.C.

Pathway	Location	Limitations	Comments
Green hydrogen (large on-grid)	Close to large hydrogen consumers or a natural gas transmission pipeline.	Limited by BC Hydro generation and transmission capacities.	Electricity rates too high for cost-effective production.
Green hydrogen (small on-grid)	Distributed, near loads.	Reduced impact on grid.	Electricity rates too high for cost-effective production.
Blue hydrogen	Northern B.C., near gas fields.	Long lead times.	Risk of not qualifying as a low carbon gas.
Turquoise hydrogen	Near hydrogen users, such as refineries.	Changing gas composition in grid may affect viability.	Pre-commercial Risk of not qualifying as a low carbon gas.
Waste hydrogen	Chemtrade / Hydra Energy, Prince George (see Section 4.1.5)	No other locations known.	Currently envisaged as a transportation fuel.
Syngas in lime kilns	Kraft mills	May also be used in paper mills, veneer mills, lumber drying kilns etc.	Commercial but not widely used.
Syngas to hydrogen	Pulp & paper mills, less greenfield.	Requires wood handling infrastructure.	Pre-commercial.
Syngas to RNG	Pulp & paper mills, less greenfield.	Requires wood handling infrastructure.	Pre-commercial, promising technology development.
Agricultural RNG	Lower Mainland, Vancouver Island, Peace County.	Low hanging fruit; stiff competition from other jurisdictions.	Highest carbon abatement potential.
Municipal RNG	Large urban centres	Often in cooperation with agricultural or WWTPs.	Hinges on effective organics collection system.
Waste water treatment gas	Large urban centres	Wastewater treatment plants with a 'critical mass.'	Should be made mandatory for new plants and upgrades of plants.
Landfill gas	Large urban centres	Needs at least 10 years of landfill.	Landfills produce less gas with diversion of organics

Table 42 provides a summary of ideas for a provincial strategy to foster renewable and low-carbon gas production. A full strategy would have to be created with industry input. Before engaging in strategy development, the government may want to take a more systemic approach by looking at energy use in the various sectors (residential, commercial, industrial, transport) to identify where and how overall efficiency can be increased (see Section 6.2.5) and how costs can be optimised by defining a strategy and related policies.

Table 42 Elements of a B.C. Renewable and Low-Carbon Gas Strategy

Sector	Goal	Regulation	Subsidies & Other
Forestry	• Make integrated harvesting the default approach in B.C. • More than half of all harvesting residue to be recovered by 2030.	• Create incentives to recover additional harvesting residue (e.g., increase stumpage when less is recovered). • Enhance mechanisms and funding to remove biomass from forests outside commercial harvesting, i.e., pre-commercial thinning or removal for fire prevention. • Slash burning to be (geographically) limited.	• Subsidize demonstration projects for integrated harvesting tailored to B.C. conditions. • Develop an internet platform to offer currently unharvested wood residue to potential buyers. • Work with treasury to quantify firefighting expenses and design a system to reward fire risk reduction. Develop plan to monetize benefits of increased residue harvesting.
Forest products sector	• Convert lime kilns to syngas. • Construct commercial-scale hydrogen and RNG production sites at mills. • Create new revenue streams to increase international competitivity.	• Develop rules and regulations that favour in-province renewable gas production over out-of-province purchases of RNG (for example, by offering a lower price per gigajoule for imports, due to decreased social benefits).	• Develop a new bioenergy & bioproducts strategy for B.C. • Support demonstration projects for hydrogen and RNG production from wood. • Resolve potential conflicts with mills losing the environmental benefits of renewable and low-carbon gas production and use when they sell the gas to a gas utility.
Hydrogen	• Build green hydrogen close to end users, such as refineries. • Upgrade natural gas network.	• Cannot play any major role unless \$31/GJ cost cap is removed or modified. • Allowing for monetisation of grid services (energy storage, grid balancing) could improve economics.	• Review of carbon intensity of natural gas production, incl. blue hydrogen production, is necessary.
Utilities Commission	• Protect consumers. • Lower the carbon intensity of gas retailed in B.C. • Maximise social and environmental benefits for B.C.	• Consider flexibility with financing, production, and with buying gas. • Mandate carbon footprint of pipeline gas. • Consider introducing feed-in tariffs for different gas types.	• Create new funding mechanisms for commercial-scale projects. • Allow gas utilities to buy renewable and low-carbon gases at an average of \$31/GJ (rather than a set maximum cost).

Sector	Goal	Regulation	Subsidies & Other
Gas utilities and gas transmitters	• Source increasing amounts of renewable and low-carbon gases. • Keep gas pricing affordable. • Hedge against high gas pricing.		• Engage with potential producers inside and outside B.C. to secure 20-year contracts. • Invite carbon black producers to B.C. by offering contracts for turquoise hydrogen. • Engage with BC Hydro and enter the queue for services early, to adjust planning for increasing amounts of electricity used for renewable gas production. • Engage with natural gas producers to facilitate blue hydrogen production.
Municipal biogas producers	• Maximise production and use in B.C.	• Widen municipal requirements to source-separate wood and organics from other waste. • Increase landfill gas use instead of flaring.	• Directly subsidize feasibility and FEED studies. • Provide bonds for WWTP upgrades and landfill gas capture. • Support demonstration of new and innovative technologies deemed to have a significant impact on advancement of biogas production in B.C.
Agricultural biogas producers	• Maximise production and use in B.C.	• Develop a Minister's Bylaw Standard for permitting agricultural digesters.	• Verify and align current GHG quantification protocols. • Reward local benefits from improved nutrient management. • Create a capital subsidy program for RNG production to accelerate deployment.
Municipal/ industrial organic waste management	• Maximise production and use in B.C.	• Require municipalities to consider anaerobic digestion when looking at compost facilities.	• Directly subsidize feasibility and FEED studies. • Provide bonds for municipalities building anaerobic digesters. • Provide support to help municipalities find long-term opportunities for land application of digestate nutrients.

Appendix A – BAT Lists

A. *Gasification of solid biomass and renewable production*

A.1 Renewable Gas Production from Solid Biomass

To produce a useful gas from biomass, the solid biomass needs to be gasified, and the resulting syngas needs to be conditioned. Unless the syngas is then used directly to replace fossil fuels, it then is further processed to maximize methane or hydrogen content. The main components of a typical facility would be:

- **Biomass pre-treatment:** depending on the gasifier type, it will require pre-treatment of the incoming biomass, such as drying and comminution. These processes are fully commercial and can be purchased to complete the other plant components.
- **Gasifier:** Several technologies exist, some of which are commercial. There was, however, no commercial biomass-to-hydrogen or -methane plant in operation at the time of writing.
- **Gas treatment:** The syngas contains a mixture of CO, H_2, CO_2, and CH_4, along with impurities and solids, and needs to be treated in order to be ready for the water-shift reaction. Several commercial gas treatment technologies (mainly, removal of tars and particulates) exist. They usually rely on gas cooling and then scrubbing or dry filtering of the syngas.
- **Water-shift reactor and methanation:** Commercial technologies exist but no commercial integration has yet taken place (see above). Compressors may be needed to achieve the required gas pressure to facilitate the reaction.
- **Hydrogen or methane separation:** Several commercial technologies exist, such as pressure-swing absorption, cryogenic or membrane technologies, and amine absorption (removal of CO_2).

A.2 Commercial Gasification Technologies

The main concerns with renewable gas production from solid biomass are the gasifier and subsequent gas treatment technologies, as well as how the entire plant is configured and operating as a whole. Gasification systems suitable for synthetic fuel product are provided by a variety of manufacturers. Several companies provide commercial, or are actively commercializing, indirectly-heated biomass gasification technologies. Table 43 presents an overview of key gasifier vendors, and their suitability to the various processes included in the project scope.

Table 43 Commercial Fluidized and Fixed Bed Gasifiers

Vendor	H_2	RNG	Lime Kiln	Products	Deployment
Synova	++	++	+	MILENA (Indirect)	Petten, NL; Portugal; India;
Enerkem	+	+	+	O_2 Blown gasifier, methanol, ethanol, jet, high octane gasoline.	Varennes, QC; Edmonton, AB; planned facilities in Tarragona, Spain and Rotterdam, Netherlands
Air Products (Texaco)	+	+	+	Over 60 Plants based on fossil fuels. Former Texaco technology	
Air Products (Shell)	+	+	+	50 plants worldwide, mainly coal	
Siemens	+	+	+	Dry feed system, can be used for a broad range of feedstock types	

Vendor	H_2	RNG	Lime Kiln	Products	Deployment
Concord Blue	++	++	+	Indirect gasifier similar to fluidized bed (called ‘falling bed’).	Owego, NY (MSW/Biomass); Omuta, Japan (Sewage Solids to H2); Mahad, India (Toxic Waste); Pune, India (MSW to Electricity
Valmet (CFB)	-	-	++	Air-blown gasifier used for cogeneration and lime kiln.	Vaskiluodon Voima Oy, Vaasa, Finland (Biomass syngas firing in coal power station); OKI Pulp Mill, Indonesia (Lime kiln); Aanekoski, Finland (Pulp mill lime kiln);
Repotec (Güssing)	++	++	+	Indirect CFB gasifier.	Güssing, Austria (Demonstrator/Cogeneration); GobiGas, Sweden with Valmet (Wood to RNG [mothballed]); Wajima, Japan (Thermal Power Generation); Senden, Germany (Gas Engine/ORC Combined Cycle Cogeneration)
Andritz	-	-	++	Carbon Circulating Fluidized Bed (Formerly Pyroflow)	Cheming, China (pulp mill lime kiln), Joutenso, Finland (pulp mill lime kiln), Tampere, Finland (Pilot Plant)
Air Liquide (Ruhr-Lurgi)	++	++	++	Direct fluidized bed (air/O2)	Sasol; Great Plains Synfuels, North Dakota; 101 total
Thyssen Krupp /Uhde	+	+	+	Winkler gasifier (pressurized)	70 plants (coal/pet coke)
Wood (Amec Foster Wheeler)	++	++	+	Direct fluidized bed	More than 9000 operating hours for a 12 MW gasifier (Värnamo, SE); project at Varkaus (FI) and 0.5 MW trial at VTT.[159]
Sunshine Kaidi New Energy Rentech-Silvagas	++	++	+	Indirectly heated dual-fluidized bed gasifier	One 40 MW demonstration in Burlington VT, proposed plant in Kemi, Finland
Agnion	++	++	-	Heat pipes (small-scale units only)	Developed by TU Munich
Air Products	+	+	+	Over 60 Plants based on fossil fuels. Former Texaco and then GE technology and 50 plants based on Shell technology (mainly coal)	
Exxon	+	++	-	Catalytic gasifiers	Only used with coal so far; no methanation necessary

[159] Schildhauer, Tilman and Boliaz, Serge: *Synthetic Natural Gas: From Coal, Dry Biomass, and Power-to-Gas Applications.* Wiley, 2016

Vendor	H_2	RNG	Lime Kiln	Products	Deployment
Nexterra	-	-	+	Fixed bed	
Synthesis Energy (U-Gas)	+	+	+	Fluidized bed gasifier directed at both coal and biomass markets developed in partnership with the Gas Technology Institute	Coal-based gasification projects in China and biomass demonstrations historically.
Siemens	+	+	+	Dry feed system, can be used for a broad range of feedstock types	
Thermochem Recovery International	++	++	++	Steam reforming technology	Commercial Demonstration at mill in Trenton, Ontario using black liquor for lime kiln firing

A.3 Pre-Commercial Gasifiers

Several new concepts are currently under development, and sometimes very close to commercialization. No unique gasifier concept has yet evolved that would dominate the market or even the R&D field, so future outcomes are as yet uncertain.

Table 44 Indirectly-heated fluidized bed gasification suppliers

Company Name	TRL	H_2	RNG	Lime Kiln	Products	Deployment
Highbury Energy Inc.	7	++	++	++	Indirect gasification with aims at Fischer-Tropsch liquid production. States that proprietary *in situ* tar removal process achieves 99% removal.	
Taylor Energy (New York)	6	++	++	++	Three-chambered gasification system designed for woody MSW and biomass to produce syngas with 13 MJ/M3	Project planned in Montgomery, New York with 307 tpd
West Biofuels Gasification	8	++	++	++	Modified Repotec fluidized bed gasifier	Facility under construction in Hat Creek, CA for power generation

For larger-scale plants, a partial list of CFB oxygen-blown gasifiers is shown below. In some cases, the technologies have been designed for MSW feedstocks. Nonetheless, the high biomass component in this feedstock suggests that they are also viable for RNG production from wood feedstock.

Table 45 Directly-heated fluidized-bed gasification suppliers

Company Name	TRL	H_2	RNG	Lime Kiln	Products	Deployment
TCG Global	8	++	++	++	Air/O_2 blown gasifier; building 125,000 tonne per year wood input Fischer-Tropsch plant in Oregon.	Red Rock Biofuels in Oregon
Advanced Biofuel Solutions Ltd. (Radgas)	4-5	++	++	+	Syngas production from biomass/MSW with Metso Outotec Oy oxy-steam fluidized bed with plasma treatment	Swindon, UK
Andritz Carbona (BFB)	8	+	+	++	Air blown gasifier.	Skive, Denmark (Cogeneration with Engine);
Andritz Carbona (BFB) Sungas	8	++	++	+	O_2 blown gasifier.	GTI, Chicago (demonstrator); Coal-based projects in China
Renergi	6-7	-	-	-	Two-stage gasification (air, steam) with focus on MSW and low-temperature tar reforming	Demonstration (Australia); ARENA pegged TRL at 7-8 in 2019
Suny-Cobleskill / Caribou Biofuels	5-6	-	-	++	Inclined rotary gasifier; air-blown	
Endeavour Energia	5-6	++	++	++	Fluidized-bed O2, steam-blown gasifier	Demonstration scale (UK); cold commissioning supposed to be in 2020; designed for biomethane
Jet Sprouted Bed Gasification (Taylor Energy [California])	7	++	++	+	O2-blown gasification with intermittent pulse jets to enhance reaction rate	2 t/day tested in California

Providers of entrained-flow oxygen-blown gasifiers are listed below. Many of these are designed for fossil fuels, such as coal and pet coke, but could be adapted to run on biomass.

Table 46 Entrained-flow gasifier suppliers[160]

Company Name	TRL	H_2	RNG	Lime Kiln	Products	
Lulea Green Fuels (Formerly Chemrec)	7	++	+	++	Proven with air/O_2 Blows for lime kiln and methanol DME synthesis	Pitea, Sweden (Black liquor gasification for Lime Kiln [also formerly DME synthesis]); New Bern, NC (pulp mill lime kiln)
BioLiq	6	++	+	++	Pilot plant producing under 100 Litres of gasoline per hour	Demonstration in Germany
Meva Energy	7-8	-	-	-	Entrained flow cyclone gasifier based on research at Luleå University of Technology sized at around 5 MW.	Hortlax, Sweden
Multi-fuel Conversion (MFC) Technology from RWE	3-4	++	+	++	Lab-scale but aims to recover phosphorous from biosolids and lignite using oxygen blown entrained flow gasification sized up to 125 MW (fuel input).	130 Kg/h pilot under construction in n Niederaussem, Germany

Different concepts that may pursue alternatives to the traditional three gasifier technologies described above, such as including a pyrolysis step or supercritical water, are outlined below. Their technical maturity is generally low and they are not expected to become commercially available in the coming decade.

Table 47 Other gasifier technologies

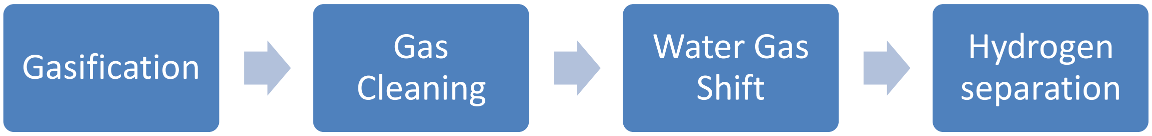
Company Name	TRL	H_2	RNG	Lime Kiln	Products	Examples
Cortus (WoodRoll)	8	++	++	+	WoodRoll Syngas units applying pyrolysis following by indirectly-heated, low-pressure, entrained-flow gasification of char.	Koping, Sweden (RNG/Syngas/Liquids Demo); Hogansas,Sweden (syngas for steel production)
Torrgas	6-7	++	++	+	Three step process involving torrefaction, low-temperature gasification and high-temperature gasification with biochar product.	700 kW demonstration and 13 MW planned plants
Wildfire Energy	3-4	+	0	+	Horizontal batch fixed bed gasification for power and hydrogen production. Oxygen blown trials planned for 2021.	Ipswich, Queensland, Australia

160 National Energy Technology Laboratory, "Entrained Flow Gasifiers." Website. https://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/entrainedflow [Accessed September 20, 2019].

Plasco (Now OMNI)	5-6	++	++	+	Multi-stage gasification based on grate gasification , fixed bed and plasma reforming. Aimed at engine generator, hydrogen, & Chemicals markets . Can be on O_2 or air blown	Richmond, Ontario
G4 Insights	7-8	-	++	-	PyroCatalytic Hydropyrolysis which converts wood to CH_4 directly	Demo in Edmonton, AB
Genifuel	7?	++	++	-	Hydrothermal Processing to liquid fuels and RNG with 20% of input converted to methane and 60%+ to biocrude	Developed at PNNL and demonstration planned at Metro Vancouver WWTP
Kore Infrastructure	N/A	++	++	+	Pyrolysis of biosolids	Demonstration planned in Los Angeles, CA
Treatech	3	++	++	+	Hydrothermal gasification	

A.4 Gas Processing to Maximize Hydrogen Content

Wood to hydrogen production is done by water shift reaction of syngas; given the low hydrogen content of wood (around 6%), additional hydrogen is added in the form of water, which is split into hydrogen and oxygen, which reacts with the carbon in the syngas to form CO_2. To maximize hydrogen content, gasifiers are operated at very high temperatures above 1,200°C, requiring more expensive materials than gasifiers used for methane production, which operate at under 900°C. In order to simplify gas separation, direct gasification with oxygen or indirect fluidized bed gasifiers (such as FICFB or Milena) are preferred. Air-blown gasification, although low cost, is not suitable. Post gasification hydrogen content for most indirect gasification ranges from 25 to under 50%. Sorption enhanced reforming can remove CO_2 in the bed material, facilitating hydrogen volumetric contents of up to 75%. In all of the above cases, further processing is needed to achieve commercial hydrogen concentrations. Hydrogen is purified using either a pressure swing adsorption and membrane filters. Some experimental work in supercritical water gasification has also been completed. Another technology under development is the Ways2H technology. which combines preheating and O_2-based reforming to generate hydrogen (Figure 37).[161]



[161] Helena Tavares Kennedy (2021, April 4th) A Waste-to-Hydrogen Tokyo Facility Ready to Rock – Is 2021 the Year of Hydrogen? *Biofuels Digest.* Accessed August 18th, 2021

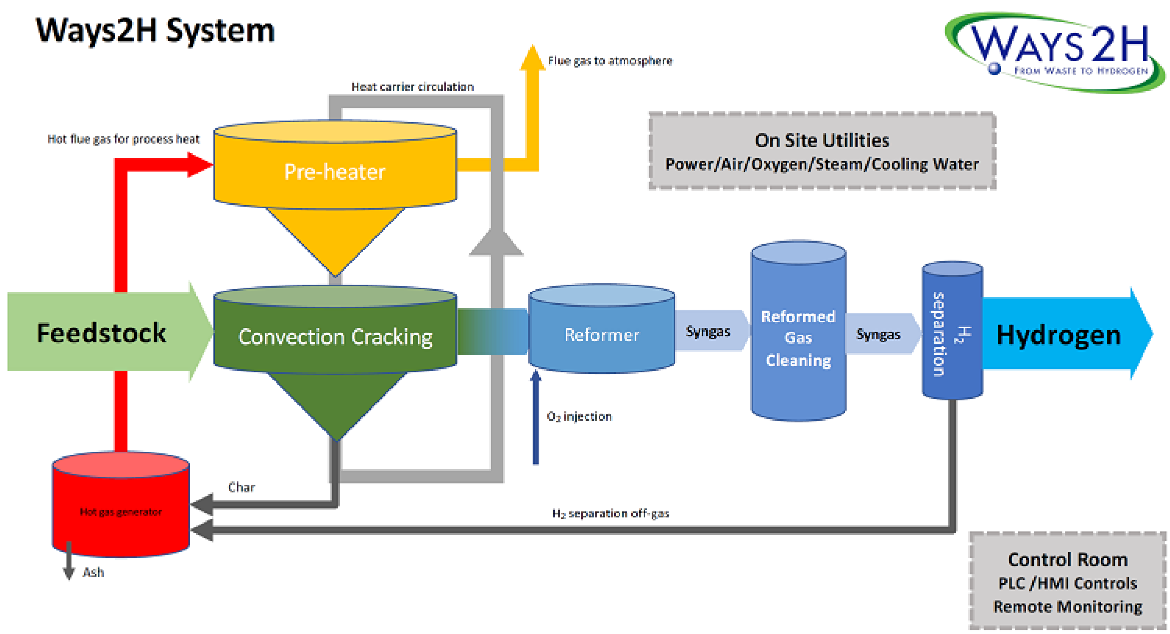


Figure 37 Process diagram of Ways2H Biomass to Hydrogen System

Table 48 lists current projects that attempt to produce hydrogen from solid biomass and MSW. Essentially, many of the technologies identified in the previous sections (gasifiers) can be used as part of such endeavours.

Table 48 Biomass to Hydrogen Systems

Vendor	Products	Deployment
Sungas Renwables	GTI fluidized bed gasification system with downstream gas cleaning and hydrogen production	Chicago Area, US
Hyper Project	Cranfield University based bulk hydrogen production project using Gas Technology Institute's sorption enhanced steam reforming process	Under development at Cranfield University, UK
Ways2H	Modular gasification technology using steam reforming of syngas	MSW-based project in Tokyo, Japan

A.5 Methanation

Pre-commercial systems: Once the syngas has been cleaned and particulates, water, sulfur and chlorine have been removed, it enters a water shift reactor. This reactor adds steam, which reacts with the carbon monoxide in the gas stream to form additional hydrogen, according to reaction (1). This hydrogen rich gas is then further processed into methane in an exothermic methanation step (2), followed by gas upgrading to pipeline standards.

(1) $CO + H_2O \leftrightarrow H_2 + CO_2$

(2) $CO + 3H \rightarrow CH_4 + H_2O$

Likewise, CO_2 can react with surplus hydrogen to form extra methane, resulting in a gas that consists of predominantly methane and some water vapour. Low temperatures (200°C) and high pressure (20-30 bar) are required to maximize methane content in the outgoing gas mixture. The Haldor Topsoe process converts H_2 and CO with a ratio of 3/1 into methane. It has a chemical efficiency of about 80 % and produces a product stream with up to 98% methane.[162] The molar ratio between hydrogen and CO needs to be close to 3 in order to maximize methane yields and minimize hydrogen in the gas. Generally, the mass yield of methane from biomass is around 0.33-0.35 kg per kg(dry),[163] which equates to 60-70% of energy. As the ratio in syngas is usually below 3, a water shift reactor needs to be added in order to adjust the ratio and maximize methane production.

The production of RNG from biomass through gasification is not commercial. Yet, numerous pilot and demonstration plants have been built – mainly in Europe. Two such project is being planned for B.C., i.e. the REN Energy project in the Kootenays and another one in Williams Lake. The best known and most successful (1200 operating hours) project has been the GoBiGas project in Sweden, which was mothballed in 2018 due to its economic underperformance, despite its relative technical success. ENGIE's Gaya project, which started in 2010 and has a demonstration unit operational since 2017, is also noteworthy. Based on the Güssing gasifier technology (FICFB), the Gaya site regroups several partners working together to make RNG production from biomass more efficient and more affordable. E.ON is also planning a commercial-size project in Sweden, using established technologies, and there are also several projects being planned in the U.S. Table 49 lists RNG projects using gasification, mainly from the past decade, as well as some planned projects. Note that although some projects are designated as TRL 8, this status could only be assumed to exist once the projects will have been commissioned successfully.

Table 49 Pre-commercial Methane Production from Biomass

Facility	TRL	Size	Technology	Deployment
GoBiGas, Gothenburg (SE)	7	20 MW (input)	Indirect gasification at atmospheric pressure (Valmet, Circulating Fluidized Bed), gas cleaning, methane production (via nickel catalyst) using Haldor Topsoe technology	One successful demonstration in Sweden, based on previous Chalmers tests
REN Energy (B.C.)	5	1 PJ/yr	Gasification at 900°C, methanation (technology unknown)	Planned for B.C.
Güssing (AT)	6	1 MW (input)	Dual fluidized bed steam gasifier (Fast Internal Circulation Fluidized Bed - FICFB), a two-stage gas cleaning system; no gas injection (internal use)	2009 Pilot was not further pursued at Güssing plant
Gaya Project (FR)	5	0.5 MW (input)	FICFB gasifier, proprietary metallic catalyst for methanation. 20 MW plant planned by ENGIE.[164]	R&D pilot (2015)
ECN (NL)	5	0.8 MW (input)	MILENA gasifier, OLGA gas cleaning and ECN's ESME methanation technology	Laboratory pilot

[162] Karstensson, Johan: *Feasibility study for gasification of biomass for synthetic natural gas (SNG) production*. Department of Chemical Engineering, Faculty of Engineering, Lund University, May 2016

[163] Schildhauer, Tilman and Boliaz, Serge: *Synthetic Natural Gas: From Coal, Dry Biomass, and Power-to-Gas Applications*. Wiley, 2016 (Table 2.1)

[164] Sherrard, Alan: Project GAYA Passes Historic Milestone. *Bioenergy International* No. 1, March 2021

Facility	TRL	Size	Technology	Deployment
Swindon (UK)	5	1 MW (input)	Fluidized bed gasifier and plasma converter; uses refuse-derived fuel	Commercial facility planned (see below)
Advanced Biofuels Solutions Ltd	(8)	8000 tpy	ABSL RadGas and Wood VESTA; CO2 is separated and used. Uses both RDF and wood as feedstock; produces both hydrogen and RNG.	Planned for 2021[165]
Japan NEDO project	3	200 MW (input)	LPG production from biomass, using an entrained-flow biomass gasification and direct LPG synthesis process with hybrid catalyst.	4-year R&D project; apparently discontinued
Köping (SE)	5	0.5 MW	WoodRoll technology by Cortus Energy (gasifier), combined with catalytic methanation unit developed by Karlsruhe Institute of Technology	Pilot plant; first RNG produced in 2020[166]
E.ON Bio2G (SE)	(8)	345 MW	First commercial project; funding approved. Direct pressurized oxygen blown gasifier and the adiabatic TREMP (Haldor Topsoe) methanation	Decision to build not confirmed
Woodland (US)	4	1 MW (input)	FICFB gasifier	R&D project, lab scale
San Joaquin Renewables (US)	7	900 tpd	Oxygen-blown pressurized fluidized bed gasifier and methanation (catalytic BING process)	Successful pilot completed
Sungas Renewables (US)	6	1000 or 300 tpd	Bubbling fluidized bed gasifier by GTI	Successful pilot completed (Stockton, CA)
AMEC FW Vesta	(8)	315 MW (input)	AMEC CFB and VESTA methanation	Feasibility study only
Ambigo, Alkmaar (NL)	6	1 tph/4 MW	MILENA (indirect gasifier), OLGA gas cleaning, ESME methanation unit. Currently on hold.[167]	Planned demonstration project
Enerkem (CA)	4		Research facility since 2003; produced liquid fuels and RNG from a mix of feedstocks, including wood and straw	Pilot; no continuous operation
Great Point Energy (US)	5	1 tpd	Bluegas technology – catalytic gasification in fluidized bed gasifier (one-step methanation)	Company out of business since 2019[168]

[165] IEA Bioenergy. "Facilities" , Accessed August 18th, 2021 from https://www.ieabioenergy.com/installations/

[166] Cortus Energy AB (2020, March 26th). "Cortus första biosyngas i Höganäs [Cortus first biosyngas in Höganäs]",Accessed August 18th, 2021 from https://www.globenewswire.com/news-release/2020/03/26/2006761/0/sv/Cortus-f%C3%B6rsta-biosyngas-i-H%C3%B6gan%C3%A4s.html

[167] Alkmaar Centraal (2019, May 16th). "Provincie Schrapt Voorwaarde Voor 960.000 Euro Subsidie Investa Alkmaar [Province removes condition for 960,000 Euro subsidy in Alkmaar". Accessed August 17th, 2021 from https://www.alkmaarcentraal.nl/nieuws/60040330-provincie-schrapt-voorwaarde-voor-960-000-euro-subsidie-investa-alkmaar)

[168] National Energy Technology Laboratory. "Great Point Energy". Accessed August 18th, 2021 from https://netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/gpe

Facility	TRL	Size	Technology	Deployment
IHI (JP)	5	6 tpd	TIGAR fluidized bed gasifier. Can use coal and biomass to produce methane. Successful pilot with biomass accomplished.[169]	Demonstration (50 tpd) planned for Indonesia
Transition Energy (CA)	7	n.a.	Based on GoBiGas technology	Proposed for Williams Lake
G4 Insights	5	6.7 MW (input)	Pyrocatalytic hydrogenation	Pilot at ATCO natural gas yard in EDmonton

Other emerging technologies: Although no wood-to-methane pathway is truly commercial, the above-mentioned demonstration projects have been successful in showing that the technology is technologically viable, albeit not commercially viable without stronger policies. Whereas gasification is still being perfected and appears to be the main pathway for short-term project development, hydrothermal gasification is one emerging technology that may offer advantages, mainly because it does not require pre-drying of biomass feedstock.

A catalytic hydrothermal gasification process was developed at the Paul Scherrer Institut (PSI) in Switzerland that allows for the production of methane from woody biomass. This process is carried out in an aqueous system at conditions near or above the critical point of water: 647 K (374°C) and 22.1 MPa. Whereas salts are highly soluble in subcritical water, they precipitate out in supercritical water. Supercritical water is more like an organic solvent. With a suitable device, the salts can be separated in a continuous way from the biomass stream prior to gasification. This has several advantages. Not only could salts poison the catalyst, but once separated in a concentrated form, they can also be used as nutrients. Products are clean water and SNG only – all possible hormones and bioactive proteins (e.g. prions) are destroyed. There is no solid residue that needs to be dried and burnt as hazardous waste.[170]

Supercritical water can also be harnessed for hydrogen production from biomass, such as bagasse.[171] The tolerance to water and salts suggests the technology could also be used with problematic feedstock, such as wastewater treatment sludge or industrial or agricultural wet residue otherwise used in anaerobic digesters, albeit it remains unclear what the required economies of scale would be. No demonstration plant has been constructed yet, which leaves this technology at a TRL around 3-4.

Syngas cleaning is another area of on-going R&D. Although commercial systems exist, they usually rely on a cool gas to be treated with filters or scrubbers (the Swedish Bio2G project also relies on high-temperature gas cleaning at around 600°C). The ability to remove contaminants from hot syngas instead of first cooling the gas has the potential to yield significant energy savings, thus reducing operating costs. RTI International has made progress in this area by developing a sorbent-based warm syngas cleanup process for H_2S and CO_2 removal that operates at 250–650°C. Others are using electric arcs to treat the syngas. Supercritical water would remove the need for additional gas cleaning.[172] Likewise, biological

[169] Yosuke TSUBOI et al.: SNG Production from Woody Biomass Using Gasification Process. *Journal of the Combustion Society of Japan* (2016), Volume 58, Issue 185, Pages 137-144

[170] Paul Scherrer Institute. Untitled. Accessed August 18th, 2021 from https://www.psi.ch/en/cpe/projects/sngfromhydgasificationen

[171] H. Ishaq, I. Dincer: A new energy system based on biomass gasification for hydrogen and power production. *Energy Reports*, Volume 6 (2020), Pages 771-781

[172] Modular CO_2 Capture Processes for Integration with Modular Scale Gasification Technologies: Literature Review and Gap Analysis for Future R&D. National Energy Technology Laboratory, October 2020

conversion to methane could reduce gas cleaning needs; some emerging technologies such as Electrochaea and Viessmann are listed below (see also **Table 56**).

Strictly speaking of methanation units, several commercial technologies exist. The best known are listed in Table 50. As these commercial systems are integrated into a full methane production facility, however, much fine-tuning needs to take place and therefore, such facilities have a lower TRL as indicated above.

Table 50 Commercial Methanation Technologies

Vendor	TRL	Products	Deployment
BASF	9	BASF sells methanation catalysts which are used in coal to methane facilities in China	China (location unknown); Likely with DEMOSNG but this is not confirmed
WOOD	9	Vesta system designed to simplify processing by removing CO2 after methanation, facilitating better temperature control and eliminating the need for recycling compression. The VESTA process also avoids the need for H2/CO adjustment while reducing metal dusting and coking.	
Haldor-Topsoe	9	TREMP system is designed to recovery the energy from the exothermic methanation reactions while allowing high reaction temperatures as high as 700 C.	
Johnson Matthey	9	DAVY SNG production system provides dual methanation and CO shift.	Keshiketeng County, Inner Mongolia
Man ES	9	Man Energy Systems has power to gas based CO2+H2 methanation systems suitable for power to gas, and with modification, syngas	Audi Power to Gas system
Atmostat-Alcen	5	METAMOD System is a modular technology designed primarily to handle the high heat loads generated by methanation of carbon dioxide and hydrogen in power to gas while maintaining compactness. System uses a powdered catalyst with microchannels	No information available
Electrochaea GmbH	7/8	System that feeds hydrogen and carbon dioxide to methanogenic archaea microorganisms to create methane gas.	Foulum, Denmark; Avedore, Denmark; Solothurn, Switzerland
Ineratec	8	Modular containerized methanation systems usable for syngas and power to gas applications	Koping, Sweden
MicrobEnergy (Viessman)	7/8	System that feeds hydrogen and carbon dioxide or syngas to microorganisms to create methane gas.	

A.6 Carbon Sequestration Technologies

Table 51 presents an overview of projects related to carbon capture in the biomass energy field, including waste-to-energy plants. Generally, commercial technologies are available, such as amine-based technologies currently used for demonstration projects in the fossil fuel sector. Other (amine-free) technologies are also being explored (see Table 52). Several more projects are being proposed in the U.S. due to the 45Q federal tax credit, which rewards bioenergy projects with carbon sequestration with up to US$50 per tonne of CO_2 in extra income. Not included in this table are fossil-based CCS in Canada such as the QUEST project at the Scotford Upgrader or the Boundary Dam facility near Weyburn, Saskatchewan which produces CO_2 to be used for enhanced oil production (but see Table 58 further below). It should be noted that some of the CO_2 used by Cenovus comes from the Great Plains Synfuels coal SNG plant. Due to the purity of the waste gases, around 1/3rd of the carbon in the biomass can be captured with relative ease. Around ¼ of the carbon in the biomass is lost as flue gas (unless an oxyfuel process) and the remainder goes into the RNG.

Table 51 Carbon Capture Applied to Biomass Energy Systems

Project	Carbon Capture Technology	Deployment
DRAX (UK)	C-Capture (amine-free solvent)	1 tpd pilot plant
DRAX (UK)	Mitsubishi Heavy Industries (amine-based)	Planned for 2027
Fortum (NO)	Amine scrubbers, for storage in depleted North Sea oilfields	Planned for 2024
Stockholm Energi (SE)	Hot Potassium Carbonate (carbon scrubbing – chemical adsorption/pressure swing)	Pilot underway since 2019
Copenhagen ARC (DK)	Waste incinerator; CCS for injection in depleted oilfields	Demonstration planned for 2022
Twence (NL)	Aker capture technology (amine-based); waste-to-energy plant	Planned
Mikawa (JP)	Coal-to-biomass conversion of power plant; CCS for storage in depleted oilfields	Planned
ZEROS (US)	Texas oxyfuel combustion plant for waste; CO_2 for enhanced oil recovery	Planned
Bayou (US)	Velocys project; carbon sequestration from Fischer-Tropsch biofuel production process	Planned for 2025
Summit Carbon Solutions (US)	Proposal to connect ~30 ethanol plants in the Midwest US to a carbon capture and storage system projected to store 10 mt of CO2 per year	Announced in 2021
Ambigo (NL)	Selexol	Planned; realization uncertain

Table 52 Carbon Capture Technologies

Technology	Key points	Comments
Chemical (amine) scrubbing	• Commercial • Increases energy use • Creates toxic amine residue	Technology of choice for most commercial projects; can use lower-cost heat energy instead of electricity
Physical solvent scrubbing	• Suitable for syngas separation (oxy-fuel)	Not suitable for post-combustion due to minimum 30% CO_2 concentration requirement
Solid adsorption	• Demonstration	Can be pressure or temperature-swing adsorption
Membrane separation	• Suitable for syngas separation (oxy-fuel) • Better for small streams • High energy cost	Commercial hybrid membrane/amine technologies exist; Air Liquide uses membranes to get to 95% purity;[173] also used to remove CO_2 from natural gas. Uses electricity as the energy source (high cost)
Cryogenic	• Very high energy use	More suitable for food-grade CO_2
Enzymatic	• Canadian invention • Low energy consumption • No toxic chemicals	CO_2 Solutions captures CO_2 enzymatically as bicarbonate. The company had become insolvent and its IP was sold to an Italian company, Saipem S.P.A.[174]

In terms of CO_2 utilization, several Canadian projects are underway. The potential for these technologies depends on the size of the product market, and often whether a market exists close enough to the point of production. For example, *Air Liquide* is mainly targeting the food-grade CO_2 market worldwide. *Qantiam Technologies* are targeting methanol production from CO_2 and *CarbonCure* apply CO_2 for concrete curing. Montreal-based *Carbicrete* is curing ground steel slag with CO_2, which results in a concrete substitute. *Pondtech* is using the gas to cultivate algae and Quebec company *CO2 Solutions* uses enzymes to capture CO_2. *CleanO$_2$ Carbon Capture Technologies* converts CO_2 to sodium carbonate. *Capital Power* is using a technology to turn CO_2 into carbon nanotubes. Other potential uses would include curing concrete with CO_2, aggregate production, technical applications of CO_2 (e.g. as a working fluid), or formic acid production.

The above means that not only is it desirable to obtain a clean hydrogen or methane stream but also, a CO_2-rich gas stream can become a product to be sold. Applicable both to traditional biogas and synthetic RNG made through a gasification process, Table 53 compares various commercial gas upgrading technologies that can be used to convert a methane-rich gas stream to pipeline grade methane. More information on these technologies and additional comparisons can be found in the original source.

[173]Air Liquide. “Membrane Technology”. Accessed December 16, 2020 from https://www.airliquideadvancedseparations.com/about/membrane-technology

[174] CO2 Solutions (2020, January 22th). “CO2 Solutions announces the sale of its assets”. *Scion.* Accessed December 14th, 2020 from www.newswire.ca/news-releases/co2-solutions-announces-the-sale-of-its-assets-844408266.html

Table 53 Gas Upgrading Technologies[175]

Biogas Upgrading Process	Pressure (psig)	Temp (°C)	CH_4 Product Content	Methane Slip	Methane Recovery	Sulfur Pre-Treatment	Consumables
Pressure Swing Adsorption	14 – 145	5 – 30	95–98%	1–3.5%	60 – 98.5%	Required	Adsorbent
Alkaline Salt Solution Absorption	0	2 – 50	78 – 90%	0.78%	97 – 99%	Required / Preferred	Water; Alkaline
Amine Absorption	0 (< 150)	35 – 50	99%	0.04 – 0.1%	99.9%	Required / Preferred	Amine solution; Anti-fouling agent; Drying agent
Pressurized Water Scrubbing	100-300	20 – 40	93– 98%	1–3%	82.0 – 99.5	Not needed / Preferred	Water; Anti-fouling agent; Drying agent
Physical Solvent Scrubbing	58–116	10– 20	95– 98%	1.5–4%	87–99%	Not needed/ Preferred	Physical solvent
Membrane Separation	100 – 600	25–60	85– 99%	0.5 – 20%	75 – 99.5%	Preferred	Membranes
Cryogenic Distillation	260 – 435	-59 to -45	96– 98%	0.5–3%	98 – 99.9%	Preferred / Required	Glycol refrigerant
Supersonic Separation	1,088 – 1,450	45 – 68	95%	5%	95%	Not needed	

B. *Lignin Production and Use*

Lignin is a by-product of the chemical pulping process and is produced by kraft pulp mills in their process of separating the cellulose from wood. Lignin has been traditionally burned, partly as a fuel for the pulping process, partly to get rid of an unwanted by-product, and to recover the pulping chemicals. Instead of burning lignin it can also be extracted from the spent chemicals.

Because lignin has a high calorific value it can be used to replace natural gas used in a pulp mill's lime kiln. Alternatively, it can be processed and sold to offsite markets as a high-grade solid fuel. The report will describe two pathways: onsite or offsite use as a natural gas replacement. Both pathways compete with using lignin as a feedstock for various chemical processes that generally fetch higher market prices than when used or sold as a fuel.

Pathway 1 - Lignin replacing natural gas in a lime kiln: For maintenance reasons lime kilns need to be operate at temperatures at or bove 800°C and are typically heated by natural gas burners. Wood needs to be gasified to be burned in a lime kiln. Dry lignin, however, in the form of dust can be burned in injection burners with the flame injected directly into the kiln.

[175] Ong, Matthew *et al.*: Comparative Assessment of Technology Options for Biogas Clean-Up (Draft). California Biomass Collaborative, October 2014 (Table 17)

Pathway 2 - Lignin replacing natural gas in other undetermined energy producing processes: because lignin has a rather high calorific value (26 gigajoules/t HHV) it is a more valuable fuel than conventional woody biomass (17 to 19 gigajoules/t HHV). Just as for the onsite lime kiln it could be burned with little technical modifications in the secondary wood processing industry, e.g. in direct fired lumber drying kilns, veneer dryers or immersion heaters used in veneer mills.

Kraft lignin is an emerging product with potential in binders, bioplastics, carbon fibre, resins and other products. Kraft lignin has different properties than lignosulfonates produced by sulfite pulping or further sulfonation of kraft lignin. Markets for lignosulfonates include dispersants, oil well drilling fluids and as binding agents.

West Fraser currently operates a commercial facility in Hinton, Alberta. Most of the demand for lignin is for lignosulfonates, with volumes of around 88 million tonnes per year, with kraft and Organosolv Lignin being 9% and 2% of the market, respectively. The total market value of lignin products is estimated at US 730 million.[176]

Lignin of lower quality has energy potential beyond its current combustion in recovery boilers, such as for lime kilns and even export to other energy users, due its high energy value (26 MJ/Kg compared to 18 MJ/Kg for typical biomass fuels). Some research has also occurred into thermochemical treatments to develop aviation fuels from lignin feedstock.

Typically, up to 20% of the lignin can be removed without impacting the mill's operations significantly. Lignin removal can even boost production in recovery-boiler constrained plants by 25% and with operational changes, around 70% of the lignin can be removed.[177] However, some mills might require a small amount of additional fuel in the power boiler to offset the energy loss from lignin.

As kraft lignin does contain sulphur, impacts of sulphur dioxide and other-sulphur compounds need to be considered due to their acidification and odour potential. Lignin has been used as fuel in district heating plants in Sweden, suggesting it could be transported and used as a fuel to displace natural gas and other fuels. Lignin-rich pellets made from Russian woody methanol production by-products is traded as a coal substitute [178] in some European markets, including Verdo CHP plant in Randers, Denmark.[179] Table 54 identifies a few recent projects related to lignin extraction and use.

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[176] Bajwa et al 2019. "A Concise Review of Current Lignin Production, Applications, Products and Their Environment Impact". *Industrial Crops and Products, 139.* DOI:10.1016/j.indcrop.2019.111526

[177] Valimaki et al. 2010 "A Case Study on the Effects of Lignin Recovery on Recovery Boiler Operation. Presented at the International Chemical Recovery Conference 2010, Williamsburg, VA, USA. Accessed August 14th, 2021 from https://www.researchgate.net/publication/267755440_A_Case_Study_on_the_Effects_of_Lignin_Recovery_on_Recovery_Boiler_Operation

[178] These black pellets do not involve torrefaction but the hydrophobic natural of the lignin allows it to be stored in the elements similar to coal and used similarly.

[179] Verdo (nd) "Black Pellets". Verdo Website. Accessed August 17th 2021 from Black pellets - ideal green addition or replacement to biomass and coal (verdo.com)

Table 54 Lignin Production Systems

Vendor	Products	Deployment
Valmet	Lignoboost uses CO_2 to precipitate lignin where it is then washed and filtered.	Domtar Plymouth, NC; Enso Sunila, Finland
FP Innovations	Lignoforce uses oxidization prior to CO_2 precipitation reducing sulphur and increasing solids size and percentage	Hinton, Alberta
Pure Lignin Environmental Technology	Dilute acid technology to produce lignin, cellulose and sweet liquor (suitable for fertilization)	
Fibria Innovations	Formerly Lignol Innovations, Organosolv extraction process held as part of Brazilian company's Fibria's bioeconomy strategy with some kraft lignin activities	Pilot plant

C. *Biogas and Landfill Gas*

C.1 Best Available Technologies

The production of Renewable Natural Gas (RNG) from organic material in digesters typically consists of four key process stages. These are:

1. Feedstock pre-treatment;
2. Digester tanks;
3. Biogas upgrading; and
4. Digestate management.

LFG projects consist of two key process stages. These are:

1. Landfill gas capture; and
2. Landfill gas upgrading.

Digester and landfill gas technologies are well-established, commercial technologies. The prediction of future trends can be based on existing technologies and incremental improvements. Feedstock pre-treatment technologies are fully commercial and can be deployed based on the specific feedstock qualities. They may be provided by anaerobic digester vendors as part of their product range, or may come from third-party providers within an overall engineering and design concept. Mechanical pre-treatment technologies enable biogas plants to accept food waste; food waste not only generates a large amount of biogas per tonne, but comes with a tip fee. For these reasons, mechanical feedstock pre-treatment technologies are often financially viable and could be considered BAT. Pre-treatment of feedstock that is difficult to digest is usually not economically feasible since the increased gas yields do not justify the pre-treatment expense.

Upgrading biogas/landfill gas to RNG is also commercial. This step removes carbon dioxide and other impurities (such as nitrogen, hydrogen sulphide and water) to increase methane content from approximately 55-65% to approximately 98%. Applicable technologies are listed in Table 53 above.

In cases where the nutrients in digestate are greater than the nutrient needs in the immediate vicinity of biogas plants, nutrient recovery technology is often used. Nutrient recovery technology extracts nutrients from digestate into a more concentrated form. The extracted nutrients can be transported away from the biogas plant more cheaply than digestate, while any remaining, nutrient-depleted liquid digestate can be spread locally.

There are dozens of different nutrient recovery technologies available, from simple large fibre removal (such as slope screen, screw press, rotary drum separator and roller press) to small fibre removal (such as dissolved air flotation, centrifuge, fiber filter and spiral filter) and almost complete nutrient recovery (such as mechanical vapour recompression and vacuum evaporation).

As with feedstock pre-treatment, digestate management technologies can be grouped into one of the following categories:

- Mechanical: such as screens, screw, belt presses, centrifuges and membranes;
- Chemical: such as flocculation and struvite precipitation; and
- Biological; such as ammonia stripping and use of nutrient accumulating organisms.

As with most feedstock pre-treatment technologies, nutrient recovery technologies are also considered uneconomical. The reason for this is that the end products of these technologies (a form of nutrient more concentrated than digestate) are almost always worth less than the cost to produce them. As such, nutrient recovery technologies are only used when absolutely necessary (i.e., when significant transportation cost savings are possible).

Table 55 lists several vendors of equipment relevant to RNG production that are active in Canada. These vendors will often sell equipment both for conventional biogas production and for gas upgrading to pipeline standards.

Table 55 Commercial Anaerobic Digester/RNG Systems*

Vendor	Products	Deployment
Air Liquide	Biogas/landfill gas upgraders	Widely deployed
Adicomp	Biogas/landfill gas upgraders	Widely deployed
Bio-en Power	Biogas plants	Widely deployed
Bioferm	Biogas plants & upgraders	Widely deployed
Bright Biomethane	Biogas/landfill gas upgraders	Widely deployed
DMT	Biogas/landfill gas upgraders	Widely deployed
Dorset Green Machine	Digestate Management	Widely deployed
France Evaporation	Digestate Management	Widely deployed
Greenlane Biogas	Biogas/landfill gas upgraders	Widely deployed
Host	Biogas plants	Widely deployed
Smicon	Feedstock pre-treatment	Widely deployed
Vincent	Digestate Management	Widely deployed
Waga Energy	Landfill gas upgraders	Widely deployed
Wartsila	Biogas/landfill gas upgraders	Widely deployed
Weltec	Biogas plants	Widely deployed

* Note: A very small sample of the > 100 vendors active in Canada's biogas industry.

C.2 Pre-Commercial Technology

While there are ultrasound, electrochemical, chemical, biological and combined process feedstock pre-treatment technologies being developed, these technologies are either TRL 6 or below, or are deemed to be uneconomical for the reasons provided above. Digester tanks and landfill gas capture systems are mature technology, and as such, subject to incremental improvements, and little sign of any significant pre-commercial technology developments.

Biogas/landfill gas upgraders are also mature technology, and while small advances are being made, these improvements are as a result of minor modifications to existing upgraders to improve energy consumption, reduce methane slip, etc., rather than development of new upgrading technology. The same is also true for digestate management technologies; improvements are as a result of minor modifications to existing technologies, rather than development of new technology.

One TRL 7/8 technology is ex-situ power to RNG technology. This two-step process starts with the production of hydrogen through water electrolysis using electricity. The hydrogen is then combined with carbon dioxide (from the exhaust stack of a biogas/landfill gas upgrader) and fed into a reactor with specialty micro-organisms that convert the hydrogen and carbon dioxide into RNG. This technology is different to in-situ power to gas (which is TRL 5) because it requires a separate reactor with specialty micro-organisms; in-situ power to gas feeds hydrogen and carbon dioxide into the same digester tank used for digesting organic feedstock, and where a wide range of micro-organisms exist.

The economic feasibility of ex-situ power to RNG technology depend heavily upon stranded electricity that has zero, or very low cost. This is electricity that has no use at time of production and cannot be easily stored, such as wind power in evenings or on particularly windy days. Once electricity has to be purchased for production of hydrogen through electrolysis, the economic feasibility of this technology quickly diminishes.[180] Therefore, until significant technology cost savings can be made, operational ex-situ power to RNG plants are financially viable only when inexpensive electricity is available.

As of 2019, there were an estimated 38 pilot and demonstration ex-situ power to RNG projects across 22 countries.[181] Of these, approximately half were able to inject RNG into the grid. Of these, a handful were of significant size (i.e., electrical load of electrolyser ≥ 1 MW electric) to be considered more than prototype demonstration. Most of these were conducted by research organizations or energy consortia. Of the most advanced and well-regarded technology supply companies, the following three stand out:

Table 56 Pre-commercial power-to-RNG technologies

Company Name	TRL	Products
Viessmann	7/8	Renewable natural gas
Uniper Energy Storage	7/8	Renewable natural gas
PFI Biotechnology	7/8	Renewable natural gas
Electrochea	7/8	Renewable natural gas

D. *Low-Carbon Hydrogen Production*

D.1 Green Hydrogen

The electrolysis of water is the primary manufacturing process used in the production of Green Hydrogen. The two most commonly used technologies are the alkali membrane and PEM technologies. Table 57

[180] For this reason, it is unlikely this technology will play a major role in BC. BC has hydro-electricity, which can be turned on/off to meet fluctuating demand, resulting in very little stranded electricity.
[181] Thema, M., Bauer, F., and Sterner, M. (2019). *Renewable and Sustainable Energy Reviews* 112, 775–787.

identifies commercial and pre-commercial technologies to produce green hydrogen, including several early-stage technologies.

Table 57 Green Hydrogen Production Technologies

Vendor	Products	TRL	Deployment
NEL Hydrogen	NEL Hydrogen, based in Norway, offers electrolysers that use two different types of membrane technologies. Alkali and Proton® PEM technologies[182].	9	NEL Hydrogen serves many different markets. By way of example but not limited to the production of ammonia fertiliser to hydrogen a coolant in power station electricity generation. NEL Hydrogen manufactures hydrogen refuelling stations that are deployed in numerous European countries, California, and other parts of the world.
ITM-Power	ITM is based in Sheffield in the UK. The organisation produces PEM technology electrolysers.	9	The company has partnered with Linde AG to serve large electrolyser market opportunities. ITM is constructing the largest PEM manufacturing plant in Sheffield, UK. It is planned to have a production capacity of 1GW per annum. The largest European electrolyser plant, 10MW was supplied recently by ITM to Shell GmbH in Germany. Delivering hydrogen to the Shell refinery. The REFYNE project.
CUMMINS	The organisation's electrolyser and fuel cell technologies base is in Mississauga Ontario. Cummins acquired Hydrogenics and manufactures, besides fuel cell systems both alkali and PEM electrolyser technologies.[183]	9	CUMMINS has supplied both alkali and PEM multi megawatt systems for numerous applications, and in the recent past for power to gas energy storage projects in Europe. The largest power to gas demonstration project in North America was conducted together with Enbridge in Markham, Ontario.[184] CUMMINS manufactured the largest PEM electrolyser plant assembly, 20MW, that was installed by Air Liquide in Bécancour, Quebec.
Siemens Energy	Siemens centre of excellence for PM electrolyser development is based in Munich, Germany.	9	Siemens Energy and Messer Group have entered into a cooperation agreement with the goal to work on green hydrogen projects in the 5-to-50-Megawatt (MW) range. The largest power to gas project in Mainz was supported by a Siemens PEM electrolyser.

[182] NEL Hydrogen. "Hydrogen Production". Accessed August 18th, 2021 from https://nelhydrogen.com/market/hydrogen-production/.

[183] Cummins. "Electrolysis". Accessed August 18th, 2021 from https://www.cummins.com/new-power/applications/about-hydrogen/electrolysis.

[184] Cummins. "Electrolysis" Accessed August 18th, 2021 from https://www.cummins.com/news/2020/11/12/its-second-year-north-americas-first-multi-megawatt-power-gas-facility-shows.

Vendor	Products	TRL	Deployment
			Messer Ibérica has already submitted three clean hydrogen projects in the chemical complex of Tarragona to the Spanish government. These projects will have a total electrolyser capacity of 70 MW.
McPhy	This company is a manufacturer of alkali technology electrolysers and is based in La Motte-Fanjas, France. The organisation also supplies hydrogen refuelling equipment.	9	Numerous milestones of the deployment and growth of the company span the last decade and more.[185]
NeXT Hydrogen	This company is a manufacturer of alkali technology electrolysers and is based in Mississauga, Ontario	9	NeXT Hydrogen manufactures state of the art alkali technology electrolysers and has deployed units at Canadian Tire in Canada to produce hydrogen and power fuel cell powerplant forklifts.
Pre-Commercial Technologies			
Enapter	Enapter, headquartered in Italy uses an alkali electrode membrane (AEM) technology	≤ 6	AEM technology is used mainly for small electrolysers. 2 to 3kW
Ionomr	This company also used AEM technology and is based in Vancouver	≤ 6	AEM technology is used mainly for small electrolysers. 2 to 3kW.
Haldor Topsoe	Solid Oxide Electrolyser Cell (SOEC)	≤ 6	This technology is interesting in that it offers up to 30% greater efficiency than do the incumbent electrolyser technologies in use. The disadvantages include that the products operate at 700°C and most effectively in a steady state mode.
Early-Stage Technologies			
	Electrolysis from renewables.	9	Done.
	Thermo chemical water splitting solar	≤ 4	Thermochemical water splitting uses high temperatures that are concentrated from solar power to split water.
	Thermo chemical water splitting nuclear	≤ 4	Thermochemical water splitting uses high temperatures that are concentrated from the waste heat of nuclear power reactions.
	Photoelectrical water splitting	≤ 4	PEC water splitting process converts water to hydrogen and oxygen using specially designed semiconductor materials. The materials used in the PEC process are similar

[185] McPhy. "Milestones", Accessed August 18th, 2021 from https://mcphy.com/en/mcphy/milestones.

Vendor	Products	TRL	Deployment
			semiconductor materials to those used in PV electricity generation.[186]
	Photobiological water splitting	≤ 4	Photobiological hydrogen production uses microorganisms and sunlight in a process to turn water into hydrogen.[187]

D.2 Blue Hydrogen

Blue hydrogen is produced from grey hydrogen that is manufactured using a process called steam methane reforming (SMR). It is essentially hydrogen that is created from any fossil fuel while capturing carbon dioxide. The main by-product of steam methane reforming is carbon dioxide and when this gas is separated from the SMR production stream, its capture, utilization and/or storage (CCUS) turns it into blue hydrogen. There are numerous pathways that have been and will be evaluated for the sequestration and utilization of the emitted bi-product carbon dioxide. Blue hydrogen is better described as a low carbon intensity hydrogen as the SMR process does not fully prevent the emission of greenhouse gases. Table 58 identifies commercial and pre-commercial blue hydrogen production technologies, as well as related carbon capture technologies.

Table 58 Blue Hydrogen Production and Carbon Capture Technologies

Vendor	Products and CCUS	TRL	Deployment
Numerous producers of grey hydrogen including the industrial gas companies by way of example but not limited to - Air products, Air Liquide, Praxair, Linde, and manufacturers of ammonia fertilisers.	Large SMR plants	9	The large SMR plants are found worldwide and produce about 60 million tonnes of hydrogen per annum. A smaller amount of hydrogen is produced from coal gasification. The primary use is the production of ammonia fertiliser and in oil refineries to upgrade the refining process.
There are several small modular SMR manufacturers. Including in the past some of the industrial gas companies, BayoTech (USA), ONEH2 (USA) and HyGear (Netherlands).	Small SMR products	9	These companies all offer small SMR units that are modular and offer remote and localization use siting opportunities.
Large Scale Carbon Capture Plants in Canada			
Canadian Natural Resources (CNR)	Horizon project, Alberta	9	CO2 captured and combined with the tailings feed into the settlement ponds to

[186] DOE Hydrogen and Fuel Cell Technologies Office. "Hydrogen Production: Photoelectrochemical Water Splitting". Accessed August 18th, 2021 from https://www.energy.gov/eere/fuelcells/hydrogen-production-photoelectrochemical-water-splitting.

[187] DOE Hydrogen and Fuel Cell Technologies Office. "Hydrogen Production: Photobiological". Accessed August 18th, 2021 from https://www.energy.gov/eere/fuelcells/hydrogen-production-photobiological.

Vendor	Products and CCUS	TRL	Deployment
			react in situ and form carbonates. 438,000 tonnes CO2 captured annually.
CRN	Quest project with Shell in Alberta. Known as the Quest CCS facility is part of the Athabasca Oil Sands Project. CRN is a 70% shareholder in this project	9	CO2 captured using amines and then pumped as a liquid 2 km into the earth's crust. 5 million tonnes of C02 a year.
CRN	North West Redwater (NWR) Sturgeon Refinery. CRN is a 50% shareholder in this project	9	Carbon dioxide is captured from the SMR feeding hydrogen to the refinery, injected into the Alberta carbon trunk line and used for the process of enhanced oil recovery EOR. The CO2 is injected deep into sub-terraneous reservoirs, and this helps recover a billion barrels of light oil. Approximately 14 billion tonnes of CO2 are captured and stored.
Boundary Dam coal power plant.	SaskPower - Estevan, Saskatchewan	9	The boundary dam coal fired power plant has been retrofitted to capture 1,000,000 tonnes per annum of carbon dioxide the carbon dioxide is sold to Synovis before the use of enhanced royal recovery.
New technology Carbon Capture Organisations			
Fluor	Solvent separation	4-6	Gaseous CO2
Carbon Clean	Solvent separation	4-6	Gaseous CO2
Blue Planet	Mineralisation	4-6	Carbonates. CaCO3

D.3 Turquoise Hydrogen

Beyond green, blue and grey hydrogen we also now have a new member of the hydrogen rainbow family - turquoise hydrogen. This is a by-product of the pyrolysis of methane in natural gas. Pyrolysis splits this gas into hydrogen and solid carbon. Turquoise hydrogen is becoming more popular, and it is anticipated that this production technology can also offer competitive hydrogen at a low carbon intensity. This, however, still is dependent upon the high cost of the thermal process that is required for methane pyrolysis. The major benefit that this technology pathway may offer is the sale and supply of carbon black used in applications such as rubber pigments. The carbon black industry is very large and complex. About 80 million tonnes are currently produced globally, most of which is used in rubber applications. The organisations developing this technology pathway to manufacture very low carbon intensity hydrogen include both small start-up companies and large organisations, such as BASF. Figure 38 provides further information on turquoise hydrogen development.

Table 59 Turquoise Hydrogen Production Technologies

Vendor	Technology	TRL	Deployment
Monolith Materials. Based in Lincoln NE. Mitsubishi is one of Monolith's investors	Plasma Pyrolysis	9	Emphasis on the supply of hydrogen to various applications including clear ammonia production. Target markets for the solid carbon by-products includes tire, rubber and speciality blacks.[188] First commercial production unit started up in 2020.
Hazer Group. Based in Australia	Fluidised bed Pyrolysis	4-6	Start-up
BASF, Germany	Moving bed pyrolysis	7	A large German chemical company that has tested a lab scale production unit.
C-Zero. Based in California.	Molten metal technology	1-3	Recently received as a start-up US$11.6 million dollars for a pilot plant. Working with the Californian Pacific Gas & Electric and Southern California Gas.
TNO using Ember Technology. Based in the Netherlands	Molten metal technology	1-3	Start-up.
EKONA Power. Based in BC, Canada	Pulse Methane Pyrolysis	5	Start-up.

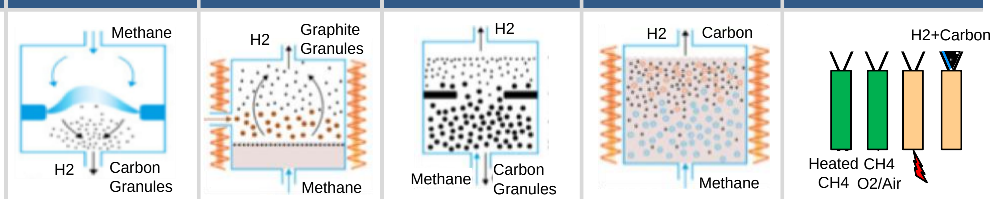
	Plasma	Fluidized Bed	Moving Bed	Molten Metal/Salt	Pulse Methane Pyrolysis
Process Reference: Turquoise Hydrogen from Methane Pyrolysis, H2 View, March 2021. EKONA July 2021					
Company	Monolith Materials	Hazer	BASF	C-Zero, TNO	Ekona
H2 Production	~95%	~92%	~92%	Up to 95%	Up to 95%
Carbon Production	Carbon black as powder or granules	80-95% graphite on catalyst dust	Carbon black as powder or granules	Carbon black as powder or granules	Carbon black as powder or granules
Reactor Type	Steady-state	Steady-state	Steady-state	Steady-state	Rapid-batch Constant volume
Catalyst Required	No	Iron-oxide	Carbon bed	Molten Nickel-Bismuth Manganese Chloride	No
Heating Mechanism	Direct plasma	Indirect reactor heat	Electrodes heat bed + Indirect reactor heat	Electrodes heat melt + Indirect reactor heat	Pulsed combustion of methane with O2/air
Reactor Temperature	2,000 C	900 C	1,000 – 1,400 C	650-1,100 C	1,200 – 1,500 C
Reactor Pressure	~Atmospheric	~Atmospheric	~Atmospheric	Up to 5 bar	Up to 20 bar

Figure 38 Methane Pyrolysis Pathway[189]

[188] Monolith Materials. "Pure, High Performance Carbon Black". Accessed August 18th, 2021 from rhttps://monolithmaterials.com/solutions/clean-carbon-blacks.
[189] EKONA Power and H2 View, March 2021 edition

D.4 Waste Hydrogen

Waste hydrogen is defined as "hydrogen gas produced by a commercial process the primary purpose of which is not the production of hydrogen gas."[190] It is produced at two sites in B.C., both owned by Chemtrade. The first of which is in North Vancouver at their chlor-alkali plant that produces chlorine for numerous markets such as the production of sodium hypochlorite. The waste hydrogen produced amounts to approximately 10 tonnes per day. Organisations have in the past attempted to buy this hydrogen to liquify and deliver the gas for local consumption. In October 2005 it was announced that Sacre Davy Engineering[191] together with partners were awarded $12.2 million to construct a cryogenic hydrogen plant using the waste hydrogen. Insufficient demand was identified and the project was dropped.

Chemtrade also produces waste hydrogen at its Prince George sodium chlorate plant. Some of this hydrogen will be used by Hydra Energy that has developed a hydrogen diesel dual fuel Call 8 truck power plant. Hydra Energy has partnered with Chemtrade to capture, clean and deliver the hydrogen for mobility applications, including their retrofitted Class 8 trucks. It is estimated that the Prince George sodium chlorate plat emits about 10 tonnes of hydrogen per day.

[190] https://www.canlii.org/en/bc/laws/regu/bc-reg-291-2010/latest/bc-reg-291-2010.html
[191] https://www.ic.gc.ca/eic/site/ito-oti.nsf/eng/00683.html

Appendix B – RNG Cost References

Table 60 compares some recent cost estimates for RNG production from biomass. The numbers are only partially comparable as they are based on different parameters, i.e., feedstock energy input, feedstock amount, or output. Efficiencies are from output energy in relation to woody biomass input, omitting process energy inputs. Capital costs and gas costs have been normalized for better comparison in Figure 18.

Table 60 Cost Estimates on RNG Production from Solid Biomass

#	Facility	Technology	Size	Energy yield	Gas cost	Capital cost	Source
1	Conceptual	Haldor Topsoe	200 MW (input)	47.2%	C$19/GJ	US$92 M	Karstensson (2016)
2	GoBiGas	Haldor Topsoe	100 MW (input)	70% (LHV)	€72/MWh	€350 M	Thunman (2018)
3	ECN	MILENA, ESME	1000 MW (input)	70% (LHV)	14-24 US$/GJ	US$1.5 Bn	ECN (2014)
4	Sungas Renewables	Andritz & Haldor-Topsoe	945 tpd	3 BCF/yr	US$13-15/MMBtu	US$340 M	LeFevers (2020)
5	Undefined	Gasification & methanation	315 MW	67%	$23-39/GJ	€340 M	SysEne (2016)
6	E.ON Bio2G	Sweden	345 MW (input)	60-65%	-	€450 M	IEA (2019)
7	Conceptual	AMEC CFB and VESTA methanation	6.1 MW	65%	€150/MWh	€19 M	Kraussler (2018)
			12.2 MW		€130/MWh	€30 M	
			49.1 MW		€95/MWh	€75 M	
8	Conceptual	Milena, G4, FICFB	30 MW	50-70%	C$19-40/GJ	C$60 M	Cheney (2018)[192]
9	Conceptual	G4 Insights	6.7 MW (input)	70%	€23/MWh	€13 M	Renewtec (2018)
10	Swindon (UK) – RDF as feedstock	Advanced Plasma Power, Progres-sive Energy and Carbotech	132 MW 84 MW (output)	60%	£21/MWh	£151 M	GoGreen (2017)[193]
11	B.C. pulp mills	Generic (Repotec, Carbona or Thyssen gasifier)	200,000 odt/yr, 2.5 PJ/yr of RNG output	65%	$15-20/GJ (variable only); $50/GJ w. profit	C$400-500 M	Browne (2019)[227]
12	REN Energy	Not published	>100,000 tonnes	67%	<$30	C$130 M	Boyd (2020)[63]
13	CHAR Technologies	High-temperature pyrolysis	76 odt/yr	33%	Unknown	C$30 M	Ross (2021)[194]

[192] Cheney, Thomas: Wood to Renewable Natural Gas Technology Assessment for Nelson Hydro. Thomas Cheney Consulting, November 2018.
[193] BioSNG Demonstration Plant - Summary of Commercial Results (Commercial models of full scale BioSNG plants). Gogreengas, June 2017.
[194] https://www.northernontariobusiness.com/industry-news/green/company-eyes-kirkland-lake-as-base-to-convert-forest-waste-to-green-natural-gas-4478260 (Accessed November 2, 2021).

Appendix C – Forest Biomass Resource Assessment

A. *Types of Forest Biomass*

B.C.'s forests provide woody feedstock for a variety of activities of the forest products industry, including sawlogs, pulp logs, and feedstock for wood pellet production. Table 61 describes log and residue streams and the terminology used. It is impossible to determine the amounts available of each residue stream exactly as they are often used jointly under existing fibre purchasing agreements.

Table 61 Types of Woody Feedstock

Fibre type	Description
Sawlogs	High-value trees that are used to manufacture dimensional wood products. The high value of these logs warrants the cost of building logging roads, felling and replanting. This resource is not used to produce energy but the residue from processing these logs is.
Pulp logs	Lower-value trees that can be harvested together with sawlogs. This is routinely done by forest product companies and the pulp logs are sold to pulp and paper mills at far lower pricing than sawlogs. Whenever pulp logs are not used by pulp and paper mills, they can be used to produce energy but are more expensive than other sources of fibre.
Chips	Wood chips can be made of pulp quality or for combustion in chip boilers. The latter remains exceptional in Canada, whereas large amounts of pulp chips are produced either by the pulp mills themselves or by saw or chip mills selling to pulp mills.
Roadside residue (or slash)	Also called harvesting residue, this fibre consists mainly of the limbs and tops of trees that are removed to obtain sawlog and pulp logs. Broken, small-diameter or deciduous trees are frequently part of 'slash piles.' This residue can be left in the forest but is often collected and piled up on the roadside. It is routinely burned, though sometimes recovered as a fuel for mills or as a feedstock for pellet production.
Mill residue	*Hog fuel* is the residue – mainly bark – left over from de-barking stems at pulp and paper mills. The term is also used to refer to any type of wood by-product or waste that can be burned for fuel but can't be categorized as chips, shavings, bark, or sawdust. It is high in ash and irregular in size. It is the lowest-value fuel and is often burned in recovery boilers at the mill where it is produced. Excess hog fuel is sold to other forest products companies at low pricing (sometimes for free). In coastal regions, bark may have been in contact with saltwater, which may require adapting processes or a pre-wash of such feedstock.
	Shavings from planer mills are a clean fuel that can be used for pellet or pulp production.
	White *sawdust* from sawmills is a sought-after residue for pellet production. It is more costly than hog fuel because of its higher quality (lower ash content, lower moisture).
	Mill residue data is not statistically collected in B.C. but can be estimated. It is only referred to as a combination of the above three streams in this report.
CLD	Construction, land clearing and demolition wood waste is a mixture of wood streams from construction activities. Removed trees to prepare the site, woody bits left over from construction, or wood separated out during deconstruction is included. Only clean wood can be used, which requires an efficient process to remove anything that is contaminated, covered with plastics or painted/treated wood. This separation process increases the cost of this fuel and it is often used in urban applications such as district heating, or by the cement industry if too contaminated.

B. *Previous Estimates*

The 2019 estimates in Table 62 are taken from the report *Revitalization of the B.C. Bioenergy Sector*, produced for BCBN in 2019. They are based on a commercial fibre supply model (the B.C. Fibre Model) taking the Annual Allowable Cut (AAC), mill activity, imports and exports of fibre between regions, to estimate surplus residue at mills and in the forest. The numbers represent the amounts available for new activity without negatively impacting existing uses of these resources by the forest products industry. The main conclusions from this work are:

- Little surplus mill residue is available in B.C. Some regions have a fibre deficit and are importing residue from neighbouring regions. Only small pockets with residue are still available in the western parts of the Skeena and Kootenay/Boundary Natural Resource Regions. These pockets may be exhausted by a single new project, such as a new pellet mill.
- Also, few pulp logs remain unharvested in most areas. By 2028, only small amounts will remain in few areas, which may be insufficient to sustain a new bioenergy facility on their own.
- The main resource available is forest roadside residue. Large amounts exist in some areas, especially when combined with other residue. Yet this resource is currently not fully recovered in B.C. There are issues with (physical and legal) access to and transport of this fibre so the cost will be higher than for mill residue. Fibre recovery zones have been set up to help use residuals for pulp wood and bioenergy. The amount indicated is based on costs up to $90 per dry tonne and omits regions that would require barging or other highly expensive transportation approaches.
- Stands of non-merchantable timber could be harvested for energy production. Most non-merchantable fibre consists of smaller trees with insufficient diameters to be used in mills. This may be recovered as roadside residue. As the AAC is usually defined for softwood, some regions – mainly in northern B.C. – have deciduous stands not covered in the AAC (in the South Peace, deciduous wood is already part of the AAC). These stands are not part of this inventory but may be obtained if close enough to relevant infrastructure. This would require a specific harvesting license from the Ministry.

The B.C. Fibre Model results are projected out to 2028. These results are further developed below, taking into account expected changes in the AAC and the impacts of recent mill closures. Whereas the B.C. Fibre Model uses specially-defined regions, the analysis in this report relies on the B.C. Resource Regions as commonly used in most government documentation and statistics (**Figure 39**).

ROM: Omineca; RSC: South Coast; RNO: Northeast, RTO: Thompson-Okanagan; RKB: Kootenay-Boundary; RCB: Cariboo; RSK: Skeena; RWC: West Coast.

Figure 39 B.C. Resource Regions[195]

[195] https://www2.gov.bc.ca/gov/content/environment/natural-resource-stewardship/cumulative-effects-framework/regional-assessments/kootenay-boundary (Accessed August 23, 2021).

Table 62 Fibre Availability in B.C. in 2019 and 2028, in Odt, According to the B.C. Fibre Model

	A		B		C		D	
	AAC (standing timber) not harvested		Non-sawlog timber (pulp logs) not consumed		Net roadside residue not consumed		Residual sawmill hog fuel not consumed	
	2019	2028	2019	2028	2019	2028	2019	2028
Coast	1,526,753	1,298,067	0	0	320,733	237,917	5,085	0
East Kootenay	60,515	4,228	0	0	116,848	116,427	0	0
West Kootenay	-448,384	-481,677	0	0	174,331	175,296	311,898	314,102
Kamloops-Okanagan	-81,658	-292,029	175,331	0	0	0	0	0
Cariboo	-1,825	-367,056	441,306	0	403,239	169,993	0	0
Prince George	-270,780	-691,946	0	0	75,019	0	0	0
Mackenzie	369,643	29,838	383,880	0	0	0	0	0
South Peace	385,172	17,502	115,167	143,337	69,295	69,295	0	0
East Prince Rupert	331,409	11,161	307,777	7,150	0	0	0	0
West Prince Rupert	1,010,806	977,830	95,912	96,264	63,953	62,387	32,097	32,097
Northeast	812,500	812,500	0	0	0	0	0	0
Northwest	98,000	76,000	0	0	0	0	0	0
TOTAL	3,792,151	1,394,417	1,519,373	246,751	1,223,419	831,315	349,080	346,199

Note: Negative numbers indicate a deficit of fibre. Wood has to be imported from other regions.

In total, the model projects that an equivalent of 126 petajoules of unallocated woody biomass is available in B.C. today (Table 63). The model predicts that this amount is reduced to 52 petajoules in 2029. These numbers refer to feedstock input and not to the amount of low-carbon fuel produced, which will vary by technology. Amounts available are strongly reduced for a mix of reasons, such as reduced AACs, expiring uplifts (temporary increases of the AAC to address the beetle epidemic), mill closures and the resulting redistribution of wood residue within the forest products industry.

Table 63 Total Woody Biomass Available in B.C. in 2019 and 2028

Region	A + B + C + D: Unallocated woody biomass in odt/yr		Calorific content (LHV) of unallocated woody biomass; in PJ/year	
	2019	2028	2019	2028
Coast	1,852,571	1,535,984	33.9	28.1
East Kootenay	177,363	120,655	3.2	2.2
West Kootenay	37,845	7,721	0.7	0.1
Kamloops-Okanagan	93,673	-292,029	1.7	-5.3
Cariboo	842,720	-197,063	15.4	-3.6
Prince George	-195,761	-691,946	-3.6	-12.7
Mackenzie	753,523	29,838	13.8	0.5
South Peace	569,634	230,134	10.4	4.2
East Prince Rupert	639,186	18,311	11.7	0.3
West Prince Rupert	1,202,768	1,168,578	22.0	21.4
Northeast	812,500	812,500	14.9	14.9
Northwest	98,000	76,000	1.8	1.4
TOTAL	**6,884,022**	**2,818,683**	**126.0**	**51.6**

C. *Annual Allowable Cut through 2050*

Generally, the AAC is set for 10 years for each Timber Supply Area and Tree Farm Licence.[196] In most Resource Regions, Timber Supply Areas (TSAs) provide about ten times more volume than Tree Farm Licenses (TFLs). The exception is Vancouver Island, where TFLs provide most of the allowable cut. On average, the actual timber harvest has been almost 20% lower than the allowable cut, particularly on the coast.[197,198] Harvesting levels have been affected in the interior by the pine beetle infestation and wildfires. Whereas wildfires initially affected the dead pine beetle forests, the 2018 wildfires affected harvestable areas, especially the Cassiar (5.6% losses of harvestable areas), Lakes (5%), and Morice (2.9%) TSAs. This did not, however, lead the Ministry of Forests to revise the AAC.[199] Whether this will be necessary after the 2021 wildfire season remains to be seen. Recent wildfires have mainly affected the Cariboo and Thompson-Okanagan regions.[200]

Current government projections do not foresee any increase in the AAC before the year 2070 (Figure 40). The AAC is expected to fall to below 55 million cubic metres per year throughout this report's forecast horizon (2050).[201] This is equal to 88% of the 2021 AAC and 100% of the 2019 actual harvest (see below). Table 64 and Figure 41 show current AACs as of August 2021 and make projections to reflect the future harvesting level of around 40 million m^3 per year for the interior. These AACs consider the areas most affected by the pine beetle and by wildfires.

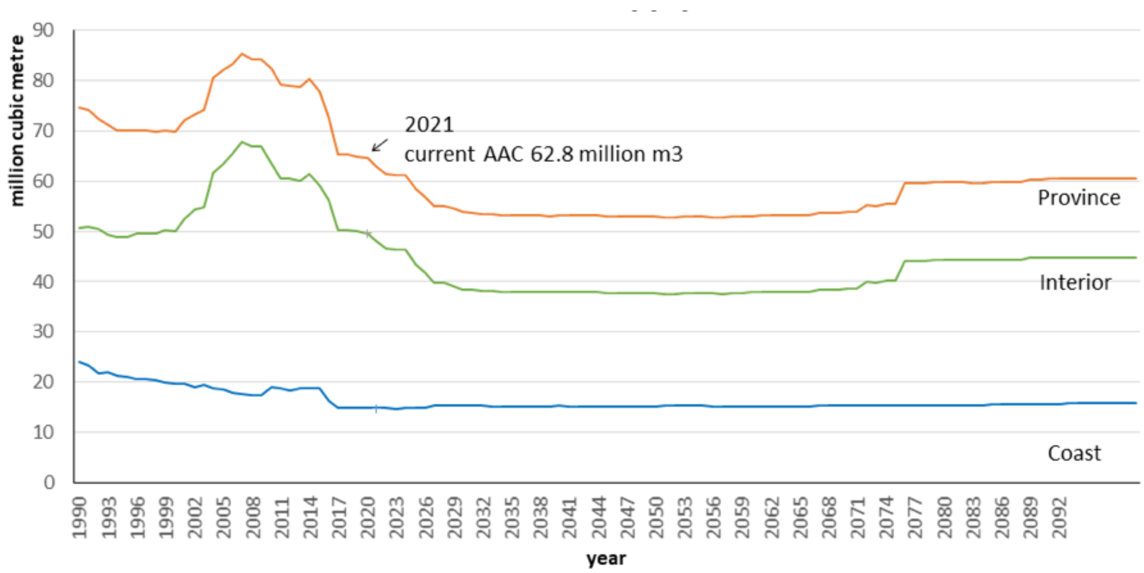


Figure 40 B.C. Timber Supply Forecast[202]

[196] https://www2.gov.bc.ca/gov/content/industry/forestry/managing-our-forest-resources/timber-supply-review-and-allowable-annual-cut/allowable-annual-cut-timber-supply-areas/cascadia-tsa (Accessed August 20, 2021).
[197] https://www.env.gov.bc.ca/soe/indicators/land/timber-harvest.html (Accessed August 23, 2021).
[198] David Elstone (2019), "TLA Breaks Down Forestry Job Loss." https://www.woodbusiness.ca/understanding-forest-industry-job-loss-4376/ (Accessed August 28, 2021).
[199] Impacts of 2018 Fires on Forests and Timber Supply in British Columbia. Office of the Chief Forester British Columbia Ministry of Forests, Lands, Natural Resource Operations and Rural Development, April 2019.
[200] https://vancouversun.com/news/local-news/b-c-wildfires-map-2021-updates-on-fire-locations-evacuation-alerts-orders?r (Accessed August 23, 2021).
[201] Nussbaum, Albert: Personal communication. Ministry of Forests, Lands, Natural Resource Operations and Rural Development, October 15, 2021.

Table 64 Annual Allowable Cut, in Cubic Metres per Year (TFLs and TSAs)[202]

	August 2021, TSA	TFL	Total AAC	*2030-2050 AAC (estimates)*
South Coast RSC	2,893,089	329,040	**3,222,129**	*3,000,000*
West Coast RWC	4,463,356	7,191,646	**11,655,002**	*12,000,000*
East Kootenay RKB	4,166,643	1,069,000	**5,235,643**	*4,500,000*
West Kootenay RTO Kamloops-Okanagan RTO	6,948,405	585,700	**7,534,105**	*6,000,000*
Cariboo RCB	6,574,805	592,500	**7,167,305**	*5,500,000*
Prince George ROM Mackenzie ROM	13,213,559	631,500	**13,845,059**	*11,800,000*
East Prince Rupert RSK West Prince Rupert RSK Northwest RSK	5,994,000	506,059	**6,500,059**	*5,300,000*
Northeast RNO South Peace RNO	6,557,350	871,000	**7,428,350**	*7,000,000*
TOTAL	**50,811,207**	**11,776,445**	**62,587,652**	***55,100,000***

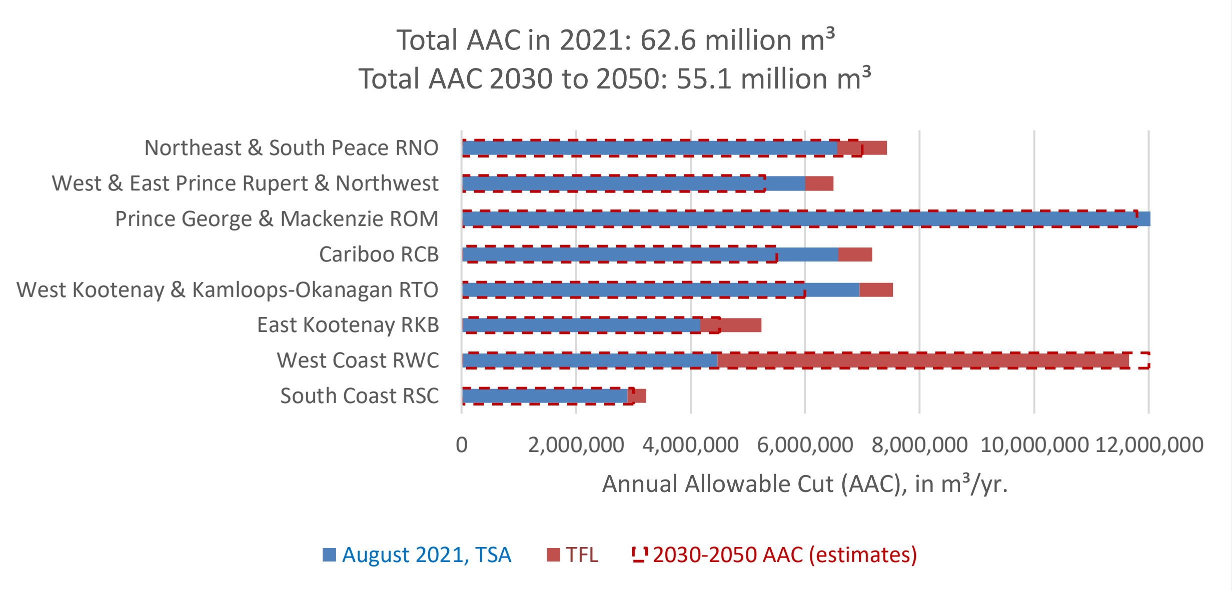


Figure 41 Annual Allowable Cut, Based on Table 64

As Table 65 indicates, the six largest forest products companies control almost half the allowable cut in B.C. This is important when trying to access harvesting residue, since users must negotiate with these companies to gain access to roadside residue.

[202] Ministry of Forests, Lands, and Natural Resource Operations - Apportionment System, August 12, 2021 – see https://www2.gov.bc.ca/gov/content/industry/forestry/forest-tenures/forest-tenure-administration/apportionment-commitment-reports-aac

Table 65 TSA Rights, in Cubic Metres per Year, Six Largest Licence Holders[203]

Company	August 2021, TSA	% of total AAC allocated to TSAs
Canadian Forest Products Ltd.	9,240,762	15%
West Fraser Mills Ltd.	5,389,622	9%
Western Forest Products Inc.	4,977,35	8%
Interfor Corporation	3,688,239	6%
Tolko Industries Ltd.	3,418,829	5%
Louisiana-Pacific Canada Ltd.	1,264,710	5%
Total	**23,002,162**	**45%**

D. *Mill Closures and Production Levels*

Statistics Canada noted a downward trend in lumber production from B.C. mills, see Figure 42. Although 2021 saw a strong increase in lumber pricing due to record housing starts, prices have recently dropped to low levels,[204] whereas delivered log pricing in B.C. remains high. The small margin between log prices and lumber caused Conifex Timber to curtail the MacKenzie mill in August 2021.[205] Several other producers curtailed production due to the numerous wildfires in the summer of 2021.[206] The strong increase in housing prices observed in 2021 may also reduce short-term demand for new homes. There is no reason to believe that B.C. mill output will reach previous levels in the coming years. Public discussion blames the decline on a set of issues affecting the cost of milling in B.C., including high stumpage fees, the pine beetle infestation, wildfires, and increased conservation efforts. Fibre costs in the B.C. interior increased by 33% between 2016 and 2019, with 25% of the delivered cost being due to stumpage fees.[207] The increasing fibre cost seems to indicate a transition towards lower harvesting rates.[208]

Since the 2019 report on the *Revitalization of the B.C. Bioenergy Industry*, several mills, including one pulp mill, have been closed or indefinitely curtailed (Table 66). According to independent forestry consultants, an additional four sawmill closures appear imminent on the coast and another five in the interior.[209] Proposed policies to curtail logging in old-growth forests and to protect caribou may result in a one-million-cubic-metre decrease in the coastal AAC and a three-million-cubic-metre decrease for the interior. These developments will affect the viability of pulp and pellet mills, as well as of biomass power plants.

[203] Provincial Linkage AAC Report. Province of British Columbia, August 12, 2021. See https://www2.gov.bc.ca/gov/content/industry/forestry/forest-tenures/forest-tenure-administration/apportionment-commitment-reports-aac
[204] https://www.nrcan.gc.ca/our-natural-resources/domestic-and-international-markets/current-lumber-pulp-panel-prices/13309 (Accessed August 23, 2021).
[205] https://getfea.com/mill-capacity-changes/conifex-timber-inc-announces-2-week-curtailment-at-mackenzie-b-c-sawmill-starting-monday-august-23-2021 (Accessed August 23, 2021)
[206] https://treefrogcreative.ca/post-peak-production-will-bc-producers-pull-back/ (Accessed August 23, 2021).
[207] https://issuu.com/truckloggers/docs/truckloggerbc_fall_2020_final_lowres/s/11119030 (Accessed August 24, 2021).
[208] Bennett, Nelson: High operating costs cripple forest industry recovery. Prince George Citizen, July 22, 2020.
[209] https://biv.com/article/2021/08/more-mill-closures-loom-bc-researcher-warns (Accessed August 24, 2021).

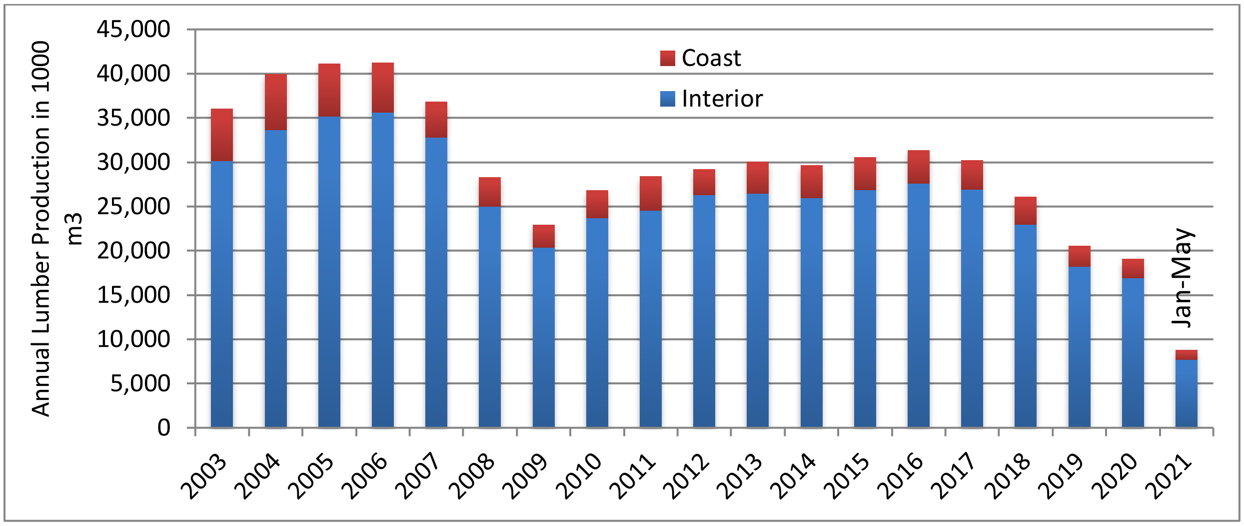


Figure 42 B.C. Lumber Production in Thousand Cubic Metres Per Year[210]

Table 66 Mill Closures and Curtailments[211]

Facility	Region	Notes	Year
Parallel 55 Fingerjoint Plant – Mackenzie	ROM	Indefinite curtailment	2019
Peace River OSB – Fort St John	RNO	Restart planned in 2022	2019
Canfor Sawmill – Mackenzie	ROM	Indefinite curtailment	2019
Conifex Sawmill - Fort St. James	ROM	Closed. Sold to Hampton Lumber	2019
Tolko Industries Sawmill – Quesnel	RCB	Closed	2019
Canfor Sawmill – Vavenby	RTO	Closed	2019
West Fraser Chasm Sawmill – 70 Mile House	RCB	Closed	2019
Norbord, 100 Mile House[212]	RCB	Indefinite curtailment	2019
Teal-Jones Harvesting Operations – Boston Bar	RSC	Closed	2019
Tolko Industries lumber mill – Kelowna	RTO	Closed	2020
Teal-Jones Harvesting Operations – Pitt Lake	RSC	Closed	2019
Interfor Hammond Sawmill – Maple Ridge	RSC	Closed	2019
Teal-Jones Harvesting Operations – Honeymoon Bay	RWC	Closed	2019
Paper Excellence (pulp), Mackenzie[213]	ROM	Closed	2021
Canfor Isle Pierre[214]	ROM	Closed	2020
Flavelle sawmill, Port Moody[215]	RSC	Closed	2020
San Group, Port Alberni[216] (small logs)	RSC	Opened	2020

[210] Statistics Canada, Table 16-10-0017-02.
[211] https://lumberforecast.com/2019-b-c-mill-closure-map/ (Accessed August 24, 2021).
[212] https://www.timescolonist.com/year-in-review-sawmill-closures-hurt-b-c-communities-1.24040975 (Accessed August 24, 2021).
[213] https://biv.com/article/2021/04/mackenzie-pulp-mill-will-close-permanently (Accessed August 24, 2021).
[214] https://getfea.com/covid-19/canfor-updates-b-c-mill-curtailments-and-closures (Accessed August 24, 2021).
[215] https://www.nipimpressions.com/bc-mill-closing-permanently-cms-10797 (Accessed August 24, 2021).
[216] https://www.woodworkingnetwork.com/news/canadian-news/first-sawmill-15-years-opens-british-columbias-west-coast (Accessed September 22, 2021).

Responsible for more than 68% of all wood consumed in B.C., sawmills remain the backbone of the forest products industry on which other mills depend. A reduction in sawmill output has impacts on downstream mills. Of the roundwood delivered to sawmills, only 45.8% become timber products in 2019,[217] 35.2% of sawmill feedstock was converted to residual chips for pulp mills and 17% was converted to sawdust and shavings used in pellet and panel mills. B.C. pulp mills processed over 22 million cubic metres of fibre, down 15% in 2019 from 2018. Of this total, pulp mills consumed about 15 million cubic metres of residual chips produced by sawmills and veneer mills, accounting for 67% of their fibre input. In addition to residual chips from sawmills, pulp mills used about 5.8 million cubic metres of whole-log chips, representing over 26% of their total fibre input. Pellet and panel mills also rely on sawmill residuals. In 2019, pellet and panel mills together processed 4.8 million cubic metres of fibre, mainly sawdust and shavings, down 5% from 2018.

Figure 43 shows the fibre flows between different players in the forestry industry of B.C. Industries depend on these fibre flows, mainly the pulp mills using chips from the sawmills and pellet mills using mainly sawdust and shavings. On the other hand, only 0.8 million cubic metres of harvesting residue is currently being used, against a remaining potential of 1.2 million tonnes (Table 62), or about 2.9 million cubic metres. The 12 B.C. veneer mills used 4.6 million cubic metres of logs. Other mills, such as shake and shingle mills, only used small amounts of fibre compared to other mill types (less than 2% of total log consumption).

Figure 44 and Figure 45 illustrate that pulp and paper mills and natural gas infrastructure are mostly near the interior working forest. Potential fibre supplies are remote for much of the coastal forest although much of the timber harvesting land base is on Vancouver Island or the south coast, close to potential users. Coastal wood is often hauled by water. Alternative logistics approaches might be needed to acquire additional feedstock suitable for gasification.

[217] 2019 Major Timber Processing Facilities in British Columbia. Ministry of Forests, Lands, Natural Resource Operations and Rural Development, January 2021.

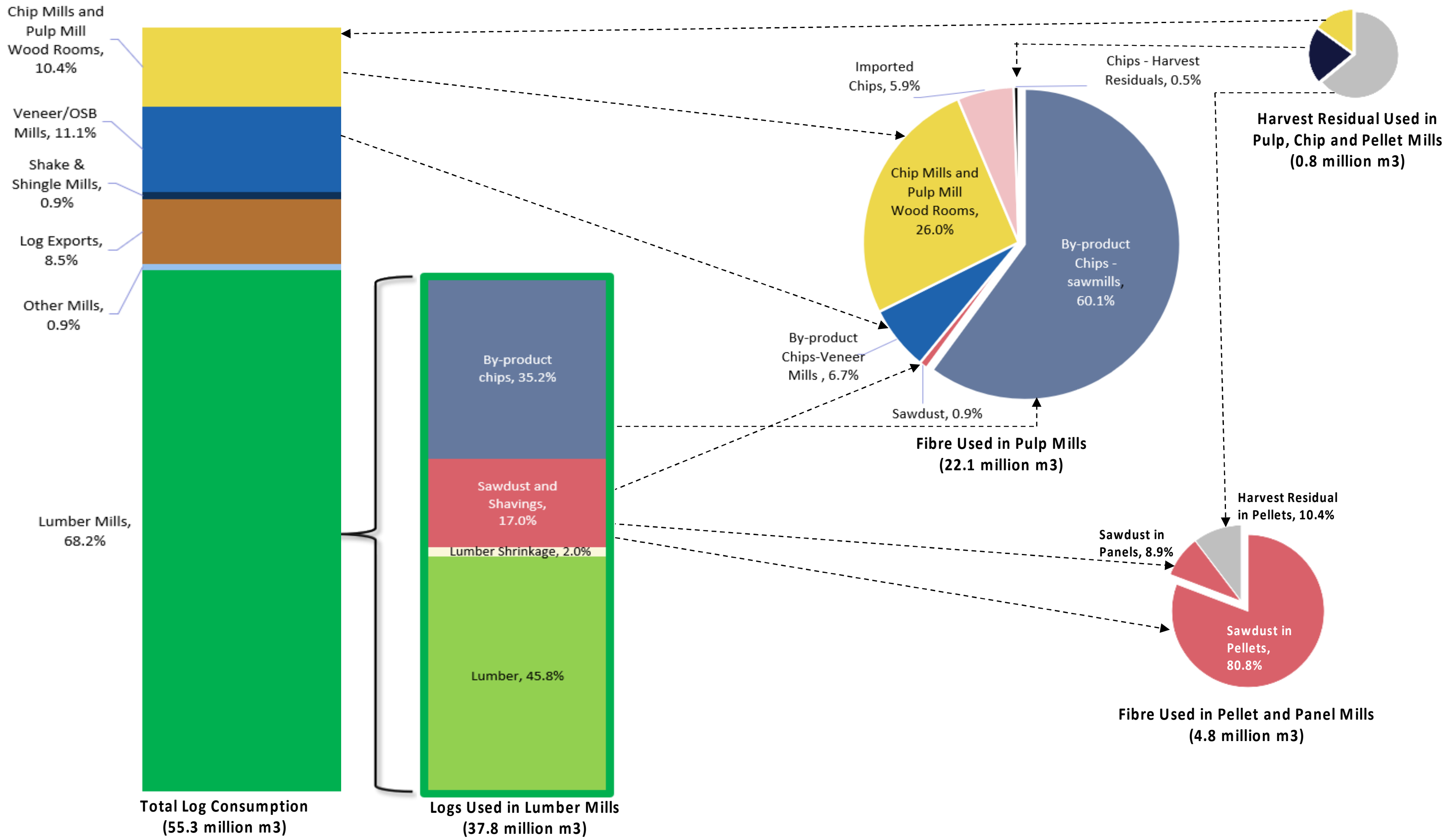


Figure 43 Fibre Flows Between Users in B.C. (2019)[217]

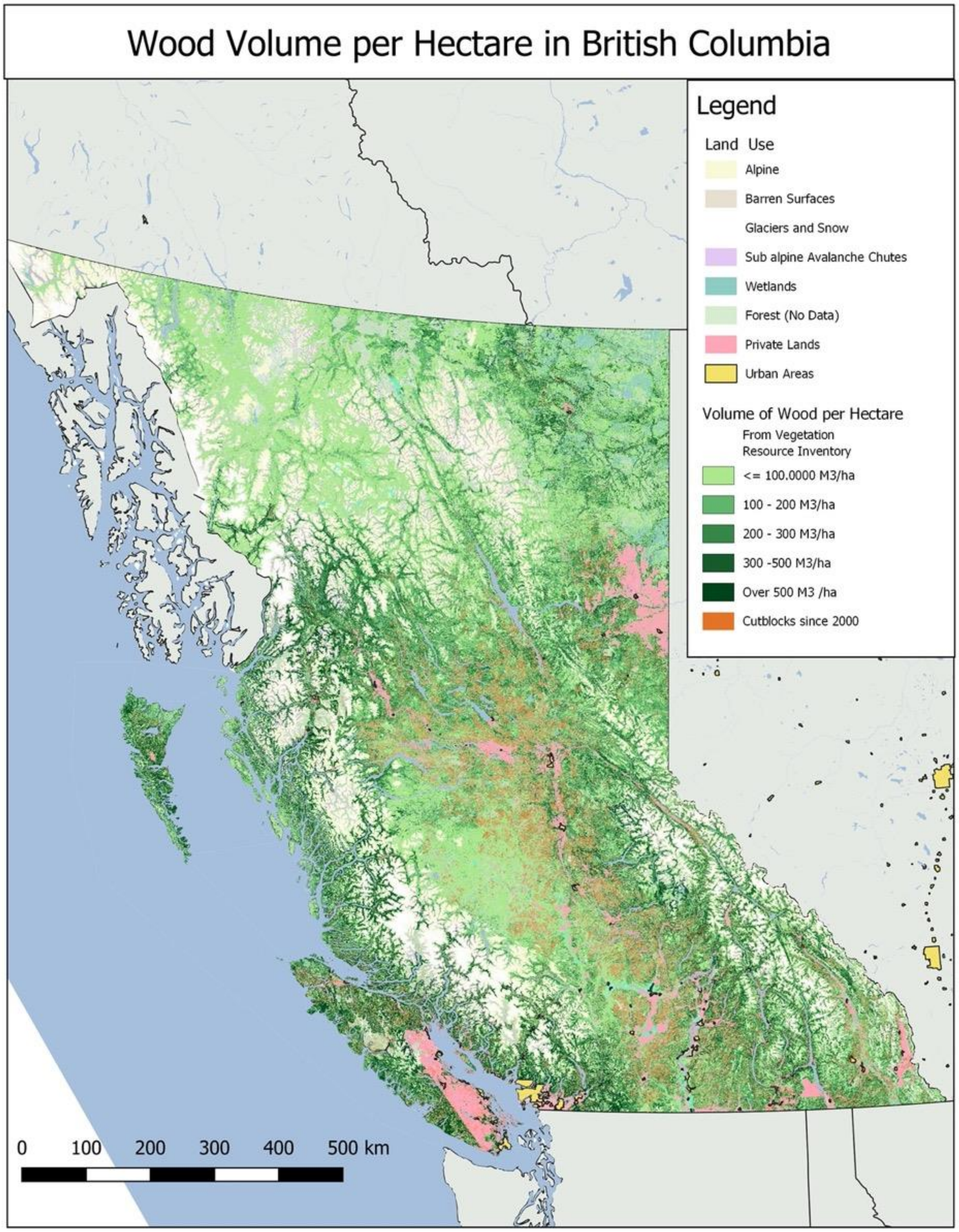


Figure 44 Concentration of Woody Biomass (Forests) in B.C.

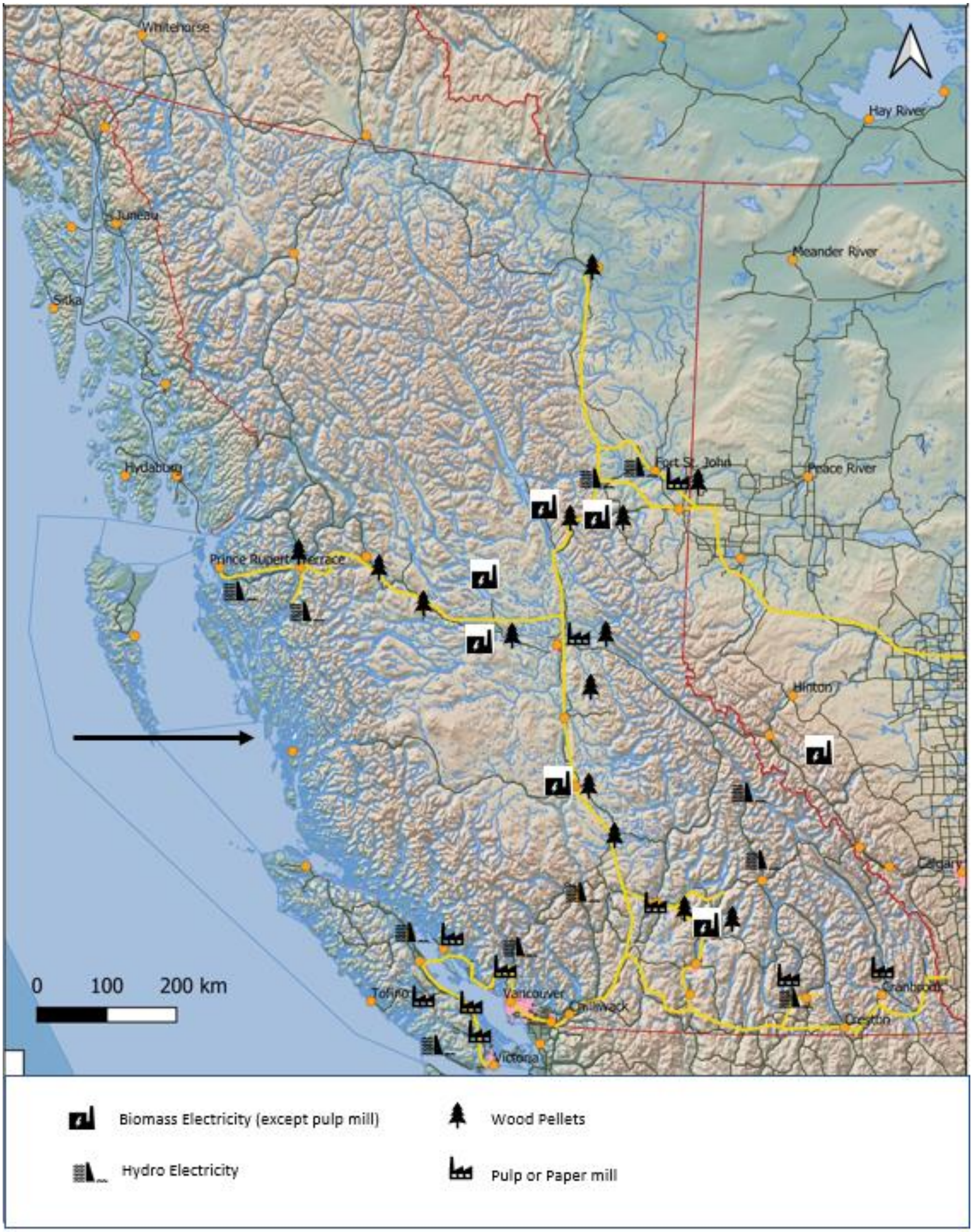


Figure 45 Location of Bioenergy Facilities and Pulp & Paper Mills

E. *Harvesting (Roadside) Residue*

Processing residues may also be augmented by roadside residue, which mainly refers to tops and branches generated during harvesting. This material may remain on the forest floor or be collected at the roadside, and a portion of the latter may be transported directly to mills to make wood products. Estimates of total roadside residue consumption were about 900,000 cubic metres in 2018[218] and 770,000 cubic metres in 2019. Whatever the total amount of residue is being consumed, the ratio of consumption by different sectors is constant, with pellet mills consuming about 64%, followed by chip mills (21%), and pulp mills (15%).

Harvesting residue has been estimated by FPInnovations (FPI) for 18 out of the 37 TSAs.[219] They determined that 2.89 million dry tonnes were available across these TSAs, representing a ratio of between 20.5% and 21.3% of the total sawlog harvest. Approximately 260,000 tonnes of estimated available residues are situated in the four coastal TSAs, and the remainder (2.63 million tonnes) are in the 14 TSAs in the interior. In the interior, FPI estimates that about 35% of this resource is economically recoverable at a cost of up to $60 per dry tonne at the plant gate. At coastal locations, only 16% are deemed recoverable at that cost. This adds up to one million tonnes of low-cost recoverable roadside residue. An additional 1.8 million tonnes may be recoverable at a cost above $60 per dry tonne. This is similar to the estimate of 1.2 million tonnes in Table 62. Note that the FPI estimates only extended to about half the total number of TSAs. Twenty percent of the total sawlog harvest across B.C. is likely to be available residues. A smaller subset is recoverable at costs acceptable to the industry. This suggests that in 2020, the total amount of available residues was as high as 3.12 million dry tonnes, based on a harvest level of approximately 37.7 million m^3.

Brian Titus of NRCan provided yet another estimate, quantifying roadside residue at a distance of 50 and 75 km from existing gas compressor stations along the pipeline network.[220] He arrived at 3.2 million dry tonnes for 50 km and 4 million tonnes for 75 km. This assessment overlaps with the FPI estimate of total available residues. It does not appear to consider existing uses of this material, or other costs such as road construction that might reduce this estimate. Uncertainties therefore remain, and improved recovery techniques and supply chains will make this resource more accessible and more affordable over time.

F. *Mill Residue Production and Consumption*

Table 67 summarizes the amounts of residue produced and consumed in B.C. for the year 2019. The great majority of mill residue is consumed within the forest products industry. Shake and shingle and other mills only consumed less than 2% of the fibre harvested (55 million cubic metres) and are left out of the table. Lumber mills accounted for almost 70% (68.2%) of harvested volumes in 2019, followed by veneer and OSB mills (11.1%) and chip and pulp mills (10.4%), which use whole tree chips for a portion of their input. Log exports were the fourth largest market for B.C. roundwood, at 8.4%.

Sawmills and veneer mills produced a total of 6.4 million m^3 of shavings and sawdust, as well as 15.7 million m^3 of chips. This meets most of the chip demand from the pulp and paper sector (22.1 million m^3),

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218 Corrected number, based on Leng, Jiali: Personal communication. Ministry of Forests, Lands, and Natural Resource Operations, October 19, 2021.

219 https://library.fpinnovations.ca/en/viewer?file=%2fmedia%2fFOP%2f8288.PDF (Accessed September 8, 2021)

220 Titus, Brian: Logging residue availability estimate. Pacific Forestry Centre of Natural Resources Canada. Cited in: Hallbar, Matthew: Resource Supply Potential for Renewable Natural Gas in B.C. PUBLIC VERSION. Hallbar Consulting, March 2017.

with the remainder provided by whole log chips and some chip imports from the U.S., mainly coastal mills. Chip and pellet mills also consume increasing amounts of roadside residue as less mill residue is available because of sawmills closing their doors. Sawdust and shavings are mainly consumed by pellet mills. The numbers in the table suggest a sawdust/shavings surplus of about one million m^3. This may be because the amount was overestimated (the Mill List Survey does not collect data on the actual production of sawdust and shavings from lumber mills) or because these resources were used internally by industry, such as for on-site drying (activities like this are not captured in the mill survey). It is somewhat in line with the previous estimate that about 300,000 dry tonnes of mill residue remain unused in B.C. (Table 62).

Table 67 Mill Residue Production and Consumption in B.C. (2019)[217]

Mill type (number)	Residue type	Amount of residue, per year
Lumber Mills (69)	Sawdust & shavings	6.42 million m^3
Lumber Mills (69)	Pulp chips	13.29 million m^3
Veneer Mills (12)	Pulp chips	2.47 million m^3
Pulp Mills (15)	Hog fuel	4.7 million m^3
Pulp Mills (15)	Residual chips	15 million m^3 + 5.8 million m^3 of whole log chips
Pulp mills (15)	Sawdust	199,000 m^3
Pulp Mills (15)	Roadside residue	116,000 m^3
Chip Mills (24)	Roadside residue	162,000 m^3
Pulp & paper Mills (20)	Chip imports	1 million m^3
Pellet Mills (13)	Sawdust & shavings	4.4 million m^3
Pellet Mills (13)	Roadside residue	493,000 m^3
Panel Mills (27)	Sawdust	427,000 m^3

Black: production; red: consumption

Table 68 lists existing and planned wood pellet mills in B.C. These mills predominantly use mill waste (about 70% of their input). Only about one-quarter comes from whole logs.[217] New mills, such as the one planned for Fort Nelson, would change this picture and would use mainly roundwood, co-harvesting both sawlogs to be sold to mills and non-merchantable trees to be chipped and dried for wood pellet production.[221] This again confirms that little easily available fibre is available in B.C. for new ventures. The Fort Nelson project accesses an abandoned TSA that was previously controlled by one of the large sawmill companies. Where mills close and additional value can be obtained from co-harvesting both sawlogs and pulp or energy logs, the forest products industry may be revived through new energy-related projects. The role of bioenergy as an outlet for low-grade logs and residuals is particularly important in regions where there is no existing pulp production such as the northwest (e.g., Coast Mountain Natural Resource District and Kispiox/Nass areas).

[221] https://thetyee.ca/Analysis/2021/02/17/Trees-Pellets-Fort-Nelson-Future-Hangs-Balance/ (Accessed September 1, 2021).

Table 68 Existing[222] and Planned Pellet Mills

Mill	Location	Capacity in kilotonnes per year
Canadian Forest Products (Canfor)	Fort St. John	75
Canadian Forest Products (Canfor)	Chetwynd	100
Pacific Bioenergy Corp	Prince George	350
Drax	Burns Lake	380
Canfor/Pinnacle Renewable Energy Inc.	Houston	220
Drax	Smithers	140
Drax	North Strathnayer	230
Drax	Williams Lake	230
Drax	Armstrong	72
Drax	Lavington	300
Princeton Standard Pellet Corp.	Princeton	100
Premium Pellet Ltd.	Vanderhoof	185
Skeena Bioenergy Ltd.	Terrace	95
Vanderhoof Specialty Wood Products	Vanderhoof	30
TOTAL		**2,507**
Peak Renewables[223]	*Ft Nelson*	*600*
Hazelton Bioenergy[224]	*Hazelton*	*100*
SMG Wood Pellets[225]	*Mission*	*160*

Note: Planned projects in italics

Expiring contracts of pulp and paper mills with BC Hydro to export excess power to the grid have been identified as another potential source of fibre (hog fuel). As new contracts have been concluded since 2019 and until the end of 2021 at lower pricing and lower power output levels than before (around 80% of previous levels), the biomass previously used to generate the excess electricity can now be used for other purposes, potentially also to produce renewable gases. The amount of this biomass is substantial and has been estimated as high as 2.2 million dry tonnes (bark),[226] with potentially another 700,000 tonnes from dedicated power plants if the latter can no longer operate cost-effectively.[234] This estimate compares to an estimated 0.8-1.0 million dry tonnes from a report by Tom Browne, possibly increasing to 1.7 million tonnes by 2029 as more mills cease to export excess power (power-only generators are not considered in this estimate).[227] Table 69 summarizes the information available on these contracts and estimates the feedstock potentially becoming available for other uses.

[222] SBP-endorsed Regional Risk Assessment for the Province of British Columbia, Canada. Sustainable Biomass Program, August 2021.
[223] https://www.argusmedia.com/en/news/2161961-canadas-peak-renewables-plans-new-bc-pellet-plant
[224] https://www.interior-news.com/news/south-hazelton-pellet-plant-on-track-for-2021-opening/
[225] http://www.biomassmagazine.com/articles/10766/proposed-pellet-plant-to-export-product-to-south-korea
[226] Issue Note on Biomass Energy Purchase Agreements - A Critical Component of BC's Integrated Forest Industry Submitted by Industry Members of the BC Pulp & Paper Coalition, August 2017.
[227] Browne, Tom: Syngas and Renewable Natural Gas options for the BC forest sector. Tom Browne & Associates, October 2019.

Table 69 Revised BC Hydro Contracts with Mills, in GWh per Year[228]

Facility	Previous Export	Year of Renewal	Renegotiated Export	Estimated odt becoming available
Paper Excellence, Howe Sound	400 GWh	2019	400 GWh	
Skookumchuck	266.7 GWh	2019	162.4 GWh	
Catalyst Paper, Powell River	157.5 GWh	2020	*125 GWh (est.)*	
Canfor PGP Pulp Bioenergy	123 GWh	2019	105.5 GWh	
Mercer, Celgar	241.5 GWh	2019	127.9 GWh	
Tolko, Armstrong	163.32 GWh	2019	126.8 GWh	
Atlantic Power, Williams Lake	545 GWh	2019	388.4 GWh	
Sub-total through 2020	**1,897 GWh**		**1,436 GWh**	**388,000**
Conifex, Mackenzie	220 GWh Strathmere	2029	0	*185,086 (est.)*
Merritt Green Energy*	303.5 GWh	2029	0	*255,335 (est.)*
Chetwynd Biomass	96.4 GWh	2029	0	*81,101 (est.)*
Ft St James Green Energy*	303.5 GWh	2029	0	*255,335 (est.)*
Fraser Lake Biomass	96.4 GWh	2029	0	*81,101 (est.)*
Kamloops Green Energy	288.3 GWh	2029	0	*242,547 (est.)*
Harmac Biomass, Nanaimo	209 GWh	2029	0	*175,832 (est.)*
Canfor, Intercon Green power	73 GWh	2029	0	*61,415 (est.)*
Canfor, Northwood	159 GWh	2029	0	*133,767 (est.)*
Cariboo Pulp & Paper	172.3 GWh	2029	0	*144,956 (est.)*
Sub-total by 2029	**1,925 GWh**		**0**	***1.6 million** (est.)*
Total potential if previous contracts expire and are not renewed				**3.2 million**

* These power plants come into full operation in 2018 and may have longer-term contracts with BC Hydro that only expire after 2030.

Almost 400,000 tonnes should be available today from modified BC Hydro contracts but over three million tonnes could become available in 2029 if the industry stopped exporting power, and if biomass power plants ceased to produce electricity. This does not take into account, however, that several sawmills have closed in recent years due to changing market conditions and changing fibre supply in various TSAs. The fibre balance in many regions has been affected. Pulp and paper mills, where cogeneration facilities are situated, may rely on at least some of this resource for their own needs, either as fuel or to produce additional wood chips. This may then affect their intake of roadside residue or hog fuel from other sources.

The 2019 Mill List[217] identifies 121 large and mid-sized lumber mills in B.C. As shown in Table 66, 14 sawmills already closed or have indefinitely suspended activities. If another nine mills are closing soon, this would mean that about 19% of B.C. mills active in 2019 will fall out of service. This, in turn, can be estimated to reduce residue production by 4.5 million cubic metres or about 1.8 million dry tonnes – about the amount potentially freed from reduced use for power production at mills. This would mean that, currently, a fibre shortage exists in B.C. and only a portion of the 3.2 million tonnes estimated in the table above may actually be available in 2029. Conversely, it is also possible that a large portion of lost production will be taken up by the remaining mills if the latter are currently running only one or two shifts per day and can now add additional shifts to increase their output. The impact of renegotiated BC Hydro contracts is therefore impossible to quantify, due to uncertainty around future negotiation outcomes, BC

[228] IPP Supply List – In Operation. BC Hydro, May 2021.

Hydro power requirements, and the internal demand of the forest products industry rebalancing in unpredictable ways.

G. *Other Sources of Wood*

Table 70 adds several more sources of wood that may contribute feedstock to a new biomass energy project. These sources are sometimes significant in size but they can also be variable or spread over a large area of B.C., so any given project may access smaller amounts of the totals estimated here. Wood from thinning around communities to reduce the fire hazard may occur regularly (i.e., thinning may have to be repeated every ten years) but is expensive to obtain. Subsidies are provided through the Forest Enhancement Society of B.C., yet the amounts recovered remain very small. Generally, a large portion of feedstock must be guaranteed for a long timeframe for a project to be bankable. This excludes many smaller or irregular resources from being counted on to start up a new project. Once in existence, however, a new facility can access a variety of these resources for part of its feedstock. The amounts of roadside residue available were estimated based on a yield of 21% of merchantable amounts.[229] Various innovations such as co-harvesting pulpwood and energy wood and yarding down to a 2" (5 cm) top is being considered in the Kootenays to use residuals that would otherwise be left on site, significantly boosting wood availability by over 20%. This approach is being employed by Celgar in the Kootenays which added specialized flail debarking technology to separate the white wood residuals from the bark. They plant to use the bark in a gasifier that will generate 1.2 million gigajoules of syngas.[230] However, road grades above 15% and cut slopes above five metres make secondary harvesting difficult with the current onsite chipping and grinding equipment. Biomass recovery on steep slopes appears to be limited without significant operational changes, such as those proposed by Celgar.

Table 70 Other Sources of Wood

Source	AAC	Roadside Residue, odt	Comments
Thinning for fire suppression (community interface, through FESBC).[231]	<40,000 m^3	16,000	124 wildfire risk reduction projects, 2016-2020; average contribution of $14 per m^3 roadside fibre recovered[232] <3% of a total of 1.25 million m^3.[233]
Heritage piles.	Unknown		Partially unusable if in state of decay.
Line and road maintenance.	Unknown		Likely thousands of tonnes, very dispersed.
Construction, demolition and land clearing.	270,000 odt[234]	270,000	Mainly in larger cities and often already being used by e.g., the cement industry or for district heating.
Sub-total		**>300,000**	Some currently used by others.
Newly available AAC due to mill closures.	10.5 million m^3	4.3 million	Roundwood; estimate based on anticipated mill closures.
		0.9 million	Roadside residue; estimate based on anticipated mill closures.
TOTAL		**>5.5 million**	

229 Friesen, Charles: Biomass Supply in BC (slide presentation). FPInnovations, February 2020.
230 Mercer Celgar (November 2019). [Untitled] Presentation to the City of Nelson Council.
231 https://www.fesbc.ca/projects/ (Accessed September 2, 2021).
232 2021/22 – 2023/24 Service Plan. Forest Enhancement Society of BC, April 2021 .
233 Kozuki, Steve: Personal information. Forest Enhancement Society of BC, September 3, 2021.
234 Revitalization of The B.C. Bioenergy Sector - Final Report. ENVINT Consulting, October 2019 (confidential).

H. *Concluding Remarks and Caveats*

A high-level estimate with respect to unused AAC can be made based on the assumption that 19% of mills are closing between 2019 and 2023 and that they have control over a commensurate amount of harvestable trees. If industry harvests about 55 million cubic metres, as indicated above for the year 2019, then there should be around four million tonnes of roundwood available from these TSAs that are no longer harvested. To that, about 21% of roadside residue could be added.

This compares to almost four million cubic metres of AAC not harvested in 2019 as previously determined (see Table 62). CFS expected most of this amount to be either used by 2028 due to increase mill output, or the AAC to be reduced. These developments may therefore affect the estimate made above, even if there were additional unharvested amounts as of 2019. The estimate appears to reflect the fact that about 10-20% of AAC is routinely not harvested in many TSAs so, in theory, more wood could be extracted from TSAs that are currently managed by sawmills. Harvesting whole trees is, however, the most expensive source of wood fibre available. It is not likely that the entire harvest would be used for gas production. Rather, valuable trees would be sold as sawlogs (with pulpwood) and only non-merchantable trees would be used, reducing the overall potential for gas production.

The results for roadside residue need to be taken with some caution. The factor determined by FPInnovations (21% of roundwood harvest) serves to identify recoverable amounts. Yet, it does not take into account regional differences (e.g., steep slopes may make recovery more difficult or uneconomic), harvesting practices (tree length vs. shortwood methods (skidding may result in much less residue being recovered than forwarding), existing uses, or actual harvesting levels. Available amounts will therefore be lower than estimated here and a local feedstock assessment is necessary to determine the amount available. The theoretically estimated amounts have therefore been reduced to 50% in 2030 and 85% by 2050 to define the Minimum and Maximum scenarios in Section 5.3. Also, harvesting residue should not be relied upon as the only resource for gas production since accessing it will often only be possible during a small window of time after the trees are harvested. This indicates that feedstock diversification should be the goal.

The results of the numbers developed above are combined graphically and in tabular format in Section 3.1.1 above. This technical potential is further developed into Minimum and Maximum scenarios in Chapter 5.0.

Appendix D-3

CAPACITY IMPACTS OF INTRODUCTING HYDROGEN OR HYDROGEN AND NATURAL GAS (OR RNG) BLENDS

APPENDIX D-3: CAPACITY IMPACTS OF INTRODUCING HYDROGEN OR HYDROGEN AND NATURAL GAS (OR RNG) BLENDS

FEI's framework to transition to a low-carbon energy future is its Clean Growth Pathway, discussed in Section 3 of the 2022 LTGRP. The Clean Growth Pathway is a diversified approach that is technology agnostic. At this point in the energy transition, it is important to maximize the number of decarbonization pathways available and explore business models that meet energy demands and maximize the use of existing assets, thereby avoiding the costs that would come with the complete reengineering of BC's energy sector. In the 2022 LTGRP, the Clean Growth Pathway is represented by the Diversified Energy (Planning) Scenario.

FEI is planning for gas supply resources made up of increasing amounts of renewable and low-carbon gas over the next 20 years and beyond. The components of this resource mix are expected to include RNG, hydrogen, natural gas, and smaller amounts of syngas and lignin, supplemented later in the planning period by CCUS. The amount of each resource to be acquired and delivered to customers throughout the planning period will ultimately be predicated by several variables, including:

- **Quantity and Timing of Resource Availability**: Although FEI has modelled the mix of renewable and low-carbon gas in certain proportions over time in the LTGRP planning scenario, the actual amount of each component that is acquired and delivered to customers could vary from the forecast amounts over the planning horizon based on a number of important factors, including resource costs and supply project opportunities and development. Renewable and low-carbon gases with the highest volume potential over the planning horizon are RNG and hydrogen. In particular, RNG is interchangeable[1] with natural gas and has wider availability so will make up a greater proportion of the resource mix in the near term. RNG will continue to be a large part of the resource mix throughout the planning horizon and beyond. While hydrogen resource development is underway, it is expected to become more widely available and make up an increasing proportion of the resource mix later in the planning horizon beyond 2030.
- **Resource Development and Delivery:** Many pathways exist for bringing the benefits of renewable and low-carbon gas to FEI's customers; however, there are several ways in which these resources can be developed and delivered to customers which will ultimately determine the capacity impact and the overall system upgrade scope and timing. The following discusses the various modes of production and delivery and explains some of the capacity impacts associated with each.
    i. **Off-System Supply and Off System Delivery:** Off-system supply is where FEI acquires renewable and low-carbon gases in other regions and the gas

[1] The physical properties of renewable natural gas, such as specific gravity, viscosity and heating value, etc., falls within the range of the physical properties of FEI's conventional sources of natural gas. The capacity impacts and gas supply resource needs are comparable, and both sources of methane can utilize the same upstream and on-system infrastructure.

transportation and consumption is conducted completely outside of FEI systems. This process achieves carbon reduction and credit for FEI customers with the environmental attributes associated with renewable and low-carbon gas. However, since FEI customers continue to physically receive conventional natural gas through FEI infrastructure the capacity requirements to meet peak demand forecasts remain the same on the FEI system. This capacity impact of off-system supply and delivery has the same neutral effect regardless of the form of the off-system energy delivered. The incorporation of these types of off-system supplies will play an important role while the transition to renewable and low-carbon gas occurs over the planning horizon until more on- or near-system resources that flow directly through FEI systems are developed.

ii. **CCUS:** processes for carbon capture at the customer location will not change the system capacity required to meet the peak demand. The process does not change the amount of conventional natural gas that would be flowing through the system to support customers using these processes.

iii. **On-System Hubs:** Local production and supply of renewable low-carbon gas will be developed. These local hubs, whether they produce RNG, or hydrogen or syngas and lignin will have some ability to free up pipeline capacity as the local demand served by this production no longer needs to be transported through the upstream transmission pipeline. For hubs that in addition to serving local demand inject RNG or electrolytic hydrogen (known as green production) into the transmission system as well there can be an additional capacity benefit on the system, however with hydrogen there can also be some offsetting capacity reduction where hydrogen blends are present in the transmission system or if conventional natural gas delivered through the upstream transmission pipeline is used as a feedstock for hydrogen production, by reformation or pyrolysis (known as blue or turquoise production respectively). The impacts of hydrogen blends on capacity are discussed further in Section 1.1 below.

iv. **Off-System Supply and On-System Delivery:** Off-system supply of RNG and hydrogen physically delivered into FEI transmission systems from upstream pipelines will produce no net change in FEI transmission system capacity to meet peak demand forecasts if the supply is RNG. If the supply is a blend of hydrogen, there will be some capacity reduction for the reasons discussed below in Section 1.1.

- **Location:** Given the length of the planning horizon, the geographic location where renewable and low-carbon supply production is physically delivered to FEI's customers is not yet known in detail. Production facilities for RNG and hydrogen supplies are expected to be developed both on FEI's system and, over time, in locations where these low-carbon gases can be injected into the existing upstream gas infrastructure. While many potential projects are in the concept and development stages, the location of all those that will proceed during the next 20 years is uncertain. In particular, the extent to which such resources are developed and delivered to customers on one portion of FEI's system will impact the amount of RNG and natural gas that will still need to be delivered on other portions of the system over the planning horizon.

Although FEI is securing about as many contracts for supply within BC as outside of BC, the larger producers, in the near term, are outside of the province. Therefore, in the early years of the planning horizon, FEI's supply will predominantly be acquired and used outside of FEI's service territory. As a result, during this early part of the planning horizon, the system capacity impacts will remain largely unchanged from what FEI would have otherwise anticipated without renewable gases, as the transmission and distribution systems continue to predominantly move conventional natural gas. By 2030 and through the end of the planning horizon, on-system delivery of renewable gases supplied within FEI systems or by upstream pipeline systems will expand.

As FEI incorporates renewable gases into the gas distribution and transmission systems, the physical properties of these gases, such as density and energy content per standard volume, can have an impact on capacity. Gases with physical properties within the range of conventional gas, such as RNG, will have no net impact on delivery capacity. Delivering hydrogen or a blend of hydrogen and natural gas or hydrogen and RNG, where the gas density and energy content are different from traditional natural gas supply, will change the energy delivery capacity. The following sections provide some additional detail and examples of the impacts on system capacity and infrastructure requirements of introducing hydrogen gas blends.

1.1 Hydrogen and Hydrogen / Natural Gas or RNG blends

FEI is planning for future pipelines to be hydrogen ready. In addition to selecting the optimum pipeline materials for construction, this means that the capacity of a pipeline that might initially deliver natural gas should be compatible with meeting the forecast energy delivery requirement when delivering hydrogen or hydrogen and natural gas blends.

For planning purposes, FEI uses an average gas heating value of around 39 megajoules per standard cubic meter (MJ/m^3) to determine the volumes of natural gas flowing through the system to meet customer peak demand. Hydrogen has a heating value of 12.1 MJ/m^3. As a result, if hydrogen is directly substituted for natural gas, around three times the volume of hydrogen must be delivered to customers to meet the same energy delivery of unit volume of natural gas. Blended mixtures of hydrogen and natural gas would fall in between in terms of the volume required to deliver the same energy to customers. This property difference in the pure gases or blends of the gases changes the energy delivery capacity in an existing transmission or distribution pipeline system. As the percentage of hydrogen flowing in the systems increases, the upgrades required to support future energy delivery requirements on the system will change. If a system is forecast to have a capacity deficit, higher blends of hydrogen supplied into the system will require system upgrades sooner, or at a lower system demand, than if the system were to deliver 100 percent natural gas.

The following example scenario is illustrative of the introduction of hydrogen into a hypothetical simple transmission system and a further example illustrates the introduction of hydrogen into an existing FEI distribution system. The examples provide some insight into the impacts hydrogen has on energy delivery systems, and the infrastructure planning considerations that need to be made to accommodate this renewable gas in FEI's transmission systems, and the capacity those systems currently possess to deliver hydrogen.

1.1.1 Hydrogen and Hydrogen / Natural Gas Through a Simple Transmission System

The following example illustrates a simple linear transmission system consisting of a 30-inch (NPS30) pipeline 240 km in length receiving gas at the upstream end at 1440 psig and delivering at the downstream end.

The critical parameter defining pipeline capacity of such a system is often the minimum delivery pressure required in the downstream systems; however, in some cases, it is limited or constrained by the velocity of gas within the pipeline. For this illustration, a delivery pressure of 500 psig or a maximum velocity of 24 meters per second (m/s) was chosen as a constraint.

For natural gas systems, sustained velocities of 20-24 m/s are typically considered in the maximum range for pipelines. FEI is currently exploring if higher allowed velocities are appropriate for hydrogen pipelines, however, in this example FEI shows how delivery capacity changes if such a maximum velocity is used to define the available capacity.

To summarize, the assumptions of this example are as follows:

- Pipeline Length: 240 kilometres
- Pipe Diameter: NPS30
- Upstream Supply Pressure: 1440 psig
- Minimum Delivery Pressure: 500 psig
- Maximum Gas Velocity: 24 m/s

In the table below, the last two lines indicate the available capacity to deliver 100 percent hydrogen using either delivery pressure or maximum gas velocity as a constraint.

Table D3-1: Pipeline Delivery of Natural Gas and Hydrogen

Hydrogen Blend (% By Volume)	Volume Delivery (MMscfd)	Energy Delivery Hydrogen (%)	Energy Delivery Natural Gas (%)	Energy Delivery Total (TJ/d)	Compressor Power (relative to 100% natural gas)	Capacity Limiting Constraint
0	871	0	100	960	100%	Delivery Pressure

Hydrogen Blend (% By Volume)	Volume Delivery (MMscfd)	Energy Delivery Hydrogen (%)	Energy Delivery Natural Gas (%)	Energy Delivery Total (TJ/d)	Compressor Power (relative to 100% natural gas)	Capacity Limiting Constraint
50	1095	23.8	76.2	791	141%	Delivery Pressure
100	1943	100	0	666	258%	Gas Velocity[1]
100	2347	100	0	805	308%	Delivery Pressure[2]

Notes:

[1] Gas velocity reaches 51 m/s
[2] Delivery pressure of 900 psig

The table illustrates how the energy delivery capacity reduces when hydrogen is blended with or replaces natural gas. Lines one through three in the table show how, as the blend of hydrogen in the gas stream increases, the volumetric flow in the pipeline also increases and the energy delivery decreases. The volume delivery increases by nearly 125 percent while the energy delivery decreases by just over 30 percent compared to the pipeline flowing 100 percent natural gas. The scenarios in lines one and two are limited by the minimum delivery pressure. Line three shows that the capacity constraint shifts from minimum delivery pressure to gas velocity. Line four shows how the energy delivery could increase in the pipeline if velocity is removed as a constraint and capacity is limited by only the minimum delivery pressure. In the scenario illustrated in line four, the gas velocity in the downstream end of the pipeline is 51 m/s. In that scenario, the energy delivery would decrease by less than 18 percent compared to the pipeline flowing 100 percent natural gas. As indicated earlier, FEI is currently exploring if higher allowed velocities are appropriate for hydrogen pipelines. While a velocity of 51 m/s is possibly excessive for a pipeline system, it is conceivable that allowed maximum velocities in future design of hydrogen pipelines will be higher than those used in natural gas pipeline design and can help mitigate the differences in capacity for pipelines carrying hydrogen or hydrogen/natural gas blends.

1.1.2 Hydrogen and Hydrogen / Natural Gas Through Distribution Systems

FEI distribution systems have capacity to deliver hydrogen and natural gas blends and with supporting capacity upgrades could deliver energy as 100 percent hydrogen. The following case study describes how the capacity of a distribution system is affected by the introduction of hydrogen. The example provided is based on the system serving Whistler, BC. Natural gas is supplied to gate stations in the south-central portion of the Whistler community through an NPS 8 pipeline from Squamish that is in turn supplied by the VITS transmission pipeline. This scenario assumes that that supply is supplemented or replaced by a hydrogen supply that is injected into that pipeline from a source near Whistler. The Whistler distribution system operates at a supply pressure at the local gate stations of 420 kPa, and as gas flows through the system to consumers, delivery pressure downstream falls below that. The farther from the gate station supply the customer resides, the lower the delivery pressure the customer would receive. The trigger for future distribution system improvement in the Whistler system is the system pressure in the northern part or "tail end" of the system in the neighbourhoods on the west end of Green Lake. When pressure at that location is projected to fall below 70 kPa under peak demand conditions, some form of capacity upgrade is required to restore higher pressure. Currently, the pressure in that portion of the system is projected to be greater than 190 kPa. Figure D3-1 below illustrates how the pressure would change at that critical location as higher and higher volumes of hydrogen are introduced. The analysis assumes the peak demand energy requirement of customers on the system is unchanged, that only the percent of hydrogen in the gas stream is changing and that the customers on the system have equipment capable of using any percentage blend of hydrogen and methane.

Figure D3-1: Whistler Distribution System Tail End Pressure vs. Volume Percent Hydrogen

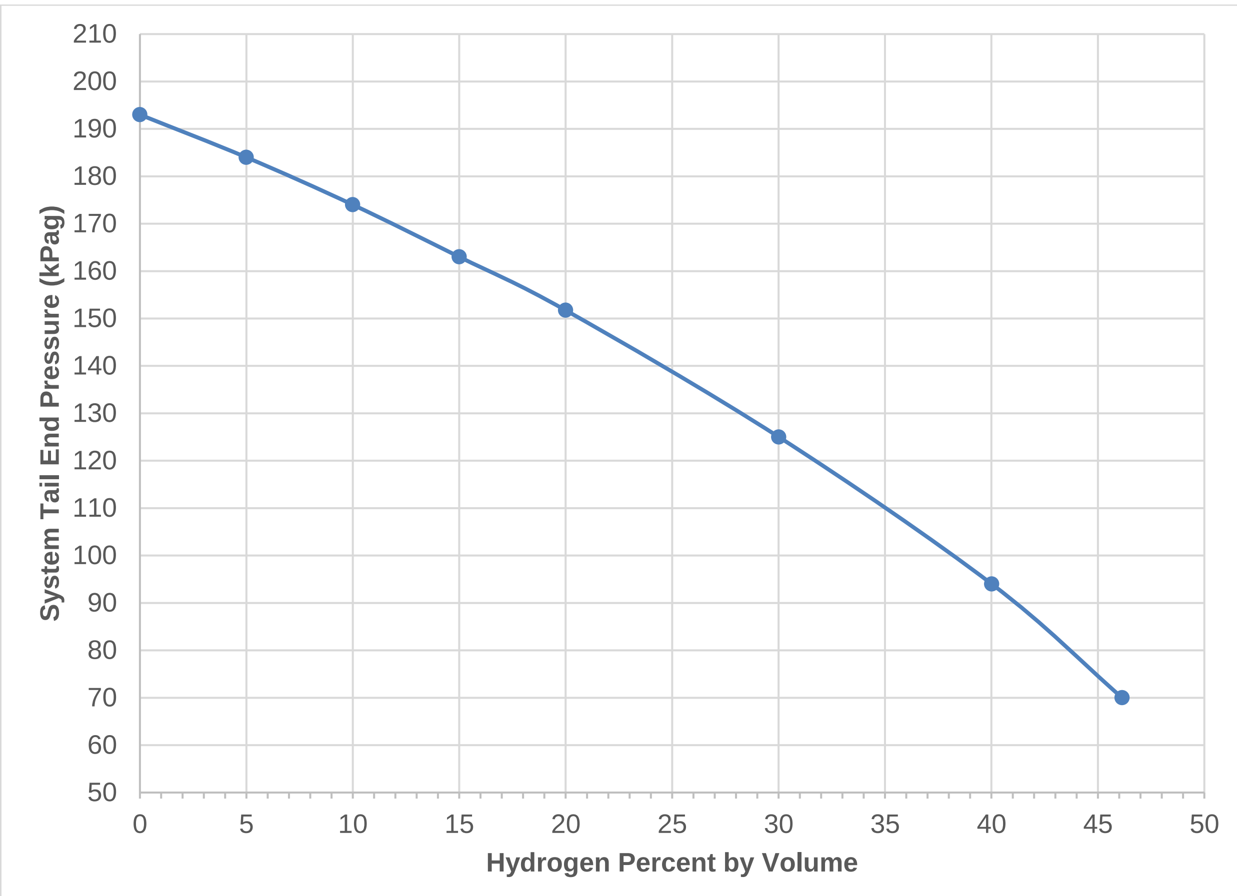
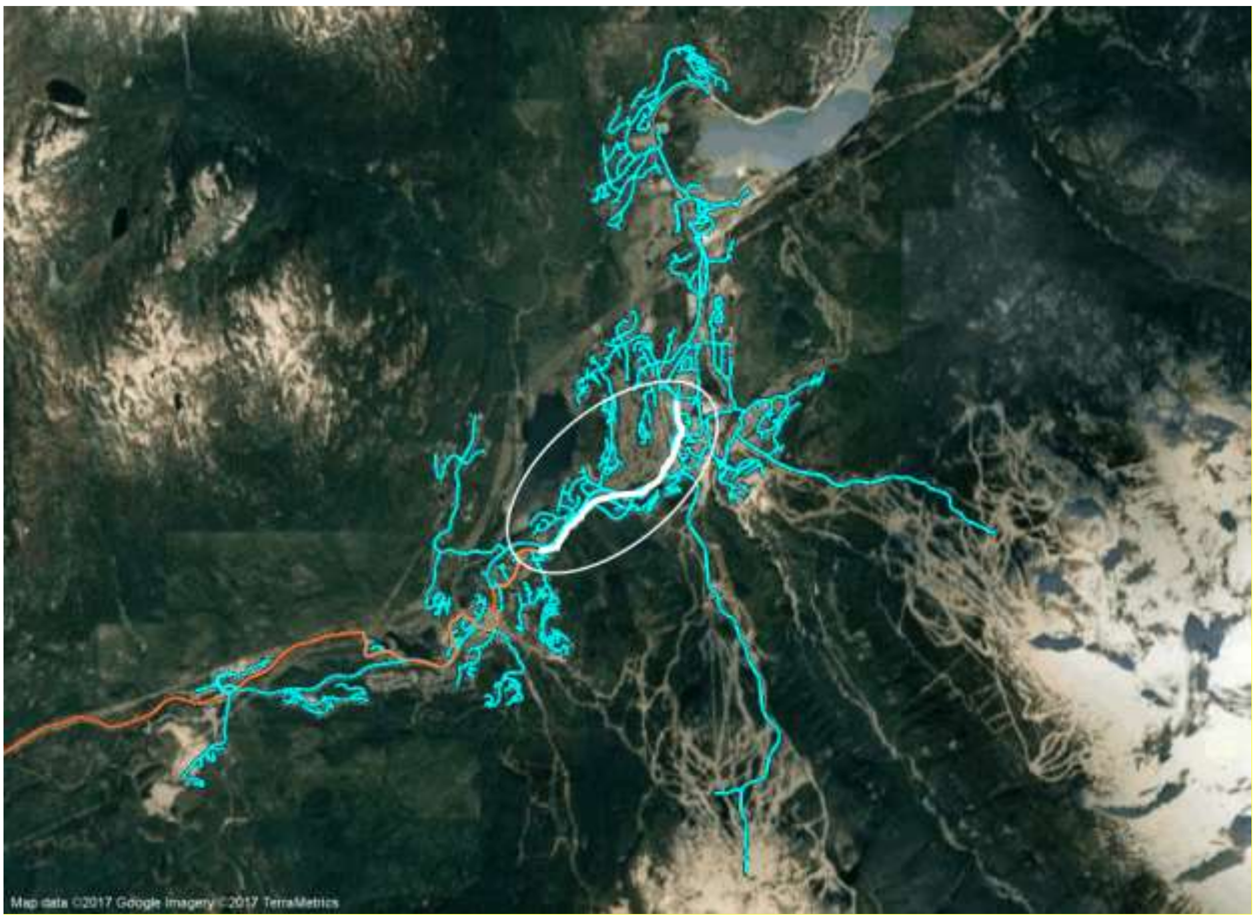


Figure D3-1 illustrates that the peak demand requirements of Whistler customers could be met without additional capacity upgrades required for blends of up to 45 percent by volume hydrogen blended with natural gas. At higher percent blends of hydrogen, the pressure for customers in the north of the system would fall below 70 kPa under peak demand and this would trigger FEI to install some distribution system upgrades to restore acceptable pressure to the area. A typical upgrade to the system would consist of a distribution main looping project that would reduce the pressure drop incurred as gas flows north in the system.

For the Whistler system, an upgrade that could restore sufficient pressure and accommodate higher percentages of hydrogen blends, up to 100 percent, could be accomplished by installing approximately 3300 metres of 8-inch distribution pressure main. This upgrade could allow the Whistler distribution system to meet the peak energy demand delivering pure hydrogen. The scale of such a project is shown highlighted in white (and circled) in Figure D3-2, in which the layout of the Whistler distribution system is presented to show that the project is a moderate upgrade to the system. A distribution project of this magnitude is not dissimilar in scale to projects FEI regularly includes in its distribution system upgrade plans and illustrates that existing distribution systems have the capacity to deliver hydrogen without extensive rebuilding.

Figure D3-2: Whistler System Upgrade to Support Hydrogen Delivery



Appendix E

GAS SYSTEM RESILIENCY PLAN

Appendix E

Gas System Resiliency Plan

May 2022

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1. INTRODUCTION

FEI files this appendix in compliance with BCUC Order G-39-19, which accepted FEI's 2017 Long-Term Gas Resource Plan (LTGRP). In Order G-39-19, the BCUC Panel directed FEI to address security of supply concerns in its next LTGRP to respond to several concerns raised by the interveners (CEC/BCSEA) about the 2018 rupture of the Westcoast Energy Inc. (Westcoast)[1] T-South pipeline. Furthermore, in BCUC's acceptance of the Application for a Certificate of Public Convenience and Necessity for the Pattullo Gas Line Replacement Project (Order C-2-21), the BCUC provided a number of directives and suggestions for FEI to integrate into the 2022 LTGRP.

FEI has assessed various resiliency-enhancing options, in conjunction with external experts, and has concluded that the resiliency of its system is best enhanced through a portfolio of measures. Just as FEI's Annual Contracting Plan (ACP) combines assets with distinct attributes to meet the shape of FEI's load profile (Section 6 of the LTRGP), a portfolio approach to resiliency incorporates enhancements with distinct attributes that together provide a cost-effective approach to resiliency.

Broadly speaking, and as discussed further in Section 1.4 below, a resilient gas system relies on a combination of pipeline diversity, ample storage, and the ability to manage load when gas supply is constrained. In the medium term, FEI's proposed expansion of LNG storage and regasification capacity at the Tilbury facility (Tilbury Liquefied Natural Gas Storage Expansion (TLSE) project), and Advanced Metering Infrastructure (AMI) project, will add key components to FEI's portfolio approach to resiliency while providing other valuable benefits for customers. In the longer term, FEI is exploring possible regional pipeline expansions to address constrained transmission capacity, and reviewing its distribution system to identify locations that present a higher risk of supply disruption.

FEI's resiliency plan is organized as follows:

- Section 2 provides the background for FEI's gas system resiliency plan as a portfolio of measures as follows:
    - Section 2.1 distinguishes between integrity, reliability and resiliency;
    - Section 2.2 explains that high consequence events can still occur on the gas system, despite it being inherently more resilient than other energy systems; and
    - Section 2.3 identifies the key elements of a resilient gas system, namely: diverse pipelines in a regional pipeline infrastructure, ample storage, and load management capabilities and how each contributes to system resiliency in different ways.
- Section 3 describes the inherent resiliency of **FEI's distribution system**, which is comprised of transmission pressure (TP) lateral systems, intermediate pressure (IP)

[1] Westcoast is a subsidiary of Enbridge Inc.

systems and distribution pressure (DP) systems, and the potential enhancements to these systems being assessed by FEI;

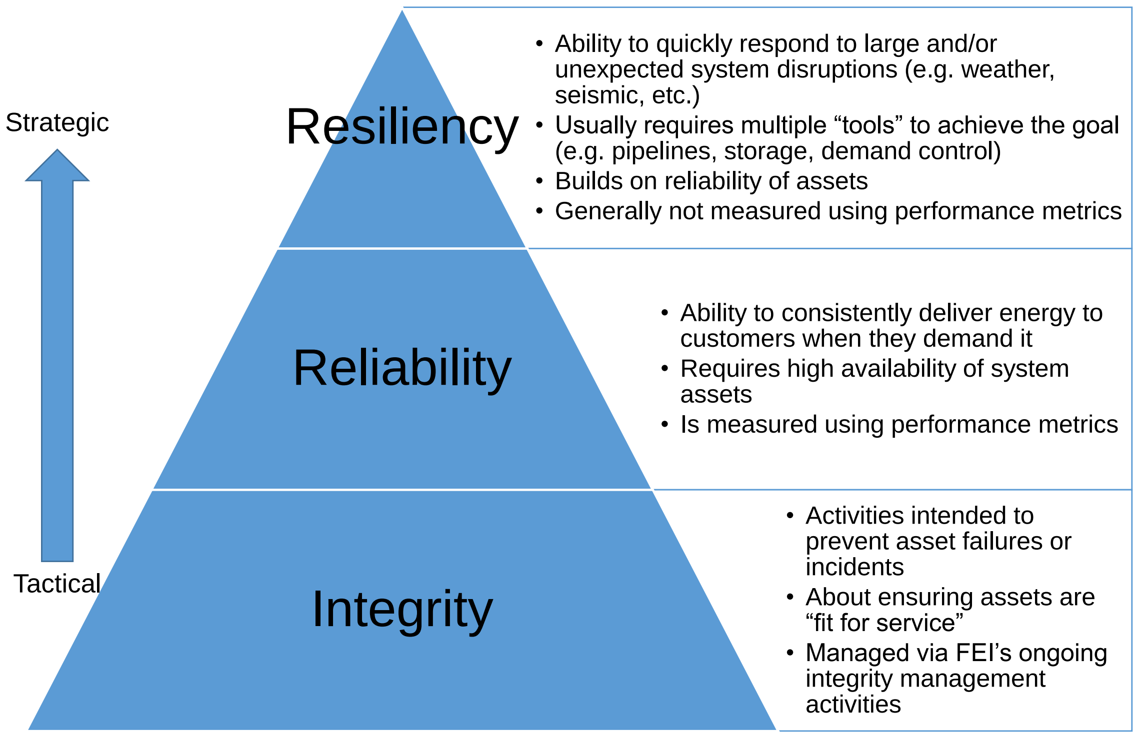
- Section 4 describes the existing resiliency of **FEI's transmission systems** including the consequences of disruption of upstream supply and the ongoing risk of supply disruption related to FEI's continued reliance on the Westcoast T-South system;
- Section 5 addresses **FEI's overall system resiliency** including the deployment of the TLSE and AMI projects, and exploration of diversified regional pipeline solutions including the proposed Regional Gas Supply Diversity (RGSD) project; and
- Section 6 provides a conclusion.

2. RESILIENCY AS A PORTFOLIO OF MEASURES

2.1 DISTINGUISHING BETWEEN INTEGRITY, RELIABILITY, AND RESILIENCY

Integrity, reliability, and resiliency are all necessary system attributes of providing service to customers. While the terms “reliability” and “resiliency” are sometimes used interchangeably, in the context of energy systems, they are not synonymous. Figure E-1 outlines these system attributes, how they differ but also how they inter-relate to each other.

Figure E-1: Integrity, Reliability and Resiliency as Building Blocks of Customer Service



2.1.1 Integrity: Having System Components Meet Design Specifications Throughout Their Lifecycle

As shown in Figure E-1 above, the integrity of system assets is foundational to the reliability and resiliency of the gas system. In the context of gas transmission and distribution, integrity refers to the ability of individual system components to meet their original design specifications, and to fulfil their intended purpose or application. The concept of integrity applies throughout the entire lifecycle of gas system assets, including planning, design, procurement, fabrication, construction, commissioning, operations, maintenance, and retirement.

FEI manages the integrity of its gas system assets in order to achieve its goal of having zero incidents on the system that result in significant consequences. Incidents of significant consequence interfere with the functionality gas system assets and may materially impact safety, the environment, and/or continuity of service to a large number of customers.

In the context of reliability and resiliency, integrity management is concerned with avoiding incidents, such as leaks or ruptures, that would undermine the ability of the assets to deliver service to customers. FEI uses tools and technology to detect and mitigate threats to system assets, such as corrosion, third-party damage, and external forces such as landslides, floods, and seismic events. Consistent with industry practice, FEI is continually seeking improved methods to address these threats, including increased use of electro-magnetic acoustic transducer in-line inspection (EMAT ILI). By reducing the likelihood of these threats resulting in incidents, integrity management ensures that it is highly likely that FEI's gas assets will be available to serve customers. Ultimately, ensuring FEI's gas assets remain fit for service is foundational to delivering safe and reliable service to customers.

2.1.2 Reliability: Adequacy and Security of Supply Throughout the Year

Reliability refers to designing and operating a system to ensure it meets the expected customer demand at all times and is a combination of two concepts: (1) adequacy, which refers to the ability to ensure a sufficient supply of energy; and (2) security, which refers to the ability to consistently deliver that supply to customers.

First, from the perspective of "adequacy", maintaining reliability requires that utility operators have sufficient resources to balance their energy supply capacity with customer demand throughout the year. This is necessary to ensure adequate energy supply during peak demand periods, while also being able to deal with the expected variability in customer demand during other times. To assist with this balance, energy can be stored directly (e.g., natural gas can be compressed, liquefied, or stored underground), or as a different form (e.g., in the electricity context, water held behind a hydroelectric dam).

Second, the "security" aspect of reliability depends on a combination of the concepts of integrity and redundancy. As discussed above, integrity is concerned with (among other things) preventing disruptions to service. Due to the nature of the assets and the success of integrity management in the natural gas industry, disruptions to natural gas service are relatively rare. In contrast, in the electric industry, where the integrity of electric assets is more difficult to maintain and disruptions are more frequent, redundancy is a mandatory requirement for a reliable system. While no mandatory redundancy requirements have been developed in the natural gas industry, gas assets such as storage and pipeline systems do nonetheless incorporate a level of redundancy in their design and operation. For example, multiple transmission pipelines within FEI's Coastal Transmission System have been looped for capacity purposes, which also provides redundancy as some transmission pipelines can be taken out of service without resulting in interruptions to downstream customers.

2.1.3 Resiliency: The Ability to Manage Through and Recover from Unexpected Events

Resiliency refers to the ability to prevent, withstand, and recover from system failures or unforeseen events. Resiliency is directly linked to the attributes of integrity and reliability in the sense that a system cannot be resilient without first having reliable components that serve their intended purpose. Resiliency also encompasses concepts such as preparing for, operating through, and recovering from significant disruptions, no matter the cause.

At a high level, the resiliency of a gas system is measured by its ability to deliver service, backed by physical assets, while preventing, withstanding and recovering from events that interrupt the flow of gas. FEI manages these risks through a portfolio of solutions that enables the utility to manage the risk of unforeseen events and their consequences. Embedded system resiliency enables the system to manage and recover from unexpected events more effectively and expeditiously.

Resiliency, as the ability to prevent, withstand, and recover from system failures or unforeseen events, is therefore critical for natural gas systems because the consequences of a lack of resiliency can be significant. In particular, insufficient resiliency poses a risk of an uncontrolled shutdown of the transmission or distribution system (also referred to as a pressure collapse). An uncontrolled shutdown or pressure collapse occurs when the pressure within a portion or all of the gas distribution system naturally decays to zero following a gas supply interruption. An uncontrolled shutdown is a serious scenario, both in terms of service disruptions and the resulting impacts on customers, and the potential for system safety concerns.

As discussed below, the overall resiliency of the system depends on the interplay between integrity, reliability, and resiliency in order to mitigate against serious events that impact FEI's ability to provide service to its customers.

2.1.4 Interplay Between the System Attributes of Integrity, Reliability and Resiliency

FEI's ability to safely, securely, and cost-effectively deliver energy to its customers is enabled through the interplay of the three necessary attributes integrity, reliability and resiliency. Resiliency is built on the foundation that a well-maintained (i.e., a system operated with appropriate integrity management) and reliable system is in place. Figure E-1 above depicts the concepts as building blocks of customer service. As discussed above:

- **Integrity** (Section 2.1.1) is ongoing, on a day-to-day basis, focusing on detecting and mitigating ongoing threats to system assets and is more "tactical" in nature.
- **Reliability** (Section 2.1.2) is built upon or includes system integrity and tends to be more of a strategic consideration (e.g., securing contracted assets for each gas year and through appropriate infrastructure capital planning).

- **Resiliency** (Section 2.1.3) is a higher-level strategic consideration that typically requires longer-term planning and solutions. It is concerned with the capability of the system to withstand a large and/or unforeseen event, such as an upstream pipeline failure. Resiliency depends on having an appropriate combination of physical assets that can provide continuity of service to FEI's customers.

2.2 GAS SYSTEMS EXHIBIT A MUCH HIGHER LEVEL OF RELIABILITY THAN ELECTRIC SYSTEMS, BUT FAILURES DO OCCUR

In general, gas transmission and distribution systems experience significantly fewer outages than electric networks.[2] However, when gas customer outages do occur, they tend to be longer in duration than electrical outages because the utility of the need to ensure isolation at each customer premise, repressurize, and safely relight customer appliances. The process currently remains a predominantly manual effort. Resiliency investments for the gas system are consequently focused on addressing what are typically low probability events. Even so, despite having a low probability, events can and do occur, and have the potential to give rise to significant consequences.

The vast majority of electric transmission in North America is via overhead power lines, which are more exposed to disruptive events, including: lightning, wind, ice, trees and third-party contacts. Consequently, electric power lines have considerably higher outage rates than underground gas lines.

Based on industry experience, on average, a typical 80 km overhead electric transmission circuit is expected to experience one unplanned outage event per year.[3] Since circuit outages are an expected occurrence in electric networks, asset redundancy is commonly employed to ensure compliance with minimum standards of reliability. The BC Mandatory Reliability Standards (MRS) require that the bulk electric system be planned and operated to withstand an unexpected outage of the single most critical system element, coincident with the forecast system peak load, while not experiencing any firm customer outages.[4] This is referred to as the N-1 reliability criterion and is based on North American industry standards. These industry standards were developed and mandated following two major Northeast blackouts, one in 1965 and one in 2003. In other words,

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[2] Industry surveys and studies conducted by the US Gas Technology Institute have demonstrated gas customer average reliability/availability levels (due to unplanned causes) of 0.9999978. (Gas Technology Institute, Topical Report (July 19, 2018) "Assessment of Natural Gas and Electric Distribution Service Reliability," p. 10.) This is consistent with the service availability levels of the Canadian Gas Association when comparing outage incidents. In contrast, the comparable average availability for most electric customers in BC is approximately 0.99959. In other words, on average the gas system is 186 times more reliable than the electric system.

[3] North American Electric Reliability Corporation (NERC). "Outage Metrics, 2019 WECC AC Circuit." Total Circuit Outage Frequency of 1.97 per 100 mi·yr (for 200-299kV circuits). https://www.nerc.com/pa/RAPA/tads/Pages/OutageMetrics.aspx

[4] BCUC Order R-27-18 (June 28, 2018). "British Columbia Hydro and Power Authority Mandatory Reliability Standard TPL-001-4 Assessment Report." P. 8, Attachment D.

the cost of this necessary system redundancy is broadly accepted by electric operators and regulators in order to ensure adequate levels of customer service.

In contrast, large-diameter, high-pressure pipelines may operate for long periods without experiencing any unplanned outage events. As such, regional gas transmission systems are typically designed and operated to transport a contracted quantity of gas, as opposed to being explicitly planned to achieve an expected level of reliability. To FEI's knowledge, there are no specified regulatory requirements for gas system reliability in North America equivalent to the electric utility N-1 criterion. However, in interconnected gas networks with numerous supply points interspersed with multiple delivery points, a reliable network is a consequential outcome. Thus, in many areas of North America, the redundancy afforded by multiple gas supplies, storage, and transportation paths results in a more resilient system.

The rates of reliability would suggest that, on average, a typical natural gas customer would expect 69 seconds of service outage per year,[5] compared to almost four hours per year for a typical electric customer in BC (even with the high standards of redundancy on the electric system).[6] In practice, the vast majority of FEI's customers have never experienced a single natural gas outage, other than for planned reasons such as a meter exchange.

Ultimately, while gas pipeline failures are relatively rare occurrences, they can nonetheless be high consequence events. If a rupture followed by ignition occurs, the result may be significant property damage, or harm to individuals in the vicinity of the failure. Further, if there is insufficient transmission pipeline redundancy in the region, the reduced transportation capacity can potentially lead to gas shortages or outages to large numbers of downstream customers.

2.3 GAS SYSTEM RESILIENCY DEPENDS ON A COMBINATION OF DIVERSE PIPELINES, AMPLE STORAGE AND LOAD MANAGEMENT CAPABILITIES

At a foundational-level, and leaving aside adequacy of natural gas production and gathering (typically referred to as "upstream" systems), there are three elements that contribute to the resiliency of FEI's gas system:

1. **Diverse Pipelines and Supply:** Transmission pipelines can continuously transport a significant amount of gas supply to the market centres on a daily basis, and therefore, address customers' baseload and seasonal demand requirements. Having access to multiple regional pipelines, preferably separated geographically, to serve the distribution system improves a utility's ability to dependably collect and deliver gas supply to consumers. As described in Section 3.1 below, pipeline diversity within distribution

[5] Gas Technology Institute, Topical Report (July 19, 2018), "Assessment of Natural Gas and Electric Distribution Service Reliability." Online: https://www.gti.energy/wp-content/uploads/2018/11/Assessment-of-Natural-Gas-Electric-Distribution-Service-Reliability-TopicalReport-Jul2018.pdf

[6] "BC Hydro F2020 Annual Reporting of Reliability Indices", p. 3, https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/2020-05-04-f05-f06-directive-26-f20120.pdf

systems is inherently more abundant and the majority of customers are situated so that supply to large numbers of customers is usually not reliant on a single gas line.

2. **Ample Storage:** Access to storage, preferably located on a utility's own system, allows a utility to manage expected or unexpected changes in supply for a period of time. Stored energy can bridge a shortfall in supply entering the utility system, or if necessary, provide time to shed load or implement a controlled shutdown of portions of the system to avoid pressure collapse. Two common gas storage methods are: (1) underground storage; and (2) LNG storage.

    - **Underground Storage:** uses natural geological formations to hold supply in gaseous form, and (as in FEI's case where underground storage is off-system) may require a functioning regional pipeline to transport stored natural gas to the utility distribution system.
    - **LNG Storage:** is held in aboveground storage facilities that are accompanied by adequate regasification capability (to convert the LNG back to gas for delivery to customers). On-system LNG storage has the benefit of being able to inject supply into the local transmission system close to the load centres and is not reliant on functioning regional pipeline infrastructure.

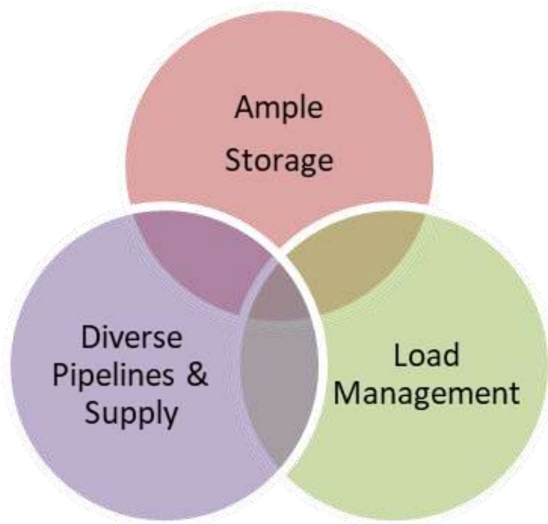
    While it is typically impractical to locate multiple storage sites within the distribution system, the presence of storage on portions of the local transmission system preventing system collapse and providing an interim supply provides a benefit to all downstream distribution systems.

3. **Load Management Capabilities:** The ability to manage load during a period of supply constraint allows an operator to shed load during a controlled shutdown, while ensuring the constrained supply of gas is maintained for the maximum number of customers. Until recently, FEI's only options for gas load curtailment were through broad public appeals to reduce consumption, or direct curtailment requests to large volume and/or interruptible customers. Under the former scenario, FEI has no way to ensure customer compliance, while under the latter scenario, the amount available to curtail may not be sufficient to prevent a system-wide pressure collapse. Moreover, neither are necessarily timely enough during a rapid-onset supply disruption.

    The pipeline diversity inherent to the distribution system means that isolating target customer segments or small targeted geographic locations, as part of a load shed plan, is impractical. This leaves the utility with certain larger scale measures (e.g., closing system valves or shutting-in stations supplying entire communities); however, these measures may not be sufficiently responsive. The deployment of new technology, such as AMI with remote-shutoff valves, will enable FEI to quickly, accurately, and directly target any required customer load shedding. As load management necessitates disrupting service to customers, it is ideally used in conjunction with other solutions (such as on-system storage) that can more directly address supply disruptions. FEI's ability to manage load is discussed further below.

As each of the three elements above adds resiliency in distinct, but complementary ways, FEI views resiliency as a combination of the above three elements, as depicted in Figure E-2.

Figure E-2: Key Elements of a Resilient Gas System



In practice, the overall resiliency of FEI's system is optimized through an appropriate combination of all three elements. For example:

- On-system LNG storage provides immediate response capabilities to ensure survival of FEI's system during a critical supply emergency.
- Diversifying regional pipeline infrastructure helps withstand longer-term interruptions or constraints, and in particular, would mitigate the risk posed by FEI's current reliance on the Westcoast T-South system.
- Load management (potentially facilitated by technology upgrades like FEI's AMI project) enables FEI to avoid an uncontrolled shutdown of the gas system in extreme events by initiating a controlled shutdown and restoration of the system as required.

As outlined above, establishing system resiliency enables the gas transmission and distribution systems to effectively respond to system disruptions and avoid or minimize the impacts of those disruptions on customers. FEI applies and leverages the three key elements of resilient gas systems on both the transmission and distribution system in a variety of ways in order to maintain and enhance the end-to-end resiliency of its system. In the following sections, FEI discusses the existing resiliency of FEI's distribution and transmission systems, and the resiliency of the overall system in the Pacific Northwest region.

3. DISTRIBUTION SYSTEM AND TP LATERAL SYSTEM RESILIENCY

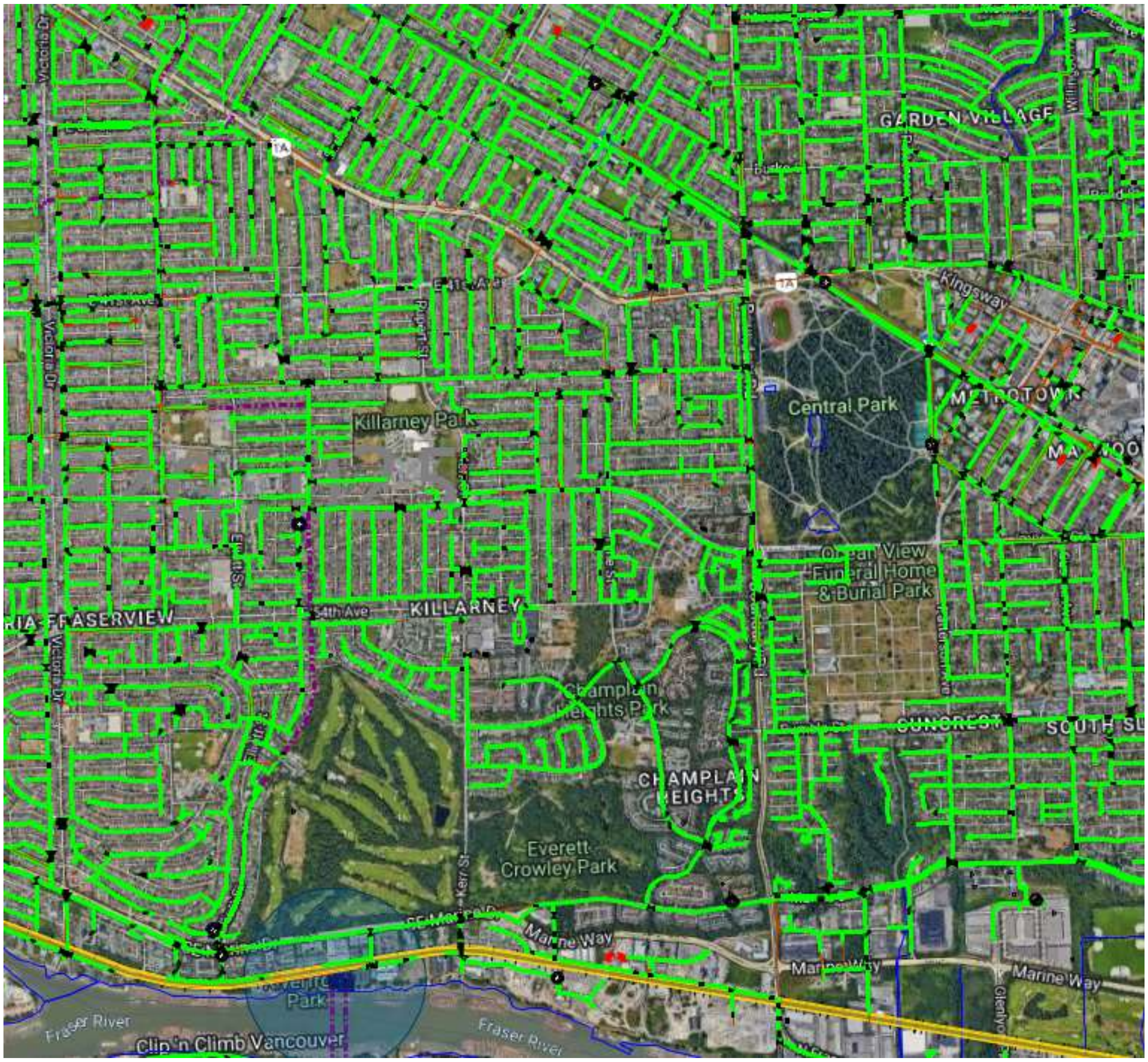
The distribution portion of a gas system is comprised of smaller gas lines that predominantly run within streets and laneways, delivering gas directly to customer premises. In the context of resiliency, FEI's distribution system comprises transmission pressure (TP) lateral,[7] intermediate pressure (IP), and distribution pressure (DP) systems. Each of these systems is considered to be part of the overall distribution system because they are highly integrated, and therefore, are capable of providing more significant support to each other than either can provide to upstream transmission systems.

As a highly interconnected system, FEI's network of gas lines are supplied by multiple gate or district stations which support the system. As a result, the distribution system has an inherent degree of resiliency, generally enabling FEI to maintain service to the majority of customers despite localized incidents on the system. For example, leaks or third-party damages rarely result in a significant supply interruptions, and when responding to and isolating damage within the system, measures can be taken by FEI's operations crews to ensure that customer impacts, if any, remain localized. As a result, FEI gas customers enjoy a very high degree of service reliability and most never experience an unplanned outage.

As a demonstration of the degree of interconnectedness in FEI's distribution system, Figure E-3 below shows gas lines (in green) located in the southern portion of Vancouver and Burnaby, and is a typical example of an urban distribution system layout.

[7] Transmission pressure (TP) laterals are pipeline branches from a transmission mainline that deliver gas at transmission pressure to one or more gate stations serving a local community distribution system or a customer station serving a larger commercial or industrial customer.

Figure E-3: Example of Distribution System Layout



3.1.1 Enhancing the Resiliency of the Distribution System and TP Lateral Systems

In this section, FEI discusses the steps it is taking to enhance the resiliency of these systems, including the development of a new resiliency-based criteria to identify and prioritize possible enhancement projects. FEI also outlines potential projects that could be developed enhance the resiliency of the distribution system, as well discussing the impacts of both recently completed and under-construction projects on resiliency in FEI's Lower Mainland system.

3.1.1.1 Development of Resiliency Criteria for the Distribution System and TP Lateral Systems

Despite the inherent resiliency of the distribution system, FEI is in the process of developing criteria to more clearly define projects where: (1) single points of failure would cause disruption to significant numbers of customers; and (2) the failure of supply would be unable to be restored in a timely manner. Such failures could result in a risk of significant number of customers being without supply for extended periods in winter conditions. As FEI is able to access the vast majority of the distribution system with relative ease, undertaking repairs and the restoration of supply is usually rapid and most often can be completed within a day or a few days (at most). Locations where repair and restoration of service cannot be completed quickly are almost exclusively related to major bridge or water crossing locations, resulting in resiliency-related risks. In some cases, small transmission lateral bridge and water crossings provide the sole source of gas supply to communities, and therefore present similar risks in the event of a supply failure. FEI is considering these types of locations in the criteria it is developing.

As part of the development of this criteria, FEI is reviewing the maximum capability of temporary "non-pipe" solutions (such as a CNG or LNG "virtual pipeline" supply alternatives) to support communities in a sustainable manner during winter conditions, while working to restore normal supply. Despite the probability of an event of this kind being relatively low, defining non-pipe capabilities and establishing the associated feasibility, timeliness of mobilization, and cost of implementation, will help FEI identify and define where opportunities to improve resiliency for non-resilient systems that are too large to be supported by non-pipe solutions if a failure occurs.

Moreover, because single feed crossings do not have the same probability or consequence of failure, establishing criteria to determine the risk associated with each location will allow FEI to prioritize addressing specific resiliency deficiencies within the distribution and lateral systems. As mentioned previously, FEI's DP and IP systems are already generally highly reliable and resilient, and the criteria FEI is developing are not expected to identify many locations where a project of significant scope or cost would result.

3.1.1.2 Metro Vancouver Distribution System Resiliency

As part of the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) project,[8] the integrity-driven need to replace an NPS 20 pipeline between Coquitlam and Vancouver also presented the unique, one-time, opportunity to increase the pipe size to NPS 30. This increased pipe size also enhanced the capacity, and therefore, the resiliency of supply to customers in the Vancouver, Burnaby, Coquitlam and North Shore areas. The BCUC was satisfied that the increased flexibility and resiliency benefits justified the added project costs associated with the increased pipe size:

> The Panel agrees that while not a mandatory requirement, restoring operational flexibility and improving system resiliency are worthy objectives for this project, and merit inclusion in the decision framework. Prior to the new NPS 30 being placed in service, customers in those areas were at risk of an outage if an upstream supply

[8] CPCN for the Lower Mainland Intermediate Pressure System Upgrade granted by the BCUC pursuant to Order C-11-15, dated October 16, 2015.

disruption occurred on FEI's Coastal Transmission System (CTS) or within the Metro Vancouver IP system.

The resiliency added through the LMIPSU project will be somewhat eroded once the existing Pattullo crossing is abandoned and replaced by the Pattullo Gasline Replacement (PGR) project, which was approved by the BCUC in June 2021. In Section 3.6 of the PGR CPCN Application, FEI described the impact the preferred alternative would have on the system resiliency recently gained through the LMIPSU project. In particular, replacing the Pattullo supply with a new pipeline, primarily supplied through Coquitlam Gate via the recently completed LMIPSU pipeline, erodes some distribution resiliency. Even so, after the PGR project enters service, the resiliency provided by the LMIPSU project will continue to be substantially higher than prior to its completion. Importantly, the system will continue to be able to accommodate a failure of supply at either of the two major gate stations serving the region, without loss of customers up to nearly the coldest day in a typical winter.

As discussed in responses to information requests during the regulatory review of the PGR project, in order to recover the eroded incremental resiliency, FEI would need to construct approximately 5 km of new IP pipeline in south Vancouver using 508mm (NPS 20) pipe. A project of this scope would be a significant undertaking, very similar to the scope of the PGR project itself.

As described above, while developing the criteria to identify other resiliency projects on the distribution system, FEI expects that these other proposed projects will address higher risk situations (e.g., where a failure would result in customers being without gas at any time of year should a failure of the single feed occur). As a result, while recovering the additional LMIPSU resiliency eroded as a result of the PGR project remains under consideration, FEI has not yet established the relative priority for the project, and therefore, at what point in the planning horizon the proposed project should proceed. For greater certainty, at this time, FEI does not intend to file an application for a project within the next five years to restore the distribution system resiliency that will be eroded when the PGR project is completed. Further consideration for the potential need and timing for any such project will be provided in a subsequent LTGRP application.

3.1.1.3 Major Distribution Pipeline Crossings

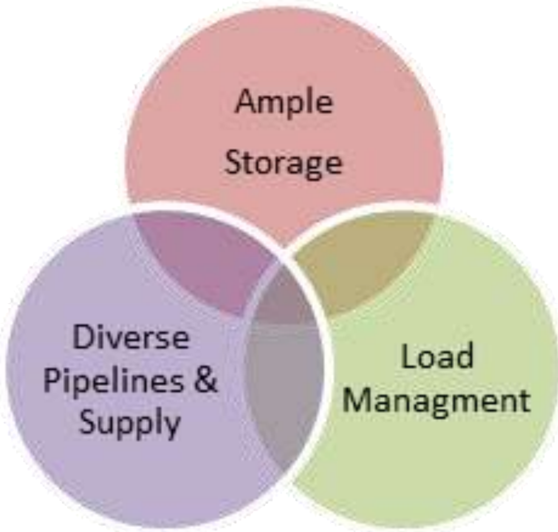
The risk of prolonged service interruptions to major distribution pipelines is almost exclusively limited to single feed gas lines at major water crossings where the line is inaccessible or otherwise extremely difficult to repair. Interruptions of this kind present a unique resiliency risk to the system. As such, FEI is examining options to improve resiliency at select points of the distribution systems, including at the Ironworkers Memorial Bridge in the Lower Mainland and at Okanagan Lake (between Kelowna and West Kelowna).

A single NPS 24 IP pipeline located on the Ironworkers Memorial Bridge provides the only gas supply to more than 45,000 customers in North Vancouver and West Vancouver. Loss of this crossing would result is an extensive outage for these customers. Similarly, in the Southern Interior region of the province, West Kelowna is supplied by a single NPS 8 IP pipeline that crosses Okanagan Lake between Kelowna and West Kelowna. While the system may require capacity upgrades later in the forecast period that could entail looping the lake crossing, this would only address capacity constraints and would not necessarily improve the resiliency of the distribution system. Therefore, FEI is in the process of studying alternatives for the crossing that would improve the resiliency of supply to West Kelowna, Summerland and Peachland.

Other than the communities mentioned above, there are few similar water crossings in FEI's distribution system where large numbers of customers remain at risk of extended supply outages because of crossing failures and a lack of redundant supply.

4. TRANSMISSION SYSTEM RESILIENCY

In the sections below, FEI discusses its approaches to addressing the three elements contributing to FEI's transmission system resiliency, namely balancing the need for: (1) diverse pipelines and supply; (2) ample on-system storage and (3) load management capabilities. For ease of reference, Figure E-2 from Section 2.3 is reproduced below.



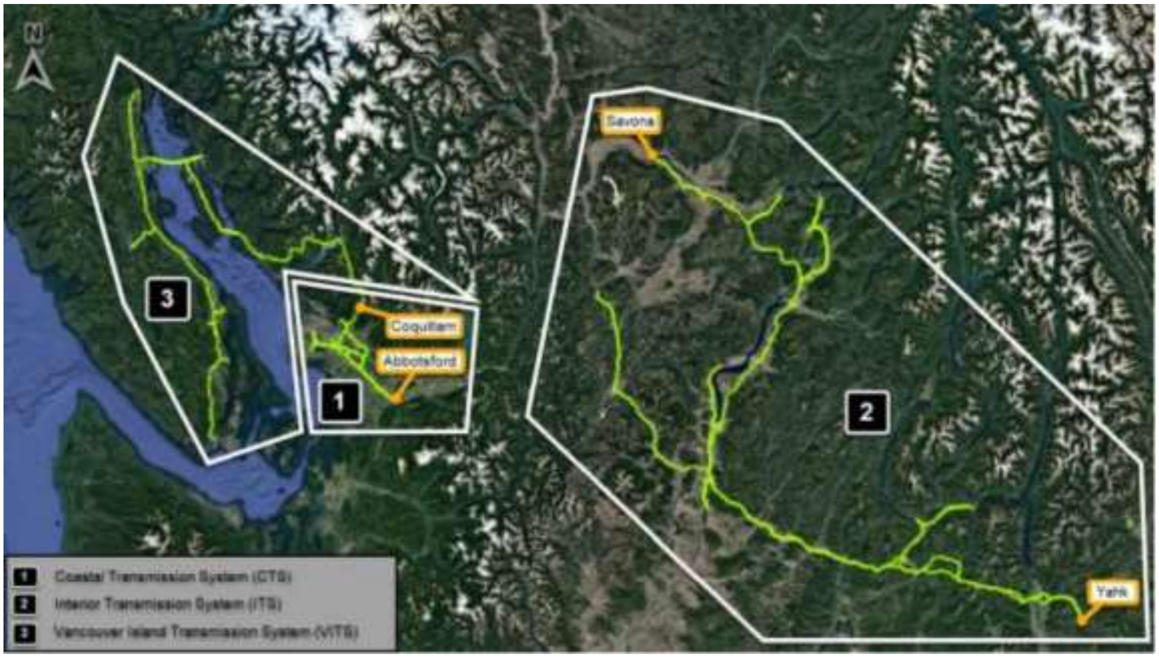
FEI then outlines the continued risk of supply disruption associated with its continued reliance on the T-South system and proposed medium and long-term resiliency enhancements.

4.1 FEI'S EXISTING PIPELINES AND ACCESS TO SUPPLY

FEI's transmission pipeline infrastructure is integral to its ability to deliver safe and reliable service to customers. In this section, FEI provides an overview of its existing transmission systems, explains the redundancy incorporated at the transmission level to date, and identifies the limitations of regional pipeline infrastructure in the province which directly impacts the gas system's overall resiliency.

Figure E-4 below shows a high-level layout of FEI's systems across the province and the Westcoast T-South system, from which FEI currently obtains the majority of its gas supply.

Figure E-4: FEI Transmission System Layout



FEI provides an overview of each of FEI's three major transmission systems below:

1. **Coastal Transmission System (CTS)**

   The CTS supplies gas to the Lower Mainland, Sunshine Coast and Vancouver Island. The CTS receives natural gas in Abbotsford and distributes it west. Construction of the CTS began in the 1950s and expansion continues today.

2. **Interior Transmission System (ITS)**

   The ITS supplies gas to the Okanagan, Kootenays, and portions of the Thompson. Natural gas is received by the ITS at two points: (1) from Savona and distributed east, and (2) from Yahk and distributed west. Construction of the ITS began in the 1950s and expansion continues today.

3. **Vancouver Island Transmission System (VITS)**

   The VITS supplies gas to the Sunshine Coast and Vancouver Island. Natural gas from the CTS is initially compressed at Coquitlam and sent to the Sunshine Coast and Vancouver Island. The VITS contains several marine crossings. Construction of the VITS began in the 1990s and expansion continues today.

Other communities in the province are served by transmission laterals supplied from other upstream pipelines, including TC Energy pipelines in the East Kootenay and Enbridge pipelines in the north and central interior.

4.1.1 FEI's Transmission System Incorporates Pipeline Redundancy

Before addressing access to upstream supply, FEI first observes that building system redundancy is a key means of improving resiliency. While redundancy may not increase reliability performance in any given year, it nonetheless enables the utility to withstand system failures and unforeseen events and prevent disruptions to gas supply when such events occur.

Redundancy can take the form of, for instance, redundant technology controlling a piece of infrastructure, excess capacity through larger sizing of a piece of infrastructure (e.g., a larger storage tank to supply more load if a pipeline fails), or duplicate infrastructure that can support loads in the event of one failing (e.g., two transmission lines or two pipelines to a source of supply).

FEI's transmission system has a degree of resiliency due to the redundancy incorporated into its design. This redundancy has been incorporated as the need arose for additional system capacity to supply customers during peak load periods. Below, FEI provides examples of redundancy incorporated into each of its three transmission systems:

Coastal Transmission System:

FEI has maintained or enhanced system resiliency on the CTS where it can be achieved cost-effectively.

First, while the CTS is configured to serve the northwest portion of the Lower Mainland from the south or the east (Fraser or Coquitlam Gate Stations respectively), the two pipelines do not provide full redundancy to the entire Lower Mainland. Further, natural gas flowing on both lines ultimately comes from the same source (the Westcoast T-South system). However, with the completion of the LMIPSU project, either of the CTS pipelines can provide supply to customers in the Vancouver, Burnaby, Coquitlam and North Shore areas in the event that flows on one of the branch lines is disrupted. In other words, the supply from either the Coquitlam or the Fraser Gate Station can independently support all downstream customers in all but the most extreme weather conditions. As described in Section 3.1.1.2 above, some of this added resiliency will be lost when the PGR project enters service and the existing Pattullo Bridge crossing pipeline is decommissioned in 2023.

FEI has also looped[9] various segments of the CTS to increase capacity.[10] While each of these projects was undertaken to increase the available capacity at peak times, a secondary benefit is that they also allow one of the parallel pipeline sections to be removed from service during light-load periods if required for maintenance, inspection, or repair.

[9] Looping refers to the construction and operation of two or more gas lines in parallel with each other, typically in the same right of way.

[10] For example, FEI added an NPS 42 pipeline to the CTS in parallel with existing NPS 18 and NPS 30 pipelines in 1977 and 1992, and looped existing NPS 20 and NPS 24 pipelines with an NPS 36 pipeline during the Coastal Transmission System Upgrade project in 2017.

Interior Transmission System:

Several portions of the ITS, across the south of the province, are looped by the Southern Crossing Pipeline (SCP). In particular, looped transmission laterals serving the communities of Cranbrook, Kimberley, Sparwood, and Salmon Arm provide additional redundancy. The proposed Okanagan Capacity Upgrade (OCU) project would provide redundant pipelines in the portions of the ITS between Penticton and Kelowna. From the end of the proposed OCU project to Savona there remains a single NPS 12 pipeline serving the Thompson Okanagan region. Increased resiliency and supply diversity within the high-population centres in this region of the ITS could be accomplished through either extensive pipeline looping and compression or through a centrally-located LNG supply that could provide short-term supply (like that proposed by the TLSE project), as discussed in Section 7.5.1.2 of the LTGRP. Further, Section 7.3.3.4 of the LTGRP provides a high level summary of the options to improve the resiliency of this portion of the ITS.

Vancouver Island Transmission System:

On the VITS, all pipeline submarine crossings in the system between the mainland and Texada Island and between Texada Island and Vancouver Island are twinned for redundancy. Moreover, as explained below, the Mount Hayes LNG facility at Ladysmith, BC provides a redundant means of supplying Vancouver Island customers if supply from the Lower Mainland is interrupted for any reason.

4.1.2 Limitations of Existing Regional Pipeline Infrastructure

As described below, there are a number of limitations in the resiliency of existing regional pipeline infrastructure upstream of FEI's system. Market and other constraints have also impeded the development of new infrastructure that would otherwise have enhanced resiliency, both for the Pacific Northwest region and for FEI's gas system.

4.1.2.1 Pipeline Interconnectivity

Compared to other regions in North America, the gas system in British Columbia has a relatively low amount of interconnectedness, decreasing the inherent resiliency of the system. In particular, the system is highly dependent on a single midstream pipeline for supply and has minimal on- and off-system storage.

The Westcoast T-South and the TC Energy (collectively, Nova Gas Transmission, Foothills BC and Gas Transmission Northwest) transmission systems serving FEI and the broader Pacific Northwest region are predominantly located in north-south corridors with limited interconnectivity between them, as shown in Figure E-5 below.

Figure E-5: Regional Gas Infrastructure

Pipeline	Daily Deliverability[1] (MMcf/day)
Westcoast T-South (Huntingdon Delivery Area)[2]	1800
Westcoast T-South (BC Interior)	224
FortisBC ITS (Oliver North)	140
FortisBC SCP (Oliver to Kingsvale)	105
FortisBC SCP (Yahk to Oliver)	245
TC FoothillsBC	2930
Northwest Pipeline Gorge	534

Market Area Storage	Daily Deliverability (MMcf/day)	Storage Capacity (Bcf)
Jackson Prairie (JPS)	1161	25
Mist	637	19

On System Storage	Daily Deliverability (MMcf/day)	Storage Capacity (Bcf)
Mt. Hayes LNG	150	1.5
Tilbury LNG	150	1.35

1. Daily deliverability is the maximum amount of gas that can flow on the pipeline or the maximum amount of gas that can be withdrawn out of storage. It is important to note that the daily deliverability out of the market area storage is assuming storage inventories are full. These resources do have withdrawal rates decline as working gas volumes decline.

2. Including 105 MMcf/day T-South Kingsvale to Huntingdon capacity.

The Westcoast T-South system consists of two looped gas transmission pipelines operating as a single system. The T-South system connects production fields in northeast BC with the Lower Mainland (Huntingdon) and Williams Northwest Pipeline (NWP) at Sumas, Washington. The T-South system flows north to south and runs approximately 916 km between Station 2 and Huntingdon. The two pipelines comprising the system are tied together by common headers and compressor stations and hence are operated as a single pipeline.

There is currently limited connectivity between the two north-south pipeline systems in BC (T-South and TC Energy), as illustrated in Figure E-5 above. FEI sources a small portion of supply from the TC Energy system in southeast BC, which is transported east to west through FEI's SCP to serve the various communities in the interior of BC. Approximately 105 MMcf/day of east to west connectivity from SCP can also be utilized to provide gas supply to customers in the Lower Mainland, via FEI's interconnection with the T-South system at Kingsvale. The SCP pipeline system has limited capacity at this time, and also relies on a 172 km segment of the T-South system (Kingsvale to Huntingdon) to deliver gas to the Lower Mainland. The FEI coastal demand centre makes up the vast majority of the FEI load and also precludes any system reinforcement other than from the northeast, east or south. This places a constraint on how much FEI is able to diversify its sourcing of gas supply away from northeast BC, so as to reduce its reliance on the T-North[11] and T-South systems.

4.1.2.2 High Cost of Development

The high costs associated with underwriting regional pipeline capacity is another reason why there has been limited new pipeline infrastructure in the region over the past several decades. To underwrite the cost of the new pipeline infrastructure generally requires broad regional support, backed by firm transportation contracts.

Historically, the regional market and regulatory model have not supported the construction of pipelines to add redundancy for reliability and/or resiliency. Rather, it has led to assets being constructed to meet the size and shape of the load in the region. The load profile in the region is significantly higher in the winter months than in the summer months, and therefore, has a low load factor. Shaping resources to match the load profile is generally the primary factor in regional gas infrastructure development given the high reliability of pipeline resources.

Furthermore, while the cost and regulatory requirements mean that regional cooperation is required for major pipeline infrastructure, it has historically been a challenge for regional shippers, such as utilities along the I-5 corridor, to agree on what the region requires to meet future load growth. This challenge, along with the difficulties in justifying the high cost of pipelines that are not utilized 365 days a year, has inhibited pipeline development in the region.

As a result of these challenges, the region has relied on lower cost smaller scale expansions, specifically, through storage assets such as off-system storage (Jackson Prairie and Mist) or on-system utility infrastructure (i.e., FEI's Mt. Hayes LNG Facility). However, regional gas demand has continued to grow since the last pipeline expansion (the SCP in 2000), and as discussed in Section 5.3 below, additional pipeline infrastructure may now be appropriate from a demand perspective, which could also benefit system resiliency.[12]

4.2 FEI'S EXISTING ON-SYSTEM STORAGE

On-system storage has unique value from a resiliency perspective and is one of three key elements of a resilient gas system. In this section, FEI describes the utility's existing on-system LNG infrastructure, which is comprised of the Tilbury and Mt. Hayes LNG facilities.

On-system storage provides a controllable supply resource with a high expectation of deliverability. This type of storage enables a utility to inject supply directly into the load centre to avoid a pressure collapse of the system. FEI's ability to draw on on-system resources in the event

[11] FEI contracts T-North Capacity to transport gas supply to and from the Aitken Creek storage facility. Aitken Creek is currently connected to the T-North section of the WEI pipeline system, which is supplied from several major gas processing plants.

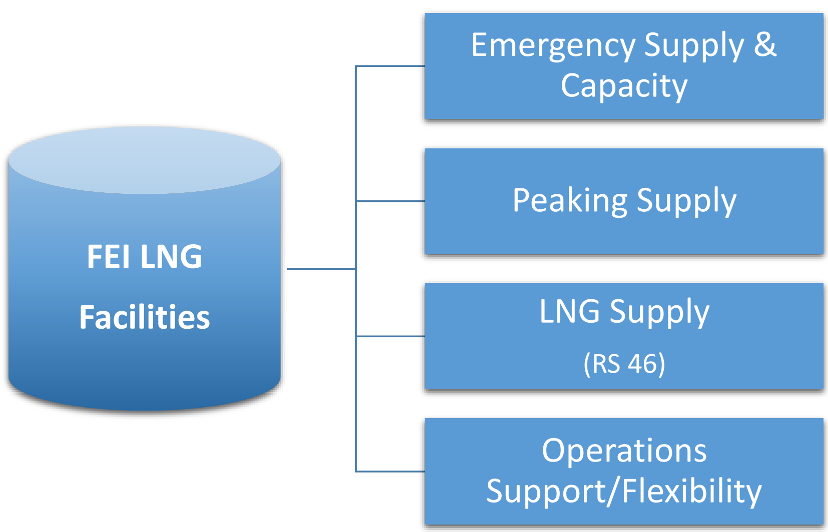
[12] Westcoast is currently constructing a small scale expansion on its T-South system (~100 MMcf/day of incremental capacity) and is planned to be placed in-service in 2021.

of a supply disruption does not depend on the physical or contractual availability of alternate pipeline capacity upstream of FEI's system. As such, on-system storage allows for additional response time until the flow of gas from pipelines can be partially or fully restored, or a new supply-demand balance can be achieved by shedding load.

Even once flows resume, pipeline capacity can remain constrained for long periods of time, and therefore, on-system storage remains important for managing typical peaking load events (e.g., cold weather). These events take on greater significance during the period that pipelines remain constrained.

As shown in Figure E-6 below, from a planning perspective, FEI's existing LNG facilities serve a number of beneficial purposes.

Figure E-6: Multiple Roles of FEI's LNG Facilities



These purposes are explained in further detail as follows:

- **Emergency Supply and Capacity** refers to the use of LNG to offset a supply shortfall and/or to provide additional capacity (via increasing pressure on the system) during a gas supply emergency;
- **Peaking Supply** refers to the use of LNG to provide supply during peak demand events due to cold weather. Similar to the above, LNG can provide additional capacity (by increasing pressure on the system) during a peaking event;
- **LNG Supply** refers to the use of LNG as a fuel source for transportation or remote energy use, such as FEI Rate Schedule (RS) 46 customers; and

- **Operations Support / Flexibility** refers to the use of LNG to support maintenance activities that may require specific flow conditions (i.e., in-line inspection) or temporary reductions in capacity.

FEI's on-system LNG inventory is managed on an integrated basis to provide these customer benefits. As part of its planning, FEI considers how much inventory may be needed for each function to ensure adequate resources are available to manage these events when they do occur.

4.2.1 Tilbury Base Plant

The Tilbury Base Plant was designed and built between 1969 and 1971 and has operated since commissioning with an excellent safety and reliability record. The facility was built to provide peaking supply, while also providing an important on-system capacity resource. The Tilbury Base Plant is strategically located providing on-system storage and gas supply support in the Lower Mainland load centre, and as such, it provides benefits related to security of supply, reliability and flexibility to serve loads within FEI's system. These are important benefits when mitigating temporary operational issues associated with FEI's pipeline infrastructure.

While the Tilbury Base Plant provides natural gas supply for short durations when demand during cold weather events exceeds contracted supply, it is not able to support the Lower Mainland demand in the event of a significant disruption in gas supply flowing to the Lower Mainland. The vapourization capacity at the Tilbury Base Plant (150 million cubic feet per day (MMcf/day)) is sufficient to serve 17 percent of the peak day requirements of FEI's RS 1 to 7 customers and RS 23 and 25 customers (i.e., firm rate schedule customers) in the Lower Mainland based on the 2019/2020 load forecast. As discussed in Section 5.2 below, the proposed TLSE Project would improve FEI's ability to withstand and manage its system through a significant supply emergency.

4.2.2 Mt. Hayes LNG Facility

The Mt. Hayes LNG facility also provides natural gas supply for short durations during cold weather events, but also provides a significant resiliency benefit to customers on Vancouver Island. This facility (which is much newer than the Tilbury Base Plant) is capable of serving the peak day load on Vancouver Island for approximately 10 days without relying on transmission support from the Lower Mainland. On low demand days on Vancouver Island, it is possible to physically flow gas from the Mt. Hayes LNG facility to the Lower Mainland by reverse flowing the VITS. However, this capability diminishes as Vancouver Island demand increases and is effectively zero during cold winter load periods. As such, the Mt. Hayes LNG facility could not also support the Lower Mainland to any significant extent.

4.3 *FEI'S EXISTING LOAD MANAGEMENT CAPABILITIES*

A key element that contributes to natural gas system resiliency is load management capabilities. Load management relates to the ability both to accurately assess the actual load across all parts of the gas system, and when necessary, to strategically reduce load on the gas system. Managing load helps to maintain the pressure on the system by restoring the balance of gas supply and demand in the event of a supply emergency. FEI currently has visibility of the overall load on the gas system; however, there is limited visibility regarding where the load is located within the system.

Similarly, controlled load shedding is partially within FEI's control today; however, FEI currently has no direct ability to remotely or automatically disconnect or otherwise curtail gas supply to customers. In the event of a sustained loss of gas supply, FEI is currently only able to respond by curtailing load in three ways: (1) directing interruptible customers to immediately disconnect from the system; (2) making public appeals for all customers to reduce their gas usage; and (3) shutting down major sections of the system with a single valve.

With FEI's current meter fleet, customers have to be manually disconnected from the system. Currently, the disconnection requires a field visit to each site which impedes FEI's ability to quickly implement load adjustments in emergency situations.

As discussed in Section 5.1 below, FEI has proposed investments in AMI in order to provide FEI with near real-time information about the total load on the overall system and detailed information about energy usage by individual customers. The utility would also be able to more accurately forecast the load on the system throughout the duration of the emergency to determine whether load shedding is required.

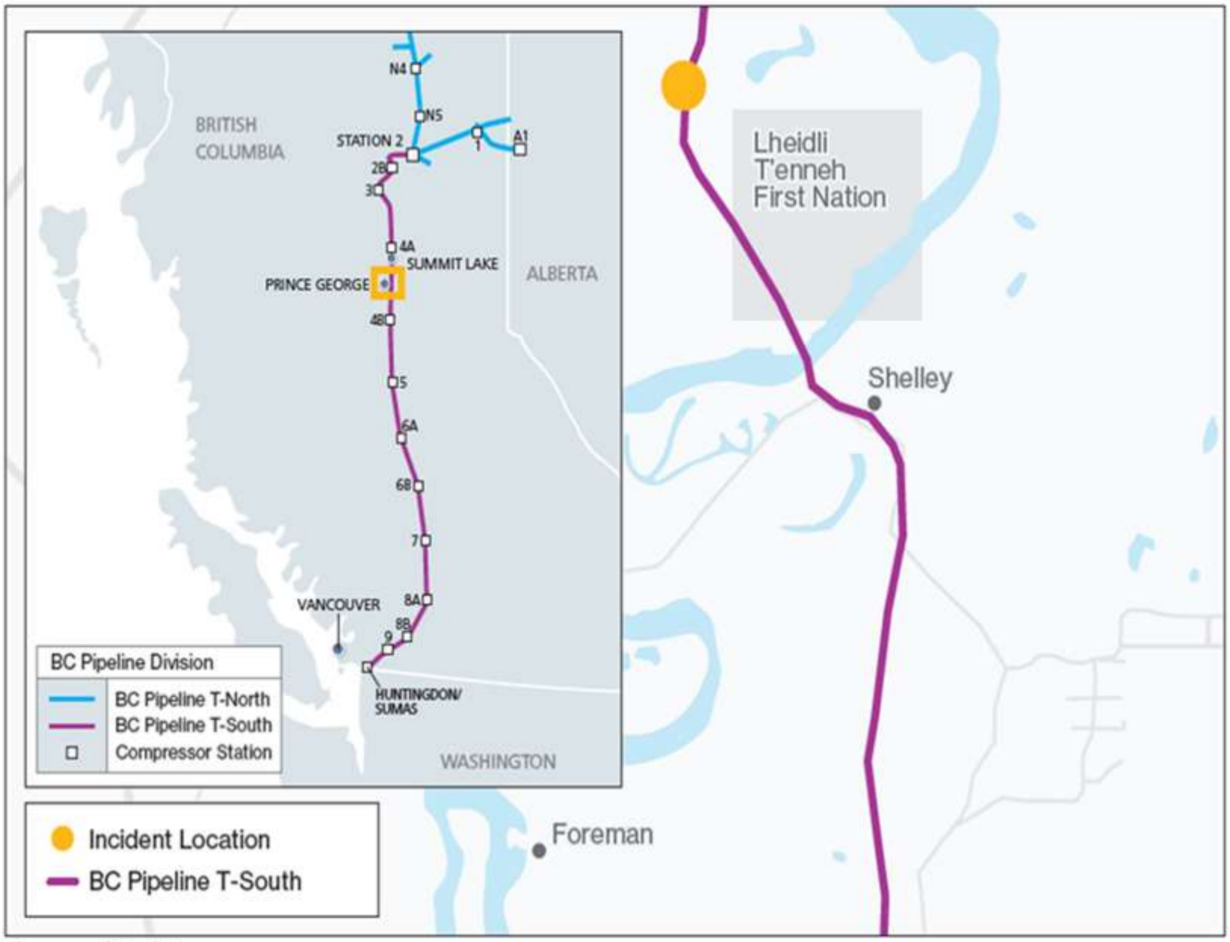
4.4 *RISK OF SUPPLY DISRUPTION DUE TO RELIANCE ON T-SOUTH SYSTEM*

FEI is dependent on the T-South system for approximately 85 percent of the gas entering its system. As discussed below, the pipeline rupture on the T-South system in 2018 highlighted the resiliency challenge posed by the extent of FEI's reliance on the T-South system – leaving FEI and its customers at risk of experiencing significant consequences resulting from a supply disruption.

4.4.1 2018 T-South Incident Underscored the Risks of Supply Interruption

On October 9, 2018, an NPS 36 natural gas pipeline forming part of the T-South system ruptured near Prince George, BC (the T-South Incident). The NPS 36 pipeline that ruptured shared the right-of-way with a second NPS 30 Westcoast pipeline. While only the NPS 36 pipeline had ruptured, the natural gas escaping from that pipeline had ignited and Westcoast shut down the adjacent NPS 30 pipeline as a precaution and monitored it to evaluate its condition. Figure E-7 below, shows the location of the gas pipeline rupture.

Figure E-7: Location of Rupture on the T-South Pipeline



Source: Enbridge

The T-South Incident underscored the value that additional resiliency in FEI's system would provide, as it resulted in a complete loss of gas supply from the two T-South pipelines. FEI's system was at risk of pressure collapse for a period of approximately 48 hours, and that outcome was narrowly avoided as a result of FEI's efforts and due to mild weather that had reduced heating load in the broader Pacific Northwest region, thereby allowing some gas to physically flow northwards across the border.[13]

The T-South Incident can be broken-down into three phases.

- **Phase 1:** This phase refers to the events that occurred in the 48 hours immediately following the rupture of the NPS 36 pipeline where gas supply on the T-South system was restricted to zero. In particular, on October 10, 2018, Westcoast issued a *force majeure* notice indicating that service was interrupted as a result of the rupture of the NPS 36

[13] As described later, there are normally physical constraints on the ability of gas to flow northwards during periods of higher demand in Washington and Oregon.

pipeline, and that flow was restricted to zero on all delivery points on the T-South system between Compressor Station 4B and Huntingdon.

- **Phase 2:** This phase refers to the period following the first phase where gas supply remained constrained, with the zero supply period in Phase 1 ending on October 11, 2018. Westcoast returned the NPS 30 pipeline to service, ramping the NPS 30 pipeline up to 80 percent of its 60 day high pressure prior to the incident, as permitted by the Canada Energy Regulator (CER)[14] order (restoring overall T-South system capacity to approximately 50 percent of firm capacity). Phase 2 concluded with the return to service of the ruptured NPS 36 pipeline on November 1, 2018, at a reduced capacity.
- **Phase 3:** The third phase refers to the 56 week period following the second phase, where the NPS 36 was returned to service. Capacity restrictions remained in place on the T-South system until Westcoast lifted its *force majeure* on December 2, 2019.[15] Given that the T-South to Huntingdon pipeline segment is normally fully utilized during the winter by customers along the I-5 corridor, the risk of a gas supply shortage persisted throughout the 2018/19 winter, not just for FEI and its customers, but for the region as a whole.

While FEI and the utilities along the I-5 corridor were able to manage through the T-South Incident and its aftermath, the incident resulted in higher gas supply costs for all market participants.

4.4.2 The Potential for Supply Interruption on the T-South System Remains

The T-South Incident highlighted that, although supply emergencies are rare, they do occur. The T-South Incident supported a re-examination of the resiliency of FEI's system, and the regional system as a whole. FEI's assessment demonstrated that:

- Additional regional pipeline infrastructure, if alternative pipeline routes can be developed, could add resiliency by reducing FEI's reliance on the T-South system;
- FEI should evaluate the potential to construct more on-system storage resources, which is a tool that can be used to prevent impacts to customers in the period immediately following a severe supply constraint or a "no-flow" event; and
- New tools to facilitate load shedding in a controlled and flexible fashion, a benefit associated with AMI, would complement on-system storage to mitigate the impacts of an outage on customers and society.

In the next section, FEI discusses the work it is currently undertaking to enhance overall system resiliency.

[14] At that time, the Canada Energy Regulator (CER) was referred to as the National Energy Board (NEB).

[15] During the Phase 3 period, the CER allowed Westcoast to increase the restricted operating pressure of the NPS 36 pipeline from 80 percent to 85 percent, and then to 88 percent of the previous 60 day high pressure by pipeline segment.

5. ENHANCING THE RESILIENCY OF THE TRANSMISSION SYSTEM CONTRIBUTES TO OVERALL SYSTEM RESILIENCY

FEI's portfolio of resiliency measures dovetails with the efficient supply portfolio outlined in its Annual Contracting Plans (ACPs), so as to avoid driving inefficient supply decisions that could be detrimental to ratepayers. FEI has effectively managed to the objectives of its ACPs in order to build an optimal gas supply portfolio.

However, and importantly, in addition to acquiring contractual rights to supply, resiliency requires backing by physical assets. This is a critically important concept. No amount of contracted supply from off-system sources, or offers of mutual aid from neighbouring utilities, will assist unless the physical infrastructure required to get the supply to the utility's own system is in place. FEI's resiliency needs are ultimately influenced by its physical location within the broader regional pipeline system, as well as customer load and composition.

In the preceding sections, FEI provided an overview of its existing resiliency solutions forming part of FEI's distribution and transmission systems and identified potential areas where resiliency-related risks remain. In this section, FEI provides the solutions it has identified to enhance the resiliency of the overall gas system. At a high-level, FEI has proposed the following enhancements:

- The adoption and implementation of automated meter reading processes, which addresses the need for better load management capabilities, through the AMI project.
- Expansion of FEI's on-system LNG storage, which ensures ample energy storage and provides immediate response capabilities to preserve the system during a critical supply emergency, through the TLSE project;
- The addition of new regional pipeline infrastructure, preferably constructed in a corridor different from the T-South system, in order to ensure supply is available during an event that involves a sustained loss of pipeline capacity, potentially through the RGSD project; and

From a resiliency portfolio perspective, on-system storage and new pipeline infrastructure are complementary assets to the supply portfolio as each separately addresses short-duration and long-duration supply issues in a cost effective manner;

Each of these proposed resiliency enhancing projects and approaches are discussed in further detail below.

5.1 *ADVANCED METERING INFRASTRUCTURE PROJECT*

On May 5, 2021, FEI filed a CPCN Application with the BCUC to implement an AMI network on its system. The purpose of this project is to deliver improved information about natural gas consumption and pipeline conditions to FEI and its customers. Importantly, the implementation of

AMI will also improve FEI's ability to manage load on its system in the event of an emergency – one of the three key elements of a resilient system. Following receipt of a BCUC decision to proceed with the project, FEI will begin AMI deployment in 2023 with final project completion anticipated in 2027.

The AMI project will involve the replacement of approximately one million existing residential and commercial customer meters with advanced meters, the associated infrastructure to support delivery of hourly metering information from the advanced meters at customer premises back to FEI. This would include the installation of communicating sensors on pipeline assets, some that would provide more complete indication of system pressure across FEI's distribution systems. Further, FEI will complete the installation of the approximately 700,000 remaining by-pass valves in order to avoid future interruption of gas service for meter-set maintenance activities at each premise and will replace gas regulators that are near end of life.

While the AMI project is primarily driven by the need to address the declining viability of manual meter reading, from a resiliency standpoint, the AMI system would significantly improve FEI's ability to manage system load during an extended loss of supply. In particular, AMI will provide FEI with more granular information regarding the demand on its system in the event of an extended loss of natural gas supply. Moreover, the remote shut-off valve in the AMI meter will enable FEI to strategically shut off gas to selected customers based on their gas usage and need, rather than solely based on their proximity to an isolated section of pipeline. These improvements will ultimately help FEI to keep the natural gas system pressurized, thereby reducing recovery time for customers that experience service interruption.

5.2 TILBURY LNG STORAGE EXPANSION PROJECT

On December 29, 2020, FEI filed a CPCN Application to add additional storage and vaporization capabilities at the existing Tilbury LNG facility, while also replacing FEI's 50-year old Tilbury Base Plant. This project is primarily a resiliency investment that will significantly improve FEI's ability to maintain continuity of service in the event of a disruption in the supply of natural gas to FEI's system, while also providing valuable ancillary benefits for system operations and customers.

The Tilbury facility will continue to serve supply requirements in the way it has done for the past 50 years, while also improve FEI's ability to withstand and manage its system through a significant supply emergency like phase 1 of the T-South Incident (discussed in Section 4.1.4 above). If approved by the BCUC, FEI plans to initiate the execution phase for the project in 2023, which would result in Project completion occurring in 2026.

As it stands, the Tilbury Base Plant provides peaking supply for FEI's core customers, as well as emergency supply to the system as a whole. However, it was designed in the late 1960s primarily as a winter peaking facility, and as such, its capability to provide emergency supply is limited.[16]

[16] In particular, the facility can only provide a fraction of the gas (approximately 17 percent) required to serve the peak demand of Firm Rate Schedule customers in the Lower Mainland.

Similarly, storage capacity at the Tilbury Base Plant is equivalent to less than one day of the Lower Mainland peak demand. In practical terms, this means that FEI would need to shed a significant portion of its load within the initial hours following an emergency event preventing natural gas from entering FEI's system during winter-time in order to mitigate the risk system collapse.

There are significant resiliency benefits that will come with increasing the storage and vapourization capacity at the Tilbury facility. In particular, the proposed project will allow FEI to withstand, and recover from, a 3-day "no-flow" event[17] on the T-South system, without having to shut down portions of FEI's distribution system or lose significant firm load.

5.3 REGIONAL GAS SUPPLY DIVERSITY (RGSD) SOLUTION

In this section, FEI discusses its consideration to augment the resiliency of the system by addressing the final element a resilient system – pipeline diversity – which necessarily involves a longer timeline (5+ years). Pipeline operators, including FEI, are exploring infrastructure options that will facilitate load growth opportunities and provide much needed gas supply resiliency to the region. Overall, any new pipeline infrastructure provides benefits to the region as a whole. However, certain projects will provide greater benefits for some shippers, depending on its proposed pipeline route.

The RGSD project would involve an expansion of the SCP, including constructing a new pipeline connecting the SCP (near Oliver, BC) to the Huntingdon/Sumas market and adding compressor stations along the SCP. At this time, this is the preferred option for FEI, as the project creates a flow path separate from the existing T-South system. Further, it would allow FEI to split the optimal amount of pipeline capacity between T-South and RGSD, thereby reducing FEI's current heavy dependence on the T-South system).

The RGSD project would also be able to mitigate the risk of a no-flow event during low demand (i.e., summer) periods, as well as help address the risks of a prolonged supply disruption similar to Phases 2 and 3 of the T-South Incident. Therefore, the project would diversity FEI's gas supply using a separate and distinct pipeline path, and supply sourcing from a different basin and market hub.

As discussed in the LTRGP, FEI believes that it is in the best interest of FEI and its customers to influence which regional pipeline infrastructure gets built, thus maximizing the value obtained from it. FEI is filing an application requesting approval of a deferral account to capture the costs of advancing the development or the RGSD project in Q2 2022. The application will demonstrate that there is a clear need for new pipeline infrastructure in the region and why FEI must continue to develop the RGSD project, while evaluating other potential pipeline expansion options, in order

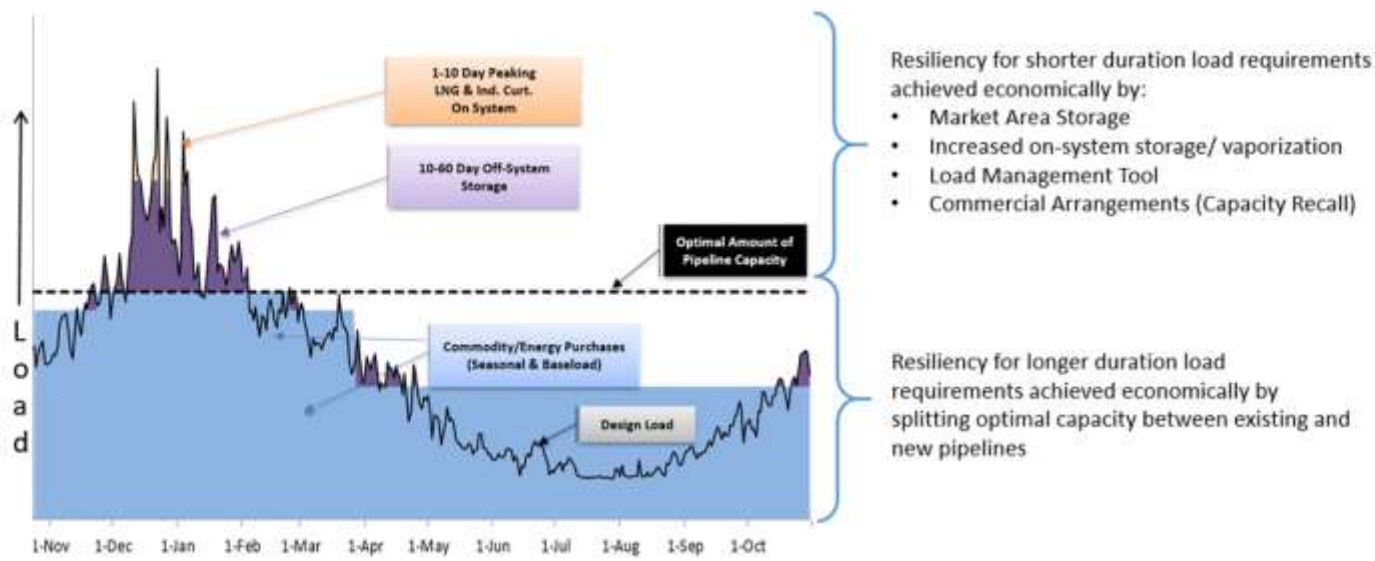
[17] FEI uses "no-flow event" to refer to an incident affecting regional pipeline infrastructure that results in the total interruption of gas flows on the pipeline. Similarly, the "no-flow" period is the period following the event that results in a total interruption of gas flows from that pipeline.

to address market conditions, reduce resiliency risks for FEI customers, and provide additional benefits.[18]

5.4 FEI'S PORTFOLIO APPROACH TO TRANSMISSION RESILIENCY

From a resiliency perspective, on-system storage and new pipeline infrastructure are complementary assets to the supply portfolio as each separately addresses short-duration and long-duration supply issues in a cost effective manner. Neither is a substitute for the other. For instance, the TLSE project will be the most cost-effective resource to respond immediately to withstand a short-term critical emergency that disrupts supply to FEI's Lower Mainland system, such as in phase 1 of the T-South Incident.[19] While FEI's ability to rely on the TLSE project in the event of a supply disruption does not depend on the physical or contractual availability of alternate pipeline capacity upstream of FEI's system, the TLSE project has limitations in addressing long-term capacity shortfalls or duration issues, as experienced during phases 2 and 3 of the T-South Incident. The RGSD project would help manage a long-duration supply disruption while also meeting the commercial needs of the region. Figure E-8 below illustrates how diverse pipeline capacity can be used efficiently, in combination with expanded peaking resources like on-system LNG storage, to build resiliency.

Figure E-8: Resiliency Measures Should Reflect Optimal ACP Supply Portfolio



If FEI proposed enhancing supply resiliency in the Lower Mainland with RGSD only, the pipeline would need to be sized to provide full replacement capacity for T-South if that system was not available for any reason. While building a new pipeline of this size may be technically possible, this would not be a cost-effective option for customers. It would come at a higher cost than FEI's

[18] FEI anticipates filing the RGSD development cost deferral account application in May 2022.
[19] Appendix E - Gas System Resiliency Plan.

portfolio approach to resiliency, given that FEI would need to hold excess total capacity on both pipelines (to ensure that full supply could be maintained in the event of an interruption on either the T-South or RGSD pipelines). This would result in FEI's customers paying demand charges for capacity on two pipelines with a significant portion going unused.

Moreover, the size of a pipeline expansion into the region would depend on potential interest from third-party shippers. Although the market requires additional pipeline capacity to satisfy growing gas demand, diversify market access especially during the winter, and provide much-needed gas supply resiliency to the region, at this time FEI does not believe there is enough support from third-party shippers to build a pipeline of that capacity (i.e., 800 MMcf per day[20]).

For the above reasons, the optimal solution is to balance the benefits and costs of additional and strategically located pipeline capacity with the benefits and costs of on-system storage located near the load centre. The optimal solution is therefore combining the benefits of the RGSD project with those of the TLSE project to cost-effectively provide broader resiliency benefits and improved flexibility to meet a range of potential supply disruptions and growing demand while also enabling the transition to renewable and low-carbon gas supplies.

[20] The TLSE Application determined 800 MMcf per day was required to meet FEI's Minimum Resiliency Planning Objective (MRPO). FEI's MRPO is a short-duration objective developed in consideration of FEI's operating experience, including its experience during the T-South Incident and the challenges that it experienced in maintaining service to customers during that time. The MRPO sets out FEI's objective to ensure that Lower Mainland system has the ability to withstand and recover from a three-day no-flow event on the T-South system without having to shut down portions of FEI's distribution system and thus avoid the loss of significant firm load.

6. CONCLUSION

In this appendix, FEI has discussed its overall approach to system resiliency, including how resiliency builds upon the foundations of system integrity and reliable infrastructure. It also described the three elements which contribute to system resiliency, namely: diverse pipelines and supply; load management capabilities; and ample on-system storage. As it stands, FEI is pursuing two major projects which will each contribute to increased system resiliency, the AMI project (which amongst other things will provide FEI with the ability to manage load at individual customer premises) and the TLSE project (which will add storage within the Lower Mainland region to allow the system to withstand a T-South no-flow event), and exploring one further project, the RGSD project (which would increase regional pipeline diversity). Finally, FEI intends to further develop its resiliency criteria for the distribution system, which it intends to include in a subsequent resource plan.

Appendix F

REFERENCED DOCUMENTS

UNITED NATIONS DECLARATION ON THE RIGHTS OF INDIGENOUS PEOPLES

United Nations

UNITED NATIONS DECLARATION ON THE RIGHTS OF INDIGENOUS PEOPLES

United Nations

Resolution adopted by the General Assembly on 13 September 2007

[without reference to a Main Committee (A/61/L.67 and Add.1)]

61/295. United Nations Declaration on the Rights of Indigenous Peoples

The General Assembly,

Taking note of the recommendation of the Human Rights Council contained in its resolution 1/2 of 29 June 2006[1], by which the Council adopted the text of the United Nations Declaration on the Rights of Indigenous Peoples,

Recalling its resolution 61/178 of 20 December 2006, by which it decided to defer consideration of and action on the Declaration to allow time for further consultations thereon, and also decided to conclude its consideration before the end of the sixty-first session of the General Assembly,

1 See Official Records of the General Assembly, Sixty-first Session, Supplement No. 53 (A/61/53), part one, chap. II, sect. A.

Adopts the United Nations Declaration on the Rights of Indigenous Peoples as contained in the annex to the present resolution.

107th plenary meeting
13 September 2007

Annex

United Nations Declaration on the Rights of Indigenous Peoples

The General Assembly,

Guided by the purposes and principles of the Charter of the United Nations, and good faith in the fulfilment of the obligations assumed by States in accordance with the Charter,

Affirming that indigenous peoples are equal to all other peoples, while recognizing the right of all peoples to be different, to consider themselves different, and to be respected as such,

Affirming also that all peoples contribute to the diversity and richness of civilizations and cultures, which constitute the common heritage of humankind, *Affirming* further that all doctrines, policies and practices based on or advocating superiority of peoples or individuals on the basis of national origin or racial, religious, ethnic or cultural differences are racist, scientifically false, legally invalid, morally condemnable and socially unjust,

Reaffirming that indigenous peoples, in the exercise of their rights, should be free from discrimination of any kind,

Concerned that indigenous peoples have suffered from historic injustices as a result of, inter alia, their colonization and dispossession of their lands, territories and resources, thus preventing them from exercising, in particular, their right to development in accordance with their own needs and interests,

Recognizing the urgent need to respect and promote the inherent rights of indigenous peoples which derive from their political, economic and social structures and from their cultures, spiritual traditions, histories and philosophies, especially their rights to their lands, territories and resources,

Recognizing also the urgent need to respect and promote the rights of indigenous peoples affirmed in treaties, agreements and other constructive arrangements with States,

Welcoming the fact that indigenous peoples are organizing themselves for political, economic, social and cultural enhancement and in order to bring to an end all forms of discrimination and oppression wherever they occur,

Convinced that control by indigenous peoples over developments affecting them and their lands, territories and resources will enable them to maintain and strengthen their institutions, cultures and traditions, and to promote their development in accordance with their aspirations and needs,

Recognizing that respect for indigenous knowledge, cultures and traditional practices contributes to sustainable and equitable development and proper management of the environment,

Emphasizing the contribution of the demilitarization of the lands and territories of indigenous peoples to peace, economic and social progress and development, understanding and friendly relations among nations and peoples of the world, *Recognizing* in particular the right of indigenous families and communities to retain shared responsibility for the upbringing, training, education and well-being of their children, consistent with the rights of the child,

Considering that the rights affirmed in treaties, agreements and other constructive arrangements between States and indigenous peoples are, in some situations, matters of international concern, interest, responsibility and character,

Considering also that treaties, agreements and other constructive arrangements, and the relationship they represent, are the basis for a strengthened partnership between indigenous peoples and States,

Acknowledging that the Charter of the United Nations, the International Covenant on Economic, Social and Cultural Rights[2] and the International Covenant on Civil and Political Rights,[2] as well as the Vienna Declaration and Programme of Action,[3] affirm the fundamental importance of the right to self-determination of all peoples, by

2 See resolution 2200 A (XXI), annex.

3 A/CONF.157/24 (Part I), chap. III.

virtue of which they freely determine their political status and freely pursue their economic, social and cultural development,

Bearing in mind that nothing in this Declaration may be used to deny any peoples their right to self-determination, exercised in conformity with international law,

Convinced that the recognition of the rights of indigenous peoples in this Declaration will enhance harmonious and cooperative relations between the State and indigenous peoples, based on principles of justice, democracy, respect for human rights, non-discrimination and good faith,

Encouraging States to comply with and effectively implement all their obligations as they apply to indigenous peoples under international instruments, in particular those related to human rights, in consultation and cooperation with the peoples concerned,

Emphasizing that the United Nations has an important and continuing role to play in promoting and protecting the rights of indigenous peoples, *Believing* that this Declaration is a further important step forward for the recognition, promotion and protection of the rights and freedoms of indigenous peoples and in the development of relevant activities of the United Nations system in this field,

Recognizing and reaffirming that indigenous individuals are entitled without discrimination to all human rights recognized in international law, and that indigenous peoples possess collective rights which are indispensable for their existence, well-being and integral development as peoples,

Recognizing that the situation of indigenous peoples varies from region to region and from country to country and that the significance of national and regional particularities and various historical and cultural backgrounds should be taken into consideration,

Solemnly proclaims the following United Nations Declaration on the Rights of Indigenous Peoples as a standard of achievement to be pursued in a spirit of partnership and mutual respect:

Article 1

Indigenous peoples have the right to the full enjoyment, as a collective or as individuals, of all human rights and fundamental freedoms as recognized in the Charter of the United Nations, the Universal Declaration of Human Rights[4] and international human rights law.

Article 2

Indigenous peoples and individuals are free and equal to all other peoples and individuals and have the right to be free from any kind of discrimination, in the exercise of their rights, in particular that based on their indigenous origin or identity.

Article 3

Indigenous peoples have the right to self-determination. By virtue of that right they freely determine their political status and freely pursue their economic, social and cultural development.

Article 4

Indigenous peoples, in exercising their right to self-determination, have the right to autonomy or self-government in matters relating to their internal and local affairs, as well as ways and means for financing their autonomous functions.

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4 Resolution 217 A (III).

Article 5

Indigenous peoples have the right to maintain and strengthen their distinct political, legal, economic, social and cultural institutions, while retaining their right to participate fully, if they so choose, in the political, economic, social and cultural life of the State.

Article 6

Every indigenous individual has the right to a nationality.

Article 7

1. Indigenous individuals have the rights to life, physical and mental integrity, liberty and security of person.

2. Indigenous peoples have the collective right to live in freedom, peace and security as distinct peoples and shall not be subjected to any act of genocide or any other act of violence, including forcibly removing children of the group to another group.

Article 8

1. Indigenous peoples and individuals have the right not to be subjected to forced assimilation or destruction of their culture.

2. States shall provide effective mechanisms for prevention of, and redress for:

   (a) Any action which has the aim or effect of depriving them of their integrity as distinct peoples, or of their cultural values or ethnic identities;

   (b) Any action which has the aim or effect of dispossessing them of their lands, territories or resources;

   (c) Any form of forced population transfer which has the aim or effect of violating or undermining any of their rights;

   (d) Any form of forced assimilation or integration;

   (e) Any form of propaganda designed to promote or incite racial or ethnic discrimination directed against them.

Article 9

Indigenous peoples and individuals have the right to belong to an indigenous community or nation, in accordance with the traditions and customs of the community or nation concerned. No discrimination of any kind may arise from the exercise of such a right.

Article 10

Indigenous peoples shall not be forcibly removed from their lands or territories. No relocation shall take place without the free, prior and informed consent of the indigenous peoples concerned and after agreement on just and fair compensation and, where possible, with the option of return.

Article 11

1. Indigenous peoples have the right to practise and revitalize their cultural traditions and customs. This includes the right to maintain, protect and develop the past, present and future manifestations of their cultures, such as archaeological and historical sites, artefacts, designs, ceremonies, technologies and visual and performing arts and literature.

2. States shall provide redress through effective mechanisms, which may include restitution, developed in conjunction with indigenous peoples, with respect to their cultural, intellectual, religious and spiritual property taken without their free, prior and informed consent or in violation of their laws, traditions and customs.

Article 12

1. Indigenous peoples have the right to manifest, practise, develop and teach their spiritual and religious traditions, customs and ceremonies; the right to maintain, protect, and have access in privacy to their religious and cultural sites; the right to the use and control of their ceremonial objects; and the right to the repatriation of their human remains.

2. States shall seek to enable the access and/or repatriation of ceremonial objects and human remains in their possession through fair, transparent and effective mechanisms developed in conjunction with indigenous peoples concerned.

Article 13

1. Indigenous peoples have the right to revitalize, use, develop and transmit to future genera-

tions their histories, languages, oral traditions, philosophies, writing systems and literatures, and to designate and retain their own names for communities, places and persons.

2. States shall take effective measures to ensure that this right is protected and also to ensure that indigenous peoples can understand and be understood in political, legal and administrative proceedings, where necessary through the provision of interpretation or by other appropriate means.

Article 14

1. Indigenous peoples have the right to establish and control their educational systems and institutions providing education in their own languages, in a manner appropriate to their cultural methods of teaching and learning.

2. Indigenous individuals, particularly children, have the right to all levels and forms of education of the State without discrimination.

3. States shall, in conjunction with indigenous peoples, take effective measures, in order for indigenous individuals, particularly children, including

those living outside their communities, to have access, when possible, to an education in their own culture and provided in their own language.

Article 15

1. Indigenous peoples have the right to the dignity and diversity of their cultures, traditions, histories and aspirations which shall be appropriately reflected in education and public information.

2. States shall take effective measures, in consultation and cooperation with the indigenous peoples concerned, to combat prejudice and eliminate discrimination and to promote tolerance, understanding and good relations among indigenous peoples and all other segments of society.

Article 16

1. Indigenous peoples have the right to establish their own media in their own languages and to have access to all forms of non-indigenous media without discrimination.

2. States shall take effective measures to ensure that State-owned media duly reflect indigenous

cultural diversity. States, without prejudice to ensuring full freedom of expression, should encourage privately owned media to adequately reflect indigenous cultural diversity.

Article 17

1. Indigenous individuals and peoples have the right to enjoy fully all rights established under applicable international and domestic labour law.

2. States shall in consultation and cooperation with indigenous peoples take specific measures to protect indigenous children from economic exploitation and from performing any work that is likely to be hazardous or to interfere with the child's education, or to be harmful to the child's health or physical, mental, spiritual, moral or social development, taking into account their special vulnerability and the importance of education for their empowerment.

3. Indigenous individuals have the right not to be subjected to any discriminatory conditions of labour and, inter alia, employment or salary.

Article 18

Indigenous peoples have the right to participate in decision-making in matters which would affect their rights, through representatives chosen by themselves in accordance with their own procedures, as well as to maintain and develop their own indigenous decision-making institutions.

Article 19

States shall consult and cooperate in good faith with the indigenous peoples concerned through their own representative institutions in order to obtain their free, prior and informed consent before adopting and implementing legislative or administrative measures that may affect them.

Article 20

1. Indigenous peoples have the right to maintain and develop their political, economic and social systems or institutions, to be secure in the enjoyment of their own means of subsistence and development, and to engage freely in all their traditional and other economic activities.

2. Indigenous peoples deprived of their means of subsistence and development are entitled to just and fair redress.

Article 21

1. Indigenous peoples have the right, without discrimination, to the improvement of their economic and social conditions, including, inter alia, in the areas of education, employment, vocational training and retraining, housing, sanitation, health and social security.

2. States shall take effective measures and, where appropriate, special measures to ensure continuing improvement of their economic and social conditions. Particular attention shall be paid to the rights and special needs of indigenous elders, women, youth, children and persons with disabilities.

Article 22

1. Particular attention shall be paid to the rights and special needs of indigenous elders, women, youth, children and persons with disabilities in the implementation of this Declaration.

2. States shall take measures, in conjunction with indigenous peoples, to ensure that indigenous women and children enjoy the full protection and guarantees against all forms of violence and discrimination.

Article 23

Indigenous peoples have the right to determine and develop priorities and strategies for exercising their right to development. In particular, indigenous peoples have the right to be actively involved in developing and determining health, housing and other economic and social programmes affecting them and, as far as possible, to administer such programmes through their own institutions.

Article 24

1. Indigenous peoples have the right to their traditional medicines and to maintain their health practices, including the conservation of their vital medicinal plants, animals and minerals. Indigenous individuals also have the right to access, without any discrimination, to all social and health services.

2. Indigenous individuals have an equal right to the enjoyment of the highest attainable standard of physical and mental health. States shall take the necessary steps with a view to achieving progressively the full realization of this right.

Article 25

Indigenous peoples have the right to maintain and strengthen their distinctive spiritual relationship with their traditionally owned or otherwise occupied and used lands, territories, waters and coastal seas and other resources and to uphold their responsibilities to future generations in this regard.

Article 26

1. Indigenous peoples have the right to the lands, territories and resources which they have traditionally owned, occupied or otherwise used or acquired.

2. Indigenous peoples have the right to own, use, develop and control the lands, territories and resources that they possess by reason of traditional ownership or other traditional occupation or use, as well as those which they have otherwise acquired.

3. States shall give legal recognition and protection to these lands, territories and resources. Such recognition shall be conducted with due respect to the customs, traditions and land tenure systems of the indigenous peoples concerned.

Article 27

States shall establish and implement, in conjunction with indigenous peoples concerned, a fair, independent, impartial, open and transparent process, giving due recognition to indigenous peoples' laws, traditions, customs and land tenure systems, to recognize and adjudicate the rights of indigenous peoples pertaining to their lands, territories and resources, including those which were traditionally owned or otherwise occupied or used. Indigenous peoples shall have the right to participate in this process.

Article 28

1. Indigenous peoples have the right to redress, by means that can include restitution or, when this is not possible, just, fair and equitable compensation, for the lands, territories and resources which they have traditionally owned or otherwise occupied or used, and which have been confiscated, taken, occupied, used or damaged without their free, prior and informed consent.

2. Unless otherwise freely agreed upon by the peoples concerned, compensation shall take

the form of lands, territories and resources equal in quality, size and legal status or of monetary compensation or other appropriate redress.

Article 29

1. Indigenous peoples have the right to the conservation and protection of the environment and the productive capacity of their lands or territories and resources. States shall establish and implement assistance programmes for indigenous peoples for such conservation and protection, without discrimination.

2. States shall take effective measures to ensure that no storage or disposal of hazardous materials shall take place in the lands or territories of indigenous peoples without their free, prior and informed consent.

3. States shall also take effective measures to ensure, as needed, that programmes for monitoring, maintaining and restoring the health of indigenous peoples, as developed and implemented by the peoples affected by such materials, are duly implemented.

Article 30

1. Military activities shall not take place in the lands or territories of indigenous peoples, unless justified by a relevant public interest or otherwise freely agreed with or requested by the indigenous peoples concerned.

2. States shall undertake effective consultations with the indigenous peoples concerned, through appropriate procedures and in particular through their representative institutions, prior to using their lands or territories for military activities.

Article 31

1. Indigenous peoples have the right to maintain, control, protect and develop their cultural heritage, traditional knowledge and traditional cultural expressions, as well as the manifestations of their sciences, technologies and cultures, including human and genetic resources, seeds, medicines, knowledge of the properties of fauna and flora, oral traditions, literatures, designs, sports and traditional games and visual and performing arts. They also have the

right to maintain, control, protect and develop their intellectual property over such cultural heritage, traditional knowledge, and traditional cultural expressions.

2. In conjunction with indigenous peoples, States shall take effective measures to recognize and protect the exercise of these rights.

Article 32

1. Indigenous peoples have the right to determine and develop priorities and strategies for the development or use of their lands or territories and other resources.

2. States shall consult and cooperate in good faith with the indigenous peoples concerned through their own representative institutions in order to obtain their free and informed consent prior to the approval of any project affecting their lands or territories and other resources, particularly in connection with the development, utilization or exploitation of mineral, water or other resources.

3. States shall provide effective mechanisms for just and fair redress for any such activities, and

appropriate measures shall be taken to mitigate adverse environmental, economic, social, cultural or spiritual impact.

Article 33

1. Indigenous peoples have the right to determine their own identity or membership in accordance with their customs and traditions. This does not impair the right of indigenous individuals to obtain citizenship of the States in which they live.

2. Indigenous peoples have the right to determine the structures and to select the membership of their institutions in accordance with their own procedures.

Article 34

Indigenous peoples have the right to promote, develop and maintain their institutional structures and their distinctive customs, spirituality, traditions, procedures, practices and, in the cases where they exist, juridical systems or customs, in accordance with international human rights standards.

Article 35

Indigenous peoples have the right to determine the responsibilities of individuals to their communities.

Article 36

1. Indigenous peoples, in particular those divided by international borders, have the right to maintain and develop contacts, relations and cooperation, including activities for spiritual, cultural, political, economic and social purposes, with their own members as well as other peoples across borders.

2. States, in consultation and cooperation with indigenous peoples, shall take effective measures to facilitate the exercise and ensure the implementation of this right.

Article 37

1. Indigenous peoples have the right to the recognition, observance and enforcement of treaties, agreements and other constructive arrangements concluded with States or their successors and to have States honour and re-

spect such treaties, agreements and other constructive arrangements.

2. Nothing in this Declaration may be interpreted as diminishing or eliminating the rights of indigenous peoples contained in treaties, agreements and other constructive arrangements.

Article 38

States in consultation and cooperation with indigenous peoples, shall take the appropriate measures, including legislative measures, to achieve the ends of this Declaration.

Article 39

Indigenous peoples have the right to have access to financial and technical assistance from States and through international cooperation, for the enjoyment of the rights contained in this Declaration.

Article 40

Indigenous peoples have the right to access to and prompt decision through just and fair procedures for the resolution of conflicts and disputes with States or other parties, as well as to effective remedies for all infringements of their individual and collective rights. Such a decision shall give due consideration to the customs, traditions, rules and legal systems of the indigenous peoples concerned and international human rights.

Article 41

The organs and specialized agencies of the United Nations system and other intergovernmental organizations shall contribute to the full realization of the provisions of this Declaration through the mobilization, inter alia, of financial cooperation and technical assistance. Ways and means of ensuring participation of indigenous peoples on issues affecting them shall be established.

Article 42

The United Nations, its bodies, including the Permanent Forum on Indigenous Issues, and specialized agencies, including at the country level, and States shall promote respect for and full application of the provisions of this Declaration and follow up the effectiveness of this Declaration.

Article 43

The rights recognized herein constitute the minimum standards for the survival, dignity and well-being of the indigenous peoples of the world.

Article 44

All the rights and freedoms recognized herein are equally guaranteed to male and female indigenous individuals.

Article 45

Nothing in this Declaration may be construed as diminishing or extinguishing the rights indigenous peoples have now or may acquire in the future.

Article 46

1. Nothing in this Declaration may be interpreted as implying for any State, people, group or person any right to engage in any activity or to perform any act contrary to the Charter of the United Nations or construed as authorizing or encouraging any action which would dismem-

ber or impair, totally or in part, the territorial integrity or political unity of sovereign and independent States.

2. In the exercise of the rights enunciated in the present Declaration, human rights and fundamental freedoms of all shall be respected. The exercise of the rights set forth in this Declaration shall be subject only to such limitations as are determined by law and in accordance with international human rights obligations. Any such limitations shall be non-discriminatory and strictly necessary solely for the purpose of securing due recognition and respect for the rights and freedoms of others and for meeting the just and most compelling requirements of a democratic society.

3. The provisions set forth in this Declaration shall be interpreted in accordance with the principles of justice, democracy, respect for human rights, equality, non-discrimination, good governance and good faith.

Designed by the Graphic Design Unit, Department of Public Information, United Nations

Data tables, 2016 Census

Low-income Indicators (4), Individual Low-income Status (6), Age (8) and Sex (3) for the Population in Private Households of Canada, Provinces and Territories, Census Divisions and Census Subdivisions, 2016 Census - 100% Data

Data table

Select data categories for this table

Geography → Geographic index

British Columbia / Colombie-Britannique

Low-income indicators (4) [1]

Low-income cut-offs, before tax (LICO-BT)

Sex (3)

Total - Sex

British Columbia / Colombie-Britannique

Age (8)	Individual low-income status (6)					
	Total - Individual low-income status [2]	Low-income status - not applicable [3]	Low-income status - applicable	In low income	Not in low income	Prevalence of low income (%) [4]
Total - Age	4,560,235	82,365	4,477,875	646,480	3,831,390	14.4

Age (8)	Individual low-income status (6)					
	Total - Individual low-income status [2]	Low-income status - not applicable [3]	Low-income status - applicable	In low income	Not in low income	Prevalence of low income (%) [4]
0 to 17 years	840,230	17,835	822,390	128,695	693,690	15.6
0 to 5 years	265,610	5,495	260,110	38,435	221,675	14.8
6 to 17 years	574,620	12,345	562,275	90,265	472,015	16.1
18 to 24 years	391,635	6,730	384,900	89,415	295,485	23.2
25 to 54 years	1,863,020	29,065	1,833,955	249,640	1,584,310	13.6
55 to 64 years	669,945	12,300	657,640	87,665	569,975	13.3
65 years and over	795,415	16,420	778,990	91,060	687,925	11.7

Symbol(s)

..	not available for a specific reference period
...	not applicable
x	suppressed to meet the confidentiality requirements of the *Statistics Act*
F	too unreliable to be published

Footnote(s)

1 Low-income cut-offs, before tax (LICO-BT) - The Low-income cut-offs, before tax refers to an income threshold, defined using 1992 expenditure data, below which economic families or persons not in economic families would likely have devoted a larger share of their total income than average to the necessities of food, shelter and clothing. More specifically, the thresholds represented income levels at which these families or persons were expected to spend 20 percentage points or more of their total income than average on food, shelter and clothing. These thresholds have been adjusted to current dollars using the all-items Consumer Price Index (CPI).

The LICO-BT has 35 cut-offs varying by seven family sizes and five different sizes of area of residence to account for economies of scale and potential differences in cost of living in communities of different sizes. These thresholds are presented in Table 4.4 Low-income cut-offs, before tax (LICO-BT - 1992 base) for economic families and persons not in economic families, 2015, Dictionary, Census of Population, 2016.

When the total income of an economic family member or a person not in an economic family falls below the threshold applicable to the person, the person is considered to be in low income according to LICO-BT. Since the LICO-BT threshold and family income are unique within each economic family, low-income status based on LICO-BT can also be reported for economic families.

2 Low-income status - The income situation of the statistical unit in relation to a specific low-income line in a reference year. Statistical units with income that is below the low-income line are considered to be in low income.

For the 2016 Census, the reference period is the calendar year 2015 for all income variables.

3 The low-income concepts are not applied in the territories and in certain areas based on census subdivision type (such as Indian reserves). The existence of substantial in-kind transfers (such as subsidized housing and First Nations band housing) and sizeable barter economies or consumption from own production (such as product from hunting, farming or fishing) could make the interpretation of low-income statistics more difficult in these situations.

4 Prevalence of low income - The proportion or percentage of units whose income falls below a specified low-income line.

Data quality note(s) – British Columbia / Colombie-Britannique

- **Incomplete enumeration flag**

Excludes census data for one or more incompletely enumerated Indian reserves or Indian settlements.

- **Short-form data quality flag**
  Global non-response rate (GNR), short-form census questionnaire: 4.9%.
- **Short-form income data quality flag**
  Default. Data quality index showing a short-form income non-response rate lower than 10%.

Source: Statistics Canada, 2016 Census of Population, Statistics Canada Catalogue no. 98-400-X2016127.

Date modified:
2019-06-17

Liberal

Cap and Cut Emissions from Oil and Gas

Greenhouse gas emissions from the oil and gas sector have risen 20% since 2005 and now makes up 26% of Canada's total emissions, making it the largest emitting sector in the country.

Climate change isn't just an environmental issue, it's a competitiveness issue for the oil and gas sector. The climate science is clear and global investors are clear, the oil and gas sector must accelerate its efforts to get on a path to net-zero emissions.

That is why a re-elected Liberal Government will put in place a decisive plan to ensure the oil and gas sector reaches net-zero emissions by 2050.

A re-elected Liberal government will:

- Make sure the oil and gas sector reduces emissions at a pace and scale needed to achieve net-zero by 2050, with 5-year targets to stay on track to achieving this shared goal. And driving down pollution starts with ensuring that pollution from the oil and gas sector doesn't go up from current levels.

- Set 2025 and 2030 milestones based on the advice of the Net-Zero Advisory Body to ensure reduction levels are ambitious and achievable and that the oil and gas sector makes a meaningful contribution to meeting the nation's 2030 climate goals.

Fortunately, Canada's largest oil and gas companies are already committed to achieving net-zero emissions by 2050. These actions will incentivize clean innovation and the adoption of clean technologies, including carbon capture, utilization, and storage (CCUS).

PAN-CANADIAN FRAMEWORK

on Clean Growth and Climate Change

Canada's Plan to Address Climate Change and Grow the Economy

PDF version
Cat. No.: En4-294/2016E-PDF
ISBN: 978-0-660-07023-0

Aussi disponible en français

PAN-CANADIAN FRAMEWORK on Clean Growth and Climate Change

Canada's Plan to Address Climate Change and Grow the Economy

FOREWORD

The Pan-Canadian Framework on Clean Growth and Climate Change presented here is our collective plan to grow our economy while reducing emissions and building resilience to adapt to a changing climate. It will help us transition to a strong, diverse and competitive economy; foster job creation, with new technologies and exports; and provide a healthy environment for our children and grandchildren.

The Pan-Canadian Framework is both a commitment to the world that Canada will do its part on climate change, and a plan to meet the needs of Canadians. We have built on the momentum of the Paris Agreement by developing a concrete plan which, when implemented, will allow us to achieve Canada's international commitments.

When First Ministers met last March in Vancouver, they agreed to take ambitious action in support of meeting or exceeding Canada's 2030 target of a 30 percent reduction below 2005 levels of greenhouse gas (GHG) emissions. First Ministers issued the Vancouver Declaration on Clean Growth and Climate Change and agreed that a collaborative approach between provincial, territorial, and federal governments is important to reduce GHG emissions and to enable sustainable economic growth.

The Pan-Canadian Framework builds on the leadership shown and actions taken individually and collectively by the provinces and territories, including through the Declaration of the Premiers adopted at the Quebec Summit on Climate Change in 2015. To note, the province of Saskatchewan has decided not to adopt the Pan-Canadian Framework at this time. The federal government has committed to ensuring that the provinces and territories have the flexibility to design their own policies and programs to meet emission-reductions targets, supported by federal investments in infrastructure, specific emission-reduction opportunities and clean technologies. This flexibility enables governments to move forward and to collaborate on shared priorities while respecting each jurisdiction's needs and plans, including the need to ensure the continued competitiveness and viability of businesses.

In the Paris Agreement, Parties agreed that they should, when taking action to address climate change, recognize and respect the rights of Indigenous Peoples. As we implement this Framework, we will move forward respecting the rights of Indigenous Peoples, with robust, meaningful engagement drawing on their Traditional Knowledge. We will take into account the unique circumstances and opportunities of Indigenous Peoples and northern, remote, and vulnerable communities. We acknowledge and thank Indigenous Peoples across Canada for their climate leadership long before the Paris Agreement and for being active drivers of positive change.

Pricing carbon pollution is central to this Framework. Carbon pricing will encourage innovation because businesses and households will seek out new ways to increase efficiencies and to pollute less. We will complement carbon pricing with actions to build the foundation of our low-carbon and resilient economy.

As Canada transitions to a low-carbon future, energy will play an integral role in meeting our collective commitment, given that energy production and use account for over 80 percent of Canada's GHG emissions. This means using clean energy to power our homes, workplaces, vehicles, and industries, and using energy more efficiently. It means convenient transportation systems that run on cleaner fuels, that move more people by public transit and zero-emission vehicles, and that have streamlined trade corridors. It means healthier and more comfortable homes that can generate as much power as they use. It means more resilient infrastructure and ecosystems that can better withstand climatic changes. It means land use and conservation measures that sequester carbon and foster adaptation to climate change. It means new jobs for Canadians across the country and opportunities for growth. It means leveraging technology and innovation to seize export and trade opportunities for Canada, which will allow us to become a leader in the global clean growth economy and will also help bring down the cost of low-emission technologies. It means healthier communities with cleaner air and healthy and diverse ecosystems across the country.

We will maintain a sustained focus on implementation of the Pan-Canadian Framework, consistent with the commitment under the Paris Agreement, to increase the level of ambition over time.

The Pan-Canadian Framework is a historic step in the transition to a clean growth and resilient economy. It is informed by what we have heard from Canadians. We will continue to grow our economy and create good jobs as we take ambitious action on climate change. We will work to ensure that the Pan-Canadian Framework opens new opportunities for Canadian businesses to not only maintain but also enhance their competitiveness. We will continue to engage Canadians to strengthen and deepen our action on clean growth and climate change. And we are committed to transparently assessing and reporting to Canadians on our progress.

Together, we have developed a Pan-Canadian Framework on Clean Growth and Climate Change. This is Canada's plan to address climate change and grow the clean economy.

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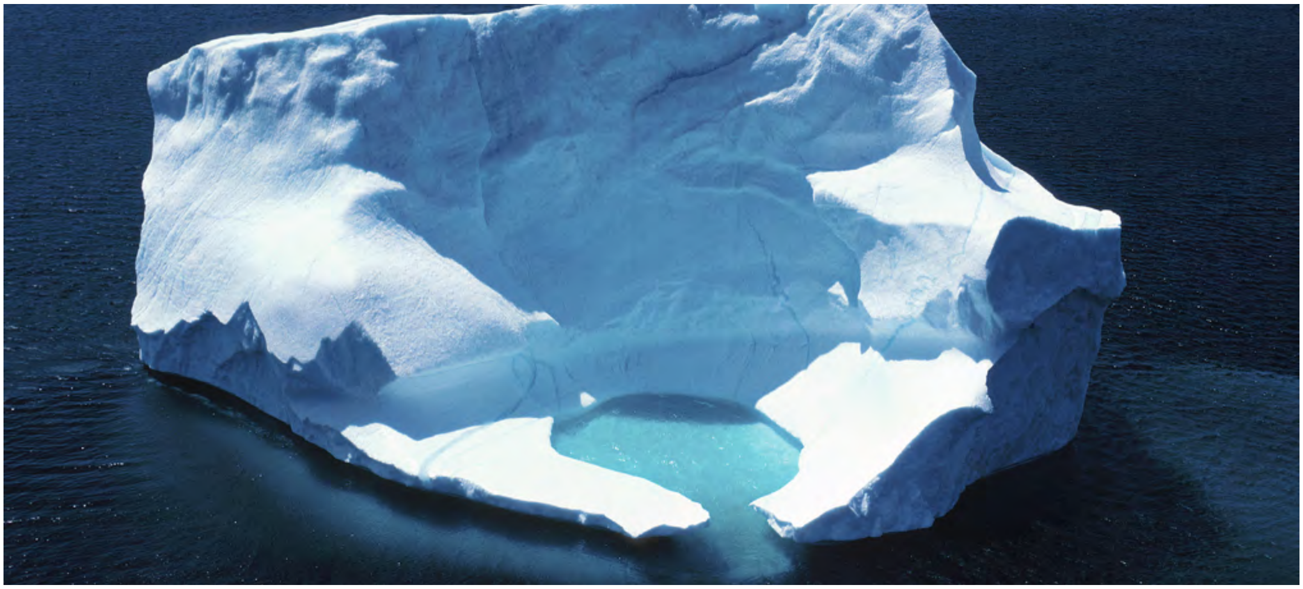


INTRODUCTION

In Canada and abroad, the impacts of climate change are becoming evident. Impacts such as coastal erosion; thawing permafrost; increases in heat waves, droughts and flooding; and risks to critical infrastructure and food security are already being felt in Canada. The science is clear that human activities are driving unprecedented changes in the Earth's climate, which pose significant risks to human health, security, and economic growth.

Taking strong action to address climate change is critical and urgent. The cost of inaction is greater than the cost of action: climate change could cost Canada $21-$43 billion per year by 2050, according to 2011 estimates from the National Round Table on the Environment and the Economy. Businesses and markets are increasingly considering climate risks. In recent years, severe weather events have cost Canadians billions of dollars, including in insured losses. Indigenous Peoples, northern and coastal regions and communities in Canada are particularly vulnerable and disproportionately affected. Geographic location, socio-economic challenges, and for Indigenous Peoples, the reliance on wild food sources, often converge with climate change to put pressure on these communities. Much has been done to begin addressing these challenges, including by Indigenous Peoples.

Acting on climate change will reduce risks and create new economic opportunities and good jobs for Canadians. There is already a global market for low-carbon goods and services worth over $5.8 trillion, which is projected to keep growing at a rate of 3 percent per year. Clean growth opportunities will benefit all sectors and regions. Canada will remain globally competitive through innovation, including through the development and promotion of innovative technologies with the potential to address climate change globally. This includes clean technology to enable the sustainable development of Canada's energy and resource sectors, including getting these resources to market, as Canada transitions to a low-carbon economy. Innovation can help further reduce emissions and the cost of taking action at home. Canadian technologies and solutions can also be exported abroad and deployed around the world, creating new markets and partners for Canadian businesses and supporting global action to reduce emissions.

The federal government will continue to work in close collaboration with other countries on climate solutions, including with partners across North America. A number of provinces and territories have already joined or are exploring entry into regional and international efforts to reduce GHG emissions.

Canadian municipalities will also continue to be important partners in developing and implementing climate solutions locally, as well as through international collaboration with other municipalities around the world.

The international community has agreed that tackling climate change is an urgent priority and also an historic opportunity to shift towards a global low-carbon economy. The adoption of the Paris Agreement in December 2015 was the culmination of years of negotiations under the United Nations Framework Convention on Climate Change. The Paris Agreement is a commitment to accelerate and intensify the actions and investments needed for a sustainable low-carbon future, to limit global average temperature rise to well below 2 °C above pre-industrial levels, and to pursue efforts to limit the increase to 1.5 °C. This will require taking action on long-lived GHGs such as carbon dioxide and short-lived climate pollutants such as methane, hydrofluorocarbons and black carbon.

As a first step towards implementing the commitments Canada made under the Paris Agreement, First Ministers released the Vancouver Declaration on Clean Growth and Climate Change on March 3, 2016.

1.1 How we developed the Framework

The development of the Pan-Canadian Framework was informed by input from Canadians across the country, who made it clear that they want to be part of the solution to climate change. Under the Vancouver Declaration, First Ministers asked four federal-provincial-territorial working groups to work with Indigenous Peoples; to consult with the public, businesses and civil society; and to present options to act on climate change and enable clean growth. The working groups heard solutions directly from Canadians, through an interactive website, in-person engagement sessions, and independent town halls.

Representatives of Indigenous Peoples contributed their knowledge and expectations for meaningful engagement in climate action and provided important considerations and recommendations either directly to working groups or to ministers, which helped shape this framework.

Ministers also reached out to Canadians, businesses, non-governmental organizations, and Indigenous Peoples to hear their priorities. In addition, ministerial tables were convened to provide their advice, including the Canadian Council of Ministers of the Environment, Ministers of Innovation, Ministers of Energy, and Ministers of Finance.

ENGAGING CANADIANS:
The Let's Talk Climate Action website was launched on April 22, 2016 to gather ideas and comments from Canadians about how Canada should address climate change. By the submission deadline of September 27, 2016, over 13,000 ideas and comments were received. In addition, consultations by governments and working groups on clean growth and climate change were held across Canada.

1.2 Pillars of the Framework

The Pan-Canadian Framework has four main pillars: pricing carbon pollution; complementary measures to further reduce emissions across the economy; measures to adapt to the impacts of climate change and build resilience; and actions to accelerate innovation, support clean technology, and create jobs. Together, these interrelated pillars form a comprehensive plan.

Pricing carbon pollution is an efficient way to reduce emissions, drive innovation, and encourage people and businesses to pollute less. However, relying on a carbon price alone to achieve Canada's international target would require a very high price.

Complementary climate actions can reduce emissions by addressing market barriers where pricing alone is insufficient or not timely enough to reduce emissions in the pre-2030 timeframe. For instance, tightening energy efficiency standards and codes for vehicles and buildings are common sense actions that reduce emissions, while also helping consumers save money by using less energy.

Canada is experiencing the impacts of climate change, so there is also a need to **adapt and build resilience**. This means making sure that our infrastructure and communities are adequately prepared for climate risks like floods, wildfires, droughts, and extreme weather events, including in particularly vulnerable regions like Indigenous, northern, coastal, and remote communities. This also means adapting to the impacts of changes in temperature, including thawing permafrost.

A low-carbon economy can and will be a strong and thriving economy. Taking action now, to position Canada as a global leader on clean technology innovation, will help ensure that Canada remains internationally competitive and will lead to the creation of new good jobs across the country. Investing in **clean technology, innovation, and jobs** will bring new and in-demand Canadian technologies to expanding global markets. These investments will help improve the efficiency and cost-effectiveness of mitigation and adaptation measures and will equip Canada's workforce with the knowledge and skills to succeed.

In implementing the Pan-Canadian Framework on Clean Growth and Climate Change, federal, provincial and territorial governments will review progress annually to assess the effectiveness of our collective actions and ensure continual improvement. First Ministers commit to **report regularly and transparently** to Canadians on progress towards GHG-reduction targets, on building climate resilience, and on growing a clean economy.

Our governments will continue to recognize, respect and safeguard the **rights of Indigenous Peoples** as we take actions under these pillars.

1.3 Elements of collaboration

The Pan-Canadian Framework reaffirms the principles outlined in the Vancouver Declaration, including

- recognizing the diversity of provincial and territorial economies and the need for fair and flexible approaches to ensure international competitiveness and a business environment that enables firms to capitalize on opportunities related to the transition to a low-carbon economy in each jurisdiction;
- recognizing that growing our economy and achieving our GHG-emissions targets will require an integrated, economy-wide approach that includes all sectors, creates jobs, and promotes innovation;
- recognizing that a collaborative approach between provincial, territorial, and federal governments is important to reduce GHG emissions and enable sustainable economic growth;
- recognizing that provinces and territories have been early leaders in the fight against climate change and have taken proactive steps, such as adopting carbon pricing mechanisms, placing caps on emissions, involvement in international partnerships with other states and regions, closing coal plants, carbon capture and storage projects, renewable energy production (including hydroelectric developments) and targets, and investments in energy efficiency;
- recognizing that the federal government has committed to ensuring that the provinces and territories have the flexibility to design their own policies to meet emission-reductions targets, including their own carbon pricing mechanisms, supported by federal investments in infrastructure, specific emission-reduction opportunities and clean technologies;
- recognizing the commitment of the federal government to work with provinces and territories to complement and support their actions without duplicating them, including by promoting innovation and enabling clean growth across all sectors;
- strengthening the collaboration between our governments and Indigenous Peoples on mitigation and adaptation actions, based on recognition of rights, respect, cooperation, and partnership;
- recognizing the importance of Traditional Knowledge in regard to understanding climate impacts and adaptation measures;

- recognizing that comprehensive adaptation efforts must complement ambitious mitigation measures to address unavoidable climate change impacts; and
- implementing a collaborative, science-based approach to inform Canada's future targets that will increase in stringency as required by the Paris Agreement.

Governments recognize the unique circumstances of the North, including disproportionate impacts from climate change and the associated challenges with food security, emerging economies and the high costs of living and of energy.

Federal, provincial, and territorial governments will work collaboratively to grow the economy, create good-paying and long-term jobs, and reduce GHG emissions in support of meeting or exceeding Canada's 2030 target. These actions will be supported by strong, complementary adaptation policies to build climate resilience. Indigenous Peoples will be important partners in developing real and meaningful outcomes that position them as drivers of climate action in the implementation of the Pan-Canadian Framework. All governments across Canada are committed to ambitious and sustained action on climate change, building on current actions and future opportunities.

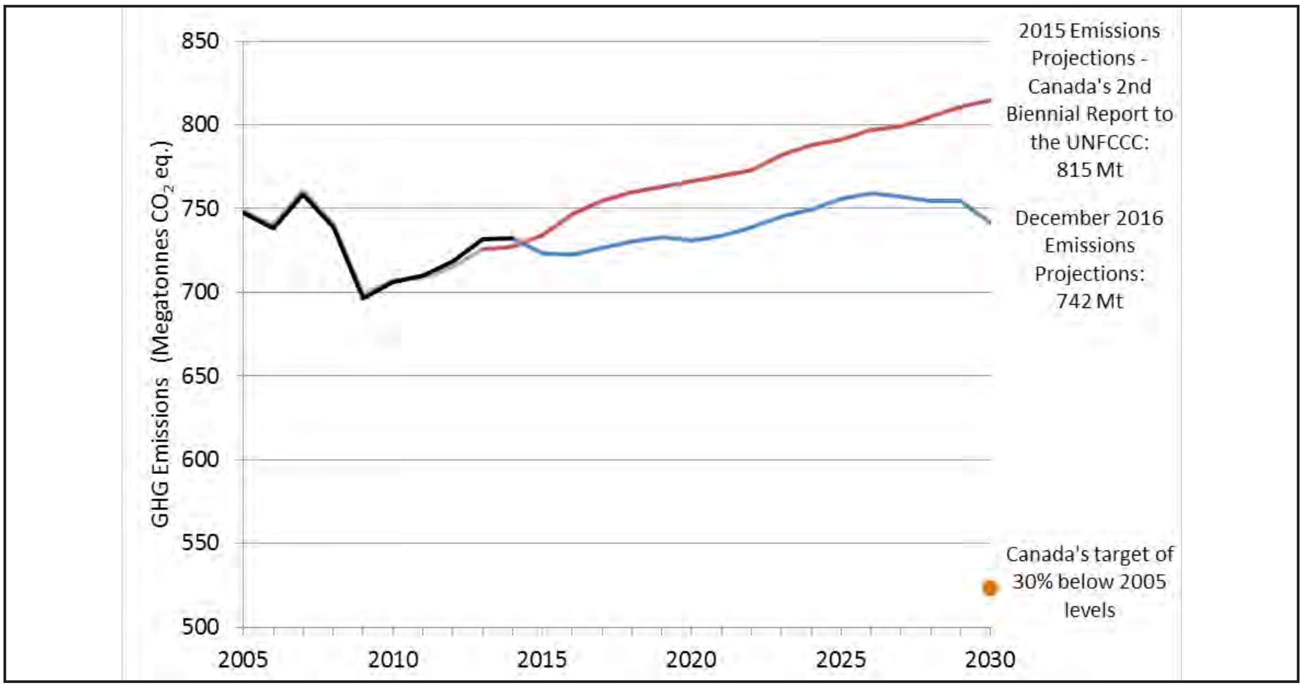
THE FEDERAL GOVERNMENT'S RENEWED RELATIONSHIP WITH INDIGENOUS PEOPLES:
The federal government also reiterates its commitment to renewed nation-to-nation, government-to-government, and Inuit-to-Crown relationships with First Nations, the Métis Nation and Inuit, based on the recognition of rights, respect, cooperation, and partnership, consistent with the Government of Canada's support for the United Nations Declaration on the Rights of Indigenous Peoples, including free, prior and informed consent.

1.4 Emissions trajectory to 2030

The graph below highlights that total Canadian GHG emissions are projected to be 742 megatonnes (Mt) in 2030 under the December 2016 emissions projections (Environment and Climate Change Canada)[1]. Canada's target is 523 Mt.

Projections from the December 2016 emissions projections include revised forecasts for GDP and oil and gas prices and production[2]. Also incorporated are new federal, provincial, and territorial government measures that have legislative or funding certainty as of November 1st, 2016 and were not included in the 2015 emissions projections. These include: federal measures for increasing energy efficiency of equipment in buildings; Ontario's commitment to join the Western Climate Initiative cap-and-trade system; Alberta's coal phase-out, carbon levy, and oil sands emissions cap; Quebec's regulations for new high-rise buildings; and, British Columbia's low carbon fuel standard.

Figure 1: Emissions Projections to 2030



1 Canada's 2016 greenhouse gas emissions projections to 2030 will be released by Environment and Climate Change Canada in December 2016.

2

	Scenarios		
December 2016 Assumptions	**Low**	**Reference**	**High**
Average Annual GDP Growth (2014-2030)	1.0%	1.7%	2.3%
2030 WTI Oil Price (2014 US$/bbl)	42	81	111
2030 Henry Hub Natural Gas Price (2014 US$/GJ)	2.89	3.72	4.62
2030 GHG Emissions (Mt C02eq.)	**697**	**742**	**790**

PRICING CARBON POLLUTION

Overview

Carbon pricing is broadly recognized as one of the most effective, transparent, and efficient policy approaches to reduce GHG emissions. Many Canadian provinces are already leading the way on pricing carbon pollution. British Columbia has a carbon tax, Alberta has a hybrid system that combines a carbon levy with a performance-based system for large industrial emitters, and Quebec and Ontario have cap-and-trade systems. With existing and planned provincial action, broad-based carbon pricing will apply in provinces with nearly 85 per cent of Canada's economy and population by 2017, covering a large part of our emissions.

The federal government outlined a benchmark for pricing carbon pollution by 2018 (see Annex I). The goal of this benchmark is to ensure that carbon pricing applies to a broad set of emission sources throughout Canada and with increasing stringency over time either through a rising price or declining caps. The benchmark outlines that jurisdictions can implement (i) an explicit price-based system (a carbon tax or a carbon levy and performance-based emissions system) or (ii) a cap-and-trade system. Some existing provincial systems already exceeded the benchmark. As affirmed in the Vancouver Declaration, provinces and territories continue to have the flexibility to design their own policies to meet emissions-reduction targets, including carbon pricing, adapted to each province and territory's specific circumstances.

> **"THERE IS A GROWING CONSENSUS AMONG BOTH GOVERNMENTS AND BUSINESSES ON THE FUNDAMENTAL ROLE OF CARBON PRICING IN THE TRANSITION TO A DECARBONIZED ECONOMY."**
>
> World Bank, State and Trends of Carbon Pricing 2015

The following **principles** guide the pan-Canadian approach to pricing carbon pollution, and they are broadly based on those proposed by the Working Group on Carbon Pricing Mechanisms:

- Carbon pricing should be a central component of the Pan-Canadian Framework.

- The approach should be flexible and recognize carbon pricing policies already implemented or in development by provinces and territories.
- Carbon pricing should be applied to a broad set of emission sources across the economy.
- Carbon pricing policies should be introduced in a timely manner to minimize investment into assets that could become stranded and maximize cumulative emission reductions.
- Carbon price increases should occur in a predictable and gradual way to limit economic impacts.
- Reporting on carbon pricing policies should be consistent, regular, transparent, and verifiable.
- Carbon pricing policies should minimize competitiveness impacts and carbon leakage, particularly for emissions-intensive, trade-exposed sectors.
- Carbon pricing policies should include revenue recycling to avoid a disproportionate burden on vulnerable groups and Indigenous Peoples.

NEW ACTIONS

1) Provincial and territorial actions on pricing carbon pollution are described in Annex II.

2) The federal government will work with the territories to find solutions that address their unique circumstances, including high costs of living and of energy, challenges with food security, and emerging economies. The federal government will also engage Indigenous Peoples to find solutions that address their unique circumstances, including high costs of living and of energy, challenges with food security, and emerging economies.

3) The overall approach will be reviewed by 2022 to confirm the path forward.

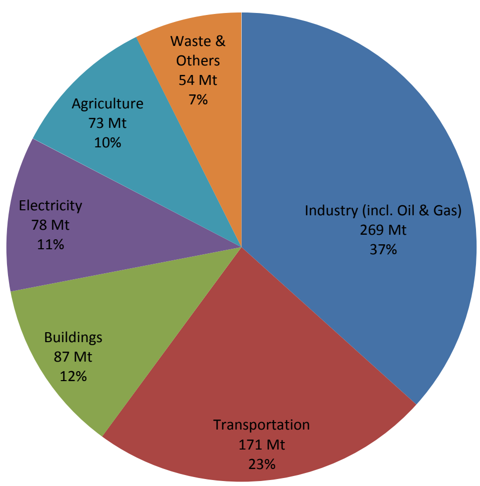
> **"CARBON PRICING IS THE MOST PRACTICAL AND COST-EFFECTIVE WAY TO LOWER GHG EMISSIONS WHILE ENCOURAGING LOW-CARBON INNOVATION."**
>
> Canada's Ecofiscal Commission

COMPLEMENTARY ACTIONS TO REDUCE EMISSIONS

Overview

To reduce emissions, meaningful action will need to be taken across all regions and sectors of the economy. Many of the things that Canadians do every day—like driving cars and heating homes—produce GHG emissions. Many activities that drive economic growth in the country, like extracting natural resources, industrial and manufacturing activities, and transporting goods to customers, also produce emissions. The policies that help drive down emissions can also help the economy to keep growing by cutting costs for Canadians, creating new markets for low-emission goods and services, and helping businesses use cleaner and more efficient technologies that give them a leg up on international competitors.

Emissions by sector in 2014 (megatonnes of CO_2 eq.)



Federal, provincial, and territorial governments will work together to make sure new actions build on and complement existing plans, policies, programs, and regulations and reflect lessons learned from past experience. New policies will be designed to focus on GHG-emission outcomes and will recognize flexibility for regional differences, including through outcomes-based regulatory equivalency agreements. Indigenous Peoples will be involved in defining and developing policies to support clean energy in their communities.

In developing policies, a number of factors will be considered, including:

- economic, environmental, and social impacts and benefits;
- how individual policies will work with carbon pricing;
- the need to consider and mitigate the impacts on emissions-intensive trade exposed sectors (e.g., resource sectors that are price takers on the global market), including the need to avoid carbon leakage;
- co-benefits such as improved health due to air pollutant reductions, and jobs and business growth;
- opportunities to realize near-term climate and health benefits through reducing emissions of short-lived climate pollutants; and,
- benefits for ecosystems and biodiversity.

FALLING COSTS OF RENEWABLE ENERGY:
Between 2010 and 2015, the costs for new utility-scale solar photovoltaic (PV) installations declined by two-thirds, while over the same period the cost of onshore wind fell by an estimated 30 percent on average (IEA, 2016)

Governments will be supporting the actions outlined in the Pan-Canadian Framework through policies and investments. Federal actions are described in Annex I, and provincial and territorial key actions and collaboration opportunities with the Government of Canada are described in Annex II.

3.1 Electricity

Canada already has one of the cleanest electricity systems in the world. About 80 percent of electricity production comes from non-emitting sources, more than any other G7 country. While electricity emissions are going down in large part due to the move away from coal-fired power toward cleaner sources, electricity generation is still Canada's fourth-largest source of GHG emissions.

Clean, non-emitting electricity systems will be the cornerstone of a modern, clean growth economy. Transformations to electricity systems will be supported by federal, provincial, and territorial governments, and, undertaken by utilities, private-sector players, and Indigenous Peoples.

The approach to electricity will include
(1) increasing the amount of electricity generated from renewable and low-emitting sources;
(2) connecting clean power with places that need it;
(3) modernizing electricity systems; and
(4) reducing reliance on diesel working with Indigenous Peoples and northern and remote communities.

Provinces and territories have already taken action on moving from traditional coal-fired generation to clean electricity. Ontario and Manitoba have already phased out their use of coal, Alberta has plans in place to phase out coal-fired electricity by 2030, Nova Scotia has created a regulatory framework to transition from coal to clean electricity generation, and Saskatchewan has a coal-fired generating unit with carbon capture technology, which captures 90 percent of emissions. New capacity will come from non-emitting sources—including hydro, wind, and solar—as well as natural gas. Energy efficiency and conservation will make added contributions to clean electricity systems.

ONTARIO'S COAL PHASE-OUT:
On April 15, 2014, **Ontario** became the first jurisdiction in North America to fully eliminate coal as a source of electricity generation. This action is the single largest GHG-reduction initiative in North America, eliminating more than 30 Mt of annual GHG emissions and equivalent to taking seven million vehicles off the road. On November 23, 2015, Ontario passed the *Ending Coal for Cleaner Air Act*, permanently banning coal-fired electricity generation in the province.

SASKATCHEWAN'S BOUNDARY DAM INTEGRATED CARBON CAPTURE AND STORAGE PROJECT:
is the world's first commercial-scale, coal-fired carbon capture and storage electricity project, and it is able to capture and sequester up to 90 percent of its GHG emissions.

WIND POWER:
Wind capacity in Canada grew 20 times between 2005 and 2015, and there is strong potential for further growth. For example, 4 wind farms in **Prince Edward Island** now generate almost 25 percent of the province's electricity requirements.

THE CANADIAN ENERGY STRATEGY:
Provinces and territories are already taking a cooperative approach toward sustainable energy development through the Canadian Energy Strategy, which was released by premiers in July 2015. As agreed under the Vancouver Declaration and building on the Quebec Summit on Climate Change in 2015, federal, provincial, and territorial energy ministers are collaborating on specific actions through the Canadian Energy Strategy, to contribute to the Pan-Canadian Framework on Clean Growth and Climate Change. Actions include energy conservation and efficiency, clean energy technology and innovation, and deployment of energy to people and global markets.

ALBERTA'S COAL PHASE-OUT:
Alberta's commitments to end emissions from coal-fired electricity and replace it with 30 percent renewable energy by 2030 are expected to achieve cumulative emission reductions of 67 Mt between now and 2030, and emissions in 2030 will be at least 14 Mt below what is forecast under the status quo. This reduction is the equivalent of taking 2.8 million cars off the road. This move will improve air quality and the health of Albertans and other Canadians. It will also ensure reliability, encourage private investment, and provide price stability for all Albertans.

Connecting clean power across Canada through stronger transmission-line interconnections will help reduce emissions and support the move away from coal. Many provinces already trade electricity across their borders, and there is potential to increase these flows, consistent with market rules and fair competition among electricity producers.

Modernizing electricity systems will involve expanding energy storage, updating infrastructure, and deploying smart-grid technologies to improve the reliability and stability of electric grids and to allow more renewable power to be added. As a leader in the development and deployment of innovative energy-storage solutions and smart-grid technology, Canadian clean technology producers stand to benefit from increased investments in our electricity systems.

Many Indigenous Peoples, as well as northern and remote communities in Canada rely on diesel fuel to produce electricity and heat. Opportunities exist for clean electricity infrastructure, distributed energy systems, renewable energy microgrids, as well as grid connections and hybrid systems, which will enhance wellbeing, create local economic opportunities, and contribute to better air quality and a cleaner environment overall. Investing in clean energy solutions will advance the priorities of Indigenous Peoples, as well as northern and remote communities to transition away from diesel.

COLVILLE LAKE SOLAR PROJECT – Colville Lake, Northwest Territories is located north of the Arctic Circle, and it is served with a winter road that is open just a couple of months each year. To reduce diesel use in this remote, off-grid community, a solar/diesel/battery hybrid electricity system has been installed. This system has allowed the diesel generators to be shut down for extended periods in the summer. This innovative energy solution has reduced diesel use and related emissions by 20-25 percent per year.

Taking these actions will have a number of benefits beyond reducing GHG emissions. Phasing out coal and reducing the use of diesel will reduce harmful air pollutants, which have significant implications for human health and associated health-care costs. Designing and building clean-power technologies and transmission lines represents major economic opportunities for Canada. Increasing the amount of clean and renewable electricity sold to the United States could also bring new revenue to utilities and provinces, respecting open-access rules under the authority of the U.S. Federal Energy Regulatory Commission.

THE CANADA INFRASTRUCTURE BANK: The federal government is creating the Canada Infrastructure Bank, which will work with provinces, territories, and municipalities to further the reach of government funding directed to infrastructure, including clean electricity systems.

COMMUNITY-BASED ENERGY GENERATION: In May 2015, **New Brunswick** introduced legislation to allow local entities to develop renewable-energy sourced electricity generation in their communities. This legislation will allow universities, non-profit organizations, cooperatives, First Nations, and municipalities to contribute to NB Power's renewable energy requirements.

NEW ACTIONS

1. Increasing renewable and non-emitting energy sources

Federal, provincial, and territorial governments will work together to accelerate the phase out of traditional coal units across Canada, by 2030, as recently announced by the federal government (see Annex I) and to build on provincial and territorial leadership.

The federal government has announced it will set performance standards for natural gas-fired electricity generation, in consultation with provinces, territories, and stakeholders (see Annex I).

Federal, provincial, and territorial governments will work together to facilitate, invest in, and increase the use of clean electricity across Canada, including through additional investments in research, development, and demonstration activities.

2. Connecting clean power with places that need it

Federal, provincial, and territorial governments will work together to help build new and enhanced transmission lines between and within provinces and territories.

3. Modernizing electricity systems

Federal, provincial, and territorial governments will work together to support the demonstration and deployment of smart-grid technologies that help electric systems make better use of renewable energy, facilitate the integration of energy storage for renewables, and help expand renewable power capacity.

4. Reducing reliance on diesel working with Indigenous Peoples and northern and remote communities

Governments are committed to accelerating and intensifying efforts to improve the energy efficiency of diesel generating units, demonstrate and install hybrid or renewable energy systems, and connect communities to electricity grids. This will be done in partnership with Indigenous Peoples and businesses. These actions will have significant benefits for communities, such as improving air quality and energy security, and creating the potential for locally owned and sourced power generation.

RAMEA WIND-HYDROGEN-DIESEL ENERGY PROJECT:
The off-grid community of Ramea in **Newfoundland and Labrador** hosts one of the first projects in the world to integrate generation from wind, hydrogen, and diesel in an isolated electricity system. Since 2010, the Ramea Wind-Hydrogen-Diesel Energy Project has successfully produced approximately 680 000 kilowatt hours of renewable energy.

3.2 Built environment

In Canada, using energy to heat and cool buildings accounted for about 12 percent of national GHG emissions in 2014 or 17 percent if emissions from generating the electricity used in buildings is also included. The emissions in this sector—created by burning fossil fuels and leaks in air conditioning systems—are projected to grow modestly by 2030 unless further action is taken.

In a low-carbon, clean growth economy, buildings and communities will be highly energy efficient, rely on clean electricity and renewable energy, and be smart and sustainable. Making the built environment more energy efficient reduces GHGs, helps make homes and buildings more comfortable and more affordable by lowering energy bills, and can promote innovation and clean job opportunities. Most building owners and architects estimate that retrofitting commercial and institutional buildings pays off in less than ten years, according to data from the Canada Green Building Council. Residential energy efficiency improvements helped Canadians save $12 billion in energy costs in 2013, an average savings of $869 per household.

The approach to the built environment will include (1) making new buildings more energy efficient; (2) retrofitting existing buildings, as well as fuel switching; (3) improving energy efficiency for appliances and equipment; and (4) supporting building codes and energy efficient housing in Indigenous communities.

Advances in clean technologies and building practices can make new buildings "net-zero energy", meaning they require so little energy they could potentially rely on their own renewable energy supplies for all of their energy needs. Through research and development, technology costs continue to fall, and government and industry efforts and investments will accelerate that trend. These advances, supported by a model "net-zero energy ready" building code, will enable all builders to adopt these practices and lower lifecycle costs for homeowners.

EFFICIENCY NOVA SCOTIA:
Canada's first energy efficiency utility—works with more than 100 local partners, and it has helped 225 000 program participants complete energy efficiency projects, saving Nova Scotians $110 million in 2016 alone. For example, the HomeWarming service is funded by the province of Nova Scotia as part of a long-term plan to upgrade all low-income homes in Nova Scotia, over the next 10 years.

At the same time, action is needed on existing buildings, since more than 75 percent of the building stock in 2030 will be composed of buildings already standing today. This can be supported by innovative policies like labelling a building's energy performance, establishing retrofit codes, and offering low-cost financing for retrofits.

Housing for Indigenous communities is particularly pressing. New housing will be built to high-efficiency standards and existing housing will be retrofitted. Indigenous Peoples have also identified the need to incorporate Traditional Knowledge and culture into building designs. Governments will partner with Indigenous Peoples in the design of relevant policies and programs.

Energy efficiency standards for equipment and appliances save consumers and businesses money on energy bills. An early market signal by the government, in the form of an intention to introduce standards by a specific year, can motivate the market to accelerate the uptake of the targeted technologies. Regulations can be supported by actions to educate consumers, to demonstrate benefits, and to overcome market barriers.

Construction in Canada is a $171 billion industry, and it employs well over a million people. New building codes will spur innovation and support Canadian businesses in developing more efficient building techniques and technologies. Investments in retrofits to improve energy efficiency have been shown to be strong job creators, providing direct local benefits, creating local jobs, and reducing energy bills.

NET-ZERO ENERGY BUILDINGS: Construction costs for net-zero energy buildings have dropped 40 percent in the past decade, and they are continuing to fall. The benefits of net-zero energy buildings are significant. Estimated operating costs for a net-zero energy ready house is 30 percent to 55 percent less than for a typical house, depending on region, fuel type and occupant behaviour. For example, on a -32 °C day, the Riverdale NetZero Project (a semi-detached duplex in Edmonton, Alberta) only needs 6500 W of power for heat—the same amount of heat produced by four toasters.

NEW ACTIONS

1. Making new buildings more energy efficient

Federal, provincial, and territorial governments will work to develop and adopt increasingly stringent model building codes, starting in 2020, with the goal that provinces and territories adopt a "net-zero energy ready" model building code by 2030. These building codes will take regional differences into account. Continued federal investment in research, development, and demonstration, and cooperation with industry will help to reduce technology costs over time.

2. Retrofitting existing buildings

Federal, provincial, and territorial governments will work to develop a model code for existing buildings by 2022, with the goal that provinces and territories adopt the code. This code will help guide energy efficiency improvements that can be made when renovating buildings.

Federal, provincial, and territorial governments will work together with the aim of requiring labelling of building energy use by as early as 2019. Labelling will provide consumers and businesses with transparent information on energy performance.

Provincial and territorial governments will work to sustain and, where possible, expand efforts to retrofit existing buildings by supporting energy efficiency improvements as well as fuel switching, where appropriate, and by accelerating the adoption of high-efficiency equipment while tailoring their programs to regional circumstances. The federal government could support efforts of provinces and territories through the Low Carbon Economy Fund and infrastructure initiatives.

3. Improving energy efficiency for appliances and equipment

The federal government will set new standards for heating equipment and other key technologies to the highest level of efficiency that is economically and technically achievable.

4. Supporting building codes and energy efficient housing in Indigenous communities

Governments will collaborate with Indigenous Peoples as they move towards more efficient building standards and incorporate energy efficiency into their building-renovation programs.

SOCIAL HOUSING RETROFITS:
To help fight climate change, Ontario invested $92 million in 2016 to retrofit social housing buildings to reduce GHG emissions by installing energy efficient boilers, insulating outer walls and mechanical systems, and installing more energy efficient windows and lighting. Ontario's Climate Change Action Plan builds on this initial investment by committing up to $500 million more for social housing retrofits over the next five years.

Aki Energy in **Manitoba** is a non-profit Aboriginal social enterprise that works with First Nations to start green businesses in their communities and to create local jobs and strong local economies. Aki Energy is committed to helping First Nations lower the utility bills to heat buildings, and it has installed over $3 million in cost-effective renewable energy technologies in partnership with Manitoba First Nations.

3.3 Transportation

The transportation sector accounted for about 23 percent of Canada's emissions in 2014, mostly from passenger vehicles and freight trucks. Transportation emissions are projected to decline slightly by 2030 if no further action is taken. Governments are already working to make all modes of transportation more efficient and convenient, but more action is needed.

Low-carbon transportation systems will use cleaner fuels, will have more zero-emission vehicles on the road, will provide convenient and affordable public transit, and will transport people and goods more efficiently.

The approach to transportation will include (1) setting and updating vehicle emissions standards and improving the efficiency of vehicles and transportation systems; (2) expanding the number of zero-emission vehicles on Canadian roads; (3) supporting the shift from higher to lower-emitting types of transportation, including through investing in infrastructure; and (4) using cleaner fuels.

Emissions standards for cars and trucks ensure new engines are more fuel efficient. Retrofitting freight trucks to reduce wind resistance can also cut emissions. And streamlining how goods are transported can improve the overall efficiency of transportation systems.

Zero-emission vehicle technologies include plug-in hybrids, electric vehicles, and hydrogen fuel-cell vehicles. Many of these are becoming increasingly affordable and viable, and governments can help accelerate these trends, including by investing in charging and fueling infrastructure.

ELECTRIFICATION OF TRANSPORTATION:
Québec has committed to take significant action on the electrification of transportation by 2020, including by increasing the number of electric and plug-in hybrid vehicles registered in Québec to 100 000; adding 5000 electric-vehicle jobs and generating $500 million in investments; reducing the amount of fuel used each year in Québec by 66 million liters; and cutting annual GHG emissions from the transportation sector by 150 000 tonnes.

Shifting from higher- to lower-emitting modes of transportation includes things like riding public transit or cycling instead of driving a car, and transporting goods by rail instead of trucks. Improving public transit infrastructure and optimizing freight corridors can help drive these shifts.

Using cleaner fuels such as advanced biofuels can reduce the lifecycle carbon intensities of all fuels across transportation systems, as well as in other sectors like industry and buildings.

Taking these actions will have additional environmental and economic benefits beyond reducing GHG emissions. Efficiency improvements can help Canadians and businesses save money by spending less on fuel and reducing the costs of transporting goods. New, cleaner fuels can create opportunities for resource sectors. Businesses that develop new fuel and vehicle technologies will create jobs, help the economy grow, and give those businesses a competitive edge.

NEW ACTIONS

1. Setting emissions standards and improving efficiency

The federal government will continue its work to implement increasingly stringent standards for emissions from light-duty vehicles, including fuel-efficient tire standards, and to update emissions standards for heavy-duty vehicles.

The federal government will work with provinces, territories, and industry to develop new requirements for heavy-duty trucks to install fuel-saving devices like aerodynamic add-ons.

The federal government will take a number of actions to improve efficiency and support fuel switching in the rail, aviation, marine, and off-road sectors.

2. Putting more zero-emission vehicles on the road

Federal, provincial, and territorial governments will work with industry and other stakeholders to develop a Canada-wide strategy for zero-emission vehicles by 2018.

Federal, provincial, and territorial governments will work together, including with private-sector partners, to accelerate demonstration and deployment of infrastructure to support zero-emission vehicles, such as electric-charging stations.

3. Shifting from higher- to lower-emitting modes and investing in infrastructure

Federal, provincial, and territorial governments will work together to enhance investments in public-transit upgrades and expansions.

Federal, provincial, and territorial governments will invest in building more efficient trade and transportation corridors including investments in transportation hubs and ports.

Federal, provincial, and territorial governments will consider opportunities with the private sector to support refueling stations for alternative fuels for light- and heavy-duty vehicles, including natural gas, electricity, and hydrogen.

4. Using cleaner fuels

The federal government, working with provincial and territorial governments, industry, and other stakeholders, will develop a clean fuel standard to reduce emissions from fuels used in transportation, buildings and industry.

This will take into account the unique circumstances of Indigenous Peoples and northern and remote communities.

3.4 Industry

Canada's industries are the backbone of the economy, but they are also a major source of GHG emissions. In 2014, industrial sectors accounted for about 37 percent of Canada's emissions, the majority of which came from the oil and gas sector. Industrial emissions are projected to grow between now and 2030 as demand grows for Canadian-produced goods, at home and abroad.

A low-carbon industrial sector will rely heavily on clean electricity and lower-carbon fuels, will make more efficient use of energy, and will seize opportunities unlocked by innovative technologies. The province of Alberta has legislated an absolute cap of 100 Mt a year on emissions from the oil sands sector. There are a number of near-term opportunities to reduce industrial emissions while maintaining the competitive position of Canadian firms.

The approach to the industrial sector will include three main areas of action: (1) regulations to reduce methane and hydrofluorocarbon (HFC) emissions; (2) improving industrial energy efficiency; and (3) investing in new technologies to reduce emissions. Together, these actions will help set the path for long-term clean growth and the transition to a low-carbon economy.

Methane and HFCs are potent GHGs, dozens to thousands of times more powerful than carbon dioxide. The oil and gas sector is the largest contributor to methane emissions in Canada. Building on provincial actions and targets, the federal government has committed to reduce methane emissions by 40-45 percent by 2025. Canada joined almost 200 other countries in signing the Kigali Amendment to the Montreal Protocol, which will push the global phase out of HFC emissions. Taking action on HFCs can prevent up to 0.5 °C of global warming due to the potency of these gases, while continuing to protect the ozone layer.

There is significant potential to improve energy efficiency in Canada's industrial sectors. Energy management systems such as ISO 50001, the Superior Energy Performance program (SEP), and the ENERGY STAR for Industry program are useful tools that help businesses track, analyze, and improve their energy efficiency.

Using today's low-emission technologies and switching to clean electricity and lower-carbon fuels are near-term actions industry can take to reduce emissions. Over the longer-term, more dramatic emission reductions will be possible by using new technologies to transform how some industries operate. Investing in promising new technologies is an important area for action. Innovation will help Canadian businesses access global markets and attract foreign investment.

LOWER-CARBON INDUSTRIAL ACTIVITY IN CANADA:
Quebec's aluminum smelters have reduced their emissions by 30 percent since 1990. The modernized world-class aluminum smelter in Kitimat, BC will boost production and reduce emissions by nearly 50 percent. As a result of these investments, Canada's aluminum industry is now the most carbon-efficient producer of aluminum in the world.

OIL SANDS INNOVATION:
COSIA (Canada's Oil Sands Innovation Alliance) is an alliance of 13 oil sands producers, representing 90 percent of production from the Canadian oil sands, who are working together to develop technologies that help reduce the environmental impact of the oil sands, including reducing GHG emissions. Member companies have shared 936 distinct environmental technologies, costing $1.33 billion, since coming together in 2012.

Taking these actions will benefit businesses. Strengthening energy performance is one of the most cost-effective ways for industry to reduce energy use, it generally has quick payback periods, and it will continually generate financial savings. Measures that help cut costs or develop new technologies can improve competitiveness and create jobs and export opportunities for the clean technology sector.

NEW ACTIONS

1. Reducing methane and HFC emissions

The federal government will work with provinces and territories to achieve the objective of reducing methane emissions from the oil and gas sector, including offshore activities, by 40-45 percent by 2025, including through equivalency agreements.

The federal government has introduced proposed regulations to phase down use of HFCs to support Canada's commitment to the Montreal Protocol amendment.

2. Improving industrial energy efficiency

Federal, provincial, and territorial governments will work together to help industries save energy and money, including by supporting them in adopting energy management systems.

3. Investing in technology

Federal, provincial, and territorial governments working with industry will continue to invest in research and development and to promote deployment of new technologies that help reduce emissions.

Federal, provincial, and territorial governments will also work with industry to identify demonstration projects for promising pre-commercial clean energy technologies required to reduce emissions from energy production and use in the Canadian economy, including in the oil and gas sector.

3.5 Forestry, agriculture, and waste

Emissions from agriculture (livestock and crop production) and extraction of forestry resources accounted for about 10 percent of Canada's emissions in 2014, and they are not projected to significantly change by 2030. Municipal waste accounts for a small portion (about 3 percent) of Canada's total GHGs, and these emissions are projected to decline, largely due to increases in landfill gas capture.

Agricultural soils and forests also absorb and store carbon. The emissions or removals from carbon sinks can fluctuate with natural disturbances (e.g. forest fires), but there are still a number of actions that can increase carbon storage and reduce emissions.

Forests, wetlands, and agricultural lands across Canada will play an important natural role in a low-carbon economy by absorbing and storing atmospheric carbon. Actions taken by jurisdictions and woodlot owners to accelerate reforestation, to continuously improve sustainable management practices, and to plant new forests where they do not currently exist will enhance stored carbon. Clean technology, such as lower-carbon bioenergy, and bioproducts that use feedstock from agriculture and forestry waste and dedicated crops to replace higher-carbon fuels can also reduce emissions. Continued innovation and clean technology in agriculture will build on past GHG reduction successes of decreasing emissions per unit of production. The municipal waste sector will also be a key source of cleaner fuels such as renewable natural gas from landfills.

The approach to these sectors will include (1) enhancing carbon storage in forests and agricultural lands; (2) supporting the increased use of wood for construction; (3) generating fuel from bioenergy and bioproducts; and, (4) advancing innovation.

Forests, wetlands, and agricultural lands can be enhanced as "carbon sinks" through actions such as planting more trees, improving forest carbon management practices, minimizing losses from fires and invasive species, restoring forests that have been affected by natural disturbances, and increasing adoption of land management practices like increasing perennial and permanent cover crops and zero-till farming. Protecting and restoring natural areas, including wetlands, can also benefit biodiversity and maintain or enhance carbon storage.

Increasing the use of wood for construction can reduce emissions as the carbon stored in that wood gets locked in for a long period of time. Increasing domestic demand for Canadian wood products will also support the vibrant forest industries across Canada, which have a long history of innovating to develop new products and more efficient and sustainable forest practices.

The **Cheakamus Community Forest** carbon offset project is located adjacent to the Resort Municipality of Whistler, within the traditional territories of the Squamish and Lil'wat Nations. The project retains more carbon in the forest by using ecosystem-based management practices that include increasing protected areas and using lower-impact harvesting techniques.

The forestry, agriculture, and waste sectors also provide biomass for bioproducts that can be used in place of fossil fuels in other sectors. For example, waste products from forestry, agriculture, and landfills can be converted into energy sources such as renewable natural gas. Dedicated crops can be grown as feedstocks for products like bioplastics. Expanding renewable fuel industries represents an opportunity to create new jobs and economic growth across Canada.

BIOMASS-FIRED DISTRICT HEATING:

Prince Edward Island is home to Canada's longest running, biomass-fired district heating system. Operating since the 1980's, the system has expanded to serve over 125 buildings in the downtown core of Charlottetown, including the University of Prince Edward Island and the Queen Elizabeth Hospital, and cleanly burns 66 000 tons of waste materials annually.

Innovative solutions, including clean technologies, are required to reduce emissions from agriculture. Promising new technologies are being developed to reduce emissions from livestock and crop production, including from the use of precision farming and "smart" fertilizers, which time the release to match plant needs, and from feed innovations that reduce methane production in cattle. Actions pertaining to the agriculture sector will be developed collaboratively through Canada's Next Agriculture Policy Framework.

These actions in the forestry, agriculture, and waste sectors, and supporting clean technology businesses, can help to create jobs and build more sustainable communities.

NEW ACTIONS

1. Increasing stored carbon

Federal, provincial, and territorial governments will work together to protect and enhance carbon sinks, including in forests, wetlands, and agricultural lands (e.g. through land-use and conservation measures).

2. Increasing the use of wood for construction

Federal, provincial, and territorial governments will collaborate to encourage the increased use of wood products in construction, including through updated building codes.

3. Generating bioenergy and bioproducts

Federal, provincial, and territorial governments will work together to identify opportunities to produce renewable fuels and bioproducts, for example, generating renewable fuel from waste.

4. Advancing innovation

Federal, provincial, and territorial governments will work together to enhance innovation to advance GHG efficient management practices in forestry and agriculture.

3.6 Government leadership

Governments are directly responsible for a relatively small share of Canada's emissions (about 0.6 percent), but they have an opportunity to lead by example. A number of provinces are already demonstrating leadership, including through carbon neutral policies.

CARBON NEUTRAL GOVERNMENT:
British Columbia's public sector has successfully achieved carbon neutrality each year since 2010. Over the past 6 years, schools, post-secondary institutions, government offices, Crown corporations, and hospitals have reduced a total of 4.3 million tonnes of emissions through improvements to their operations and investments of $51.4 million in offset projects. British Columbia was the first—and continues to be the only—carbon neutral jurisdiction on the continent.

In a low-carbon, clean growth economy, federal, provincial, and territorial governments will be leaders in sustainable, low-emission practices that support the goals of clean growth and address climate change.

Municipalities are also essential partners. How cities develop and operate has an important impact on energy use and therefore GHG emissions.

LEADERSHIP BY CITIES:
The City of Whitehorse's Sustainability Plan outlines 12 community-wide goals in areas such as transportation, buildings, waste, GHG reductions, and resilient, accessible food systems, with associated targets for 2020, 2030, and 2050. For example, Whitehorse has set a target that new buildings will be 30 percent more efficient than the National Energy Code of Canada for Buildings, the National Building Codes, or achievable comparable EnerGuide ratings, while city-owned buildings will be 50 percent more efficient than the National Energy Code.

The public sector can play an important role by setting ambitious emissions reduction targets and by demonstrating the effectiveness of policies to reduce emissions (e.g. from vehicle fleets and buildings).

The approach to government leadership will include (1) setting ambitious targets; (2) cutting emissions from government buildings and fleets; and (3) scaling up clean procurement.

Governments control a significant share of assets like fleets and buildings. By setting targets and implementing policies to make buildings more efficient and to reduce emissions from vehicle fleets, the public sector can help to demonstrate the business case for ambitious action. Governments are also major purchasers and providers of goods and services, and they can help to build demand for low-carbon goods and services through procurement policies. They can also provide a testing ground for new and emerging technologies, creating new opportunities for Canadian firms developing clean technology products, services, and processes.

NEW ACTIONS

1. Setting ambitious targets

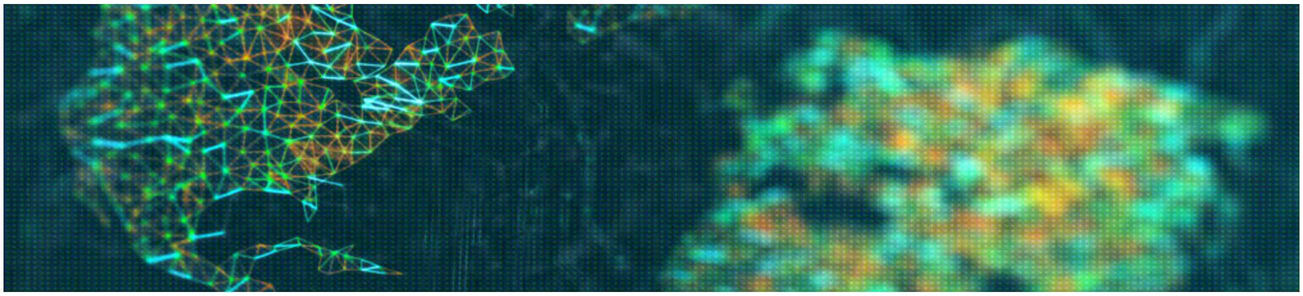
Federal, provincial, and territorial governments will demonstrate leadership through commitments to ambitious targets to reduce emissions from government operations. The federal government is committed to reduce its own GHG emissions to 40 percent below 2005 levels, by 2030 or sooner.

2. Cutting emissions from government buildings and fleets

Federal, provincial, and territorial government will scale up efforts to transition to highly efficient buildings and zero-emission vehicle fleets. The federal government has set a goal of using 100 percent clean power by 2025.

3. Scaling up clean procurement

Federal, provincial, and territorial governments will work together to modernize procurement practices, adopt clean energy and technologies, and prioritize opportunities to help Canadian businesses grow, demonstrate new technologies, and create jobs.



3.7 International leadership

Governments will work with their international partners, including developing countries, to help reduce emissions around the world. The federal government is investing $2.65 billion in climate finance to help developing countries transition to low-carbon economies and build climate resilience.

The priority is to first focus on reduction in emissions within Canada, but part of Canada's approach to climate change could also involve acquiring allowances for emissions reductions in other parts of the world, as a complement to domestic emissions reduction efforts. As recognized under the Paris Agreement (article 6), countries may choose to use emissions reductions that take place outside of their own borders, known as "internationally transferred mitigation outcomes", to meet their targets. Emissions reductions that take place outside of Canada may have lower costs and contribute to investment in sustainable development abroad. Quebec and California already participate in international emissions trading under their linked cap-and-trade system, which Ontario will soon join.

The approach to international leadership will include (1) delivering on Canada's international climate finance commitments; (2) acquiring internationally transferred mitigation outcomes; and (3) engaging in trade and climate policy.

Federal, provincial, and territorial governments will also explore mechanisms and opportunities for provinces and territories to collaborate in international fora, joint missions, and discussions on climate change and energy.

The federal government will continue to engage with and support Indigenous Peoples' action on international climate change issues, including through the United Nations Framework Convention on Climate Change, to formulate a platform for Indigenous Peoples, as agreed to in the Paris decision.

NEW ACTIONS

1. Delivering on Canada's international climate-finance commitments

The federal government will deliver on its historic commitment of $2.65 billion by 2020 to help the poorest and most vulnerable countries mitigate and adapt to the adverse effects of climate change.

2. Acquiring internationally transferred mitigation outcomes

The federal government, in cooperation with provincial and territorial governments and relevant partners, will continue to explore which types of tools related to the acquisition of internationally transferred mitigation outcomes may be beneficial to Canada and will advance a robust approach to the implementation of article 6 of the Paris Agreement. A first priority is ensuring any cross-border transfer of mitigation outcomes is based on rigorous accounting rules, informed by experts, which result in real reductions.

The federal government will work with Ontario, Quebec, and other interested provinces and territories, as well as with international partners, to ensure that allowances acquired through international-emissions trading are counted towards Canada's international target.

3. Engaging in trade and climate policy

The federal government, in cooperation with provincial and territorial governments, will work with its international partners to ensure that trade rules support climate policy.

ADAPTATION AND CLIMATE RESILIENCE

Overview

The impacts of climate change are already being felt across Canada. These changes are being magnified in Canada's Arctic, where average temperature has increased at a rate of nearly three times the global average. They pose significant risks to communities, health and well-being, the economy, and the natural environment, especially in Canada's northern and coastal regions and for Indigenous Peoples. Indigenous Peoples are among the most vulnerable to climate change due to their remote locations and reliance on wild foods. The changes already being experienced are both dramatic and permanent, with significant social, cultural, ecological, and economic implications.

Taking action to adapt to current and future climate impacts will help protect Canadians from climate change risks, build resilience, reduce costs, and ensure that society thrives in a changing climate.

INUIT AND CLIMATE IMPACTS:
Inuit and Inuit Nunangat, the homeland of Inuit in Canada, are experiencing significant climate change impacts, as highlighted in Inuit Tapiriit Kanatami's recent report on Inuit Priorities for Canada's Climate Strategy. More than 70 per cent of Canada's coastline is located in the Arctic and it is defined by ice. Average sea ice thickness is decreasing and sea ice cover is now dominated by younger, thinner ice. Some models are projecting that summer sea ice cover could be almost completely lost before 2050. These changes are already impacting access to wild foods and contributing to hazards and risks on ice.

Developing adaptation expertise and technology can further contribute to clean growth by creating jobs and spurring innovation. Adaptation is a long-term challenge, and it requires ongoing commitment to action, leadership across all governments, strong governance to assess and sustain progress, adequate funding, and meaningful engagement with, and continued leadership by, Indigenous Peoples. Federal investments (see Annex I) will support key adaptation measures.

Federal, provincial, and territorial governments have identified new actions to build resilience to climate change across Canada in the following areas:

1. Translating scientific information and Traditional Knowledge into action
2. Building climate resilience through infrastructure
3. Protecting and improving human health and well-being
4. Supporting particularly vulnerable regions
5. Reducing climate-related hazards and disaster risks

4.1 Translating scientific information and Traditional Knowledge into action

Canadians need authoritative science and information to understand current and expected changes. This includes changing conditions (e.g., rainfall, temperature, and sea ice) and the impacts of climate change across Canada. Long-term monitoring and local observations are also key. Data, tools, and information need to be widely accessible, equitable, and relevant to different types of decision-makers in different settings.

Translating knowledge into action takes leadership, skilled people, and resources. The Government of Canada's Adaptation Platform supports collaboration among governments, industry, and professional organizations on adaptation priorities. Building regional expertise and capacity for adaptation will improve risk management; support land-use planning; help safeguard investments; and strengthen emergency planning, response, and recovery. Decision-making by all governments will be guided by consideration of scientific and Traditional Knowledge.

INFORMATION AND TOOLS FOR ADAPTATION DECISIONS:
Decision-makers in five Quebec coastal municipalities collaborated with researchers, notably from the Université du Quebec à Rimouski and from Ouranos, a regional climate and adaptation consortium, to explore solutions to repeated damage of coastal infrastructure. Projections of future erosion, studies of sea ice and coastal vulnerability due to climate change, and cost-benefit analyses provided the foundation for the municipalities to make decisions on an adaptation solution.

The approach to information, knowledge, and capacity building will include (1) providing authoritative climate information and (2) building regional adaptation capacity and expertise.

Ensuring Canadians across all regions and sectors have the capacity to make informed decisions and to act on them provides the foundation for advancing adaptation in Canada. Indigenous-led community-based initiatives that combine science and Traditional Knowledge can help guide decision making. Including this information in regional and national impacts and adaptation assessments can further advance understanding of climate change across the country.

NEW ACTIONS

1. Providing authoritative climate information

The federal government will establish a Canadian centre for climate services, to improve access to authoritative, foundational climate science and information. This centre will work with provincial and territorial governments, Indigenous Peoples and other partners to support adaptation decision making across the country.

2. Building regional adaptation capacity and expertise

Governments will work with regional partners, including with Indigenous Peoples through community-based initiatives, to build regional capacity, develop adaptation expertise, respectfully incorporate Traditional Knowledge, and mobilize action. Canada's Adaptation Platform and regional consortia and centres support the sharing of expertise and information among governments, Indigenous Peoples and communities, businesses, and professional organizations and support action on joint priorities.

4.2 Building climate resilience through infrastructure

Climate change is already impacting infrastructure, particularly in vulnerable northern and coastal regions, as well as Indigenous Peoples. Climate-related infrastructure failures can threaten health and safety, interrupt essential services, disrupt economic activity, and incur high costs for recovery and replacement.

The approach to building climate resilience through infrastructure will include (1) investing in infrastructure that strengthens resilience and (2) developing climate-resilient codes and standards.

Traditional built infrastructure (e.g. roads, dykes, seawalls, bridges, and measures to address permafrost thaw) can address specific vulnerabilities. Additionally, living natural infrastructure (e.g. constructed/managed wetlands and urban forests) can build the resilience of communities and ecosystems and deliver additional benefits, such as carbon storage and health benefits.

Considering climate change in long-lived infrastructure investments, including retrofits and upgrades, and investing in traditional and natural adaptation solutions can build resilience, reduce disaster risks, and save costs over the long term.

ADAPTATION INFRASTRUCTURE:
The Red River Floodway was originally constructed in 1968 at a total cost of $63 million. It was recently expanded in 2014, at a cost of $627 million. Since 1968, the Floodway has prevented over $40 billion (in 2011 dollars) in flood-related damages for the City of Winnipeg.

NEW ACTIONS

1. Investing in infrastructure to build climate resilience

Federal, provincial, and territorial governments will partner to invest in infrastructure projects that strengthen climate resilience.

2. Developing climate-resilient codes and standards

Federal, provincial, and territorial governments will work collaboratively to integrate climate resilience into building design guides and codes. The development of revised national building codes for residential, institutional, commercial, and industrial facilities and guidance for the design and rehabilitation of climate-resilient public infrastructure by 2020 will be supported by federal investments.

4.3 Protecting and improving human health and well-being

Climate change is increasingly affecting the health and well-being of Canadians (e.g. extreme heat, air pollution, allergens, diseases carried by ticks and insects, and food security). Indigenous Peoples and northern and remote communities in particular are experiencing unique and growing risks to health and vitality.

The approach to protecting and improving human health and well-being will include (1) taking action to address climate change related health risks and (2) supporting healthy Indigenous communities.

Adaptation actions with an inclusive view of well-being (e.g. social and cultural determinants of health and mental health) will keep Canadians healthy and reduce pressures on the health system.

NEW ACTIONS

1. Addressing climate change-related health risks

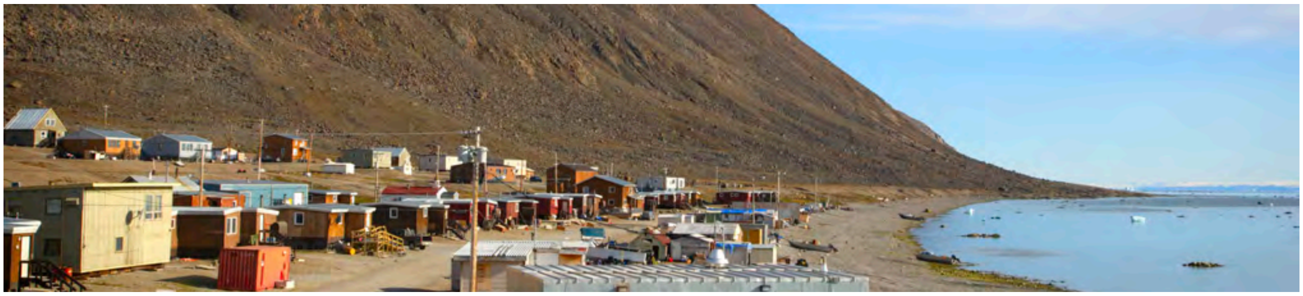
Governments will collaborate to prevent illness resulting from extreme heat events and to reduce the risks associated with climate-driven infectious diseases, such as Lyme disease. Federal adaptation investments will support actions including surveillance and monitoring, risk assessments, modelling, laboratory diagnostics, as well as health-professional education and public awareness activities. Efforts will also continue to advance the science and understanding of health risks and best practices to adapt.

2. Supporting healthy Indigenous communities

The federal government will increase support for First Nations and Inuit communities to undertake climate-change and health adaptation projects that protect public health.

The federal government will also work with the Métis Nation on addressing the health effects of climate change.

FOOD SECURITY AND SUSTAINABILITY – PLANNING FOR CLIMATE CHANGE IMPACTS IN ARVIAT, NUNAVUT:
With the goal of promoting and providing access to healthy foods, a community-based project in Arviat, **Nunavut** involved researchers and community youth to monitor and collect data on optimal growing conditions in the community greenhouse and to build capacity for its ongoing operation.



4.4 Supporting particularly vulnerable regions

The Indigenous Peoples of Canada, along with coastal and northern regions are particularly vulnerable and disproportionately affected by the impacts of climate change. Unlike rebuilding after an extreme event like a flood or a fire, once permafrost has thawed, coastlines have eroded, or socio-cultural sites and assets have disappeared, they are lost forever.

The approach to supporting vulnerable regions will include (1) investing in resilient infrastructure to protect vulnerable regions; (2) building climate resilience in the North; (3) supporting community-based monitoring in Indigenous communities; and (4) supporting adaptation in coastal areas.

Action taken to support adaptation in vulnerable regions can help communities, traditional ways of life, and economic sectors endure and thrive in a changing climate. The knowledge, expertise, technologies, and lessons from adaptation actions in vulnerable northern and coastal regions can benefit other vulnerable regions and sectors.

COLLABORATING TO ADDRESS CLIMATE IMPACTS IN THE NORTH:
Nunavut, the Northwest Territories, and Yukon hosted the Pan-Territorial Permafrost Workshop in 2013, which brought together front-line decision makers and permafrost researchers from each territory to share knowledge, form connections, and look at possibilities for adaptation in the future.

NEW ACTIONS

1. Investing in resilient infrastructure to protect vulnerable regions

Federal, provincial, and territorial governments will work together to ensure infrastructure investments help build resilience with Indigenous Peoples as well as in vulnerable coastal and northern regions.

2. Building climate resilience in the North

Federal, territorial, and northern governments and Indigenous Peoples will continue working together to develop and implement a Northern Adaptation Strategy to strengthen northern capacity for climate change adaptation. Federal investments to build resilience in the North and northern Indigenous Peoples will support this work.

3. Supporting community-based monitoring by Indigenous Peoples

The federal government will provide support for Indigenous communities to monitor climate change in their communities and to connect Traditional

Knowledge and science to build a better understanding of impacts and inform adaptation actions.

4. Supporting adaptation in coastal regions

Federal, provincial, and territorial governments will support adaptation efforts in vulnerable coastal and marine areas and Arctic ecosystems. Activities will include science, research, and monitoring to identify climate change impacts and vulnerabilities; the development of adaptation tools for coastal regions; and the improvement of ocean forecasting. This knowledge will help inform adaptation decisions related to fisheries and oceans management and coastal infrastructure. Federal adaptation investments will help advance this work.

SUPPORTING VULNERABLE COASTAL COMMUNITIES:
Through the Atlantic Climate Adaptation Solutions Project, **Newfoundland and Labrador, Nova Scotia, Prince Edward Island,** and **New Brunswick** partner together and with Indigenous communities, regional non-profits, and industry to develop practical tools and resources to help vulnerable coastal communities consider climate change in planning, engineering practices, and water and resource management. Examples include land-use planning tools, best practices, and risk assessments.

4.5 Reducing climate-related hazards and disaster risks

Climate change is impacting the intensity and frequency of events such as floods, wildfires, drought, extreme heat, high winds, and winter road failures. Recognizing this reality, Federal-Provincial-Territorial Ministers Responsible for Emergency Management are updating emergency management in Canada including work to mitigate disasters, review the Disaster Financial Assistance Arrangements, develop build-back better strategies, and collaborate on public alerting. Additionally, the Canadian Council of Forest Ministers is working on the establishment of the Canadian Wildland Fire Strategy, with climate change highlighted as a key challenge.

The approach to reducing climate-related hazards and disaster risks will include (1) investing in infrastructure to reduce disaster risks; (2) advancing efforts to protect against floods; and (3) supporting adaptation for Indigenous Peoples.

Disaster risk-reduction efforts and adaptation measures can reduce the negative impacts of these events, some of which have a disproportionate impact on Indigenous Peoples.

NEW ACTIONS

1. Investing in infrastructure to reduce disaster risks

Federal, provincial, and territorial governments will partner to invest in traditional and natural infrastructure that reduces disaster risks and protects Canadian communities from climate-related hazards such as flooding and wildfires.

2. Advancing efforts to protect against floods

Federal, provincial, and territorial governments will work together through the National Disaster Mitigation Program to develop and modernize flood maps and assess and address flood risks.

3. Supporting adaptation in Indigenous Communities

Governments will work in partnership with Indigenous communities to address climate change impacts, including repeated and severe climate impacts related to flooding, forest fires, and failures of winter roads. The federal government will provide support to Indigenous communities for adaptation.

FLOOD AND DROUGHT PROTECTIONS THROUGH WETLANDS RESTORATION:

Alberta's Watershed Resiliency and Restoration Program provided a grant to Ducks Unlimited to restore approximately 558 hectares of wetlands in the South Saskatchewan River basin for the purposes of water storage for flood and drought protection. Using historical imagery and LiDAR data to identify drained wetlands, project leads then work with and compensate landowners to restore wetlands on private land.

CLEAN TECHNOLOGY, INNOVATION, AND JOBS

Overview

Global demand for clean technologies is significant and increasing. Fostering and encouraging investment in clean technology solutions can facilitate economic growth, long-term job creation, and environmental responsibility and sustainability. Taking action on climate change will help to capture new and emerging economic opportunities, including for Indigenous Peoples and northern and remote communities. The window of opportunity exists for Canada to create the conditions for new clean technology investment and exports and seize growing global markets for clean technology goods, services, and processes.

To effectively compete in the global marketplace and capitalize on current and future economic opportunities, Canada needs a step change in clean technology development, commercialization, and adoption across all industrial sectors. Clarity of purpose, investment, and strong coordination that leverages pan-Canadian regional and provincial/territorial strengths are essential to seizing the economic growth and job-creation opportunities of clean technology. International research, development, and demonstration collaboration is also essential. Governments, Indigenous Peoples, industry, and other stakeholders all have a role to play and must be engaged.

5.1 Building early-stage innovation

To become a leader in the development and deployment of clean technologies, Canada needs a strong flow of innovative ideas.

Government investments in clean technology research, development, and demonstration will create the largest benefit where coordinated and focused in areas that will most effectively help Canada to meet its climate change goals, create economic opportunities, and expand global-market opportunities. Efforts to coordinate and focus investment must go beyond governments and involve the collaboration of industry, stakeholders, academia, and Indigenous Peoples in the innovation process. Canada must leverage its domestic strengths, which vary by region. Developing international partnerships will create new economic opportunities, build areas of shared expertise, and foster stronger bilateral relations.

Sustainable Development Technology Canada (SDTC) provides funding support to companies across Canada to develop, demonstrate, and deploy innovative new clean technologies. SDTC has also launched joint funding opportunities in collaboration with Emissions Reduction Alberta and Alberta Innovates and partners with the Ontario Centres of Excellence to enhance Ontario's Greenhouse Gas Innovation Initiative. SDTC estimates its projects have reduced annual emissions by 6.3 Mt of CO_2e, generated $1.4 billion in annual revenue and, in 2015, supported more than 9200 direct and indirect jobs.

Through its participation in Mission Innovation, the federal government has committed to double its investments in clean energy research and technology development over five years, while encouraging greater levels of private sector investment in transformative clean energy technologies. On November 14, 2016, Canada and 21 other Mission Innovation partners launched seven Innovation Challenges aimed at catalyzing global research efforts in areas that could provide significant benefits in reducing GHG emissions, increasing energy security, and creating new opportunities for clean economic growth.

NEW ACTIONS

1. Supporting early-stage technology development

Governments will support new approaches to early-stage technology development, including breakthrough technologies, to advance research in areas that have the potential to substantially reduce GHG emissions and other pollutants. Innovative partnerships with the private sector will make an important contribution to this effort.

2. Mission-oriented research and development

Governments will encourage new "mission-oriented" research approaches to focus RD&D facilities, programs, and supports on clean technology and environmental performance issues.

5.2 Accelerating commercialization and growth

Given Canada's small domestic market, Canadian firms must look to highly competitive international markets to achieve scale. Succeeding in the globally competitive clean technology marketplace requires globally competitive talent, access to the capital and resources needed to demonstrate the commercial viability of products, and strong international networks that facilitate the cross-border flow of clean technology goods and services.

Canadian clean technology producers and researchers are currently confronted by a myriad of programs and services, at the federal, provincial, and territorial level. Streamlining and integrating access to support programs and services is a priority for businesses and essential to building commercial capacity in this area.

Compared with other technology areas, clean technologies face unique challenges and often take longer to get to market, making access to "patient capital" important to successful commercialization. While federal and provincial governments already have a range of supports in place, key needs exist in terms of accessing venture capital as well as working capital and support for first, large-scale commercial projects or deployments.

20/20 Catalysts Program is a mentorship program that matches Indigenous and non-Indigenous project mentors with Indigenous mentees to promote knowledge sharing that will enable Indigenous communities to drive change towards clean technology business and economic development.

Further development of clean technologies could create new opportunities in Canada's resource sectors, increase the productivity and competitiveness of Canadian businesses, and create new employment opportunities, while also improving environmental performance. Canada will need to be able to access the skills and expertise of talented workers from around the world to enable Canadian businesses to succeed in the global marketplace. It will also be important to ensure a commitment to skills and training to provide Canadian workers with a just and fair transition to opportunities in Canada's clean growth economy.

Indigenous Peoples are leaders of change in the transition to a low-carbon economy. Indigenous governments, organizations, and businesses can play a key role in developing pathways for the adoption and adaptation of clean technology solutions for Indigenous Peoples.

Building stronger businesses and commercial capacity in all of Canada's regions is essential to taking advantage of new market opportunities. Support for new technology start-ups, through incubators and accelerators, is important to this effort. A strong, focused Canadian clean technology export strategy is needed to position Canada in growing and emerging global markets.

MaRS Cleantech works closely with entrepreneurs and investors to create solutions in energy, water, agri-tech, advanced materials and manufacturing, and smart cities. Industry looks to MaRS Cleantech to assist with company growth and to remove complex technology-adoption barriers. MaRS supports high-impact businesses by connecting innovators with potential partners, customers, investors, talent, and capital. MaRS strives to build globally competitive companies and to drive clean technology innovation.

NEW ACTIONS

1. Access to government programs

Federal, provincial, and territorial governments will work together to create a coordinated "no-wrong door" approach to supporting Canadian clean technology businesses, ensuring full and effective access to the suite of government programs and services available to support their commercial success.

2. Increasing support to advance and commercialize innovative technologies

Governments will collaborate to enable access to capital for clean technology businesses to bring their products and services to market, including at the commercial-scale demonstration and deployment stages. This will include support for clean technology businesses in the natural resource sectors to improve both competitiveness and environmental performance.

3. Strengthening support for skills development and business leadership

Governments will work together to strengthen skills development and business-leadership capacity in support of the transition to a low-carbon economy.

VENTURE CAPITAL:
BDC Capital is launching a new $135 million venture capital fund to support Canadian energy and clean technology start-up businesses with global potential. The Industrial, Clean and Energy Technology (ICE) Venture Fund II will invest in 15 to 20 new high-impact Canadian start-up firms that demonstrate efficiency and strong scalability and will support the transition to a low-carbon economy. Fund II is a follow-on to BDC Capital's highly successful ICE Venture Fund I, which was launched in 2011 with investments of $287 million now under management.

4. Expedite immigration of highly qualified personnel

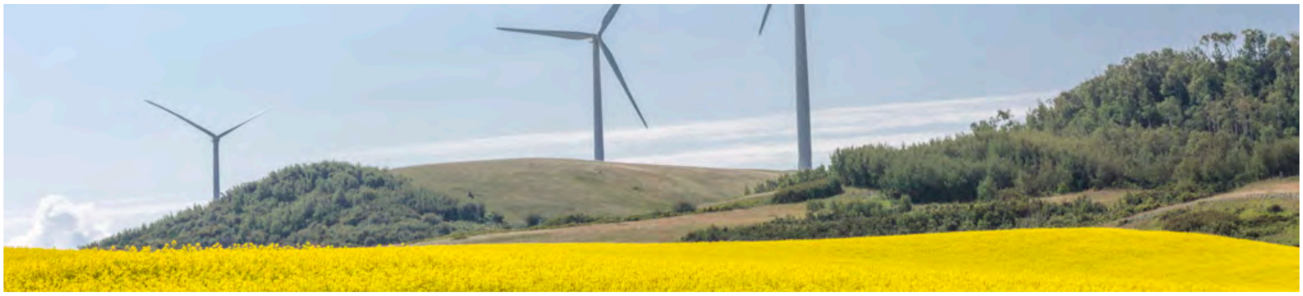
Governments will work together to enable expedited processing of visas and work permits for global talent, in particular for high-growth Canadian businesses such as those in the clean technology sector. This will attract top international talent and expand Canada's clean growth capacity.

5. Promoting exports of clean technology goods and services

Federal, provincial, and territorial governments will work collaboratively to strengthen clean technology export potential. This will include targeted export missions and the development of better market intelligence, addressing barriers to markets, support for export financing and marketing, and leveraging Canada's Trade Commissioner services.

6. Standards-setting

Governments will work together to exert a strong leadership role in international standards-setting processes for new clean technologies and to ensure that Canada's clean-technology capacity shapes future international standards.



5.3 Fostering adoption

The adoption of clean technology can create economic opportunities and improve environmental outcomes. Canada's performance on clean technology adoption by industry has significant room for improvement. Even amongst Canadian businesses that regularly adopt advanced technologies, clean technologies are the least likely to be adopted.

SmartICE (Sea-ice Monitoring And Real-Time Information for Coastal Environments) is a partnership with community, academic, government, and industry participation. It is developing an integrated system to provide near-real-time information about coastal sea-ice travel and shipping, improving safety and the ability to adapt to changing climate conditions. The pilot program is preparing to expand across the Arctic through a northern social enterprise.

Pricing carbon pollution will send a market signal that can drive innovation among Canadian businesses and, in return, will make them more competitive, including by opening up access to new markets and reducing costs of deploying clean technologies.

There is significant potential for Canadian governments to "lead by example" as early adopters of clean technology serving an essential role as a first or "reference customer" for Canadian clean technology goods, services, and processes. Having a "first sale" in Canada would boost businesses' chances of securing sales abroad. Beyond direct federal, provincial, and territorial government operations, other bodies, such as municipalities and publicly regulated utilities, could become significant markets for and adopters of clean technology.

Done effectively, the adoption of clean technology could be a mechanism for improving environmental circumstances and creating economic opportunity for Indigenous Peoples and northern and remote communities. Effective engagement and partnership with Indigenous Peoples is essential to this effort.

Encouraging dialogue between regulators and industry could improve certainty in clean technology development and allow for more effective and responsible regulation.

NEW ACTIONS

1. Leading by example

Federal, provincial, and territorial governments will develop action plans for greening government operations and encourage utilities and municipalities and other public sector entities to adopt clean technologies to lead by example.

2. Supporting Indigenous Peoples and northern and remote communities to adopt and adapt clean technologies

Federal, provincial, and territorial governments will support Indigenous Peoples and northern and remote communities in adopting and adapting clean technologies, and ensuring business models support community ownership and operation of clean technology solutions.

3. Consumer and industry adoption

Federal, provincial, and territorial governments will work together to promote and encourage effective working relationships between regulators and industry, providing for early dialogue and effective guidance, which can assist in bringing new clean technologies to market quickly and responsibly.

Governments will also support visible and effective certification programs to ensure consumer and business confidence and support green procurement.

5.4 Strengthening collaboration and metrics for success

An effective approach to clean technology development, commercialization, and adoption in Canada requires coherent, collaborative, and focused approaches. This is true within individual governments and between Canadian jurisdictions. A collaborative approach between governments should take into account regional strategies and jurisdictional responsibilities.

Regular and ongoing discussions between federal, provincial, and territorial governments regarding clean technology and clean growth would help eliminate duplication of efforts and identify gaps in support for clean technology development. Engaging Indigenous Peoples, industry, and stakeholders as a routine component of this process would be important.

There is inadequate data on Canada's clean technology capacity and potential. Building better data, and clear metrics for tracing the impact of government activities, would properly focus these activities and ensure that they achieve intended, meaningful results.

NEW ACTIONS

1. Enhance alignment between federal, provincial, and territorial actions

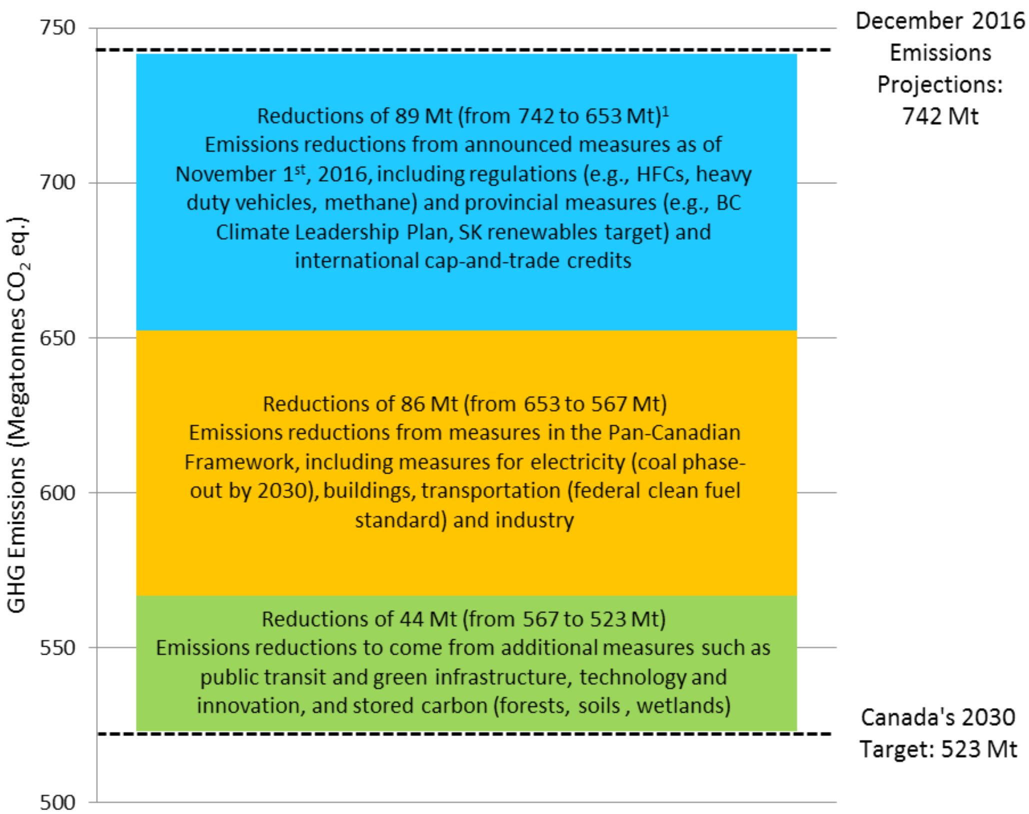
Governments will work together to improve policy and program coordination and sharing of data and best practices, which can sustain intergovernmental momentum and action on clean technology and clean growth. Continued partnership and engagement of Indigenous Peoples, industry, and stakeholders is essential to this effort.

Governments will work together to target and better align clean technology RD&D investments and activities in Canada, including opportunities for co-funding clean technology projects.

2. Establishing a clean technology data strategy

The federal government, working with the provinces and territories, will support the collection and regular publication of comprehensive data on clean technology in Canada to inform future government decision making, to improve knowledge in the private sector and stakeholder community, and to foster innovation.

PATHWAY TO MEETING CANADA'S 2030 TARGET



Note: Reductions from carbon pricing are built into the different elements depending on whether they are implemented, announced, or included in the Pan-Canadian Framework. The path forward on pricing will be determined by the review to be completed by early 2022.

[1] Estimates assume purchase of carbon credits from California by regulated entities under Quebec and Ontario's cap-and-trade system that are or will be linked through the Western Climate Initiative.

REPORTING AND OVERSIGHT

Overview

To help achieve the goals and actions laid out in this Pan-Canadian Framework, the programs and policies put in place will be monitored, results will be measured including impacts on GHG emissions, and actions and performance will be reported on publicly in a way that is transparent and accountable to Canadians. This public reporting will be complemented by ongoing public outreach, including with youth, inviting their contributions to Canada's action on clean growth and climate change. The effectiveness of actions will also be assessed with a view to ensuring continual improvement so as to increase ambition over time, in accordance with the Paris Agreement.

NEW ACTIONS

Measurement and reporting on emissions – Federal, provincial, and territorial governments will continue to collaborate on efforts to track and report GHG emissions in a consistent way across the country, to track progress on the Pan-Canadian Framework, and to support international reporting obligations. This will involve further technical work on measurement to improve emissions inventories and projections, and aligning these where possible. Federal, provincial, and territorial governments will work together through the Canadian Council of Ministers of the Environment (CCME) to examine options for the reporting of emissions and inventories to ensure consistency across provinces and territories, to support Canada's reporting to the UNFCCC, and for a pan-Canadian offset protocol framework and verified carbon credits that can be traded domestically and internationally.

Reporting on implementation – Federal, provincial, and territorial governments will work together to support the coordinated implementation of the Pan-Canadian Framework, engaging with relevant ministerial tables including ministers of environment, energy and mines, transportation, forestry, agriculture, innovation, infrastructure, emergency management, and finance, and with meaningful involvement of Indigenous Peoples. This will include a process to take regular stock of progress achieved, to report to Canadians and, to inform Canada's future national commitments in accordance with the Paris Agreement.

Analysis and advice – Federal, provincial, and territorial governments will engage with external experts to provide informed advice to First Ministers and decision makers; assess the effectiveness of measures, including through the use of modeling; and identify best practices. This will help ensure that actions identified in the Pan-Canadian Framework are open to external, independent review, and are transparent and informed by science and evidence.

Review - Federal, provincial, and territorial governments will work together to establish the approach to the review of carbon pricing, including expert assessment of stringency and effectiveness that compares carbon pricing systems across Canada, which will be completed by early 2022 to provide certainty on the path forward. An interim report will be completed in 2020 which will be reviewed and assessed by First Ministers. As an early deliverable, the review will assess approaches and best practices to address the competitiveness of emissions-intensive trade-exposed sectors.

Federal, provincial, and territorial governments will continue to engage and partner with Indigenous Peoples as actions are implemented and progress is tracked.

LOOKING AHEAD

This Plan provides a foundation for working together to grow the economy, reduce emissions, and strengthen resilience. Ongoing, collaborative action is needed to generate transformational change and to ensure that all Canadians benefit from the transition to a low-carbon economy. First Ministers are tasking their officials to develop an agenda for federal, provincial, and territorial Ministers to implement this Plan. Annual reports to First Ministers will enable governments to take stock of progress and give direction to sustain and enhance efforts.

ANNEX I: FEDERAL INVESTMENTS AND MEASURES TO SUPPORT THE TRANSITION TO A LOW-CARBON ECONOMY

FEDERAL INVESTMENTS

The federal government will help catalyze the transition to a clean growth economy through significant new investments to complement provincial and territorial actions and investments, including investments in infrastructure, the Low-Carbon Economy Fund, and clean technology funding.

- Budget 2016 outlined a number of new federal investments that will support a transition to a low-carbon economy. Some of these investments include
  - » $62.5 million to support the deployment of infrastructure for alternative transportation fuels, including charging infrastructure for electric vehicles and natural gas and hydrogen refueling stations as well as demonstration of next generation recharging technologies;
  - » $50 million over two years to invest in technologies that will reduce GHG emissions from the oil and gas sector;
  - » $82.5 million over two years to support research, development, and demonstration of clean energy technologies with the greatest potential to reduce GHG emissions;
  - » $100 million per year from the Regional Development Agencies to support clean technology, representing a doubling of thei existing annual aggregate support;
  - » $50 million over four years to Sustainable Development Technology Canada (SDTC) for the SD Tech Fund. These resources will enable SDTC to announce new clean technology projects in 2016 that support the development and demonstration of new technologies that address climate change, air quality, clean water, and clean soil;

THE FEDERAL GOVERNMENT HAS COLLABORATED WITH THE FEDERATION OF CANADIAN MUNICIPALITIES ON THE GREEN MUNICIPAL FUND (GMF) SINCE 2000.

- Budget 2016 provided an additional $125 million over two years including for projects that reduce GHG emissions.
- Recently announced projects under the GMF include a $31.5 million investment for 20 new sustainable municipal projects, such as Canada's first net-zero municipal library and Halifax's ground-breaking Solar City project.

» $40 million over five years to integrate climate resilience into building design guides and codes. The funding will support revised national building codes by 2020 for residential, institutional, commercial, and industrial facilities;
» $129.5 million to implement programming focused on building the science base to inform decision making, protecting the health and well-being of Canadians, building resilience in the North and Indigenous communities, and enhancing competitiveness in key economic sectors; and
» $10.7 million over two years to implement renewable energy projects in off-grid Indigenous and northern communities that rely on diesel and other fossil fuels to generate heat and power.

- Building on the infrastructure investments outlined in Budget 2016, the federal government has announced an additional $81 billion over 11 years for investments in public transit, social infrastructure, transportation that supports trade, Canada's rural and northern communities, smart cities, and green infrastructure.
- Green infrastructure funding will support projects that reduce GHG emissions, enable greater climate change adaptation and resilience, and ensure that more communities can provide clean air and safe drinking water for their citizens. Specific projects could include interprovincial transmission lines that reduce reliance on coal, the development of new low-carbon/renewable power projects, and the expansion of smart grids to make more efficient use of existing power supplies.
- The federal government is proposing the creation of the Canada Infrastructure Bank that will work with provinces, territories, and municipalities to further the reach of government funding directed to infrastructure. The Canada Infrastructure Bank will be responsible for investing at least $35 billion on a cash basis from the federal government into large infrastructure projects that contribute to economic growth through direct investments, loans, loan guarantees, and equity investments.
- Funding under the $2 billion Low Carbon Economy Fund will begin in 2017. This Fund will support new provincial and territorial actions to reduce emissions between now and 2030. Projects will focus on concrete measures that generate new, incremental reductions, while considering cost-effectiveness.
- The Government has also committed more than $1 billion, over four years, to support clean technology including in the forestry, fisheries, mining, energy and agriculture sectors.

FEDERAL CARBON PRICING BENCHMARK

The federal government outlined a benchmark for carbon pricing that reflects the principles proposed by the Working Group on Carbon Pricing Mechanisms and the Vancouver Declaration. Its goal is to ensure that carbon pricing applies to a broad set of emission sources throughout Canada with increasing stringency over time to reduce GHG emissions at lowest cost to business and consumers and to support innovation and clean growth.

The benchmark includes the following elements:

1. Timely introduction.

All jurisdictions will have carbon pricing by 2018.

2. Common scope.

Pricing will be based on GHG emissions and applied to a common and broad set of sources to ensure effectiveness and minimize interprovincial competitiveness impacts. At a minimum, carbon pricing should apply to substantively the same sources as British Columbia's carbon tax.

3. Two systems.

Jurisdictions can implement (i) an explicit price-based system (a carbon tax like British Columbia's or a carbon levy and performance-based emissions system like in Alberta) or (ii) a cap-and-trade system (e.g. Ontario and Quebec).

4. Legislated increases in stringency, based on modelling, to contribute to our national target and provide market certainty.

For jurisdictions with an explicit price-based system, the carbon price should start at a minimum of $10 per tonne in 2018 and rise by $10 per year to $50 per tonne in 2022.

Provinces with cap-and-trade need (i) a 2030 emissions-reduction target equal to or greater than Canada's 30 percent reduction target and (ii) declining (more stringent) annual caps to at least 2022 that correspond, at a minimum, to the projected emissions reductions resulting from the carbon price that year in price-based systems.

5. Revenues remain in the jurisdiction of origin.

Each jurisdiction can use carbon-pricing revenues according to their needs, including to address impacts on vulnerable populations and sectors and to support climate change and clean growth goals.

6. Federal backstop.

The federal government will introduce an explicit price-based carbon pricing system that will apply in jurisdictions that do not meet the benchmark. The federal system will be consistent with the principles and will return revenues to the jurisdiction of origin.

7. Five-year review.

The overall approach will be reviewed by early 2022 to confirm the path forward, including continued increases in stringency. The review will account for progress and for the actions of other countries in response to carbon pricing, as well as recognition of permits or credits imported from other countries.

8. Reporting.

Jurisdictions should provide regular, transparent, and verifiable reports on the outcomes and impacts of carbon pricing policies.

The federal government will work with the territories to address their unique circumstances, including high costs of living, challenges with food security, and emerging economies.

OTHER RECENT FEDERAL MEASURES

The federal government has also recently announced new federal measures, including

- During the North American Leaders Summit in June 2016, the federal government made joint commitments with the United States and Mexico to
  - » phase out fossil fuel subsidies by 2025. The commitment was reaffirmed by G-20 countries in September 2016.
  - » reduce methane emissions from the oil and gas sector by 40 to 45 percent below 2012 levels by 2025.
- On October 15, 2016, Canada signed onto the Kigali Amendment to the Montreal Protocol and committed to propose new regulations to significantly reduce HFC consumption and prohibit the manufacture and import into Canada of certain products containing HFCs. These proposed regulations were published on November 26, 2016. This is additional to measures already introduced to increase the recovery, recycling, and destruction of HFCs in refrigeration and air conditioning equipment and to established regulatory provisions for an HFC reporting system.
- On November 17, 2016, Canada released its Mid-Century Long-Term Low-Greenhouse Gas Development Strategy. The mid-century strategy describes various pathways for innovative and creative solutions. Canada's mid-century strategy is not a blueprint for action nor is it policy prescriptive. It is based on modelling of different scenarios and looks beyond 2030 to start a conversation on the ways we can reduce emissions for a cleaner, more sustainable future by 2050. As a result, it will be a living document.
- On November 21, 2016, the federal government announced that it would be amending its existing coal-fired electricity regulations to accelerate the phase out of traditional coal-fired electricity by 2030. The federal government also announced that, to support the transition away from coal towards cleaner sources of generation, performance standards for natural gas-fired electricity are also being developed.
- On November 25, 2016, the federal government announced that it will consult with provinces and territories, Indigenous Peoples, industries, and non-governmental organizations to develop a clean fuel standard. It is expected that once developed, a clean fuel standard would promote the use of clean technology and lower carbon fuels, and promote alternatives such as electricity, biogas, and hydrogen.

ANNEX II: PROVINCIAL AND TERRITORIAL KEY ACTIONS AND COLLABORATION OPPORTUNITIES WITH THE GOVERNMENT OF CANADA

INTRODUCTION

The Paris Agreement and the Vancouver Declaration have set an ambitious course for low carbon growth and climate action in Canada. The Pan-Canadian Framework on Clean Growth and Climate Change will build on the leadership shown and actions taken by the provinces and territories as well as new policies announced by the federal government.

This annex outlines provincial and territorial accomplishments in reducing greenhouse gas emissions and accelerating clean growth, and presents steps that each jurisdiction has taken or is taking to implement carbon pricing.

The annex also outlines areas where the federal government and each provincial and territorial government will work together to implement the Pan-Canadian Framework in order to spur growth and jobs for Canadians, reduce our emissions and adapt to climate change.

Each province and territory is unique and is responding to the urgency of climate change and the opportunity offered by clean growth in its own way. Effective action will require close collaboration between governments. Each provincial and territorial government has identified multiple areas for potential partnerships with the federal government, adapted to their own priorities, circumstances and strengths. Governments are committed to working together on these priorities to support the implementation of the Pan-Canadian Framework. Governments will also engage the contributions of Indigenous Peoples in advancing shared goals.

This work will be supported by significant new federal investments to drive the transition to a clean growth economy, as outlined in Budget 2016 and the 2016 Fall Economic Statement, including public transit and Green Infrastructure, the Canada Infrastructure Bank, the Low-Carbon Economy Fund, and funding for clean technology and innovation. Federal investments are intended to supplement and accelerate investments by provinces and territories, and will follow applicable program criteria.

BRITISH COLUMBIA

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in British Columbia include:

British Columbia's Climate Leadership Plan

B.C. has proven that it is possible to reduce emissions while growing the economy and creating jobs and it's important that this balance be maintained. With this in mind, B.C. released its Climate Leadership Plan in the summer of 2016.

Building on the comprehensive foundation established in 2008, the plan lays out a series of targeted, sector-specific actions that will reduce emissions by 25 million tonnes (Mt) of carbon dioxide equivalent (CO_2e) and create 66,000 jobs. The plan will be further strengthened in the months and years ahead, as B.C. continues to work with First Nations, the federal government, communities, industry and others. B.C. is committed to reducing GHG emissions by 80% below 2007 levels by 2050. To read B.C.'s Climate Leadership Plan, visit: http://climate.gov.bc.ca/

Revenue-Neutral Carbon Tax

B.C. has the highest broad-based carbon tax in North America. The carbon tax sets a transparent and predictable price on carbon while returning all revenue to B.C. individuals and businesses. The price signal creates a real incentive to reduce emissions across the economy and is the backbone of B.C.'s approach to climate action.

Forestry

B.C.'s forests offer potential for storing carbon, so the Province is taking further action to rehabilitate up to 300,000 hectares of Mountain Pine Beetle and wildfire impacted forests over the first five years of the program; recover more wood fibre; and avoid emissions from burning slash.

Clean LNG

B.C. has an abundance of natural gas, which is a lower carbon fuel that will play a critical role in transitioning the world economy off of high carbon fuels such as coal. B.C. is developing the resource responsibly, and provincial legislation will make the emerging LNG sector the cleanest in the world. B.C. is also electrifying upstream development of natural gas and will require a 45% reduction in methane emissions by 2025.

100% Clean Electricity

Thanks to significant historical investments, B.C.'s electricity is already 98% clean or renewable and British Columbians have the third-lowest residential rates in North America. Going forward under the Climate Leadership Plan, 100% of the supply of electricity acquired by BC Hydro for the integrated grid must be from clean or renewable sources. The $8.3 billion Site C Clean Energy Project is a major part of B.C.'s clean energy future and will create enough electricity to power 450,000 homes.

Clean Transportation

B.C. is taking real action to reduce emissions from the transportation sector and help British Columbians make greener choices—initiatives include Zero Emissions Vehicles rebates and funding for more charging stations (which have helped BC become the Canadian leader in clean energy vehicle sales per capita); a scrap-it program; low carbon and renewable fuel standards; and historic investments in transit. B.C.'s actions in the transportation sector have already reduced annual emissions by an estimated 2.5 Mt and combined with the new actions, will reduce annual emissions by up to a further 3.4 Mt by 2050.

Adaptation

In 2010, the Province created a comprehensive strategy to address the changes we will see as a result of climate change. It is based on three key strategies: build a strong foundation of knowledge and tools; make adaptation a part of government business; and assess risks and implement priority adaptation actions in key climate sensitive sectors. The Province is now working with the federal government and other Canadian jurisdictions to further improve the management of the risks associated with a changing climate.

These actions provide a strong contribution to a comprehensive pan-Canadian framework.

ACTION ON PRICING CARBON POLLUTION

B.C.'s revenue-neutral carbon tax has been in place since 2008. It is set at $30/tonne and covers approximately 75% of the province's economy. All revenues generated will be returned to tax payers. B.C. will assess the interim study in 2020 and determine a path forward to meet climate change objectives.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

British Columbia and the Government of Canada intend to collaborate in the following domains of priority to address climate change and advance clean growth:

Growing our forests; reducing our emissions

Forests present a unique opportunity to address climate change because trees absorb CO_2 when they grow. British Columbia, the Government of Canada and First Nations will work together to reduce GHG emissions through forestry activities, including reforestation, enhanced silviculture techniques, and the salvaging of unmerchantable trees for processing into dimensional lumber and bioenergy. The initiative is expected to reduce emissions by 12 Mt in 2050 and create 20,000 jobs.

Preparing for and adapting to climate change

British Columbia and the Government of Canada will support projects across the province to make infrastructure more resilient to a changing climate, and to help communities adapt to a changing climate. Flood mitigation will be an area of focus.

Reduce Emissions from Natural Gas Activities

British Columbia and the Government of Canada will work together to bring clean grid electricity to natural gas operations in northeast B.C. They will co-fund the construction of new transmission lines and other public electrification infrastructure that could serve up to 760 megawatts of upstream natural gas processing load and avoid up to 4 Mt of emissions per year.

Electricity Grid Interconnection

British Columbia and the Governments of Canada and Alberta will work together to restore the capability of the existing high-voltage electricity grid interconnection with Alberta. This project will improve access to clean electricity in Alberta and will result in lower GHG emissions and air pollution, and improved grid reliability in both provinces.

Clean Technology Innovation

British Columbia and the Government of Canada will work together to spur the development and commercialization of new technologies that will reduce emissions and create jobs for Canadians.

ALBERTA

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in Alberta include:

Climate Leadership Plan

The Climate Leadership Plan is a made-in-Alberta climate change strategy, specifically designed for Alberta's unique economy. While details of the final strategy are still being developed, the Alberta government has moved forward on a number of key areas.

Clean Electricity

Alberta will phase-out GHGs from coal-fired power plants and achieve 30% renewable energy by 2030.

Alberta will add 5,000 megawatts of renewable energy capacity by 2030 through the Renewable Electricity Program. To meet this target, investment in Alberta's electricity system will be solicited through a competitive and transparent bidding process, while ensuring projects come online in a way that does not impact grid reliability and is delivered at the lowest possible cost to consumers.

A new provincial agency, Energy Efficiency Alberta, has been created to promote and support energy efficiency and community energy systems for homes, businesses and communities.

Capping Oil Sands Emissions

A legislated maximum emissions limit of 100 Mt in any year, with provisions for cogeneration and new upgrading capacity, will help drive technological progress.

Reducing Methane Emissions

Alberta will reduce methane gas emissions from oil and gas operations by 45% by 2025.

Innovation and Technology

Alberta is investing in innovation and technology to reduce GHGs, encourage a more diversified economy and energy industry, and create new jobs, while improving opportunities to get the province's energy products to new markets. Alberta has created a task force that will make recommendations on a Climate Change Innovation and Technology Framework.

These actions provide a strong contribution to a comprehensive pan-Canadian framework.

ACTION ON PRICING CARBON POLLUTION

A carbon levy to be included in the price of all fuels that emit greenhouse gases when combusted, including transportation and heating fuels such as diesel, gasoline, natural gas and propane. The levy will be applied at a rate of $20/tonne on January 1, 2017 and will increase to $30/tonne one year later.

The Climate Leadership Plan is designed for Alberta's economy. The economic impact of carbon pricing is expected to be small, and every dollar will be reinvested back into the local economy. Reinvesting carbon revenue in our economy will diversify our energy industry by investing in large scale renewable energy, bioenergy initiatives, and transformative innovation and technology. Over the next 5 years:

$6.2 billion will help diversify our energy industry and create new jobs:

- $3.4 billion for large scale renewable energy, bioenergy and technology

- $2.2 billion for green infrastructure like transit
- $645 million for Energy Efficiency Alberta

$3.4 billion will help households, businesses and communities adjust to the carbon levy:

- $2.3 billion for carbon rebates to help low- and middle-income families
- $865 million to pay for a cut in the small business tax rate from 3% to 2%
- $195 million to assist coal communities, Indigenous communities and others with adjustment

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

Alberta and the Government of Canada intend to collaborate in the following domains of priority to address climate change and advance clean growth:

Clean Electricity

Alberta and the federal government will to work together to advance renewable energy, coal to natural gas conversion, and potential hydroelectric projects, including pump storage projects. Alberta is committed to developing incentives for renewable generation in a manner that is compatible with Alberta's unique electricity market.

B.C. – Alberta Intertie

Alberta is working with British Columbia and the federal government to explore new and enhanced interties. The Alberta Electric System Operator is currently working with BC Hydro and industry on a key project, the restoration of the B.C.-Alberta 950 MW intertie to its full path rating (expected completion is in 2020). This restoration would allow imports of 1200 MW on the BC-AB intertie.

Innovation and Technology

Alberta is focused on the opportunity to leverage environmental policies and programs into new manufacturing, innovation, and clean technology businesses. Current opportunities include superclusters, advanced sensor technology for environmental applications including methane monitoring and reductions, and municipal waste diversion. Innovative solutions will result in meaningful GHG reductions across Canada and the export of solutions to promote a lower carbon world.

Disaster Mitigation / Infrastructure

Alberta is undertaking targeted work to address the hazards to which Albertans are vulnerable, including flood, wildfire, heat, drought, landslides, and wind.

While hazards and disaster risks have always been a concern, climate change is driving the need to adapt to more intense and frequent events. Federal support for wildfire mitigation infrastructure will reduce the risk of wildland fires. In addition, flood risk requires immediate mitigation infrastructure such as dykes and dams. Federal partnership on these initiatives will support risk management.

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ONTARIO

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in Ontario include:

Permanent Closure of Coal-fired Electricity Generating Stations

On April 15, 2014, Ontario became the first jurisdiction in North America to fully eliminate coal as a source of electricity generation. This action is the single largest GHG reduction initiative in North America. On November 23, 2015, Ontario passed the *Ending Coal for Cleaner Air Act*, permanently banning coal-fired electricity generation in the province.

Ontario's Climate Change Strategy and Action Plan

On November 24, 2015, Ontario released its Climate Change Strategy setting the framework for the province to meet its long-term 2050 GHG emissions reduction target. The Strategy highlights five key objectives for transformation:

1. A prosperous low-carbon economy with world-leading innovation, science and technology
2. Government collaboration and leadership
3. A resource-efficient, high-productivity society
4. Reducing GHG emissions across sectors
5. Adapting and thriving in a changing climate

On June 8, 2016, Ontario released its Climate Change Action Plan to implement the strategy over the next five years and put Ontario on the path to achieve its longer term objectives. Policies and programs identified in the Action Plan include:

- Transforming how ultra-low and carbon-free energy technologies are deployed in our homes and workplaces, and how we move people and goods
- Halting rising building-related emissions, with a focus on helping homeowners and small businesses move to low- and zero-carbon energy
- Making available funding for industries and manufacturers proposing to transform their operations and move off carbon-based fuels and peak electricity
- Aligning Ontario's R&D and innovation funding to place a greater emphasis on climate change science and technologies, with a view to making the discoveries that could lead to breakthroughs in zero-carbon technology

Ontario has made measurable progress in reducing GHGs. According to Environment and Climate Change Canada's 2016 National Inventory Report, from 2005 to 2014, Ontario's emissions decreased by 41 Mt (-19%), over the same period, Canada-wide emissions fell by 15 Mt (-2%).

These actions provide a strong contribution to a comprehensive pan-Canadian framework.

ACTION ON PRICING CARBON POLLUTION

On May 18, 2016, Ontario passed its landmark *Climate Change Mitigation and Low-carbon Economy Act,* which creates a long term framework for climate action. The Act creates a robust framework for cap and trade program, ensures transparency and accountability on how any proceeds collected under the program are used and enshrines emission reduction targets in legislation.

Ontario's approach, including its cap and trade program and associated emissions reduction targets, will exceed the standards of the federal carbon pricing benchmark. Ontario's targets are:

- 15% below 1990 levels by 2020;
- 37% below 1990 levels by 2030; and
- 80% below 1990 levels by 2050.

Ontario is a founding member of the Western Climate Initiative (WCI), a not-for-profit organization established in 2008 to help member states and provinces execute their cap and trade programs. In 2017, Ontario will link its cap and trade system with those of WCI members Quebec and California to create the largest cap and trade system in North America.

Ontario will set a cap on total emissions from the covered sectors in 2017 based on the forecast emissions for large final emitters, electricity generation and transportation and heating fuels. Allowances will then be created in an amount equal to the cap and either sold or provided free-of-charge to Ontario emitters.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

Ontario and the Government of Canada intend to collaborate in the following domains of priority to address climate change and advance clean growth:

Invest in Zero Emission Transportation and Infrastructure

Ontario is committed to increase uptake of zero emission passenger and commercial vehicles, both by providing purchasing incentives and by expanding the EV charging network across Ontario. In its 2016 budget, the federal government committed to support the deployment of alternative transportation fuel infrastructure, including electric charging stations. Ontario and the Government of Canada will work together to support the deployment of EV vehicles through enabling infrastructure.

Invest in Other Zero Emission Transportation

Ontario seeks a partnership with the Government of Canada to support enabling infrastructure that will increase the availability and use of lower carbon fuels, including LNG, increase the use of low carbon trucks and buses and increase the availability of LNG fueling infrastructure. Ontario is dedicating significant resources for these additional transportation initiatives. Expected emissions reductions in the transportation sector overall are 2.45 Mt in 2020.

Assist with Building Retrofits, Energy Audits and Technology Deployment

Ontario seeks a partnership with the Government of Canada as the province develops programs for fuel switching and energy efficiency, such as retrofits for existing residential buildings (including targeted initiatives for low-income households), and clean technologies for industries and small and medium enterprises. Partnership would increase investment in this area, allowing acceleration and scaling up of progress.

Ontario Climate Modelling Services Consortium

Ontario seeks a partnership with the Government of Canada to build regional capacity and support adaptation actions. Ontario plans to establish an Ontario Climate Modelling Services Consortium, which would act as a one window source of data to help the public and private sectors make evidence-based decisions.

The Consortium would operate at arm's length from government. Ontario would seek partnerships with other governments, non-governmental organizations and the private sector to ensure the organization's effectiveness and long term success. The Consortium would also be expected to develop service fee revenue streams to contribute to the organization's fiscal sustainability.

Electricity Transmission

Ontario, in collaboration with the Government of Canada, will work with its regional partners to advance opportunities to expand and upgrade electricity transmission infrastructure to support clean hydroelectric power to displace the production of electricity from fossil fuels.

Ontario will also collaborate with the Government of Canada to accelerate access to clean electricity in remote Indigenous communities. This will lessen dependence on expensive diesel fuel and reduce greenhouse gas emissions and air pollution.

QUÉBEC

KEY ACTIONS TO DATE

Some of the key measures taken to date by Québec, which has the lowest greenhouse gas emissions per capita between the provinces in Canada, include:

2013-2020 Action Plan on Climate Change (PACC 2013-2020)

PACC 2013-2020 will reduce GHG emissions by 20% below the 1990 level by 2020. Among its other measures, the action plan offers financial help to the different stakeholders of Québec society so they can reduce their energy consumption, improve their practices, innovate and adjust. The work surrounding the development of the actions of Québec after the 2020 period is underway, in particular to reduce GHG emissions of the province by 37.5 % below the 1990 level by 2030.

2016-2030 Energy Policy

The Energy Policy will favour a transition to a low carbon footprint economy, chiefly by improving energy efficiency by 15%, by reducing petroleum consumption by 40%, and by increasing the production of renewable energies by 25%. Québec is one of the world's main producers of renewable energy, which represents 99.8% of its total electricity production.

2013-2020 Governmental Climate Change Adjustment Strategy

The Strategy will mitigate the impact of climate change on the environment, the economy and the communities, and will strengthen the resiliency of Québec society. The government of Québec has, notably, invested in the Ouranos consortium in order to get a better understanding of the impact of climate change on its territory, and to better inform the decision-making process and the development of solutions.

2015-2020 Transport Electrification Plan

Québec targets 100,000 electric vehicles on the road in 2020 and one million in 2030. The zero-emission vehicle (ZEV) standard adopted in October 2016 will encourage automotive manufacturers to improve their offer of ZEV, and the investments in electrification will allow Québec to build up its available renewable energies, its expertise and its world-class know-how.

These measures represent a major contribution at the Pan-Canadian level.

ACTION ON PRICING CARBON POLLUTION

Pioneer in the use of cap-and-trade systems for greenhouse gas emissions allowances, Québec`s system has been linked to California's since 2014, and will soon be linked to that of Ontario. It represents the largest carbon market in North America, and is often referred to as an example of performance and rigour. Because it is based on hard caps to reduce GHG emissions, it is a robust and efficient tool to achieve the ambitious mitigation goals Québec has set for itself for 2020 and 2030.

Furthermore, auction revenues from its cap-and-trade system are entirely reinvested in measures that will spur the transition of Québec's economy to a more resilient and low-carbon one. This comprehensive approach, tailored to the needs and specificities of Québec, allows Québec to fulfill its leadership role in the fight against climate change in North America and internationally.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

The governments of Québec and Canada intend to collaborate in the following priority areas in order to fight climate change and allow clean economic growth:

Electric and Public Transport

Support the development of the offer and infrastructure of electric and public transport, by completing various projects such as the Metropolitan Electric Network (MEN), the implementation of bus rapid transit (BRT) systems between Montreal and Laval, the extension of the BRT in Gatineau, and the implementation of a BRT in Québec.

Energy Efficiency and Conversion

Speed up the reduction of GHG emissions in Northern communities, as well as on the Lower North Shore and Magdalen Islands, by replacing diesel with renewable energy sources for the electricity supply of their free-standing network.

Promote the implementation of energy performance and efficiency standards for new buildings, as well as for the renovation of existing buildings. Invest in the industrial sector to improve the energy performance of fixed production processes, by providing innovative technologies and reducing the use of gases with high warming potential such as hydrofluorocarbons, which Québec will continue to prioritize.

Recognition of the International Trade of Emission Rights

Contribute to the implementation of Articles 6 and 13 of the Paris Accord, to which the accounting and disclosure principles of the Western Climate Initiative (WCI) can contribute, as well as within a possible agreement between Canada and the United States regarding the accounting and attribution of "internationally transferred mitigation outcomes" as part of the contributions determined at national level (CDN).

Québec will also share with the government of Canada a detailed methodology, developed in collaboration with California and soon Ontario, in order to tabulate in its international reports the emission reductions achieved by Québec thanks to the carbon market.

Innovation and Adjustment to Climate Change

Promote innovation in green technology and GHG emission reduction, and collaborate on increasing the resiliency of the communities affected by climate change, by assessing the vulnerabilities and risks, adjusting land planning and use, and designing sustainable projects.

Québec will provide its expertise to the initiatives of the government of Canada, focusing in particular on joint financing of prevention and protection infrastructure against certain natural disasters linked to climate change.

NEW BRUNSWICK

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in New Brunswick include:

Transitioning to a Low-Carbon Economy: New Brunswick's Climate Change Action Plan

The Climate Change Action Plan outlines a bold vision for New Brunswick and sets renewed GHG reduction targets: 2030 target of 35% below 1990 levels; and 80% below 2001 levels by 2050. The plan also address other commitments, such as the Canadian Energy Strategy, released by the Council of the Federation in 2015, and contains a Climate Change Adaptation Strategy supported by actions to build resilience into New Brunswick communities, businesses, infrastructures and natural resources.

The Action Plan provides a clear path forward to reduce GHG emissions while promoting economic growth and enhancing current efforts to adapt to the effects of climate change.

Locally-owned Renewable Energy Projects that are Small Scale (LORESS)

In May 2015, the province introduced legislation to allow local entities to develop renewable energy sourced electricity generation in their communities. This will enable universities, non-profit organizations, co-operatives, First Nations and municipalities to contribute to NB Power's renewable energy requirements.

Shifting to renewables in electricity generation

Two fossil fuelled power plants were closed in recent years – one coal and one heavy oil. Also, 300 megawatts of wind energy was installed in the province and biomass fuel use in industry was expanded to displace oil. Solid waste landfills are capturing biogas and some are generating electricity.

These actions are allowing NB Power to achieve the regulated Renewable Portfolio Standard of 40% of in-province sales from renewable energy sources by 2020. This translates to approximately 75% non-emitting by 2020 including nuclear.

Adaptation

The province has developed a progressive Climate Change Adaptation Program including assembling future climate projections, and supporting climate impact vulnerability assessments in communities and for infrastructure. Adaptation projects also focus on solutions building and advanced planning to help reduce or avoid the costs of impacts such as more severe and frequent flooding, coastal erosion and storm events and disease and pest migration.

Several projects are carried out in collaboration with other Atlantic provinces, notably under the Regional Adaptation Collaborative (RAC), which involves federal support, as well as with the Gulf of Maine Council and US partners.

These actions provide a strong contribution to a comprehensive Pan-Canadian Framework.

ACTION ON PRICING CARBON POLLUTION

The province will implement a made-in-New Brunswick carbon pricing mechanism that addresses the requirements of the federal government for implementing a price on carbon emissions by 2018 and that at the same time recognizes New Brunswick's unique economic and social circumstances. The provincial government will take into consideration the impacts on low-income families, trade-exposed and energy-intensive industries, and consumers and businesses, when developing the specific mechanisms and implementation details, including how to reinvest proceeds.

Any carbon pricing policy will strive to maintain competitiveness and minimize carbon leakage (i.e., investments moving to other jurisdictions). Proceeds from carbon emissions pricing will be directed to a dedicated climate change fund.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

The Government of New Brunswick and the Government of Canada intend to collaborate in the following domains of priority to address climate change and advance clean growth:

Enhanced Electricity Generation and Transmission System

New Brunswick will work with the other Atlantic provinces and the Government of Canada to advance opportunities for clean electricity generation, transmission, storage and demand management linkages across the region. This will: improve access to non-emitting electricity; support the phase-out of coal-fired electricity generation; improve grid reliability and energy security; and, consistent with fair market principles, help provinces access export markets for clean, non-emitting electricity.

This will contribute to both the Atlantic Growth Strategy and Canadian Energy Strategy and will build on existing regional coordination efforts, leading to an integrated regional electricity strategy.

Energy Efficiency

The Government of New Brunswick, in partnership with the Government of Canada, will seek to enhance energy efficiency programs by targeting GHG emission reduction opportunities across sectors and fuels.

Examples of possible targeted interventions include programs that help: trucking fleets add aerodynamic and other efficiency measures to existing equipment; small- to medium-size industry improve their compressed air systems, boilers and lighting; commercial and institutional facilities invest in heating, lighting and other retrofits; and families retrofitting their homes to reduce energy costs, with special treatment for low- and fixed-income families.

Industrial Emissions Reductions

The Government of New Brunswick and the Government of Canada will work to support industrial emission reduction initiatives through technology and energy efficiency improvements while maintaining productivity. For example, there are significant opportunities to reduce emissions resulting from industrial production in the Belledune area of New Brunswick.

NOVA SCOTIA

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in Nova Scotia include:

The Environmental Goals and Sustainable Prosperity Act (2007)

In 2007, Nova Scotia passed legislation outlining principles for sustainable economic growth, including a requirement to reduce GHG emissions in the province to 10% below 1990 levels by 2020. The development and implementation of the Nova Scotia Climate Action Plan led to early action on the electricity sector, the largest source of emissions in the province. As a result, Nova Scotia has not only achieved its target six years early, it has also already met the Canadian 2030 target of 30% below 2005 levels, and is on a track to continue reducing emissions.

Nova Scotia's Greenhouse Gas Emissions Regulations

Nova Scotia was the first province in Canada to place a hard cap on GHG emissions from the electricity sector. These regulations, created in 2009 and enhanced in 2013, required the utility to reduce GHG emissions by 25% by 2020, and 55% by 2030. This is a measured and flexible approach which will enable a transition from coal to clean energy in the province.

Nova Scotia's Renewable Energy Regulations

In addition to the hard cap on GHG emissions, Nova Scotia also has a renewable energy standard for the electricity sector. This standard established requirements for 25% of electricity to be sourced from renewable energy by 2015, and 40% by 2020.

Energy Efficiency

Nova Scotia has Canada's first energy efficiency utility, Efficiency Nova Scotia. This independent organization has achieved an annual reduction in electricity demand of over 1% since its creation. It also administers comprehensive energy efficiency programs for low income and First Nations Nova Scotians. These efforts reduce GHG emissions while supporting the growth of the low carbon economy.

Tidal Energy

The Bay of Fundy and Minas Basin are home to the highest tides in the world- every day, more water flows into this bay than the output from all the rivers in the world combined. Nova Scotia has been supporting the development of these tides as a source of clean, predictable and reliable energy for Nova Scotians and as a clean technology export. The Fundy Ocean Research Centre for Energy (FORCE) now has a grid connected 2MW tidal turbine with plans to install more in the coming years.

Waste Management

Nova Scotia is also making efforts to reduce GHG emissions by diverting organic waste from landfills, recycling and creating a circular economy. Progress on waste diversion is reflected in a 30% reduction in greenhouse emissions from the waste sector since 2002.

These actions are just a snapshot of what Nova Scotians are doing to reduce GHG emissions and provide a strong contribution to a comprehensive pan-Canadian framework.

ACTION ON PRICING CARBON POLLUTION

As part of the pan-Canadian benchmark for carbon pricing, Nova Scotia has committed to implement a cap and trade program in the province that builds on our early action in the electricity sector.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

The Government of Nova Scotia and the Government of Canada intend to collaborate in the following priority domains to address climate change and advance clean growth:

Energy Efficiency

Nova Scotia and the Government of Canada are committed to partnering to enhance the existing provincial energy efficiency programs for homes and businesses with the objective of reducing energy use and saving energy costs. This could include expanded energy efficiency programs, efforts to accelerate the electrification of homes and businesses through heat pumps and smart meters, district energy systems, as well as electric vehicle infrastructure.

Renewable Energy Generation, Transmission and Storage

Nova Scotia, in partnership with the Government of Canada, will work together to advance opportunities for renewable energy generated from sources such as wind, tidal and solar, as well as the enabling transmission and storage infrastructure to ensure growth beyond current technical limits. Research and development capacity will continue to be strengthened.

Planning and Implementing Adaptation Infrastructure

Nova Scotia and the Government of Canada will work together and invest in projects to make infrastructure more resilient to a changing climate, and to help communities increase their capacity to adapt to a changing climate.

Regional Electricity Grid Connections

Nova Scotia will work with the other Atlantic provinces and the Government of Canada to advance opportunities for clean electricity generation, transmission, storage and demand management linkages across the region.

This will: improve access to non-emitting electricity; support the phase-out of coal-fired electricity generation; improve grid reliability and energy security; and, consistent with fair market principles, help provinces access export markets for clean, non-emitting electricity. This will contribute to both the Atlantic Growth Strategy and Canadian Energy Strategy and will build on existing regional coordination efforts, leading to an integrated regional electricity strategy.

PRINCE EDWARD ISLAND

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in Prince Edward Island include:

Climate Change Policy Framework

Prince Edward Island's primary areas of strategic focus for climate change fall into the themes of built environment, transportation, agriculture, conservation and adaptation. Prince Edward Island is in the process of developing new climate change strategies that will result in further actions and initiatives to reduce GHG emissions across the province, increase our resilience to a changing climate, and advance measures to strengthen and grow a prosperous green economy in the province.

Prince Edward Island does not have a legislated provincial emissions reduction target but does contribute to the regional target set by the Conference of the New England Governors and Eastern Canadian Premiers (NEG-ECP). The targets are 10% reductions from 1990 by 2020, 35% - 45% below 1990 levels by 2030, and 75-85% reduction from 2001 levels by 2050. PEI has realized a 9% reduction in GHG emissions since 2005.

PEI Wind Energy

Prince Edward Island is a world leader in producing clean electricity from wind. Prince Edward Island boasts the highest penetration of wind in Canada and 2nd highest in the world next to Denmark. The Government of Prince Edward Island has demonstrated a long-term commitment and investments of $119 million to wind energy.

The first commercial wind farm in Atlantic Canada was developed by the PEI Energy Corporation at North Cape in 2001. North Cape was expanded in 2003, doubling in size.

In January 2007, the PEI Energy Corporation commissioned its second wind farm at East Point. In 2014, the Island's newest wind farm was commissioned at Hermanville/ Clearspring. As a result, Prince Edward Island now has a total installed wind capacity of 78% of peak load, which supplies almost 25% of the province's total electricity requirements.

Biomass

Prince Edward Island is home to Canada's longest-running, biomass-fired district heating system. Operating since the 1980s, the system has expanded to serve over 125 buildings in the downtown core of Charlottetown, including the University of Prince Edward Island and the Queen Elizabeth Hospital. It has contributed to the establishment of a local waste-wood fuel-supply market. The system burns approximately 66,000 tons of waste materials annually.

Coastal Erosion

Prince Edward Island has partnered with the University of Prince Edward Island (UPEI) Climate Research Lab to study coastal vulnerability, including the award-winning Coastal Impacts Visualization Environment (CLIVE). CLIVE is an innovative 3D platform for visualizing the potential future impacts of coastal erosion and coastal flooding at local community scales, on PEI and elsewhere, using past data and Intergovernmental Panel on Climate Change models.

The province has also invested in UPEI in its development of an expansive, cutting-edge coastal erosion monitoring network. This research includes the use of drone and GIS technology to quantify and assess erosion volume of shoreline disappearance along Prince Edward Island's coastline.

Environmental Awareness in Agriculture

As a key industry for Prince Edward Island, agriculture is of particular consequence for climate change and green growth. In recent years, PEI farmers, watershed groups and the fertilizer industry have been implementing a 4R Nutrient Stewardship program to encourage the efficient use of fertilizer and help reduce related emissions.

Island farmers have been making advances in crop diversification, including testing potato varieties that require less fertilizer and adding nitrogen-fixing pulse crops which improve the environmental sustainability of annual cropping systems. The further use of robotics in dairy farming and food additives in livestock production is being employed to reduce methane emissions.

Prince Edward Island is also the first and only jurisdiction in Canada with a provincially-supported Alternative Land Use Services program. Currently, the program has converted almost 4,000 hectares of marginal land from annual crop production to perennial or permanent cover.

These actions provide a strong contribution to a comprehensive pan-Canadian framework and are helping facilitate the transition to a low-carbon economy.

ACTION ON PRICING CARBON POLLUTION

Prince Edward Island will introduce a made-in-PEI approach to carbon pricing which positively contributes to climate change action while benefitting Prince Edward Islanders and ensures optimal conditions for continued growth of the provincial economy. Prince Edward Island will focus on measures that will meaningfully decrease our GHG emissions and recognize the particular elements of our economy.

Our approach will ensure consistent and competitive alignment with efforts being made across the country, including mitigation and price initiatives in all provinces, especially those in our region. PEI is committed to an approach that will directly enhance provincial adaptation and mitigation efforts.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

Prince Edward Island and the Government of Canada intend to collaborate in the following domains of priority to address climate change and advance clean growth:

Energy Efficiency

Prince Edward Island, in partnership with the Government of Canada, will pursue improved energy efficiency for all sectors in the province as outlined in the 2016 PEI Energy Strategy. The Strategy and forthcoming Climate Change Action Plan are key policy tools in reducing GHGs, driving economic growth and creating jobs locally and in the region.

Prince Edward Island is committed to engaging in incremental actions through solutions for the built environment, including businesses and homes, as well as in new building construction. It has been clearly illustrated by research in the region that investing in efficiency is one of the most effective means of delivering jobs and economic growth widely – across sectors and regions – while reducing emissions and providing savings to consumers.

With a predominantly rural population and some of the highest electricity rates in the country, particular consideration will be given to low-income Island families, and sectors that may find the transition to a lower-carbon environment challenging.

Clean Energy

Energy resilience and security and a move to greater electrification are key priorities for the province. Prince Edward Island, in partnership with the Government of Canada, will work to expand its world-class wind resource, invest in solar, and enable greater integration of renewable energy through storage. Prince Edward Island will work with the other Atlantic Provinces and the Government of Canada to advance opportunities for clean electricity generation, transmission, storage and demand management linkages across the region.

This will: improve access to non-emitting electricity; support the phase-out of coal-fired electricity generation; improve grid reliability and energy security; and, consistent with fair market principles, help provinces access export markets for clean, non-emitting electricity. This will contribute to both the Atlantic Growth Strategy and Canadian Energy Strategy and will build on existing regional coordination efforts leading to an integrated regional electricity strategy.

Adaptation

With its 1100 km of coastline, Prince Edward Island is uniquely vulnerable to climate impacts and is positioned to advance innovative solutions to make infrastructure more resilient to a changing climate.

Prince Edward Island and the Government of Canada will work together to act on findings from disaster risk reduction planning and coastal infrastructure assessment, and to improve decision-making capacity to adapt to climate change through planning, training and monitoring.

Research and Development

Prince Edward Island and the Government of Canada will work together to support research and development on promising practices and innovation in the areas of agriculture, marine industries, and smart grid and micro-grid/storage. Prince Edward Island provides an ideal demonstration site for development in these areas.

This research will advance better understanding of influences on emissions and opportunities for clean growth in key sectors of the Prince Edward Island economy.

Transportation

Prince Edward Island relies on exports for continued economic growth. The Prince Edward Island economy is heavily reliant on ground transportation for the movement of goods to markets across Canada and around the world, and the movement of people across the province. The province has no rail system, large container ports, or robust public transit. As the most rural province in Canada, mitigation in transportation is a difficult challenge.

Prince Edward Island and the Government of Canada will work together on methods to support an eventual move to greater electrification in transportation, including corresponding work with other jurisdictions in Canada. Proposed specific areas of work include installation of public charging infrastructure across the province and in collaboration regionally where possible.

NEWFOUNDLAND & LABRADOR

KEY ACTIONS TO DATE

Newfoundland and Labrador is making significant investments to increase the use of clean and renewable hydroelectric power in the province. The Muskrat Falls hydroelectric development, with capital costs of over $9 billion, will result in 98% of electricity consumed in the province coming from renewable sources by 2020.

Muskrat Falls will facilitate advancing by more than a decade the decommissioning of the largest thermal oil-fired electricity generation facility in the province, reducing greenhouse gas (GHG) emissions by about 1.2 Mt annually (equivalent to more than 10% of the province's total emissions in 2015), and assisting other jurisdictions to meet their GHG reduction targets.

To focus the province's efforts to tackle climate change, Newfoundland and Labrador has adopted GHG emission reduction targets of 10% below 1990 levels by 2020 and 75-85% below 2001 levels by 2050, and has endorsed, on a regional basis, the Conference of New England Governors and Eastern Canadian Premiers' reduction marker range of at least 35-45% below 1990 levels by 2030.

To make progress towards these targets Newfoundland and Labrador released a Climate Change Action Plan in 2011 identifying 75 actions to reduce GHG emissions and adapt to the adverse impacts of climate change. Building on this work, Newfoundland and Labrador passed the *Management of Greenhouse Gas Act* in June 2016, creating a legislative framework for reducing GHGs from large industry, and has completed public consultations to inform new provincial actions on climate change.

These actions provide a strong contribution to a comprehensive Pan-Canadian Framework.

ACTION ON PRICING CARBON POLLUTION

The Government of Newfoundland and Labrador and the Government of Canada continue to collaborate to ensure that Newfoundland and Labrador's climate change plan, including carbon pricing, is consistent with the goals in the Pan-Canadian Framework to reduce GHG emissions, improves resilience to climate impacts, and accelerates innovation and job creation.

This made-in-Newfoundland and Labrador plan will address the province's particular social, economic, and fiscal realities. This includes sensitivity to the particular circumstances facing Labrador communities, and the need to consider impacts on all remote and isolated communities, vulnerable populations, consumers and trade-exposed industries, as well as the need to take account of the province's reliance on marine transportation and the absence of lower carbon alternatives.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

Newfoundland and Labrador and the Government of Canada intend to explore collaboration in the following priority domains to address climate change and advance clean growth:

Renewable Energy

Newfoundland and Labrador and the Government of Canada intend to jointly explore opportunities to develop renewable energy, including such actions as enhancing hydroelectric capacity, increasing transmission infrastructure, and offsetting diesel use in small-scale off-grid electricity systems.

These efforts will also seek to maximize collaboration with other Atlantic provinces in the electricity sector, contributing to both the Atlantic Growth Strategy and Canadian Energy Strategy, and will build on existing regional coordination efforts, leading to an integrated regional electricity strategy.

Transportation

Newfoundland and Labrador and the Government of Canada intend to jointly explore opportunities to reduce GHG emissions in all parts of the transportation sector, including electric vehicles and associated infrastructure, on- and off-road freight and industrial transportation, marine vessels, and public transit.

Energy Efficiency

Newfoundland and Labrador and the Government of Canada intend to jointly explore opportunities to develop energy efficiency programming, improve energy codes, and support fuel switching in all sectors reliant on fossil fuels.

Adaptation

Newfoundland and Labrador and the Government of Canada intend to jointly explore opportunities to expand climate monitoring and adaptation product and information development, as well as best management practices.

Green Innovation

Newfoundland and Labrador and the Government of Canada intend to jointly explore opportunities in research and development in green technology, including fostering innovation networks and initiation of pilot projects.

YUKON

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in Yukon include:

Yukon Government Climate Change Action Plan

The Yukon government *Climate Change Action Plan* has four goals: reducing GHG emissions; addressing the impacts of climate change; leading Yukon action on climate change; and enhancing our knowledge and understanding of climate change.

KEY ACTIONS

Work to date in achieving *Climate Change Action Plan* goals includes:

Reducing GHG emissions (mitigation)

- Setting nine sector-specific targets in the areas of transportation, heating buildings, electricity, and industrial operations.
- Completing a study of Yukon's transportation sector, and launching a Ride Share program in partnership with the City of Whitehorse.
- Supporting Yukon homeowners with the Good Energy Residential Incentives Program, which provides incentives to purchase high efficiency wood stoves, boilers and pellet stoves.
- Carrying out detailed energy audits of seven high-consumption Yukon government buildings.
- A Yukon Biomass Strategy to guide the development of a biomass energy sector in the territory.

Addressing the impacts of climate change (adaptation)

- Completing ten adaptation projects in the areas of permafrost impacts to highways, buildings, hydrological responses, and agricultural capacity; flood risk mapping; forestry implications including the encroachment of mountain pine beetle in lodgepole pine forests; and bioclimate shifts.
- With the Pan-Territorial Adaptation Strategy, territorial governments are collaborating on practical adaptation measures for the north. Permafrost thaw has been a key focus.

Leading Yukon action on climate change

- Participating in international and national climate change efforts that impact Yukon, such as the United Nations Framework Convention on Climate Change Conference of the Parties (COP) meetings, including a developmental opportunity for a Yukon youth ambassador.
- Currently supporting the Yukon College to develop a climate change policy course to be offered by Yukon College.

Enhance our knowledge and understanding of climate change

- Supporting development of the Climate Change Indicators and Key Findings report, an important source of independent information that will guide action and research on climate change in Yukon.
- Provide ongoing funding for the Northern Climate Exchange at Yukon College.

These actions provide a strong contribution to a comprehensive pan-Canadian framework.

ACTION ON PRICING CARBON POLLUTION

The Government of Yukon recognizes the role of carbon pricing in the pan-Canadian Framework for Clean Growth and Climate Change.

Given Yukon's particular circumstances, the Government of Canada and the Government of Yukon will work together to assess the implications of carbon pricing in the territory for its economy, communities and people including energy costs, and to develop solutions together.

The Government of Yukon and the Government of Canada will also work together to assess the implications of carbon pricing in Canada on the cost of living in Yukon. This will be an important consideration for future policy development.

As outlined in the federal government's benchmark, 100% of the revenues from carbon pricing will be retained by Yukon. Yukon government will distribute these revenues back to individual Yukoners and businesses through a rebate.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

Yukon and the Government of Canada intend to collaborate in the following domains of priority to address climate change and advance clean growth:

Advancing Renewable Energy

Yukon government and the Government of Canada will partner in advancing renewable energy projects in Yukon. This will improve the energy infrastructure in Yukon, including developing new renewable energy sources to provide clean energy for current and future electricity needs.

It will also support remote communities in diminishing their reliance on diesel for electricity and will support the expanded use of biomass as a cleaner option for heating in Yukon.

Energy Efficiency

Yukon government, in partnership with the Government of Canada, will support energy efficiency through the retrofitting of existing buildings. Sound investments in retrofits and new energy efficiency projects will be supported by expanding the capacity for collecting, analyzing, and reporting emissions data that will help identify the areas of greatest opportunity for reducing emissions.

Adaptation: Building Resilient Yukon Communities

Canada's Northern jurisdictions and the Government of Canada are working together to develop the Northern Adaptation Strategy. The Government of Canada will partner with Yukon to help build climate-resilient Yukon communities.

Research collaboration will build the knowledge necessary for evidence-based decision-making in community planning. Investments in infrastructure will address known risks such as infrastructure built on thawing permafrost.

Green Innovation and Technology

Yukon government and the Government of Canada will partner on new research and pilot projects that will explore promising areas for climate action in the north, such as seasonal energy storage, cleaner transportation options, and community-level renewable energy generation.

NORTHWEST TERRITORIES

KEY ACTIONS TO DATE

NWT Climate Change Strategic Framework

The Government of the Northwest Territories (GNWT) has committed to develop a climate change strategy that takes northern energy demands and the cost of living into account. It will reflect commitments to reduce greenhouse gas emissions, explore carbon pricing systems and how to develop local alternatives such as hydro, biomass, wind and solar.

NWT Energy Strategy

The GNWT is currently working on a new 10 year Energy Strategy. The Energy Strategy will focus on the affordability, reliability and environmental impacts of energy in the NWT and will promote energy efficiency, renewable and alternative energy in the electricity, heating and transportation sectors.

The GNWT continues to take the following territorial adaptation actions:

- Support adaptation decision-making with knowledge, information collection and sharing
- Build capacity to translate adaptation knowledge into action
- Build climate-resilience through investments in infrastructure
- Invest in land use planning, management plans and building adaptation capacity and expertise
- Support most vulnerable regions, conducting risk assessments and completing hazard mapping
- Reduce climate-related hazards and disaster by developing disaster risk management plans
- Adapt renewable energy options and solutions for cold regions

The GNWT continues to take the following territorial emissions mitigation actions:

- Work with our federal, provincial indigenous partners and others to find solutions to address diesel use in remote off-grid communities including to develop the NWT's hydroelectricity potential to reduce GHG emissions in the electricity sector.
- Implement policies to support the adoption of lower carbon and energy efficient technologies.
- Implement policies to support industry and large emitters in the adoption of lower carbon and energy efficient technologies.
- Continue biomass initiatives and work towards the development of a local forest and wood product industry and develop local wood pellet manufacturing as an alternate local fuel source.
- Addressing energy use and GHG emissions in government buildings and operations.

These actions provide a strong contribution to a comprehensive pan-Canadian framework.

ACTION ON PRICING CARBON POLLUTION

Through the Climate Change Strategic Framework, the GNWT is exploring potential impacts and opportunities that may arise from pursuing different carbon pricing systems in the territory.

The GNWT recognizes the role of carbon pricing in the pan-Canadian Framework for Clean Growth and Climate Change. Given the NWT's particular circumstances, the Government of Canada and the GNWT will work together to assess the implications of carbon pricing in the territory for its economy, communities and people including energy costs, and to develop solutions together.

The GNWT and the Government of Canada will also work together to assess the implications of carbon pricing in Canada on the cost of living in the NWT. This will be an important consideration for future policy development.

As outlined in the federal government's benchmark, 100% of the revenues from carbon pricing will be retained by the NWT.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

The NWT will work with the Government of Canada, in collaboration with regional partners, to advance opportunities for clean electricity generation, transmission, storage and demand management linkages across the region.

This will: improve access to non-emitting electricity; support the phase-out of coal-fired electricity generation; improve grid reliability and energy security; and, subject to fair market principles, help the region access export markets for clean, non-emitting electricity.

The NWT and the Government of Canada intend to collaborate in the following priority areas to address climate change and advance clean growth:

Taltson Hydro Expansion and Transmission Links

The proposed Taltson hydro expansion is a small scale run of river hydro project that could be developed with little environmental impact next to the existing power plant, on an already developed river, and combined with a transmission link to provide a green energy corridor to our southern neighbours.

The expansion of the Taltson hydro facility would help reduce Canada’s GHG emissions by 360,000 tonnes annually for 50-plus years.

The 60 MW expansion of the Taltson hydro facility could be built in partnership with NWT Indigenous governments, creating economic opportunities for Indigenous-owned businesses across the North. The NWT and Government of Canada will undertake technical and feasibility studies as a first step, including the NWT launching the environment assessment process.

Renewable Solutions for Off-Grid Diesel Communities

The Government of Canada and the GNWT will explore opportunities for reducing reliance on diesel in off-grid communities. For example, the Inuvik Wind Project could produce between 2 and 4 megawatts of wind energy for the Town of Inuvik. The project would reduce GHG emissions by 4,300 tonnes per year and eliminate the need for 1.3 million litres of diesel annually in the largest diesel community in the NWT, and help reduce the cost of living for residents.

For other off-grid diesel powered communities of the NWT, a suite of renewable solutions such as solar and wind in combination with energy storage systems and variable generators could reduce diesel use and emissions by 25 percent, an annual GHG elimination of nearly 3000 tonnes.

All-Weather Road Infrastructure for Adapting to Climate Impacts

The safety and reliability of winter roads is being impacted by climate change. Construction of the Mackenzie Valley Highway from Wrigley to Norman Wells would provide safe, secure, and reliable access into the Sahtu region, helping decrease the high cost of living in communities and support the development of resources in the region.

The Great Bear River is a priority as the seasonal ice crossing is increasingly vulnerable to impacts of climate change. Climate change is also limiting access to existing diamond mining operations in the Slave Geological Province.

Construction of an all-weather Slave Geological Province Access Corridor would reduce costs for industry exploration and development in a region that holds world-class deposits of natural resources and continues to be a major contributor to the Canadian and NWT economy.

NUNAVUT

KEY ACTIONS TO DATE

Some of the key actions taken to date or under development in Nunavut include:

Energy efficiency upgrades

The Nunavut Energy Retrofit Program was piloted in Iqaluit in 2007, and addressed all of the government of Nunavut's Iqaluit Government of Nunavut-owned buildings. The one-time project investment of $12.8 million has led to annual savings in excess of $1.6 million and 1,594 tonnes of GHG reductions.

In combination with the conversion of three of our facilities to residual heat, our GHG reduction is approximately 4,100 tonnes, which is roughly 20% of those buildings' total emissions.

Development of a Climate Change and Adaptation strategy

Upagiaqtavut was developed in 2011 and serves as a guiding document for the impacts of climate change in Nunavut (http://climatechangenunavut.ca/sites/default/files/3154-315_climate_english_reduced_size_1_0.pdf).

Climate change databank

The Government of Nunavut is developing and uses information technology to centralize and increase the access to climate change information, such as permafrost data and landscape hazards maps. The information is used to improve infrastructure planning and help mitigate the effects of climate change across Nunavut.

Climate Change Secretariat

The Government of Nunavut is establishing a Climate Change Secretariat (CCS), which will be the central point within the government to address both climate change adaptation and mitigation issues.

ACTION ON PRICING CARBON POLLUTION

The Government of Nunavut recognizes the role of carbon pricing in the pan-Canadian Framework for Clean Growth and Climate Change. Given Nunavut's particular circumstances, the Government of Canada and the Government of Nunavut will work together to assess the implications of carbon pricing in the territory for its economy, communities and people including energy costs, and to develop solutions together.

The Government of Nunavut and the Government of Canada will also work together to assess the implications of carbon pricing in Canada on the cost of living in Nunavut. This will be an important consideration for future policy development.

As outlined in the federal government's benchmark, 100% of the revenues from carbon pricing will be retained by Nunavut.

COLLABORATION PARTNERSHIP OPPORTUNITIES FOR CLEAN GROWTH AND CLIMATE CHANGE

Nunavut and the Government of Canada intend to collaborate in the following domains of priority to address climate change and advance clean growth:

Nunavut and the Government of Canada will assess the economic and technical feasibility of electrification through hybrid power generation in Nunavut's communities. Hybrid power generation would significantly reduce emissions while at the same time ensure that Nunavut's isolated communities have reliable power.

Nunavut and the Government of Canada will work together to develop a retrofit program to increase the energy efficiency of public and private housing. Investment in safe and energy efficient housing is a key component of building strong resilient communities in the Arctic.

Government of Canada Gouvernement du Canada

What is the clean fuel standard?

On this page

Overview

Canadians and businesses use fuel every day – to produce and transport goods, and get from place to place. These fuels help power our economy, but their extraction and combustion also represent a significant source of pollution in Canada. In fact, the largest sources of greenhouse gas (GHG) emissions in Canada are from the extraction, processing and combustion of fossil fuels. The fossil fuels we use for transportation also have significant impacts on Canadians' health, creating harmful air pollution when they're extracted, refined and burned in car and truck engines.

As the world strives to achieve net-zero emissions by 2050, a major shift will occur to lower carbon and non-emitting fuels. Canada is in a powerful position to be the producer and consumer of these fuels that consumers are looking for now, and will increasingly be looking for in the future.

The Clean Fuel Regulations will drive investment and growth in Canada's clean fuel sector by increasing incentives for the development and adoption of clean fuels and technologies and processes. The goal of the Clean Fuel Standard is to significantly reduce pollution by making the fuels we use every day cleaner over time. The Clean Fuel Standard will require liquid fuel (gasoline and diesel) suppliers to gradually reduce the carbon intensity of the fuels they produce and sell for use in Canada over time, leading to a decrease of approximately 13% (below 2016 levels) in the carbon intensity of our liquid fuels used in Canada by 2030.

To speed up the transition to clean fuels, technologies and processes across Canada, the Government is supporting the development of a leading clean fuels sector in Canada through a series of significant investments and initiatives that complement the Clean Fuel Standard regulation.

These measures include the Government of Canada’s recent investment of $1.5B towards a Low-carbon and Zero-emissions Fuels Fund, which will increase support for domestic production of low-carbon fuels and their adoption, such as hydrogen and biofuels. These investments will also help implement early opportunities identified in the *Hydrogen Strategy for Canada*, which was announced by Natural Resources Canada on December 18 2020, by supporting the increased production of clean hydrogen.

This domestic growth will also position Canada to become a world-leading supplier of hydrogen and hydrogen technologies, generating economic opportunities through exports and direct foreign investment.

In addition, Canada's fall economic statement announced $150 million in additional funds to accelerate the deployment of infrastructure for zero-emission vehicles and the government’s intention to continue supporting electrification of public transit systems across Canada. These measures will work hand in hand with the CFS in supporting Canadians in their transition to a low-carbon future and in the uptake of ZEVs.

In the context of the continued increase to the carbon price and the new measures to support the production of hydrogen and biofuels, the scope of the Clean Fuel Standard has been narrowed to target only liquid fossil fuels, like gasoline and diesel, which are mainly used in the transportation sector. This is a progression in the design of the Clean Fuel Standard from its initial discussion in 2016, when it was proposed that the new measure will cover liquid, gaseous and solid fuels.

How fuels will become cleaner

The Clean Fuel Standard takes a lifecycle approach, meaning it takes into account the emissions associated with all stages of fuel production and use – from extraction through processing, distribution, and end-use.

The Clean Fuel Standard will require liquid fossil fuel primary suppliers (i.e., producers and importers) to reduce the carbon intensity of their liquid fossil fuels used in Canada from 2016 carbon intensity levels. In 2022 the carbon intensity reduction requirement will start at 2.4 gCO2e/MJ. It will gradually increase over time reaching 12 gCO2e/MJ in 2030. To achieve this, fuel producers will need to provide innovative solutions and new fuel options to consumers.

To drive innovation at the lowest cost, the Clean Fuel Standard establishes a credit market. Regulated parties (producers and importers of gasoline and diesel) must create or buy credits to come into compliance with the reduction requirements. Parties with an excess of credits can bank them for use in later years or sell them. The Clean Fuel Standard also provides opportunities for non-regulated parties to create credits.

The Clean Fuel Standard provides three ways to create credits:

1. Compliance category 1: undertaking projects that reduce the lifecycle carbon intensity of fossil fuels (e.g., carbon capture and storage, on-site renewable electricity, co-processing)
2. Compliance category 2: supplying customers with low carbon intensity fuels (e.g., ethanol, bio-diesel)
3. Compliance category 3: investing in advanced vehicle technologies (e.g., electric or hydrogen fuel cell vehicles)

Economic benefits of cleaner fuels

The Clean Fuel Standard will create economic opportunities for voluntary parties like biofuel producers and other lower carbon fuel producers to create and sell credits. In turn, this will create opportunities for feedstock providers like farmers and foresters supporting lower carbon fuel production.

The Clean Fuel Standard will also promote the uptake of advanced vehicle technologies, like electric vehicles. To allow for a wide range of participants to have access to this economic opportunity, any party can become a credit creator for residential electric vehicle charging. Revenues from credits associated with residential electric vehicle charging must be reinvested in vehicle charging infrastructure, rebates for consumers or electricity distribution infrastructure.

By promoting investments in low carbon fuels and technologies, the Clean Fuel Standard will:

- create well-paying jobs across the economy including in clean technology and in clean fuels like biofuels and hydrogen;

- grow Canada’s clean fuels industry at a time when the global market for clean fuels is rapidly expanding;
- create opportunities for companies producing renewable fuels and the farmers and foresters supplying their feedstock; and
- promote the accelerated use of zero-emission vehicles.

Key dates

The proposed regulations for the Clean Fuel Standard were published in *Canada Gazette*, Part I, on December 18. The draft regulations were available for a 75-day comment period.

Final regulations are targeted for publication in spring 2022.

Questions and answers

► Q1.) What is the Clean Fuel Standard?

► Q2.) How does it work?

► Q3.) What are the benefits of the Clean Fuel Standard?

► Q4.) Who has been consulted on this regulation?

► Q5.) Which other countries and jurisdictions currently have low carbon fuel policies, such as renewable fuel mandate or a clean fuel standards?

► Q6.) How much emissions will be reduced by the Clean Fuel Standard?

► Q7.) Will the removal of the CFS gaseous stream negatively impact the demand for low-carbon gaseous fuels, such as hydrogen and renewable natural gas?

► Q8.) How does removing the gaseous and solid fuels obligations affect gaseous and solid credit creation opportunities and incentives for uptake of low carbon gaseous and solid fuels?

More information

Learn more about the Clean Fuel Standard, including compliance options for industries and how the regulations will be implemented in the years ahead.

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Government of Canada Gouvernement du Canada

A Healthy Environment and a Healthy Economy

From: Environment and Climate Change Canada

Backgrounder

As the Government of Canada continues to protect and support Canadians through the COVID-19 pandemic, it is also important that the country look to the future. Canadians want to see a growing middle class where no one is left behind. They want a future where their kids and grandkids have access to clean air and water. That future is within reach. Collectively, Canada needs to accelerate climate action to get there.

A Healthy Environment and a Healthy Economy is Canada's plan to build a better future. This plan builds on the Pan-Canadian Framework on Clean Growth and Climate Change. It continues down the path that Canadians, their governments, and businesses have been setting.

This plan is a cornerstone of the government's commitment in the 2020 Speech from the Throne to create over one million jobs, restoring employment to pre-pandemic levels. The plan includes 64 new measures and $15 billion in investments in addition to the Canada Infrastructure Bank's $6 billion for clean infrastructure announced this fall as part of its growth plan.

A Healthy Environment and a Healthy Economy will make life more affordable for households. It will make Canadian communities more livable. And it will, at every turn, focus on workers and their careers in a fair and just transition to a stronger and cleaner economy. The plan will do this through five pillars

Making the Places Canadians Live and Gather More Affordable by Cutting Energy Waste

Energy-efficient homes and buildings are more comfortable and cost less to power. This plan will make it easier for Canadians to improve the places in which they live and gather. This will cut pollution, make life more affordable and create thousands of good jobs and new careers in construction, technology, manufacturing and sales. To bring these benefits to communities, the government will:

- Invest $1.5 billion over three years for green and inclusive community buildings, and require that at least 10 percent of this funding be allocated to projects serving First Nations, Inuit and Métis communities.
- Provide $2.6 billion over seven years to help homeowners make their homes more energy efficient. This funding will provide grants of up to $5,000, up to one million free EnerGuide assessments, and support to recruit and train EnerGuide auditors.
- Work with the building materials sector and other stakeholders to develop a robust, low-emission building materials supply chain to ensure Canadian, locally-sourced products are available, including low-carbon cement, energy-efficient windows and insulation.

- Continue working with and building on successful provincial and territorial low-income retrofit programs to increase the number of low-income households that benefit from energy retrofits.
- Continue to work with provincial and territorial governments to develop a new model ’retrofit‘ code for existing buildings, by 2022, with the goal of collaborating with provinces and territories to have this code in place by 2025.
- Conduct Canada’s first-ever national infrastructure assessment, starting in 2021, to help identify needs and priorities in the built environment, and undertake long-term planning toward a net-zero emissions future.
- Invest $2 billion in financing commercial and large-scale building retrofits, which will be repaid by energy savings costs. This commitment is part of the CIB’s $10 billion Growth Plan.
- Develop a simple, low-cost loan program that integrates and builds on energy audits and grants to finance deeper home energy retrofits for homeowners.

Making Clean, Affordable Transportation and Power Available in Every Canadian Community

The government will expand the supply of clean electricity through investments in renewable and next-generation clean energy and technology, and encourage cleaner modes of transportation, such as low and zero-emission vehicles, transit and active transportation. This will make communities healthier, less congested and more vibrant.

To ensure Canadians have access to cleaner, more affordable transportation options, the government will:

- Invest an additional $287 million over two years to continue the Incentives for Zero-Emission Vehicles (iZEV) program until March 2022. The program provides a rebate of up to $5000 on a light-duty zero-emission vehicle.
- Invest an additional $150 million over three years in charging and refueling stations across Canada, as announced in the 2020 Fall Economic Statement.
- Work with partners in the year ahead on supply-side policy options to achieve additional reductions from Canada's light-duty vehicle fleet, including regulations and investments to accelerate and expand the consumer availability of ZEVs in Canada as demand grows.
- Build on historic investments in public transit in the Investing in Canada Infrastructure Program to develop next steps on public transit, including the government's plan to help electrify public transit systems, and provide permanent public transit funding.
- Engage the incoming United States Administration on approaches to increase the consumer availability of zero-emission vehicles in both countries, given the integrated nature of the North American auto sector.
- Work to align Canada's Light-Duty Vehicle regulations with the most stringent performance standards in North America post-2025, whether at the United States federal or state level.
- Develop a national active transportation strategy, and explore ways to deliver more active transportation options, such as walking trails, cycling paths and other forms of active mobility, which are a

complementary tool that can reduce reliance on cars and provide healthy transportation alternatives.

- Include the 100-percent tax write off for commercial light-duty, medium- and heavy-duty ZEVs.
- Implement Canada's Off-road Compression-Ignition (Mobile and Stationary) and Large Spark-Ignition Engine Emission Regulations to make new equipment and machines used by Canadians less polluting and more fuel-efficient.
- Further improve the efficiency of heavy-duty vehicles standards for post-2025 by aligning with the most stringent standards in North America—whether at the United States federal or state level.

And to make clean, affordable electricity options more available, the government will:

- Invest an additional $964 million over four years to advance smart renewable energy and grid modernization projects.
- Invest an additional $300 million over five years to advance the government's commitment to ensure rural, remote and Indigenous communities that currently rely on diesel have the opportunity to be powered by clean, reliable energy by 2030.
- Work with provinces and territories to connect parts of Canada that have abundant clean hydroelectricity with parts that are currently more dependent on fossil fuels for electricity generation—including by advancing strategic intertie projects, such as the Atlantic Loop and other regional initiatives. The Canada Infrastructure Bank has earmarked $2.5 billion as part of its $10 billion Growth Plan. The

government will invest an additional $25 million to support predevelopment work.

- Work with provinces, utilities and other partners to ensure that Canada’s electricity generation achieves net-zero emissions before 2050.

Continuing to Ensure Pollution Isn’t Free and Households Get More Money Back

Canada has proven that putting a price on carbon pollution and returning the proceeds back to households can meet our economic needs and our environmental goals at the same time. We cannot grow the economy we all want and need if it’s free to pollute. Moving forward, the government proposes to:

- Continue to put a price on pollution through to 2030, rising at $15 per tonne after 2022, while returning the proceeds back to households such that the majority receive more money back than they pay in provinces where the federal system applies.
- Move from carbon pollution pricing rebate payments being distributed on an annual basis to quarterly, starting as early as 2022.
- Explore the potential of border carbon adjustments, and work with like-minded economies—including the E.U. and Canada’s North American partners—to consider how this approach could fit into Canada’s broader strategy to meet climate targets while ensuring a fair environment for businesses.

- Review the standards used to assess provincial systems, also known as the federal "benchmark criteria", and engage with provinces and territories as well as with Indigenous Peoples on these proposals over the coming months.

In the context of the continued increase to the carbon price, the scope of the Clean Fuel Standard has been narrowed to cover only liquid fossil fuels. This is a progression in the design of the Clean Fuel Standard from its initial discussion in 2016, when it was proposed that the new measure would cover liquid, gaseous and solid fuels.

Building Canada's Clean Industrial Advantage

In the years ahead, Canada's industrial advantage and the jobs that will come from it will depend on the speed and success of decarbonisation efforts. In order to achieve the country's full potential, the government must assist Canadian companies as they seek to meet the demands of domestic and global consumers for low-carbon goods and services, and make investments that can drive Canada's low-carbon economy.

That is why the government will:

- Launch a Net-Zero Challenge for large emitters to support Canadian industries in developing and implementing plans to transition their facilities to net-zero emissions by 2050.
- Make investments to support decarbonization and drive the immediate creation of well-paying, resilient jobs, in complement to the Challenge. This would involve the Strategic Innovation Fund's Net-Zero

Accelerator Fund, through an investment of $3 billion over five years. The fund will rapidly expedite decarbonization projects with large emitters, scale-up clean technology and accelerate Canada's industrial transformation across all sectors.
- Use proceeds collected from the Output-Based Pricing System (OBPS) for industry to further support industrial projects to cut emissions and use cleaner technologies and processes.
- Invest $1.5 billion in a Low-carbon and Zero-emissions Fuels Fund to increase the production and use of low-carbon fuels (e.g., hydrogen, biocrude, renewable natural gas and diesel, cellulosic ethanol) in a manner that complements federal carbon pollution pricing, regulatory efforts and other federal programming.
- Introduce Canada's Hydrogen Strategy, which sets out a path for integrating low emitting hydrogen across the Canadian economy, before the end of the year.

The government will also:

- Propose to strengthen Canada's approach to reducing methane emissions from the oil and gas sector by establishing new targets and associated regulations for 2030 and 2035, based on international best practices. The design of the amended federal regulations to achieve additional reductions in 2030 and 2035 will be determined through consultations with provinces, territories, the oil and gas industry and civil society.
- Invest $165.7 million over seven years to support the agriculture sector in developing transformative clean technologies and help farmers adopt commercially available clean technology.

- Set a national emission reduction target of 30 percent below 2020 levels from fertilizers and work with fertilizer manufacturers, farmers, provinces and territories, to develop an approach to meet it.
- Continue to support Sustainable Development Technology Canada with an additional $750 million over five years. This would support startups and scale-up companies to enable pre-commercial clean technologies to successfully demonstrate feasibility as well as support early commercialization efforts.
- Leverage the Government of Canada’s purchasing power to support emerging clean technologies across Canada’s economic sectors, such as technologies to reduce emissions in federal buildings and reduce embodied carbon in construction materials. This would be part of the updated greening government strategy.
- Work with small businesses to get their feedback on all potential ways to further support them in taking action to reduce emissions, including through rebates, targeted investments, and other supports.
- Continue helping Canadian businesses navigate available federal resources and measures, understand their environmental outcomes, while exploring opportunities to integrate into supply chains of larger private and public purchasers, and expand their reach in Canadian and global markets.
- Develop new federal regulations to increase the number of landfills that collect and treat methane, and ensure that landfills already operating these systems make improvements to collect all they can.

Embracing the Power of Nature to Support Healthier Families and More Resilient Communities

Just as nature is under threat from climate change, it is also an ally in the fight against it. By planting two billion trees and better conserving and restoring our natural spaces, the government will cut pollution, clean the air we breathe, make communities more resilient and increase access to natural spaces. The government will also create thousands of jobs in areas such as tree planting, urban planning and tourism. The government will:

- Invest up to $3.16 billion over 10 years, to partner with provinces, territories, non government organizations, Indigenous communities, municipalities, private landowners, and others to plant two billion trees.
- Invest up to $631 million over 10 years to work with provinces, territories, conservation organizations, Indigenous communities, private landowners, and others to restore and enhance wetlands, peatlands, grasslands and agricultural lands to boost carbon sequestration.
- Provide $98.4 million over 10 years to establish a new Natural Climate Solutions for Agriculture Fund.
- Continue to support partnerships with Indigenous communities across the country through the establishment of new Indigenous Protected and Conserved Areas and Indigenous Guardians programs.

Additional Measures

The plan also commits to developing Canada's first-ever national adaptation strategy. It contains new measures to support Indigenous climate leadership. It will support a strong Canadian contribution toward international climate action. Every dollar spent in the post pandemic stimulus plan outlined in the Fall Economic Statement—amounting to three to four percent of GDP—will be assessed for its effectiveness in furthering the goals of this plan. The plan also commits to applying a climate lens to integrate climate considerations throughout government decision-making.

Next Steps

A Healthy Environment and a Healthy Economy builds on continuing work through the Pan Canadian Framework on Clean Growth and Climate Change. The Pan Canadian Framework has done more to cut pollution in a practical and affordable way than any other climate plan in Canada's history. Taken together with the Pan Canadian Framework, this means Canada will exceed its 2030 greenhouse-gas-reduction target—making it the first time ever this country has set a climate target and outlined a path to not only meet it but exceed it.

The plan will also establish the right building blocks to get to net zero by 2050 so that our kids and grandkids can grow up in a country with clean air and water.

Moving forward, the federal government will consult with provinces and territories, Indigenous partners, and Canadians in all socio-economic sectors to further elaborate a strong plan for a healthier environment and economy that we can implement together. By further working with provinces and territories, the government is confident Canada can achieve reductions within the range of 32 to 40 percent below 2005 levels in 2030. So let's keep working together to build a healthier environment and healthier economy.

Search for related information by keyword: NE Nature and Environment | Climate change | Environment | Environment and Climate Change Canada | Canada | Environment and natural resources | general public | backgrounders | Hon. Jonathan Wilkinson

Date modified:
2021-03-08

Government of Canada Gouvernement du Canada

Canada.ca > Natural Resources Canada > Energy Efficiency

> Energy Efficiency for Homes

Start your energy-efficient retrofits

Apply and get advice on making your home more energy-efficient

Explore careers in energy efficiency

Get trained to be an energy advisor or register as an eligible service organization

Discover energy efficiency resources

Retrofit your home with the know-how to get it done right

Where are we now?

Find out more about the status of applications and steps we're taking to improve the experience for Canadians in our Winter update.

Explore the latest

Saving energy saves you money

Buildings, including our homes, account for 18% of Canada's greenhouse gas emissions. We want to help Canadians make where they live more energy-efficient. This means homes will be more comfortable and more affordable to maintain while also supporting our environmental objectives. The Canada Greener Homes Grant will help homeowners make their homes more energy-efficient, create new jobs across Canada for energy advisors, grow our domestic green supply chains, and fight climate change.

What's available through the initiative?

Up to 700,000 grants of up to $5,000 to help homeowners make energy efficient retrofits to their homes, such as better insulation

- **EnerGuide evaluations (worth up to $600) and expert advice** to homeowners so they can begin to plan their retrofits
- **Recruitment and training of EnerGuide energy advisors** to meet the increased demand; this will create new jobs across Canada.

Participants are eligible for up to $5,600 total under the initiative. Updates will be provided over the life of the initiative to keep homeowners informed. As part of our work, we are committed to ensuring Greener Homes reaches diverse Canadians including those living in remote and northern communities and those with limited internet access. We are working on building a diverse network of energy advisors to provide career opportunities to all Canadians and to meet the need of our communities.

Be wary of high-pressure sales tactics that claim to have EnerGuide or Natural Resources Canada (NRCan) backing

NRCan has not approved any third parties to reach out to homeowners in an unsolicited fashion to register or participate in the Canada Greener Homes Grant. The Government of Canada, NRCan and its family of brands (ENERGY STAR, EnerGuide) never solicit over the telephone, by email or go door-to-door asking to enter Canadians' homes to inspect, sell, or rent heating and cooling products. EnerGuide home energy evaluations are performed by licensed service organizations only at the request of homeowners.

Learn how to recognize energy scams

Apply for the Canada Greener Homes Grant

Log in to your Canada Greener Homes account to view an existing application

Login to your Greener Homes service account (for service organizations and energy advisors only)

Date modified:
2022-02-23

Government of Canada Gouvernement du Canada

Strategic Assessment of Climate Change Revised, October 2020

The Strategic Assessment of Climate Change [PDF (Portable Document Format) - 663 KB (Kilobyte)]

On this page

Executive summary

In August 2019, the *Impact Assessment Act* (IAA) came into force. The IAA establishes a new process for considering environmental, health, social and economic effects of projects that will undergo a federal impact assessment. One of the factors to be considered in the impact assessment process of a designated project is the extent to which the effects of the designated project hinder or contribute to the Government of Canada's ability to meet its commitments in respect of climate change such as the Paris Agreement, Canada's 2030 target and the goal of Canada achieving net-zero emissions by 2050.

The strategic assessment of climate change will enable consistent, predictable, efficient and transparent consideration of climate change throughout federal impact assessments.

A draft strategic assessment of climate change was published in August 2019. This final version [1] considers comments received on the August 2019 version and reflects the Government's goal of net-zero emissions by 2050.

This strategic assessment of climate change:

- describes the greenhouse gas (GHG) and climate change information that project proponents need to submit at each phase of a federal impact assessment;
- requires proponents of projects with a lifetime beyond 2050 to provide a credible plan that describes how the project will achieve net-zero emissions by 2050; and
- explains how the Impact Assessment Agency of Canada (IAAC) or lifecycle regulators, with support from expert federal authorities, will review, comment on and complement the climate change information provided by proponents.

Environment and Climate Change Canada (ECCC) plans to review and update the strategic assessment of climate change every 5 years.

Glossary

Best Available Technologies / Best Environmental Practices (BAT/BEP)

the most effective technologies, techniques, or practices, including emerging technologies, that can be technically and economically feasible for reducing GHG emissions during the lifetime of the project.

Carbon leakage

the situation that may occur if economic activity moves to other countries with less stringent emissions constraints, which could lead to an increase in global emissions.

Carbon sink

the ability of a forest, ocean or other natural environment to absorb carbon dioxide from the atmosphere.

Climate change resilience

the ability of a system (built, natural, social or economic) to anticipate, withstand, recover, adapt to and transform in response to a climate-related hazard.

Downstream GHG emissions

the emissions that may occur after the project, including emissions resulting from the end use of products made by a project.

Lifecycle regulators

agencies that regulate a project from planning through to project abandonment. These agencies include the Canada Energy Regulator (CER), the Canadian Nuclear Safety Commission (CNSC) and the Offshore Petroleum Boards.

Net GHG emissions

see Section 3.

Offset credits

Represent GHG emission reductions or removals generated from activities that are additional to what would have occurred in the absence of the offset project (i.e., generated from activities that go beyond legal requirements and a business-as-usual standard). Each offset credit generated by an offset project represents one tonne of carbon dioxide equivalent (CO_2 eq) reduced or removed from the atmosphere.

Projects undergoing a federal impact assessment

projects under the IAA, as well as projects under review by lifecycle regulators.

Upstream GHG emissions

emissions from all stages of production, from the point of resource extraction or utilization to the project under review.

1. Introduction

1.1 Objective

The strategic assessment of climate change will enable consistent, predictable, efficient and transparent consideration of climate change throughout the impact assessment process. It describes the climate change-related information requirements throughout the federal impact assessment process, and requires proponents of projects with a lifetime beyond 2050 to provide a credible plan to achieve net-zero emissions by 2050. It also explains how the Impact Assessment Agency of Canada (IAAC) or lifecycle regulators, with support from expert federal authorities, will review, comment on and complement this information.

Environment and Climate Change Canada (ECCC) plans to review and update the strategic assessment of climate change every 5 years.

1.2 Application

The strategic assessment of climate change applies to designated projects under the *Impact Assessment Act* (IAA).

The principles and objectives underlying the strategic assessment of climate change will be built into guidance for the review of non-designated projects on federal lands and outside Canada under the IAA. Guidance for projects regulated by the Canada Energy Regulator (CER) will similarly consider the principles and objectives of the strategic assessment of climate change.

The strategic assessment of climate change may also apply to environmental reviews by other federal lifecycle regulators, and be used in regional assessments.

1.3 Using this document

The strategic assessment of climate change complements other policy and guidance documents that support the impact assessment process. It is assumed that readers of this document have a good understanding of the impact assessment process. [2]

This document is organized as follows:

Section 2: Context

Provides an overview of Canada's climate change commitments, of Canada's impact assessment system, and of the process for conducting the strategic assessment of climate change.

Section 3: Quantification of GHG Emissions from a Project

Provides guidance on how to quantify a project's GHG emissions, and identifies the conditions when an upstream GHG assessment is required.

Section 4: Climate Change in the Planning Phase

Outlines how the information related to GHG emissions and climate change provided in the Planning Phase will be used to develop the Tailored Impact Statement Guidelines.

Section 5: Climate Change in the Impact Statement Phase

Outlines the information that will be asked for all projects, when an upstream GHG assessment will be required, and when a credible plan to achieve net-zero emissions by 2050 will be required.

Section 6: Climate Change in the Impact Assessment Phase

Outlines how IAAC and relevant lifecycle regulators will analyze the information provided by proponents in the Impact Statement and complement it with input from expert federal authorities.

Section 7: Climate Change in Decision-Making and Conditions

Explains how the information related to GHG emissions and climate change will inform the decision on the project and conditions related to project approvals.

Section 8: Climate Change in the Post-Decision Phase

Explains how a follow-up program, if required, could be used to ensure the proponent is meeting any conditions related to GHG emissions and climate change.

Section 9: Contact information

Provides contact information for the strategic assessment of climate change.

2. Context

2.1 Canada's climate change commitments

The Paris Agreement is an international agreement to strengthen the global response to the threat of climate change, building on the United Nations Framework Convention on Climate Change. The Paris Agreement, which entered into force in November 2016, established a collective long-term goal to hold the increase in the global average temperature to well below 2 degrees Celsius above pre-industrial levels, and to pursue efforts to limit that increase to below 1.5 degrees. [3] The Paris Agreement also establishes a global goal of enhancing adaptive capacity, strengthening resilience and reducing vulnerability to climate change with a view to contributing to sustainable development and ensuring an adequate adaptation response in the context of the temperature goal. [4]

Since 2016, the Government of Canada has been working with provinces, territories, and Indigenous peoples, to implement the Pan-Canadian Framework on Clean Growth and Climate Change. This plan outlines over 50 concrete measures to reduce carbon pollution, help us adapt and become more resilient to the impacts of a changing climate, spur clean technology solutions, and create good jobs that contribute to a stronger economy.

In Fall 2019, the Government of Canada announced further commitments to strengthen existing, and introduce new, actions to exceed Canada's 2030 emission reduction target, and to develop a plan to set Canada on a path to achieve a prosperous net-zero emissions future by 2050.

The IAA establishes a process for considering the environmental, health, social and economic effects within federal jurisdiction of certain projects for determining whether those projects are in the public interest. [5] Among other factors, the IAA requires that this decision account for the extent to which the effects of the designated project hinder or contribute to the Government of Canada's ability to meet its commitments in respect of climate change.

Other features of the IAA include:

- A planning phase to allow for early engagement, increased efficiency, improve project design, and give project proponents certainty about the next steps, requirements and timelines in the process;
- Indigenous engagement and partnership throughout the process;
- Increased public participation opportunities within legislated, prescribed timelines;

- Legislated timelines, tailored impact assessment guidelines and rigorous timeline management to provide clarity and regulatory certainty;
- Strong follow-up, monitoring and enforcement; and
- Transparent decisions based on science and Indigenous knowledge.

IAAC leads assessments of designated projects under the IAA. Where projects link to lifecycle regulators – such as the CER and the Canadian Nuclear Safety Commission (CNSC), IAAC will work in collaboration with them to draw on their expert knowledge and ensure that safety, licensing requirements, international obligations and other relevant regulatory factors are considered as part of a single, integrated assessment.

2.2 Technical guides

ECCC plans to publish technical guides to provide additional details on specific elements of the strategic assessment of climate change in 2020-2021, such as:

- Quantification of net greenhouse gas (GHG) emissions, upstream GHG emissions, and carbon sinks;
- GHG mitigation measures, Best Available Technologies / Best Environmental Practices (BAT/BEP) and plans to achieve net-zero emissions by 2050; and
- Climate change resilience.

3. Quantification of GHG emissions

from a project

Proponents of projects undergoing a federal impact assessment will be required to provide an estimate of the project's GHG emissions and, in certain cases, an upstream GHG emission assessment. An estimate of downstream emissions is not required.

A consistent and coherent approach to quantifying a project's GHG emissions will ensure fairness during the impact assessment process and accurate emission intensity comparisons with comparable projects.

While the general approach to quantify GHG emissions is provided in this document, ECCC plans to publish a technical guide with additional detailed guidance on how to quantify a project's net and upstream GHG emissions.

The GHG emissions for new projects and replacement or expansion projects are assessed differently. For new projects, the GHG emissions should reflect the full design capacity of the project. For replacement or expansion projects, GHG emissions are assessed based on the additional capacity the project creates in comparison to the original design capacity.

3.1 Quantification of a project's net GHG emissions

3.1.1 Net GHG emissions calculation

The *Information and Management of Time Limits Regulations* [6] under the IAA set out the information that proponents are required to provide in their initial and detailed Project Descriptions, which includes an estimate of any GHG emissions associated with the project. This should be calculated as the net GHG emissions associated with the project and estimated based on the information available to proponents at each stage. An initial estimate would be provided in the initial Project Description, updated in the detailed Project Description, and further refined in the Impact Statement as more information becomes available. Equation 1 defines net GHG emissions.

Equation 1: Net GHG emissions

Net GHG emissions =

Direct GHG emissions

+ Acquired energy GHG emissions

- CO_2 captured and stored

- Avoided domestic GHG emissions

- Offset credits

In the Impact Statement, each term of equation 1 must be reported separately for each year of the project lifetime (i.e., for all phases of the project: construction, operation and decommissioning).

Project proponents must provide the methodologies, a description of the model if a model is used, data, emission factors and any assumption used to estimate a project's net GHG emissions.

Direct GHG emissions: GHG emissions generated by activities that are within the defined scope of the project. (Note: If transportation of products beyond the project is included in the scope of the project, then emissions generated by that transportation are to be included as direct GHG emissions.)

Examples of direct emissions include:

- Emissions from land use change (e.g., land clearing including deforestation, biomass decay, etc.);
- Emissions from mobile combustion (e.g., vehicle, machinery, etc.);
- Emissions from stationary combustion (e.g., boilers, burners, reciprocating engines, etc.);
- Emissions from industrial process (e.g., chemical, mineral and metal production, incineration, etc.); and
- Flaring, venting and fugitive emissions.

Acquired energy GHG emissions: GHG emissions associated with the generation of electricity, heat, steam or cooling, purchased or acquired from a third-party for the project. Examples of acquired energy GHG emissions include: emissions associated with the generation of purchased or acquired electricity from the grid, and of purchased or acquired steam, heat or cooling from an adjacent facility. Upstream GHG emissions, as defined in Section 3.2, are assessed separately and are not included in this definition.

CO_2 captured and stored: CO_2 emissions that are generated by the project and permanently stored in a storage project that meets the following criteria:

- the geological site into which the CO_2 is injected is a deep saline aquifer for the sole purpose of storage of CO_2, or a depleted oil reservoir for the purpose of enhanced oil recovery; and
- the quantity of CO_2 stored for the purposes of the project is captured, transported and stored in accordance with the federal, provincial, U.S., or state laws.

Avoided domestic GHG emissions: GHG emissions that are reduced or eliminated in Canada as a result of the project. The avoided GHG emissions only apply to the project's net GHG emissions (i.e., not to any upstream emissions calculations).

The following examples illustrate avoided domestic GHG emissions:

- In the case of an expansion project, the emissions reduction resulting from the replacement of existing equipment with more energy-efficient equipment on the project site.
- In the case of a new project, the emissions reduction resulting from the replacement of a high-emitting facility with a lower-emitting facility.
- In the case of any facility that generates and sells surplus energy, the amount of emissions saved from producing that energy from the previous, higher-emitting source.

Avoided domestic GHG emissions can also include GHG emissions removed as a result of mitigation measures seperate from the project and not reflected in the project's direct GHG emissions. This could include, for example, action taken at the corporate level in Canada, such as the use of diret air capture technology and afforestation, provided that action is not required by law, is not also counted as offset credits (see below), and can be assigned to the project.

Infrastructure Canada's Climate Lens General Guidance [8] provides general guidance on how to quantify avoided emissions. The proponent must select the appropriate "total net baseline scenario emissions" and the "total net baseline scenario removals", and provide the rationale for those scenarios. The scenarios must consider new measures (e.g., policies, regulations, plans and programs) applicable to the project put in place by provincial, territorial and federal governments, be realistic, conservative and take into account market conditions and feasibility.

In the quantification approach, the avoided domestic GHG emissions should represent reductions or removals that are real, additional, quantified, verifiable, unique, and permanent.

Avoided foreign emissions should not be quantified in the avoided domestic GHG emissions. Proponents will have the opportunity to discuss potential impacts of their project on global GHG emissions. Section 5.1.3 describes this consideration. Further details on quantification of avoided domestic GHG emissions will be included in the technical guide on GHG quantification.

Offset credits: Represent GHG emission reductions or removals generated from activities that are additional to what would have occurred in the absence of the offset project (i.e., generated from activities that go beyond legal requirements and a business-as-usual standard). Each offset credit generated by an offset project represents one tonne of carbon dioxide equivalent (CO_2 eq) reduced or removed from the atmosphere.

Offset credits must:

- Not have been retired / cancelled for any other purpose, including:
    - compliance with any regulatory requirement;
    - voluntary claims by the proponent (i.e., for purposes unrelated to the impact assessment); or
    - compliance or voluntary purposes by any other entity.

- Be sourced from a project that is registered in a Canadian regulatory offset program that aligns with the best practices outlined in the Canadian Council of Ministers of the Environment Pan-Canadian Offsets Framework. [9]
- Be issued on the basis of the GHG reductions and removals that have already occurred, instead of on the basis of expected reductions or removals.
- Be verified to a reasonable level of assurance by an accredited third-party verification body.
- Be sourced from project activities that are verifiable, quantifiable, additional to a business-as-usual scenario and a project baseline that incorporates legal or regulatory requirements.

In addition:

- Any offset credits used to compensate for project emissions should have been issued no more than 5 years before the year the emissions occured.
- With the exception of offsets that satisfy the next criterion, offset credits must be sourced from offset projects in Canada, and represent emission reductions of one or more of the greenhouse gases included in Canada's most recent version of the National Inventory Report.
- Foreign offset credits will only count if they fully comply with the rules for Internationally Transferred Mitigation Outcomes (ITMOs) established in Article 6 of the Paris Agreement, all applicable decisions adopted by the Conference of the Parties and any further criteria for international offsets to be developed by ECCC. For

example, international offset credits must represent real, quantified and additional mitigation outcomes, which have been authorized by the host country for use toward Canada’s national emissions targets under the Paris Agreement, and are subject to robust accounting to avoid double-counting.

- Proponents should provide an annual report with information on the offsets retired or cancelled for the previous year.

3.1.2 Emission intensity calculation

In addition to providing the project’s net GHG emissions, the proponent will provide the estimated GHG emission intensity using Equation 2.

Equation 2: Emission intensity calculation

$$\text{Emission intensity} = \frac{\text{Net GHG Emissions}}{\text{Units produced}}$$

The proponent must calculate the emission intensity estimate for each year of the operation phase of the project. The emission intensity and units produced must be reported separately for each year of the operation phase of the project.

The emission intensity will be used to compare the project to similar high-performing, energy-efficient project types in Canada and internationally in the Impact Statement. The emission intensity units will be specified in the Tailored Impact Statement Guidelines; the emission intensity estimate may not be possible nor relevant for some project types.

3.2 Assessing a project’s upstream GHG emissions

3.2.1 Overview

Upstream emissions are the domestic and non-domestic emissions from all stages of production, from the point of resource extraction or utilization, to the project under review.

In 2016, the Government of Canada published a draft methodology for estimating upstream GHG emissions in *Canada Gazette*, Part I. [10] An upstream GHG assessment has two parts:

- **Part A** is a quantitative estimate of upstream GHG emissions associated with the project based on the project's maximum throughput or capacity (new project) or additional throughput or capacity (replacement or expansion project). This requires information on the methodology, data, assumptions, and approach to estimating those upstream GHG emissions.
- **Part B** is a qualitative discussion about the incrementality of the upstream GHG emissions estimated in Part A. It provides the conditions under which the upstream emissions estimated in Part A could be expected to occur regardless of whether the project proceeds.

3.2.2 When an upstream GHG emissions assessment will be required

Proponents of projects likely to exceed the upstream GHG emissions threshold outlined in Table 1 will need to complete an upstream GHG assessment. The upstream GHG emissions threshold declines over time.

Table 1: Upstream GHG emissions thresholds for conducting an upstream GHG assessment

Publication year of Tailored Impact Statement Guidelines	Upstream GHG threshold (kt CO_2 eq/year)
2020-2029	500
2030-2039	300
2040-2049	200
2050 and beyond	100

The Tailored Impact Statement Guidelines will confirm if an upstream GHG assessment is required in the Impact Statement based on preliminary calculations conducted by IAAC with the support of expert federal authorities.

3.3 Discussion on the development of emissions estimates and uncertainty assessment

Project proponents should describe the uncertainty associated with their project's net and upstream GHG emissions estimates. This description can be qualitative, although quantitative estimations of uncertainty should also be included where available.

Two types of uncertainty should be considered: i) uncertainty related to data and ii) uncertainty related to methods and models.

The discussion of uncertainty related to data should identify any assumptions made in selecting the data, its applicability to the project, its representativeness, and its completeness. The discussion should explain how the data may be improved with more certainty on the project design and variables (type and volume of fuel used for example). A comparison of the data to comparable data sets may inform the uncertainty discussion. The discussion of uncertainty should also acknowledge that the uncertainty of GHG emissions estimates generally increases for years further out into the future.

The discussion on uncertainty of the methods and models, if applicable, should list the assumptions related to the method or model used and their rationale. The uncertainty could be represented using different methods and models, or by developing scenarios with varying data inputs to generate a range of reasonable emissions. There could be scenarios related to changes in project design and scenarios related to external considerations that may affect a project's GHG emissions over time. Examples include a qualitative discussion on how the economics surrounding the project could influence the project's emissions, such as the price of commodities, and how the emissions could change depending on the type of equipment, fuel or other source of energy used.

Finally, the discussion on uncertainty should describe how the uncertainty of the emissions estimates was reduced.

Further guidance on the development of the emissions estimates will be provided in the technical guide on quantifying GHG emissions for projects.

4. Climate change in the Planning Phase

Projects subject to the IAA will go through a Planning Phase in which potential impacts are discussed with the public and with Indigenous peoples at the outset of the impact assessment process. The information collected in the Planning Phase will inform the Tailored Impact Statement Guidelines, which will outline the scope and information related to climate change required in the Impact Statement.

Information related to the project's GHG emissions and climate change will be provided through three avenues during the Planning Phase:

1. **The initial and detailed Project Description**, which includes: the project type, its purpose and an estimate of its GHG emissions, which should be calculated as net GHG emissions.
2. **Engagement with Indigenous peoples, local communities, other jurisdictions, the public, and federal authorities**. Following engagement on the initial Project Description, IAAC (or relevant body) will prepare a Summary of Issues. This will outline the issues it considers relevant to the assessment, informed by the input from Indigenous peoples, stakeholders, other jurisdictions and the public during early engagement on the project and the expertise of federal departments.
3. **Additional information provided by the proponent** during the Planning Phase, such as the proponent's response to the Summary of Issues, and any other information provided by the proponent at its discretion.

4.1 Initial and detailed project description

The *Information and Management of Time Limits Regulations* [11] under the IAA set out the information that proponents must provide in their initial and detailed Project Descriptions. On GHG emissions and climate change, proponents are required to provide an estimate of the project's GHG emissions, and are encouraged to provide information on GHG mitigation measures to be considered in the Impact Statement.

4.1.1 GHG emissions estimates

The *Information and Management of Time Limits Regulations* require project proponents to provide an estimate of any GHG emissions associated with the project. To fulfill this requirement, the following information should be provided in initial and detailed Project Descriptions:

- estimate of the maximum annual net GHG emissions for each phase of the project, including a breakdown of each term of Equation 1; and
- the methodology, data, emission factors and assumptions used.

4.1.2 Carbon sinks

The *Information and Management of Time Limits Regulations* require project proponents to provide a description of the physical and biological environment of the project's location. Project proponents should provide the following information to help IAAC, or the relevant lifecycle regulators, with the support of expert federal authorities, understand the potential impacts on carbon sinks:

- a description of the activities that would result in an impact on carbon sinks; and
- land areas expected to be impacted by the project, by ecosystem type (forests, cropland, grassland, wetlands, built-up land) over the course of the project lifetime, including any areas of restored or reclaimed ecosystems.

4.1.3 Alternative means of carrying out the project

The *Information and Management of Time Limits Regulations* require project proponents to list (for the initial Project Description) or describe (for the detailed Project Description) the potential alternative means of carrying out the project that are technically and economically feasible, including through the use of best available technologies.

When evaluating alternative means of carrying out the project, project proponents should discuss the potential impacts of the alternatives on GHG emissions and how GHG emissions were considered as a criterion in the alternatives selection.

Project proponents are also encouraged to provide information on the measures being considered to reduce the project’s GHG emissions on an ongoing basis. These measures could include technologies and practices to reduce the project’s GHG emissions.

For projects with a lifetime beyond 2050, proponents are encouraged to provide an overview of the measures being considered to ensure projects are net-zero emissions by 2050.

4.2 Tailored Impact Statement Guidelines

The scope of information related to GHG emissions and climate change in the Impact Statement will be tailored to the project in the Tailored Impact Statement Guidelines published by IAAC at the end of the Planning Phase.

All projects undergoing a federal impact assessment will be required to provide information with respect to GHG emissions, impact of the project on carbon sinks, impact of the project on federal emissions reduction efforts and on global GHG emissions, GHG mitigation measures, and climate change resilience.

Proponents of projects with **upstream GHG emissions likely greater than or equal to the threshold** outlined in Table 1 (refer to Section 3.2.2) will also be asked to provide an upstream GHG assessment (refer to Section 5.2).

Proponents of projects with **lifetime beyond 2050 will be asked to provide a credible plan** for the project to achieve net-zero emissions by 2050 (refer to Section 5.3).

Other information that may arise in the Planning Phase, either provided by the proponent in the initial or detailed Project Description, or from engagement on the Summary of Issues prepared by IAAC or relevant body, may be considered in determining the scope and type of information that will be requested in the Impact Statement. For example, a description of any potential benefits of the project with respect to GHG emissions and climate change provided by the proponent in the Project Description could be considered in tailoring the scope and type of information that will be asked for in the Impact Statement.

5. Climate change information in the Impact Statement Phase

Following the publication of the Tailored Impact Statement Guidelines for the project, the proponent will prepare an Impact Statement that adheres to the Tailored Impact Statement Guidelines. Information provided in the Impact Statement will be reviewed by IAAC, or relevant lifecycle regulators, with the support of expert federal authorities in the Impact Assessment Phase, as outlined in Section 6.

5.1 Information to be provided for all projects

All project proponents will be asked to provide information on GHG emissions, impact of the project on carbon sinks, impact of the project on federal emissions reduction efforts and on global GHG emissions, mitigation measures and climate change resilience.

5.1.1 GHG emissions

Project proponents must provide:

- A description of each of the project's main sources of GHG emissions and their estimated annual GHG emissions over the lifetime of the project;
- Net GHG emissions by year for each phase of the project based on the project's maximum throughput or capacity (new project) or additional throughput or capacity (replacement or expansion project) (refer to Section 3.1.1);
- Each term of Equation 1 (direct GHG emissions, acquired energy GHG emissions, CO_2 captured and stored, avoided domestic GHG

emissions and offset credits, if applicable), per year for each phase of the project (refer to Section 3.1.1);

- Emission intensity for each year of the operation phase of the project (refer to Section 3.1.2);
- The quantity and a description of the ”units produced” used in Equation 2 for each year of the operation phase of the project (refer to Section 3.1.2);
- Methodology, data, emission factors and assumptions used to quantify each element of the net GHG emissions (refer to Section 3.1.1);
- A discussion on the development of emissions estimates and uncertainty assessment (refer to Section 3.3); and
- A description of large sources of GHG emissions that may be the consequence of accidents or malfunctions.

5.1.2 Impact of the project on carbon sinks

The calculation of a project’s net GHG emissions accounts for emissions related to land-use change. Proponents must also provide a qualitative description of the project’s positive or negative impact on carbon sinks. This is because some projects may improve or reduce the ability of an ecosystem, land area or ocean to absorb carbon dioxide from the atmosphere. An impact on a carbon sink implies the interruption or alteration of a natural continual process that removes carbon from the atmosphere.

This information must include:

- Description of project activities in relation to significant landscape features such as topography, hydrology and regionally dominant ecosystems.
- Land areas directly impacted by the project, by ecosystem type (forests, cropland, grassland, wetlands, built-up land) over the course of the project lifetime; this includes the areas of restored or reclaimed ecosystem(s).
- Initial carbon stocks in living biomass, dead biomass and soils (by ecosystem type) on land directly impacted by the project over the course of the project lifetime.
- Fate of carbon stocks on directly impacted land, by ecosystem type: immediate emissions, delayed emissions (timeframe), storage (e.g., in wood products).
- Anticipated land cover on the impacted land areas after the project is in place.

ECCC is developing an approach to estimate losses or gains to carbon sinks. ECCC will provide that approach in the technical guide on GHG Quantification. Once the methodology is published in the technical guide, proponents will be required to provide a quantitative and qualitative description of the project's positive or negative impacts on carbon sinks. Estimating quantitative impacts of a project on carbon sinks amounts to estimating the reduction (or increase) in the quantity of carbon that an area would have accumulated without the project, over the project lifetime.

5.1.3 Impact of the project on federal emissions reduction efforts and on global GHG emissions

Proponents must provide in their Impact Statement:

- An explanation of how the project may impact **Canada's efforts to reduce GHG emissions**, if applicable. For some projects, there will be nothing to add in this section. For some, however, the Impact Statement may be able to explain how the project would result in GHG emission reductions in Canada (e.g., by replacing higher-emitting activities).
- A discussion on how the project could **impact global GHG emissions**, if applicable. This could include, for example:
  - If there is a risk of carbon leakage if the project is not built in Canada, the Impact Statement could include an explanation of the likelihood and possible magnitude of carbon leakage if the project is not approved.
  - If the project may displace emissions internationally, the Impact Statement could describe how the project is likely to result in global emission reductions. For example, a project that enables the displacement of high-emitting energy abroad with lower-emitting energy produced in Canada could be considered as having a positive impact.

5.1.4 GHG mitigation measures

In the Impact Statement, proponents must describe the mitigation measures they will take to minimize GHG emissions throughout all phases of the project. Emphasis should be placed on minimizing absolute emissions as early as possible in the project lifespan. Proponents will be asked to conduct a BAT/BEP Determination for their project, including an assessment of emerging technologies. The

BAT/BEP Determination will play an important role in the Impact Assessment Phase as it may inform the enforceable conditions imposed on the project if it is approved.

For all projects proceeding to the Impact Assessment Phase, the proponent will be asked to provide in the Impact Statement:

- A BAT/BEP Determination to identify ways to minimize the project's GHG emissions (refer to Section 5.1.4.1).
- A description of any additional mitigation measures (such as direct air capture technology and afforestation) that will be taken to mitigate remaining GHG emissions, if applicable.
- A description of any offset credits that have been or will be obtained to mitigate remaining GHG emissions, if applicable. Proponents may also provide information on their intent to acquire or generate international offset credits. Offset credits must comply with the criteria in Section 3.1.1, and will be considered as the last option in terms of GHG mitigation measures.
- A description of measures taken to mitigate the project's impact on carbon sinks, including measures to restore disturbed carbon sinks, if applicable.
- Subject to the public availability of information, a comparison of the project's projected GHG emission intensity to the emission intensity of similar high-performing, energy-efficient project types in Canada and internationally. If applicable, the comparison should explain why the emission intensity of the project is different.
- A list of the federal, provincial or territorial GHG legislation, policies or regulations that will apply to the project.

5.1.4.1 Best Available Technologies / Best Environmental Practices Determination

BAT/BEP are defined as the most effective technologies, techniques, or practices, including emerging technologies, that can be technically and economically feasible for reducing GHG emissions during the lifetime of the project.

This assessment is to be conducted to confirm that the project's design will minimize GHG emissions, in line with the boundaries of the project undergoing the federal impact assessment. Setting the scope of the analysis at the project level, instead of the equipment level, gives project proponents flexibility to optimize the project's overall design while demonstrating the use of BAT/BEP.

The BAT/BEP Determination process is outlined in Table 2.

Table 2: BAT/BEP Determination

Process step	Information requirement
Listing	Proponent establishes a list of all technologies and practices, including emerging technologies, based on the identified sources of emissions for the project during its lifetime.
Technical Feasibility Assessment	Proponent eliminates options determined to not be technically feasible, providing rationale. Proponent describes the timing and circumstances in which the eliminated options could become technically feasible.

Process step	Information requirement
GHG Reduction Potential Assessment	Proponent ranks remaining options based on GHG reduction potential.
Economic Feasibility Assessment and Additional Considerations	Proponent eliminates options determined to not be economically feasible, providing rationale. Proponent describes the timing and circumstances in which the eliminated options could become economically feasible. Proponent outlines additional environmental, social, or other considerations, providing rationale.
Selection of BAT/BEP	Proponent describes the technologies and practices to be used in the Project, and provides a justification for selecting any technology or practice that is not a BAT/BEP. Proponent provides information on how the options eliminated because of technical and economical unfeasibility could be phased in during the project lifetime, including how they could be considered during periods of project maintenance and facility upgrades.
Review	IAAC or the relevant lifecycle regulator, with support from expert federal authorities, reviews the BAT/BEP Determination and requests additional information if required.

The conclusion of the BAT/BEP Determination will be provided in the Impact Statement, and will include:

- The technologies that will be used to mitigate the project's GHG emissions. These could include, for example, the use of low-emitting technologies, the use of low-carbon or renewable fuel, electrification, or carbon capture and storage.
- The practices that will be taken to mitigate the project's GHG emissions, such as anti-idling practices for mobile equipment, leak detection and repair systems, continuous monitoring systems, or fleet optimization.
- The additional technologies and practices that could be considered during periods of project maintenance and facility upgrades to further reduce the project's GHG emissions through the lifetime of the project, as well as the planning process, timing and circumstances for that consideration.

ECCC plans to publish a technical guide to help project proponents conduct their BAT/BEP determination by providing additional information on technical, economic, social and environmental considerations.

5.1.5 Climate change resilience

A commitment in the Paris Agreement, climate change resilience aims to strengthen the global response to climate change. Adaptation and resilience is also a pillar of the Pan-Canadian Framework on Clean Growth and Climate Change, which recognizes that the impacts of climate change are already being felt across Canada. Climate change may alter the likelihood or magnitude of sudden weather events such as extreme precipitation that can contribute to flooding, as well as contribute to longer-term changes such as sea level rise, permafrost thaw and changes to migration patterns. Changes related to warming are already evident in many parts of Canada, and are projected to continue in the future with further warming. If not properly considered, such changes may cause issues such as equipment failures that can threaten the environment, human health and safety, interrupt essential services, disrupt economic activity, and require high costs for recovery and replacement.

All proponents will be required via the Tailored Impact Statement Guidelines, to provide information in the Impact Statement on how the project is resilient to and at risk from both the current and future impacts of a changing climate. This information will include descriptions of:

- the scope and timescale of the climate change resilience assessment and of the methods used to identify, evaluate and manage the climate risks that could affect the project itself and thereby the surrounding environment; and
- the project's vulnerabilities to climate change both in mean conditions and extremes over the full project lifetime from project construction to decommissioning. This could include the impacts of extreme weather events on project infrastructure, impacts to water quality and availability, etc.

ECCC plans to publish a technical guide to provide further instructions and details on the level of information for the climate change resilience assessment.

The resilience assessment should consider multiple scenarios, and should discuss the assumptions and data sources used and the confidence or uncertainty in the results. Where in-house models or forecasts are developed to support a specific assessment, the modeling methodology, assumptions, statistical certainty and data sources should be provided.

In general, given the inherent uncertainty and ongoing research in projecting future climate and associated impacts, proponents should look to global climate model projections of future climate, models of potential impacts and expert advice to inform how their project is resilient to climate change.

Proponents are encouraged to draw from reports such as the current national assessment, Canada in a Changing Climate: Advancing our Knowledge for Action, which was launched in 2017. [12] This series of reports outlines the state of knowledge pertaining to changes in Canada's climate, the impacts of these changes, and how we are adapting to reduce risk. The first report in this series is Canada's Changing Climate Report. [13]

Infrastructure Canada's Climate Lens - General Guidance [14] provides general information on conducting climate change resilience assessments, including guidance for assessing climate impacts and risks to a project, as well as a variety of resources to assist proponents in undertaking such analysis.

Information about how to access and use historical and future climate data can be obtained from the Canadian Centre for Climate Services (CCCS), established by the Government of Canada so that Canadians have the information and support they need to understand and reduce the risks from climate change.

5.2 Upstream GHG emissions assessment

Proponents of projects with upstream GHG emissions likely greater than or equal to the thresholds outlined in Table 1 (refer to Section 3.2.2) will be required in the Tailored Impact Statement Guidelines to provide an upstream GHG assessment and related uncertainty assessment (refer to Section 3.3).

5.3 Plan to achieve net-zero emissions by 2050

Proponents of projects with a lifetime beyond 2050 will be required to provide a credible plan that describes how the project will achieve net-zero emissions by 2050. The plan will complement and be informed by the GHG mitigation measures planned by the proponent (refer to Section 5.1.4).

The plan should demonstrate how the net GHG emission equation in Section 3.1.1 (Equation 1) will equal 0 kt CO_2 eq / year by 2050 and thereafter for the remainder of the lifetime of the project. The plan to achieve net-zero emissions does not apply to upstream GHG emissions, even if an upstream GHG emissions assessment was conducted.

A net-zero plan does not need to describe every technology or practice the project will implement over time to acheive net-zero emissions. Proponents can describe the process they will follow in order to make the decisions and investments needed to achieve net-zero emissions by 2050. A net-zero plan should describe emissions reductions at specified intervals up to 2050 and seek to maximize absolute emissions reductions in the earlier years of a project's lifespan.

Proponents may also identify any supportive actions by the Government that they would need in order to be able to achieve net-zero emissions. This could include, for example, identifying the need for the construction of a grid intertie to enable access to clean electricity.

The project's plan should explain the impact of the actions the company will take to achieve net-zero emissions on Canada's net-zero goal. The project's credible plan to achieve net-zero emissions can refer to the corporate's net-zero emission plan.

Like all of the other information to be provided under an impact assessment, the content of the plan will be taken into account by the relevant decision-makers with respect to project approvals. The submission of a plan that does not specify how a project will achieve net-zero emissions by 2050 will not disqualify a project from proceeding through the impact assessment process. Where it is not feasible to specify how later-year reductions will be achieved, if the project is approved, the Minister of Environment and Climate Change may require a proponent to update plans to specify how additional emissions reduction will be achieved (refer to Section 7) as a condition in the Decision Statement.

ECCC plans to publish a technical guide to provide further guidance and details on developing a credible plan to achieve net-zero emissions by 2050.

6. Climate change in the Impact Assessment Phase

IAAC or the lifecycle regulator, with the support of expert federal authorities, will review, comment on and complement, as needed, the GHG and climate change-related information provided by project proponents in their Impact Statements. This may include consideration of the methodologies, data, emission factors and assumptions used by the proponent, as well as comments received by the public and Indigenous peoples on the Impact Statement.

IAAC or the lifecycle regulator, with the support of expert federal authorities, will review, comment on and complement, as needed, the information about federal, provincial or territorial climate policies and measures that will apply to the project. This will not involve an assessment or commentary on the adequacy of these policies and measures, but will ensure that IAAC or the lifecycle regulator has complete information about all applicable policies and measures and their implication for the project.

In reviewing the project, IAAC or the lifecycle regulator, with the support of expert federal authorities, will consider mitigation measures that are in use in similar high-performing, energy-efficient project types, and will compare the project's emission intensity with similar projects in Canada and internationally. For projects with a lifetime beyond 2050, IAAC or the lifecycle regulator will review the proponent's plan to achieve net-zero emissions by 2050 and will also consider the supportive government actions identified by the proponent in order for the project to be able to achieve net-zero emissions.

Finally, IAAC or the lifecycle regulator, with the support of expert federal authorities, will provide supplemental analysis on the project's (net and upstream) GHG emissions in the context of Canada's emissions targets and forecasts, including Canada's commitments under the Paris Agreement, the goal for Canada to achieve net-zero emissions by 2050, Canada's 2030 emissions targets and Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy. This may include considering, for example, whether the project's emissions are built into the sector projections in ECCC's national forecast in Canada's National Communications and Biennial Reports submitted to the United Nations Framework Convention on Climate Change.

IAAC or the lifecycle regulator, with the support of expert federal authorities, will also review, comment on and complement, as needed, the proponent's climate change resilience assessment.

The review and analysis of the Impact Statement by IAAC or the lifecycle regulator, with the support of expert federal authorities, will be made available to the public and decision-makers.

7. Climate change in decision-making and conditions

Under the IAA, the Minister or Governor in Council [15] must decide whether the project is in the public interest.

The IAA also requires that the Minister or Governor in Council consider, among other factors, the extent to which the effects of the project hinder or contribute to the Government of Canada's ability to meet its environmental obligations and its commitments in respect of climate change. The information provided by project proponents pursuant to the guidance in this strategic assessment of climate change, together with the analysis of that information by IAAC or the lifecycle regulator, will ensure that assessment decisions account for a project's likely climate change-related effects. Decision-makers will be provided with analysis, including but not limited to, the project's GHG emissions in the context of Canada's emissions targets and forecasts, such as Canada's commitments under the Paris Agreement, Canada's 2030 emissions targets, Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, and Canada's goal for achieving net-zero emissions by 2050.

The Minister will issue a decision statement on whether the project is in the public interest. If the project is in the public interest and allowed to proceed, the decision statement will contain **enforceable conditions**, as well as the rationale for the decision. The GHG emissions-related conditions would only be applicable to a project's net GHG emissions, not to upstream activities even if an upstream GHG assessment was conducted. The GHG emissions-related **enforceable conditions** may refer to **mitigation measures and other requirements** to reduce or control a project's GHG emissions. These conditions may also include a reporting program in which the proponent would demonstrate progress towards implementing these mitigation measures and the plan for reaching net-zero emissions by 2050 for projects with a lifetime beyond 2050.

8. Climate change in the post-decision phase

If a decision is made that the project can proceed, the proponent must comply with any conditions in the Minister's decision statement. **These may include conditions** related to **GHG mitigation measures** and **follow-up program requirements**, including requirements to report progress in implementing these GHG mitigation measures and in implementing the plan for reaching net-zero emissions by 2050 for projects with a lifetime beyond 2050.

Proponents will submit information to IAAC to demonstrate they are in compliance with the conditions in the decision statement. IAAC will review the information, and may conduct on-site visits.

9. Contact information

For any question on the strategic assessment of climate change, correspondence should be sent to:

Strategic Assessment of Climate Change
Environment and Climate Change Canada
351 St. Joseph Boulevard, 12th Floor
Gatineau, QC K1A 0H3

Email: ec.escc-sacc.ec@canada.ca

Annex I – Useful resources

- 2019 National Inventory Report 1990-2016: Greenhouse Gas Sources and Sinks in Canada
- Canada's Changing Climate Report
- Canadian Center for Climate Services
- Climate Lens – General Guidance
- Discussion Paper Developing a Strategic Assessment of Climate Change
- Greenhouse gas projections
- Impact Assessment Regulations
- Mid-Century Long-Term Low-Greenhouse Gas Development Strategy
- Pan-Canadian Framework on Clean Growth and Climate Change
- Pan-Canadian Greenhouse Gas Offsets Framework (PDF; 132 kB)
- Terms of Reference for conducting the Strategic Assessment of Climate Change

Annex II – Developing the strategic assessment of climate change

On July 19, 2018, ECCC published a discussion paper to seek views on the objectives and scope of the strategic assessment of climate change. [16] Comments received informed the development of the Terms of Reference and the draft strategic assessment of climate change.

On March 11, 2019, ECCC published Terms of Reference that outlined the scope, process and timelines for conducting the strategic assessment of climate change [17].

The strategic assessment of climate change has been developed under the authority of the *Department of the Environment Act*, adhering as closely as possible to the provisions in the IAA, including the obligations to:

- Take into account any scientific information and Indigenous knowledge provided;
- Make the information used available to the public; and
- Ensure the public is provided with an opportunity to participate meaningfully.

The Terms of Reference outlined the scope of the strategic assessment of climate change, and stated that it would provide guidance for:

1. Quantifying a project's GHG emissions, including the approach to estimating direct and upstream GHG emissions, and how avoided emissions, GHG offsets and carbon sinks could be factored into estimates of GHG emissions;
2. Considering climate change in the Planning Phase of a project review; and
3. Considering climate change in the Impact Assessment Phase of a project review.

ECCC engaged provinces, territories, industry stakeholders, environmental non-government organizations, and Indigenous peoples in developing the draft strategic assessment of climate change. ECCC has:

- convened three Provincial/Territorial working group meetings to provide information and seek feedback on the approach to the strategic assessment of climate change;
- held a multi-stakeholder meeting and compiled the results of this engagement to inform the approach; and
- invited Indigenous peoples that provided comment on the discussion paper to individual meetings.

The draft strategic assessment of climate change was published on August 8, 2019. In August 2019, ECCC organized webinars to present the document to stakeholders, respond to questions and receive feedback. Comments received in response to the draft strategic assessment of climate change were considered in the development of the strategic assessment of climate change.

Minister Wilkinson deemed the strategic assessment of climate change, published in July 2020, a strategic assessment conducted under section 95 of the *Impact Assessment Act*.

In October 2020, a revised version of the SACC was published to provide further clarity on how the net-zero plans and offset credits will be considered in the impact assessment process.

Footnotes

1 The final SACC was originally published on July 16th 2020. This revised version provides further clarity on how the net-zero plans and offset credits will be considered in the impact assessment process.

2 For more information on the impact assessment process, please consult the Impact Assessment Agency of Canada (IAAC) website.

3 For more information, visit Canada's international action on climate change.

4 For more information, visit The Paris Agreement.

5 For more information, visit Policy and guidance.

6 *Information and Management of Time Limits Regulations*

8 Climate Lens - General Guidance

9 Pan-Canadian Greenhouse Gas Offsets Framework

10 Draft methodology for estimating upstream GHG emissions in *Canada Gazette*, Part I

11 *Information and Management of Time Limits Regulations*

12 Canada in a Changing Climate

13 Canada's Changing Climate Report (2019)

14 Climate Lens - General Guidance

15 For impact assessments conducted by the IAAC, the Minister is responsible for making the public interest determination or may refer the decision to the Governor in Council. For impact assessments conducted by a review panel, or an integrated review panel with a lifecycle regulator, the Governor in Council is responsible for making the public interest determination.

16 Discussion paper Developing a Strategic Assessment of Climate Change

17 Terms of Reference

Date modified:
2020-10-06

DISCUSSION PAPER ON STRATEGIC ASSESSMENT OF CLIMATE CHANGE

A NEW IMPACT ASSESSMENT SYSTEM

Terms of Reference for Conducting a Strategic Assessment of Climate Change

1. Context

The Government is undertaking a Strategic Assessment of Climate Change to provide guidance on how Canada's climate change commitments should be considered in impact assessments.

This strategic assessment will provide guidance relevant to environmental assessments under the *Canadian Environmental Assessment Act*, 2012. It will also provide guidance for impact assessments under the proposed *Impact Assessment Act* if it becomes law.

The Strategic Assessment of Climate Change will be developed under the authority of the *Department of the Environment Act*, but will adhere as closely as possible to the provisions in the proposed *Impact Assessment Act*, including the obligations to:

- take into account any scientific information and Indigenous knowledge provided;
- make the information used available to the public; and
- ensure the public is provided with an opportunity to participate meaningfully.

Under the proposed *Impact Assessment Act*, the impact assessment must take into account the extent to which the project's effects will hinder or contribute to Canada's ability to meet its climate change commitments and the environment's potential impact on the project, including as a result of climate change.

The Strategic Assessment of Climate Change will be an evergreen document that can be updated over time to reflect relevant changes in climate change policy and targets.

2. Objectives

The Strategic Assessment of Climate Change will provide guidance to proponents, stakeholders, Indigenous Peoples and decision-makers on how climate change policies and commitments should be considered in impact assessments. Central to this work is engagement with provinces and territories.

3. Approach to Conducting the Strategic Assessment of Climate Change

In conducting the Strategic Assessment of Climate Change, ECCC will:

- Convene a Provincial/Territorial working group to provide information, advice, and feedback in the development of the Strategic Assessment of Climate Change (further details on the working group in section 5);
- Arrange for multi-stakeholder input and compile the results of engagement to inform the approach and assessment;
- Provide an opportunity for the public to comment on a draft Strategic Assessment of Climate Change; and
- Publish a final Strategic Assessment of Climate Change.

4. Content of the Strategic Assessment of Climate Change

The Strategic Assessment of Climate Change will include, at a minimum, the following guidance:

1) Quantification of a project's GHG emissions

The Strategic Assessment of Climate Change will provide an approach to quantifying the GHG emissions of proposed projects. This will include clarifying:

- the approach to estimate direct and upstream GHG emissions;
- that downstream emissions will not be assessed; and

- how avoided emissions, GHG offsets, and carbon sinks could be factored into estimates of GHG emissions.

2) Consideration of climate change in the planning phase of a project review

Under the proposed *Impact Assessment Act*, a planning phase would be used to confirm whether an impact assessment of a project is required, the type of assessment (i.e. Agency-led review or Panel review) and the factors to be considered in the assessment. The Government is developing *Information Requirements and Time Management Regulations* for the proposed *Impact Assessment Act* to set out the requirements of an initial project description at the planning phase. The Strategic Assessment of Climate Change will provide additional guidance on the information that could be used to support the consideration of climate change at the planning stage. This guidance could include:

- an explanation of how applicable federal, provincial or territorial GHG laws, regulations and policies will be considered;
- the roles of best available technology and best environmental practices economically feasible to mitigate emissions; and
- significance of the level of emissions.

3) Consideration of climate change in the impact assessment phase of a project review

For projects that proceed to an assessment whether under existing environmental assessment regimes or under the proposed *Impact Assessment Act*, the Strategic Assessment of Climate Change will provide guidance on the information needed to assess the GHG emissions of the project as well as other climate change considerations. This guidance could include:

- how to consider applicable federal, provincial, or territorial GHG laws, regulations and policies, and international climate commitments;
- when upstream GHG emissions will be assessed; and
- how to account for the use of best available technology and best environmental practices and innovation.

Over time, ECCC may supplement the Strategic Assessment of Climate Change with additional guidance documents to provide further details on key elements of the Strategic Assessment of Climate Change, such as guidance on methodologies for estimating project GHG emissions.

5. Engagement

5.1 Working Group

ECCC will convene a Provincial/Territorial Working Group to provide information, advice and feedback to ECCC during the development of the Strategic Assessment of Climate Change. The Provincial/Territorial Working Group will be open to all provincial and territorial governments.

ECCC will send invitations to provincial and territorial members of the Canadian Council of Ministries of the Environment.

ECCC will request that each province and territory assign one official to the group, and that those officials represent departments or agencies with responsibility for climate change and environmental assessments.

5.2 Working Group Meetings

The Provincial/Territorial Working Group will meet at least three times during the course of the Strategic Assessment of Climate Change. Members will be able to attend in person or remotely. ECCC's Director General of the Energy and Transportation Directorate and ECCC's Director General of the Fisheries Act and Impact Assessment Team will co-chair the Working Group meetings. Working Group members will be given reasonable notice of meetings, and be provided with the necessary background materials ahead of time.

The first meeting will be an introductory session on the Strategic Assessment of Climate Change to:

- provide an overview of comments received as a result of the Strategic Assessment of Climate Change Discussion Paper;
- provide an overview on how climate change features in the proposed *Impact Assessment Act*;
- discuss working group planning: schedules, expectations, and work plans; and
- seek initial views and guidance on:
    - the approach to quantifying the GHG emissions of a project; and
    - considering climate change in planning and impact assessment.

Working Group members will be provided one week for comments on the materials presented and discussed during the Working Group Meetings.

5.3 Indigenous Engagement

Recognizing the unique experiences of Indigenous Peoples with respect to climate change, ECCC will seek their views and input. This engagement will be flexible and goal-oriented, and will seek to avoid duplicating other Indigenous engagement initiatives related to the proposed *Impact Assessment Act*.

6. Timelines

The intent is to complete the Strategic Assessment of Climate Change by summer 2019.

Category	Timelines
Launching the Strategic Assessment of Climate Change with the Publication of the terms of reference	February 2019
First Working Group Meeting	February 2019
Second Working Group Meeting	March 2019
Third Working Group Meeting	Late March 2019
Indigenous Engagement through Regular Information Sessions	February to May 2019
Publication of the draft Strategic Assessment of Climate Change followed by a 30-day public comment period	Late April – Late May 2019
Publication of the final Strategic Assessment of Climate Change	Summer 2019

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DECLARATION ON THE RIGHTS OF INDIGENOUS PEOPLES ACT ACTION PLAN

2022-2027

BRITISH COLUMBIA

Copies of this report are available from:

Reconciliation Transformation and Strategies Division
BC Ministry of Indigenous Relations and Reconciliation
Email: declaration@gov.bc.ca

and electronically (in a .pdf file) from:
http://declaration.gov.bc.ca

Cover design:

Cover photo: The photo was taken by Melody Charlie, a First Nations photographer. Melody is based out of Yuuthluithaht (Ucluelet) B.C. Her photography reflects the love and respect she holds for her culture and ways of life, always focussing on the strengths and resilience of her people.

Front and back cover art: The feather and drum art presented on the cover was developed by Andy Everson. Andy is an accomplished artist from the K'omoks First Nation on Vancouver Island. He draws upon his roots amongst the Kwakwaka'wakw, Salish and Tlingit peoples to create artwork that reflects the convergence of ancient traditions with modern society.

The four feathers represent the diversity of the Indigenous Peoples of British Columbia, while the drum symbolizes the heartbeat of ceremonies. The feathers are arranged in four directions to represent the people of the North Coast (North), Interior (East), Salish (South) and those who are disenfranchised or have relocated to western Canada (West).

BRITISH COLUMBIA

JOINT MESSAGE FROM THE PREMIER OF BC AND THE MINISTER OF INDIGENOUS RELATIONS AND RECONCILIATION

On November 26, 2019, with the unanimous passage of the *Declaration on the Rights of Indigenous Peoples Act* in the B.C. legislature, we committed to upholding the human rights of Indigenous Peoples. Under this legislation, we have begun with a five-year action plan in consultation and cooperation with Indigenous Peoples to advance this vital work. We are pleased to present the first *Declaration on the Rights of Indigenous Peoples Act* action plan.

This has been challenging work in challenging times. Over the past two years while we worked together on this plan, we faced incredible adversities. We have been grappling with a global pandemic, a toxic drug supply crisis, and our communities were ravaged by wildfires, floods and heat waves. Through all of these challenges, Indigenous Peoples have carried a disproportionate burden. This burden was made even heavier by the devastating findings of unmarked graves at former residential school sites. These experiences have been stark reminders of the continued effects of colonialism and systemic racism. They also reinforce with absolute certainty the importance of the work to be carried out through this action plan to implement and uphold the human rights of Indigenous Peoples.

Even in the face of these overwhelming challenges, Indigenous Peoples throughout the province continued to work with us on this action plan, determined to create a better future for all generations to come. We are grateful for the time, energy, leadership, and expertise they contributed to finalizing this action plan.

We are also grateful for the dedication of the many public servants who contributed to this work, and who will work in partnership with Indigenous Peoples to carry out these actions to advance our shared long-term vision of reconciliation. We acknowledge the support for this action plan from local governments, business and industry, the non-profit sector, scholars, and many others who share our commitment to reconciliation.

Our government is committed to pursuing the goals and achieving the outcomes articulated in this action plan. It includes 89 actions that represent contributions by each and every ministry. Together, we will work to advance reconciliation in tangible and measurable ways in communities across the province.

This work requires real and meaningful systemic change. We see the commitment to that change across the board – from the Province, Indigenous Peoples, allies, and supporters, and it gives us great hope that the outcomes of this plan are not only possible, but achievable. We have much work ahead of us, and together we will create a better future for everyone.

John J. Horgan

John Horgan
Premier

Murray Rankin

Murray Rankin, QC
Minister of Indigenous
Relations and Reconciliation

CONTENTS

INTRODUCTION

The *Declaration on the Rights of Indigenous Peoples Act* (Declaration Act)[1] was unanimously passed by the British Columbia Legislative Assembly in November 2019. This made B.C. the first jurisdiction in Canada to adopt the United Nations Declaration on the Rights of Indigenous Peoples (UN Declaration).[2] The Declaration Act was developed jointly with Indigenous leaders and legal staff and was introduced through historic ceremony.

The Declaration Act established the UN Declaration as the Province's framework for reconciliation, as called for by the Truth and Reconciliation Commission.[3] Section 4 of the Declaration Act requires development and implementation of an action plan, in consultation and cooperation with Indigenous Peoples,[a] to achieve the objectives of the UN Declaration. The UN Declaration is a "universal framework of minimum standards for the survival, dignity and well-being of the Indigenous [P]eoples of the world and it elaborates on existing human rights standards and fundamental freedoms as they apply to the specific situation of Indigenous [P]eoples."[4] The provincial government is committed to upholding these human rights in its institutions, laws, policies and practices to advance reconciliation and address the legacy and harms of colonialism on Indigenous Peoples. The Province reaffirms its intent to achieve government-to-government relationships based on respect, recognition and exercise of Aboriginal title and rights and reconciliation of Aboriginal and Crown titles and jurisdiction.

The *Declaration on the Rights of Indigenous Peoples Act* contributes to the implementation of the UN Declaration in B.C. by:

- requiring the Province, in consultation and cooperation with Indigenous Peoples to take all measures necessary to ensure the laws of B.C. are consistent with the UN Declaration (section 3);
- requiring the development and implementation of an action plan, in consultation and cooperation with Indigenous Peoples, to achieve the objectives of the UN Declaration (section 4);
- requiring the Province to report annually on progress made toward alignment of laws and achievement of the goals in the action plan (section 5); and
- enabling agreements with Indigenous governing bodies, including joint or consent-based decision-making agreements that reflect free, prior and informed consent (sections 6 and 7).

This action plan outlines significant actions the Province will undertake in consultation and cooperation with Indigenous Peoples over the next five years. The Province will continue to demonstrate commitment and ensure accountability to implement the UN Declaration and the Declaration Act Action Plan through collaborative annual reporting.

a Consistent with section 35 of the *Constitution Act, 1982* and section 1 of the Declaration Act, the term "Indigenous Peoples" includes First Nations, *Métis* and Inuit Peoples in Canada.

The Province conducted initial engagement to develop the draft action plan with Indigenous Peoples between July 2020 and February 2021.[b,5] The Province conducted broader engagement on the draft action plan to seek input from Indigenous Peoples to inform the final action plan between June and September 2021. Engagement focused on Indigenous Peoples in B.C.; however, local governments and non-Indigenous people, organizations, business and industry leaders also participated.[c] Engagement feedback was carefully reviewed, considered and utilized to finalize this action plan.

Colonization and the associated attempted genocide of Indigenous Peoples fractured the self-determined lives, cultures and well-being of Indigenous Peoples across Canada. The Declaration Act is both an acknowledgment of these histories and a commitment by the Government of B.C. to respect and uphold the human rights of Indigenous Peoples. If history is a teacher, meeting this collective responsibility will require a different approach from that previously taken. This action plan has been built through discussion with Indigenous Peoples in B.C. It describes initial actions for the Province to take in consultation and cooperation with Indigenous Peoples over the next five years. Through the action plan, the Province is committed to changing the trajectory of history through coherent, concrete and cooperative action.

b For further details on the development of the draft action plan, see the *Declaration on the Rights of Indigenous Peoples Act 2020/21 Annual Report*.

c Further details and reflection on the draft action plan engagement process will be included in the forthcoming annual report for 2021-2022.

PURPOSE

This action plan provides a province-wide, whole-of-government approach to achieve the objectives of the UN Declaration over time. The Province acknowledges the widespread socio-economic and health inequities for Indigenous Peoples in B.C. and across Canada. This includes the overrepresentation of Indigenous people in the justice and child welfare systems, lower rates of education, and higher instances of poverty, unemployment and homelessness. The goals and outcomes of this action plan focus on addressing the inequities experienced by Indigenous Peoples by achieving the highest attainable standard for health and well-being.

DISTINCTIONS-BASED APPROACH:

The Province is committed to a distinctions-based approach. This requires that the Province's dealings with First Nations, Métis and Inuit Peoples be conducted in a manner that acknowledges the specific rights, interests, priorities and concerns of each, while respecting and acknowledging these distinct Peoples with unique cultures, histories, rights, laws, and governments. Section 35 of the *Constitution Act, 1982*, recognizes and affirms the rights of Aboriginal Peoples of Canada, while all Indigenous Peoples have human rights that are expressed in the UN Declaration. However, not all rights are uniform or the same among or between all Indigenous Peoples. In many cases, a distinctions-based approach may require that the Province's relationship and engagement with First Nations, Métis and Inuit Peoples include different approaches or actions and result in different outcomes.

These actions are intended to support changes in understandings, behaviours and systems to shift the status quo, address Indigenous-specific racism and establish new foundations of government that respect and uphold the human rights of Indigenous Peoples. The actions identified advance a distinctions-based approach that recognizes First Nations, Métis and Inuit as the Indigenous Peoples of Canada.

The action plan is meant to help everyone who lives in British Columbia understand the importance of reconciliation and how it will help the province achieve its greatest social, cultural and economic potential.

The actions identified in the plan build on priorities brought forward through decades of advocacy and leadership by Indigenous Peoples. These include existing priorities identified in current agreements between the Province and Indigenous organizations.

The 2018 *Implementing the Commitment Document - Concrete Actions: Transforming Laws, Policies, Processes and Structures*[6] is one existing document between the First Nations Leadership Council[d] and

d The First Nations Leadership Council is comprised of the political executives of the BC Assembly of First Nations, First Nations Summit, and the Union of BC Indian Chiefs.

the Province that sets out priorities with First Nations, including with respect to policy and legislative changes that reflect the recognition and implementation of title and rights.

The October 27, 2021 Letter of Intent[7] between Métis Nation British Columbia (MNBC) and the Province is another document that commits to strengthening relationships. This Letter of Intent proposes a new whole-of-government approach to Métis relations as a partnership between MNBC and British Columbia that respects Métis self-determination.

The 2022 government-to-government Shared Priorities Framework between each of the eight modern treaty nations and the Province commits to concrete actions to ensure timely, effective and fully resourced implementation of modern treaties.

Each action listed in this plan will be implemented in consultation and cooperation with Indigenous Peoples, reflecting our commitment to work in partnership and collaboration. The plan outlines actions that will be undertaken between 2022 and 2027. Progress will be reviewed on an annual basis and publicly reported in the Declaration Act annual reports.

It is important to note that the action plan does not include all provincial initiatives to advance reconciliation in B.C. Further, while closely linked to work under section 3 of the Declaration Act to ensure laws are consistent with the UN Declaration, the action plan is a separate and distinct obligation. Actions proposed in this plan do not replace, limit, change or stop existing initiatives or related commitments. These efforts will continue alongside the development and implementation of the action plan.

ANTI-RACISM:

The government of British Columbia recognizes the need to address Indigenous-specific racism in this province and within our systems, practices, and policies. First Nations, Métis and Inuit Peoples have experienced ongoing, systemic and race-based discrimination that has maintained unequal treatment and normalized the false notion that Indigenous Peoples are 'less than' their non-racialized counterparts.

Anti-racism is fundamental to achieving the objectives of the UN Declaration. Therefore, anti-racism is foundational to the goals, objectives and actions laid out in this plan. Key to the implementation of the Declaration Act are actions that identify, challenge, prevent, eliminate and change the values, structures, policies, programs, practices and behaviours that perpetuate racism. This will require understanding and targeting the root causes of systemic discrimination, our colonial and racist foundations, and committing to take action to create conditions of greater inclusion, equality and justice.[e,8]

e Indigenous-specific racism and anti-racism in this action plan are defined as per the 2020 *In Plain Sight* Report.

MODERN TREATIES IN BRITISH COLUMBIA:

The Province's relationship with the eight Nations with whom it has signed modern treaties is distinct and unique. These treaties, to which the Government of Canada is also a signatory, set out constitutionally protected rights and obligations of the parties and contain the actions and language necessary to carry out those rights and obligations. The rights and obligations contained in modern treaties have been established, a distinction that has significant and important implications for the work the Province does with modern treaty nations.

The Province recognizes that, consistent with the distinctions-based approach, all Indigenous Nations can choose whether they wish to enter the treaty making process.

The Province's work with modern treaty nations to fully implement these treaties occurs both with individual nations and collectively through the Alliance of British Columbia Modern Treaty Nations (the Alliance). The Alliance was formed to collaborate and advance areas of shared interest relating to the implementation of modern treaties in B.C.

As part of the continued work under the action plan, the Province has entered into a government-to-government Shared Priorities Framework with modern treaty nations with the goal of renewing its commitment to timely, effective and fully resourced implementation of modern treaties. The framework will address three broad outcomes:

- Comprehensive organizational and policy changes in the public service to ensure timely, effective, fully resourced whole-of-government approach to treaty implementation;
- Appropriate fiscal arrangements to fulfill treaty rights and obligations; and
- Meaningful involvement of modern treaty nations in legislative and policy initiatives.

Progress made to achieve these outcomes will be included in future annual Declaration Act annual reports.

SHARED UNDERSTANDINGS

This action plan and its implementation are informed by the following understandings:

Comprehensive The articles of the UN Declaration are interrelated and interdependent, intended to be read together and understood as an indivisible whole.

Distinctions-based The Province of British Columbia recognizes First Nations, Métis and Inuit as the Indigenous Peoples of Canada with rights recognized and affirmed in section 35(1) of the *Constitution Act, 1982*. The Province also recognizes that First Nations, Métis and Inuit are distinct, rights-bearing communities, and is committed to a distinctions-based approach to its relationship with each.

Diverse The action plan reflects the principle of diversity amongst Indigenous Peoples as stated in section 1(2) of the Declaration Act, which includes meeting the standard in article 37(2) that nothing in the UN Declaration "may be interpreted as diminishing or eliminating the rights of [I]ndigenous [P]eoples contained in treaties, agreements and other constructive arrangements."[9]

Legally Plural The action plan is grounded in the affirmation, consistent with the UN Declaration, that upholding the human rights of Indigenous Peoples includes recognizing that within Canada there are multiple legal orders, including Indigenous laws and legal orders with distinct roles, responsibilities and authorities.

Principled The goals, outcomes and actions in the action plan, and the process of implementing them will be consistent with "the minimum standards for the survival, dignity and well-being"[10] of Indigenous Peoples in the UN Declaration.

Cooperative The action plan has been developed and will be implemented in consultation and cooperation with Indigenous Peoples.

Enabling The action plan must enable and support government-to-government relationships between Indigenous Peoples and the Province based on recognition and implementation of the rights of Indigenous Peoples.

Impactful The implementation of the action plan must make tangible improvements to Indigenous Peoples' social, physical, cultural and economic well-being.

Transparent Progress under the action plan will be reviewed and publicly reported on annually.

2022-2027 ACTIONS

The actions are organized by the following four themes:

1. **Self-determination and inherent right of self-government**
2. **Title and rights of Indigenous Peoples**
3. **Ending Indigenous-specific racism and discrimination**
4. **Social, cultural and economic well-being**

Each theme includes a ***Goal***, with ***Outcomes*** and ***Actions.***

The **goals** and **outcomes** are drawn from the UN Declaration. They describe what the Province is striving for with this action plan and set the vision for achieving the objectives of the UN Declaration.

The **actions** articulate the specific commitments and steps that the Province will take between 2022 and 2027 to achieve those goals and outcomes.

Each action identifies the ministry or ministries responsible for leading its implementation. As this action plan takes a cross-government approach, other ministries may be involved in the work, even if they are not listed within an action.

INTERPRETIVE GUIDANCE

The following *must* be applied when interpreting and implementing this action plan.

First, all actions identified in this action plan are to be implemented in consultation and cooperation with Indigenous Peoples in B.C., as described in the Declaration Act.

Second, a wide range of terminology is used in the goals, outcomes and actions referring to Indigenous peoples including: "Indigenous Peoples," "First Nations," "Indigenous Nations," and others. Effort has been made to use this terminology consistently and coherently using a distinctions-based approach; wherever possible, reference to First Nations, Métis and Inuit Peoples are made intentionally to reflect these distinctions. There are currently some variances in use for several reasons; for example, out of respect for the diversity of preferences among Indigenous Peoples, or to reflect and remain consistent with terminology used in existing commitments, agreements and other constructive arrangements. A distinctions-based approach must be applied in the interpretation and implementation of the action plan. Some of the actions referencing Indigenous Peoples may, through implementation, come to be more aptly focused on First Nations and/or Métis people.

Lastly, progress on implementing this action plan will be provided through the Declaration Act annual reports. In those reports, the Province must make reference to First Nations, Métis and Inuit Peoples intentionally to uphold a distinctions-based approach.

THEME

1 Self-Determination and Inherent Right of Self-Government

THEME 1. Self-Determination and Inherent Right of Self-Government

GOAL

Indigenous Peoples exercise and have full enjoyment of their rights to self-determination and self-government, including developing, maintaining and implementing their own institutions, laws, governing bodies, and political, economic and social structures related to Indigenous communities.

OUTCOMES

A British Columbia where:

- Indigenous Peoples are fully supported in their work of freely determining and implementing their systems and institutions of government, through their internal processes of nation-rebuilding.
- Through their governments, Indigenous Peoples are recognized and engaged through formalized and predictable relationships with the Province, and exercise their jurisdictions and laws.
- Indigenous Peoples exercise self-determination and self-government.
- Through their governments, Indigenous Peoples have open, respectful and productive working relationships with the Province that recognize legal pluralism and reflect cooperative federalism.
- Indigenous Peoples have the necessary legal space to strengthen the application of their Indigenous Laws and legal orders in various areas not adequately addressed through the Canadian legal system.
- The overall emergency management structure and regime in B.C. is revised, in collaboration with the Government of Canada and Indigenous Peoples, to enhance Indigenous Peoples' emergency management outcomes through a strong tripartite approach.

2022-2027 ACTIONS

The Province recognizes that the work of nation-rebuilding is the work of Indigenous Peoples, and is to be conducted in accordance with Indigenous legal processes, rights, cultures, languages, protocols, traditions and standards, and undertaken as part of expressing, building, strengthening and implementing freely chosen governance systems.

To advance this, the Province will take the following actions in consultation and cooperation with Indigenous Peoples from 2022 to 2027:

1.1 In partnership with the Government of Canada, establish a new institution designed and driven by First Nations to provide supports to First Nations in their work of nation- and governance-rebuilding and boundary resolution in accordance with First Nations laws, customs and traditions. *(Ministry of Indigenous Relations and Reconciliation)*

1.2 Shift from short-term transactional arrangements to the co-development of long-term agreements that recognize and support reconciliation, self-determination, decision-making and economic independence. *(Ministry of Indigenous Relations and Reconciliation)*

1.3 Utilize sections 6 and 7 of the Declaration Act to complete and implement government-to-government agreements that recognize Indigenous self-government and self-determination. *(Ministry of Indigenous Relations and Reconciliation)*

1.4 Co-develop with Indigenous Peoples a new distinctions-based fiscal relationship and framework that supports the operation of Indigenous governments, whether through modern treaties, self-government agreements or advancing the right to self-government through other mechanisms. This work will include collaboration with the Government of Canada. *(Ministry of Finance, Ministry of Indigenous Relations and Reconciliation)*

1.5 Co-develop and implement new distinctions-based policy frameworks for resource revenue-sharing and other fiscal mechanisms with Indigenous Peoples. *(Ministry of Finance, Ministry of Indigenous Relations and Reconciliation)*

1.6 Co-develop an approach to deliver on the BC Tripartite Education Agreement commitment, in which the Ministry of Education and Child Care and the First Nations Education Steering Committee will co-develop legislation that requires local education agreements (LEAs) with First Nations where a First Nation wants one, and that requires the application of the provincial LEA at the request of a First Nation. *(Ministry of Education and Child Care)*

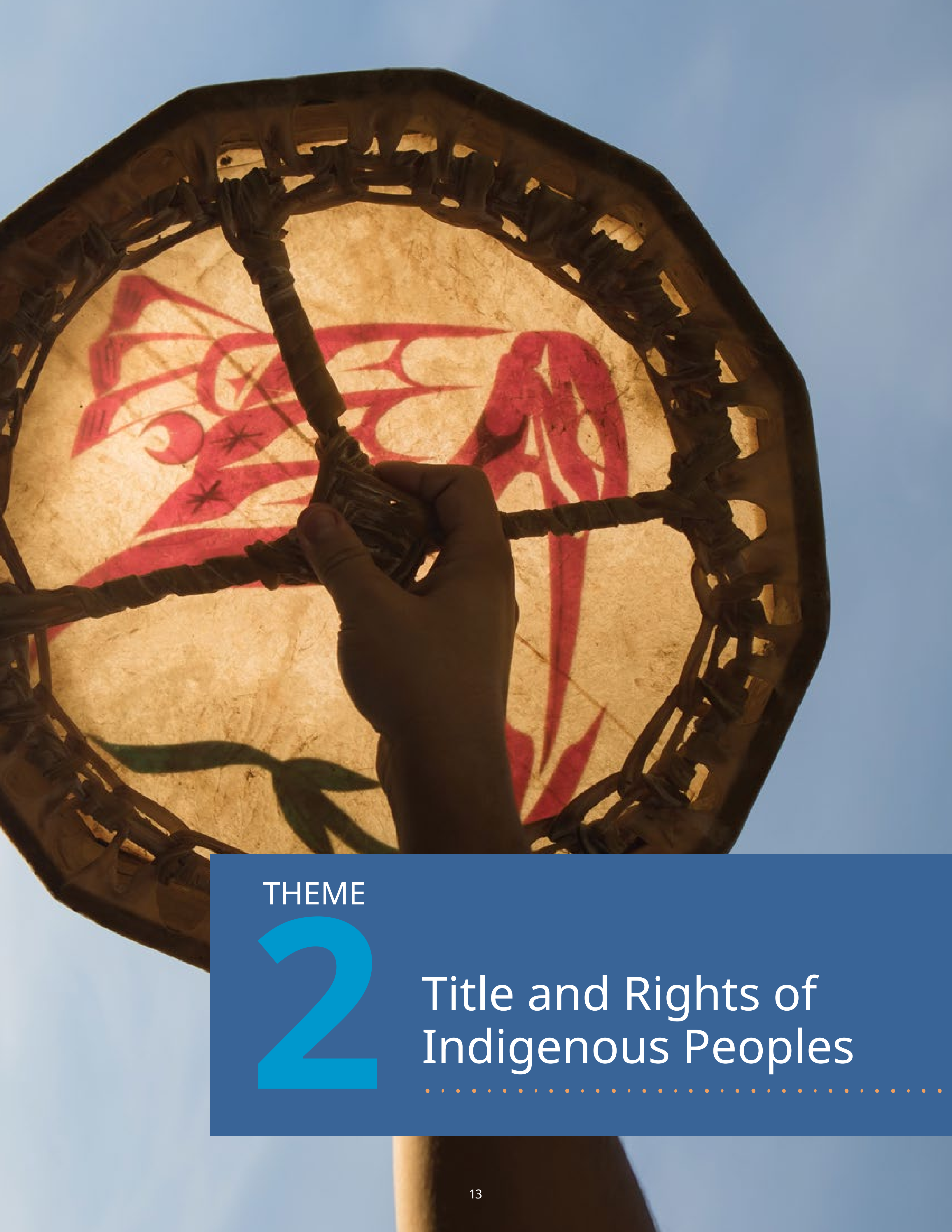
1.7 Update the Bilateral Protocol agreement between the BC Ministry of Education and Child Care and the First Nation Education Steering Committee for relevancy, effectiveness, and consistency with the UN Declaration to support First Nation students in the K-12 education system. *(Ministry of Education and Child Care)*

1.8 Recognize the integral role of Indigenous-led post-secondary institutes as a key pillar of B.C.'s post-secondary system through the provision of core funding, capacity funding and the development of legislation. This includes institutes mandated by First Nations, as well as a Métis post-secondary institute being developed by Métis Nation BC. *(Ministry of Advanced Education and Skills Training)*

1.9 Work with the Nicola Valley Institute of Technology, and the Urban Native Youth Association to co-develop an urban Indigenous centre that supports the childcare, housing and post-secondary needs of Indigenous learners, and strengthen the capacity of the Native Education College to provide culturally relevant post-secondary opportunities for urban Indigenous learners. *(Ministry of Advanced Education and Skills Training)*

1.10 Co-develop modernized emergency management legislation (replacing the *Emergency Program Act*) with First Nations. *(Emergency Management BC)*

1.11 Support inclusive regional governance by advancing First Nations participation in regional district boards. *(Ministry of Municipal Affairs)*



THEME

2 Title and Rights of Indigenous Peoples

THEME 2. Title and Rights of Indigenous Peoples

GOAL

Indigenous Peoples exercise and have full enjoyment of their inherent rights, including the rights of First Nations to own, use, develop and control lands and resources within their territories in B.C.

OUTCOMES

A British Columbia where:

- The distinctions-based rights of Indigenous Peoples are respected, upheld and exercised.
- The rights of Indigenous Peoples, including First Nations title, are exercised, recognized and respected, and cooperatively implemented including through treaties, government-to-government agreements and other constructive arrangements.
- The Province's laws, policies and practices recognize and respect the distinctions-based rights of Indigenous Peoples.
- Dispute-resolution and relationship-building with Indigenous Peoples are supported through cooperatively established institutions and processes that are fair, just and accessible, integrate Indigenous laws and protocols, and use the court system only as a last resort.
- First Nations benefit socially, culturally and economically from land and resources in their territories, including having access to multiple and diverse streams of revenue to finance their governments and deliver services to their citizens.
- Through their governments, Indigenous Peoples exercise their autonomy to set their own priorities, allocate fiscal resources and determine how to deliver programs and services to their citizens.
- Indigenous Peoples have meaningful and sufficient access to abundant and healthy traditional foods and have peaceful enjoyment of their harvesting rights.
- First Nations exercise their right to determine and develop priorities and strategies for the development, use and/or stewardship of their traditional territories and other resources.

2022-2027 ACTIONS

The Province recognizes the need to shift from patterns of litigation, and expensive and slow negotiations about title and rights, to cooperative implementation through effective government-to-government relationships.

To advance this, the Province will take the following actions in consultation and cooperation with Indigenous Peoples from 2022 to 2027:

2.1 Establish a Secretariat to guide and assist government to meet its obligation to ensure legislation is consistent with the UN Declaration on the Rights of Indigenous Peoples, and is developed in consultation and cooperation with Indigenous Peoples. *(Declaration Act Secretariat)*

2.2 Finalize the Draft Principles that Guide the Province of British Columbia's Relationship with Indigenous Peoples.[11] *(Ministry of Indigenous Relations and Reconciliation)*

2.3 Issue guidelines from the Attorney General of B.C. to the Ministry of Attorney General legal counsel regarding the conduct of civil litigation involving the rights of Indigenous Peoples. *(Ministry of Attorney General)*

2.4 Negotiate new joint decision-making and consent agreements under section 7 of the Declaration Act that include clear accountabilities, transparency and administrative fairness between the Province and Indigenous governing bodies. Seek all necessary legislative amendments to enable the implementation of any section 7 agreements. *(Ministry of Indigenous Relations and Reconciliation, Ministry of Land, Water and Resource Stewardship)*

2.5 Co-develop and employ mechanisms for ensuring the minimum standards of the UN Declaration are applied in the implementation of treaties, agreements under sections 6 and 7 of the Declaration Act and other constructive arrangements with First Nations. *(Ministry of Indigenous Relations and Reconciliation)*

2.6 Co-develop strategic-level policies, programs and initiatives to advance collaborative stewardship of the environment, land and resources, that address cumulative effects and respects Indigenous Knowledge. This will be achieved through collaborative stewardship forums, guardian programs, land use planning initiatives, and other innovative and evolving partnerships that support integrated land and resource management. *(Ministry of Land, Water and Resource Stewardship, Ministry of Indigenous Relations and Reconciliation, Ministry of Environment and Climate Change Strategy, Ministry of Forests, Ministry of Energy, Mines and Low Carbon Innovation, BC Oil and Gas Commission)*

2.7 Collaborate with First Nations to develop and implement strategies, plans and initiatives for sustainable water management, and to identify policy or legislative reforms supporting Indigenous water stewardship, including shared decision-making. Co-develop the Watershed Security Strategy with First Nations and initiate implementation of the Strategy at a local watershed scale. *(Ministry of Land, Water and Resource Stewardship)*

2.8 Collaborate with Indigenous partners on issues related to conservation and biodiversity in B.C., including the protection of species at risk. *(Ministry of Land, Water and Resource Stewardship)*

2.9 Develop new strategies to protect and revitalize wild salmon populations in B.C. with First Nations and the federal government, including the development and implementation of a cohesive B.C. Wild Pacific Salmon Strategy. *(Ministry of Land, Water and Resource Stewardship)*

2.10 Reform forest legislation, regulations and policy to reflect a shared strategic vision with First Nations that upholds the rights and objectives of the UN Declaration. *(Ministry of Forests)*

2.11 Integrate traditional practices and cultural uses of fire into wildfire prevention and land management practices and support the reintroduction of strategized burning. *(Ministry of Forests, Emergency Management BC)*

2.12 Collaboratively develop and implement CleanBC and the Climate Preparedness and Adaptation Strategy to support resilient communities and clean economic opportunities for Indigenous Peoples that benefit our shared climate and advance reconciliation. *(Ministry of Environment and Climate Change Strategy)*

2.13 Identify and advance reconciliation negotiations on historical road impacts and road accessibility with First Nations on reserve, treaty and title lands, including reporting-out on the completion and implementation of these negotiations collaboratively with First Nations partners. *(Ministry of Transportation and Infrastructure)*

2.14 Modernize the *Mineral Tenure Act* in consultation and cooperation with First Nations and First Nations organizations. *(Ministry of Energy, Mines and Low Carbon Innovation)*

THEME

3 Ending Indigenous-specific Racism and Discrimination

THEME 3. Ending Indigenous-specific Racism and Discrimination

GOAL

Indigenous Peoples fully express and exercise their distinct rights, and enjoy living in B.C. without interpersonal, systemic and institutional interference, oppression or other inequities associated with Indigenous-specific racism and discrimination, wherever they reside.

OUTCOMES

A British Columbia where:

- All citizens have a constructive and respectful understanding of the distinct history and unique rights of Indigenous Peoples in B.C.
- The overrepresentation of Indigenous Peoples in the justice system is eliminated.
- Indigenous Peoples feel safe accessing the health-care system, knowing that they will receive high quality care, be treated with respect and receive culturally safe and appropriate services.
- Indigenous women, girls, and 2SLGBTQQIA+[f] people enjoy full protection and guarantees against all forms of violence and discrimination.
- Indigenous Knowledge, laws and legal orders are affirmed and recognized as part of decision-making.
- Indigenous learners feel welcomed, respected, and comfortable learning and being Indigenous in schools and other educational institutions.

2022-2027 ACTIONS

The Province recognizes that systemic racism and discrimination against Indigenous Peoples exists throughout British Columbia and that fundamental changes to systems, behaviours, attitudes and beliefs are needed.

To advance this, the Province will take the following actions in consultation and cooperation with Indigenous Peoples between 2022 and 2027:

3.1 Develop essential training in partnership with Indigenous organizations, and deliver to the B.C. public service, public institutions and corporations that aims to build foundational understanding and competence about the history and rights of Indigenous Peoples, treaty process, rights and title, the UN Declaration, the B.C. Declaration Act, the dynamics of proper respectful relations, Indigenous-specific racism, and meaningful reconciliation. *(Public Service Agency, Ministry of Finance – Crown Agencies and Board Resourcing Office)*

3.2 Establish an operational approach to set and achieve targets for equitable recruitment and retention of Indigenous Peoples across the public sector, including at senior levels. *(Public Service Agency, Public Sector Employers' Council Secretariat)*

f 2SLGBTQQIA+ refers to two-spirit, lesbian, gay, bisexual, transgender, queer, questioning, intersex, asexual and other sexually and gender diverse people.

3.3 Conduct an external review of Indigenous-specific racism and discrimination in the provincial public education system, and create a strategy, including resources and supports, to address findings. *(Ministry of Education and Child Care)*

3.4 Implement a mandatory course or bundle of credits related to First Peoples as part of graduation requirements in B.C. and co-create culturally relevant provincial resources with Indigenous people for use by all educators across the K-12 education system. *(Ministry of Education and Child Care)*

3.5 Provide resources to Indigenous organizations to improve public understanding of Indigenous histories, rights, cultures, languages and the negative impacts of Indigenous-specific racism. *(Ministry of Tourism, Arts, Culture and Sport)*

3.6 Introduce anti-racism legislation that addresses Indigenous-specific racism. *(Ministry of Attorney General)*

3.7 Implement recommendations made in the *In Plain Sight: Addressing Indigenous-specific racism and discrimination in B.C. health care*[12] report, striving to establish a health care system in B.C. that is culturally safe and free of Indigenous-specific racism. *(Ministry of Health)*

3.8 Develop and implement community-driven activities to end violence against Indigenous women, girls and 2SLGBTQQIA+ people, beginning with the foundational activities in *A Path Forward: Priorities and Early Strategies for B.C.*[13] and steps towards achieving the mandate commitment to develop a gender-based violence action plan. *(Ministry of Public Safety and Solicitor General, Ministry of Attorney General, Ministry of Finance - Gender Equity Office)*

3.9 Identify and implement multi-modal transportation solutions that provide support and enable the development of sustainable, safe, reliable and affordable transportation options for First Nations communities. *(Ministry of Transportation and Infrastructure)*

3.10 Implement improvements to public safety oversight bodies and complaints processes, such as enhanced investments in the B.C. Human Rights Tribunal and new models for including Indigenous laws in complaints resolution. *(Ministry of Attorney General, Ministry of Public Safety and Solicitor General)*

3.11 Develop and implement comprehensive policing reforms to address systemic biases and racism. This will include: updating the *Police Act*, BC Provincial Policing Standards[14] and mandatory training requirements; enhancing independent oversight; clarifying the roles and responsibilities of police officers in the context of complex social issues such as mental health, addiction and homelessness; and contributing to the modernization of the federal First Nations Policing Program. *(Ministry of Public Safety and Solicitor General, Ministry of Attorney General, Ministry of Mental Health and Addictions)*

3.12 Prioritize implementation of the First Nations Justice Strategy to reduce the substantial overrepresentation of Indigenous Peoples involved in and impacted by the justice system. This includes affirming First Nations self-determination and enabling the restoration of traditional justice systems and culturally relevant institutions. *(Ministry of Attorney General, Ministry of Public Safety and Solicitor General)*

3.13 Prioritize endorsement and implementation of the Métis Justice Strategy to reduce the substantial overrepresentation of Métis Peoples in and impacted by the justice system. This includes affirming Métis self-determination, and enabling the restoration of traditional justice systems and culturally relevant institutions. *(Ministry of Attorney General, Ministry of Public Safety and Solicitor General)*

3.14 Advance the collection and use of disaggregated demographic data, guided by a distinctions-based approach to Indigenous data sovereignty and self-determination, including supporting the establishment of a First Nations-governed and mandated regional data governance centre in alignment with the First Nations Data Governance Strategy. *(Ministry of Citizens' Services)*

3.15 Adopt an inclusive digital font that allows for Indigenous languages to be included in communication, signage, services and official records. *(Ministry of Citizens' Services)*

THEME

4 Social, Cultural and Economic Well-being

THEME 4. Social, Cultural and Economic Well-being

GOAL

Indigenous Peoples in B.C. fully enjoy and exercise their distinct rights to maintain, control, develop, protect and transmit their cultural heritage, traditional knowledge, languages, food systems, sciences and technologies. They are supported by initiatives that promote connection, development, access and improvement, as well as full participation in all aspects of B.C.'s economy. This includes particular focus on ensuring the rights of Indigenous women, youth, Elders, children, persons with disabilities and 2SLGBTQQIA+ people are upheld.

OUTCOMES

A British Columbia where:

- Indigenous Peoples, communities and nations in B.C. are thriving and prospering as full participants in the social, cultural and economic landscape of the province.
- Indigenous Peoples design, control and set the standards and policies for the services that support and facilitate the well-being of Indigenous citizens.
- Indigenous Peoples care for their own children and youth in their communities, and exercise jurisdiction over their own child and family services through systems and practices they determine for themselves, with family preservation prioritized and children and youth kept within their families and communities.
- Indigenous children in need of protection are cared for by their community, and where they cannot be cared for by their community, they are connected to their communities and cultures.
- Health, social and education systems apply an intersectional lens to meet the needs and honour the worldviews, cultures, lived experiences, knowledge and histories of Indigenous Peoples.
- Indigenous languages are living, used, taught and visible throughout their respective territories, including in the provincial public education system.
- Indigenous food systems are recognized and supported in their foundational and interconnected role in providing for cultural, social, environmental and economic well-being.
- Indigenous learners lead graduation rates, are supported to pursue their own excellence, and can access relevant and responsive post-secondary education and skills training.
- Government functions in such a way that distinct Indigenous cultures and identities are understood, upheld and respected, including how Indigenous Peoples access and interact with all provincial government services.
- Respect for Indigenous cultures is tangibly demonstrated through Indigenous maintenance, control, protection and development of their cultural heritage resources, intellectual property, art, spiritual traditions, knowledge systems, economic systems, food systems and spiritual and sacred sites.

- Indigenous Peoples are thriving in their role as stewards and managers of their cultural heritage and receive funding and support to develop community-based cultural heritage plans and programming that will assist with: documenting oral histories and cultural traditions; managing cultural heritage sites, objects and systems; and supporting the intergenerational transmission of cultural knowledge; and showcasing and commemorating Indigenous cultural heritage.
- First Nations create archives for historical community records, mapping services and place-naming.
- Governance of the economy respects, acknowledges and upholds Indigenous rights and interests and First Nations title, is co-led with Indigenous Peoples, and ensures that all First Nations have economic opportunities and benefit from the lands and resources in their territories.
- Indigenous Peoples freely determine their economic development goals, priorities and strategies, and exercise their right to maintain and develop their economic systems and institutions to support self-governance, along with traditional and other economic activities.
- The Province and Indigenous Peoples collaborate and participate in ongoing, meaningful, and enduring dialogue to achieve a more inclusive, innovative, and sustainable economy for the benefit of present and future generations that reflects Indigenous values, interests, goals and worldviews.
- The Province and Indigenous Peoples collaborate through meaningful dialogue to create more inclusive, sustainable and low carbon economies for the benefit of present and future generations and a just climate transition.
- Indigenous peoples with disabilities are supported in accessing culturally relevant care and services.

2022-2027 ACTIONS

The Province recognizes that social and economic disparities exist in British Columbia with particular impacts on Indigenous Peoples, and that addressing these disparities while supporting the cultural distinctiveness of Indigenous Peoples is fundamental to upholding human rights.

To advance this, the Province will take the following actions in consultation and cooperation with Indigenous Peoples from 2022 to 2027:

Social

4.1 Identify and undertake concrete measures to increase the literacy and numeracy achievement levels of Indigenous students at all levels of the K-12 education system, including the early years. *(Ministry of Education and Child Care)*

4.2 Develop and implement an effective recruitment and retention strategy to increase the number of Indigenous teachers in the K-12 public education system. *(Ministry of Education and Child Care, Ministry of Advanced Education and Skills Training)*

4.3 Co-develop and implement a framework for the involvement of Indigenous Education Councils in school district financial planning and reporting. *(Ministry of Education and Child Care)*

4.4 Identify, develop and implement mechanisms and approaches to enable boards of education to better support Indigenous students, including increasing and ensuring equitable access to education and safe environments. *(Ministry of Education and Child Care)*

4.5 Co-develop a policy framework for Indigenous post-secondary education and skills training that includes:

- supporting post-secondary institutions to be more culturally relevant and responsive to the needs of First Nations, Métis and Inuit learners and communities;
- expanding the Aboriginal Service Plan program to all 25 public post-secondary institutions;
- ensuring that Indigenous learners have access to student housing that is safe, inclusive, and enables them to thrive personally, academically, and culturally;
- developing mechanisms for First Nations, Métis and Inuit learners and communities to play an integral role in public post-secondary institutions' decision-making; and
- identifying legislative amendments needed to ensure all public post-secondary institution boards include at least one Indigenous person.

(Ministry of Advanced Education and Skills Training)

4.6 Promote culturally relevant sport, physical activity and recreation initiatives and opportunities that increase Indigenous engagement, participation and excellence in both traditional and mainstream sports for individuals in both urban and rural or remote areas. *(Ministry of Tourism, Arts, Culture and Sport)*

4.7 Demonstrate a new and more flexible funding model and partnership approach that supports First Nations to plan, design and deliver mental health and wellness services across a full continuum of care and to address the social determinants of health and wellness. *(Ministry of Health, Ministry of Mental Health and Addictions)*

4.8 In alignment with the tripartite health plans and agreements, continue to strengthen and evolve the First Nation health governance structure in B.C. to ensure First Nations are supported to participate as full and equal partners in decision-making and service delivery at local, regional and provincial levels, and engage First Nations and the Government of Canada on the need for legislation as envisioned in the tripartite health plans and agreements. *(Ministry of Health, Ministry of Mental Health and Addictions)*

4.9 As a part of the implementation of the *Accessible British Columbia Act*, support the identification, prevention and removal of barriers for Indigenous persons with disabilities. This includes ensuring that the development of accessibility standards considers the rights recognized and affirmed by the UN Declaration. *(Ministry of Social Development and Poverty Reduction)*

4.10 Prioritize the implementation of Primary Care Networks, the First Nations-led Primary Health Care Initiative, and other primary care priorities, embedding Indigenous perspectives and priorities into models of care to increase Indigenous Peoples' access to primary care and other health services, and to improve cultural safety and quality of care. *(Ministry of Health)*

4.11 Increase the availability, accessibility and the continuum of Indigenous-led and community-based social services and supports that are trauma-informed, culturally safe and relevant, and address a range of holistic wellness needs for those who are in crisis, at-risk or have experienced violence, trauma and/or significant loss. *(Ministry of Public Safety and Solicitor General, Ministry of Health, Ministry of Mental Health and Addictions)*

4.12 Address the disproportionate impacts of the overdose public health emergency on Indigenous Peoples by:

- applying to the Government of Canada to decriminalize simple possession of small amounts of illicit drugs for personal use, and continuing campaigns and other measures to help end the stigma and shame associated with addiction;
- expanding prescribed safer supply and other harm reduction measures; and
- ensuring accessibility of recovery beds, and evidence-based, culturally relevant and safe services to meet the needs of Indigenous Peoples, including youth.

(Ministry of Mental Health and Addictions, Ministry of Public Safety and Solicitor General, Ministry of Attorney General)

4.13 Increase the availability and accessibility of culturally safe substance use services, including through the renovation and construction of Indigenous-run treatment centres and the integration of land-based and traditional approaches to healing. *(Ministry of Health, Ministry of Mental Health and Addictions)*

4.14 Increase the availability and accessibility of resources to Indigenous partners in COVID-19 pandemic health and wellness planning and response, including the implementation of the Rural, Remote, First Nations and Indigenous COVID-19 Framework[15] to ensure access for all Indigenous Peoples to immediate and culturally safe and relevant care closer to home. *(Ministry of Health, Ministry of Mental Health and Addictions)*

4.15 Incorporate Indigenous experiences and knowledge of poverty and well-being into ongoing poverty reduction efforts and the 2024 Poverty Reduction Strategy. The strategy will recognize the ongoing impacts of colonialism and include Indigenous-identified actions and progress measures. *(Ministry of Social Development and Poverty Reduction)*

4.16 Co-develop a B.C.-specific fiscal framework, in partnership with First Nations, Métis and Inuit, and in consultation with key Indigenous organizations, to support and move forward with jurisdiction over child and family services. *(Ministry of Children and Family Development)*

4.17 In collaboration with B.C. First Nations and Métis Peoples, and Inuit, continue implementing changes to substantially reduce the number of Indigenous children and youth in care through increased prevention and family support services at all stages of contact with the child welfare system. *(Ministry of Children and Family Development)*

4.18 As committed to in the First Nations Children and Youth in Care Protocol, co-develop and implement measures to support improved education outcomes of current and former First Nation children and youth in care, including meaningful data collection to inform policy planning and service delivery. *(Ministry of Education and Child Care, Ministry of Children and Family Development, Ministry of Advanced Education and Skills Training)*

4.19 As part of a commitment to an inclusive, universal childcare system, work in collaboration with B.C. First Nations, Métis, and Inuit Peoples to implement a distinctions-based approach to support and move forward jurisdiction over child care for First Nations, Métis and Inuit Peoples who want and need it in B.C. *(Ministry of Education and Child Care)*

4.20 Advance a collaborative, whole-of-government approach in the partnership between the Métis Nation of British Columbia and the Province of B.C., respecting Métis self-determination and working to establish more flexibility and sustainability in funding. *(Ministry of Indigenous Relations and Reconciliation)*

4.21 Bring together key Indigenous urban leaders to create a provincial urban Indigenous advisory table to develop and implement a five-year plan to address the priorities of urban Indigenous Peoples, including a focus on Elders, youth, children, women, men, 2SLGBTQQIA+ and persons with disabilities. *(Ministry of Indigenous Relations and Reconciliation, Ministry of Social Development and Poverty Reduction)*

4.22 Ministers and executives across the provincial government social sector will meet annually with urban Indigenous service organization leaders, such as the provincial urban Indigenous advisory table (see Action 4.21), to discuss successes, innovations, and challenges of supporting the social, cultural and economic needs of urban Indigenous Peoples. (*Ministry of Indigenous Relations and Reconciliation*)

4.23 Undertake a cross-government review of provincial supports and services for Indigenous Peoples in urban settings and develop a plan with clear timelines that will provide greater collaboration and coordination to meet needs. *(Ministry of Indigenous Relations and Reconciliation)*

4.24 Expand support to Aboriginal Friendship Centres and other urban Indigenous organizations that serve the needs of urban Indigenous people in B.C. while also acknowledging that Aboriginal Friendship Centres and other urban Indigenous organizations play a vital role for those that wish to connect to their cultures and traditions. *(Ministry of Indigenous Relations and Reconciliation)*

4.25 Work with Indigenous Peoples to build more on- and off-reserve housing and pursue new federal contributions. *(Ministry of Attorney General, Ministry of Indigenous Relations and Reconciliation)*

4.26 Strengthen the health and wellness partnership between Métis Nation British Columbia, the Ministry of Health and the Ministry of Mental Health and Addictions, and support opportunities to identify and work to address shared Métis health and wellness priorities. *(Ministry of Health, Ministry of Mental Health and Addictions)*

Cultural Heritage

4.27 Review the principles and processes that guide the naming of municipalities and regional districts, and evolve practices to foster reconciliation in local processes. *(Ministry of Municipal Affairs)*

4.28 Draft a report with recommendations for how BC Parks can better reflect Indigenous Peoples' histories and cultures in provincial parks and protected areas. *(Ministry of Environment and Climate Change Strategy)*

4.29 Establish an Indigenous-led working group to develop a strategy for the revitalization of Indigenous languages in B.C., including potential legislative supports. *(Ministry of Indigenous Relations and Reconciliation, Ministry of Education and Child Care, Ministry of Advanced Education and Skills Training)*

4.30 Support Indigenous language revitalization through sustainable funding. *(Ministry of Indigenous Relations and Reconciliation, Ministry of Advanced Education and Skills Training)*

4.31 Develop full-course offerings in First Nation languages and implement the educational Calls to Action from the Truth and Reconciliation Commission in the K-12 education system. *(Ministry of Education and Child Care)*

4.32 Co-develop a K-12 First Nations Language Policy and associated implementation plan for the public education system with the First Nations Education Steering Committee, including ensuring that the language and culture of the local First Nation(s) on whose territory(ies) a board of education operates schools are the ones primarily reflected in any First Nations language and culture programs and services of the board. *(Ministry of Education and Child Care)*

4.33 Co-develop a policy framework to support repatriation initiatives. *(Ministry of Tourism, Arts, Culture and Sport)*

4.34 Reset the relationship between the Royal BC Museum and Indigenous Peoples in B.C. by ensuring that Indigenous voices are prioritized and inform the development of narratives, exhibitions and learning programs. *(Ministry of Tourism, Arts, Culture and Sport)*

4.35 Work with First Nations to reform the *Heritage Conservation Act* to align with the UN Declaration, including shared decision-making and the protection of First Nations cultural, spiritual, and heritage sites and objects. *(Ministry of Forests, Ministry of Tourism, Arts, Culture and Sport)*

Economic

4.36 Ensure every First Nations community in B.C. has high-speed internet services. *(Ministry of Citizens' Services)*

4.37 Provide funding to assist Indigenous tourism businesses that have been financially impacted by the COVID-19 pandemic, in order to further support recovery of the Indigenous tourism sector in B.C. *(Ministry of Tourism, Arts, Culture and Sport)*

4.38 Provide investments to Indigenous Tourism B.C. to support Indigenous tourism, Indigenous job creation, preservation of Indigenous languages, celebration of Indigenous cultures and the stewardship of territories, and to tell the stories of Indigenous Peoples in B.C. in their own words. *(Ministry of Tourism, Arts, Culture and Sport)*

4.39 Work with the Province's Economic Trusts and First Nation partners to develop a mechanism that ensures inclusion of First Nations at a regional decision-making level. *(Ministry of Jobs, Economic Recovery and Innovation)*

4.40 Ensure Indigenous collaboration in the development and implementation of the BC Economic Plan, including a technology and innovation roadmap. *(Ministry of Jobs, Economic Recovery and Innovation)*

4.41 Work with First Nations, Métis chartered communities and urban Indigenous organizations to provide funding for self-determined, community-led programs for Indigenous Peoples to upgrade skills, obtain credentials, secure employment, and develop and support community economies. *(Ministry of Advanced Education and Skills Training, Ministry of Social Development and Poverty Reduction)*

4.42 Co-develop economic metrics to help evaluate progress as reconciliation is advanced. The baseline data will begin to address the persistent gap in Indigenous-specific economic metrics and through this co-designed effort, build a comprehensive set of data to measure Indigenous economic well-being and track progress over time. *(Ministry of Jobs, Economic Recovery and Innovation, Ministry of Indigenous Relations and Reconciliation)*

4.43 Co-develop recommendations on strategic policies and initiatives for clean and sustainable energy. This includes identifying and supporting First Nations-led clean energy opportunities related to CleanBC, the Comprehensive Review of BC Hydro, and the BC Utilities Commission Inquiry on the Regulation of Indigenous Utilities. *(Ministry of Energy, Mines and Low Carbon Innovation)*

4.44 Review, evaluate and improve B.C.'s Indigenous Youth Internship Program. *(Public Service Agency)*

4.45 Prioritize and increase the number of technology sector training opportunities for Indigenous Peoples and other groups currently under-represented in B.C.'s technology sector. *(Ministry of Jobs, Economic Recovery and Innovation)*

4.46 Improve economic supports for Indigenous workers and employers by increasing access for Indigenous clients to the Ministry of Labour's services and programs, including employment standards, workers' compensation and workplace safety. *(Ministry of Labour)*

4.47 Advance a collaborative approach to cannabis-related governance and jurisdiction between First Nations and the Province that reflects common objectives to protect youth, prioritize public health and safety, strengthen First Nations governance capacity and secure economic benefits for First Nations. *(Ministry of Public Safety and Solicitor General)*

4.48 Work with the B.C. Indigenous Advisory Council on Agriculture and Food and other Indigenous partners to identify opportunities to strengthen Indigenous food systems and increase Indigenous participation in the agriculture and food sector. *(Ministry of Agriculture and Food)*

4.49 Review existing provincial mandates to enhance treaty and self-governing Nations' fiscal capacity to deliver services to their citizens. *(Ministry of Indigenous Relations and Reconciliation)*

ACCOUNTABILITY AND IMPLEMENTATION

The Province's development of the action plan was undertaken in consultation and cooperation with Indigenous Peoples in B.C. and centred around the shared understandings outlined on page 6. The process to implement the action plan will be approached in the same way: comprehensive, distinctions-based, diverse, legally plural, principled, cooperative, enabling, impactful and transparent.

Ministries across government will continue to work in consultation and cooperation with Indigenous Peoples across the province to implement actions identified in this plan, reflecting our mutual commitment to work together in partnership. Identified ministries are accountable for their actions as well as ensuring effective monitoring and reporting on progress. As the action plan is province-wide in scope, it requires an all-of-government approach with coordination across ministries to support implementation.

The Province will work with Indigenous Peoples to identify suitable tools, indicators and measures for monitoring, assessing and reporting progress on implementation of the Declaration Act. Progress under the action plan will be reviewed on an annual basis and publicly reported in an annual report that will be prepared consultation and cooperation with Indigenous Peoples, and submitted to the B.C. Legislature by June 30 each year. The action plan will be comprehensively updated within five years.

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PHOTOGRAPHY CREDITS

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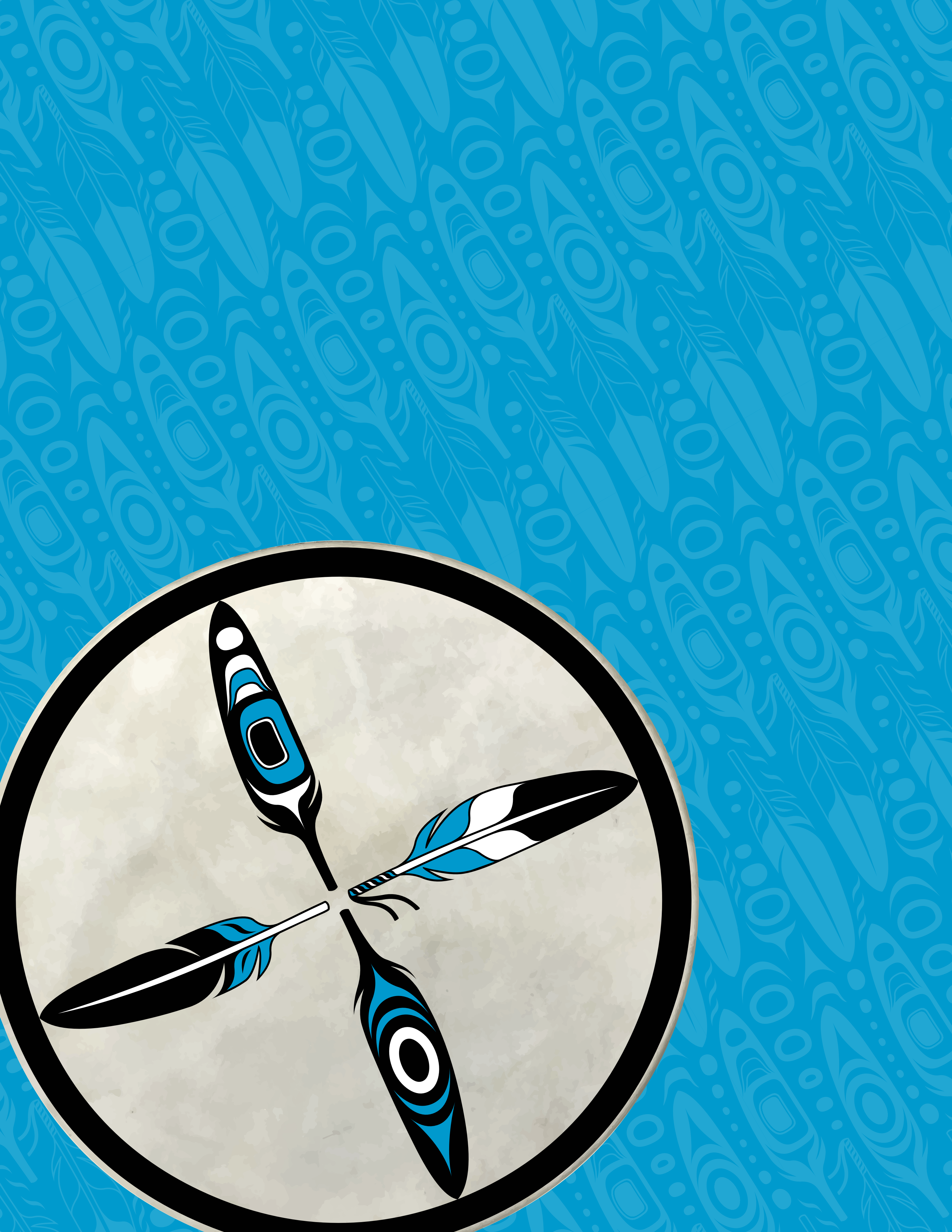

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Truck Secondary Energy Use, GHG Emissions and Explanatory Variables Detailed Tables

1) Data on GHG emissions are presented excluding GHG emissions related to electricity production.

Office of Energy Efficiency, Demand Policy and Analysis Division, Market Analysis Group.

British Columbia and Territories
Table 28: School Bus Secondary Energy Use and GHG Emissions by Energy Source

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
School Bus Energy Use (PJ)	**2.6**	**2.6**	**2.6**	**2.8**	**2.2**	**2.1**	**2.0**	**2.2**	**2.5**	**1.9**	**1.9**	**1.8**	**1.7**	**1.7**	**1.6**	**1.6**	**1.8**	**1.1**	**1.3**
Energy Use by Energy Source (PJ)																			
Natural Gas	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2
Motor Gasoline	0.2	0.1	0.0	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Diesel Fuel Oil	2.3	2.5	2.6	2.7	2.1	2.0	2.0	2.1	2.4	1.8	1.9	1.7	1.7	1.6	1.5	1.3	1.5	0.7	0.9
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.0	0.0	0.0	0.0	0.0	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shares (%)																			
Natural Gas	2.3	1.3	0.6	0.2	0.2	0.0	0.0	0.0	0.0	1.7	0.7	0.0	0.6	0.6	1.4	6.7	7.9	20.6	15.9
Motor Gasoline	9.2	2.3	1.5	3.1	4.6	1.6	3.0	4.2	1.6	2.9	2.5	3.1	4.2	4.2	6.6	6.8	7.1	11.4	10.5
Diesel Fuel Oil	88.5	96.3	97.9	96.7	95.2	98.4	97.0	95.8	98.4	95.3	96.7	96.8	95.0	95.0	91.7	86.5	85.0	68.0	73.6
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.1	0.1	0.2	0.2	0.2	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Activity																			
Passenger-kilometres (millions)	4,182	4,397	4,670	5,049	4,128	4,182	4,724	4,287	4,633	4,187	4,523	4,051	4,192	4,144	3,769	3,616	4,045	4,354	4,511
Energy Intensity (MJ/Pkm)	**0.61**	**0.59**	**0.56**	**0.56**	**0.52**	**0.49**	**0.43**	**0.51**	**0.53**	**0.45**	**0.43**	**0.44**	**0.42**	**0.41**	**0.42**	**0.43**	**0.45**	**0.24**	**0.28**
School Bus GHG Emissions (Mt of CO_2e)	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.1**	**0.1**	**0.2**	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
GHG Emissions by Energy Source (Mt of CO_2e)																			
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Motor Gasoline	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel Fuel Oil	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.0	0.0	0.0	0.0	0.0	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shares (%)																			
Natural Gas	1.7	0.9	0.4	0.1	0.1	0.0	0.0	0.0	0.0	1.2	0.5	0.0	0.4	0.4	1.0	4.7	5.6	15.2	11.5
Motor Gasoline	8.8	2.2	1.4	3.0	4.4	1.5	2.8	4.0	1.5	2.8	2.4	3.0	4.0	4.0	6.3	6.6	7.0	11.6	10.5
Diesel Fuel Oil	89.6	96.8	98.2	96.9	95.5	98.5	97.2	96.0	98.5	96.0	97.0	96.9	95.4	95.4	92.5	88.7	87.5	73.2	77.9
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.1	0.1	0.2	0.1	0.2	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GHG Intensity (tonne/TJ)	**70.1**	**70.7**	**70.9**	**70.9**	**70.9**	**71.1**	**71.0**	**71.0**	**71.1**	**70.7**	**71.0**	**71.1**	**70.9**	**70.9**	**70.7**	**69.5**	**69.2**	**66.2**	**67.3**

British Columbia and Territories
Table 29: Urban Transit Secondary Energy Use and GHG Emissions by Energy Source

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Urban Transit Energy Use (PJ)	**5.1**	**5.6**	**6.3**	**6.1**	**5.7**	**5.8**	**4.4**	**5.5**	**5.9**	**4.9**	**5.2**	**4.9**	**5.1**	**5.7**	**5.3**	**5.3**	**4.9**	**5.2**	**5.6**
Energy Use by Energy Source (PJ)																			
Electricity	0.4	0.4	0.5	0.5	0.5	0.5	0.4	0.5	0.6	0.7	0.8	0.7	0.8	0.8	0.8	0.7	0.7	0.8	0.8
Natural Gas	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Motor Gasoline	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Diesel Fuel Oil	4.4	5.0	5.5	5.3	4.8	4.3	3.9	5.0	5.2	4.1	4.4	4.1	4.0	4.7	4.3	4.3	4.0	4.2	4.6
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.0	0.0	0.0	0.0	0.0	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Propane	0.0	0.1	0.2	0.2	0.3	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shares (%)																			
Electricity	8.4	7.4	8.2	8.8	8.7	8.7	9.6	9.3	10.4	13.8	14.8	14.9	15.8	13.3	15.4	13.9	15.0	14.6	13.5
Natural Gas	5.4	1.6	0.9	1.0	1.0	0.9	1.2	1.1	1.0	1.5	2.1	2.1	4.2	3.2	3.7	4.0	4.2	4.7	4.4
Motor Gasoline	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.4	0.5	0.7	1.1	1.1
Diesel Fuel Oil	86.1	89.3	87.9	87.5	84.4	74.8	89.2	89.6	88.5	84.5	83.0	82.9	79.9	83.2	80.5	81.5	80.1	79.7	80.9
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.0	0.0	0.0	0.0	0.0	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Propane	0.0	1.5	2.8	2.5	5.7	15.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Activity																			
Passenger-kilometres (millions)	2,595	3,187	3,528	3,417	3,274	3,409	3,069	3,030	3,270	2,896	3,154	3,202	3,372	3,415	3,194	3,144	2,669	3,219	3,359
Energy Intensity (MJ/Pkm)	**1.95**	**1.77**	**1.79**	**1.78**	**1.75**	**1.70**	**1.44**	**1.83**	**1.79**	**1.68**	**1.66**	**1.54**	**1.50**	**1.67**	**1.67**	**1.67**	**1.85**	**1.63**	**1.68**
Urban Transit GHG Emissions Excluding Electricity (Mt of CO_2e)	**0.3**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.3**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
GHG Emissions by Energy Source (Mt of CO_2e)																			
Electricity	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Motor Gasoline	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel Fuel Oil	0.3	0.4	0.4	0.4	0.3	0.3	0.3	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.0	0.0	0.0	0.0	0.0	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Propane	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shares (%)																			
Electricity	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Natural Gas	4.2	1.2	0.7	0.7	0.8	0.7	0.9	0.8	0.7	1.2	1.7	1.7	3.5	2.6	3.1	3.2	3.4	3.8	3.6
Motor Gasoline	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.5	0.6	0.8	1.2	1.2
Diesel Fuel Oil	95.7	97.2	96.5	96.6	93.6	84.3	99.0	99.1	99.2	98.6	98.1	98.2	96.4	97.1	96.5	96.2	95.8	95.0	95.2
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.0	0.0	0.0	0.0	0.0	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Propane	0.0	1.4	2.6	2.4	5.4	14.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GHG Intensity (tonne/TJ)	**63.9**	**65.3**	**64.7**	**64.4**	**64.1**	**63.1**	**64.1**	**64.3**	**63.5**	**61.0**	**60.2**	**60.1**	**59.0**	**61.0**	**59.4**	**60.4**	**59.6**	**59.8**	**60.5**

1) Data on GHG emissions are presented excluding GHG emissions related to electricity production.

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Table 30: Inter-City Bus Secondary Energy Use and GHG Emissions by Energy Source

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Inter-City Bus Energy Use (PJ)	**1.2**	**1.5**	**1.6**	**1.4**	**1.1**	**1.1**	**1.0**	**1.2**	**1.2**	**0.7**	**0.7**	**0.6**	**0.6**	**0.8**	**0.8**	**0.7**	**0.6**	**0.5**	**0.5**
Energy Use by Energy Source (PJ)																			
Motor Gasoline	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Diesel Fuel Oil	1.1	1.5	1.6	1.4	1.1	1.1	1.0	1.1	1.2	0.7	0.7	0.6	0.6	0.7	0.8	0.6	0.6	0.4	0.4
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.0	0.0	0.0	0.0	0.0	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Shares (%)																			
Motor Gasoline	8.6	0.7	1.3	1.1	1.3	2.1	1.8	1.5	1.5	2.4	2.3	2.4	3.1	3.8	4.1	4.5	5.2	11.4	11.6
Diesel Fuel Oil	91.4	99.3	98.7	98.9	98.7	97.9	98.2	98.5	98.5	97.6	97.6	97.5	96.8	96.1	95.7	95.5	94.8	88.6	88.4
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.1	0.1	0.1	0.1	0.2	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Activity																			
Passenger-kilometres (millions)	1,565	1,836	2,054	1,778	1,476	1,485	1,153	1,500	1,430	987	894	850	806	1,044	866	819	803	923	993
Energy Intensity (MJ/Pkm)	**0.80**	**0.81**	**0.78**	**0.77**	**0.76**	**0.75**	**0.85**	**0.77**	**0.82**	**0.69**	**0.76**	**0.70**	**0.78**	**0.73**	**0.91**	**0.81**	**0.73**	**0.51**	**0.46**
Inter-City Bus GHG Emissions (Mt of CO_2e)	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**
GHG Emissions by Energy Source (Mt of CO_2e)																			
Motor Gasoline	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.0	0.0	0.0	0.0	0.0	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Shares (%)																			
Motor Gasoline	8.1	0.6	1.3	1.0	1.2	2.0	1.7	1.4	1.4	2.3	2.2	2.3	2.9	3.6	3.9	4.2	5.0	10.9	11.1
Diesel Fuel Oil	91.9	99.4	98.7	99.0	98.8	98.0	98.3	98.6	98.6	97.7	97.7	97.6	97.0	96.3	95.9	95.8	95.0	89.1	88.9
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.1	0.1	0.1	0.1	0.1	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
GHG Intensity (tonne/TJ)	**70.6**	**71.0**	**71.0**	**71.0**	**71.1**	**71.1**	**71.1**	**71.1**	**71.1**	**71.1**	**71.1**	**71.1**	**71.1**	**71.1**	**71.1**	**71.1**	**71.0**	**70.8**	**70.8**

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Table 35: Freight Light Truck Secondary Energy Use and GHG Emissions by Energy Source

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Freight Light Truck Energy Use (PJ)	**21.6**	**21.3**	**21.6**	**21.4**	**22.3**	**21.0**	**19.4**	**21.4**	**21.3**	**20.8**	**21.5**	**20.5**	**21.0**	**21.7**	**22.6**	**23.8**	**26.6**	**27.4**	**29.1**
Energy Use by Energy Source (PJ)																			
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Motor Gasoline	18.3	17.8	18.3	18.5	19.7	18.8	17.6	18.9	18.3	18.7	18.6	17.7	18.4	19.2	20.3	22.1	25.0	25.7	26.6
Diesel Fuel Oil	1.0	1.2	1.2	1.1	1.0	0.9	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.4	0.5	0.5	0.6
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.7	0.8	0.7	0.7	0.7	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Propane	2.3	2.3	2.1	1.8	1.6	1.3	1.6	2.3	2.8	1.8	1.9	1.8	1.7	1.5	1.2	1.3	1.1	1.1	1.8
Shares (%)																			
Natural Gas	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.1
Motor Gasoline	84.8	83.6	84.9	86.4	88.3	89.5	90.9	88.4	85.8	90.0	86.6	86.2	87.2	88.5	89.6	92.9	94.1	93.9	91.6
Diesel Fuel Oil	4.4	5.4	5.5	5.3	4.3	4.1	0.9	0.9	1.2	1.0	1.0	1.0	1.1	1.2	1.4	1.5	1.7	1.8	2.0
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	3.1	3.7	3.5	3.2	3.3	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Propane	10.6	10.9	9.5	8.3	7.4	6.3	8.1	10.6	13.0	8.8	9.0	8.7	7.8	6.7	5.4	5.3	4.0	4.1	6.3
Activity																			
Tonne-kilometres (millions)	2,596	2,606	2,661	2,663	2,797	2,672	2,500	2,778	2,775	2,734	2,858	2,743	2,854	2,971	3,112	3,311	3,734	3,890	4,159
Energy Intensity (MJ/Tkm)	**8.31**	**8.18**	**8.11**	**8.04**	**7.97**	**7.87**	**7.76**	**7.69**	**7.68**	**7.59**	**7.52**	**7.48**	**7.37**	**7.32**	**7.26**	**7.20**	**7.11**	**7.04**	**6.99**
Freight Light Truck GHG Emissions (Mt of CO_2e)	**1.5**	**1.5**	**1.5**	**1.5**	**1.6**	**1.5**	**1.3**	**1.5**	**1.4**	**1.4**	**1.5**	**1.4**	**1.4**	**1.5**	**1.5**	**1.6**	**1.8**	**1.8**	**1.9**
GHG Emissions by Energy Source (Mt of CO_2e)																			
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Motor Gasoline	1.3	1.3	1.3	1.3	1.4	1.3	1.2	1.3	1.3	1.3	1.3	1.2	1.2	1.3	1.4	1.5	1.7	1.7	1.8
Diesel Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.0	0.1	0.0	0.0	0.0	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Propane	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Shares (%)																			
Natural Gas	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1
Motor Gasoline	86.1	84.9	86.0	87.3	89.2	90.2	91.8	89.5	87.1	90.9	87.5	87.0	88.0	89.1	90.1	93.3	94.4	94.2	92.0
Diesel Fuel Oil	4.6	5.6	5.7	5.5	4.4	4.2	1.0	1.0	1.2	1.1	1.1	1.1	1.1	1.3	1.5	1.7	1.8	1.9	2.2
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	3.1	3.7	3.5	3.2	3.3	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Propane	9.3	9.5	8.3	7.2	6.4	5.5	7.1	9.4	11.6	7.9	8.1	7.9	7.1	6.1	4.9	4.8	3.6	3.8	5.7
GHG Intensity (tonne/TJ)	**69.7**	**69.8**	**69.9**	**70.0**	**69.7**	**69.5**	**68.8**	**68.2**	**67.7**	**67.8**	**67.5**	**67.2**	**66.9**	**66.8**	**66.7**	**66.7**	**66.9**	**66.9**	**66.7**

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Table 36: Medium and Heavy Truck Secondary Energy Use and GHG Emissions by Energy Source

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Medium Trucks																			
Medium Truck Energy Use (PJ)	**26.4**	**30.9**	**30.5**	**39.6**	**44.7**	**46.3**	**56.8**	**48.3**	**56.5**	**59.2**	**64.3**	**59.8**	**61.3**	**65.8**	**63.5**	**61.2**	**62.7**	**63.7**	**68.1**
Energy Use by Energy Source (PJ)																			
Motor Gasoline	14.5	14.3	13.1	16.0	18.7	18.9	25.2	19.7	22.1	25.5	25.2	23.4	23.9	24.4	24.5	25.7	27.3	27.0	27.5
Diesel Fuel Oil	11.7	16.3	17.2	23.2	25.4	26.9	31.6	28.6	34.4	33.1	37.6	34.9	36.0	40.0	37.7	35.2	35.2	36.4	40.2
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.9	1.0	0.9	0.9	0.9	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Shares (%)																			
Motor Gasoline	55.0	46.4	42.9	40.5	41.9	40.8	44.3	40.7	39.1	43.0	39.2	39.1	38.9	37.1	38.6	42.0	43.5	42.5	40.4
Diesel Fuel Oil	44.3	52.7	56.4	58.5	56.8	58.1	55.7	59.3	60.9	56.0	58.5	58.4	58.8	60.8	59.4	57.5	56.1	57.1	59.0
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1.4	1.7	1.5	1.3	1.4	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Activity																			
Tonne-kilometres (millions)	3,362	3,914	3,902	5,109	5,845	6,111	8,388	7,230	8,319	8,206	9,527	8,998	9,364	10,180	9,988	9,803	10,225	10,541	11,439
Energy Intensity (MJ/Tkm)	**7.85**	**7.88**	**7.83**	**7.74**	**7.65**	**7.57**	**6.77**	**6.68**	**6.79**	**7.21**	**6.74**	**6.64**	**6.55**	**6.46**	**6.35**	**6.24**	**6.14**	**6.04**	**5.95**
Medium Truck GHG Emissions (Mt of CO_2e)	**1.8**	**2.1**	**2.1**	**2.7**	**3.1**	**3.2**	**3.9**	**3.4**	**3.9**	**4.1**	**4.5**	**4.2**	**4.3**	**4.6**	**4.4**	**4.3**	**4.4**	**4.4**	**4.7**
GHG Emissions by Energy Source (Mt of CO_2e)																			
Motor Gasoline	1.0	1.0	0.9	1.1	1.3	1.3	1.7	1.3	1.5	1.7	1.7	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.9
Diesel Fuel Oil	0.8	1.2	1.2	1.6	1.8	1.9	2.2	2.0	2.5	2.4	2.7	2.5	2.6	2.8	2.7	2.5	2.5	2.6	2.9
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.1	0.1	0.1	0.1	0.1	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Shares (%)																			
Motor Gasoline	53.6	45.1	41.6	39.3	40.7	39.6	43.0	39.4	37.8	41.8	38.0	37.9	37.8	36.0	37.4	40.7	42.2	41.2	39.2
Diesel Fuel Oil	45.7	54.1	57.8	59.9	58.2	59.5	57.0	60.6	62.2	57.4	59.9	59.7	60.1	62.1	60.7	58.8	57.4	58.4	60.3
Ethanol	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1.3	1.6	1.5	1.3	1.4	n.a.	n.a.	n.a.	n.a.
Biodiesel Fuel	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
GHG Intensity (tonne/TJ)	**68.7**	**69.1**	**69.3**	**69.5**	**69.4**	**69.5**	**69.5**	**69.6**	**69.7**	**69.5**	**69.6**	**69.6**	**69.6**	**69.7**	**69.7**	**69.6**	**69.6**	**69.6**	**69.7**
Heavy Trucks																			
Heavy Truck Energy Use[1] (PJ)	**39.8**	**33.3**	**32.7**	**35.3**	**40.0**	**36.6**	**32.0**	**37.8**	**37.9**	**31.1**	**31.0**	**29.2**	**31.8**	**35.3**	**35.7**	**34.3**	**35.8**	**36.9**	**40.6**
Activity																			
Tonne-kilometres (millions)	19,582	16,590	16,448	17,972	20,603	18,329	14,268	16,281	17,251	13,194	13,247	12,137	13,585	15,406	16,315	16,944	19,888	19,453	19,893
Energy Intensity (MJ/Tkm)	**2.03**	**2.01**	**1.99**	**1.97**	**1.94**	**1.99**	**2.24**	**2.32**	**2.20**	**2.36**	**2.34**	**2.41**	**2.34**	**2.29**	**2.19**	**2.02**	**1.80**	**1.89**	**2.04**
Heavy Truck GHG Emissions[1] (Mt of CO_2e)	**2.8**	**2.4**	**2.3**	**2.5**	**2.8**	**2.6**	**2.3**	**2.7**	**2.7**	**2.2**	**2.2**	**2.1**	**2.3**	**2.5**	**2.5**	**2.4**	**2.6**	**2.6**	**2.9**
GHG Intensity (tonne/TJ)	**71.0**	**71.0**	**71.1**	**71.1**	**71.1**	**71.1**	**71.2**	**71.2**	**71.2**	**71.2**	**71.2**	**71.2**	**71.2**	**71.2**	**71.2**	**71.2**	**71.2**	**71.2**	**71.2**

1) Heavy trucks consume only diesel fuel oil.

Canada Energy Regulator
Régie de l'énergie du Canada

Canada's Energy Future 2021

Canada

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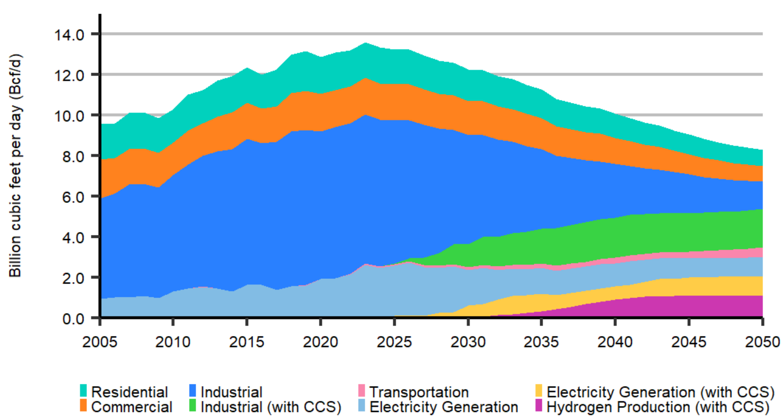
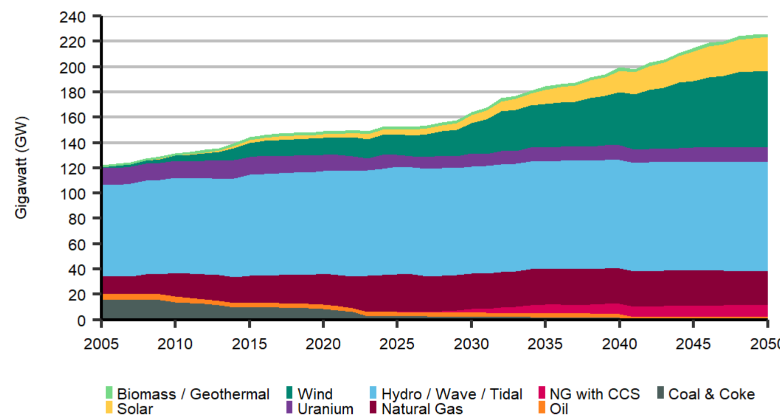
Date: 09 February 2022

In reference to corrections for the following document:

Canada's Energy Future 2021: Energy Supply and Demand Projections to 2050 (EF2021)

1. **Key Finding #7:** Figure ES.14 – Y axis unit of measurement changed from petajoules (PJ) to billion cubic feet per day (bcf/d)





2. **Results - Electricity:** Figure R.25 – updated natural gas and oil capacities from 2026 to 2050. Removed 2 100 megawatts (MW) of oil capacity from 2026 to 2050 and added it (2 100 MW of capacity) to natural gas.

3. **Results - Hydrogen:** Updated 2.95 megatonnes (MT) of hydrogen to 2.69 MT. This correction can be found above Figure R.31.

Table of Contents

Introduction

Current Policies Scenario: A new name for the Reference Scenario

In EF2021, we have renamed one of the core scenarios of the Canada's Energy Future series. The "Current Policies Scenario" shares the same premise as the "Reference Case" or "Reference Energy System Scenario" in past versions of the report. We changed the name to "Current Policies" to increase clarity and be more explicit about the assumptions of the scenario: that it models only energy and climate policies that are currently in place. This change also clarifies that the scenario is not meant to be a most-likely or base-case scenario. EF scenarios provide alternative views on how the energy system could evolve in Canada given different inputs and assumptions.

Canada's Energy Future 2021: Energy Supply and Demand Projections to 2050 (EF2021) is the latest long-term energy outlook from the Canada Energy Regulator (CER). The *Canada's Energy Future* series explores how possible energy futures might unfold for Canadians over the long term. We use economic and energy models to make these projections. The CER bases our projections on assumptions about future trends in technology, energy and climate policies, energy markets, human behaviour, and the structure of the economy.

EF2021 includes two core scenarios: The Evolving Policies Scenario and the Current Policies Scenario. The central difference between these scenarios is the level of future climate action, both globally and domestically. In both scenarios we provide projections for all energy commodities and all provinces and territories.

EF2021 also includes six additional electricity scenarios that explore what Canada's electricity system might look like in a net-zero[1] world. These scenarios focus only on how Canada will meet given electricity demands under different conditions, and do not include projections for other energy commodities. Electricity is an important contributor to achieving net-zero emissions, so these projections are an important step in modeling related to a net-zero energy system in the *Canada's Energy Future* series.

The analysis and projections for EF2021 are based on several important assumptions, outlined for the core scenarios in the "Scenarios and Assumptions" section of the report. The "Results" section provides an overview of our core scenario projections for various parts of the Canadian energy system to 2050, focusing on the Evolving Policies Scenario. The "Towards Net-Zero" section explores what Canada's electricity system could look like in a net-zero world, including assumptions and projections. Finally, the "Access and Explore Energy Futures Data" section provides links to access data, tools, and interactive data visualizations that offer further insight into EF2021.

1 Net-zero GHG emissions refers to the concept of balancing human-caused GHG emissions with removals from the atmosphere. See the text box "What is "Net-Zero"?" in the Towards Net-Zero section for more information.

Executive Summary

Overview and Background

The *Canada's Energy Future* series explores how possible energy futures might unfold for Canadians over the long term. *Canada's Energy Future 2021: Energy Supply and Demand Projections to 2050* (EF2021) is our latest long-term energy outlook. The outlook covers all energy commodities and all Canadian provinces and territories, and makes projections using economic and energy models. We also make assumptions about technology, energy and climate policies, energy markets, human behaviour, and the economy.

In the long term, global and Canadian ambition to reduce greenhouse gas (GHG) emissions will be a critical factor in how energy systems evolve. EF2021 considers two main scenarios, where energy supply and demand projections differ based on the level of future action[2] to reduce GHG emissions. EF2021 also includes six additional scenarios that explore what Canada's electricity system might look like in a net-zero world. The two main scenarios include projections for all energy commodities, whereas the six electricity scenarios focus only on how Canada will meet given electricity demands under different conditions.

[2] "Action" in this context is led by increasing policies, while also considering behavioural decisions by consumers and firms.

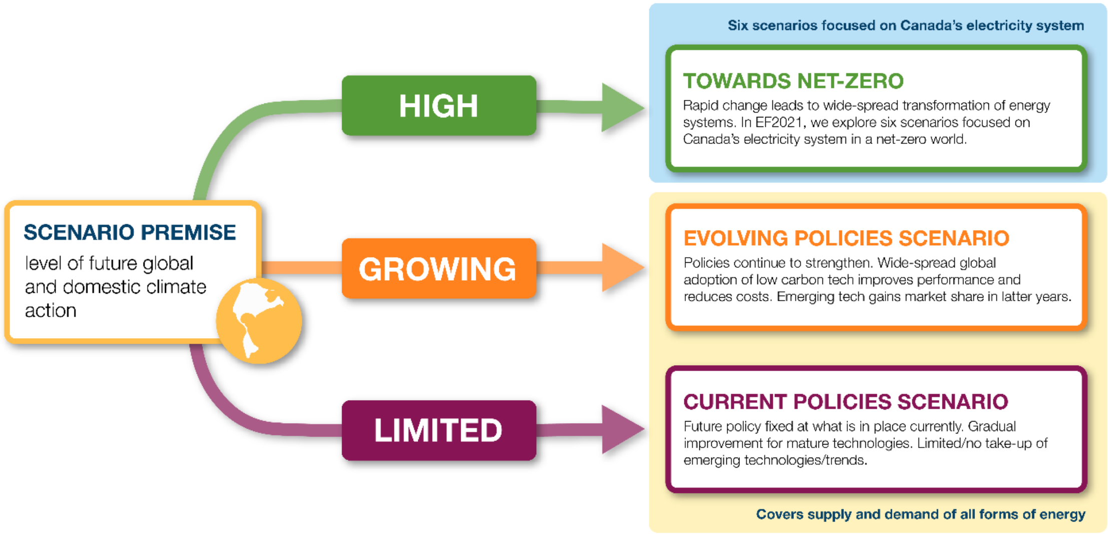
The first main scenario in EF2021 is the Evolving Policies Scenario. The premise of this scenario is that action to reduce GHG emissions from our energy system continues to increase at a pace similar to recent history, in both Canada and the world. Relative to a scenario with less action to reduce GHG emissions, this projection implies less global demand for fossil fuels, and greater use of low-carbon technologies. The second main scenario is the Current Policies Scenario, which assumes limited action to reduce GHGs beyond policies in place today.

These scenarios do not explicitly model climate goals or targets. Instead, we make assumptions based on the scenario premises and rely on the Energy Futures Modelling Framework to make long-term projections of energy supply and demand in Canada. Together, these scenarios provide insights into what the energy system might look like if action to reduce GHG emissions continues to grow at the pace it has in recent years, or if it were to stop at current levels.

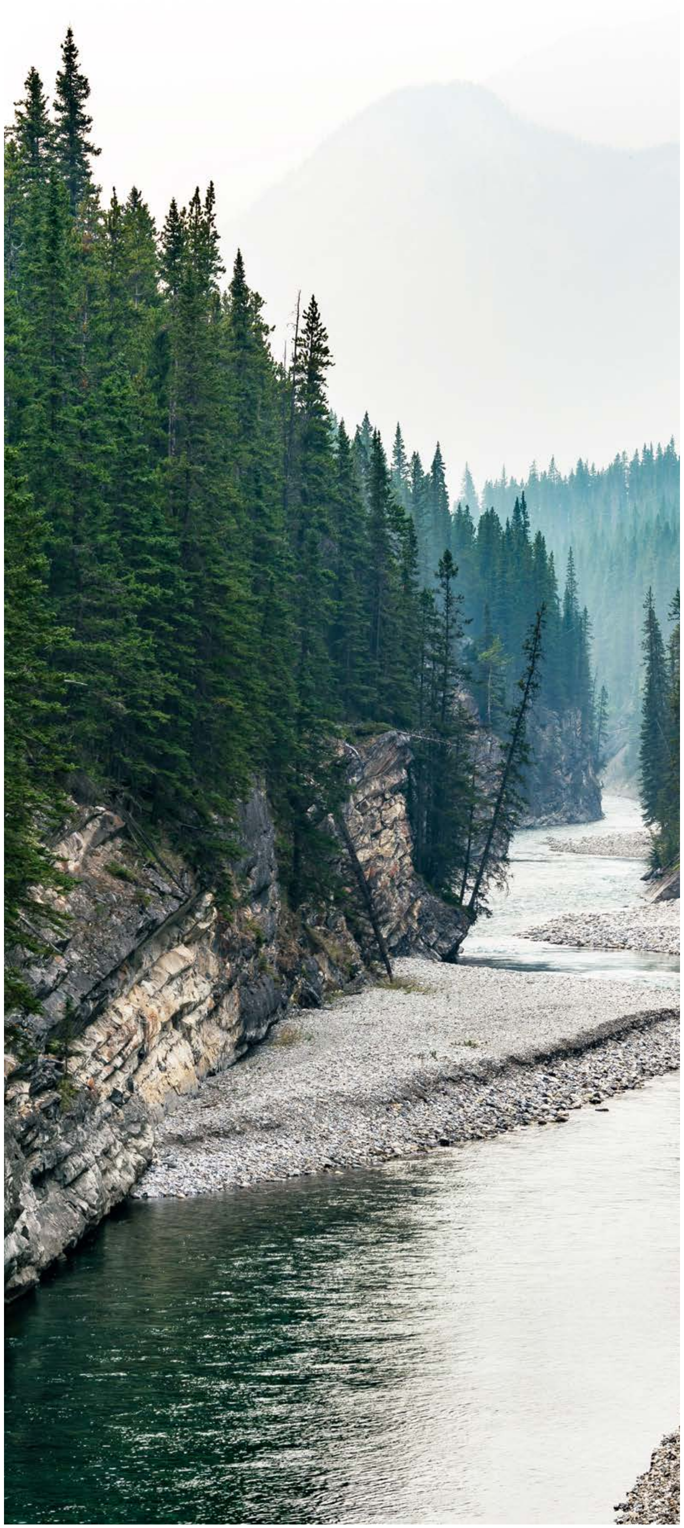
Canada has committed to reducing its GHG emissions by 40 to 45% below 2005 levels by 2030 and achieving net-zero GHG emissions by 2050. Reducing emissions to these levels will likely require more change than we model in the Evolving or Current Policies scenarios. Therefore, EF2021 introduces six new scenarios that explore a net-zero future. Specifically, these scenarios explore what Canada's electricity system might look like in a net-zero world under different assumptions about future technologies, climate policies, and electricity use. Electricity is expected to be an important contributor to achieving net-zero emissions, so these projections are an important step in modeling related to a net-zero energy system in the *Canada's Energy Future* series.

Figure ES.1 provides a conceptual illustration of the two main scenarios included in EF2021, as well as the net-zero scenarios focused on electricity.

Figure ES.1:
Conceptual Illustration of EF2021 Scenarios



This Executive Summary highlights the key findings of EF2021. The "Scenarios and Assumptions" section outlines the specific assumptions used in the Evolving and Current Policies scenarios. The "Results" section provides an overview of the projections for the various parts of the Canadian energy system under our two main scenarios, with a focus on the Evolving Policies Scenario. The "Towards Net-Zero" section includes the first major net-zero modeling exercise of the *Canada's Energy Future* series: six scenarios that examine the effect of different factors (e.g. technology, policies, level of electrification, infrastructure) on Canada's electricity system in a net-zero world. Finally, the "Access and Explore Energy Futures Data" section provides links to access data, tools, and interactive data visualizations for further exploration of EF2021.



Key Findings

1. In the Evolving Policies Scenario, combustion of fossil fuels whose emissions are not captured falls 62% from 2021 to 2050, while use of low and non-emitting energy sources increases. While this implies a significant reduction in GHG emissions by 2050, achieving net-zero will likely require more change than is included in this scenario.

In the Evolving Policies Scenario, Canadians reduce their energy consumption and adopt lower carbon sources (Figure ES.2). Total primary energy use falls 21% from 2021 to 2050 as energy efficiency improves. Low and non-emitting sources–including renewables, nuclear, and fossil fuels with carbon-capture and storage (CCS)–grow to make up the strong majority of energy use. Unabated fossil fuel combustion (fossil fuel combustion without CCS) falls 19% from current levels by 2030, 45% by 2040, and 62% by 2050 (Figure ES.3).

Policy assumptions in the Evolving Policies Scenario are based on strengthening or expanding existing global and domestic policies at a pace consistent with recent trends. The Evolving Policies Scenario projections show significant changes in Canada's energy system and imply large reductions in GHG emissions. However, given the remaining unabated fossil fuel demands in 2050, the Evolving Policies Scenario also signals the need for greater long-term change in order to reach Canada's target of net-zero emissions by 2050. In addition to policy, many other factors we discuss in EF2021–such as global energy markets, technology, and consumer behaviour and preferences–will also influence future Canadian energy and emission trends.

Figure ES.2:
Total Canadian Energy Use, Evolving Policies Scenario

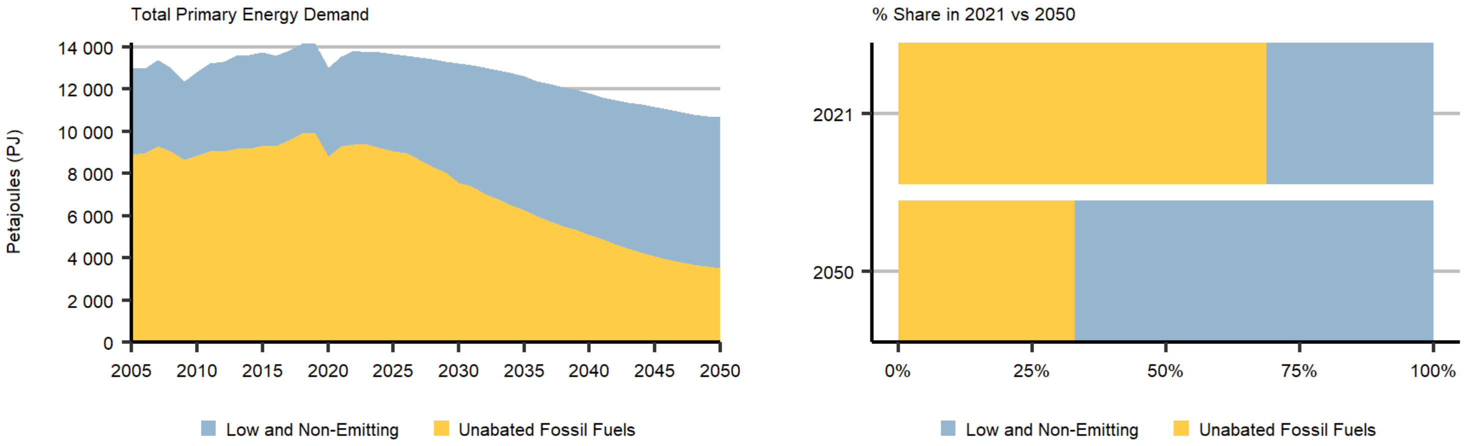
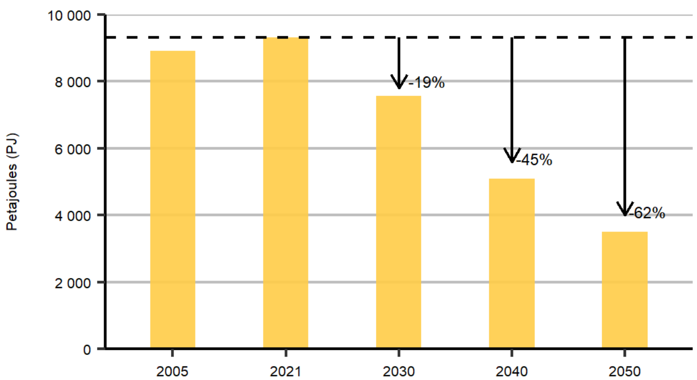


Figure ES.3:
Total Canadian Energy Use, Evolving Policies Scenario



2. Canadians use more electricity, from increasingly low-carbon sources. Despite total energy use declining, electricity demand grows 44% from 2021 to 2050 in the Evolving Policies Scenario, much of it from new areas such as electric vehicles and hydrogen production. Canada's electricity system also gets greener, going from 82% low and non-emitting in 2021 to 95% in 2050.

Compared to the past two decades when electricity use grew very slowly, electricity demand grows quickly over the projection period in the Evolving Policies Scenario. This increase is driven by increased electrification of the energy system. Total electricity demand increases by 44% from 2021 to 2050, or by about 245 terawatt hours (TWh) (Figure ES.4). Half of this increase is driven by increased electrification in the industrial, residential, and commercial sectors. The other half comes from electric vehicles in transportation and the production of hydrogen. In particular, by 2050, electric vehicles dominate Canada's vehicle mix and increase electricity demand by 70 TWh. This results from the Evolving Policies Scenario assuming nearly all new passenger vehicles sold in 2035 are battery or plug-in hybrid electric vehicles.

As demand grows, Canadian electricity generation increases. Wind and solar generation provide much of this additional electricity over the projection period, given their low cost. Natural gas generation is increasingly equipped with CCS. Low and non-emitting electricity generation make up 82% of total generation in 2021, rising to 88% by 2030, 94% by 2040, and 95% by 2050.

Figure ES.4:
Electricity Demand by Sector, Evolving Policies Scenario

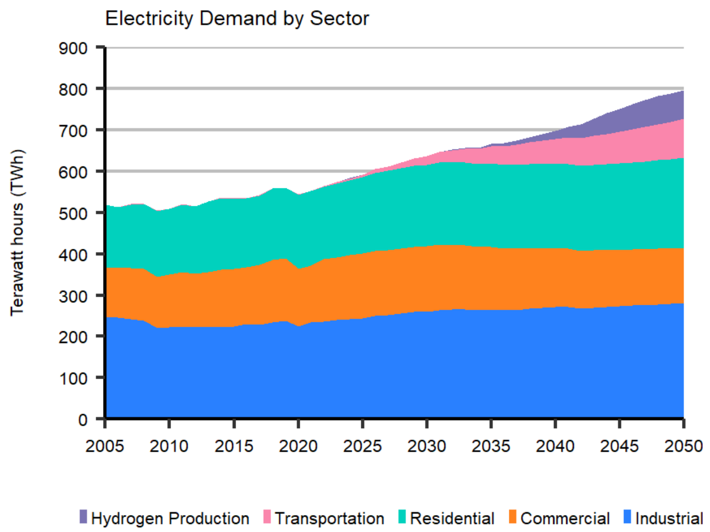
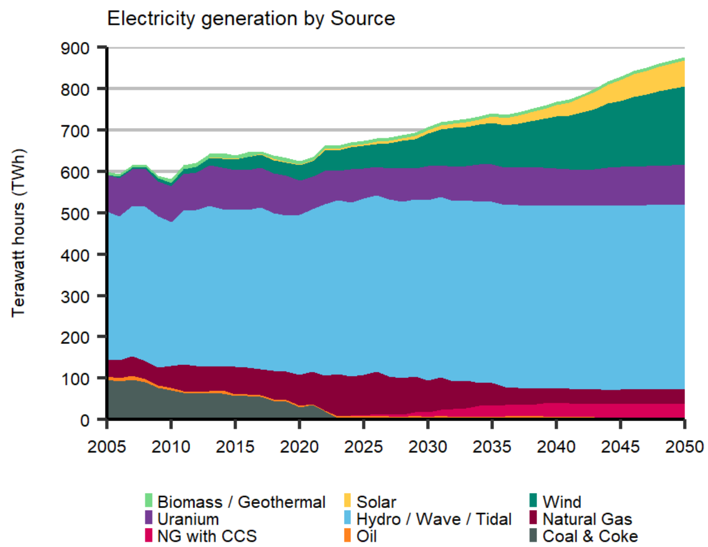


Figure ES.5:
Electricity Generation by Source, Evolving Policies Scenario

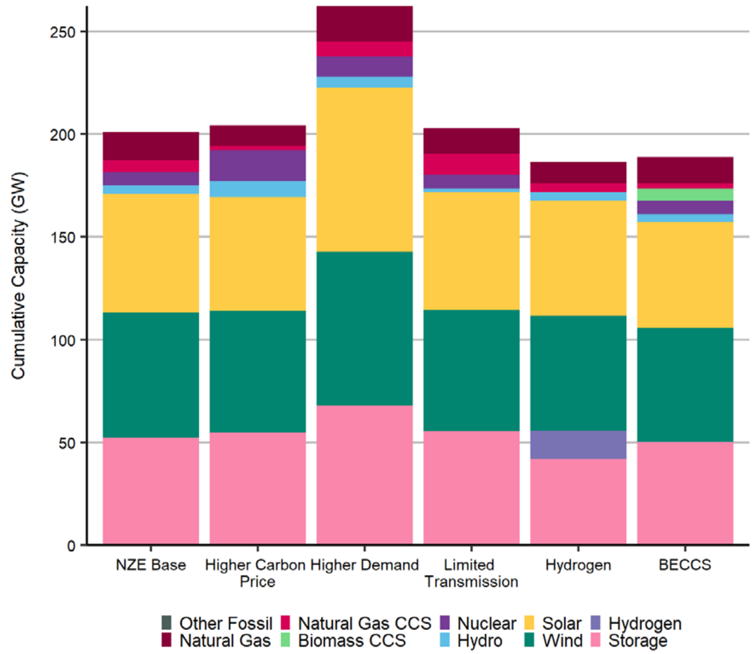


3. Wind, solar, and battery storage dominate electric capacity additions in all six net-zero electricity scenarios, making up between 82-85% of added capacity. With rising levels of wind and solar, all scenarios require flexible generation sources to balance supply and demand. There are large differences in the types and capacities of flexible generation sources adopted among scenarios.

The net-zero electricity scenarios each have a unique set of assumptions that examine many factors including technology, policies, level of electrification, and infrastructure. Figure ES.6 shows the net capacity additions for all six scenarios from 2019 to 2050. Consistent across all scenarios are large additions of wind and solar capacity, ranging from 100 gigawatts (GW) to 150 GW. These technologies are increasingly adopted due to their assumed low future costs in all scenarios. With large amounts of wind and solar capacity, power systems require additional flexible generating resources to balance supply and demand (given the variability of wind and sun conditions). Across the net-zero scenarios, the flexible generating resources are a combination of battery storage, natural gas-fired generation (with and without CCS), small modular nuclear reactors, hydropower, hydrogen-fired generation, biomass-fired generation with CCS, and transmission between provinces. The relative share of these flexible resources varies significantly across the scenarios, though the role of storage in balancing the grid increases dramatically in all scenarios.

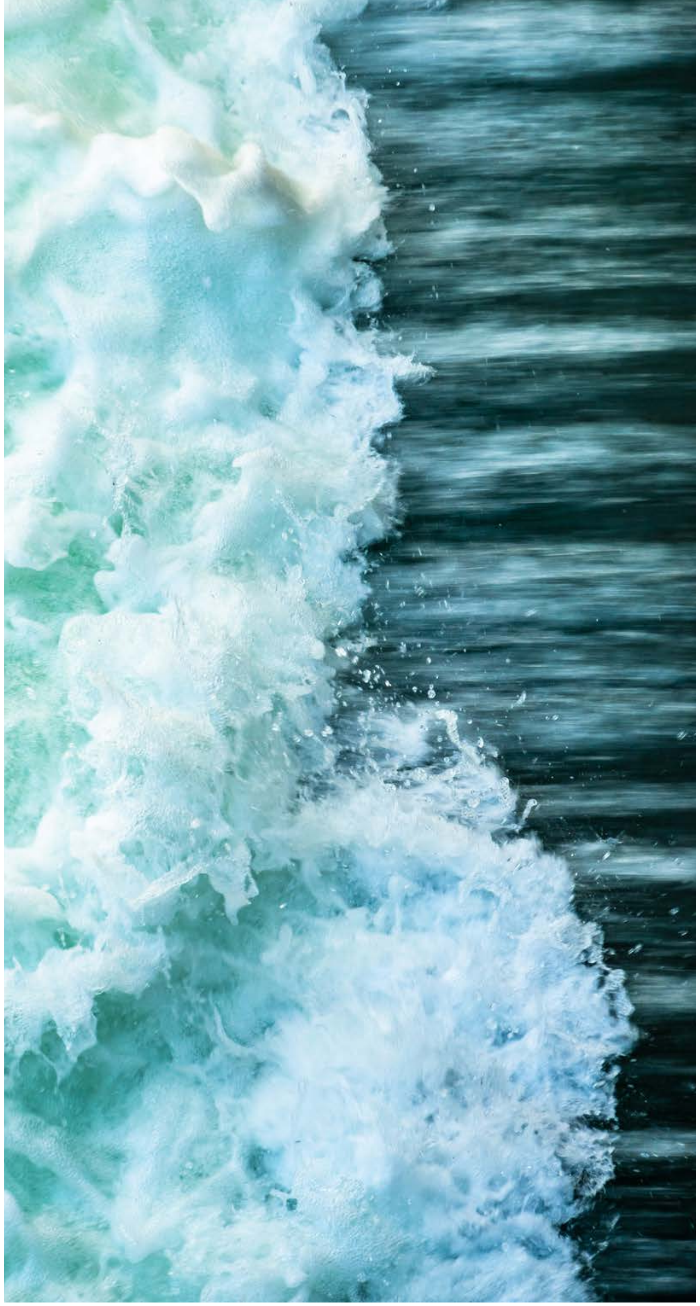
Figure ES.6:

Cumulative Capacity Additions to 2050, All Net-Zero Electricity Scenarios



Electricity Emissions in a Net-Zero World

In these scenarios, the emissions from the electricity sector drops dramatically, but a very small amount of emissions remains from natural gas-fired plants in five of the six scenarios. We allow these emissions because the value of these facilities in terms of electricity system reliability and stability is high. This allowance reflects that, in the context of a broader net-zero world, the use of carbon removal options could potentially provide more cost-effective options than reducing those last few emissions from the electricity system in 2050.



4. The net-zero electricity scenarios suggest that Canadian power systems will continue to be very distinct across the country, even in a low-carbon future. In each net-zero electricity scenario, the ten provinces meet their electricity demands in diverse ways, with widely varying mixes of hydro, nuclear, fossil fuel with CCS, wind, solar, hydrogen, and biomass with CCS.

Figure ES.7 shows the generation mix for each province in the main net-zero electricity scenario. In British Columbia (B.C.), Manitoba, Quebec, and Newfoundland and Labrador, electricity generation continues to be primarily hydropower. Nuclear power remains limited to Ontario and New Brunswick and represents about 41% and 24%, respectively, of those provinces' electricity supply in 2050.

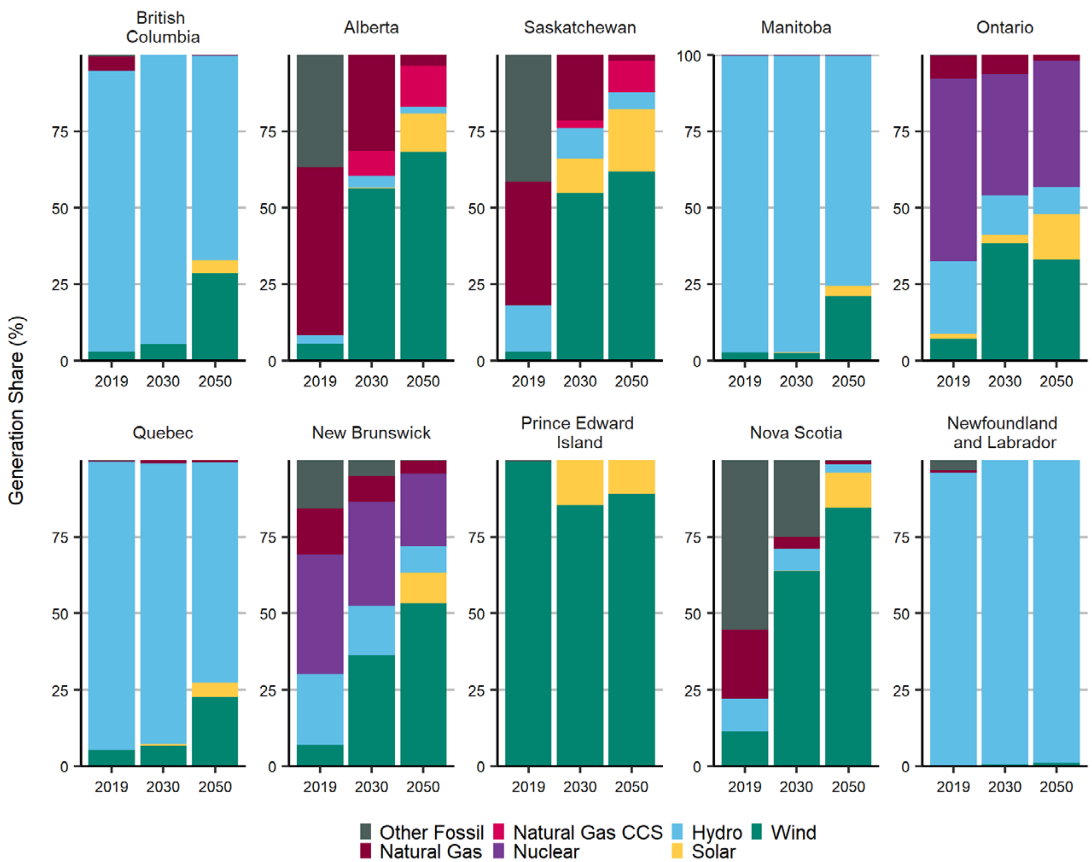
Natural gas-fired electricity generation remains a relatively important share, about 15%, of the electricity supply of Alberta and Saskatchewan in the main net-zero electricity scenario. However, by 2050, the vast majority of this generation utilizes CCS technology. In many other provinces, although the generation share is small, natural gas units nonetheless provide flexible capacity required to maintain system reliability.

Transmission between provinces is a key factor that enables the electricity system to reach net-zero. For example, in the Base net-zero electricity scenario, increased transmission occurs in western Canada, where hydroelectric generation from B.C. and Manitoba helps Alberta and Saskatchewan decarbonize.

While we continue to see diversity between the various provincial electricity systems in each net-zero electricity scenario, results vary somewhat between cases. In a scenario where transmission expansions are limited, Alberta and Saskatchewan use more generation from natural gas with CCS. By contrast, in the Higher Carbon Price scenario, natural gas with CCS is lower in these provinces as small modular reactors make inroads in western Canada. Meanwhile, in the Hydrogen scenario there is a 26% reduction of all types of natural gas-fired generation relative to the main net-zero electricity scenario in 2050, and the flexible nature of hydrogen-fired generation means battery storage falls by 32%. In the Bioenergy with CCS (BECCS) scenario, the availability of biomass CCS units for electricity generation partially displaces all other generation technologies in Alberta and Saskatchewan. Due to the carbon removal capability of biomass CCS, the electricity system in Canada becomes a net negative emissions economic sector in the BECCS scenario.

Figure ES.7:

Electricity Generation Share by Technology, Main Net-Zero Electricity Scenario



5. In the Evolving Policies Scenario, crude oil production grows much more slowly than in the past decade, rising 16% to a peak of 5.8 MMb/d in 2032. Afterwards, production declines slowly to 2050. As crude oil available for export from western Canada increases over the next decade , it comes close to filling the level of total export capacity that would be provided by existing pipeline capacity, planned pipeline expansions, and structural rail.

Canadian crude oil production recovered to pre-pandemic levels by late 2020, after steep reductions in the spring of 2020. In both scenarios, production increases in the near term, but long-term trends differ significantly based on scenario assumptions, such as future price levels and domestic climate policy.

In the Evolving Policies Scenario, Canadian production growth slows over the next decade, peaking at 5.8 million barrels per day (MMb/d) in 2032, up from 5.0 MMb/d in 2021 (Figure ES.8). After 2032, production declines steadily, reaching 4.8 MMb/d in 2050. In the Evolving Policies Scenario, the assumed Brent crude oil price gradually falls from an annual average of US$68 per barrel in 2021 to US$40 per barrel in 2050 (2020 dollars, adjusted for inflation).

Canadian crude oil production levels are resilient through to 2050 despite the Evolving Policies Scenario's relatively low prices and steadily more ambitious climate policies. This largely stems from the nature of the oil sands facilities, which are long-lived and have low operating costs once built. Throughout the projection period, the vast majority of oil sands production is from facilities that are producing today (Figure ES.9).

Future global climate policy, and how it affects global crude oil markets, will be important for Canadian production. The Current Policies Scenario assumes higher global oil prices than the Evolving Policies Scenario, premised on there being higher global oil demand. The Brent crude oil price stays at US$70 per barrel through much of the projection period and Canadian production increases more rapidly, plateauing in 2040 at 6.7 MMb/d. Conversely, some recent global net-zero scenarios, such as the International Energy Agency's Net Zero Emissions by 2050 scenario in World Energy Outlook 2021, show rapidly declining global oil demand, which could lead to significantly lower Canadian production levels compared to the Evolving Policies Scenario.

Figure ES.8:
Crude Oil Production, Evolving and Current Policies Scenarios

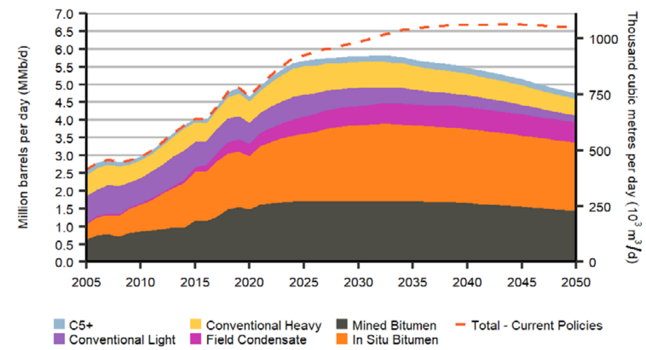
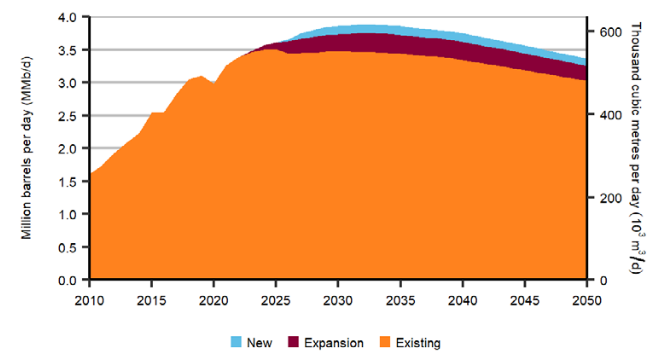
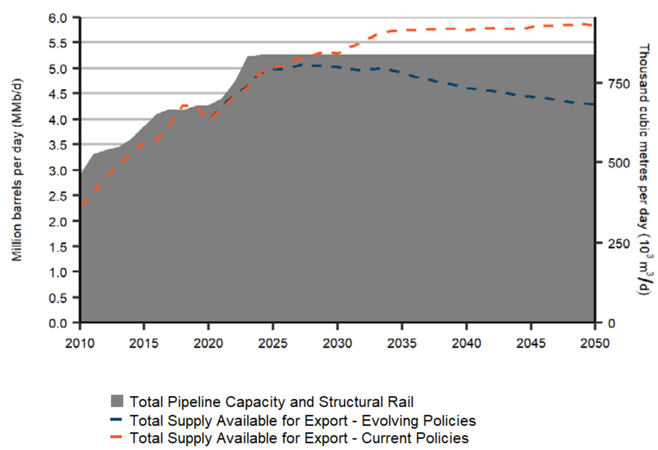


Figure ES.9:
Oil sands Production from Currently Producing Facilities, Expanded, and New Facilities, Evolving Policies Scenario



A key issue for Canadian oil pricing and production trends over the last number of years was the availability of crude oil export pipeline and rail capacity. In the Evolving Policies Scenario, crude oil available for export from western Canada comes very close to, but stays slightly below the illustrative total export capacity provided by existing plus planned pipeline capacity and structural rail, as shown in Figure ES.10. EF2021 does not assess whether additional pipeline capacity would be required to avoid constraining Canadian crude oil production below levels projected in the Evolving Policies Scenario. In the Current Policies Scenario, however, production would clearly be constrained below projected levels without additional pipeline capacity, as supply significantly exceeds the illustrative total export capacity through much of the projection period. Our crude oil supply projections are not adjusted to reflect potential pipeline constraints in either scenario.

Figure ES.10:
Illustrative Export Capacity from Pipelines and Structural Rail, vs. Total Crude Oil Supply Available from the Western Canadian Sedimentary Basin (WCSB), Evolving and Current Policies Scenarios



Crude Oil Pipelines in Canada's Energy Future

The *Canada's Energy Future* series makes projections of energy production and use in Canada. To develop these projections, we need to make assumptions about crude oil markets. Figure ES.10 is an illustrative comparison of our crude oil supply projections with the level of total export capacity that would be provided if planned pipeline expansions go ahead, existing pipelines otherwise experience no increases or decreases in capacity, and a consistent level of structural rail exports continues.

Making this comparison provides insight into whether pipeline constraints might impact crude oil production in our scenarios. However, we do not adjust our crude oil production projections based on potential constraints. EF2021 does not explore the complexities of how pipeline infrastructure interacts with energy supply and demand outcomes. Instead, EF2021 assumes that western Canadian crude oil prices will consistently track prices in international markets. In reality, this is not always the case. For example, if the pipeline system is very full–where export volumes are above or only slightly below total pipeline capacity–crude prices in western Canada can fall well below prices in international markets.

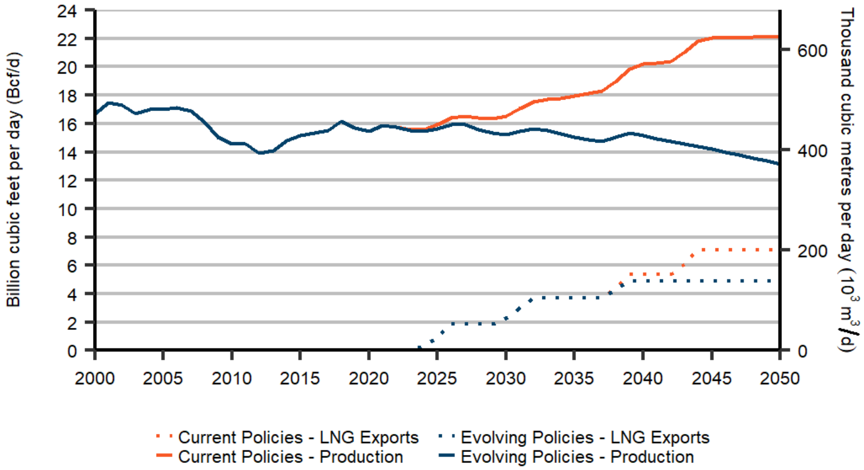
Sufficient spare pipeline capacity is generally required for western Canadian prices to consistently track prices in international markets. Spare capacity provides oil producers and others in the marketplace with flexibility to access higher value markets, and avoid the impacts of maintenance, unforeseen outages, and higher cost rail. This flexibility would remain even with excess capacity and long-term underutilization of pipelines, though this could result in higher pipeline tolls, which could lead to some consistent incremental discounting of western Canadian crude prices. Analysis of these considerations is beyond the scope of EF2021. We caution readers from drawing definitive conclusions from the illustrative comparison shown Figure ES.10.

6. Investment in natural gas production is spurred by assumed liquefied natural gas (LNG) exports in both scenarios. In the Evolving Policies Scenario, nearly 40% of Canadian natural gas production is liquefied and exported to global markets by 2050. Despite considerable LNG-related production growth, natural gas production remains relatively stable through much of the projection period before declining gradually to reach 13.1 Bcf/d by 2050, 17% lower than current levels.

In the Evolving Policies Scenario, natural gas production remains near current levels of approximately 15.5 billion cubic feet per day (Bcf/d) through much of the next two decades. We assume that LNG exports grow over that period, starting with 1.8 Bcf/d by 2026 and reaching 4.9 Bcf/d by 2039 in the Evolving Policies Scenario. The additional investment in production to feed these LNG exports sustains overall production levels. Without LNG, production would otherwise decline given the assumed natural gas prices and the costs associated with assumed domestic climate policies. After 2040, with LNG exports assumed to stay flat, total production begins to decline, falling to 13.1 Bcf/d by 2050. Assumed Henry Hub natural gas prices in the Evolving Policies Scenario steadily increase from US$3.00 per Million British Thermal Units (MMBtu) in 2021 to US$3.64/MMBtu by 2050 (2020 dollars, adjusted for inflation).

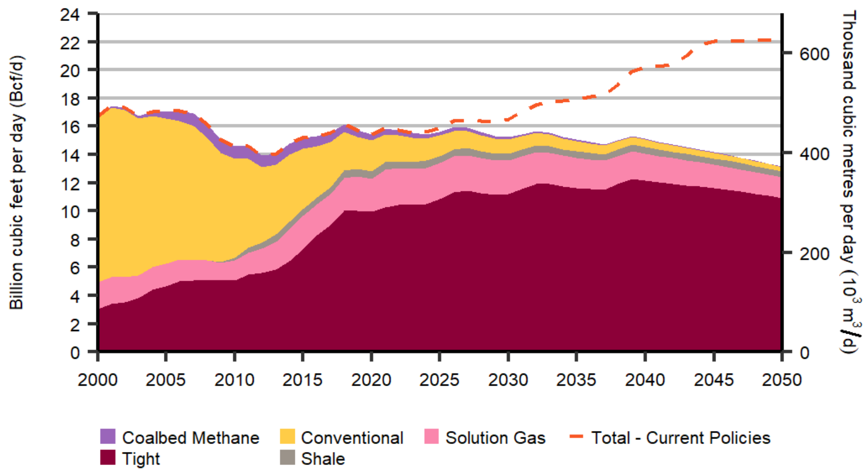
In the Current Policies Scenario, natural gas production is significantly higher. To reflect higher global and North American demand for natural gas due to the scenario's lower climate action, we assume LNG exports increase to 7.1 Bcf/d by 2044 and the Henry Hub price reaches $4.40/MMBtu by 2050 (2020 dollars, adjusted for inflation). These two drivers, combined with less stringent domestic climate policies relative to the Evolving Policies Scenario, lead to natural gas production increasing steadily throughout the projection, reaching 22.2 Bcf/d in 2050, a 40% increase from 2021 production levels.

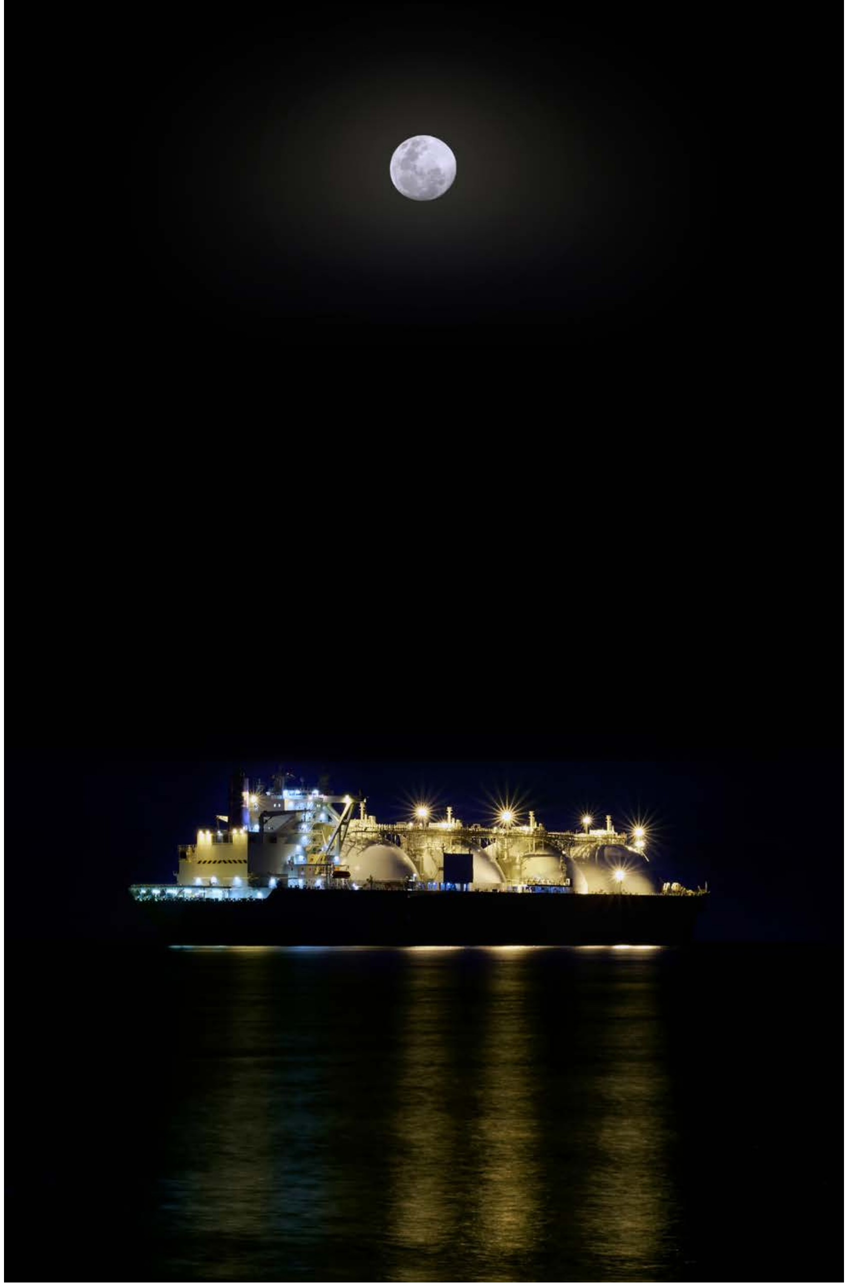
Figure ES.11:
Total Natural Gas Production and LNG Export Assumptions, Evolving and Current Policies Scenarios

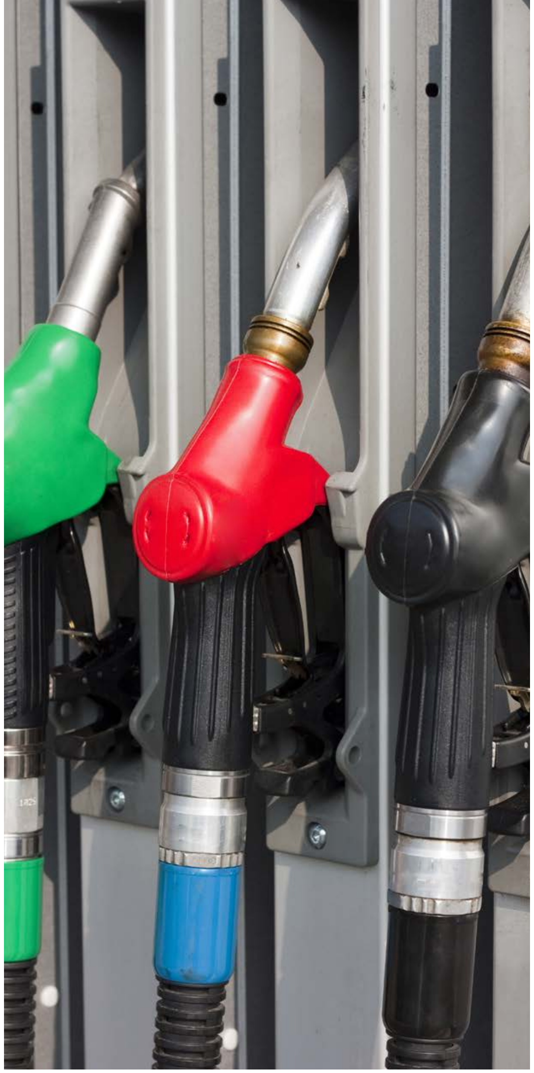


In both scenarios, natural gas production from the Montney Formation, which straddles the Alberta-B.C. boundary and is rich in higher value natural gas liquids (NGLs), grows significantly. In many other regions, production is stable or declines throughout the projection. Much of the production growth related to LNG exports occurs in B.C. and production in B.C. surpasses that of Alberta by 2028.

Figure ES.12:
Natural Gas Production, Evolving and Current Policies Scenarios







7. As Canada's energy system decarbonizes in the Evolving Policies Scenario, we use less fossil fuels. Coal becomes a negligible part of the energy mix. Use of oil-derived fuels declines, especially gasoline and diesel for transportation. After briefly rising in the near term, total natural gas use declines, and our consumption of natural gas is increasingly tied to the future of CCS. Natural gas with CCS for industrial uses, power generation, and hydrogen production are key demand growth areas.

In the Evolving Policies Scenario, total Canadian fossil fuel use declines over 40% from 2021 to 2050. However, projections differ across the various fossil fuels. Canadian demand for natural gas has seen relatively strong growth over the last decade, driven by increased use in the oil sands and power generation as coal was phased out. In the Evolving Policies Scenario, gas demand grows over the next two years, as Alberta electricity producers aim to no longer use coal for electricity generation by 2023. Over the longer term, although natural gas remains an important part of Canada's energy mix, total demand declines from around 13 Bcf/d in 2021 to 8.5 Bcf/d in 2050. Factors that reduce natural gas demand include: increasing use of renewables in power generation, renewable natural gas and hydrogen blended into gas streams, energy efficiency improvements, and declining crude oil and natural gas production (which itself requires natural gas). These declines are partially offset by applying CCS technology when using natural gas in industry, the power sector and to produce low-carbon hydrogen.

Coal consumption declines significantly over the projection, driven by its phase-out from electricity generation. Coal drops to less than 1% of Canada's energy mix by 2035, compared to 5% in 2019. Use of refined petroleum products (RPPs) and NGLs gradually falls throughout most of the projection period, driven by declines in gasoline and diesel fuel demand. In the earlier years, this fall is driven by fuel efficiency improvements and increased blending of biofuels, and in the long term by increased use of electric and hydrogen vehicles in transportation. Demand for RPPs used for non-combustion purposes (petrochemical feedstocks, asphalt, lubricants, etc.), as well as for aviation fuel, is relatively steady throughout the projection.

Figure ES.13:
Fossil Fuel Demand by Type, Evolving Policies Scenario

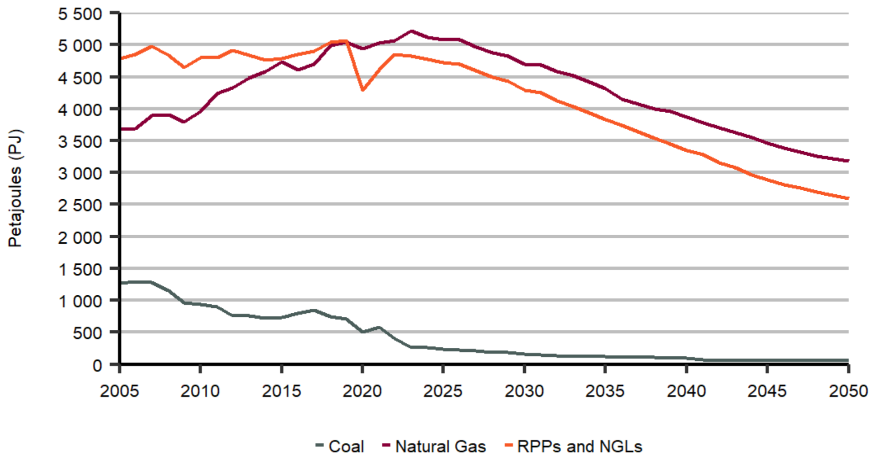
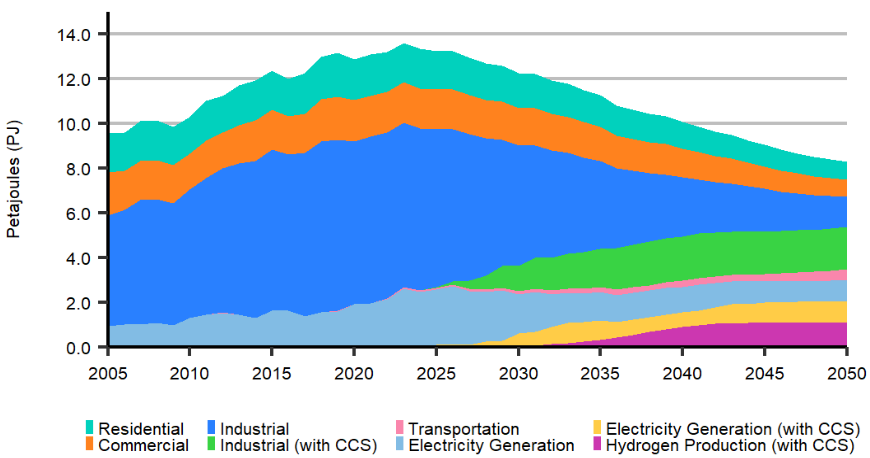
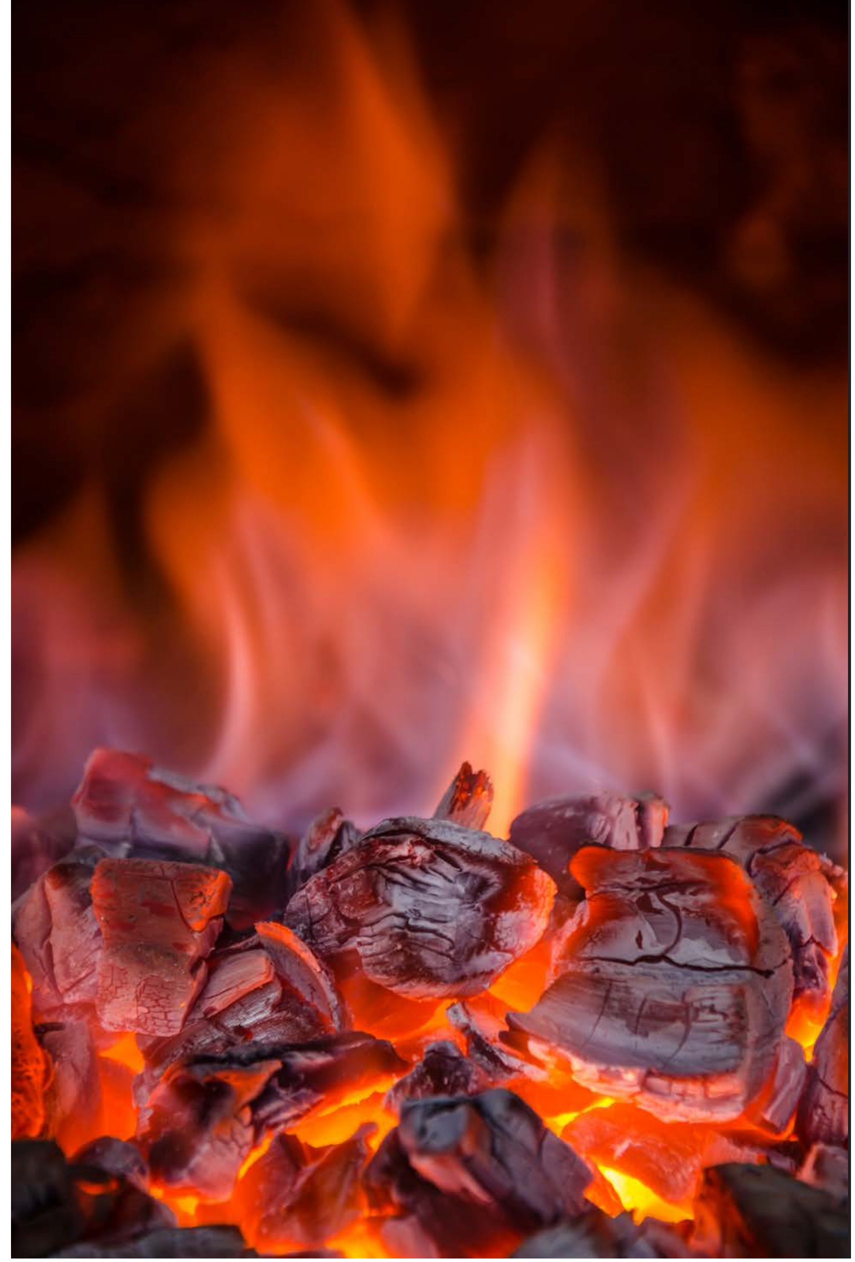


Figure ES.14:
Natural Gas Demand by Sector, Evolving Policies Scenario





Scenarios and Assumptions

This chapter describes the two core scenarios in EF2021, the Evolving Policies Scenario and the Current Policies Scenario, and the assumptions that underpin those scenarios. The six scenarios, and underpinning assumptions, that explore what achieving net-zero means for Canada's electricity system are described in the "Towards Net-Zero" section of this report. However, Figure A.1 illustrates the key differences between the two core scenarios and the group of six additional net-zero scenarios that explore the electricity system.

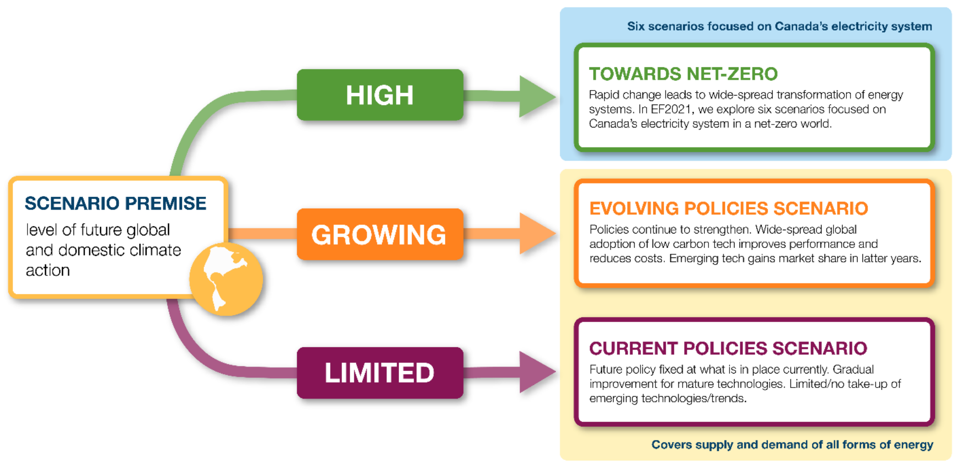
Scenario Premise

EF2021 includes two core scenarios: the Evolving Policies Scenario and the Current Policies Scenario. The central premise to these scenarios is based on the level of future climate action, both globally and domestically. The Evolving and Current Policies scenarios provide projections for all energy commodities and all Canadian provinces and territories.

The primary scenario in EF2021 is the Evolving Policies Scenario. The core premise of the scenario is that action to reduce the GHG intensity of our energy system continues to increase at a pace similar to recent history, in both Canada and the world. Relative to a scenario with less action to reduce GHG emissions, this evolution implies less global demand for fossil fuels, and greater adoption of low-carbon technologies. In contrast, the core premise of the Current Policies Scenario is that there is generally no additional action to reduce GHGs beyond those policies in place today, implying relatively higher global demand for fossil fuels and less adoption of low-carbon technologies. Consistent with these implications, the Evolving Policies Scenario assumes lower international prices for fossil fuels and a higher pace of technological change over the projection period, compared to the Current Policies Scenario.

The Evolving and Current Policies scenarios do not explicitly model climate goals or targets. Given its static policy framework, the Current Policies Scenario is extremely unlikely to lead to the significant GHG reductions needed to meet Canada's Paris commitments. In the Evolving Policies Scenario, significant GHG emission reductions will be realized, but ambitious goals such as net-zero by 2050 are unlikely to be met.

Figure A.1:
Conceptual Illustration of EF2021 Scenarios



The Energy Futures Analytical Process

The analysis in EF2021 follows a three-step process

1. Define the premises of the Scenarios: We develop the scenarios in the *Canada's Energy Future* series to explore key uncertainties for the future of the energy system. In EF2021, the primary premise which differentiates the scenarios is the level of global and domestic climate action. We then consider the implications of that premise on factors such as global fossil fuel demand and technology development. These implications are discussed further in this section, under the heading "Scenario Premise."

2. Make explicit assumptions on key inputs: We then make explicit assumptions about key factors which will influence the Canadian energy system. These assumptions are intended to be consistent with the scenario premises defined in Step 1. Key inputs include specific domestic climate policies such as carbon prices, international crude oil and natural gas benchmark prices, and technology cost and performance trends. These are detailed in this section under the heading "Key Assumptions."

3. Develop projections: Given these input assumptions, we develop projections to 2050 using the Energy Futures Modeling System. Results from these projections are included in the following chapters. Additional information about the energy modeling system is included in Appendix 2: Overview of the Energy Futures Modeling System.

Table A.1:
Explaining the Scenarios and Relationship Between the Assumptions

KEY DIFFERENCES BETWEEN SCENARIOS	EVOLVING POLICIES	CURRENT POLICIES
SCENARIO PREMISE	**PREMISE**: Continually increasing global and Canadian action to reduce GHG emissions. The pace of increase in future action continues the historical trend.	**PREMISE**: Global and Canadian action to reduce GHG emissions generally stops at current levels.
INTERNATIONAL CRUDE OIL MARKETS	**GENERAL IMPLICATION**: Due to increasing policy action, global crude oil demand is lower than the Current Policies Scenario.	**GENERAL IMPLICATION**: Less policy action leads to higher global crude oil demand compared to the Evolving Policies Scenario.
	EXPLICIT ASSUMPTION INCLUDED IN EF MODELING: Lower demand implies lower crude oil prices compared to the Current Policies Scenario. Brent crude oil trends gradually downward, reaching $40/bbl 2020USD in 2050.	**EXPLICIT ASSUMPTION INCLUDED IN EF MODELING**: Stronger demand implies stronger crude oil prices compared to the Evolving Policies Scenario. Brent crude oil averages $70/bbl 2020USD through most of the projection period.
INTERNATIONAL NATURAL GAS MARKETS	**GENERAL IMPLICATION**: Due to increasing policy action, global natural gas demand is lower than the Current Policies Scenario.	**GENERAL IMPLICATION**: Less policy action leads to higher global natural gas demand compared to the Evolving Policies Scenario.
	EXPLICIT ASSUMPTION INCLUDED IN EF MODELING: Henry Hub natural gas prices rise from $3.00/MMbtu 2020 USD in 2021, but at a slower pace than the Current Policies Scenario, reaching $3.64/mmbtu 2020USD in 2050. Canadian liquefied natural gas (LNG) exports increase to 4.9 bcf/d by 2050.	**EXPLICIT ASSUMPTION INCLUDED IN EF MODELING**: Henry Hub natural gas prices rise faster and higher than in the Evolving Policies Scenario, to $4.40/mmbtu 2020USD in 2050. Canadian LNG exports increase to 7.1 bcf/d by 2050.
LOW-CARBON TECHNOLOGIES	**GENERAL IMPLICATION**: Increasing policy action drives increasing global adoption of low-carbon technologies, which leads to cost and efficiency improvements as technology advances.	**GENERAL IMPLICATION**: Limited policy action provides a weaker incentive for global technology adoption. Cost declines and performance of low-carbon technologies are weaker compared to the Evolving Policies Scenario
	EXPLICIT ASSUMPTION INCLUDED IN EF MODELING: Costs for technologies with a growing market share, such as wind and solar power, fall faster compared to the Current Policies Scenario. Emerging technologies are included on a larger scale. Performance of both technology categories improves as compared to the Current Policies Scenario.	**EXPLICIT ASSUMPTION INCLUDED IN EF MODELING**: Costs continue to improve for technologies where there is a clear trend, such as wind and solar power, but at a slower rate than the Evolving Policies Scenario. Limited inclusion of emerging technologies.
DOMESTIC CLIMATE POLICIES	**GENERAL IMPLICATION**: Policy action continues to increase at the pace of the historical trend.	**GENERAL IMPLICATION**: Policy action is fixed to what is currently in place.
	EXPLICIT ASSUMPTION INCLUDED IN EF MODELING: A hypothetical suite of future policy changes is assumed. This includes an increase in carbon pricing beyond 2030, tightening of standards for large emitters, a national ZEV mandate, and an increasingly strict emissions intensity mandate for fuels beyond 2030.	**EXPLICIT ASSUMPTION INCLUDED IN EF MODELING**: Only policies that are law or near-law are included.

Table A.1 summarizes the implications of the core premise of the scenarios across some key areas. It describes how the premise of the Evolving and Current Policies scenarios affects each area, first in a general sense (rows labelled "General Implication") and then how these translate into explicit assumptions, such as prices or technology costs, included in the EF models (rows labelled "Explicit Assumption Included in EF Modeling"). Many of these areas, such as international markets and technology development, are international in nature. Since EF2021 analysis is focused on Canada, the explicit assumptions, such as market prices and technology cost trends, are developed via a review of global scenario analysis produced by institutions, academia, industry, private forecasters, and other relevant energy analysis.[3]

[3] Key resources that informed the Evolving and Current Policies scenario assumptions include: ECCC Healthy Economy, Healthy Environment (2021), various federal, provincial and territory policy documents, IEA World Energy Outlook (2020) and Net-Zero by 2050 (2021), EIA Annual Energy Outlook (2021) and Short Term Energy Outlook (various 2021), BP Outlook (2020), Shell Scenarios (2021), National Renewable Energy Laboratory Annual Technology Baseline (2021), price forecasts from GLJ and Sproule, and scenario analytics services from IHSMarkit, S&P Global, and WoodMackenzie.

EF2021 is a Baseline for Discussion

It is important to note that the projections presented in EF2021 are a baseline for discussing Canada's energy future today and do not represent the CER's predictions of what will take place in the future. EF2021 projections are based on assumptions which allow for analysis of possible outcomes. Any assumptions made about current or future energy infrastructure, market developments, or climate policies, are hypothetical and have no bearing on any regulatory proceeding that is, or will be, before the CER.

Over the projection period, it is likely that developments beyond normal expectations, such as geopolitical events or technological breakthroughs, will occur. Also, new information will become available, and trends, policies, and technologies will continue to evolve. This report is not an official, or definitive, impact analysis of any specific policy initiative, nor does it aim to show how specific goals, such as Canada's climate targets, will be achieved.

Key Assumptions

Domestic Climate Policy

The Evolving Policies Scenario begins with domestic climate policies currently in place. It then builds on the current policy framework with a hypothetical suite of future policy developments. These policies are chosen to reflect increasing ambition to reduce GHG emissions, and generally align with the broad trends of historical progress. Alternatively, the Current Policies Scenario only includes policies that are currently in place. This section outlines specific policies included, and additional policy detail is available in Appendix 1: Domestic Climate Policy Assumptions.

Existing policies:

The Current Policies Scenario includes only policies that currently exist. In the Evolving Policies Scenario, existing policies provide a baseline that is built upon over the projection.

In order to determine whether to include a policy in the analysis, the following criteria were applied:

- The policy was publicly announced prior to 1 August 2021.
- Sufficient details exist to model the policy.[4]
- Goals and targets, including Canada's international climate targets, are not explicitly modelled. Rather, policies that are announced, and in place, to address those targets are included in the modelling and analysis.

Relative to Canada's Energy Future 2020 (EF2020), key changes in the Evolving and Current Policies scenarios include the increased carbon pricing included in the Federal Strengthened Climate Plan. The Clean Fuel Standard for liquid fuels has also been included in the Current Policies Scenario, following the publishing of the draft regulations in December 2020.

[4] For example, in July 2021, the Federal government announced a forthcoming mandate for all passenger vehicle sales to be zero-emissions by 2035, but at the time of analysis there was not sufficient detail to include this mandate in the Current Policies Scenario.

Future policies:

The Evolving Policies Scenario adds a hypothetical suite of future policy developments to existing policies. These policy assumptions take into account several considerations:

- Announced policies that are currently in the development stage are included to the extent possible. Generally, their inclusion requires simplifying assumptions as final regulations are not available.
- Some policies that are being increasingly enacted by various jurisdictions are broadened to other jurisdictions later in the projection period.
- Existing policies that can be strengthened over time, are strengthened. For example, following the carbon price increases to 2030 that are set out in current policy, we include a hypothetical carbon price that continues to rise from 2031 to 2050, as well as a hypothetical tightening of the benchmarks for large emitters subject to the output-based pricing system.

Table A.2 describes specific policy initiatives. Figure A.2 compares the federal backstop carbon price to the increasing cost of carbon pollution in the Evolving Policies Scenario.

Table A.2:
Overview of Domestic Policy Assumptions

Key Differences Between Scenarios

Key Existing Policy Assumptions:
The base for policy assumptions in the Evolving Policies Scenario, while the Current Policies Scenario only includes these existing policies.

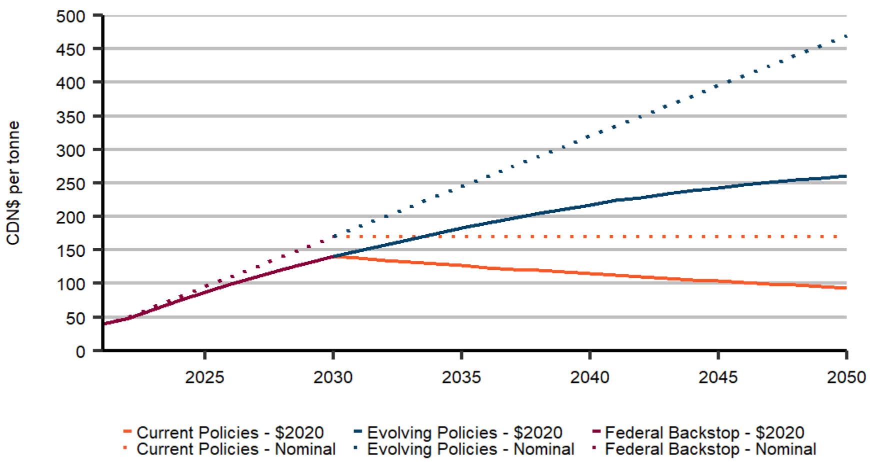
Policy	Description
Carbon Pricing	Current provincial and territorial systems, as well as the Federal Carbon Pricing Backstop.
Coal Phase-Out	Traditional coal-fired generation is phased out of electricity generation by 2030.
Clean Fuel Regulation	Liquid fuels only, where standard strengthens to 2030.
Energy Efficiency	Currently in place regulations including appliance standards, building codes, and vehicle standards.
Electric Vehicles	Provincial policies and initiatives including those in British Columbia (B.C.) and Quebec, as well as Federal rebates and infrastructure program.[5]
Renewable Energy	Current requirements for renewable electricity, and blending of ethanol, biodiesel, and renewable natural gas.

Key Future Policy Assumptions:
Hypothetical increases in policy stringency only included in the Evolving Policies Scenario

Hypothetical Policy Change	Description
Carbon pricing	Carbon prices continue to rise beyond existing announcements. For the federal pricing system, prices continue to increase after 2030 at $15 per tonne of carbon dioxide equivalent (CO_2e) per year, in nominal terms, as shown in Figure A.2. In systems for large emitters, such as the federal output-based pricing system, benchmarks are tightened by 2% annually from 2022 to 2050.
Low Carbon/Clean Fuel Regulations	The Federal Clean Fuel Regulation emission intensity improvement trend (2022-2030) for liquid fuels is extrapolated through the remainder of the projection period. A federal renewable natural gas blending requirement is introduced in 2030, rising to 10% by 2040.
Zero-Emission Vehicles	A federal zero-emission vehicle (ZEV) mandate is introduced in 2025, rising to 100% of new passenger vehicle sales by 2035 in the provinces. Remote communities and the territories are assumed to be exempt.
Energy Efficiency	Gradually stronger energy efficiency regulations across the economy, including net-zero-ready building codes, improving appliance standards, and increasing light-duty vehicle efficiency standards.
Support for clean energy technology and infrastructure	Policy continues to support new technology development as well as key infrastructure developments including electric transmission, carbon capture and storage (CCS), hydrogen production, and electric vehicle charging infrastructure.

[5] In June 2020 the Federal government announced a goal for 100% of car and passenger truck sales to be zero-emission by 2035 in Canada.
At the time of analysis, policy measures to achieve this target were still under development, and this goal is not included in the Current Policies Scenario.

Figure A.2:
Current Federal Backstop Carbon Pricing Schedule[6] (2020 to 2030), and Evolving and Current Policy Scenario Economy-wide Carbon Pricing Assumptions (2030 to 2050)



[6] For illustration purposes: In the EF2021 analysis, carbon prices are modeled based on individual provincial and territorial systems, many of which differ from the federal backstop system. The Federal Backstop price includes the announced increase to $170/tonne by 2030 in nominal terms. For the remainder of the Current Policies Scenario projection, this is held constant, and the price in inflation-adjusted terms declines by the rate of inflation.

Evolving Policies Scenario: Key Changes between EF2020 and EF2021

The Evolving Policies Scenario was introduced as the new primary scenario of the *Canada's Energy Future* series in EF2020. In the time since EF2020 analysis was completed, there have been some significant changes in global and domestic trends that have led to revisions in Evolving Policies Scenario assumptions between EF2020 and EF2021. Key changes include:

Significantly stronger domestic climate policy, including Canada's Strengthened Climate Plan carbon price path. Several new domestic policy initiatives have been introduced, including a higher federal carbon pricing backstop to 2030, draft regulations for the federal clean fuel regulation, and several provincial and territorial policies and plans.

Higher crude oil and natural gas prices in the near term, but lower prices in the longer term. Prices have trended higher than those in EF2020 in the near term, through the combined effect of pandemic recovery, vaccine rollout, and global crude oil production cuts. Over the longer term, EF2021 crude oil and natural gas prices are lower than EF2020, in light of several new international policy and GHG reduction target announcements.

Increased momentum for emerging technologies. Since EF2020's release, Canada has released hydrogen and small modular reactor (SMR) roadmaps. Automakers have announced more models of electric vehicles (EVs). Several major carbon-capture and storage (CCS) and hydrogen projects have also been announced.[7]

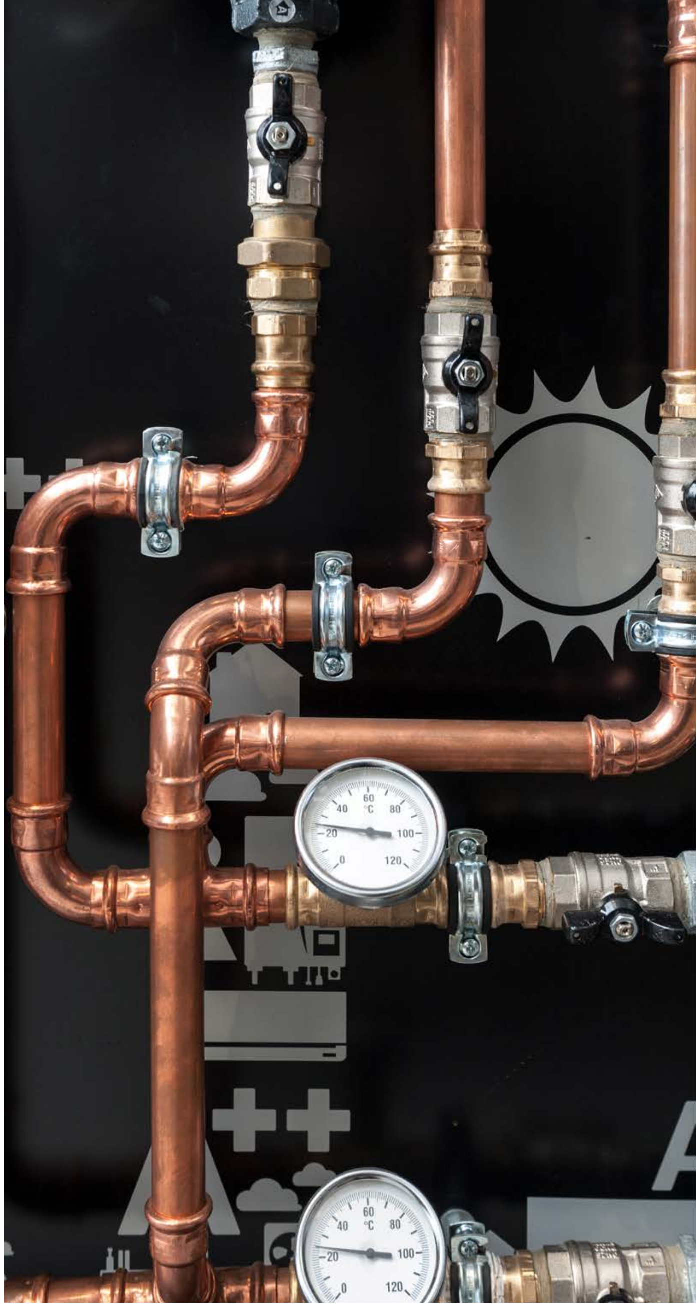
[7] These include the Hydro-Québec green hydrogen electrolyzer project, the Air Products Net-Zero Hydrogen Energy Complex, the Pembina and TC Energy Alberta Carbon Grid, Pieridae Caroline Carbon Capture Power Complex, Nauticol Energy and Enhance Energy's Blue Methanol facility, and the Shell Polaris CCS project.

Technology

Technological changes can have large impacts on energy systems. There is a strong link between policies and the pace of technological development. Policy frameworks are key drivers of technological innovation and greater use of GHG-reducing technologies. Over the past decade, technological advancements have provided access to unconventional fossil fuel resources and dramatically reduced the cost of technologies like wind, solar, and batteries. The Evolving Policies Scenario assumes substantial technological progress, including adoption of many promising technologies currently in the early stages of commercialization. The Current Policies Scenario assumes slower technological progress compared to the Evolving Policies Scenario, including incremental efficiency improvements and cost reductions for well-established technologies. Table A.3 provides an overview for key technology assumptions in the Evolving and Current Policies Scenarios.

Table A.3:
Technology Assumptions, Evolving and Current Policies Scenarios

Technology	Evolving Policies Scenario	Current Policies Scenario
Wind and Solar Electricity	Costs fall and performance improves. See table A.4 for details.	Costs continue to fall, but at a slower rate than the Evolving Policies Scenario. See table A.4 for details.
Electric Vehicles	Battery costs fall from 2020US$ 170/kilowatt (kW) in 2021 to $ 45/kW in 2050 (reduction of 74%).	Battery costs fall to 2020US$ 100/kW by 2050 (reduction of 40%).
Hydrogen	Cost of low-carbon hydrogen falls throughout the projection period. Electrolysis hydrogen falls from $2020 US$ 6-10 currently to $1.5-6 by 2050. Natural gas with CCS derived hydrogen falls from $2020 US$ 1.6-2 currently to $1.5-1.7 by 2050.	Currently announced projects included, costs remain near current levels.
Renewable Natural Gas	Costs an average 2020US$ 15/GJ throughout the projection, with a maximum demand of 500 petajoules (PJ).	Only current projects and in-place blending policies (B.C. and Quebec) are included.
Solvent-Assisted Oil Sands Extraction	All new oil sands facilities added post 2025 include solvent-assisted extraction. Adoption in existing facilities begins in the latter half of the projection period.	Limited adoption of solvent-assisted technology.
Small Modular Nuclear Reactors (SMRs)	Cost falls from 2020US$ 7000/kW in 2030 to 6000/kW in 2040, 5000/kW in 2050.	Not included.



Critical Minerals and the Energy Transition

A continued global transition toward low-emission energy systems will involve the deployment of many existing and emerging technologies, such as wind turbines, solar panels, and batteries. These technologies require input materials, and global scenario analysis (such as International Energy Agency's (IEA's) *Net Zero by 2050* and *The Role of Critical Minerals in Clean Energy Transitions*, and MIT Energy Initiative's *Insights into Future Mobility*) are increasingly focused on the inputs necessary to produce these technologies. The cost and availability of minerals that are needed to manufacture low-carbon technologies are key uncertainties for energy systems.

Increasing demand for these critical minerals (such as lithium, cobalt, nickel, and copper) could put upward pressure on their prices. In turn, increasing raw material prices could limit cost reductions for wind, solar, and batteries. If costs of these technologies are higher than assumed in the EF2021 scenarios (see Table A.4), there could be lower adoption than projected, and/or higher energy system costs.

Conversely, sustained demand for critical minerals can encourage investment in new sources of supply or increased recycling, potentially keeping price increases at bay or even driving down prices over time.[8] Technology development could offset potential increases in input material costs through changes in design (such as changing lithium-ion battery chemistry to use less cobalt, and/or use of different technologies, such as moving towards a solid-state battery and away from the nickel-manganese-cobalt technology used today), or production improvement.[9]

Although the outlook for the global critical minerals market is uncertain, it is clear that mining critical minerals for low-carbon technologies will have major economic impacts. The IEA's Net Zero Energy scenario estimates that the global value of select critical minerals will grow substantially over the next two decades, reaching today's level for coal market value (about $400 billion 2019USD) by 2040. In the Canadian context, the Canadian Institute for Climate Choices' *Canada's Net Zero Future* study finds that increased mining and manufacturing activity could be an important contributor to Canada's economic growth as Canada and the world decarbonize.

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8 For example, exploration for rare earth metals substantially increased in the early 2010s, driven by the prospect of increased demand (Eggert, R. G. (2011). Minerals go critical. Nature Chemistry, 3, 688-691.). For a discussion of critical minerals exploration dynamics see Humphreys, D. (2014). The mining industry and the supply of critical minerals. In British Geological Survey, Critical Metals Handbook (pp. 20-40). John Wiley & Sons, Ltd. doi:10.1002/9781118755341.

9 See Victoria et al., Solar photovoltaics is ready to power a sustainable future, Joule (2021), for a discussion on how production efficiencies have reduced material needs for Solar PV, and reduced risk exposure to input materials.

Crude Oil and Natural Gas Markets

International crude oil and natural gas prices are a key driver of the Canadian energy system and are determined by supply and demand factors beyond Canada's borders. Canadian crude oil and natural gas benchmark prices (such as western Canada Select (WCS) for heavy crude oil and Nova Inventory Transfer (NIT) for natural gas) are driven by international trends, but are also driven by local factors, such as local crude quality and adequacy of pipeline capacity. In recent years, the availability of pipeline capacity within and leaving western Canada has been a key issue that has affected both Canadian markets and production levels.

Figure A.3 shows the EF2021 crude oil assumptions for Brent, the primary global benchmark price for crude oil, for the Evolving and Current Policies scenarios. Global crude oil prices fell in 2020 due to the COVID-19 pandemic. In the second half of 2021, prices have increased to 2019 levels and above. In the longer term, prices in the Evolving and Current Policies scenarios diverge based on their different premises. In the Evolving Policies Scenario increased global action on climate change, which implies reduced demand for crude oil relative to the Current Policies Scenario, puts downward pressure on prices and the Brent price declines to 2020US$40/barrel (bbl)[10] by the end of the projection period, from 2020US$68/bbl in 2021. In the Current Policies Scenario, crude oil prices stay at 2020US$70/bbl over the projection period. In both scenarios, West Texas Intermediate (WTI), a key North American crude benchmark, is 2020US$4.00 lower than Brent in the long term.

Both EF2021 scenarios assume that the Canadian heavy benchmark price is discounted to WTI consistent with the historical average. The WTI-WCS differential is 2020US$12.50/bbl for most of the projection. However, in reality, if future supply available for export approaches and/or exceeds the level of total capacity provided by pipelines and structural rail, this differential could increase significantly. We do not adjust the assumed differential for such dynamics. Figure R.14 in the "Results" section provides an illustration of how tight or constrained pipeline capacity could become in our two scenarios, based on existing pipeline capacity, planned pipeline expansions, and structural rail.

Figure A.4 shows the EF2021 natural gas price assumptions for the Evolving and Current Policies Scenarios. Over the projection period, Henry Hub, a key North American benchmark price, increases gradually reaching 2020 US$3.60/MMBtu by 2050 in the Evolving Policies Scenario, from $3.00/MMBtu in 2021. In the Current Policies Scenario, natural gas prices rise faster, reaching 2020 US$4.40/MMBtu by 2050. This is consistent with greater North American demand growth and LNG export volumes compared to the Evolving Policies Scenario. EF2021 assumes Henry Hub is 2020US$0.90/MMBtu higher than NIT for the majority of the projection. However, the NIT price discount could materially rise if there are periods where pipeline capacity becomes constrained for moving western Canadian natural gas to markets.

[10] This means $40 in USD currency, and adjusted for inflation in real terms with a base year 2020.

Figure A.3:
Brent Crude Oil Price Assumptions to 2050, Evolving and Current Policies Scenarios

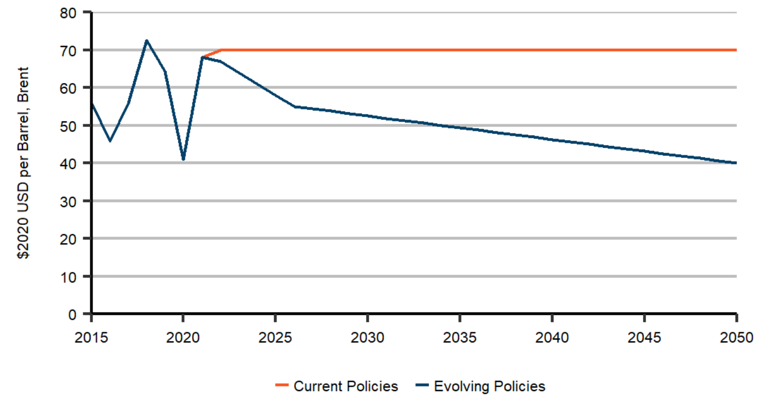
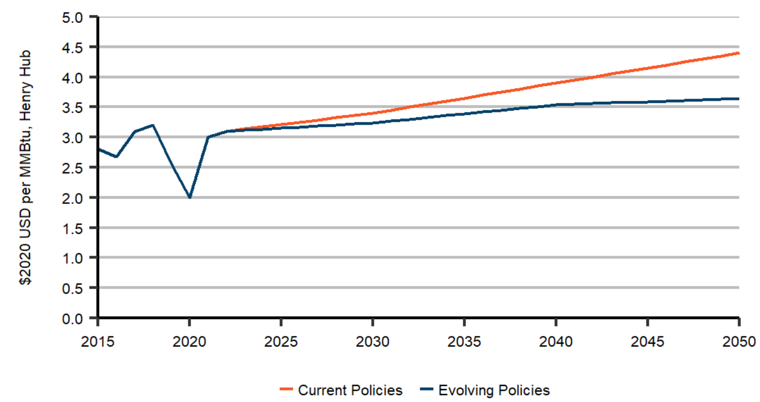
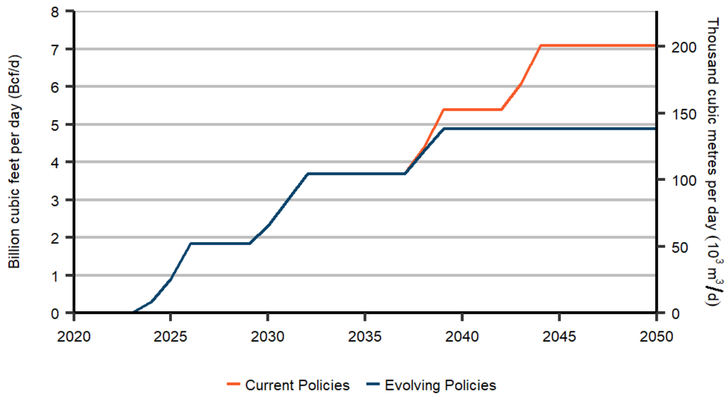


Figure A.4:
Henry Hub Natural Gas Price Assumptions to 2050, Evolving and Current Policies Scenarios



EF2021 assumes LNG export volumes from Canada as shown in Figure A.5. We assume all volumes originate from Canada's west coast. These volumes include Phase 1 of the LNG Canada project, which has a positive final investment decision and is currently under construction. We also include an assumption of additional volumes that are not specific to a particular project. The Current Policies Scenario assumes greater LNG exports than in the Evolving Policies Scenario, beginning in 2039. Future LNG development is uncertain and could be significantly different than implied by these assumptions. For both scenarios, we assume that 75% of the natural gas that will be liquefied will come from natural gas production dedicated to supplying LNG facilities. This means that this 75% comes from production that only exists because LNG export capacity exists and is above and beyond what would be produced based solely on our North American natural gas price assumptions.

Figure A.5:
Canadian LNG Export Volume Assumptions to 2050, Evolving and Current Policies Scenarios



Full benchmark price assumption data and LNG export assumption levels are available in the accompanying data files and appendices, described in the "Access and Explore Energy Futures Data" section.

Electricity

The analysis in EF2021 reflects current utility and system operator expectations of future electricity developments in their respective regions, especially for major planned projects. We also make assumptions on the cost to add new electricity generating capacity in the future. Table A.4 shows assumptions for natural gas, solar, and wind costs, including their capacity factors. Current schedules and plans from utilities, companies, and system operators are the primary basis for the timing and magnitude of other forms of generation added over the projection period (such as hydroelectric and nuclear refurbishments).

As discussed earlier in this section, costs for wind, solar, and other emerging technologies are lower in the Evolving Policies Scenario than the Current Policies Scenario. This assumes a stronger global shift towards these low-carbon technologies, and advancements and efficiencies that continue to lower their costs and improve their performance.

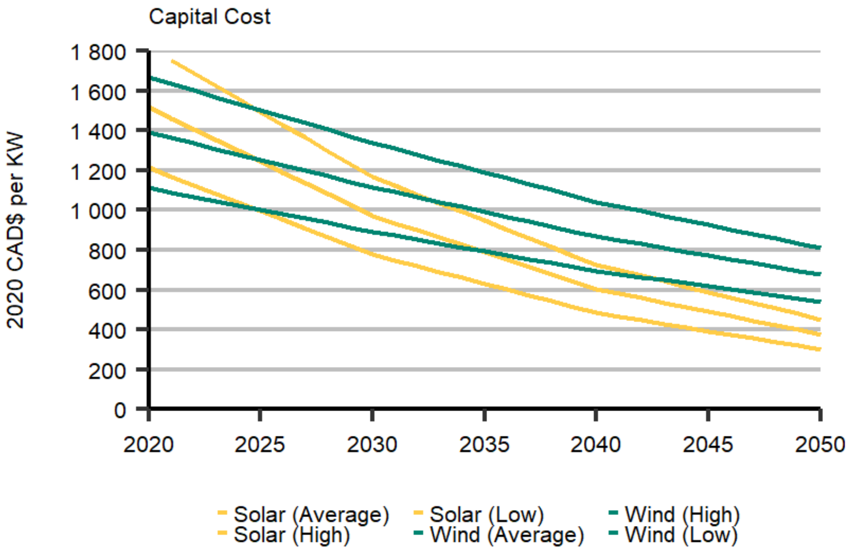
Table A.4:

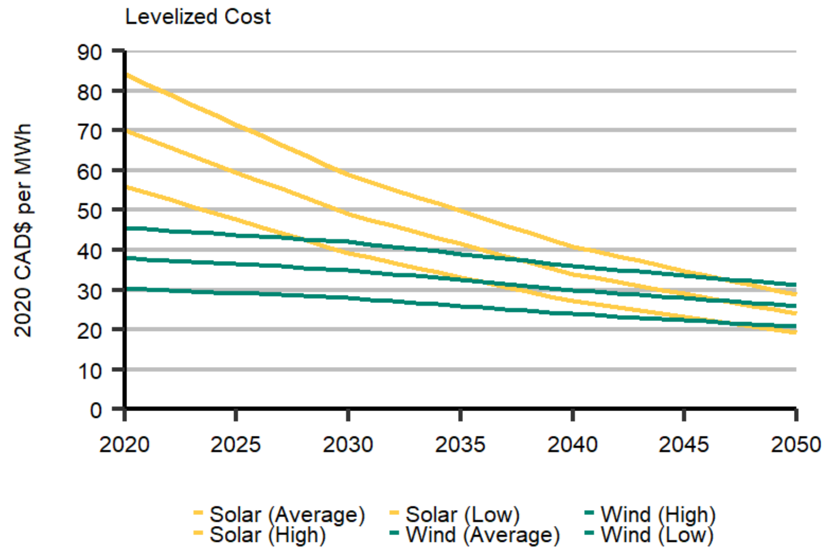
Electricity Cost Assumptions for Natural Gas, Onshore Wind, and Utility Scale Solar to 2050, Evolving and Current Policies Scenarios

	Capital Cost (2020CN $/ kilowatt(kW))	Fixed Operating and Maintenance Costs (2020CN$/kW)	Variable Operating and Maintenance Costs (2020CN$/ megawatt hour(MWh))	Capacity Factor (%)[11]
Gas Combined Cycle (2020-2050, both scenarios)	1 300-1 800	21	5	70
Gas Peaking (2020-2050, both scenarios)	950-1 400	18	5	20
Wind (2020)	1 389	25-60	0	30-45
Solar (2020)	1 516	20-27	0	10-20
Evolving Policies Scenario				
Wind (2030)	1 115	25-60	0	35-55
Wind (2040)	868	25-60	0	35-55
Wind (2050)	676	25-60	0	35-55
Solar (2030)	972	20-27	0	15-25
Solar (2040)	605	20-27	0	15-25
Solar (2050)	376	20-27	0	15-25
Current Policies Scenario				
Wind (2030)	1 226	25-60	0	30-45
Wind (2040)	1 184	25-60	0	30-45
Wind (2050)	1 117	25-60	0	30-45
Solar (2030)	1 066	20-27	0	10-20
Solar (2040)	772	20-27	0	10-20
Solar (2050)	561	20-27	0	10-20

[11] Capacity factors are the actual energy produced by a generator divided by the maximum possible generation over a given period. Capacity factors vary by region and technology, and on average improve throughout the projection period due to improved performance.

Figure A.6:
Wind and Solar Capital Costs and Levelized Cost[12] Assumptions to 2050, Evolving Policies Scenario





12 The range around the capital costs is +/- 20%, which reflects the variability across different estimates of current, and future, wind and solar costs. Costs and performance characteristics can vary across regions and time. The ranges around the levelized costs include the variation in capital costs shown in the figure, ranges in other costs and capacity factors shown in Table A.2, as well as higher and lower project financing costs.

Hydrogen

Hydrogen can be produced from organic compounds such as biomass, natural gas, or coal through various processes. It can also be produced from water via electrolysis. The two main forms of production in EF2021 are electrolysis and natural gas with CCS.

- **Natural gas with CCS:** Currently, the most common method for hydrogen production is steam methane reforming of natural gas. In this method, high-temperature steam reacts with methane to produce hydrogen and carbon dioxide (CO_2). Coupling this method with a CCS technology can produce hydrogen with relatively low CO_2 emissions. Going forward, autothermal reforming (ATR) could have a cost advantage compared to steam methane reforming and could allow for a higher rate of CO_2 capture. The recently announced Air Products project in Alberta is proposing to use an ATR technology for its facility. In our analysis we assume all natural gas with CCS hydrogen production has a capture rate greater than 90%. We also assume that because of proximity to sequestration capacity, hydrogen production from natural gas with CCS is only an option in B.C., Alberta, and Saskatchewan.

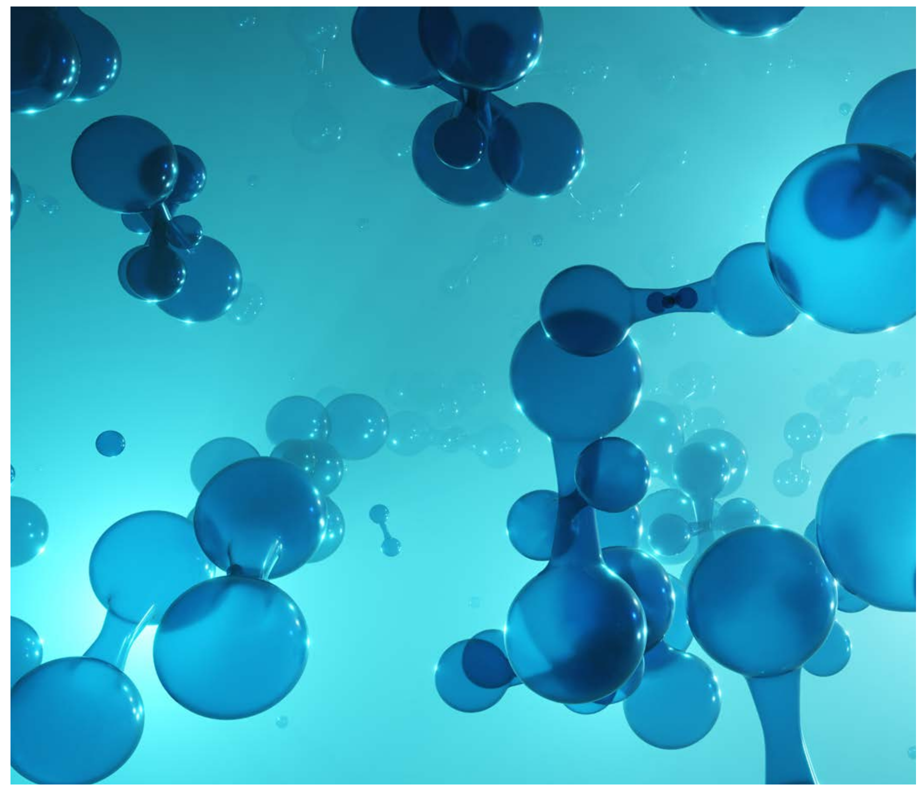
- **Electrolysis:** Electrolysis is a process whereby electricity is passed through water and splits water into its components: hydrogen and oxygen. Depending on the source of electricity, hydrogen produced through this process can have low- to zero-carbon emissions. EF2021 distinguishes between two categories of electrolysis based on how the electricity is supplied: a) grid electrolysis, which uses electricity from the provincial grid at a similar price to industrial users, and b) renewable electrolysis, which utilizes dedicated wind and solar resources.[13] Electrolysis is available in all provinces, and its adoption is based on relative costs.

Hydrogen production cost varies by region and resource availability. The cost of hydrogen production will depend on technology improvements and future electricity and natural gas prices. We assume costs significantly decline in the Evolving Policies Scenario (Table A.6), and remain near current levels in the Current Policies Scenario.

[13] Electricity price is the largest cost component of hydrogen production that uses the electrolysis method. Dedicated renewable electrolysis reduces this cost by producing electricity onsite with the hydrogen production.

Table A.6:
Hydrogen Technology Costs, Evolving Policies Scenario

Cost by Technology type (2020US$/kg)	2020	2030	2040	2050
Electrolysis – Grid	$6.00-8.00	$4.00-7.00	$4.00-$6.00	$4.00-6.00
Electrolysis – Dedicated renewables	$8.00-10.00	$4.00-6.00	$2.00-3.00	$1.50-2.00
Natural Gas with CCS	$1.60-2.00	$1.50-$1.80	$1.50-$1.80	$1.50-$1.70



Given falling costs, as well as other policies such as increasing carbon prices, hydrogen has the potential for adoption across Canada's energy system. The relative economics of hydrogen are a key driver of adoption in the various demand sectors. At the same time, each sector has some other important considerations and uncertainties.

- **Residential and Commercial:** There are physical limits on how much hydrogen can be blended into existing natural gas pipelines and used in conventional end-use devices.[14] To account for this uncertainty we assume maximum blending of hydrogen in the natural gas stream gradually increases throughout the projection period, as infrastructure and technology improves. Maximum blending increases to 3% by volume (1% by energy content) by 2030, 15% by volume (5% by energy content) by 2040, and 20% by volume (7% by energy content) by 2050.

- **Industrial:** Hydrogen demand is modeled on a sector-by-sector level, as industrial sectors have unique characteristics that could influence hydrogen adoption. Certain industries, such as iron and steel, have emerging technologies that are able to incorporate high concentrations of hydrogen as the main fuel. In some industries, such as cement production, it remains more uncertain if significant amounts of hydrogen will be consumable as a low carbon alternative fuel without significantly alerting the final industrial product.

- **Transportation:** As hydrogen costs fall, and carbon prices increase, hydrogen could offer substantial fuel cost savings compared to diesel in freight trucking. Adoption will be determined by other factors as well, such as the cost of hydrogen fuel cell trucks relative to conventional diesel trucks, as well as the development of hydrogen distribution and refuelling infrastructure. We assume fuel cell trucks become cost comparable to diesel trucks around 2035 to 2040, and infrastructure sees widespread deployment from 2035 to 2050 as hydrogen fuel cell trucks gain market share.

We assume that hydrogen is produced within each province to meet local demands, and there is no inter-provincial and international trade. This is an important assumption which affects the results, in that regions with lower cost options for producing low-carbon hydrogen–such as Alberta, with CCS access and announced projects, and Quebec, with relatively low grid electricity prices–are early adopters of the technology. This assumption follows recent hydrogen projects, which are intended for use at the facility where the hydrogen is produced, or in the nearby region. However, large-scale hydrogen trade has been proposed[15] and is still being analyzed. If significant trade between regions occurs, it could alter the production and consumption trends shown in our hydrogen results.

[14] Studies by the National Renewable Energy Laboratory and the Transition Accelerator have suggested that current end-use technologies and pipeline infrastructures could handle up to 15% blending by volume.

[15] For example, Alberta's 2021 Hydrogen Roadmap highlights hydrogen exports as a key pillar, potentially by 2030.

Results

This section presents results of the EF2021 projections. The primary focus is the Evolving Policies Scenario. These projections are not a prediction, but instead present possible future outcomes based on the assumptions described in the previous section. There are many factors and uncertainties that will influence future trends. Key uncertainties are discussed in each section.

For a description of the various ways to access the data supporting this discussion, including full data tables for both the Evolving and Current Policies scenarios, see the “Access and Explore Energy Futures Data” section.

Macroeconomics

The economy is a key driver of the energy system. Economic growth, industrial output, inflation, exchange rates, and population growth all influence energy supply and demand trends.

In the near term, the economy continues its gradual recovery from the COVID-19 pandemic. As shown in Figure R.1, total real gross domestic product (GDP) declined 5.3% in 2020 and grows by 5.7% in 2021.

The long-term projections for key economic variables are in Figure R.2. Economic growth (adjusted for inflation) averages 1.6% per year over the projection period in both the Evolving Policies Scenario, and the Current Policies Scenario, with the Current Policies Scenario slightly higher. Economic growth over the projection is generally slower than the 1990 to 2018 historical period for a variety of reasons, including an aging population and slower global economic growth.

KEY UNCERTAINTIES:

Macroeconomics

COVID-19 pandemic recovery: Recovery from COVID-19 is a key uncertainty for global, North American, and Canadian macroeconomic growth.

Global economic growth: Global economic growth affects many factors that are important for Canada's economy, including commodity prices, and demand for Canadian energy and non-energy exports.

Figure R.1:
GDP Growth Rebounds Following a Steep Decline in 2020

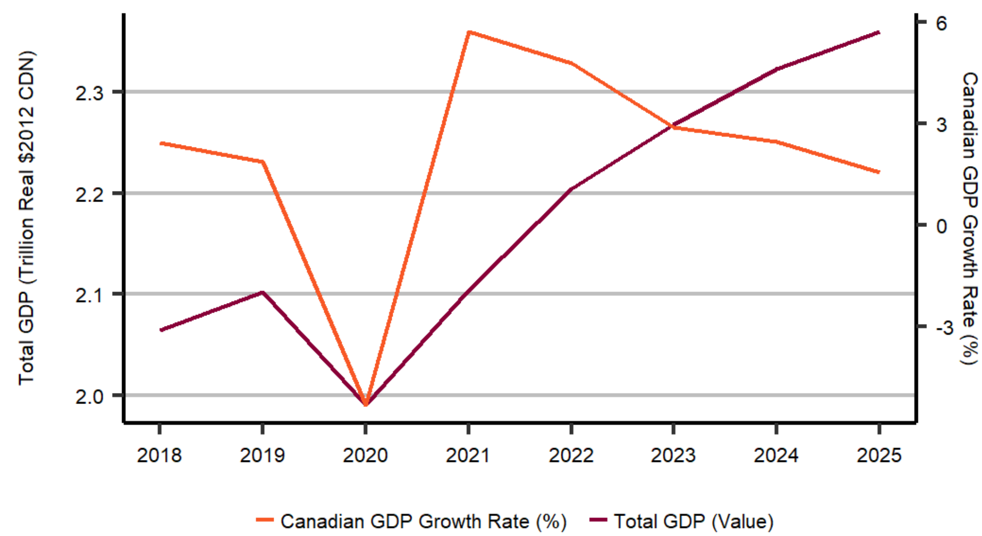
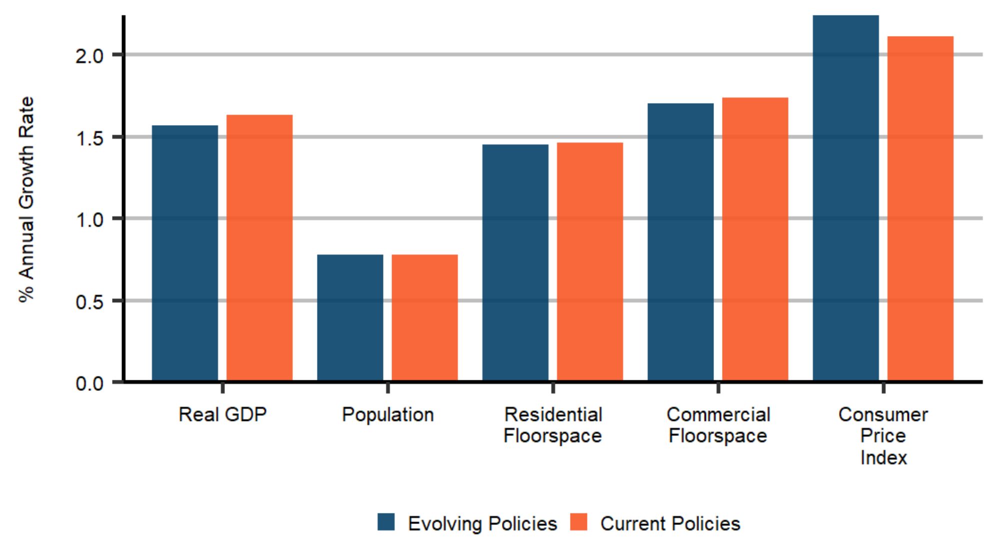


Figure R.2:
Economic Indicators, Evolving and Current Policies Scenarios (2019 to 2050)



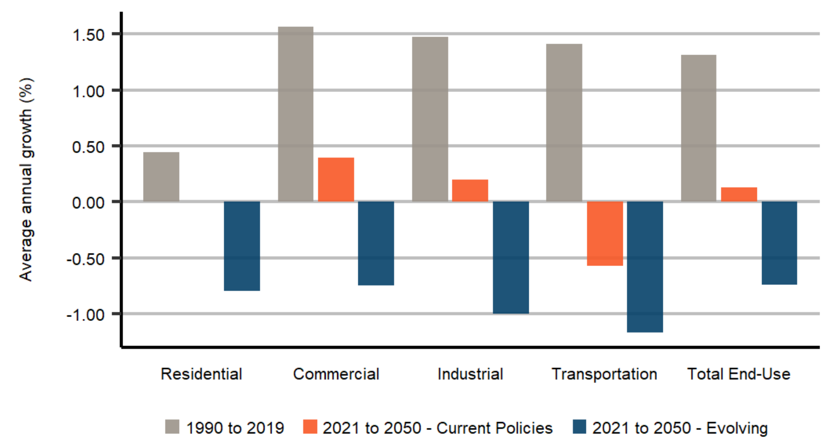
Energy Demand

This section first discusses secondary (or “end-use”) energy demand projections by reviewing energy use by sector of the economy, before turning to our economy wide primary energy demand projections. End-use demand includes electricity and hydrogen, while the fuel used to produce electricity and hydrogen is accounted for in primary energy demand. Historical data is sourced primarily from Statistics Canada’s Report on Energy Supply and Demand in Canada. This data is supplemented with additional details from Environment and Climate Change Canada (ECCC), Natural Resources Canada, and various provincial data sources.

In the near term, energy use follows macroeconomic trends. We estimate that demand declined 8% in 2020, and project it to increase in 2021 and 2022. In the long term, the Evolving Policies Scenario projects Canadian energy use to decline to 2050. Figures R.3 and R.4 break energy use down by sector, showing declines in all sectors. The largest declines are in the industrial (including upstream oil and gas) and transportation sectors. These declines are due to factors such as improved energy efficiency, increasing electrification of the transportation sector,[16] and various policies, like carbon pricing. Partially offsetting these factors, economic growth and a near-term increase in crude oil production provide some upward pressure on energy use. However, economic growth is slower than historical trends, and crude oil and natural gas production eventually declines. The Current Policies Scenario sees moderate demand growth over the projection period (though at levels lower than recent history) due to the lack of additional climate policy action beyond current policies, higher crude oil and natural gas production, and less electrification.

[16] On an energy equivalent basis, EVs use less energy to travel a given distance than conventional vehicles. As EVs gain market share, the offsetting reduction in gasoline demand will be larger than the electricity added, leading to a net reduction of energy consumption. Additional details on EV efficiency and economics can be found in CER Market Snapshot: Levelized Costs of driving EVs and conventional vehicles.

Figure R.3:
End-use Demand Declines in All Sectors in the Evolving Policies Scenario



KEY TRENDS:
Energy Demand

- Total energy use declines in the Evolving Policies Scenario and grows slowly in the Current Policies Scenario.
- Growth rates for end-use demand by sector are lower than in the past for both scenarios.
- The mix of energy sources that Canadians use continues to change in the Evolving Policies Scenario, shifting towards a majority of low- or non-emitting energy sources in the longer term.
- In the Evolving Policies Scenario, energy use declines while population and GDP continue to grow, resulting in a significant decline in energy use per person and per dollar of economic activity.

Energy use trends vary by sector and by energy type in the Evolving Policies Scenario (See Figure R.5). These trends result from many different drivers, including macroeconomics, energy production trends, energy efficiency improvements, policies, technology advancements, and market developments. Highlights include:

- In the residential and commercial sectors, improving efficiency of devices and building envelopes reduces overall energy consumption. Rising carbon prices and improving technology drive penetration of heat pump technology in buildings, reducing natural gas use. Blending of renewable natural gas and hydrogen into natural gas streams also reduces natural gas use. This is driven by a combination of policy assumptions (see the "Scenarios and Assumptions" section), and economics in the longer term as carbon prices increase and technology costs fall.

- In the industrial sector, trends vary by industry. The oil and gas sector becomes more efficient, and production growth slows and eventually peaks for crude oil production, while natural gas production stays relatively steady and then declines. Solvent-assisted production in in situ oil sands helps improve energy intensity significantly in the latter half of the projection period. In the longer term, hydrogen reduces natural gas use, especially in key sectors such as iron and steel, cement, refining, as well as the oil and gas sectors. At the same time, increasing use of CCS puts upward pressure on energy demand as the CCS process requires energy.

- The transportation sector undergoes a notable low-carbon transition. Refined petroleum products (RPPs) like gasoline, diesel, and jet fuel have historically dominated the transportation sector, and this begins to change in the Evolving Policies Scenario. The Evolving Policies Scenario assumes that the recently announced Federal goal for all new vehicle sales to be ZEVs by 2035 is achieved, and that adequate supplies of battery and plug-in hybrid electric vehicles will exist and meet demand.[17] This substantially reduces gasoline demands in the projection. Electric freight, particularly light-to-mid-duty, hydrogen-powered freight (mid-to-heavy duty), and increasingly electrified public transportation (electric bussing) grow steadily in the 2030s and 2040s. Biofuels blending into gasoline and diesel increases from current levels in both scenarios, driven by policies like the Federal Clean Fuel Regulation.

[17] Electricity demand associated with electric vehicles is included in the transportation sector in these projections, although large amounts of at-home charging are likely to occur.

Figure R.4:

End-use Energy Consumption Peaks in 2019 and Declines over the Long Term in the Evolving Policies Scenario

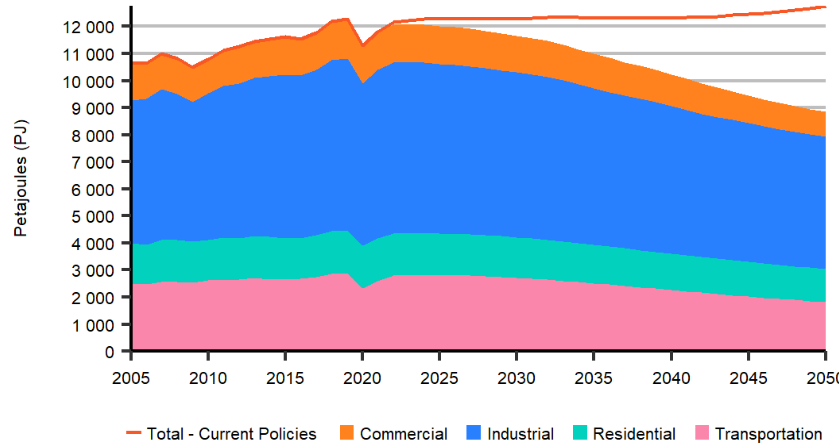
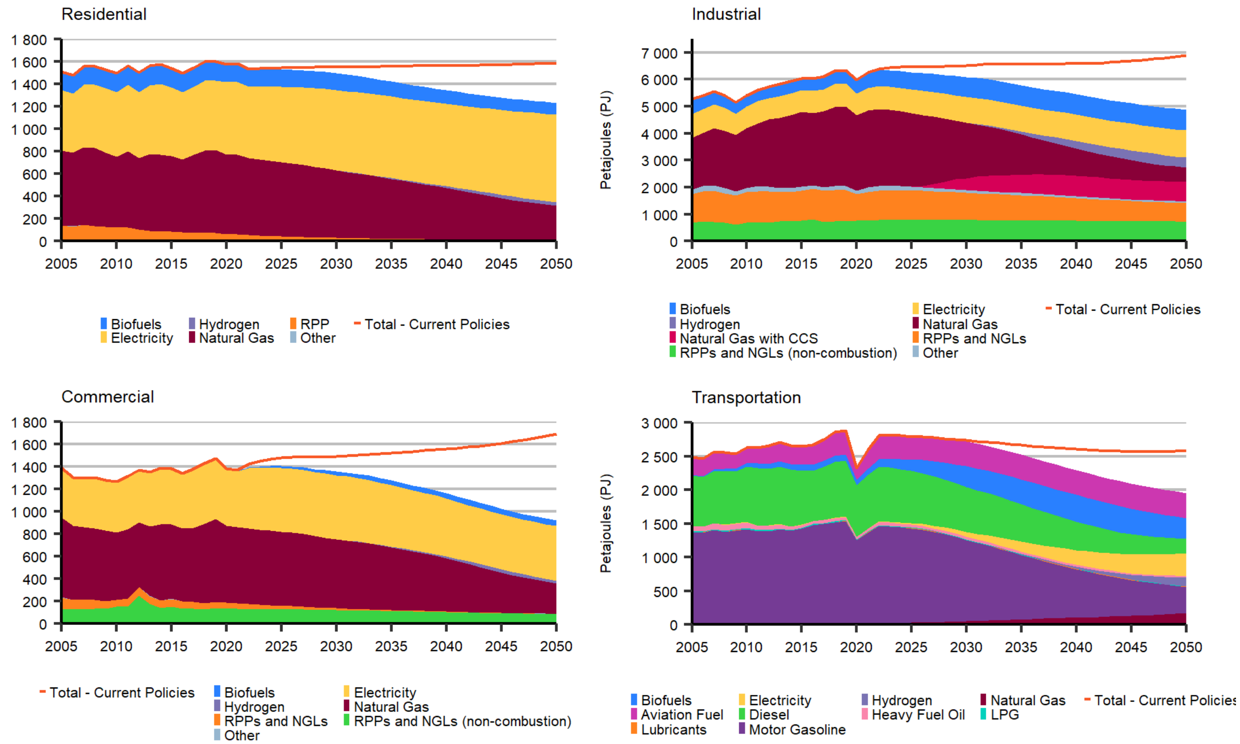


Figure R.5:

End-Use Energy Demand Trends Vary by Sector and By Fuel in the Evolving Policies Scenario



In this analysis, primary demand is the total amount of energy used in Canada. Primary demand is calculated by adding the energy used to generate electricity and hydrogen to total end-use demand, and then subtracting the end-use demand for electricity and hydrogen. Primary demand is higher than end-use demand due to factors such as heat loss in thermal electric generation, and the energy required for the hydrogen production process. This implies that it takes more than one unit of natural gas or coal to produce the same energy unit of electricity, and similarly more than one unit of natural gas or renewables to produce one energy unit of hydrogen.

Figure R.6 shows primary demand by fuel for the Evolving Policies Scenario, compared with total primary demand in the Current Policies Scenario. In the Evolving Policies Scenario, total demand gradually falls, driven by declining fossil fuel use. Coal demand declines considerably due to the phase-out of coal-fired power generation. RPP demand falls along with improving energy efficiency and electrification of the transportation sector. Demand for non-energy oil products, such as asphalt, lubricants, and feedstocks are relatively stable. Natural gas demand grows slowly to about 2025, driven by increasing crude oil production as well as its increasing role in power generation. From 2025 to 2050 total natural gas demand steadily declines, as less is used for crude oil and natural gas production (due to both increased efficiency and, eventually, less production), energy efficiency improves, renewables replace some natural gas in power generation, and renewable natural gas and hydrogen are blended into the natural gas stream. Increasing natural gas use to produce hydrogen, as well as adding CCS to natural gas use in industrial electricity generation and power, partially offsets this decline.

Driven by increased electrification at the end-use level, overall electricity demand rises steadily in the Evolving Policies Scenario. This demand leads to stable production of nuclear power and growth in renewable power as major hydro projects are completed, and wind and solar costs continue to fall. Renewables become an increasingly important part of the energy mix. Increased blending of renewable fuels in liquid fuels and natural gas also support increasing renewable demand.

Energy use falls while both the economy and Canada's population grow, implying that energy intensity–measured in energy use per capita or per $ of real GDP–declines significantly. This is shown in Figure R.7. From 2019 to 2050, real GDP increases 60% and population increases over 27% in the Evolving Policies Scenario. Primary energy use declines 25%. These different trends imply that energy use per $ of real GDP declines over 50% from 2019 to 2050, while energy use per person declines over 40% in the Evolving Policies Scenario.

Figure R.6:

Primary Demand Gradually Declines and Renewables Account for a Larger Share in the Evolving Policies Scenario Energy Mix

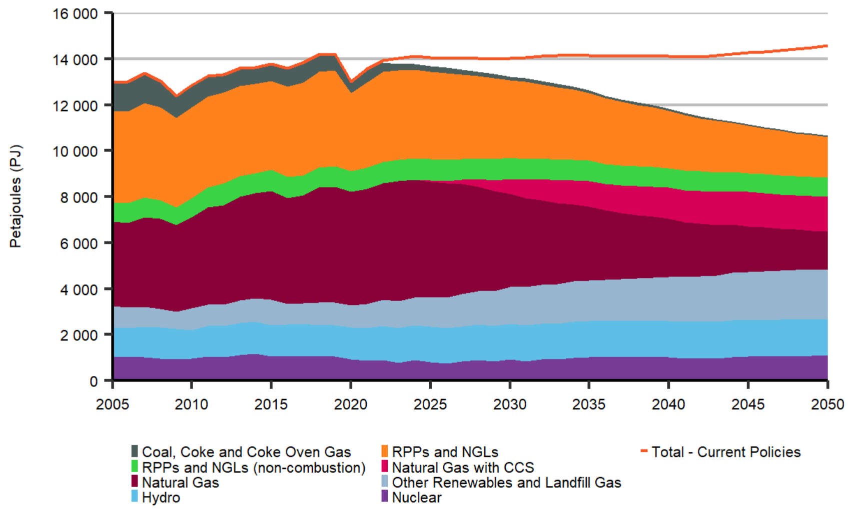
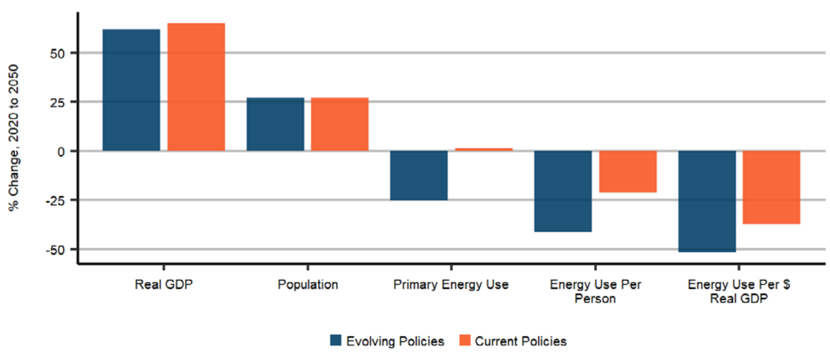


Figure R.7:

The Economy Grows Faster than Energy Use, and Energy Intensity Declines in both the Evolving Policies Scenario and the Current Policies Scenario



KEY UNCERTAINTIES:

Energy Demand

Future policy changes: In December 2020, Canada announced a significant increase to its carbon pricing pathway, and revisions to the proposed Clean Fuel Standard (published in the Canada Gazette as the Clean Fuel Regulation). Canada has recently committed to a stronger 2030 target in its Nationally Determined Contribution submitted to the United Nations, and announced intentions for 100% of passenger vehicle sales to be ZEVs by 2035. These changes illustrate how dynamic climate policy has been in recent years. This may continue if urgency and ambition to reach climate targets increases. Future policy changes will have significant impacts on energy projections.

Technological influences: The impacts of technology on the energy system are substantial and can be difficult to predict. The Evolving Policies Scenario continues the momentum for increased use of established technologies and allows for the adoption of emerging technologies currently near commercialization. The pace, types, and costs of new technological adoption are highly uncertain and likely to be different from those assumed and modelled in our scenarios.

Alternative fuels and new end-uses: Both core scenarios show a shift towards electricity, supported by the increasing use of renewables. They also feature increasing adoption of low-carbon fuel alternatives, such as hydrogen, renewable natural gas, and liquid biofuels, to varying degrees. Faster electrification of the economy, or investment and growth in alternative fuels production could lead to different trends compared to those shown here.

Crude Oil

Crude oil is produced in Canada for domestic refining as well as for export. In 2019, Canadian crude oil production averaged 4.9 million barrels per day (MMb/d) (784 thousand cubic metres per day ($10^3m^3/d$)). Production declined by 5% in 2020, largely due to the COVID-19 pandemic, but had returned to 2019 levels by the end of 2020. In recent years, most production growth has been concentrated in the oil sands. Regionally, most production is in Alberta, with additional volumes in Saskatchewan and offshore Newfoundland and Labrador.[18]

Figure R.8 shows Canadian crude oil production by type in the Evolving Policies Scenario, compared to total Current Policies Scenario production. Canadian crude oil production in the Evolving Policies Scenario peaks at 5.8 MMb/d (930 $10^3m^3/d$) in 2032 and declines to 4.8 MMb/d (756 $10^3m^3/d$) in 2050, a decrease of 4% from 2021. For comparison, production peaks at 6.7 MMb/d (1064 $10^3m^3/d$) in 2044 in the Current Policies Scenario, driven by higher crude oil price assumptions and other assumptions related to the lack of future domestic and global climate policy action.

Production growth in the oil sands continues in the near term, peaking in 2032 and declining slightly through 2050 in the Evolving Policies Scenario. Figure R.9 shows Evolving Policies Scenario oil sands production by type, while Figure R.10 shows it by vintage. Growth is dominated by in situ projects. Most production growth in this scenario are expansions to existing projects, which are profitable given Evolving Policies Scenario price levels and technology improvements that increase productivity.

[18] Information on crude oil ultimate potential and remaining reserves is available in the EF Data Appendices.

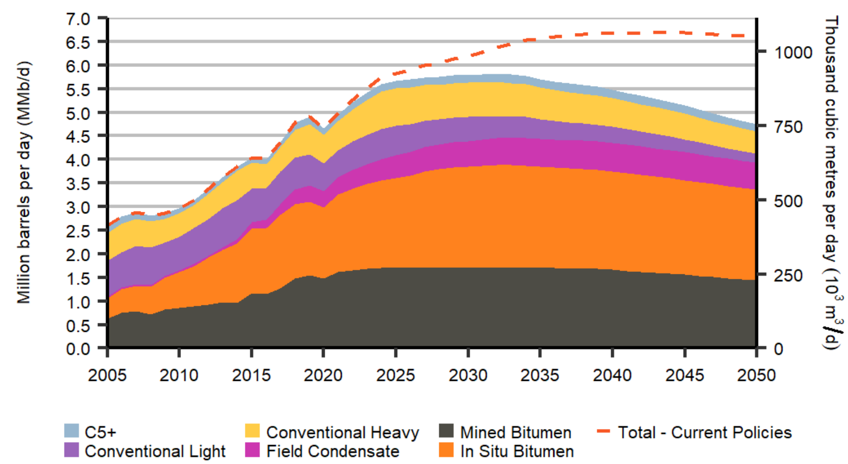
KEY TRENDS:

Crude Oil Production in the Evolving Policies Scenario

- Production grows through the start of the projection period with most growth occurring before 2025. After this point, production is relatively flat and peaks in 2032 at just under 5.8 MMb/d, before declining to 4.8 MMb/d in 2050. This compares to production of 5.0 MMb/d in 2021. Price assumptions underpin this growth. Longer term, assumptions of lower crude oil prices and increasing carbon costs lead to declines in production.
- From 2019 to 2032, crude oil production increases 19%. Between 2032 and 2050 production decreases by 19%.
- In situ bitumen production grows to 2.2 MMb/d in 2032 before declining to 1.9 MMb/d by 2050, from 1.7 MMb/d in 2021.
- Mined bitumen production peaks in 2024 at 1.7 MMb/d, declining thereafter to 1.4 MMb/d by 2050, from 1.6 MMb/d in 2021.

Figure R.8:

Total Crude Oil Production Peaks in 2032 and then Declines through 2050 in the Evolving Policies Scenario



[Conventional](), [tight](), and [shale]() production is classified as [light]() or [heavy](), depending on the [API gravity]() of the oil. In 2020, 51% of western Canadian conventional production was heavy and 49% was light. Near-term growth in production in these categories is primarily due to increases in light oil production in Alberta, along with growing heavy oil production in Saskatchewan. Light oil, particularly tight oil, growth is based on producers' preference to target wells which have higher initial production rates and a quicker return on investment. Growth in Saskatchewan's heavy oil production is due to the low cost and low decline rates of heavy oil reservoirs in the province (Figure R.11).

The majority of condensate production has and is projected to come from Alberta. Growth in condensate production in the projection period occurs in Alberta and B.C., as producers focus on liquids-rich natural gas plays like the Montney Formation and the Duvernay (Figure R.12). Condensate is used as a diluent for bitumen and heavy oil.

Newfoundland offshore production in the Evolving and Current Policies scenarios steadily declines as shown in Figure R.13. We assume no new discoveries in the Evolving Policies Scenario. Additional discoveries and developments could change these trends. In the Current Policies Scenario, we assume new discoveries are made and start producing oil beginning in 2032.

Figure R.9:

Oil Sands Production Peaks in 2032 and then Declines Throughout the Projection Period in the Evolving Policies Scenario

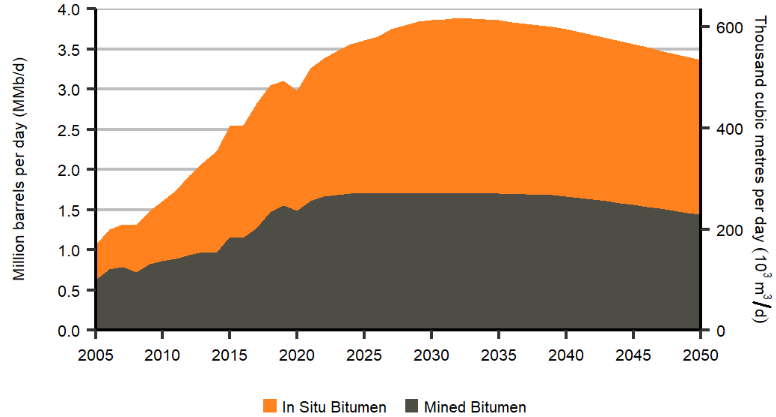


Figure R.10:

Oil Sands Production: Existing vs. Projected Additions in the Evolving Policies Scenario

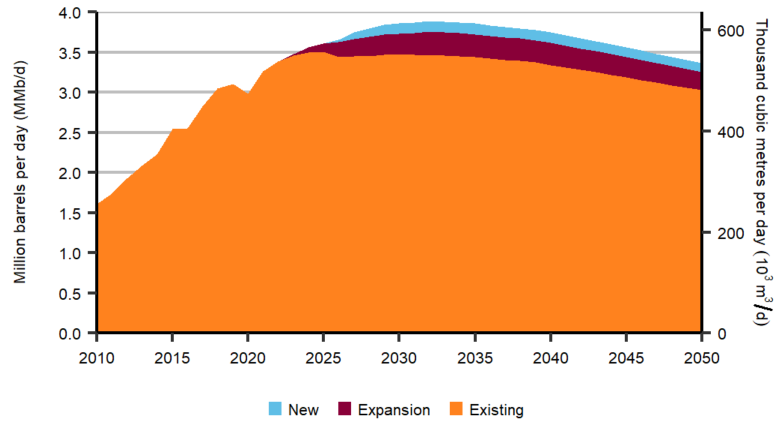


Figure R.11:
Conventional, Tight, and Shale Oil Production Decreases Steadily over the Projection in the Evolving Policies Scenario After a Brief Increase Over the Next Five Years

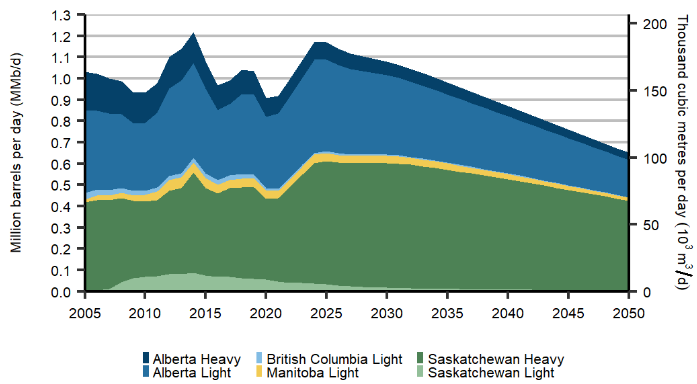
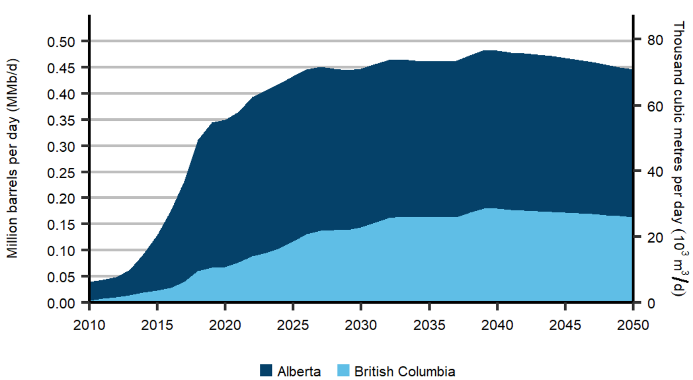


Figure R.12:
Condensate Production Driven by Increasing Diluent Demand in the Evolving Policies Scenario



New Technology in Oil Sands Production

In the Evolving Policies Scenario, we assume that technological improvement in extraction and upgrading methods of existing oil sands projects continues at the same pace as recent history. Although uncertainties exist, the improvements have the potential to reduce the per-barrel costs to produce bitumen, offsetting the higher carbon costs and lower commodity prices. These improvements also lead to lower per barrel emissions.

Much of the growth in oil sands production is in the form of expansions to existing facilities. By the end of the projection, facility expansions make up 7% of all oil sands production, or just over 0.23 MMb/d. Growth also comes from new facilities. No new oil sands mining or upgrading facilities will be created over the projection period. However, new in situ facilities make up 4% or 0.11 MMb/d of total oil sands production from 2019 to 2050.

We assume new or expanded facilities, which begin production after 2025, use the following technologies to lower their emissions intensity:

Steam and pure solvents: The injection of heated solvents (typically a mixture of natural gas liquids (NGLs)) into the reservoir to replace the steam generation units currently in use, lowering emissions. This process also leaves some of the less desirable components within bitumen (asphaltenes) in the reservoir. Pure solvents have the potential to reduce per-barrel operating costs by up to $3.50 per barrel.

In-pit extraction: A technique currently being developed by Canadian Natural Resources Limited at its Horizon Oil Sands mine, which involves separating oil sands ore into its component parts within the extraction pit of the operation. This method requires comparatively less heavy equipment and electric power, resulting in less emissions per barrel, and a potential cost savings of $2.00 per barrel.

Figure R.13:
Newfoundland Offshore Oil Production Steadily Declines to 2050 in the Evolving Policies Scenario

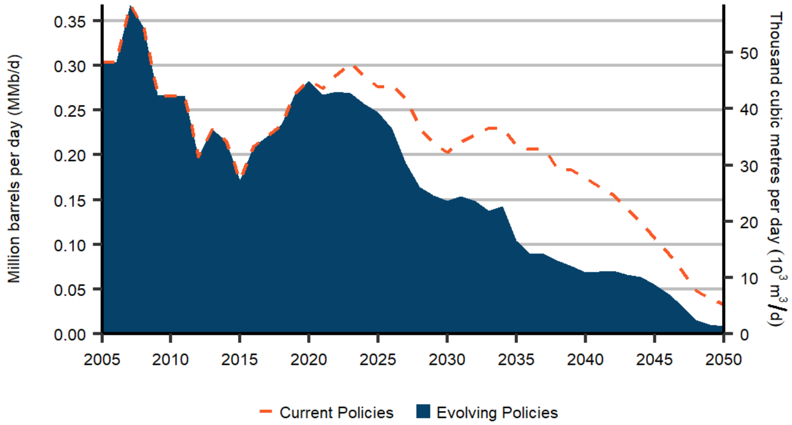
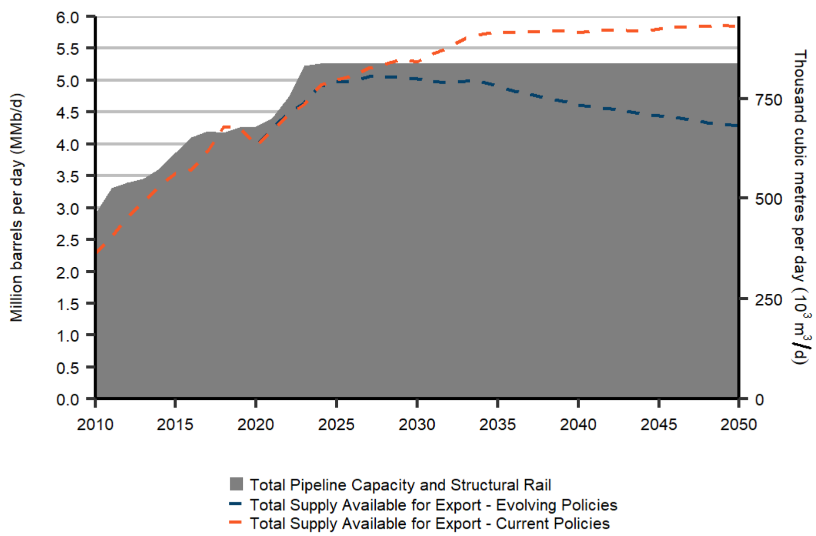


Figure R.14:
Illustrative Export Capacity from Pipelines and Structural Rail, vs. Total Supply Available for Export in the Evolving and Current Policies Scenarios



A key issue for Canada's energy system over the last number of years was the availability of crude oil export pipeline and rail capacity. This has implications for Canadian oil pricing and production trends. When total export capacity is very full, it can lead to widening differentials, particularly when there are unexpected outages. Figure R.14 is an illustrative comparison of our crude oil supply projections and the level of total export capacity that would be provided by existing pipeline capacity, planned pipeline expansions, and structural rail.[19] Making this comparison allows us to get an understanding of whether pipeline constraints might impact crude oil production in our scenarios. However, we do not adjust our crude oil production projections based on potential constraints.

In the Evolving Policies Scenario, crude oil available for export from western Canada stays below the total hypothetical export capacity throughout the projection period. However, into the mid-2030s the difference between capacity and supply is small. EF2021 does not assess whether in this scenario, additional pipeline capacity would be required to avoid constraining Canadian crude oil production below what is projected throughout the projection period.

In the Current Policies Scenario, supply exceeds capacity through much of the projection period. This clearly suggests that without additional pipeline capacity, production would be constrained below what is projected.

EF2021 does not explore the complexities of how pipeline infrastructure interacts with energy supply and demand outcomes. For example, some spare pipeline capacity can benefit crude oil producers by providing flexibility to access higher value markets or avoid the impacts of maintenance or unforeseen outages. It's also possible that excess capacity and long-term underutilization of pipelines could result in higher pipeline tolls for crude oil producers. Analysis of these considerations is beyond the scope of EF2021. We caution readers from drawing definitive conclusions from the illustrative comparison shown Figure R.14.

It is also important to note that the estimate of what total available pipeline capacity and the level of structural rail could be is uncertain and the result of many key assumptions. Table R.1 describes the infrastructure assumptions that underpin Figure R.14. Available capacity on existing pipeline systems could be higher or lower than reflected in Figure R.14, as pipeline systems evolve over time. The level of structural crude by rail could also be somewhat higher or lower than reflected in this figure.

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19 Structural rail refers to crude oil that is exported by rail regardless of a given WCS-WTI differential. Companies may choose to export crude oil by rail in this way due to a number of factors. These include existing contractual commitments, ownership of the crude-by-rail infrastructure, and the need to access locations not well connected by pipeline.

Table R.1
Pipeline Capacity Assumptions for Figure R.14

Name	Takeaway Capacity (current or timing as noted) (Mb/d)	Notes
Enbridge Mainline	3 207	Stated capacity includes the fully completed Line 3 Replacement Project which adds 370 Mb/d of capacity to the Enbridge Mainline in late 2021.
Keystone	586	Capacity held fixed over the projection period. The cancelled Keystone XL project is not included in Figure R.14.
Trans Mountain	300	Capacity is held fixed over the projection period. This capacity approximates the crude oil portion of capacity, by removing 50 Mb/d from the full capacity of Trans Mountain (350 Mb/d) to accommodate transportation of 50 mb/d of RPPs on the pipeline.
Trans Mountain Expansion	540	The Trans Mountain Expansion Project adds capacity starting in December 2022, and increases to full capacity by the spring of 2023. As with the existing Trans Mountain system, full capacity of the Trans Mountain Expansion (590 Mb/d) is reduced to accommodate transportation of 50 Mb/d of RPPs.
Express	310	Capacity held fixed over the projection period.
Milk River	97	Capacity held fixed over the projection period.
Aurora/Rangeland	44	Capacity held fixed over the projection period.
Structural Rail	120	Capacity held fixed over the projection period.
Capacity Increases to Existing Pipelines	58	Includes announced optimizations to boost the capacity of existing pipelines. The capacity increases are reflected in 2021 to 2023.
Total	**5 262**	

KEY UNCERTAINTIES:
Crude Oil Production in the Evolving Policies Scenario

Future crude oil demand: As climate policy announcements and ambitions increase around the world, many global scenarios have shown a significant reduction in global crude oil demand. These reductions may be needed to meet Paris climate goals of keeping temperature increases to well below 2 degrees Celsius, and to preferably limit warming to 1.5. If these ambitions are realized, falling crude oil demand could have significant impacts on market prices and investment that would affect future Canadian hydrocarbon production (see box "Global fossil fuel market dynamics and implications for Canadian production trends").

Technological development in the oil sands: Reducing GHG emissions and costs are two significant factors in the future development of oil sands facilities. Technologies are currently being developed to address both aspects, although their future adoption is uncertain. As in previous editions of *Canada's Energy Future*, EF2021 assumes that companies continue to work towards lowering both the cost and GHG emissions of their operations.

Western Canadian takeaway capacity: EF2021 assumes that western Canadian crude oil prices will consistently track prices in international markets, consistent with historical averages. The balance between future export pipeline capacity and supply available for export could affect future price relationships and crude oil production levels (see box "Crude Oil Pipelines in Canada's Energy Future" in the Executive Summary).

ESG considerations: The investment community is shifting its attention towards firms that align with their environmental, social, and governance (ESG) performance criteria.[20] The extent and nature to which ESG considerations may alter upstream investment trends could affect future production trends.

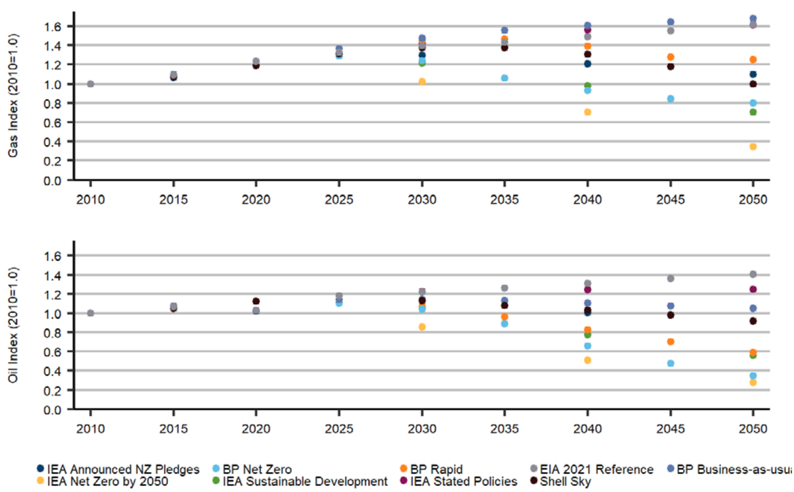
[20] Responsible Investment Association, 2018 Canadian Responsible Investment Opportunity: Trends Report, pg. 12, October 2018.

Global fossil fuel market dynamics and implications for Canadian production trends

The Evolving and Current Policies scenarios explore the impact of changing policy trends, both domestic and global, on the Canadian energy system. The results show that the different assumptions in the scenarios have a large effect on Canadian crude oil and natural gas production projections. This establishes future climate action–particularly global action, which impacts global demand and prices–as a key uncertainty for Canadian production levels. At a high level, the EF2021 production projections have a similar conclusion to global scenario work from the IEA, and companies such as BP and Shell: increasing levels of climate action will decrease production.

Over the past several years, there has been an increasing body of scenario analysis on what net-zero by 2050 means for the global energy system. Figure R.15 shows global oil and natural gas demand trends in a variety of scenarios that vary in their level of decarbonization. The range presented here is large and includes both business as usual and net-zero scenarios. For global oil demand, these scenarios have a range of 37% more to 73% lower compared to current levels by 2050. For natural gas, global demand ranges from 68% more to 54% less relative to current levels by 2050.

Figure R.15:
Growth of Global Natural Gas and Oil Demand, Various International Scenarios by Other Organizations



If the assumptions made in the global net-zero scenarios materialize, there will likely be significant impacts for global crude oil and natural gas markets. In the IEA's Net Zero by 2050 scenario, the global crude and North American natural gas prices are significantly lower than the Evolving Policies Scenario assumptions. The Canadian Institute for Climate Choices Net Zero Report finds that only scenarios with high oil prices and high levels of carbon dioxide removals see Canadian oil production similar to current levels in the long term. These results suggest that in a net-zero world, there could be significant decreases in Canadian oil and natural gas production.

Canadian fossil fuel production in a net-zero world will depend on many factors, such as:

- market prices,
- the evolution of light and heavy oil refinery demand,
- the cost of reducing the upstream emissions of Canadian oil and natural gas production, and
- the extent to which low-carbon natural gas technologies (such as CCS-equipped hydrogen production, electricity generation and industrial use with CCS, and natural gas use for direct air capture) are implemented.

In addition, oil and natural gas production is itself a large user of energy in Canada. As a result, the uncertainty in future production trends is an uncertainty for Canadian energy demand and GHG emissions trends. In the Evolving Policies Scenario, the oil and gas sector makes up about 20% of the remaining unabated fossil fuel demand in Canada in 2050, down from approximately 30% today. The future of global oil and gas trends, and how they affect Canadian investment and production trends, will therefore likely be important for Canada's own net-zero transition.

Natural Gas

In Canada, natural gas is produced for domestic use and exports. In 2020, Canadian marketable natural gas production averaged 15.5 Bcf/d or 438 million cubic metres per day ($10^6m^3/d$).

Natural gas production in Alberta has been relatively flat over the last few years, while B.C. production has been steadily increasing since 2010. This increase has been driven by a variety of factors including:

- Drilling to evaluate natural gas resources expected to supply LNG exports off of Canada's west coast.
- NGLs in the Montney tight gas play driving drilling and production despite lower natural gas prices.
- Horizontal drilling and hydraulic fracturing technological advancements.

In the Evolving Policies Scenario, natural gas production remains near 2020 levels of 15.5 Bcf/d through much of the next two decades. The additional investment in production to meet assumed LNG export volumes sustains production levels. Without these investments, production would otherwise decline, given the assumed North American natural gas prices and the costs associated with assumed domestic climate policies. After 2040, with LNG exports assumed to stay flat, total natural production begins to decline, falling to 13.1 Bcf/d by 2050. Much of the production growth related to LNG exports occurs in B.C., and production in B.C. surpasses that of Alberta by 2028.[21]

In the Current Policies Scenario, natural gas production continues increasing in the longer term, reaching 22.2 Bcf/d (627.4 $10^6m^3/d$) by 2050. Current Policies Scenario projections are driven by assumptions of higher prices, a lack of future domestic and global climate action, and higher LNG exports.

[21] EF2021 projections did not include possible effects stemming from the 29 June 2021 B.C. Supreme Court ruling in Blueberry River First Nations v. Province of British Columbia (Yahey) or the initial agreement reached on 7 October 2021 between B.C. and Blueberry River First Nations addressing, among other things, existing permits and restoration funding. Future analysis will consider any effects as appropriate.

KEY TRENDS:

Natural Gas Production

- Natural gas production is fairly level in the Evolving Policies Scenario to 2040, before declining through the remainder of the projection period.
- Production from the Montney Formation in the form of liquids-rich tight gas grows significantly and becomes the majority of Canadian production over the projection period.

Figure R.16:

Total Natural Gas Production Declines in the Evolving Policies Scenario and Increases in the Long Term in the Current Policies Scenario

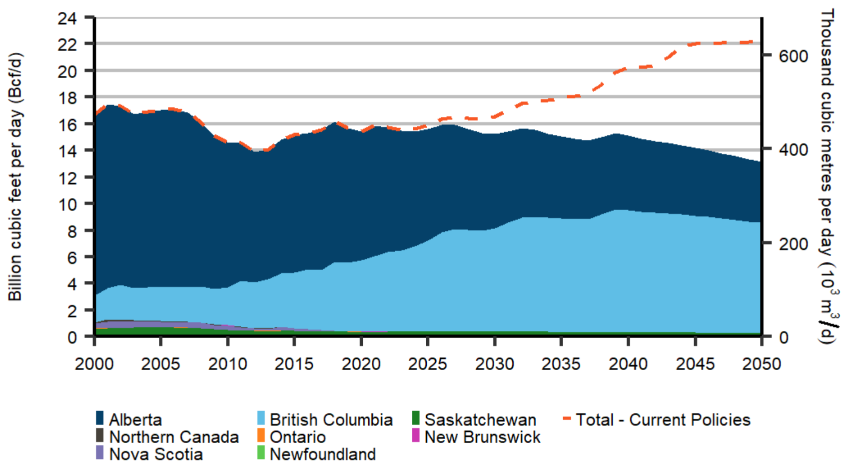


Figure R.17 shows production of natural gas by type in the Evolving Policies Scenario. Production is increasingly made up of tight natural gas produced from the Montney Formation in Alberta and B.C., which has already grown significantly over the past five years. Alberta Deep Basin tight natural gas production declines. There are minimal amounts of shale gas production from the Duvernay and Horn River shales, while solution gas declines and coal bed methane production declines significantly over the projection period.

Figure R.18 illustrates total Evolving Policies Scenario production divided into production that would result from the market prices of the Evolving Policies Scenario, and additional production due to LNG exports. The additional LNG-related production is based on our assumption that 75% of LNG feedstock comes from incremental production that only exists because LNG export capacity exits. The other 25% of LNG feedstock is supplied by the market-driven production (i.e. production that occurs based on assumed North American gas prices). Figure R.18 shows that without additional production to feed LNG exports, production would continuously decline over the projection period to 9.5 Bcf/d (267.7 $10^6 m^3/d$) in 2050.

Figure R.17:

Natural Gas Production is Increasingly Made Up of Montney Formation Tight Gas in the Evolving Policies Scenario

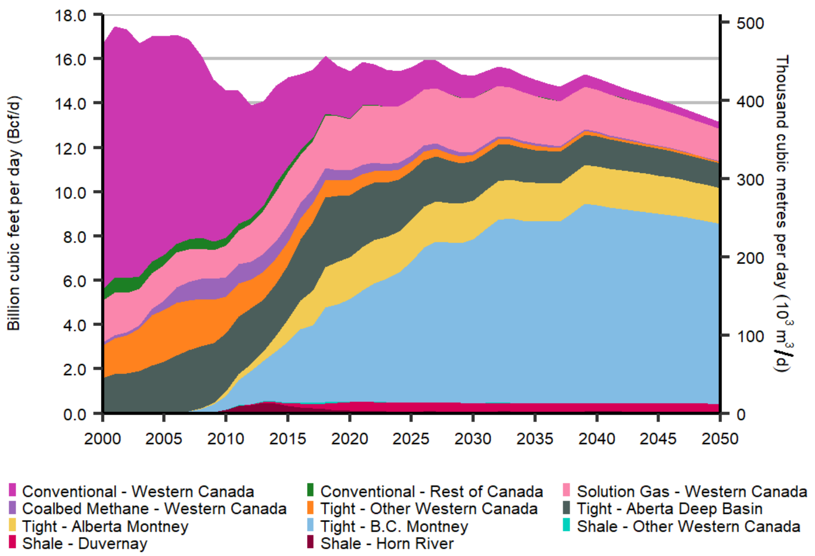
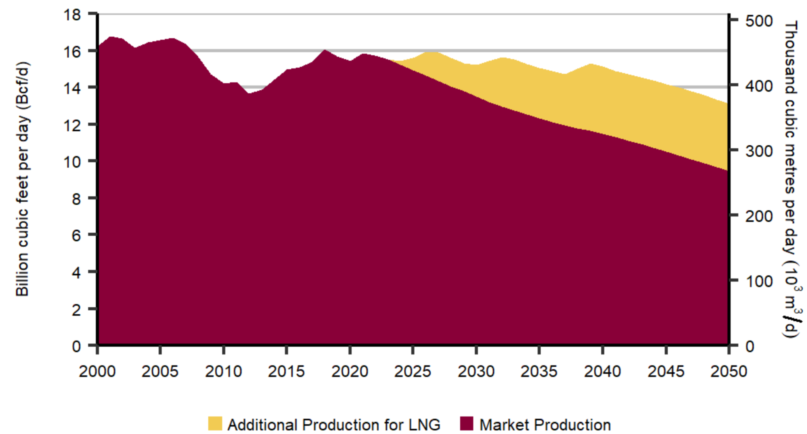


Figure R.18:

LNG Exports Support Natural Gas Production in the Evolving Policies Scenario



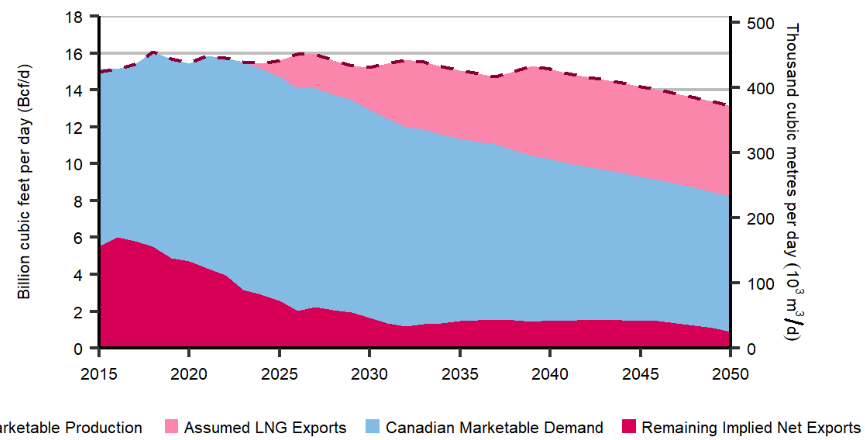
Natural gas exports to the western U.S. have increased over the last several years. Imports to Canada have been relatively steady over the last decade, ranging from 2-3 Bcf/d (57-85 $10^6 m^3/d$). Imports could potentially rise as pipeline capacity increases from the northeastern U.S. to Dawn, Ontario.

Figure R.19 breaks total marketable production in the Evolving Policies Scenario into a) Canadian marketable demand, b) the assumed LNG export volumes, and c) the remaining implied net exports. The remaining implied net exports is mostly by pipeline and calculated as Canadian natural gas production minus Canadian demand and LNG exports.[22] Remaining implied net exports shrink throughout the projection period, resulting from the production, consumption, and LNG export trends discussed earlier in this section. Lower remaining implied net exports do not necessarily mean that non-LNG exports are falling, just that the difference between imports and non-LNG exports is smaller.

[22] This value of natural gas demand is lower than the primary natural gas demand value discussed earlier because it does not include non-marketed natural gas used directly by those that produce it. Examples of this include flared gas, natural gas produced and then consumed by in-situ oil sands producers, and natural gas produced and consumed by offshore oil production.

Figure R.19:

Natural Gas Supply and Demand Balance sees the Increasing Importance of LNG Exports as Domestic Demand Declines in the Long Term in the Evolving Policies Scenario



KEY UNCERTAINTIES:
Natural Gas Production

Future international natural gas prices: Benchmark U.S. prices (i.e. Henry Hub) could be higher or lower, which would lead to different production results under both EF2021 scenarios.

Western Canadian natural gas price discounts: Differentials for western Canadian natural gas relative to Henry Hub could be affected by many factors, including pipeline bottlenecks, and market dynamics. Differentials that vary from what we assume could lead to different production in the longer term.

Future natural gas demand: As climate policy announcements and ambition increase around the world, many global scenarios have shown a significant reduction in global natural gas demand (see textbox "Global fossil fuel market dynamics and implications for Canadian production trends"). If these ambitions are realized, falling natural gas demand could have significant impacts on market prices and investment that would affect future Canadian hydrocarbon production. At the same time, the extent to which natural gas is used for low-carbon hydrogen production and/or direct air capture could impact natural gas demand trends in low-emission scenarios

LNG exports: It is possible that global market conditions and the costs of constructing new LNG export capacity may change in the future, influencing future volumes of LNG exports from Canada in both EF2021 scenarios.

ESG considerations: The investment community is shifting its attention towards firms that align with their ESG performance criteria.[23] The extent and nature to which ESG considerations may alter upstream investment trends could affect future production trends.

[23] Responsible Investment Association, 2018 Canadian Responsible Investment Opportunity: Trends Report, pg. 12, October 2018.

Natural Gas Liquids

Natural gas liquids (NGLs) are produced along with natural gas, as well as from oil sands and refinery processes. Natural gas production is the main source of NGL production in Canada. Demand for certain NGLs adds value to natural gas production and has been a driver of natural gas drilling. Raw natural gas at a wellhead is comprised primarily of methane, but often contains NGLs such as ethane, propane, butane, condensate and other pentanes.

Figure R.20 shows that total NGL production grows around 10% to 2050 in the Evolving Policies Scenario, from the 1 159 Mb/d (184 10^3m^3/d) produced in 2020. Growth is dominated by condensate, which grows 28% by 2050. Condensate, along with butanes, are added to bitumen as a diluent to enable it to flow in pipelines and be loaded on to rail cars. Condensate demand has, and will continue to, influence natural gas drilling to focus on NGL-rich plays.

Propane and butane production declines slightly over the projection period in the Evolving Policies Scenario. Demand for these NGLs increases in the medium term as demand from petrochemical producers in Alberta increases, which may affect export levels of propane and butane.

Additional Detail on Crude Oil, Natural Gas, and NGL Projections

For additional data on crude oil, natural gas and NGL production, see the EF2021 Data Appendices. These datasets include additional geographical and monthly details on production and drilling trends.

Further information about these and other available EF2021 data sets can be found in the "Access and Explore Energy Futures Data" section.

The majority of ethane is extracted at large natural gas processing facilities located on major natural gas pipelines in Alberta and B.C. In 2020, ethane made up 20% of NGL production. Ethane production is flat in the Evolving Policies Scenario, as its recovery from the natural gas stream is constrained by the capacity of the ethane extraction and petrochemical facilities in Alberta, which is assumed to remain constant. Ethane produced in excess of this capacity is reinjected back into the natural gas pipeline system to be consumed by end-users as natural gas, and these volumes do not count in our ethane production numbers.

In the Current Policies Scenario, total NGL production grows 70% to 1 967 Mb/d (313 10^3m^3/d). NGL production growth is due to natural gas production growth in this scenario. Condensate also has the most significant growth in this scenario–growing 121% over the projection, from 349 Mb/d (56 10^3m^3/d) in 2020 to 770 Mb/d (122 10^3m^3/d) in 2050.

Figure R.20:

Condensate has an increasing share of NGL Production in the Evolving Policies Scenario

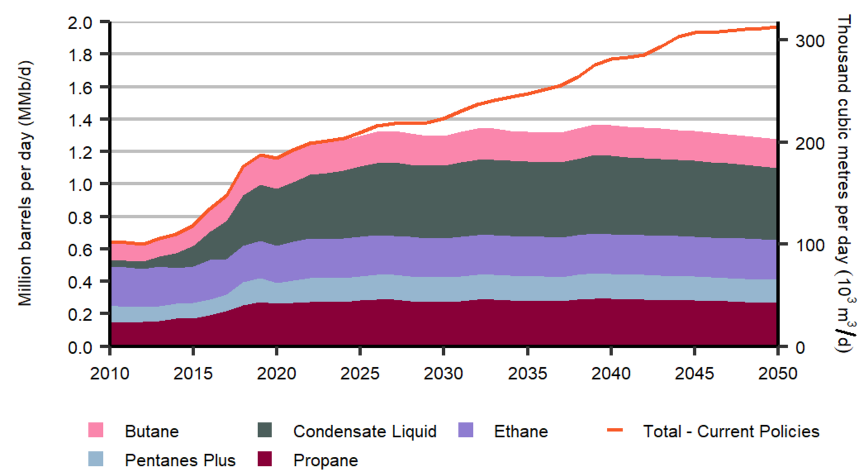


Figure R.21:
Ethane Potential

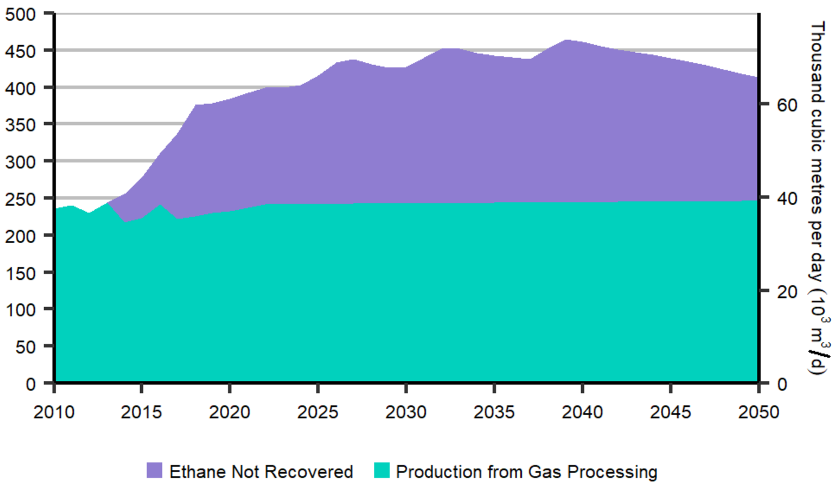


Figure R.22:
Propane Disposition

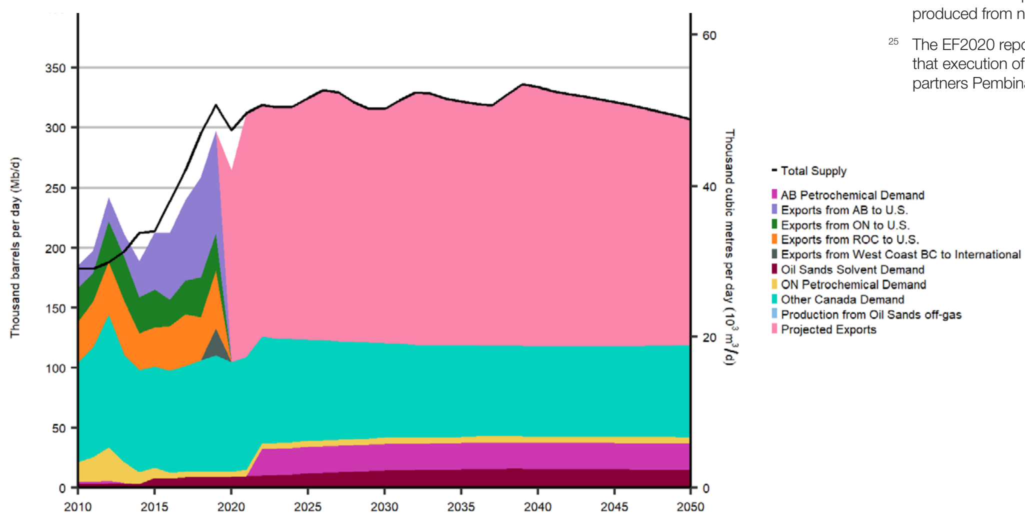


Figure R.21 shows ethane that is extracted from the natural gas stream, and ethane that is not recovered (which includes ethane reinjected in the natural gas stream). Growth in ethane that is not recovered means there is growing potential to recover more ethane, in the event of future increases in the capacity of the ethane extraction and petrochemical facilities.[24]

Figure R.22 shows total propane production broken out into its disposition. There are various uses of propane in Canada in all sectors, and over the next few years, petrochemical demand is projected to increase with the start of The Heartland Complex.[25] Propane exports to the U.S. have grown significantly this past decade as U.S. domestic demand and propane exports *from* the U.S. grew. In 2019, propane exports from the west coast of B.C. began, in the form of liquefied petroleum gas (LPG). These west coast exports could continue to increase, with potential for significant additional LPG projects and exports. Given recent export growth trends, and potential for petrochemical growth above what is projected, the Canadian propane market could see tightening in the longer term if propane production levels off then slightly declines, as projected in the Evolving Policies Scenario.

24 In May 2021 Wolf Midstream announced a positive final investment decision on the NGL North project, anticipated to be in-service in 2023 subject to regulatory and environmental approvals. This project in Alberta would recover up to 70 000 b/d of liquids. This project is not included in either scenario, and if it comes into operation it would increase ethane produced from natural gas processing.

25 The EF2020 report had a larger value for future Alberta petrochemical demand, but EF2021 has been updated to reflect that execution of one of the two proposed petrochemical complexes was suspended in late 2020, by joint venture partners Pembina Pipeline Corp. and Kuwait's Petrochemical Industries Co.

KEY UNCERTAINTIES:
Natural Gas Liquids

Natural gas: NGLs are a byproduct of natural gas production, and as such, any uncertainty discussed in the natural gas section applies for NGL projections.

Oil sands: The rate of oil sands and other heavy oil production growth, and the amount of blending, will affect the demand for condensate and butanes required for diluent. Likewise, the increased use of solvents to reduce steam requirements in the oil sands would increase demand for propane and butanes, and could influence how much they are targeted by future natural gas drilling.

Petrochemical development: There is potential for ethane recovery to increase further if there is an increase in the capacity of ethane extraction and petrochemical facilities. This could be spurred by government programs, such as royalty credit incentives for petrochemical facilities in Alberta's Petrochemicals Diversification Program.

Global LPG export market: Several large-scale facilities have been approved by provincial and federal regulators to export LPG from B.C.'s coast. Propane exports from the B.C. coast began in May 2019 and butanes also became part of the LPG mix in April 2020. Over the outlook period, propane will likely be the majority of exported LPG. The amount and composition of the LPG stream exported at proposed and existing terminals could impact domestic NGL prices and the attractiveness of drilling for NGL-rich natural gas.

Electricity

In the Evolving Policies Scenario, electricity demand grows by 44% from 2021 to 2050, as shown in Figure R.23. This is driven by growth in all sectors, with transportation and hydrogen production being emerging growth areas. In transportation, electrification provides an alternative in a sector long-dominated by RPP use. Hydrogen production is another growth area for electricity demand, as electricity is used in electrolysis to produce hydrogen.

Currently, electricity makes up approximately 16% of Canada's end-use energy demand. In the Evolving Policies Scenario, end-use electricity demand (excluding electricity to produce hydrogen) increases at an average annual rate of 1% over the projection period, which raises electricity's share of end-use demand to nearly 30% by 2050. See Figure R.24.[26]

[26] Electricity used to produce hydrogen is excluded from these figures to avoid double-counting, as hydrogen produced by electricity is included in the total and sectoral end-use demand figures. These shares are consistent with the sector demand charts earlier in this section.

Figure R.23:
Electricity Demand Grows Steadily in the Evolving Policies Scenario

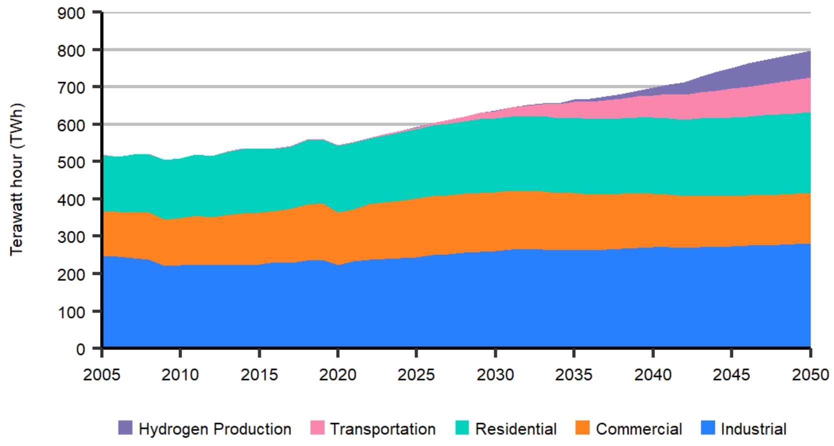


Figure R.24:
Share of Electricity in End-use Demand by Sector and Total in the Evolving Policies Scenario

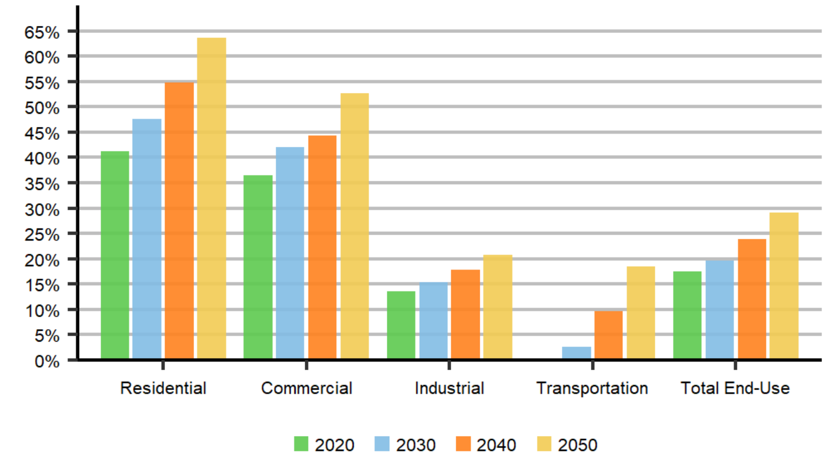


Figure R.25:

Electricity Capacity Grows Significantly in the Evolving Policies Scenario

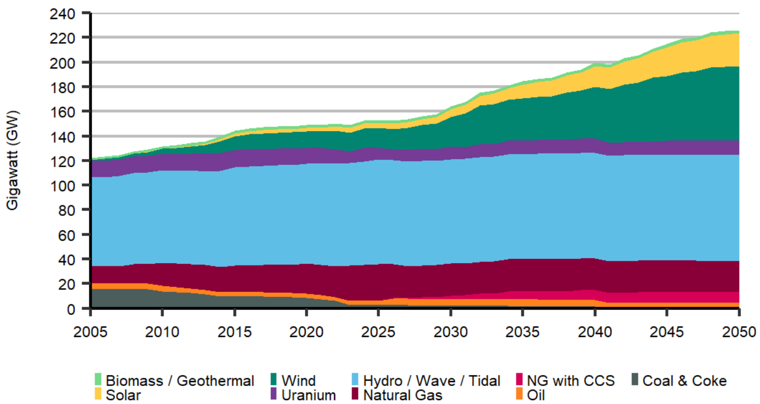
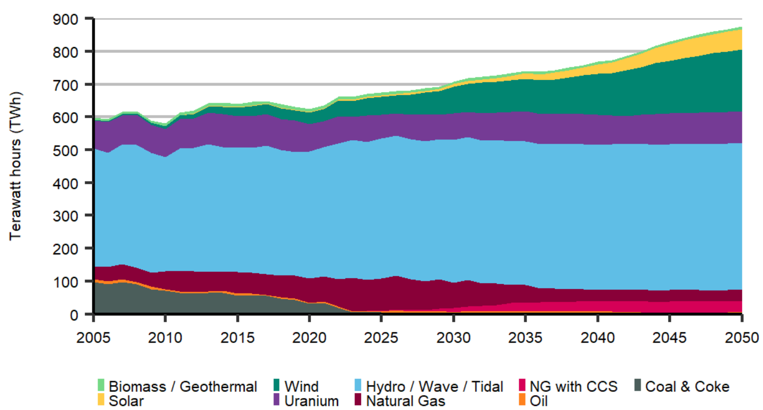


Figure R.26:

Electric Generation Trends by Primary Fuel Type in the Evolving Policies Scenario



Canada has considerable renewable resource potential including hydro, wind, biomass, and solar. Over the past decade, there have been significant changes in Canadian electricity capacity and generation trends, and it continues to evolve in the EF2021 projections. Figure R.25 shows total Canadian installed capacity by fuel type, and Figure R.26 shows electric generation by fuel type. In the earlier part of the projection, renewables and natural gas replace phased out coal generation.[27] Coal falls faster than previous projections, as recent announcements from companies suggest coal will be phased out of the Alberta electricity mix by 2023. In the longer term, falling costs lead to large growth in non-hydro renewables such as wind and solar. Nuclear generation remains relatively stable overall in the projection, with some significant year-to-year variation because of Ontario's nuclear refurbishments in the first half of the projection period. The share of low and non-emitting generation (renewables, nuclear, and fossil fuel with CCS) increases from 82% currently to 95% in 2050.[28]

Wind and solar generation also increases in the Current Policies Scenario. However, given lower carbon prices and higher wind and solar costs, wind and solar increase to a lesser degree and there is a relatively higher share of natural gas generation compared to the Evolving Policies Scenario. In 2050, natural gas makes up 16% of total generation in the Current Policies Scenario. The share of renewables and non-emitting electricity increases to 83% by 2050, compared to 95% in the Evolving Policies Scenario.

[27] Small amounts of coal with CCS generation remain to 2050, reflecting the Saskatchewan Boundary Dam project. No additional coal with CCS projects are added in the projection period based on comparative economics with natural gas with CCS and other low/non-emitting electricity.

[28] Renewable and nuclear shares refer to total electricity generation, including cogeneration.

The increase in non-hydro renewables is driven by falling costs, technological improvements, and improved integration of variable renewable energy sources such as wind and solar. Figure R.27 shows that by 2050, wind and solar capacity is added in a variety of Canadian regions. Total wind capacity rises to over 57 GW and total solar capacity rises to 26 GW. Post 2030, solar is the fastest growing renewable.

Integration of increasing wind and solar–whose generation is variable due to changing wind and sun conditions–is supported in a number of ways in the Evolving Policies Scenario. Other forms of energy, such as hydropower and natural gas, help back up these non-hydro renewables. In the Evolving Policies Scenario, energy interconnection between provinces will increase, including between Manitoba-Saskatchewan and Alberta-B.C. This adds to significant trade in Eastern and Atlantic Canada, which could increase further if projects such as the proposed Atlantic Loop increase transmission capacity. This increased ability to exchange power helps regions integrate larger amounts of variable wind and solar energy. Finally, the Evolving Policies Scenario includes around 25 GW of utility scale battery storage. This level is based on the falling costs of storage, as well as the falling costs of renewables, especially solar. Storage is particularly critical for large additions of solar.

Canada is a net exporter of electricity to the U.S., and large amounts of electricity are also traded between provinces, mainly in eastern Canada. By connecting the electricity grids of different regions, grid operators can take advantage of regional differences in electricity mixes, available variable renewable energy, and periods of peak electricity demand. Figure R.28 shows projected net exports out of Canada, as well as aggregate interprovincial trade volumes. Trade remains relatively small when compared to total generation.[29]

[29] From 2010 to 2020, annual net exports average 49 TWh, ranging between 25 and 64 TWh.

Figure R.27:
Increasing Capacity of Non-Hydro Renewables in the Evolving Policies Scenario

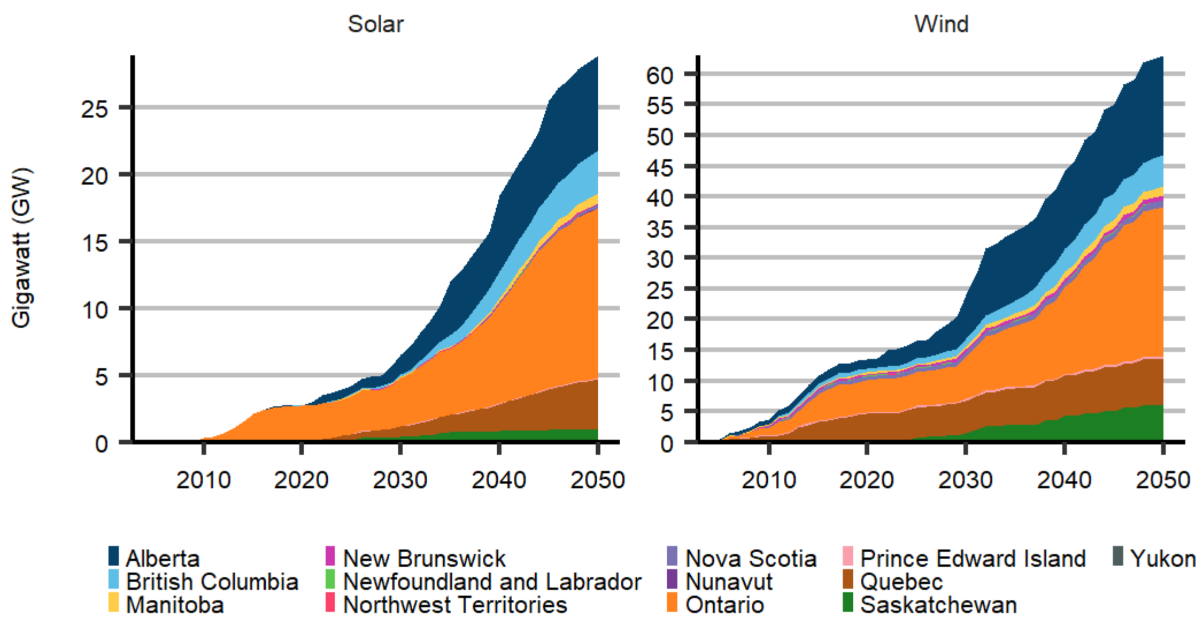
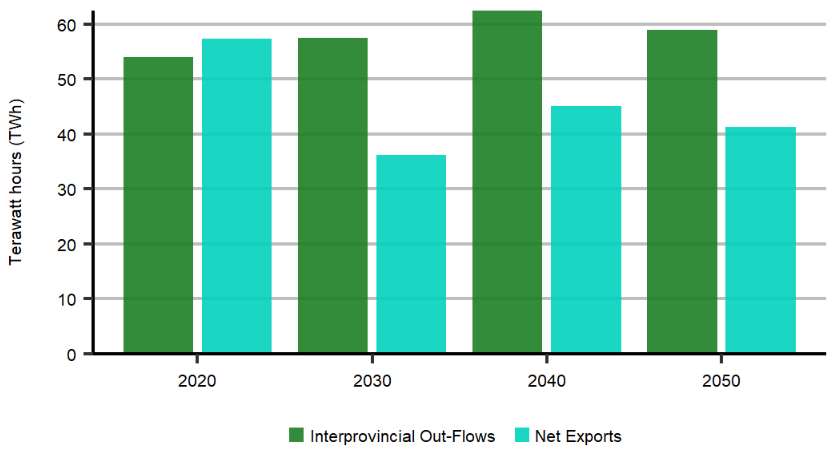


Figure R.28:
Net Exports of Electricity and Interprovincial Trade



KEY TRENDS:
Electricity Generation

- Technologies enabling Canada's transition to a low-carbon economy make inroads across the energy system, particularly in electricity generation.
- Natural gas and renewable generation is added, and most nuclear will be refurbished.
- Coal will be phased out.
- In the Evolving Policies Scenario, the share of non- and low-emitting generation increases from 82% currently, to 95% in 2050.

KEY UNCERTAINTIES:
Electricity Generation

Future cost declines of generating technology: The costs associated with different generating technologies is an important factor in determining what type of facilities are built. This is especially true with rapidly changing technologies such as wind, solar, and battery storage.

Renewable enabling technologies: Deployment of technologies to improve the integration of variable renewable energy, such as smart grids, storage, and transmission, could allow for greater levels of wind and solar in the projections.

Electricity demand growth: This is important in determining future electricity supply. As a result, the uncertainties identified in the energy demand section are uncertainties that also apply to the electricity supply projections.

Export market developments: Climate policies, fuel prices, electrification and power sector decarbonization in export markets could impact future projects and transmission developments.

Hydrogen

In recent years there has been increasing interest in low-carbon hydrogen as an important fuel in Canada and the world's transition to a low-carbon economy. Over the past few years, many countries, including Canada, have released hydrogen strategies. EF2021 is the first edition of the *Canada's Energy Future* series with a dedicated section on hydrogen supply and demand, and also introduces a hydrogen table in our online data appendix.

Our focus in this section is on hydrogen use as an energy carrier and produced by methods that emit little or no CO_2.[30] In the Current Policies Scenario, we include only currently announced projects.

In the Evolving Policies Scenario, total hydrogen demand reaches 4.7 megatonnes (MT), or 565 PJ, by 2050, as shown in Figure R.29. This accounts for 6% of total end-use energy demand. By 2050, the industrial sector accounts for 60% of hydrogen use. In this sector, hydrogen is mainly used in steel manufacturing, oil sands production, and chemical and fertilizer production. The transportation sector accounts for 15% of hydrogen demand, mostly displacing diesel in long distance freight trucking and marine transportation. The final 10% of hydrogen is used in the residential and commercial sectors, where it is blended into the natural gas stream and used for space and water heating.

Figure R.30 shows hydrogen demand by province. Hydrogen demand is the highest in Alberta, which accounts for 53% of total hydrogen demand in 2050. Alberta's relatively high demand is due to its existing industrial makeup, and its ability to produce hydrogen from natural gas with CCS, which has relatively lower costs than electrolysis earlier in the projection period. lberta's future hydrogen use is mainly in oil sands production, where it is used to replace natural gas as a source of process heat. By 2050, hydrogen demand in Alberta's industrial sector accounts for 76% of the province's total demand.

[30] Currently almost all of Canada's hydrogen is produced using a process that converts natural gas to hydrogen and CO_2, with the CO_2 being vented to the atmosphere. This hydrogen is mainly used in refineries and for fertilizer production, and is not explicitly broken out from our industrial natural gas use data.

Figure R.29:
Hydrogen Demand by Sector

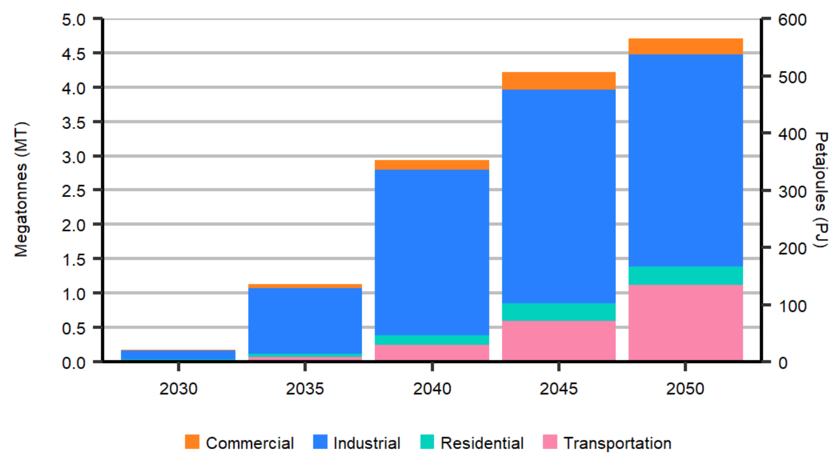
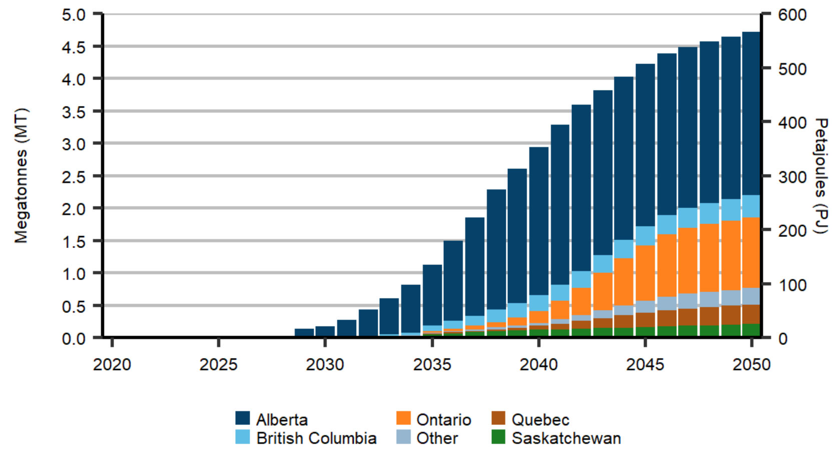


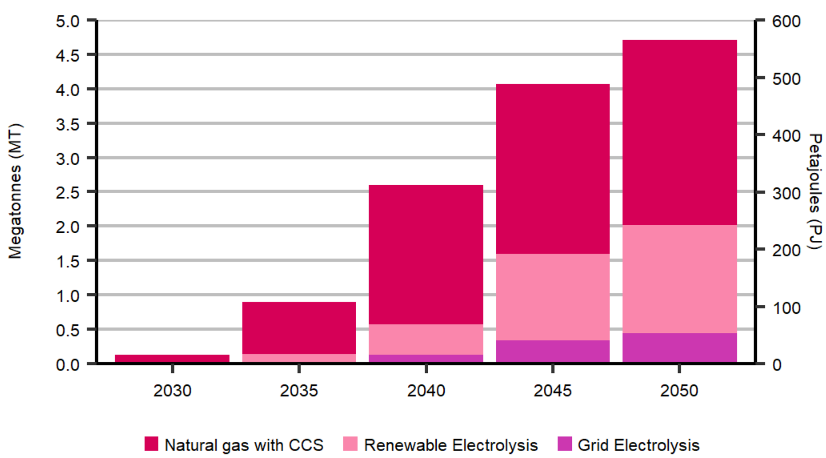
Figure R.30:
Hydrogen Demand by Region



Given that we assume hydrogen is produced to meet local demands (with no international or inter-provincial trade), hydrogen production aligns with demand. Accordingly, in the Evolving Policies Scenario, Canada produces 4.7 MT of hydrogen by 2050, matching domestic demand, and Alberta is the largest producer (with 2.5 MT of production in 2050).

In the early years of the projection, natural gas with CCS is the dominant technology for hydrogen production. Electrolysis powered by electricity from the grid and dedicated renewables becomes cost competitive towards the end of the projection. By 2050, natural gas with CCS makes up 57% of total production (Figure R.31). Production from electrolysis powered by dedicated renewables and the grid make up 33% and 9% respectively. Most regions in Canada produce hydrogen using electrolysis powered by electricity from the grid or dedicated renewables. Ontario has the highest hydrogen production from electricity, with 48% of Canada's electrolysis-based total. By 2050 close to 70 TWh of electricity is used to produce 1.8 MT of hydrogen. Similarly, natural gas with CCS uses over 422 PJ of natural gas to produce 2.95 MT of hydrogen.

Figure R.31:
Hydrogen Production by Technology



KEY UNCERTAINTIES:
Hydrogen

Infrastructure: Development of new and existing infrastructure will have an impact on the pace of hydrogen adoption in all sectors. The maximum amount of hydrogen that can be safely blended in existing infrastructure is limited to a portion of the existing pipeline capacity.

Trade: Interprovincial and international trade could alter the hydrogen supply and demand projections in this chapter. Many factors will influence the extent of trade, including whether existing transportation infrastructure is adapted to carry hydrogen, new infrastructure is built primarily for hydrogen transportation, and the evolution of costs between technologies and regions.

Future cost declines of production technology: Large scale low-carbon hydrogen production will depend on production technologies' cost decline associated with electrolyzers, CCS technology, storage, and distribution. The relative cost between various production methods will also be important, as different regions have different characteristics such as accessibility to storage, and wind and solar resource quality.

Carbon intensity: For hydrogen derived from natural gas to play a role in decarbonization, its associated emissions need to be low. Carbon capture rates greater than 90%, as assumed in this analysis, will be important. Other important areas include reducing emissions from natural gas production, including methane emissions, which are currently covered by various provincial and federal policy initiatives.

Greenhouse Gas Emissions

Currently, energy use and GHG emissions in Canada are closely related. ECCC produces Canada's official emission projections for the United Nations Framework Convention on Climate Change.[31]

The majority of GHGs emitted in Canada are a result of fossil fuel combustion. Fossil fuels provide much of the energy used to heat homes and businesses, transport goods and people, and power industrial equipment. Energy related emissions accounted for 82% of Canadian GHG emissions in 2018.[32] The remaining emissions are from non-energy sources such as agricultural and industrial processes and waste handling.

[31] Data sets are also available through the Government of Canada's Open Government portal.

[32] As defined in ECCC's national inventory report, energy related emissions includes stationary combustion sources, transportation, fugitive sources, and CO_2 transport and storage.

KEY TRENDS:

Fossil Fuel Use and GHG Emissions

- Overall unabated fossil fuel use declines in the Evolving Policies Scenario.
- Natural gas, oil, and coal each have their own distinct future trend, but use of all three falls over the long-term.
- The emission intensity of fossil fuel use falls, driven by the phase out of coal and the long-term adoption of CCS.

Does the Evolving Policies Scenario Meet Canada's Climate Commitments?

The Evolving Policies Scenario provides an energy supply and demand outlook for Canada under the general premise that global and domestic climate action continues to increase at its recent pace. EF2021 focuses on potential future outcomes for Canada's energy system. It should not be viewed as an assessment, or a pathway, for meeting Canada's climate commitments.

ECCC produces the official analysis of Canada's current emissions outlook and performance against its climate commitments. Recent ECCC projections included in Canada's updated Nationally Determined Contribution (NDC)[33] show that with the latest measures in the Strengthened Climate Plan and Budget 2021, a GHG emission reduction of 36% below 2005 levels by 2030 is achieved. This reduction exceeds Canada's original NDC pledge of 30% below 2005 levels, but additional measures could be needed to hit the updated NDC of 40-45% below 2005 levels.

The unabated fossil fuel demand trends in the Evolving Policies Scenario, as shown in this section, imply significant reduction in GHG emissions. They also imply that the Evolving Policies Scenario is unlikely to achieve net-zero emissions by 2050. Recognizing this fact, we have included the "Towards Net-Zero" section in EF2021.

[33] Submitted to the UNFCCC as part of the Paris agreement.

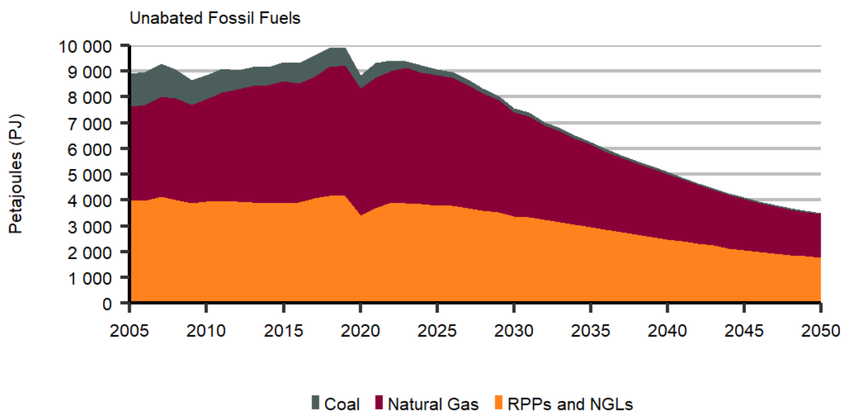
Figure R.32 breaks out total primary demand into unabated fossil fuel demand, which will make up the majority of Canadian GHG emissions, and low emission sources, which include renewable, nuclear, fossil fuels with CCS, and fossil fuels for non-combustion purposes.[34] Relative to 2020 levels, unabated fossil fuel consumption is 19% lower in 2030, 45% lower in 2040, and 62% lower in 2050. Meanwhile, low-emission energy rises, and accounts for 67% of energy use in 2050, compared to just 31% in 2021.

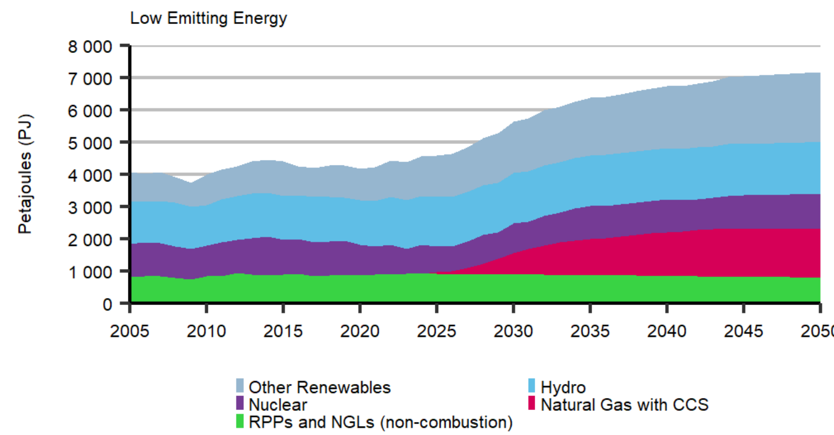
Trends vary among fossil fuels. Coal consumption significantly declines over the projection, driven by its phase-out from electricity generation by 2030.[35] Use of RPPs, such as gasoline and diesel, gradually declines throughout the projection period. In the earlier years, this decline is driven by efficiency improvements and increased blending of biofuels, and in the long term is driven by increased electrification of the transportation sector. Use of natural gas continues to grow in the very early part of the projection period, following its increased role in power generation and its use in rising oil sands production. In the longer term, its overall use falls but its use with CCS increases significantly for industrial and power generation use and low-carbon hydrogen production.

[34] Examples of fossil fuels for non-combustion purposes include petrochemical feedstocks, asphalt and lubricants. We include these non-energy demands along with energy use because they are derived from energy commodities such as crude oil and NGLs, and form part of Canada's energy balances.

[35] Small amounts of coal with CCS generation remain to 2050, reflecting the Saskatchewan Boundary Dam project. No additional coal with CCS projects are added in the projection period based on comparative economics with natural gas with CCS and other low/non-emitting electricity.

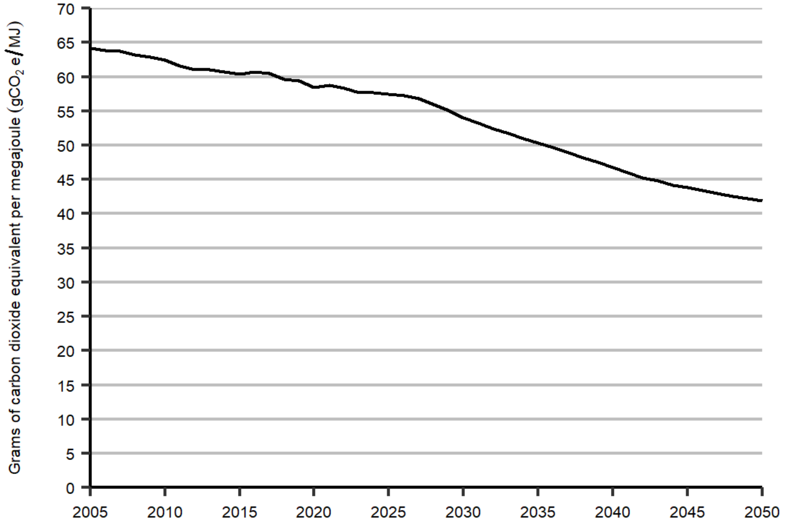
Figure R.32:
Total Primary Demand by Type





Changing proportions of which fossil fuels are consumed leads to declining combustion-related GHG emissions per unit of fossil fuel energy used in the Evolving Policies Scenario, particularly with coal use declining to 2030. Deployment of CCS technology in industrial facilities also reduces the GHG intensity of fossil fuel use in the longer term. As shown in Figure R.33, fossil fuel emission intensity in 2030 is 9% lower than 2019, and 16% lower than 2005 in the Evolving Policies Scenario. By 2050 it is 29% lower than 2019, and 35% lower than 2005 in the Evolving Policies Scenario. This decline drives emission reductions when combined with falling fossil fuel use, as 2030 total fossil fuel use is 16% lower than 2019, and 6% lower than 2005. By 2050, total fossil fuel use is 46% lower than 2019, and 40% lower than 2005. Accounting for reductions in non-combustion emissions, such as reducing methane emissions, as well as including emission credits purchased through international trading mechanisms (like Quebec's emission trading with California), could further decrease emission intensity.

Figure R.33:
Fossil Fuel Emission Intensity Falls due to Higher Shares of Natural Gas, Less Coal, and Greater Adoption of CCS in the Evolving Policies Scenario



Could Carbon Removals Bring Canada to Net-Zero in the Evolving Policies Scenario?

Global and domestic net-zero pathway exercises rely on some degree of carbon removal or negative emission technology to reach net-zero by 2050. The degree varies depending on the scenario and underlying assumptions. For example, the Net-Zero Emissions by 2050 Scenario in the IEA's Net-Zero by 2050 report includes about 1.9 gigatonnes of CO_2 that is removed by negative emissions technologies in 2050. In the Canadian context, the Canadian Institute for Climate Choices' Canada's Net Zero Future report shows availability of engineered negative emission technologies, particularly direct air capture, and accounts for 0 to 425 MT of CO_2 emission reductions in 2050 across the 62 scenarios they analyzed. However, the Canadian Institute for Climate Choices recognizes potential challenges, both technical and economic, and identifies ways to reach net-zero in the absence of negative emissions technologies.

Negative emissions technologies and enhanced biological sinks involve removing CO_2 from both the emissions' source and the atmosphere, and storing it in land, ocean, or geological reservoirs.[36] While hypothetically promising, most assessments agree that negative emissions technologies are not a replacement for conventional mitigation and adaptation methods, due to high costs, potential risks, and uncertainties involved.[37]

Notable GHG removal methods include:

Reforestation and afforestation[38]: Carbon can be sequestered in biomass through restocking of existing forests and woodlands that have been depleted, or introducing trees to areas that have not previously been forested.

Soil carbon sequestration[39]: Carbon can be removed from the atmosphere and stored in the soil carbon pool, primarily in the form of soil organic carbon. This can be accomplished through a variety of methods, including the restoration of degraded soils or widespread adoption of soil conservation practices in agriculture. For instance, reducing soil carbon loss can be achieved in certain circumstances by switching from tillage to no-till cropping.

Bioenergy with carbon capture and storage (BECCS)[40]: Carbon can be captured and stored by geological sequestration or land application, as energy is extracted from biomass through combustion, fermentation, or other conversion methods. Limiting factors for BECCS include the availability and sustainability of feedstock biomass, and the availability of carbon storage capacity.

Direct air capture: Carbon can be captured from the atmosphere to produce a concentrated stream of CO_2. It can then be sequestered (resulting in emission removals), or used to make carbon-neutral synthetic fuels. Direct air capture uses a lot of energy, so large scale deployment could impact energy supply and demand trends.

The Evolving Policies Scenario shows a 60% drop in unabated fossil fuel use by 2050, which would result in a significant reduction in emissions. The Evolving Policies Scenario does not include assumptions related to deployment of large-scale carbon removals. Whether the Evolving Policies Scenario could be net-zero with deployment of carbon removals depends on two key considerations:

1. Although unabated fossil fuel use falls, it is still a significant part of the energy mix, and implies significant levels of emissions. This would require a large deployment of carbon removal technology. The feasibility of this deployment would depend on many factors, including cost reductions of emerging technologies such as direct air capture, and the availability and costs of BECCS and nature-based solutions. Given these are emerging solutions, large deployment is highly uncertain.

2. Deployment of large-scale carbon removals would likely change the Evolving Policies Scenario projections. For example, large scale direct air capture deployment would involve a significant increase in natural gas and/or electricity use. Likewise, a large deployment of BECCS could change the Evolving Policies Scenario electricity projections.

Given the uncertainty with removal technologies, especially at large scales, and the fact that large scale removals would affect the projections, the Evolving Policies Scenario as described in this section should not be considered a net-zero pathway.

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36 IPCC AR5 – Assessing Transformation Pathways.

37 IPCC AR5 – Assessing Transformation Pathways.

38 IPCC AR5 – Agriculture, Forestry and Other Land Use.

39 IPCC AR5 – Agriculture, Forestry and Other Land Use.

40 For a review of BECCS and direct air capture research, see section 6.9 of IPCC AR5 - Assessing Transformation Pathways.

Towards Net-Zero

Electricity Scenarios

A key objective of the 2015 Paris Agreement is to hold the increase in the global average temperature to well below 2 degrees Celsius and pursuing efforts to limit the temperature increase to 1.5 degrees above pre-industrial levels. Scientific assessments have shown that limiting the temperature increase at those levels requires deep GHG emission reductions, with a key milestone being achieving net-zero emissions or carbon neutrality by 2050.[41] As of August 2021, about 130 countries, including Canada, have set or are considering net-zero by 2050 emissions targets.[42] Canada has set targets to reduce the country's GHG emissions by 40-45% below 2005 levels by 2030 and to achieve net-zero GHG emissions by 2050.

Over 82% of Canada's GHG emissions are from energy producing and consuming processes. To achieve net-zero emissions by 2050, transformational changes are required to the way Canadians produce and consume energy. The pathway to achieving net-zero will likely require a greater level of change than we model in EF2021 or previous reports in the *Canada's Energy Future* series.

In this section, we introduce six new scenarios that explore net-zero pathways for Canada's electricity sector. This analysis is an important step in modeling related to a net-zero energy system in *Canada's Energy Future* series.

[41] For example, the IPCC Special Report on Global Warming of 1.5 °C (SR15) finds that limiting global warming to 1.5°C would reducing anthropogenic emissions of CO_2 by about 45 percent from 2010 levels by 2030, reaching 'net zero' around 2050.

[42] Based on data reported by the Energy and Climate Intelligence Unit.

Why the Electricity Sector?

In this analysis, we focus on the electricity sector, recognizing the pivotal role of electricity in the pathway to net-zero. Many climate modeling and energy system assessment studies have shown that an electricity sector with net-zero or net-negative emissions, and an increasing share of electricity in the end-use fuel mix, is a cornerstone of an energy system in a carbon neutral world. For example, the *IPCC Special Report on Global Warming of 1.5 °C* shows that pathways that would limit global warming below 1.5 °C include a rapid decline in the carbon intensity of electricity and an increase in electrification of energy end-use.

There are some unique aspects of electricity that make it an important part of most deep decarbonization pathways. Mature and commercially ready technologies exist for decarbonizing electricity. The costs of many low or zero GHG emission generation technologies have declined over the past decade, making them attractive for electric utility investors. Electricity is also a highly versatile form of energy. Converting electricity into end-use energy services can be done at high efficiencies and without any emissions at the point of consumption.

One major challenge for economy-wide deep decarbonization is the distributed nature of GHG emissions. For example, millions of vehicles emit GHGs when fossil fuels are combusted to move the vehicles around. Similarly, millions of buildings combust fossil fuels for space heating, emitting a significant amount of GHGs. When energy end-uses are electrified, no GHGs are emitted at the point of consumption. When energy end-uses are electrified in a decarbonized electricity sector (i.e. where the electricity is generated with low or zero GHG emissions), economy-wide deeper GHG reductions can be component of climate action.

In pursuit of net-zero emissions, the electricity sector in Canada has an early advantage. About 82% of Canada's electricity already comes from non-GHG emitting sources such as hydro, nuclear power, wind, and solar. This share has been growing, and emissions associated with the remaining generation have declined significantly over the past two decades. The GHG emissions intensity of Canada's electricity generation has declined by 45% from 220 grams CO_2 equivalent (gCO_2e)/kWh in 2005 to 120 gCO_2e/kWh in 2019.[43]

The critical role of Canada's electricity sector in achieving net-zero emissions has received the attention of policy makers across Canadian jurisdictions. As outlined in the Policy Appendix, many programs and policies have been implemented by the federal, provincial, and territorial governments of Canada to reduce GHG emissions from the electricity sector and to promote electrification of end-use energy. For example, Canada's strengthened climate plan, A Healthy Environment and a Healthy Economy, commits about $4 billion of investment to expand the supply of cleaner electricity, modernize Canada's electricity systems, and make electrification of energy end-uses affordable.

[43] Obtained from National Inventory Report 1990 – 2019: Greenhouse Gas Sources and Sinks in Canada.

What is "Net-Zero"?

"Net-zero" GHG emissions refers to the concept of balancing human-caused GHG emissions with removals from the atmosphere. This includes non-energy emissions from land use, agriculture, and industrial production, in addition to emissions from the energy system. Reaching net-zero emissions does not necessarily require eliminating all emissions everywhere. Instead, residual emissions can be balanced by enhancing biological sinks and using negative emission technologies. What the exact balance might be between removing and emitting GHGs into the atmosphere is uncertain. However, it is clear that Canada's likelihood of achieving our net-zero target increases as our energy system emissions fall.

See the Towards Net-Zero section in our Energy Futures 2020 report for a discussion of what "Net-Zero" means, and what achieving net-zero GHG emissions could mean for Canada's energy system.

Methods and Assumptions

The basis for our modelling of Canada's electricity sector in a net-zero world begins with the electricity production and consumption results of the Evolving Policies Scenario. We build on those results in three main ways:

1. We dive deeper into the electric power sector by applying an electric power system planning and operations simulation model. It selects and operates the optimal set of power generation technologies that minimize the total cost while satisfying future power demand.
2. For each province, we assume a specific higher electricity demand level than the Evolving Policies Scenario to capture an increased level of energy end-use electrification consistent with expectations of a net-zero future.
3. We assume more stringent climate action in the form of a higher carbon price than the Evolving Policies Scenario. The expected result is that a sufficiently high carbon price will drive the electricity sector towards net-zero emissions.

Given the uncertainty around the costs and viability of different low-carbon technologies, there are many potential pathways to achieve a net-zero electricity system. For this reason, the analysis is developed around six scenarios that explore some of the key uncertainties. Across scenarios we change key inputs such as demand, carbon prices, and technology availability. The main scenario we developed for this part of the analysis is called Net Zero Electricity (NZE) Base scenario. The premise and main characteristics of the NZE Base and other alternative scenarios are presented in Table NZ.1.

Table NZ.1:

Premise and Characterizing Features of Net-Zero Electricity Scenarios

Scenario	Scenario Rationale	Allowable Capacity Expansions	Other Features
NZE Base	Continually increasing Canadian climate policies may lead to a higher carbon price and a higher level of end-use energy demand electrification than the assumptions made in the Evolving Policies scenario.	Generation technologies: natural gas fired combined cycle, natural gas fired simple cycle, and natural gas fired combined cycle with CCS* units, wind, solar, hydro, conventional nuclear, and SMR. Electricity storage. Inter-provincial transmission.	Electricity demand is 10-30% higher than the Evolving Policies Scenario, depending on the province. Carbon pricing is higher than the Evolving Policies Scenario, reaching $2020 300/tonnes CO_2 by 2050.
Higher Carbon Price	It is plausible that more aggressive climate action is needed to drive the energy systems towards net-zero, leading to a higher carbon price than the value assumed in the NZE Base scenario.	Same as NZE Base.	Same electricity demand as Base. **Carbon pricing reaches $2020 800/t$CO_2$ by 2050.**
Higher Demand	A higher level of electrification is possible due to uncertainty around specific climate action and technology development.	Same as NZE Base.	**Electricity demand is 15-45% higher than the Evolving Policies Scenario, depending on the province.** Same carbon pricing as NZE Base.
Limited Transmission	Interprovincial transmission expansion is costly, and the timing of investments is uncertain. Therefore, new interprovincial transmission development may not be feasible.	Same as NZE Base, but **no new inter-provincial transmission is allowed.**	Same electricity demand and carbon pricing as NZE Base.
Hydrogen	There is a high level of interest in hydrogen as a technology path to decarbonize the economy. Accordingly, there is the possibility of low-cost low/zero carbon hydrogen being available for electricity generation.	All NZE Base options and **hydrogen fired generation technologies.**	Same electricity demand and carbon pricing as NZE Base.
BECCS	Negative emissions technologies feature prominently in previous net-zero scenarios. Within that scope, biomass-fired electricity generation with CCS is attractive as it simultaneously produces electricity and removes carbon dioxide from the atmosphere. Therefore, it is plausible that biomass-fired electricity generation with CCS is available in the near future.	All NZE Base options and **biomass CCS* generation technology.**	Same electricity demand and carbon pricing as NZE Base.

* CCS technologies including natural gas with CCS and BECCS are only allowed to be built in Alberta and Saskatchewan due to the greater availability of proven geological potential to store CO_2 and availability of active CCS projects in these provinces.

A core set of assumptions including technology costs, fuel prices, and hourly demand profile shapes were held constant across scenarios. Assumed capital costs of generation and storage technologies are listed in Table NZ.2.

Table NZ.2:
Assumed Technology Capital Costs ($2020 CDN/kW) by Investment Year

Technology	Aggregated Group	Capital Cost in Investment Year		
		2030	2040	2050
Natural Gas Simple Cycle	Natural Gas	950	950	950
Natural Gas Combined Cycle	Natural Gas	1 300	1 300	1 300
Natural Gas Combined Cycle with CCS	Natural Gas CCS	3 000	2 500	2 000
Solar	Solar	972	604	376
Wind	Wind	1 115	868	676
Hydropower	Hydro	4 000	4 000	4 000
Nuclear	Nuclear	7 000	7 000	7 000
Small Modular Reactor	Nuclear	7 000	6 000	5 000
Hydrogen Simple Cycle	Hydrogen	1 625	1 560	1 430
Hydrogen Combined Cycle	Hydrogen	1 813	1 813	1 813
Biomass with CCS	Biomass CCS	4 752	4 512	4 299
Battery Electricity Storage (4 h storage duration)	Storage	425	275	190

Notes
Where applicable, capital cost reduction due to technology development and learning is considered.
In results figures, some generation technologies are aggregated into a group as indicated in the column "Aggregated Group."

Other simplifying assumptions in the net zero electricity analysis:

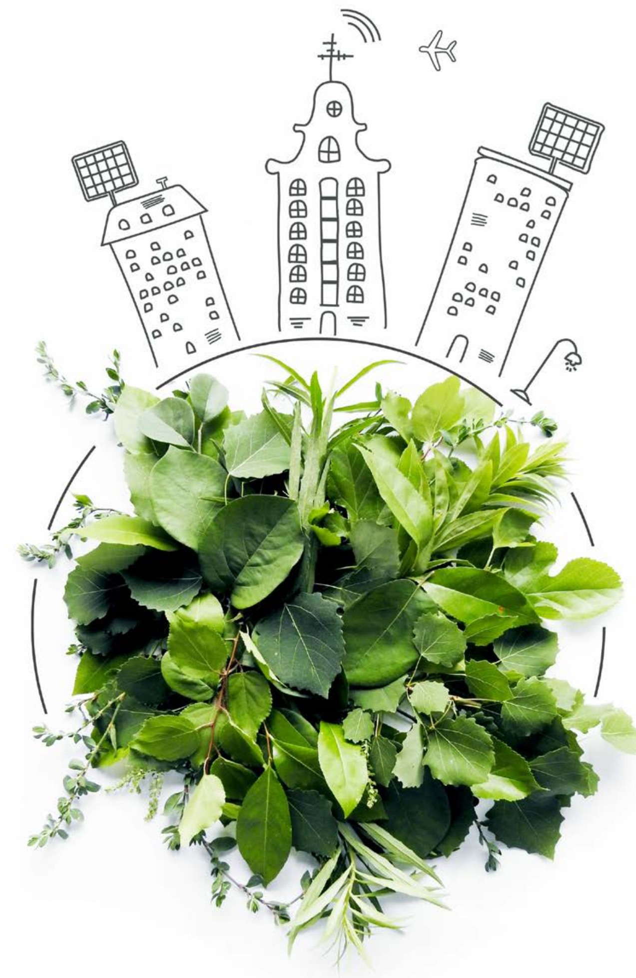
- The analysis is limited to the ten provinces. Electricity systems of the three territories are excluded from the analysis.
- A few other low carbon generation technologies that have attracted recent interest, including geothermal, tidal, conventional biomass, and offshore wind are excluded.
- Electricity storage is limited to battery electric storage with four-hour storage capacity.
- Demand-side management and distributed electricity resources are excluded.
- Only grid-connected generation is modelled.
- Electricity trade with the U.S. is not modelled.

This analysis is based on the hourly electricity module of the Energy Futures Modeling System (see Appendix 2). It optimizes the capacity investments and operations of the provincial electricity systems at one-hour intervals. Interprovincial electricity trade is also modelled. The main objective of the model is to construct and operate an optimal generating unit fleet that would minimize the total cost of satisfying electricity demand in Canada under the particular scenario assumptions. We complete this analysis for the period 2030-2050. Here we present the results for 2030 and 2050, the two years for which Canada has set major emission reduction targets.

Approach to Electricity Sector Emissions in this Net Zero Electricity Analysis

The net-zero electricity scenarios described in this section are intended to explore how Canada's electricity system might evolve in the broader context of Canada moving towards net-zero for the entire energy system. In an economy-wide net-zero transition, it is possible that some specific sectors could continue to emit GHGs, which would have to be offset by emission removals in other sectors at a given price.

Therefore, in our analysis, we do not force the electricity sector to be purely non-emitting in any year. Rather, we use the assumed carbon price, which serves as a proxy for the cost of carbon removal, as well as potential technology options to determine the ultimate carbon emissions of the sector. Our emission intensity results show that if bioenergy with CCS is available, the electricity sector could be negative emitting. Other scenarios show a dramatic reduction in grid emission intensity compared to current levels, but achieving net-zero could require moderate levels of offsets from carbon removal options such as nature-based solutions or direct air capture.



Results

NZE Base Scenario Electricity Supply

We first discuss the results for the NZE Base scenario and visit the other scenario results later in the section. Figure NZ.1 shows the installed electricity generation capacity mix in Canada by technology in the NZE Base scenario.

In the NZE Base scenario, non-emitting generation technologies (i.e., hydro, nuclear, solar, and wind) and electricity storage account for 80% of the installed generation capacity in 2030. By 2050, that share increases to 89%. Additionally, low-emitting natural gas CCS units are built in Alberta and Saskatchewan. Our results see an addition of about 5.6 GW of natural gas CCS units by 2050. Natural gas CCS account for about 2% of all provincial capacity and 8% of capacity in Alberta and Saskatchewan.

At a combined capacity of 134 GW, which is about 41% of the installed capacity, solar and wind dominate the electricity generation fleet in 2050. Wind capacity doubles from 2019 levels by 2030, and is five times greater by 2050. Solar capacity is twenty times larger compared to 2019 levels by 2050. Electricity storage is installed to facilitate the operations of variable renewables and support grid operations. At an average annual growth rate of about 1.7 GW/year, storage sees a rapid growth throughout the analysis period. From 2019 capacity of about 0.01 GW, storage capacity reaches 52 GW by 2050.

New hydropower capacity additions are relatively small and only see a cumulative new capacity addition of about 4.2 GW in the period 2030 to 2050, a 5% increase from 2019. Similarly, the growth of nuclear power is also comparatively small. All new nuclear additions are through small modular reactor (SMR) technology. About 6.6 GW of SMR units are added by 2050. Based on our cost assumptions, no new nuclear capacity is added until 2040. In combination, hydropower and nuclear represent 5% of new capacity additions. Despite the lower share of new capacity additions, as discussed later in this section, hydropower and nuclear power play an important role in supporting Canada's electricity supply on the path towards net-zero.

Fossil fuel-based technologies, mainly natural gas units, represent approximately 20% of total generating capacity in 2030 and decline to 11% by 2050. Natural gas unit additions are dominated by simple cycle gas turbines and primarily provide grid balancing.

Figure NZ.2 shows electricity generation by technology in the NZE Base scenario. In general, the electricity system must constantly balance electricity generation with electricity use. Electricity use varies with minute-to-minute changes in demand by homes, businesses, and industry. Electricity generation then must vary to match this demand. Some generation types are flexible and can be altered by system operators to meet demand. Other resources are less flexible, and others, such as wind and solar, are not flexible and instead vary based on wind or sunlight availability. Our model takes these factors into account and chooses the optimal generation mix based on level of demand, relative costs, and resource constraints.

Figure NZ.1

Installed Electricity Generation Capacity in Canada in the NZE Base Scenario

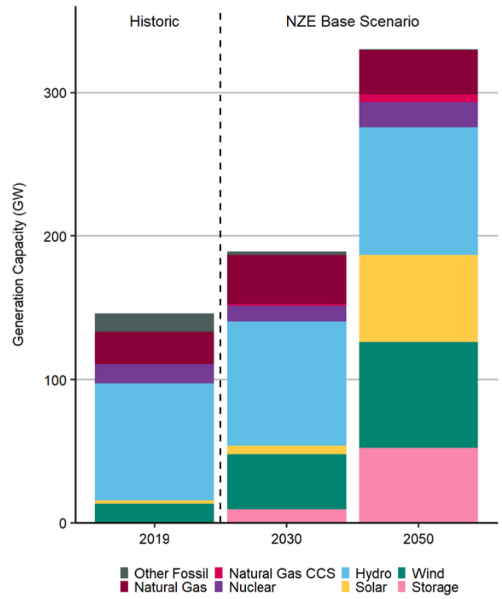


Figure NZ.2

Electricity Generation in Canada by Technology in the NZE Base Scenario

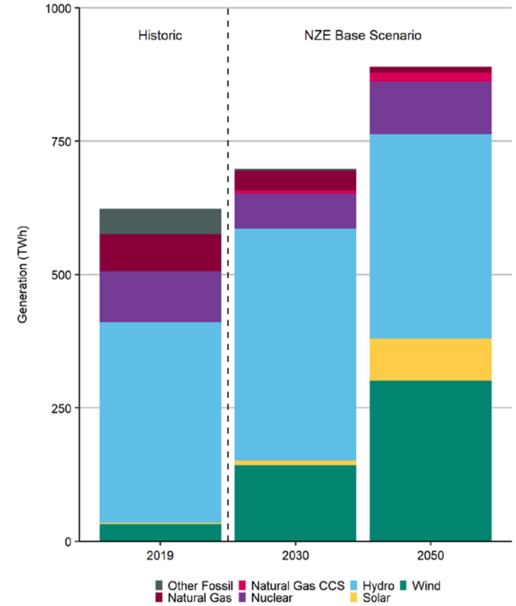


Figure NZ.2 Notes: Since storage is not a primary generator of the electricity it stores and ultimately dispatches, it is not included in this figure. By 2050, storage is primarily used to store electricity produced by wind and solar in low demand periods, for use in high demand periods. About 7.5% of the electricity produced in 2050 by solar and wind is first stored in storage units and later delivered to the consumers.

KEY TRENDS:

Electricity Supply in the NZE Base Scenario

- Wind and solar dominate new capacity additions. These two technologies account for 59% of new capacity additions through 2050.
- Electricity storage sees a rapid growth and reaches 15% of total installed capacity in 2050.
- New demand growth is primarily satisfied by wind and solar with other low carbon technologies such as SMR, hydropower, and natural gas CCS providing supplemental energy.
- All new nuclear additions are SMR units, which begin to make inroads after 2040.
- Natural gas CCS plays an important role but is restricted to the provinces with greater carbon storage potential.
- Almost all conventional fossil fuel-fired electricity supply comes from natural gas simple cycle units.
- The importance of hydropower remains high. However, there are not major hydropower capacity additions due to relatively high assumed capital costs.

In the NZE Base Scenario, non-emitting generation (e.g., hydro, nuclear, solar, and wind) produces 93% of electricity in 2030, and 97% in 2050. Overall, by 2030, 94% of electricity is generated by low- and non-emitting technologies (renewables, nuclear, and CCS-enabled fossil fuel), rising to 99% in 2050. Hydropower and nuclear power provide the largest share of the electricity supply in both periods. However, the amount of electricity provided by those two technologies remains relatively unchanged from 2019 levels, at roughly 50 TWh throughout the projection period. New demand growth is primarily satisfied by wind and solar, with electricity storage systems and to a lesser degree, simple cycle gas turbines, ensuring system reliability.

The current share of fossil fuel-based electricity generation is 19%, and this decreases over the projection period. By 2050, the total share of electricity produced by natural gas-fired generation reaches 3% of the total electricity supply. About two-thirds of that comes from natural gas units equipped with CCS technology. The remainder consists of natural gas simple cycle units that provide some grid balancing services to maintain system reliability.

Storage systems do not produce electricity but rather store electricity produced by other generating units for later delivery to consumers. This is a critical service needed to operate electricity systems with larger shares of variable generating sources such as solar and wind. Our results show that storage is primarily used to move electricity produced by wind and solar in low demand periods to high demand periods. We find that about 7.5% of the electricity produced by solar and wind is first stored in storage units and later delivered to the consumers.

Canada has a diverse energy system. Figure NZ.3 shows the generation mix for each province in the NZE Base scenario. We find that electricity generation in B.C., Manitoba, Quebec, and Newfoundland and Labrador continues to see the supply dominated by hydropower. In the three former provinces, however, new demand is satisfied by wind and solar. Nuclear power[44] is limited to Ontario and New Brunswick and represents about 41% and 24%, respectively of the provincial electricity supply in 2050.

[44] Nuclear power includes the electricity produced by both legacy units and new SMR units.

Natural gas-fired electricity generation remains a relatively important share, about 12% and 15%, respectively of the electricity supply of Alberta and Saskatchewan in the NZE Base scenario in 2050. However, by 2050, about 80% of the natural gas-fired generation in these two provinces is from natural gas CCS units.

In the NZE Base scenario, inter-provincial electricity transmission capacity expansions increase, mostly among the four western provinces. The combined electricity transfer capacity of the three western inter-provincial electricity corridors (i.e., B.C.–Alberta, Alberta–Saskatchewan, Saskatchewan–Manitoba) almost triples in the NZE Base scenario. Outside of the western region, only the New Brunswick–Prince Edward Island inter-provincial corridor sees transmission expansion at about 30% growth compared to current levels.[45]

[45] Other assessments have suggested that inter-provincial transmission expansion among eastern Canadian provinces, particularly among the Atlantic provinces, would facilitate the electricity system decarbonization efforts. Our analysis does not capture that under the assumptions we make, with a potential factor being our simplifying exclusion of electricity trade with the U.S.

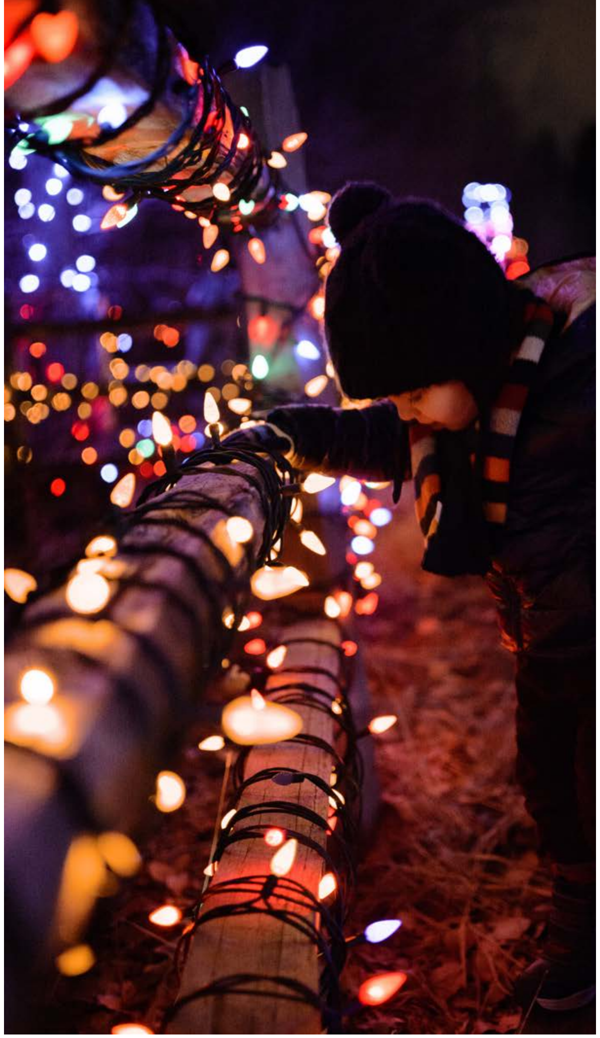
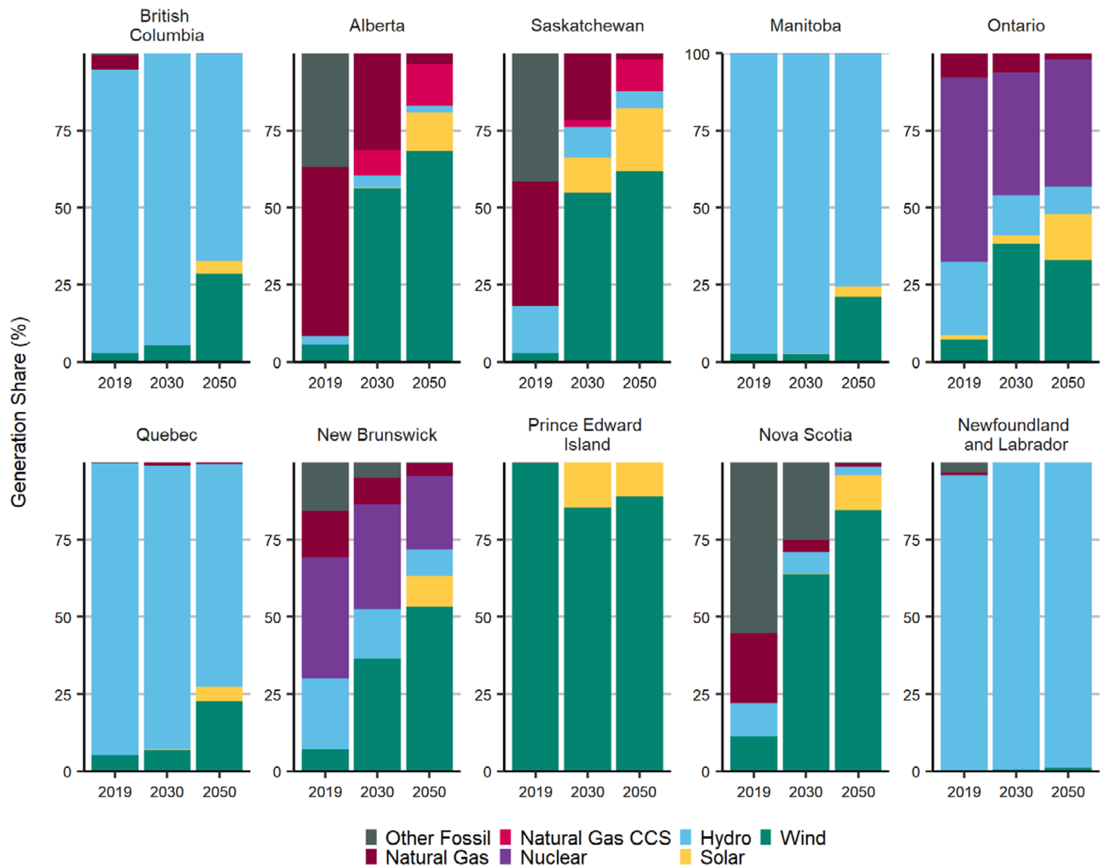


Figure NZ.3

Share of Electricity Generation by Technology in Canadian Provinces in the NZE Base Scenario



As noted above, in the NZE Base scenario the share of electricity supplied by technologies with zero carbon intensities increases to about 97%, while another 2% is from low-emission natural gas CCS units. This is driven by two main factors. First, the capital cost of wind, solar, and electricity storage declines significantly in this scenario, thereby reducing their average cost of production. Second, the increasing carbon price leads to higher generation costs for fossil fuel-fired generating units, making them less competitive against other options.

Similar results were observed in other scenarios, but some noteworthy observations are discussed below.

Electricity Supply in Alternative Scenarios

In this section, we compare the results in other electricity scenarios with the NZE Base scenario. All alternative scenarios see a nearly identical level of inter-provincial transmission expansion as the NZE Base scenario. The exception is the Limited Transmission scenario, where no additional transmission expansions are allowed. Furthermore, similar to the NZE Base scenario, most of the new demand is satisfied by wind and solar, while high GHG emission generation technologies see rapid decline.

Figure NZ.4 shows installed capacity by technology in different scenarios. Figure NZ.5 shows the cumulative new capacity additions by technology type by 2050 in different scenarios. Figure NZ.6 shows the amount of electricity generation.

Figure NZ.4:
Installed Capacity by Technology in Different Scenarios

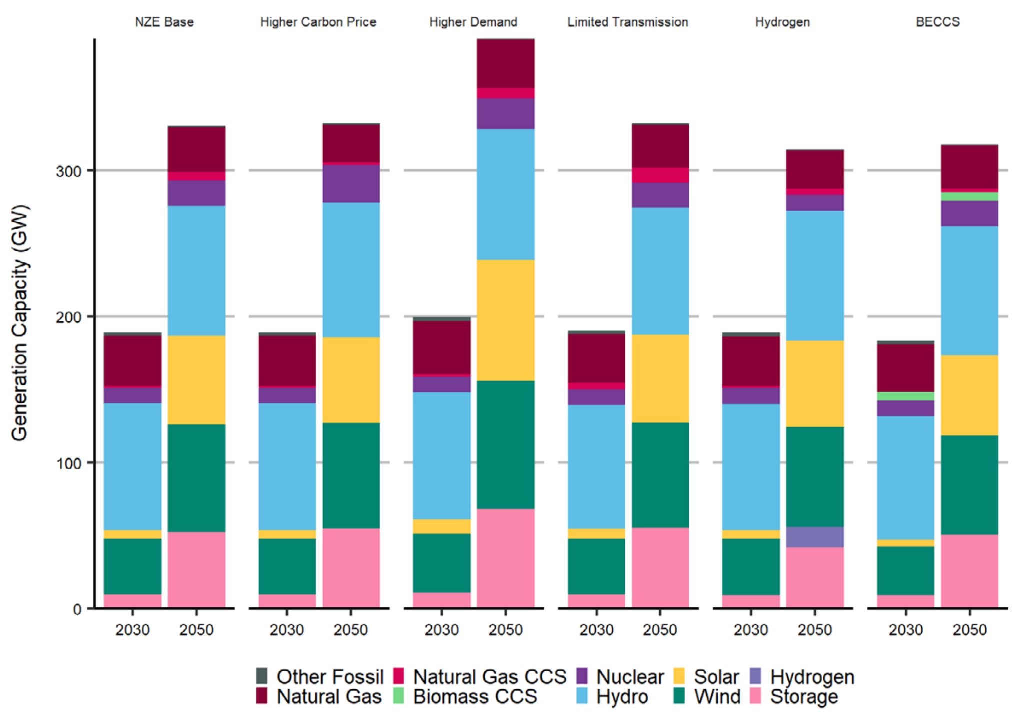


Figure NZ.5:
Cumulative New Capacity Additions by 2050 in Different Scenarios

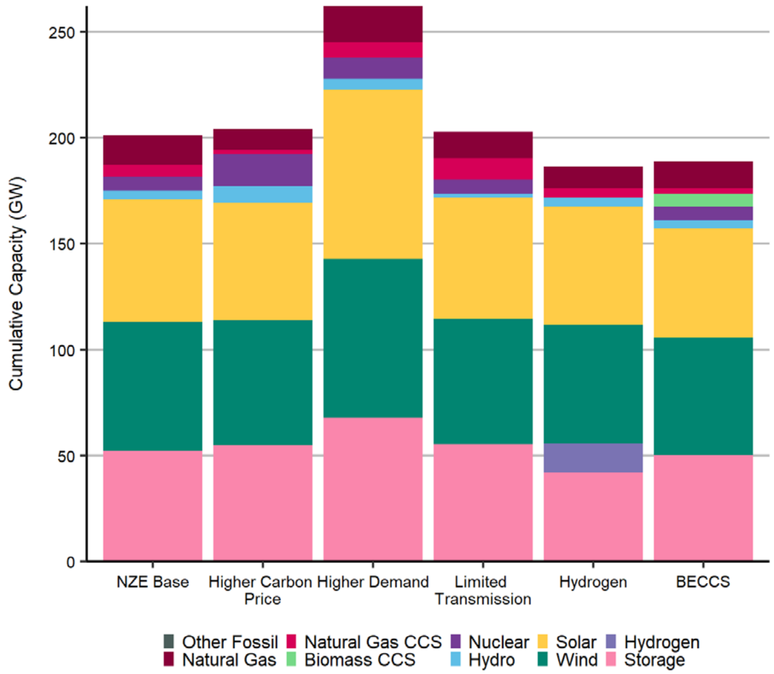
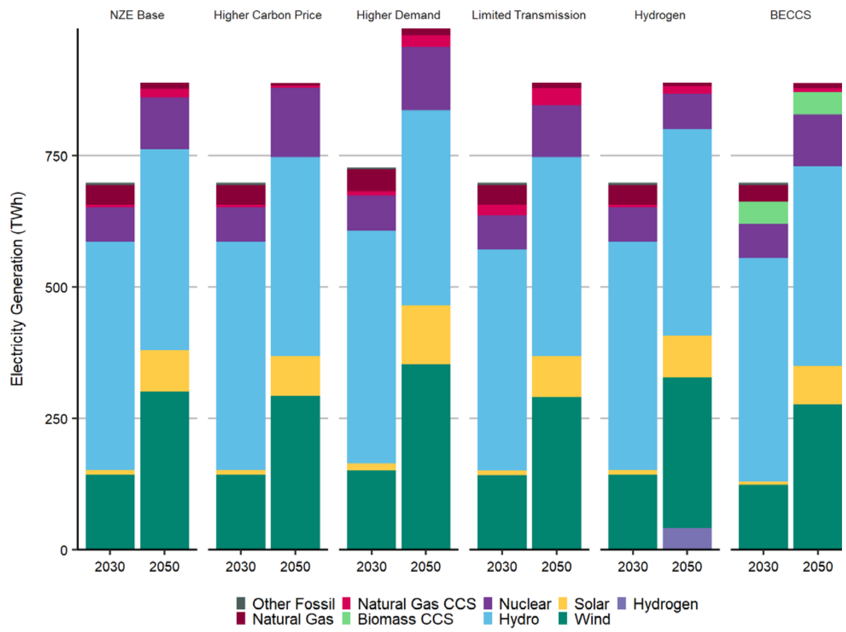


Figure NZ.6:
Electricity Generation by Technology in Different Scenarios



KEY TRENDS:

Electricity Supply in Alternative Net Zero Electricity Scenarios

- The Higher Carbon Price scenario increases nuclear and hydro but reduces natural gas generation, relative to the NZE Base scenario.
- The Limited Transmission scenario increases natural gas CCS generation in Alberta and Saskatchewan, relative to the NZE Base scenario.
- The BECCS scenario provides a technology pathway for economy wide GHG emissions reductions.
- Increased demand in the Higher Demand Scenario is mainly satisfied by solar, wind, and nuclear power.
- The Hydrogen scenario reduces the capacity and generation levels of all other low/zero-carbon emissions technologies except those of hydropower, relative to the NZE Base scenario.

Higher Carbon Price Scenario

In the Higher Carbon Price scenario, we see reductions in capacity and electricity generation by natural gas units in 2050 compared to the NZE Base scenario. Cumulative new natural gas capacity additions are 30% lower than NZE Base by 2050. Compared to NZE Base, natural gas-fired generation is 60% lower in 2050. Natural gas CCS is also impacted by the higher carbon price. Our assumption is that any residual CO_2 emissions that are not captured by the CCS process (10% of the combustion emissions) will see the full carbon price. Even though the carbon price only applies to this 10%, the higher carbon price increases the average cost of electricity produced by natural gas CCS by about 50% relative to the NZE Base scenario. That makes natural gas CCS less competitive. Compared to NZE Base, natural gas CCS cumulative capacity additions are 60% lower and electricity generation is 70% lower. The reductions in natural gas-fired generation capacity is offset by an increase in hydropower and nuclear SMR. Hydropower and SMR see a doubling of cumulative new capacity additions compared to the NZE Base scenario. Furthermore, this is the only scenario where we observe the addition of SMR units outside of Ontario and New Brunswick, with Alberta, Saskatchewan, and Nova Scotia seeing SMR additions.

Higher Demand Scenario

The Higher Demand scenario assumes a higher level of electrification and therefore about 12% higher electricity demand overall, or about 104 TWh in 2050. In 2050, the higher electricity demand in this scenario is satisfied by increased solar (+ 33 TWh), wind (+51 TWh), nuclear (+23 TWh), and natural gas CCS (+5 TWh) generation compared to NZE Base. Compared to the NZE Base scenario, those four technologies see a supply increase of 42%, 17%, 23%, and 31%, respectively. The installed storage capacity is 30% or about 16GW higher than NZE Base. The level of hydropower generation remains relatively unchanged.

Limited Transmission Scenario

The Limited Transmission scenario only sees notable changes in the four western provinces. In the NZE Base scenario the hydropower resources in B.C. and Manitoba partially provide system flexibility to manage variable wind and solar power supply in Alberta and Saskatchewan. This process is facilitated by the addition of new transmission capacity. The Limited Transmission scenario inhibits new transmission capacity additions and consequently the combined wind and solar power generation declines by about 5% relative to NZE Base. This reduction in generation is filled by a higher level of natural gas CCS units in Alberta and Saskatchewan. Compared to NZE Base, the Limited Transmission scenario sees a doubling of natural gas CCS capacity and generation.

Hydrogen Scenario

In many net-zero scenarios in previous studies,[46] low-carbon hydrogen plays an important role in many sectors, and hydrogen production increases. Our Hydrogen scenario assumes the existence of a relatively mature market for hydrogen in Canada, where hydrogen costs through electrolysis and natural gas with CCS have fallen significantly and supplies of low-carbon hydrogen are accessible for electricity producers. This supply of hydrogen is assumed to be exogenous to the producers, that is, they do not have to produce the hydrogen themselves, but purchase hydrogen at a delivered price, assumed to be about $2020 US$1.00/kg by 2050. We assume two hydrogen-fired generation technologies, hydrogen combined cycle and hydrogen simple cycle. In this scenario, we observe a cumulative hydrogen-fired generation capacity addition of 13 GW. Hydrogen technologies impact other technologies in a complex manner.

Under the assumed conditions, hydrogen technologies have lower overall economic costs compared to all natural gas technologies. Consequently, we see a 25% reduction in 2050 of non-CCS natural gas capacity (i.e., combined cycle and simple cycle) compared to NZE Base. Furthermore, the GHG emissions intensity of hydrogen combined cycle technology is lower than natural gas CCS. Therefore, natural gas CCS sees a 20% capacity reduction in 2050 compared to NZE Base.

[46] For example, the IEA's Net Zero by 2050 report projects the hydrogen-based fuel in the global energy mix to grow from about 90 Mt in 2020 to 530 MT in 2050. According to the IEA about 100 MT of hydrogen will be used to produce electricity in 2050, where currently the contribution of hydrogen for electricity generation is negligible.

The Hydrogen scenario also sees a 10% reduction in wind and solar capacity relative to NZE Base in 2050. The overall economics of the use of hydrogen for electricity supply is more favorable than building wind, solar and the additional flexible capacity they necessitate to balance supply and demand. Similarly, hydrogen technologies are more competitive than nuclear under the assumed conditions in most of the analysis period. Therefore, no new nuclear growth is seen in this scenario. Hydropower capacity remains unchanged compared to NZE Base.

Finally, hydrogen units also displace 32% of the storage capacity in 2050 compared to NZE Base as hydrogen-fired generating technologies can partially satisfy the overall electric power system's flexible capacity requirements.

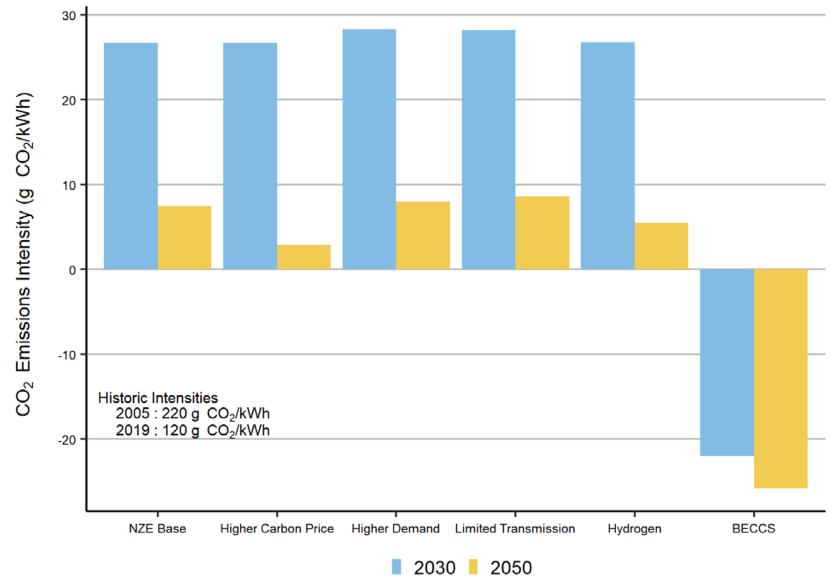
BECCS Scenario

The BECCS scenario assumes the availability of biomass CCS units for electricity generation in Alberta and Saskatchewan. Biomass CCS is considered to have negative GHG emissions, and we assume that the technology would get credit for carbon removal from the atmosphere. The credit is assumed to be calculated using the full carbon price. As the carbon price increases, biomass CCS units become a negative cost generation option, where its average cost of electricity in 2050 is -$85/MWh. Therefore, biomass CCS partially displaces all other generation technologies in Alberta and Saskatchewan. Relative to NZE Base, we estimate the resulting reduction in natural gas CCS generation in 2050 to be 56% and that of combined wind and solar to be about 15%.

The cumulative biomass CCS capacity addition by 2050 is 6 GW. Due to the limitations in available biomass resources, we assume this is the maximum possible biomass CCS capacity. At higher carbon prices, it may be economically competitive to import biomass for electricity production from other regions into Alberta and Saskatchewan, where CCS is viable. However, further analysis is required to verify this assumption.

Due to the carbon removal capability of biomass CCS, the electricity system in Canada becomes a net negative emissions economic sector in the BECCS scenario.

Figure NZ.7:
GHG Emissions Intensity of the Electricity Sector in Canada in Different Scenarios



GHG Emissions Intensity of Electricity Sector in Canada

Figure NZ.7 shows the GHG emissions intensity of the electricity sector in Canada in 2030 and 2050 in all scenarios we considered, compared to 2005 and 2019 levels.

In all scenarios, except the BECCS scenario, the GHG emissions intensity of Canada's electricity sector reaches about 27 grams of carbon dioxide equivalent per kilowatt-hour (gCO_2/kWh) in 2030. The value is 78% lower than the electricity sector emissions intensity in 2019. The emissions intensity further reduces in 2050 but varies across scenarios. The NZE Base scenario emissions intensity in 2050 is 8gCO_2/kWh, a 93% reduction compared to the emissions intensity in 2005. The Higher Carbon Price scenario sees the 2050 emissions intensity declining to 3gCO_2/kWh. While significant emissions reductions are achieved, none of the scenarios, except BECCS, see the overall electricity sector reaching net-zero.

Almost all of the remaining emissions come from natural gas-fired conventional units, which generate electricity infrequently, and uncaptured emissions from natural gas CCS units. Blending renewable natural gas with natural gas could potentially further reduce the small amount of remaining emissions in the sector, or provide a pathway for negative emissions if coupled with CCS. However, we have not assessed the potential of renewable natural gas to decarbonize Canada's electricity sector in this analysis.

The BECCS scenario sees the emissions intensity of the electricity sector going net negative, through carbon removal by the biomass CCS units. This would provide some emissions allowances for other economic sectors in Canada's path towards a net-zero future.

The electricity sector could play an important role in achieving deeper emissions reductions in Canada's energy system, both by reducing emissions from generating electricity and by reducing emissions in other sectors by electrification. Our analysis shows that there are many technological pathways to achieve significant emission reductions in the electricity sector. The majority of technologies required are available today, and Canadian electric utilities have experience in building and operating them. In Canada's pathway towards a net-zero future, the country's electricity sector will have multiple roles, including the supply of energy and potentially carbon removal through investing in negative emissions technologies.

KEY UNCERTAINTIES:
Net-Zero Electricity Results

Economics: The results and trends presented in this section are driven by the economic assumptions made on capital and operating costs of generating technologies, storage, and transmission lines. Any changes to our assumptions, particularly the ones made for variable renewables and storage, could potentially alter the results.

Policy Assumptions: The analysis makes hypothetical carbon pricing assumptions. The level of stringency and mechanisms of the carbon pricing system could potentially change the results.

Transmission System Representation: The current analysis does not model intra-provincial transmission systems. A need for significant increases in intra-provincial transmission in a given scenario can vary the results.

Demand profile: The demand profiles (i.e., how electricity demand changes over different time periods) used are constructed using historic observations. Changes to end-use energy demand, particularly under higher electrification, could impact the results.

Technology Representation: The analysis models only a limited number of generation technologies. Several other zero/low emissions technologies as well as grid management options such as demand side management exist. The inclusion of them could potentially change the comparative results.

Access and Explore Energy Futures Data

Datasets related to EF2021:

- **Figure Data:** Download the EF2021 figure data [EXCEL 365 KB]
- **Data Appendix:** The Energy Futures Data Appendix has customizable, downloadable tables arranged by variable (macroeconomic drivers, end-use demand, crude oil production, etc.) and publication year.
- **Machine Readable Files:** Looking to download all of the EF2021 data at once? It is available on Open Government.

Energy Futures Fact Sheets

- Deep dive into the projections with more detailed datasets, including monthly projections for:

  EF2021 Overview | Electricity | Energy Demand | Conventional Oil | Natural Gas | Natural Gas Liquids | Oil Sands

Explore Energy Futures – Interactive Data Visualization

Explore Canada's Energy Future with an interactive tool that allows users to visualize, download, and share the data behind long-term energy outlooks.

Student Resources

In partnership with Ingenium, the CER developed educational activities based on Canada's forecasted energy demand and supply.

Targeted at students between the grades of 9 and 11, the activities encourage students and educators to explore Canada's energy ecosystem using an interactive tool. This tool allows users explore how the future of energy in Canada over the long term. The material and student resources are available here.

Data Science with Open Data

Partnered with Fireside Analytics, this course is an introduction to Data Science with Open Data sets and R Studio. Learners will learn common buzzwords used in Data Science and will do hands-on labs visualizing and analyzing Open Data from the Canada's Energy Future series. This course is designed for learners who are new to computer programming and data science.

About the Canada Energy Regulator

The Canada Energy Regulator (CER) works to keep energy moving safely across the country. We review energy development projects and share energy information. We enforce some of the strictest safety and environmental standards in the world in a manner that respects the Government of Canada's commitments to the rights of the Indigenous peoples of Canada. The CER regulates:

- Oil & Gas Pipelines – Construction, operation, and abandonment of interprovincial and international pipelines and related tolls and tariffs.
- Electricity Transmission – Construction and operation of international power lines and designated interprovincial power lines
- Imports, Exports & Energy Markets – Imports and exports of certain energy products; monitoring aspects of energy supply, demand, production, development and trade.
- Exploration & production – Oil and gas exploration and production activities in the offshore and on frontier lands not covered by an accord.
- Offshore renewables – Offshore renewable projects and offshore power lines.

The Energy Information Program is one of four core CER responsibilities. We collect, monitor, analyze, and publish fact-based information on energy markets and supply, sources of energy, and the safety and security of pipelines and international power lines. Using tools like interactive pipeline maps and visualizations, we make complex pipeline and energy market data user-friendly and accessible.

Our Commitment:

- Canadians have access to and use energy information for knowledge, research, and decision making.
- Canadians have access to community specific information about CER-regulated pipelines, powerlines, and other energy infrastructure.
- Broader and deeper collaboration with stakeholders and partners informs our energy information.

About this Report

The CER's Energy Information core responsibility is closely linked to its mandate and responsibilities under the Canadian Energy Regulator Act (Act), which includes advising and reporting on energy matters. As well, under Part 7 of the Act, the CER regulates the export and import of natural gas and the export of natural gas liquids, crude oil and petroleum products, and electricity. The CER must ensure that, if authorized, oil and gas exports are surplus to Canadian requirements. The CER's monitoring of energy markets and assessments of Canadian energy requirements and trends helps support the discharge of its regulatory responsibilities. This report, Canada's Energy Future 2021: Energy Supply and Demand Projections to 2050, is the continuation of the Canada's Energy Future series, and projects long-term Canadian energy supply and demand trends.

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If a party wishes to rely on material from this report in any regulatory proceeding before the CER, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

Appendix 1:

Domestic Climate Policy Assumptions

This appendix reviews the domestic climate policy assumptions included in the Evolving Policies Scenario and the Current Policies Scenario. The Current Policies Scenario includes only domestic policies currently in place. The Evolving Policies Scenario assumes greater policy action over time, at roughly the same pace as recent historical policy implementation. It does this by assuming a hypothetical suite of domestic policy initiatives that build upon current policies. Some Evolving Policies Scenario policies increase the stringency or coverage of Current Policies Scenario policies. In these cases, the Evolving Policies Scenario policy in question takes over from the Current Policies Scenario policy. For example, in the Evolving Policies Scenario Canada's carbon pricing increases from the Current Policies Scenario schedule of $170/t by 2030 to $470/t by 2050.

In addition to extending Current Policies Scenario policies, the Evolving Policies Scenario also includes support for technologies that currently have limited commercial application. This means that these technologies see greater adoption through our Evolving Policies Scenario projection compared to the Current Policies Scenario, without adoption necessarily being explicitly driven by a particular policy. Examples include high-efficiency natural gas heat pumps for buildings, hydrogen fuel cells for heavy trucking and industry, utility scale battery storage, electrification and efficiency improvements in the industrial sector, and reduced emission intensity of oil and gas production.

Policy inclusion criteria for the Current Policies Scenario

The Current Policies Scenario includes energy and climate policies that were expected to be implemented in Canada at the time of analysis. To determine whether a policy was included in the analysis we applied the following criteria:

- the policy was publicly announced by 1 August 2021;
- there was sufficient information available to model the policy; and
- the policy was expected to significantly change our energy system projections.

Policy inclusion criteria for the Evolving Policies Scenario

The Evolving Policies Scenario includes all Current Policies Scenario policies. It adds to these a hypothetical suite of future policy developments, which aim to approximate "greater policy action over time, at roughly the same pace as recent historical policy implementation." Hypothetical Evolving Policies Scenario policies are designed based on the following premises:

- Announced policies that are being developed are included to the extent possible. Simplifying assumptions are made as required by a lack of regulatory detail.
- The types of hypothetical future policies that are modelled have historical precedent in those implemented by federal, provincial, or municipal governments.
- Policies gradually strengthen over time, as opposed to a concentration of policy development at a given time.

Table A1.1 provides an overview of the major policies included in the Current Policies and Evolving Policies Scenarios. All dollar values are given in nominal terms, unless otherwise stated.

Table A1.1

Overview of Domestic Climate Policies and EF2021 Assumptions[47]

Region	Policy or Strategy	Description	Assumption in EF2021 *Evolving and Current Policies scenarios unless otherwise noted*
Federal	Backstop Carbon Pricing	Applies a regulatory charge on fossil fuels at the end-use level. Industrial sectors that qualify for the Output Based Carbon Pricing System are exempt from fuel charge.	The fuel charge rises from \$30/t in 2020 to \$50/t CO_2e by 2022, then to 170\$/t by 2030. **Current Policies:** The fuel charge is constant from 2030 to 2050. **Evolving Policies:** The fuel charge increases \$15/t annually from 2030 to 2050, rising to 470\$/t by 2050.
Federal	Output Based Carbon Pricing System	A performance-based carbon pricing system for industrial facilities. Applies a regulatory charge to industrial sectors based on their emissions intensity of output.	**Current Policies:** Most industrial sectors are required to reduce their emissions intensity of output by 20% relative to their 2014 to 2016 average from 2020 to 2050. The backstop carbon price is applied to residual emissions. **Evolving Policies:** Most industrial sectors are required to reduce their emissions intensity of output by 20% relative to their 2014 to 2016 average from 2020 to 2050, which then declines by 2% annually until 2050. The backstop carbon price is applied to residual emissions.
Federal	Phase out of coal-fired generation of electricity	A carbon intensity performance standard for coal-fired power plants.	Limits emissions intensity of existing coal-fired electricity generation to 370 CO_2e/GWh by 2030. No new coal-fired power plants are built.
Federal	Methane Regulations for the Upstream Oil and Gas Sector	Oil and gas facilities are required to adopt minimum standards for methane control technologies.	A minimum methane control technology is required to take market share from 2020 to 2030.
Federal	Zero emission passenger vehicle incentives	Market shares are adjusted to account for zero-emission passenger vehicles for federal policies.	Major policies include the iZev subsidy program, funding for charging network initiatives and tax write-offs for businesses. Quebec and B.C.'s zero emission vehicle mandates are modelled separately (described below). **Evolving Policies:** Zero emissions passenger vehicle new sales reach 100% by 2035. Remote communities and the territories are assumed to be exempt. Given that a federal mandate or regulation to reach 100% ZEV sales does not currently exist, we make several simplifying assumptions: ZEVs are available to meet Canadian demands, Canadian demands for vehicle types (such as car vs trucks/SUVs) are similar to current levels, ZEV adoption accelerates as we approach 2035, and increased deployment of electric vehicle infrastructure underlies ZEV adoption.
Federal	Northern REACHE Program	Program to reduce diesel use for electricity and heat in remote communities.	Increased market share for alternative technologies.
Federal	Energy Efficiency Regulations	Minimum energy efficiency standards for energy using technologies in the residential, commercial, and industrial sectors (e.g. space conditioning equipment, water heaters, household appliances, lighting).	Includes Amendment 16 to the Energy Efficiency Regulations. Major standards include minimum fuel utilization efficiencies for natural gas furnaces, a minimum energy factor for gas water heaters and ban of incandescent light bulbs. **Evolving Policies:** Includes Amendment 17 to the Energy Efficiency Regulations. Major standards include increasing the energy efficiency performance of home appliances, in addition to commercial space conditioners.

[47] For an exhaustive review of climate measures in Canada, see Environment and Climate Change Canada's Fourth Biennial Report on Climate Change, and Canada's revised NDC

Region	Policy or Strategy	Description	Assumption in EF2021 *Evolving and Current Policies scenarios unless otherwise noted*
Federal	Light-duty vehicle GHG emissions standards	New passenger vehicles and light-commercial vehicles/light trucks sold in Canada must meet progressively more stringent GHG emission standards.	**Current Policies:** We assume the fuel economy of new passenger cars and light trucks improves by 5% annually from 2022 to 2030, driven by increasing standards which will be aligned with the U.S. Environmental Protection Agency and currently under development. From 2031 to 2050 fuel economy improves by 2% per year for both passenger cars and light trucks. **Evolving Policies:** The fuel economy of new passenger cars and light trucks improves by 5% annually from 2020 to 2050. The fuel economy of new light trucks improves by 5% per year from 2022 to 2030, and 3.5% from 2031 to 2050.
Federal	Heavy-duty vehicle GHG emissions standards	New heavy duty vehicles sold in Canada must meet progressively more stringent GHG emissions standards.	**Current Policies:** We assume the fuel economy of new heavy duty vehicles improves by 2.25% per year from 2020 to 2030, driven by more stringent standards that require improvement covering up to model year 2027. Improvement slows over the later decades to 0.5% from 2031 to 2050. **Evolving Policies:** The fuel economy of new heavy duty vehicles improves by 2.25% per year from 2020 to 2050.
Federal	Clean Fuel Standard	Reduction in carbon intensity of gasoline and diesel over time, through several mechanisms, including: supplying low-carbon fuels (e.g. ethanol), end-use fuel switching in transportation fuels (e.g. electric and hydrogen vehicles), and upstream projects (e.g. carbon capture and storage).	**Current Policies:** Carbon intensity decrease of 12gCO_2e/MJ below 2016 levels by 2030. **Evolving Policies:** Continues same rate of decrease (about 1.2g CO_2e/MJ) from 2031 to 2050. Increased renewable natural gas blending, incentivized by credit creation mechanism.
Federal	Small Modular Reactor (SMR) Action Plan	Plan for the development, demonstration, and deployment of SMRs for multiple applications.	**Evolving Policies:** Assumes SMR development in Ontario and New Brunswick.
Federal	National energy code for buildings	Sets out technical requirements for the energy efficient design and construction of new buildings.	Assumes that the 2017 building code applies throughout the projection period, with marginal efficiency improvements to building shells and space conditioning. Evolving Policies: Assumes that new buildings are "net-zero energy ready" by 2030 across provinces and territories by substantially increasing the efficiency of building shells and space conditioning technologies.
Federal	Renewable Fuels Regulations	Minimum renewable fuel content for all regions except for Newfoundland and Labrador, and the Territories.	Specifies a minimum renewable fuel content of 5% for gasoline and 2% for diesel fuel sold in Canada by volume.
British Columbia	Zero- emissions vehicle mandate and incentives	Requires automakers to sell a minimum share of zero- or low- emission vehicles in addition to government-funded purchase subsidies and charging network incentives.	Follows the zero-emission vehicles act; Achieves 10% light duty zero-emission vehicles sales by 2025, 30% by 2030, and 100% by 2040.
British Columbia	CleanBC Better Homes and Better Buildings programs	Incentives for residential and commercial building efficiency improvements.	Rebates for switching to high-efficiency space and heating equipment, and building shells. Includes $3,000 rebate for types of residential heat pumps if switching from fossil fuel heating.
British Columbia	CleanBC industrial electrification		Electrification of planned natural gas production in the Peace region. **Evolving Policies:** Increased electrification of other industrial sectors.

Region	Policy or Strategy	Description	Assumption in EF2021 *Evolving and Current Policies scenarios unless otherwise noted*
British Columbia	CleanBC Industry Fund	Government investment in greenhouse gas-reducing projects and clean technologies.	Gradual market adoption of near-commercial clean industrial technologies.
British Columbia	Clean Energy Amendment Act	Sets a minimum percentage of electricity generation that must be provided by non-fossil fuels.	100% of provincial electricity generation must be provided by renewable or "clean" sources by 2025.
British Columbia	Energy Efficiency Act	Sets energy efficiency performance standards for energy using technologies.	Minimum energy efficiencies for household appliances, heating and cooling systems, lighting, industrial equipment.
British Columbia	Renewable Fuel Regulation	A minimum renewable fuel content for gasoline and diesel fuel.	5% ethanol content in gasoline, 4% biodiesel content in diesel
British Columbia	Low Carbon Fuel Standard	Requires a decrease in average carbon intensity of transport fossil through several compliance pathways.	Decrease in average carbon intensity of transport fossil fuels by 20% in 2030 relative to 2010.
British Columbia	Renewable Natural Gas Regulation	Requires that a portion of natural gas consumption be renewable natural gas by 2030.	Requires that 15% of natural gas consumption be provided by renewable natural gas by 2030. **Evolving Policies:** Renewable natural gas consumption increases to 20% by 2050.
Alberta	Technology Innovation and Emissions Reduction (TIER) Regulation	Carbon pricing system for large industrial emitters. Emitters pay a carbon price if they fail to meet the required emissions intensity reductions, and can earn credits if they surpass their required reductions.	Oil sands producer's emissions intensity benchmarks are the maximum of facility specific benchmarks (these decline 1% annually), or TIER "high performance" benchmarks from 2020 to 2030. Benchmarks remain at 2030 levels from 2031 to 2050. Evolving: Emissions intensity benchmarks decline at 2% relative to 2020 levels from 2031 to 2050.
Alberta	Renewable Fuels Standard	Requires renewable fuels to be blended into gasoline and diesel fuel.	5% ethanol content of gasoline, 2% biodiesel content of diesel.
Alberta	Methane Emissions Reduction Regulation	Requires the reduction of methane emissions from oil and gas operations by 45% by 2025 relative to 2014 levels.	A minimum methane control technology is required to take market share from 2020 to 2030.
Saskatchewan	Boundary Dam Carbon Capture Project	This project stores and captures CO_2 emissions from a 115MW coal plant	CCS projections account for the project.
Saskatchewan	Ethanol Fuel Act and Renewable Diesel Act.	Requires renewable fuels to be blended into gasoline and diesel fuel	7.5% ethanol content of gasoline, 2% biodiesel content of diesel.

Region	Policy or Strategy	Description	Assumption in EF2021 *Evolving and Current Policies scenarios unless otherwise noted*
Saskatchewan	Methane Action Plan	Requires a reduction in methane emissions from oil and gas extraction by 40 to 45% of 2015 levels	A minimum methane control technology is required to take market share from 2020 to 2030.
Manitoba	Strengthened Biofuels Act	Requires renewable fuels to be blended into gasoline and diesel.	Minimum of 10% ethanol in gasoline, and 5% biodiesel in diesel.
Manitoba	Efficiency Manitoba Act	Provides consumers with rebates and other incentives.	Includes lighting, space conditioning, and building shell rebates across residential, commercial, and some industrial sectors.
Manitoba	Green Energy Equipment tax credit	Tax credit for residential and commercial geothermal heat pumps.	15% tax credit.
Ontario	Strengthened Greener Gasoline Regulation and Greener Diesel Regulation (O Reg 97/14)	Requires renewable fuels to be blended into gasoline and diesel.	Requires 15% ethanol blending in gasoline by 2030and 4% biodiesel blending in diesel by 2020.
Quebec	Roulez vert program	Incentives for electric vehicles and charging station installations.	Rebates include $8,000 for new vehicles and $600 for home charging stations.
Quebec	Zero-emissions vehicle standard	Requires automakers to sell a minimum share of zero- or low-emission passenger vehicles via a credit market.	Credit target increases gradually to reach 22% by 2025. **Evolving:** Credit target increases to 100% zero-emissions vehicle new sales by 2035.
Quebec	Renewable Natural Gas Mandate	Requires that a portion of natural gas consumption be renewable natural gas.	1% of total by 2020 and 5% of total by 2025. **Evolving:** Increases gradually to 20% by 2050.
Quebec	Chauffez Vert program	Rebates for residential renewable energy space or water heating systems, if replacing fossil fuel system.	$1,275 for light fuel oil system replacements, $850 for propane system replacements.
New Brunswick	Renewable Portfolio Standard	Requires a minimum share of in-province electricity sales to be generated by renewable sources by 2020.	Minimum share is set to 40%. Imports from other jurisdictions and energy efficiency improvements qualify for compliance.
New Brunswick	Energy Efficiency Programs	Provides purchase incentives for energy efficient appliances in residential, commercial, and industrial sectors	Various rebates for approved technologies

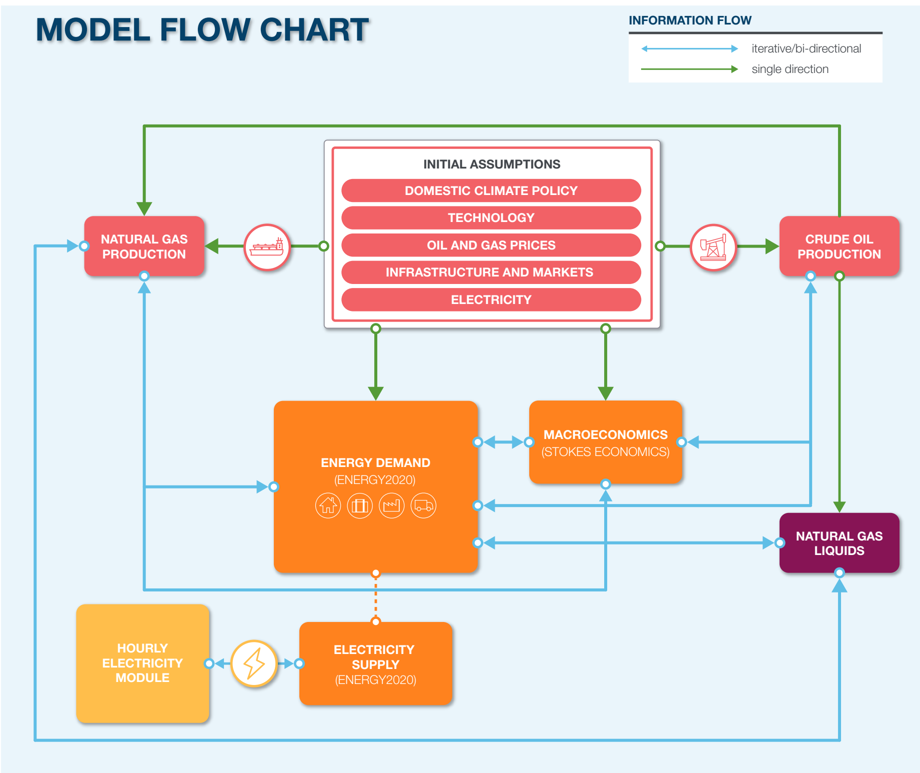
Region	Policy or Strategy	Description	Assumption in EF2021 *Evolving and Current Policies scenarios unless otherwise noted*
Nova Scotia	Electricity Generation GHG emissions cap.	Requires declining GHG emissions from in-province electricity generators.	Requires emissions from the electricity sector to decline to 4.5Mt by 2030.
Nova Scotia	Renewable Electricity Regulations	Requires a minimum percentage of electricity consumption be provided by renewable resources.	Set at 40% by 2020.
Nova Scotia	Maritime Link	High-voltage transmissions line that will connect Nova Scotia to the Muskrat Falls hydroelectric project in Newfoundland.	Included.
Nova Scotia	EfficiencyNS Programs	Incentives for residential, commercial, and some industrial sectors.	Included.
Newfoundland	Energy Efficiency Programs	Incentives for residential, commercial, and some industrial sectors.	These programs include a home energy savings program, heat pump rebates, and commercial sector rebates for select appliances.
Prince Edward Island	EfficiencyPEI Rebates	Incentives for residential, commercial, and some industrial sectors.	Various rebates on energy efficient appliances, such as heat pumps, solar systems, biomass heating, and fuel-efficient furnaces.
Northwest Territories	2030 Energy Strategy	Measures that aim to support low-carbon energy for transportation and space heating. Incentives for energy efficiency and conservation.	Key measures include: promoting the use of wood as an alternative source of energy to fossil fuels, supporting the development and implementation of community energy plans, incentives for energy efficiency and alternative energy projects, support for alternatives to diesel electricity generators, rebates for zero and low emissions vehicles.
Yukon	Our Clean Future	Various measures that aim to reduce greenhouse gas emissions.	Key measures include: 10% zero emissions vehicles new sales by 2025 and 30% by 2030, zero-emission vehicles rebates, blending of renewable fuels into diesel and gasoline, energy efficiency incentives and regulations, and renewable energy projects for remote communities.

Appendix 2:

Overview of the Energy Futures Modeling System

Energy Futures includes a wide range of projections for Canadian energy supply and demand. These projections are the result of a modeling system consisting of several interactive components (or modules) which produce future Canadian energy trends. Figure A2.1 outlines the system in a diagram.

Figure A2.1:
Energy Futures Modelling Framework Flow Chart



In EF2021, the full Energy Futures Modeling System is used to create projections for the Evolving and Current Policies Scenarios. The six Towards Net-Zero electricity scenarios were modeled using the hourly electricity module.

Overview of Model Components

Initial Assumptions: The starting point for Energy Futures analysis is the development of initial assumptions on various aspects of the global and Canadian energy system. Benchmark crude oil and natural gas price assumptions are based on a survey of projections by other forecasting agencies like the IEA and the U.S. Energy Information Administration, complemented by internal analysis. It is important to note that these assumptions are not predictions of future crude oil and natural gas prices, but necessary inputs for the analytical process. Other starting assumptions include energy and climate policies and programs, scenario details such as technology fuel pathways, and volumes of LNG exports.

Oil Production: This module provides crude oil production projections for the various regions and crude types in Canada, based on our price assumptions and other factors such as carbon pricing and technological improvements. It includes an oil sands module, and non-oil sands deliverability module for western Canada, and analysis of other regions in Canada.

Gas Production: This module estimates the production of natural gas throughout Canada. The module relies upon oil and natural gas price assumptions, LNG export assumptions, as well as a crude oil production estimated from the oil supply module and other factors such as technological change and policies. The module includes the Western Canadian Sedimentary Basin natural gas deliverability model, as well as trend analysis for other producing regions (e.g. New Brunswick).

Macroeconomics: Macroeconomic projections for each of the scenarios were provided by Stokes Economic Consulting Inc. Stokes developed unique projections of key macroeconomic indicators such as GDP, exchange rate, and industry gross output for each of the scenarios, based on the price assumptions and output of the CER's supply and demand models.

Demand: The demand projections are developed using ENERGY2020: a detailed energy model created by Systematic Solutions Incorporated. It creates projections for energy demand and electricity generation based on historical energy data and, where needed, assumed future trends for parameters such as supply, demand, economic growth, efficiency, prices, and investment.

Electricity: The electricity projections are developed using ENERGY2020: a detailed energy model created by Systematic Solutions Incorporated. It creates projections for energy demand and electricity generation based on historical energy data, and where needed, assumed future trends for parameters such as supply, demand, economic growth, efficiency, prices, and investment. The ENERGY2020 projections are guided by the hourly electricity module, which provides increased temporal granularity which is important for analyzing how the system responds to increasing levels of variable renewable energy, storage, and transmission.

Natural Gas Liquids: This module provides estimates of NGL supply and demand in Canada. The module simulates various categories of liquids: ethane, butane, propane, condensate and pentane plus. For each liquid, the module provides estimates of production, supply and demand at the individual provincial/territorial level.

Appendix G

GLOSSARY OF TERMS AND ACRONYMS

APPENDIX G – GLOSSARY OF TERMS AND ACRONYMS

Acronym or Term	Definition
ACP	Annual Contracting Plan
AECO/NIT	Alberta Energy Company/Nova Inventory Transfer - refers to an important storage and exchange point for Canadian natural gas. AECO/NIT is commonly used to refer to the benchmark pricing index for the Alberta natural gas marketplace.
AMI	Advanced Metering Infrastructure
Annual demand	The cumulative daily demand for natural gas over an entire year.
BAU	Business as Usual
BC	British Columbia
BC Hydro	British Columbia Hydro and Power Authority (BC Hydro)
BC-LCFS	*Greenhouse Gas Reduction (Renewable & Low Carbon Fuel Requirements) Act* and the 5 *Renewable & Low Carbon Fuel Requirements Regulation*, which are collectively known as British Columbia's low carbon fuel standard.
Bcf	One billion cubic feet
Bcf/d	One billion cubic feet per day
BCUC	British Columbia Utilities Commission, or Commission - the BCUC is the provincial body regulating utilities in British Columbia.
BERC	Biomethane Energy Recovery Charge
CCA	Washington's *Climate Commitment Act*
CCAA	*Climate Change Accountability Act*
CCE	Cost of Conserved Energy - a standard method for expressing cost-benefit test results for energy efficiency initiatives in dollars per unit of energy savings. Electric utilities use the CCE to express the net cost of saving one unit of utility-supplied energy. In the 2017 LTGRP, FEI uses the CCE to express in dollars per GJ the UCT results; thus the CCE represents annualized and, where applicable, discounted UCT costs divided by annual energy savings.
CCUS	Carbon capture utilization and storage
CEA	*Clean Energy Act*

Acronym or Term	Definition
CEUS	Commercial End-use Study
Clean Growth Pathway	Clean Growth Pathway to 2050
CNG	Compressed natural gas
CNZEAA	Canadian Net-Zero Emissions Accountability Act
Commission	*see British Columbia Utilities Commission, BCUC*
CO_2e	Carbon dioxide-equivalent - a unit to express an amount of greenhouse gas emission in terms of carbon dioxide (CO_2) based on the relative global warming potential of each gas. Commonly expressed in million tonnes, i.e. $MtCO_2e$.
CPCN	Certificate of Public Convenience and Necessity - a certificate obtained from the British Columbia Utilities Commission under Section 45 of the *Utilities Commission Act* for the construction and/or operation of a public utility plant or system, or an extension of either, that is required, or will be required, for public convenience and necessity.
Company	FortisBC Energy Inc.
Core	A category of FEI customers rely on FEI to both procure their gas supply and also deliver this supply to their meters in a non-interruptible manner. This includes Rate Schedules 1, 2, 3, 4, 5, and 6.
CPR	Conservation Potential Review - a comprehensive economic analysis of energy conservation potential that looks at where energy savings opportunities exist
CTS	Coastal Transmission System
Daily demand	The amount of natural gas consumed by the Utilities' customers throughout each day of the year.
Declaration Act	The Canadian *Declaration on the Rights of Indigenous Peoples Act*
Demand forecast	A prediction of the demand for natural gas into the future for a given period and under a specified set of expected future conditions.
DEP	Diversified Energy (Planning) Scenario
DP	Distribution pressure
DSM	Demand-side management - commonly defined as any utility activity that modifies or influences the way in which customers utilize energy services.

Acronym or Term	Definition
DSM Regulation	Demand-Side Measures Regulation: one of the regulatory instruments that govern utility demand-side measure programs in BC.
Design day, or design hour demand	The maximum expected amount of gas in any one day or hour required by customers on the utility system. Since core customers' demand is primarily weather dependent, design-day or design-hour demand is forecasted based upon a statistical approach called Extreme Value Analysis, which provides an estimate of the coldest day weather event expected with a 1-in-20-year return period. For transportation customers, the design-day is equivalent to the firm contract demand (*also see Peak day*).
EAA	*Environmental Assessment Act*
EECAG	Energy Efficiency and Conservation Advisory Group
EMAT	Electro-Magnetic Acoustic Transducer - a type of advanced in-line inspection technology for pipelines.
ERP	Emissions Reduction Plan
FBC	FortisBC Inc.
FEI	FortisBC Energy Inc.
Firm Transportation	A category of FEI customers who procure their own gas supply but rely on FEI to deliver this supply to their meters in a non-interruptible manner. This includes Rate Schedules 23, 25, and the contracted firm delivery component of Rate Schedule 22 (including 22A and 22B) and other special Rate Schedules.
FIS	Forecast Information System
FPIC	Free, prior, and informed consent
GGRR	Greenhouse Gas Reduction (Clean Energy) Regulation
GHGRS	Greenhouse Gas Reduction Standard
GHG	Greenhouse gas
GJ	Gigajoule - a unit of energy equivalent to one billion joules. One joule of energy is equivalent to the heat needed to raise the temperature of one gram (g) of water by one degree Celsius (ºC) at standard pressure (101.325 kPa) and standard temperature (15ºC).
HEHE	*A Healthy Environment and a Healthy Economy* (a plan released by the federal government)
HP	Horsepower

Acronym or Term	Definition
Huntingdon-Sumas	Gas flow regulating stations on either side of the British Columbia /Washington state (U.S.) border through which much of the regional gas supply is traded.
I-5 Corridor	The natural gas regional market area served by infrastructure located along Interstate-5 in the northwestern U.S. The I–5 corridor includes B.C.'s Lower Mainland and Vancouver Island, Western Washington and Western Oregon.
IAA	*Impact Assessment Act*
IG	Island Generation (BC Hydro) - a cogeneration plant located at Elk Falls, Campbell River that supplies electricity and thermal energy on Vancouver Island.
IGU	Inland Gas Upgrade project
ILI	In-line inspection
IP	Intermediate pressure
ITS	Interior Transmission System
km	Kilometer
kPa	Kilopascal - a metric measurement unit of pressure. Gauge pressure is often given in units with a 'g' appended, e.g. 'kPag'.
kW	kilowatt (a unit of energy equal to one thousand watts) - the commercial unit of measurement of electric power. A kilowatt is the flow of electricity required to light ten 100-watt light bulbs.
kWh	Kilowatt hour (equal to one thousand watts used for a period of one hour) - the basic unit of measurement of electric energy. On average, residential customers in B.C. use about 10,000 kWh per year.
LCT	Low-Carbon Transportation
LICO	Low Income cut-offs
LMIPSU	FEI Lower Mainland Intermediate Pressure System Upgrade Project
LNG	Liquefied Natural Gas - natural gas stored under low temperature, which turns to liquid form. Approximately 600 times as much natural gas can be stored in its liquid state than in its typical gaseous state; however, specialized storage facilities must be constructed.
Load	The total amount of gas demanded by all customers at a given point in time.

Acronym or Term	Definition
LTERP	Long Term Electric Resource Plan – FortisBC Inc.'s LTERP examines future electric demand and supply resource conditions over the next 20 years and recommends actions needed to ensure customers' energy needs are met over the long term.
LTGRP	Long Term Gas Resource Plan – FEI's LTGRP examines future gas demand and supply resource conditions over the next 20 years and recommends actions needed to ensure customers' energy needs are met over the long term.
mm	Millimeter
MMBtu	One million British Thermal Units
MMcf/d	One million cubic feet per day
MMscfd	One million standard cubic feet per day, sometimes also mmscfd
MOP	Maximum operating pressure
MRPO	Minimum Resiliency Planning Objective
$MtCO_2e$	One megatonne of CO_2 equivalent (*also see* CO_2e).
MTRC	Modified Total Resource Cost - a modification to the Total Resource Cost test that is set out in the B.C. Demand-side Measures Regulation to recognize the environmental value of energy conservation.
MW	Megawatt - a unit of power equal to one million watts or one thousand kilowatts, commonly used to measure both the capacity of generating stations and the rate at which electric energy can be delivered.
NGTL	Nova Gas Transmission Ltd.
NOx	Nitrogen oxides - a form of atmospheric pollutants that are regulated in many jurisdictions.
NPS	Nominal Pipe Size (in inches) - a North American set of standard pipe sizes.
NRCan	Natural Resources Canada
NW Natural	Northwest Natural Gas Company
OCAP	Oregon Climate Action Plan
OCU	FEI Okanagan Capacity Upgrade Project
OEM	Original Equipment Manufacturer
Pathways Report	Pathways for British Columbia to Achieve Its GHG Reduction Goals Report

Acronym or Term	Definition
PCF	The Pan-Canadian Framework on Clean Growth and Climate Change
Peak day, peak demand, peak day demand	The maximum expected amount of gas in any one day or hour required by customers on the FEI system. Since Core customers' demand is primarily weather dependent, design-day or design-hour demand is forecasted based upon a statistical approach called Extreme Value Analysis, which provides an estimate of the coldest day weather event expected with a 1 in 20 year return period. For transportation customers, the design-day is equivalent to the firm contract demand (*also see: design day*).
PGR	FEI Pattullo Gasline Replacement Project
PHF	Peak Hour Factor – the ratio of peak hour consumption to peak day consumption
PJ	Petajoule - a unit of energy equal to 1,000 terajoules or 10^6 gigajoules
PM	Particulate matter - the sum of all solid and liquid particles suspended in the atmosphere; most PM particles form as a result of chemical reactions between pollutants.
PNW	Pacific Northwest - a region that is commonly referred to as the three northwestern states of Washington, Oregon, Idaho and the Province of B.C.
Posterity	Posterity Group
PRMP	Price Risk Management Plan
Rate volatility	The amount to which natural gas rates fluctuate and the frequency of those fluctuations.
Resources	The demand side and supply side means available to meet forecasted energy needs. Examples of supply-side resources within the context of resource planning are pipeline looping, compression and storage.
REUS	Residential End Use Study
RG Program Application	FEI's Comprehensive Review and Application for a Revised Renewable Gas Program filed December 17, 2021
RGSD	Regional Gas Supply Diversity Project
RNG	Renewable natural gas
Roadmap	CleanBC Roadmap to 2030
RPAG	Resource Planning Advisory Group

Acronym or Term	Definition
RPS	Renewable Portfolio Standard – a form of regulation requiring a specified percentage of energy/fuel provision to contain renewable energy/fuel.
SACC	Strategic Assessment of Climate Change
SCP	Southern Crossing Pipeline
SCGT	Simple cycle gas-fired turbine – typically for electricity generation.
SFC	Seaspan Ferries Corp.
SOx	Sulfur oxides – a form of atmospheric pollutants that are regulated in many jurisdictions.
TAC	Technical Advisory Committee – a group of members of the public with significant interest, stake, and experience in determining energy conservation potential in BC; this group provides input and feedback during development of the BC CPR.
TJ	Terajoule - a unit of energy equal to 1,000 gigajoules.
TJ/d	Terajoules per day
TLSE	Tilbury LNG Storage Expansion Project
TP	Transmission pressure
Traditional Annual Method	FEI's traditional time-series based method for forecasting annual energy demand.
Traditional Peak Method	FEI's longstanding and well-established method for forecasting peak energy demand.
TC Energy	TC Energy Corporation (formerly TransCanada PipeLines Limited).
TRC	Total Resource Cost - a standard cost-benefit test for energy efficiency initiatives that compares the present value of all costs of efficiency for all members of society with the present value of benefits in order to assess the impacts of a portfolio of energy efficiency initiatives on the economy at large.
TSA	(FEI-BC Hydro) Transportation Service Agreement, which expired April 2022
T-South incident	The Westcoast Energy Inc. (Westcoast) T-South pipeline rupture that occurred on October 9, 2018 and which resulted in capacity restrictions thereafter on the T-South system.
UCA	*Utilities Commission Act*
UN Declaration	United Nations Declaration on the Rights of Indigenous Peoples

Acronym or Term	Definition
UNDRIP Act	*United Nations Declaration on the Rights of Indigenous Peoples Act*
UPC	Use per customer
UPC_{peak}	Peak hour use per customer
UCT	Utility Cost Test - a standard cost-benefit test for energy efficiency initiatives that compares the present value of all costs of efficiency for the utility which offers an energy efficiency program with the present value of benefits in order to assess the impacts of a portfolio of energy efficiency initiatives on the utility specifically.
VBBL	Vancouver Building Bylaw
VIGJV	Vancouver Island Gas Joint Venture - a joint venture of industrial customers (primarily large mills) on Vancouver Island who contract for transportation services as a single entity.
VITS	Vancouver Island Transmission System, also referred to as VI Transmission System
Westcoast	Westcoast Energy Inc. A wholly-owned subsidiary of Enbridge Inc.
Woodfibre LNG project	A small-scale LNG export and processing facility proposed on the site of the former Woodfibre pulp mill near Squamish.

Appendix H

DRAFT ORDERS

Appendix H-1

DRAFT ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
2022 Long Term Gas Resource Plan

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On May 9, 2022, FortisBC Energy Inc. (FEI) filed its 2022 Long Term Gas Resource Plan (LTGRP) pursuant to section 44.1 of the *Utilities Commission Act*, for acceptance by the British Columbia Utilities Commission (BCUC). FEI is not seeking approval of any particular elements identified within the LTGRP;

B. By Order G-##-22 dated [DATE], the BCUC established a written hearing process to review the LTGRP;

C. The BCUC has reviewed the LTGRP and the evidence submitted in the proceeding and considers that acceptance of the LTGRP is warranted.

NOW THEREFORE for the reasons set out in the Decision accompanying this order:

1. The BCUC accepts the FEI 2022 LTGRP as being in the public interest, pursuant to subsection 44.1(6) of the *Utilities Commission Act*.

2. The BCUC directs FEI to comply with all determinations and directives as set out in the Decision.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Appendix H-2

DRAFT PROCEDURAL ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
2022 Long Term Gas Resource Plan

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On May 9, 2022, FortisBC Energy Inc. (FEI) filed its 2022 Long Term Gas Resource Plan (LTGRP) for acceptance by the British Columbia Utilities Commission (BCUC), in accordance with section 44.1(2) of the *Utilities Commission Act* (UCA);

B. FEI's 2022 LTGRP presents FEI's long term view of the demand-side and supply-side resources identified to meet expected future gas demand, reliability requirements, and Provincial greenhouse gas reduction requirements, taking into consideration the cost to FEI's customers over the 20-year planning horizon (2022-2041). The 2022 LTGRP includes a 20-year vision for FEI and culminates in an Action Plan that identifies the activities that FEI intends to pursue over the next four years;

C. In order to inform the 2022 LTGRP, FEI offered stakeholders the opportunity to participate in discussions including, but not limited to, workshops with a resource planning advisory group, community engagement workshops and dialogue with Indigenous communities, industry associations and other advisory groups;

D. FEI's previous LTGRP, the FEI 2017 Long Term Gas Resource Plan, was accepted by the BCUC by Order G-39-19 on February 25, 2019;

E. Section 44.1(5) of the UCA provides that the BCUC may establish a process to review long term resource plans; and

F. The BCUC considers that a public hearing process for the review of FEI 2022 LTGRP is warranted and that a regulatory timetable should be established.

NOW THEREFORE pursuant to section 44.1(5) of the UCA, the BCUC orders as follows:

1. A written public hearing process is established for the review of the FortisBC Energy Inc. (FEI) 2022 Long Term Gas Resource Plan (Application) in accordance with the regulatory timetable as set out in Appendix A to this order.

2. FEI must publish the Public Notice, attached as Appendix B to this order, in display-ad format in appropriate news publications, such as but not limited to, local and community newspapers to provide adequate notice to those parties who may have an interest in or be affected by the Application, as soon as reasonably possible, but no later than Friday, July 8, 2022.

3. FEI of the Application on its social media platforms, no later than Friday, July 8, 2022. FEI must also publish weekly reminder notices on each of these platforms until the conclusion of the intervener registration period on Thursday, July 21, 2022.

4. As soon as is reasonably possible, FEI is directed to publish the Application, this order, and the regulatory timetable on its website and to provide a copy of the Application and this order to:

    a. All invitees and attendees of the stakeholder engagement process outlined in Section 8 of the Application; and

    b. Registered interveners and interested parties in the:

        i. FEI 2017 Long Term Gas Resource Plan proceeding; and

        ii. FEI Annual Review for 2022 Delivery Rates proceeding.

5. Parties who wish to actively participate in the proceeding are to register with the BCUC by completing a Request to Intervene Form, available on the BCUC's website at https://www.bcuc.com/get-involved/get-involved-proceeding.html, by the date established in the regulatory timetable, and in accordance with the BCUC's Rules of Practice and Procedure attached to Order G-15-19.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment

FortisBC Energy Inc.
2022 Long Term Gas Resource Plan

REGULATORY TIMETABLE

Action	Date (2022)
FEI Publishes Notice of Filing by	Friday, July 8
Registration of Interveners and Interested Parties	Thursday, July 21
FEI Submits Energy Scenarios Evidentiary Update	Friday, August 12
BCUC Information Request No. 1	Tuesday, August 30
Intervener Information Request No. 1	Thursday, September 8
FEI Responses to Information Requests No. 1	Thursday, October 27
BCUC and Intervener Information Request No. 2	Thursday, November 24
	Date (2023)
FEI Responses to Information Requests No. 2	Thursday, January 26
Notification by Interveners of Intent to file Evidence	Thursday, February 9
Submissions on Process or Procedural Conference	To be determined

bcuc
British Columbia
Utilities Commission

PUBLIC NOTICE

FortisBC Energy Inc. 2022 Long Term Gas Resource Plan

On May 9, 2022, FortisBC Energy Inc. (FEI) filed its 2022 Long Term Gas Resource Plan (LTGRP) for acceptance by the British Columbia Utilities Commission (BCUC), in accordance with section 44.1(2) of the *Utilities Commission Act*.

FEI's long term view of the demand-side and supply-side resources identified to meet expected future gas demand, reliability requirements, and Provincial greenhouse gas reduction requirements, taking into consideration the cost to FEI's customers over the 20-year planning horizon (2022-2041). The 2022 LTGRP includes a 20-year vision for FEI and culminates in an Action Plan that identifies the activities that FEI intends to pursue over the next four years.

HOW TO PARTICIPATE

- **Submit a letter of comment**
- **Register as an intervener**
- **Request intervener status**

IMPORTANT DATES

- **Thursday, July 21, 2022** – Deadline to register as an intervener with the BCUC.

For more information about the Application, please visit the **Proceeding Webpage** on bcuc.com under "Our Work – Proceedings". To learn more about getting involved, please visit our website at **www.bcuc.com/get-involved** or contact us at the information below.

GET MORE INFORMATION

FortisBC Energy Inc. Regulatory Affairs

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British Columbia Utilities Commission

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