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May 13, 2021

British Columbia Public Interest Advocacy Centre
Suite 803 470 Granville Street
Vancouver, B.C.
V6C 1V5

Attention: Ms. Leigha Worth, Executive Director

Dear Ms. Worth:

Re: FortisBC Energy Inc. (FEI)

Project No. 1599152

Application for a Certificate of Public Convenience and Necessity for the Okanagan Capacity Upgrade Project (Application)

Response to the British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 2

On November 16, 2020, FEI filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-97-21 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCOAPO IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

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A. PROJECT NEED AND JUSTIFICATION

6.0 Reference: FEI Okanagan Capacity Upgrade Project CPCN
Updated Application, page 2 & 11
BCUC IR 1.11.1
Topic: Need and Cost/Schedule Risk

Preamble: FEI states:

> Specifically, without adding more delivery capacity to the existing ITS, FEI will be required to curtail customers in these regions, shedding load from the system in order to maintain pressure and preserve supply to remaining customers. In a worst-case scenario, during cold winter days, should it become impossible to shed sufficient load through the curtailment of large interruptible service customers, core customers (i.e., firm supply customers) in these areas may be impacted by a loss of gas supply resulting in these customers being left without gas for heat, hot water, and cooking, which could last for few days depending on the extent of the capacity shortfall. **(Updated Application, page 2)**

> However, recent FEI gas load and system capacity forecasts indicate that the system will approach its maximum capacity and a major upgrade is required to maintain secure and reliable supply to the central and north Okanagan regions prior to the winter of 2023/2024. **(Updated Application, page 11)**

6.1 Please discuss FEI's view as to which aspects of the project (that is, Alternative 3) poses the greatest risk that the project schedule will be delayed.

Response:

The three greatest risks which could cause OCU Project delays are delays in the discussions with Indigenous groups regarding the OCU Project, delays in permitting and a failed horizontal directional drilling (HDD) crossing of Penticton Creek.

Delays in Discussions with Indigenous Groups

FEI has been engaging with Indigenous groups since June 2019 and expects to continue discussions related to environmental, cultural and economic impacts, benefits and mitigations related to the Project. FEI acknowledges that the COVID-19 pandemic has impacted Indigenous groups' ability to be responsive to FEI's requests for meetings and information and appreciates the engagement it has received. Further delays in these discussions could result in impacts to the timing of the Project's design and permitting phases.

Delays in Permitting

FEI estimated durations and activities for obtaining BCUC and BC Oil and Gas Commission (BCOGC) approval in the Project schedule based on historical approval times. An unexpectedly long period for receiving CPCN approval or BCOGC permits would result in a loss of schedule float/contingency associated with execution of the Project construction. This could result in planned work being shifted to times of the year when certain activities are limited (i.e., wildfire risks, bird nesting season, fisheries windows, etc.).

Failed HDD Crossing of Penticton Creek

A failure of the Penticton Creek HDD installation is the greatest construction-related risk that could result in a schedule delay.

6.2 Please discuss FEI's view as to which aspects of the project (that is, Alternative 3) poses the greatest risk for cost overruns.

Response:

This response is being redacted pursuant to section 18 of the BCUC's Rules of Practice and Procedure as set out in Order G-15-19. The information in the response below is being redacted because the information is commercially sensitive that, if disclosed, could hamper or prejudice FEI's negotiations with contractors on current and future projects.

A confidential version of this response is being filed with the BCUC under separate cover and can be made available to registered parties upon providing a signed Confidentiality Declaration and Undertaking similar to that provided in the Application, Appendix J-3.

[redacted]

[redacted]

6.3 If the project is delayed beyond the winter of 2023/24, is it FEI's expectation to meet the energy requirements of customers with CNG injection until the upgrade is operational?

Response:

Please refer to the response to PIB IR1 18.1 for a discussion on the impact of a project delay.

6.3.1 What is the magnitude of the impact on project cost associated with 1) a one-month delay during adverse winter conditions; 2) a six-month delay?

Response:

This response is being redacted pursuant to section 18 of the BCUC's Rules of Practice and Procedure as set out in Order G-15-19. The information in the response below is being redacted because the information is commercially sensitive that, if disclosed, could hamper or prejudice FEI's negotiations with contractors on current and future projects.

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[1] [redacted]

[redacted]

[redacted]

7.0 Reference: FEI Okanagan Capacity Upgrade Project CPCN
Updated Application, page 22
BCUC IR 1.5.1 and series 1.8.1 – 8.2
Topic: System Capacity under Maximum Operating Conditions

Preamble: FEI states:

> FEI considers the three-year average to be the appropriate balance between stabilizing the UPCpeak for system planning, while also reflecting any developing trends between the current consumption and historical results. In determining an appropriate UPCpeak for system planning, FEI considers these two competing objectives. **(BCUC IR 1.5.1);**

> FEI's DDD [Design Degree Day] temperature for any system operating within a region is the coldest day that is statistically likely to occur only once in any given 20-year period. In determining the DDD value, FEI uses an extreme value statistical method called the Gumbel Method of Moments. This method returns the expected extreme value for a given historical data set based on a specified return period. FEI uses a 1 in 20 return period on a data set that represents the coldest recorded daily mean temperature at the region's weather station each winter over a 60-year period. **(Updated Application, page 22)**

> FEI has two main objectives that are met by using a 60-year data set. The first is to determine a sufficiently infrequent weather event to design the gas system to ensure reliability and security of supply can be met under the associated high demand forecast to occur during such an event. The second is that the design event is a stable and reproducible target for designing the system and doesn't change from year to year. **(BCUC IR 1.8.2.1)**

7.1 Please confirm or otherwise explain whether FEI's methodology to arrive at its Design Degree Day and the consumption contribution of customers to peak demand are intended to ensure the energy requirements of firm customers are met under maximum day operating conditions, even if those conditions occur rarely.

Response:

Confirmed. The impacts of a gas supply shortage under severe winter conditions (i.e. extreme low temperatures) can present very significant health and safety issues for customers if they are without gas for heat, hot water, and cooking for an extended period. Once supply is lost, service restoration for impacted areas can take many days or weeks. Consequently, FEI designs the system to ensure supply requirements of firm customers are met under maximum day operating conditions, even if those conditions occur rarely.

7.1.1 Please confirm, or otherwise explain, that FEI's methodology is consistent with its past practice for system design.

Response:

Confirmed. FEI has followed the same system design practices consistently for many years in determining capacity requirements across its service territory and has not used any system design practices for the OCU Project that are inconsistent with other projects or applications. Please also refer to the response to BCSEA IR1 5.1.

7.1.2 Please discuss whether the reliance of a 20-year or 60-year data set of frequency and severity of extreme conditions has a material impact on overall project scope and costs.

Response:

Please refer to the response to BCUC IR2 43.3.1.

7.1.3 Please confirm or otherwise explain, that but for those occasions when maximum day operating conditions are experienced, Interruptible load can generally be met without interruption?

Response:

For forecasting purposes, FEI plans such that interruptible customers would only be curtailed during weather conditions colder than the sixth coldest day in a design year. Under warmer conditions, the lower demand of firm customers is sufficient to allow interruptible customer demand to be met. As such, interruptible customers should expect to be curtailed to maintain supply to firm customers on peak days. Notwithstanding this, FEI maintains the right to curtail interruptible customers at any time for reasons other than weather conditions.

8.0 Reference: FEI Okanagan Capacity Upgrade Project CPCN

BCUC IR 1.7.1, 7.2.1

Topic: Coincident/Non-Coincident Peak

Preamble: FEI states:

> FEI builds system-wide peak demand based on the loads originating from within the distribution system. The vast majority of industrial customers served by the ITS are located within distribution systems operating at a maximum pressure of 420 kPa. These distribution systems are designed on a peak hour basis as they have no capacity or useable line pack to accommodate hourly load swings. The system capacity is therefore designed to support the maximum hourly load and industrial customer load is assessed to determine their maximum hourly loads. These loads are applied to the distribution system models and roll up into the Transmission system models. The metered data for industrial customers does not have a high degree of consistency as customers can have daily periods of extended high flow, daily periods of extend low flow, or daily periods of intermittent high flow and low flow. **(BCUC IR 1. 7.1)**

> FEI provides the figure below that shows the total hourly load profile of firm industrial customers on the system for the coldest days in 2018, 2019, and 2020 with flow sustained through the day. The data indicates a relatively steady cumulative industrial firm demand, with flow varying through the day but not significantly. The time of day when the peak occurs is also variable, with the maximum flows aligned at different points in the day. FEI also notes that the industrial demand on February 21, 2018 was higher than on January 14, 2020, a day that was 5.3 degrees colder. This indicates the industrial demand is not well correlated to temperature, and colder days could also experience much higher industrial demand than that represented in the figure. As a result of this uncertainty around when, and how sustained, the peak industrial flow will be on any given day, FEI models system capacity to support a sustained maximum industrial demand equal to the highest hourly value observed for each customer. **(BCUC IR 1.7.1.2)**

8.1 Please explain whether FEI's view and methodology approach to capacity determination related to the Okanagan Capacity Upgrade is one that is more consistent with a coincidental peak or a non-coincidental peak?

<u>Response:</u>

The application of coincidental versus non-coincidental peak is more related to a peak-hour loading approach which is used to design systems with limited or no line pack, such as distribution systems. Due to the available line pack in the Interior Transmission System, the forecast peak-day load is not dependent on the hour of the day in which the peak occurs in the downstream distribution system. For this reason, the Interior Transmission System is designed using peak-day loads, and the determination of coincidence is not directly applicable to it, or, by extension, to the Project.

9.0 Reference: FEI Okanagan Capacity Upgrade Project CPCN

BCUC IR 1.6.3.1

Topic: Capacity Planning and Rate-Setting

Preamble: FEI states:

> There are no differences in the objectives of forecasting customer accounts for rate-setting and forecasting for capacity planning. The sole objective of the customer forecast process is to develop a single, accurate forecast that can be aggregated and disaggregated with consistency and reasonableness.
>
> For the purposes of capacity planning, FEI considers a longer forecast period up to 20 years and considers the future impact of the peak demand on the system. Peak demand occurs over a short period of hours or days. Capacity planning takes a longer forecast view in order to identify and plan for upgrade projects that may take many years to construct. In addition, capacity planning is concerned with where on the system peak demand occurs and so the more granular information from the BC Stat/LHA forecasts meets that objective.
>
> For the purposes of rate setting, a shorter forecast period is considered. The rate setting demand forecast considers regional annual demand and is not impacted by peak demand or the locality of the demand on the system. **(BCUC IR 1.6.3.1)**

9.1 Please discuss the relative impact on overall project costs of meeting peak demand requirements vs. capacity planning that considers a longer forecast view.

<u>Response:</u>

FEI clarifies that its capacity planning (such as for the OCU Project) is developed based on peak demand requirements; therefore, FEI is not certain what comparison BCOAPO is requesting. Assuming BCOAPO is instead asking for the effects of scoping a project to meet a peak demand forecast that is less than the 20 years indicated in BCUC IR1 6.3.1, the response is:

> Meeting peak demand requirements is tied to the forecast period in the sense that FEI is projecting growth in peak demand over time. In order for the OCU Project to be a robust and long-lasting solution, FEI has scoped the project to meet peak demand requirements late into the forecast period. If the project were designed to meet peak demand for a shorter forecast period, the initial project scope and costs might be reduced, but FEI would likely then need to address capacity constraints on the system through additional capital projects as peak demand continues to increase. Inefficiencies associated with multiple mobilizations, including multiple CPCN applications, would result in the total cost of these multiple projects being higher than what is identified in the

Application. As such, the current balance of OCU Project cost and longevity in meeting peak demand requirements of current and future customers is reasonable and prudent.

B. PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACT

10.0 Reference: FEI Okanagan Capacity Upgrade Project CPCN
Updated Application, page 1
BCUC IR 1.34.1
Topic: Rate Impacts

Preamble: FEI states:

> This population growth has led to a corresponding increase in natural gas demand, and FEI forecasts a shortfall in its existing Interior Transmission System (ITS) capacity, which needs to be addressed prior to the winter peak of 2023/2024. The OCU Project would add adequate capacity to FEI's existing ITS so that FEI can continue to provide long-term safe and reliable gas service to its customers in Okanagan region. **(Updated Application, page 1);**

> FEI did not consider growth in customer accounts, growth in volumes, or growth in delivery margin revenue when calculating the Project rate impacts. This approach is consistent with previous FEI CPCN applications. The purpose of the rate impact calculations in the Updated Application is to show the impact to existing rates, or in this case, relative to what was approved in the FEI Annual Review for 2021 Rates; i.e. holding the delivery margin revenue and volumes constant over the years. This results in a high-level estimate of the rate impact relative to the most recently approved rates. The actual rate impacts of the Project will not be known until a future Annual Review or Revenue Requirements proceeding when the costs of the Project are added to rate base at that time. **(BCUC IR 1.34.1)**

10.1 Please explain whether FEI anticipates disproportionate future rate impacts (compared to the 2.21%) to customers taking service at, for example, the Transmission level, once the costs of this project (and other upgrade projects) are incorporated into the Corporation's revenue requirement and cost allocation study (as transmission-related) and/or as a result of large differences between embedded and current cost?

<u>Response:</u>

All else being equal, the 2.21 percent estimated rate impact will be borne by all non-bypass customers as an equal percentage adjustment to the delivery margin of each non-bypass rate class. This is consistent with the method used to apply the BCUC approved annual revenue requirement increases to customer charges. FEI notes that the development of the revenue requirement for 2024 has not yet begun, thus it is unable to compare against the 2.21 percent increase in 2024 associated with the OCU Project. FEI notes the actual rate impact in 2024 may be higher or lower than the 2.21 percent due to various projects entering rate base at that time, as well as offsetting factors such as load growth, tax changes, etc. All of these will be considered during FEI's annual review process for setting 2024 rates.

FEI also notes the purpose of a cost of service allocation (COSA) study is to allocate FEI's revenue requirement[2] at that time among the different customer classes. The overall delivery rate impact of the OCU Project will remain the same (i.e., 2.21 percent) regardless of the COSA study. Transmission system costs are predominantly allocated based on peak day demand and the allocation of the OCU Project costs will have the same allocation as all other historical (embedded) transmission costs within the revenue requirement. As such, assuming all else being equal,[3] when compared to FEI's 2016 COSA study accepted by BCUC Order G-4-18, the transmission costs associated with the OCU Project will have the same impact to all rate classes in terms of cost allocation as the costs already embedded in the revenue requirement. In other words, since the allocation method would be the same as all historical (embedded) costs, FEI is not anticipating the incorporation of the transmission costs associated with the OCU Project to FEI's next COSA study will lead to the overall revenue requirements being disproportionately allocated among different rate classes.

2 FEI's revenue requirement is the current annual cost of service of both historical and current costs (all considered embedded costs).

3 Peak day demand between rate schedules does not change substantially, among other studies and assumptions used in cost allocation.

C. ENVIRONMENT AND ARCHAEOLOGY

11.0 Reference: FEI Okanagan Capacity Upgrade Project CPCN

BCUC IR 1.36.1

Topic: MoTI Variance Application

Preamble: In response to BCUC IR 1.36.1, FEI states:

> The second meeting was held to discuss the specific details of and the need for variances. FEI submitted the variance application in January 2021 and expects a response from the MoTI in March 2021.

11.1 Please advise whether FEI's requested variance application was approved by the MoTI as anticipated.

<u>Response:</u>

Please refer to the response to BCUC IR2 58.1.

11.2 Does FEI anticipate that its variance application will be approved by the MoTI as proposed or does it anticipate any significant approval conditions that will drive material impacts on the project schedule in terms of timing and cost? Please explain.

<u>Response:</u>

Please refer to the response to BCUC IR2 58.1.

12.0 Reference: FEI Okanagan Capacity Upgrade Project CPCN

BCUC IR 1.37.1

Topic: Gas Line Construction Through Landfill

Preamble: In response to BCUC IR 1.37.1, FEI states:

> FEI is currently working with the Campbell Mountain Landfill operator's preferred environmental consultant, Sperling Hansen, to better understand the environmental implications of constructing a gas line through a short section of the landfill. FEI will continue to consult with the operators of the Campbell Mountain Landfill until all outstanding issues are resolved.

12.1 Please explain whether FEI anticipates material construction schedule delays or cost impacts related to gas line construction through a landfill, with reference to lessons learned from past practice, if possible.

<u>Response:</u>

FEI does not anticipate any material schedule or cost implications associated with the route through the landfill as the OCU Project route only runs 40 metres through the landfill property.

FEI has experience with both installation of a new pipeline near an existing landfill and new landfills developing around an existing pipeline. FEI applied lessons learned within the current design and cost estimate including in relation to strength of materials, potential deflections, and soil and/or leachate contamination.

D. CONSULTATION AND ENGAGEMENT

13.0 Reference: FEI Okanagan Capacity Upgrade Project CPCN

BCUC IR 1.39.2, 39.2.1

Topic: Expropriation

13.1 In response to BCUC IR 1.39.2, FEI advises that none of the Municipal City of Penticton rights-of-way have thus far been completed. Please provide an update on the rights-of-way negotiations with the Municipality and whether FEI anticipates any material schedule delays or project cost impacts.

Response:

FEI continues to work with the City of Penticton to secure land rights for the Project. FEI and the City of Penticton meet on a bi-weekly basis to discuss the Project and work towards an agreement. Based on the discussions to date, FEI anticipates that it will reach a negotiated agreement with the City of Penticton to acquire necessary land rights, and as such, FEI does not anticipate any material schedule delays or project cost impacts.

In response to BCUC IR 1.39.2.1, FEI states:

> FEI's objective is to reach mutually acceptable negotiated agreements with landowners. Should an agreement not be reached and result in the potential for Project construction delays, FEI will take steps to expropriate the required land rights. Should FEI need to proceed with expropriation in a particular situation, FEI would make an application under Section 6 of the Gas Utility Act or section 34(3) of the Oil and Gas Activities Act as appropriate for approval to expropriate the necessary land. Should FEI have to undertake expropriation, costs are not expected to vary beyond those in the estimate.

13.2 Please discuss FEI's views on the impact of an expropriation process to the project schedule.

Response:

This response is being redacted pursuant to section 18 of the BCUC's Rules of Practice and Procedure as set out in Order G-15-19. The information in the response below is being redacted because the information is commercially sensitive that, if disclosed, could hamper or prejudice FEI's negotiations with contractors on current and future projects.

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[redacted]

- [redacted]
- [redacted]
- [redacted]

E. PROVINCIAL GOVERNMENT ENERGY OBJECTIVES

14.0 Reference: FEI Okanagan Capacity Upgrade Project CPCN

BCUC IR 1.40.1

Topic:

In response to BCUC IR 1.40.1, FEI states:

> More generally, the Project is aligned with the provincial energy objective to reduce greenhouse gas emissions. The gas energy delivery system, including the Project, delivers low carbon energy (i.e. renewable gas) to customers in the province. FEI continues to increase its supply of renewable gas in alignment with the provincial CleanBC target to achieve 15 percent renewable gas content by 2030. Over the longer term to 2050, FEI envisions a future where the majority of the energy it delivers, including through the Project, is renewable.

14.1 Please elaborate on FEI's perspective that it envisions a future where the majority of energy it delivers will be renewable.

Response:

FEI has conducted detailed analysis and modelling to explore the role that its gas distribution infrastructure will play in a low-carbon future that achieves BC's legislated GHG emission reduction targets to 2030 and 2050. The Pathways to 2050[4] report, developed by Guidehouse Consulting, found that BC could achieve its 80 percent GHG reduction target by 2050 using a diversified approach that leverages the decarbonization potential of both the gas and electricity systems. Guidehouse found that a diversified pathway, requiring the majority of the energy delivered in the gas system to be renewable, would be a more affordable and resilient pathway to achieve emissions reductions targets as compared to a pathway that focuses solely on electrification.

More specifically, the diversified pathway proposes that almost three-quarters of the total energy delivered to customers through FEI's system would be renewable. This would require over 130 PJ of renewable gas supply comprised of:

- renewable natural gas (RNG) from anaerobic digestion;
- RNG derived from biomass waste using gasification technology; and
- hydrogen produced from low-carbon sources.

The primary economic advantage of using renewable gases as a drop-in replacement within the existing gas distribution system is that it leverages existing gas delivery infrastructure, avoiding

[4] https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/clean-growth-pathway-brochure.pdf.

the need for significant and costly expansion of long-lead energy infrastructure such as electric generation, transmission, and distribution systems. Furthermore, the gas system is specifically designed to address seasonal energy peaks with its ability to cost effectively store large volumes of energy for long periods of time. Transitioning to delivering renewable gases as a drop-in replacement takes advantage of these operational benefits.

Finally, BC has significant potential to produce renewable gases. Independent analyses by Hallbar Consulting and Zen and the Art of Clean Energy, in partnership with the Provincial government, conclude that together, over 130 PJ of renewable gases could be produced in BC at a cost-effective price compared to other clean energy commodities.

For further in-depth analysis and discussion please refer to Attachment 14.1 for the Pathways to 2050 report.

Attachment 14.1

PATHWAYS FOR BRITISH COLUMBIA TO ACHIEVE ITS GHG REDUCTION GOALS

Submitted by:
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Reference No.: 205334
August 2020

NAVIGANT
A Guidehouse Company

PREPARED FOR

FORTIS BC
Energy at work

DISCLAIMER

This deliverable was prepared by Guidehouse Inc. for the sole use and benefit of, and pursuant to a client relationship exclusively with FortisBC ("Client"). The work presented in this deliverable represents Guidehouse's professional judgement based on the information available at the time this report was prepared. The information in this deliverable may not be relied upon by anyone other than Client. Accordingly, Guidehouse disclaims any contractual or other responsibility to others based on their access to or use of the deliverable.

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

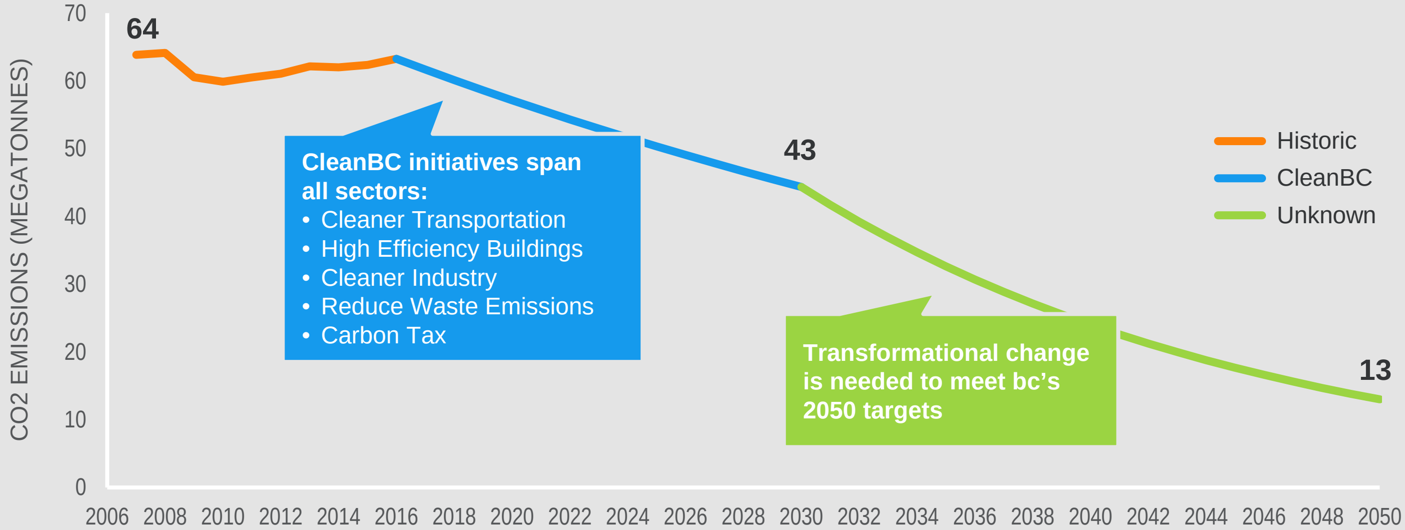
As part of its Climate Change Accountability Act, British Columbia (BC) has committed to reducing greenhouse gas (GHG) emissions to 80% below 2007 levels by 2050. The CleanBC plan puts the province on a path toward this goal, but only sets in action initiatives designed to meet a 2030 target (30% reduction 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.

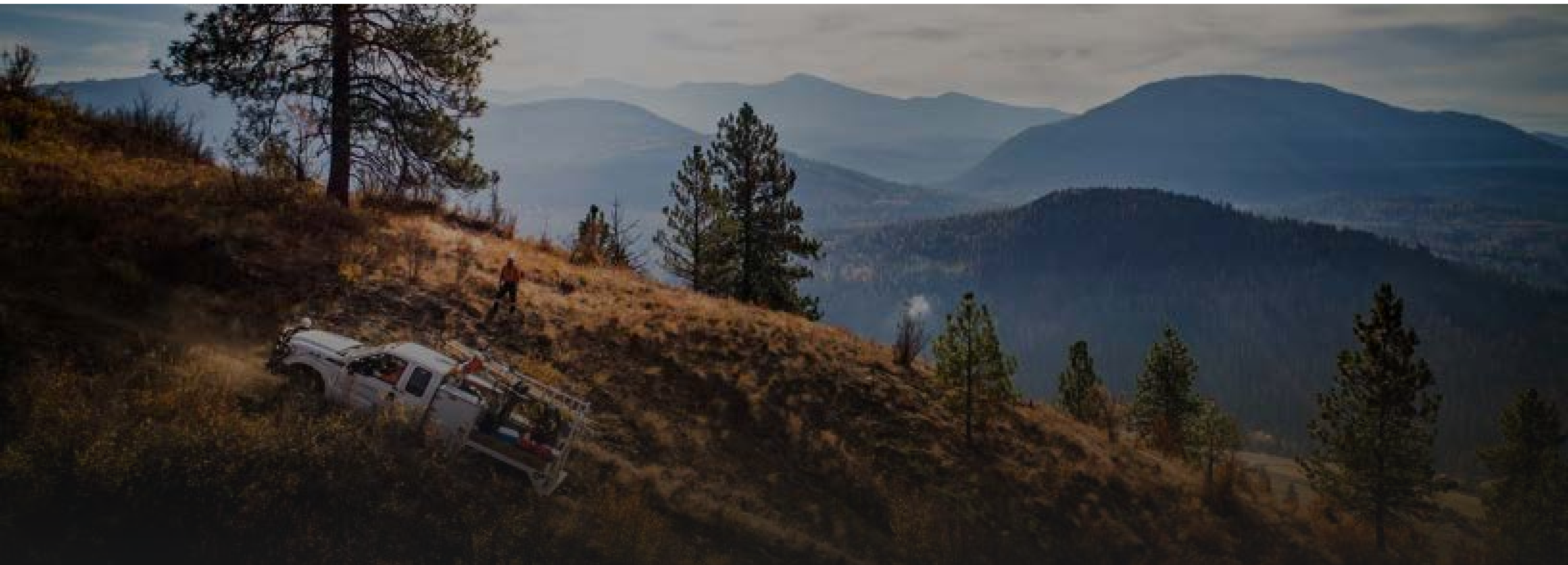
The study's core conclusions are as follows:

- 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.

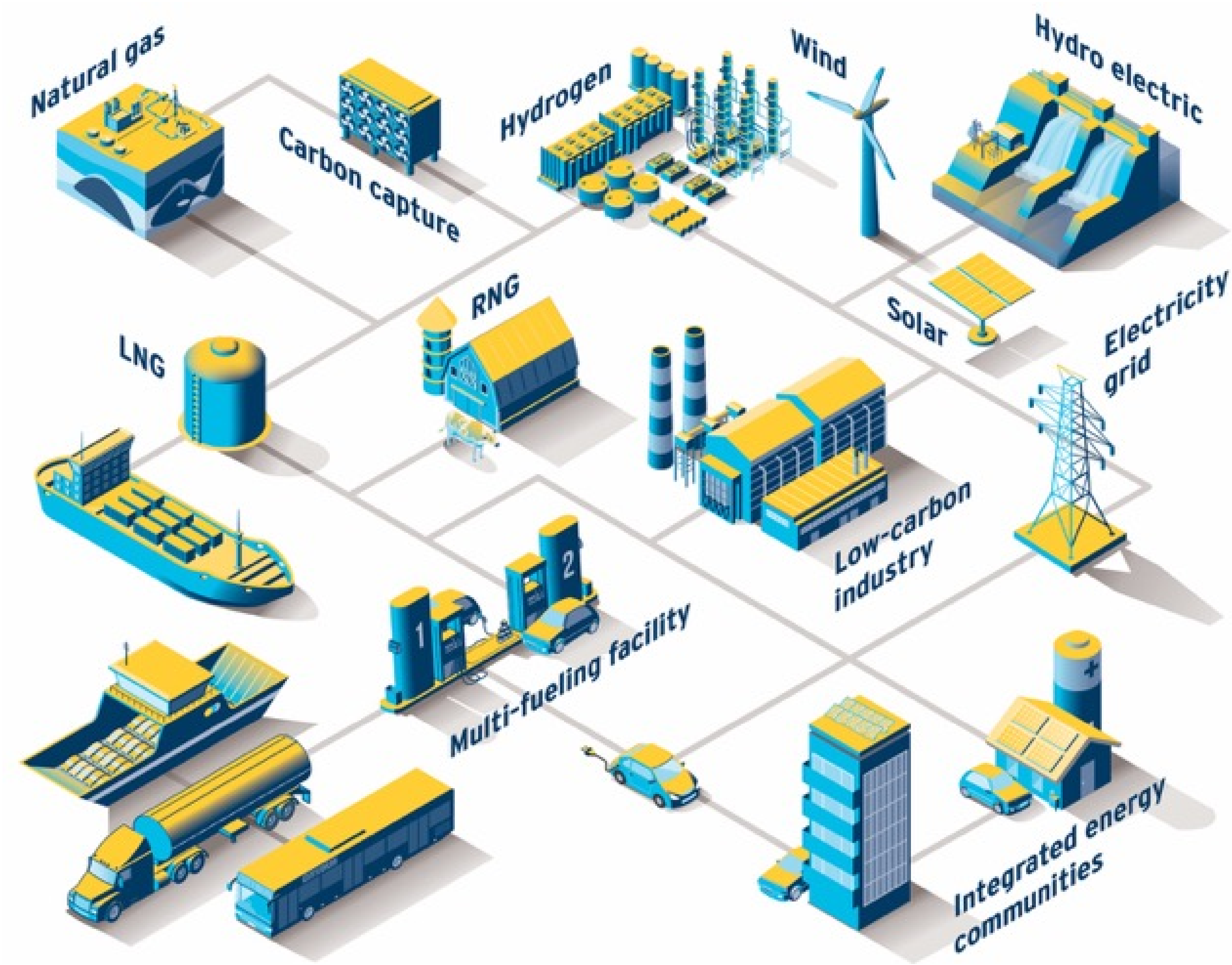


[2] Both pathways developed in this study achieve 95% of the domestic reductions required by 2050.

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

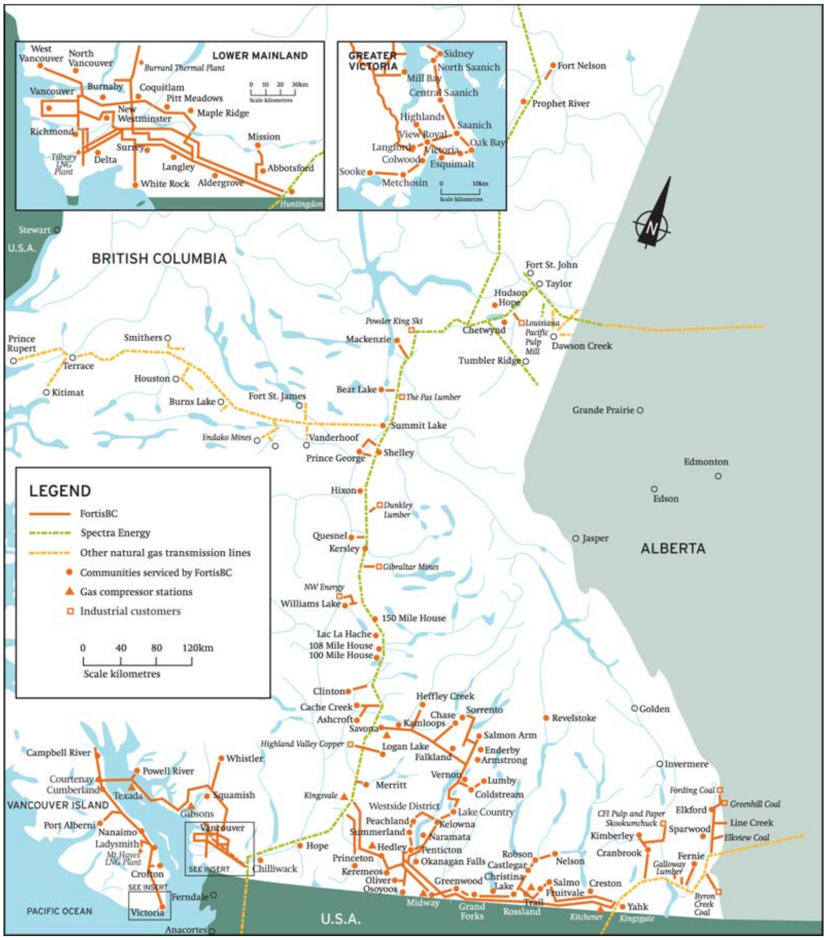
FortisBC operates approximately 49,000 km of natural gas transmission and distribution pipelines in BC. This infrastructure, along with the natural gas pipelines owned by Pacific Northern Gas, TC Energy, Enbridge, and other organizations, spans across the province. The system has multiple import/export 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.

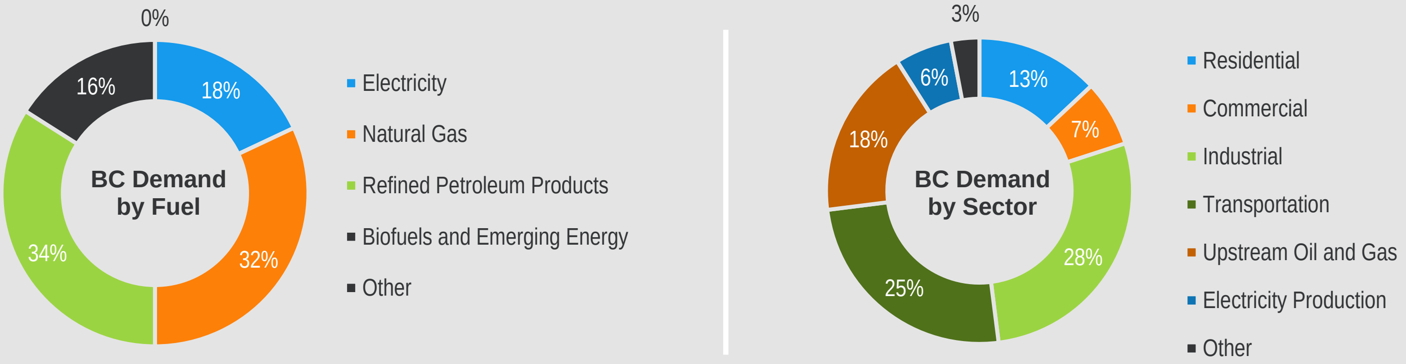
FIGURE 3. NATURAL GAS INFRASTRUCTURE SERVING BC



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.

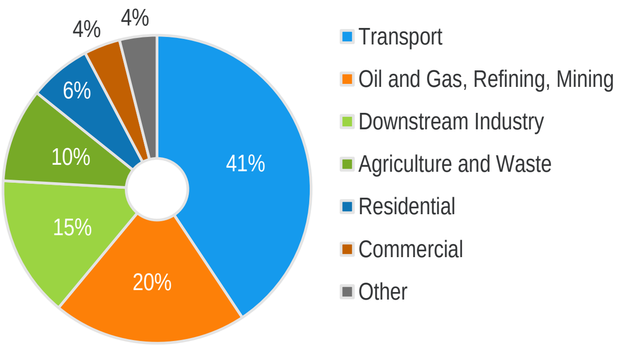
BC has large domestic resources of natural gas and electricity. In 2018, net electricity imports made up 2% of domestic generation. Over 90% of the natural gas consumed in BC is produced in BC (remaining supply is imported from Alberta). However, BC's total natural gas production is greater than its 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.

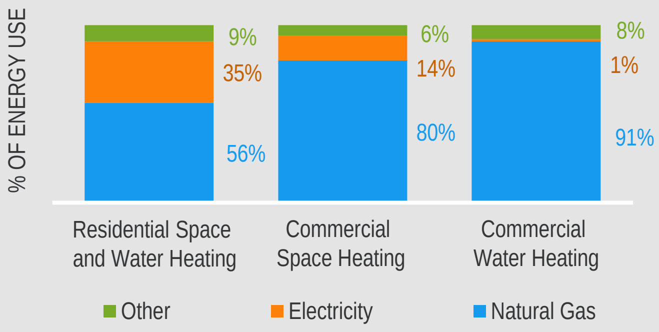
A focus on reduction of emissions across all sectors will be required to achieve the reductions targeted by 2050. Given the significant emissions associated with the transportation and industrial sectors, substantial efforts will be required in these sectors.

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.

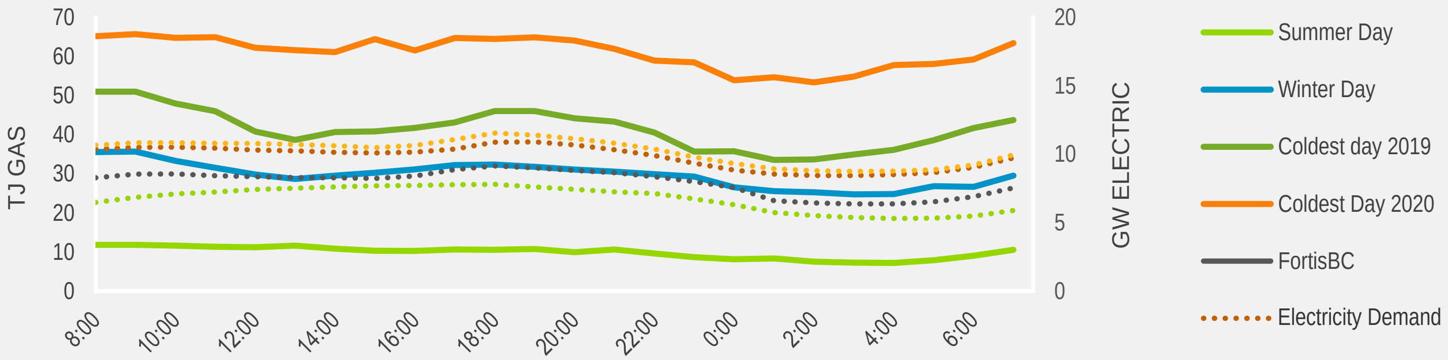
On a very cold day, such as January 14, 2020 when temperatures in the Lower Mainland approached -10°C, the energy delivered by the gas system can be double an average winter day and 50% higher than the coldest day in 2019.

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.

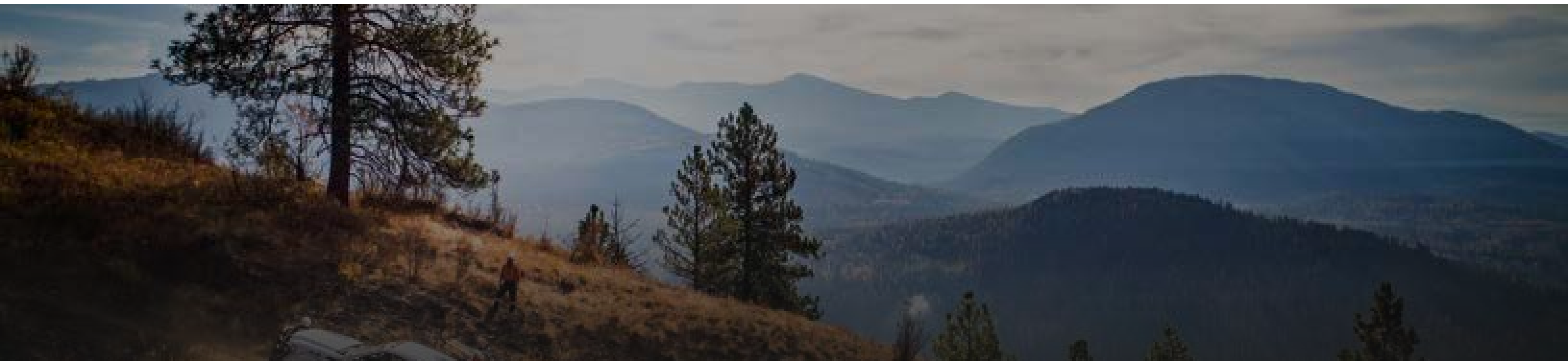
Although electric storage costs are falling significantly, they are still much more costly between $50 and $90 per GJ equivalent comparatively.[9] In addition to Aitken Creek, several smaller natural gas storage facilities exist throughout BC. Natural gas is injected into seasonal storage in summer months 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

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.

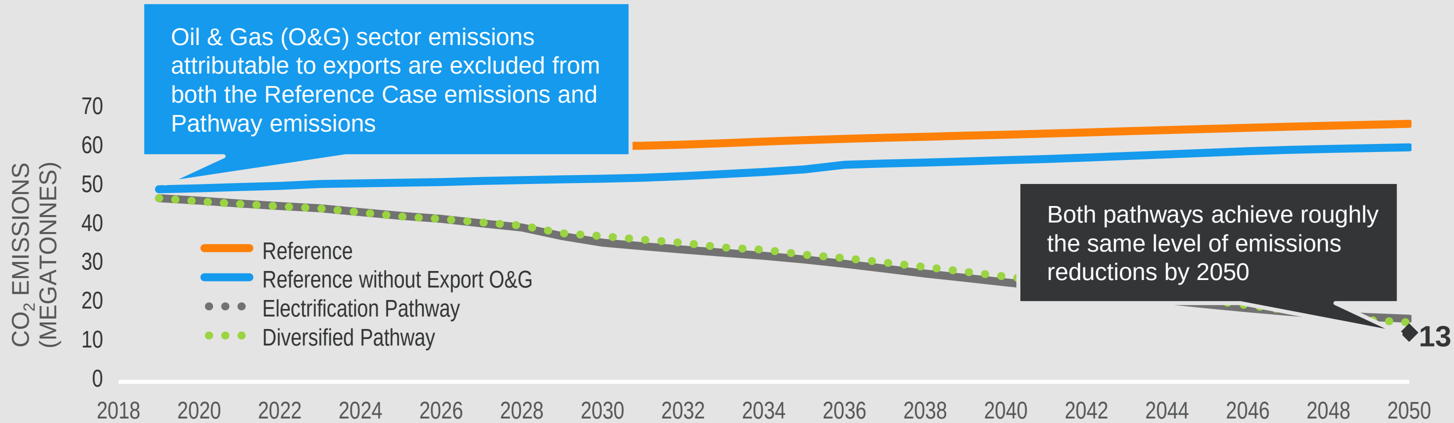
5. STUDY RESULTS – SIDE BY SIDE COMPARISON OF PATHWAYS

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

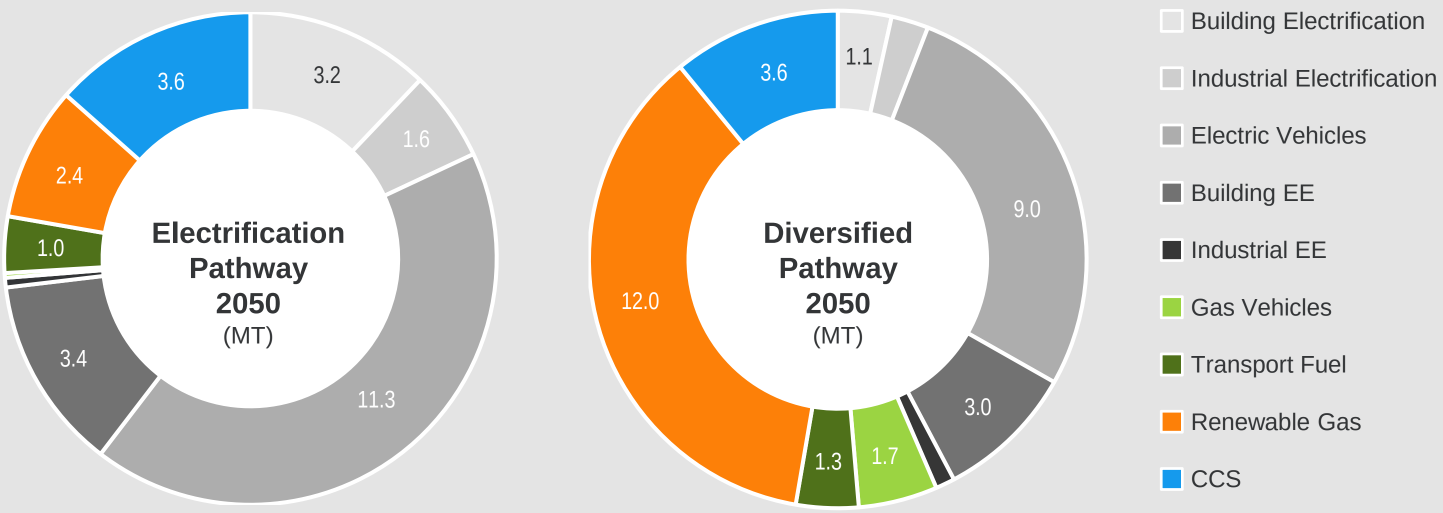
As Figure 11 shows, light duty EVs have a large role to reduce GHG emissions in both pathways, as both pathways were modelled to include the Zero-Emission Vehicles [20] Act; the Zero-Emission Vehicles Act requires 100% of light duty vehicles sold in 2040 to be zero-emissions vehicles.[21] MHD vehicles 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

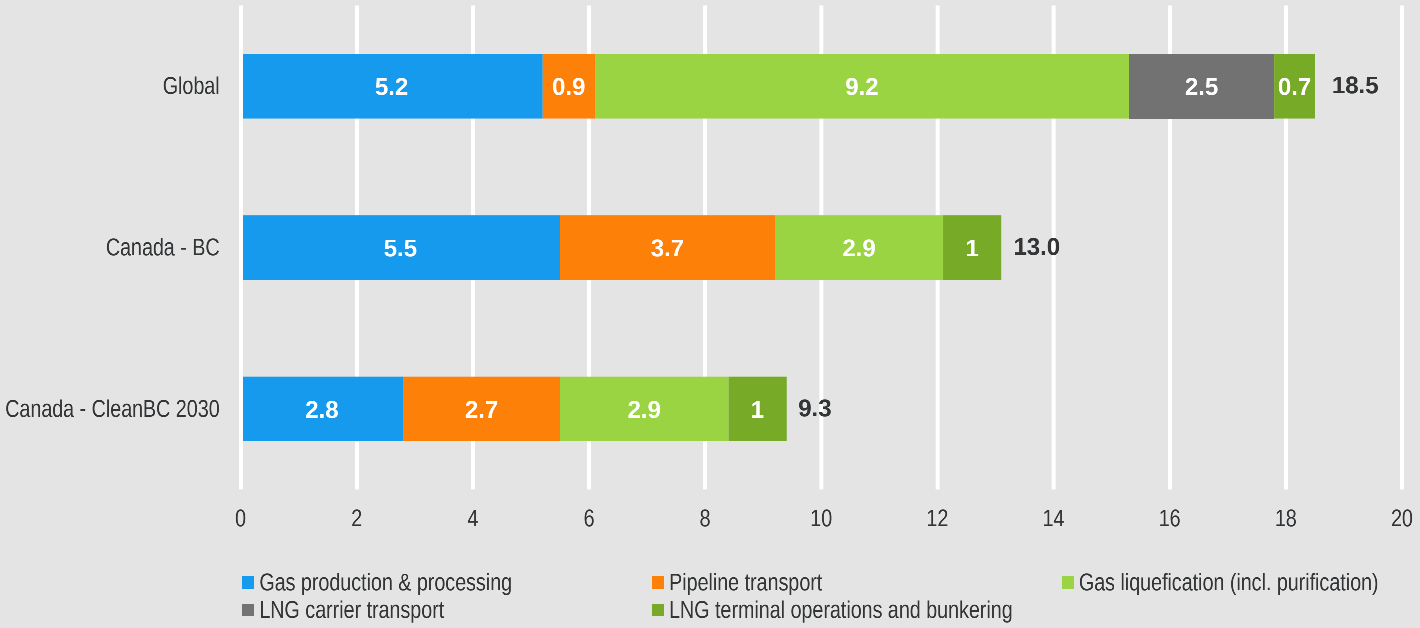
The gas system can also lead to GHG emissions reductions outside of BC. Although these reductions were not evaluated in this analysis, FortisBC has conducted separate evaluations on the role of the gas system to supply LNG to marine vessels and to displace carbon-intensive energy consumption in China 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)



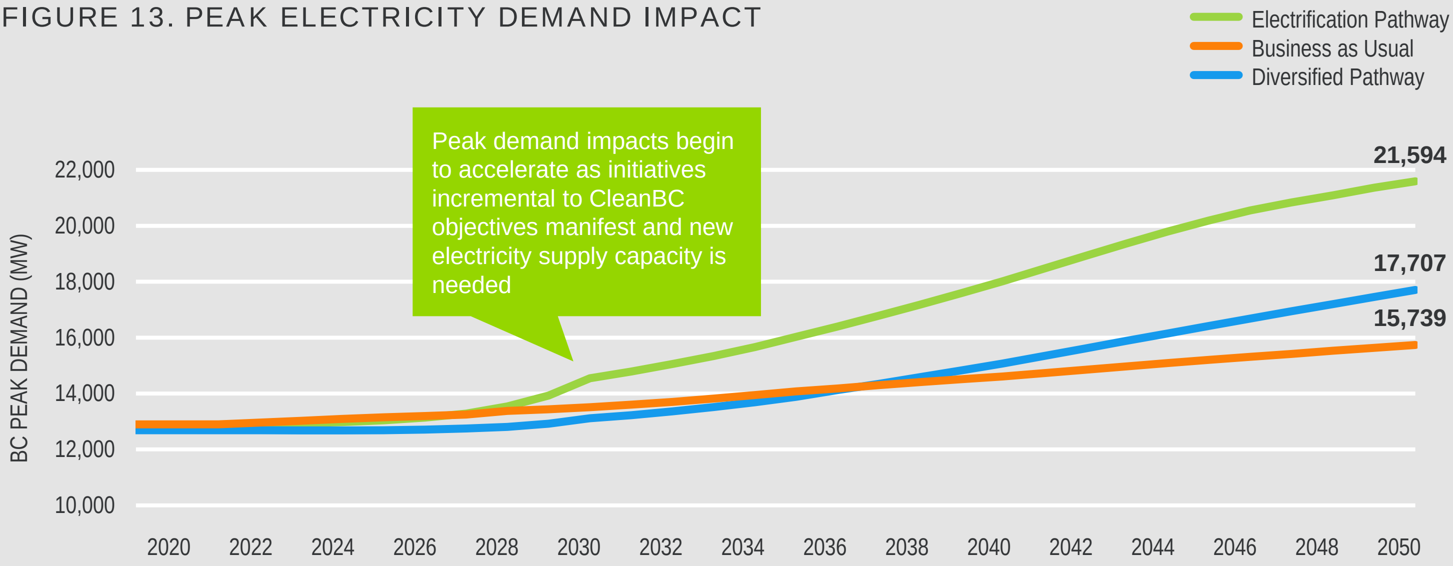
Source: Thinkstep, Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver: 2nd Project Phase, 2020

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

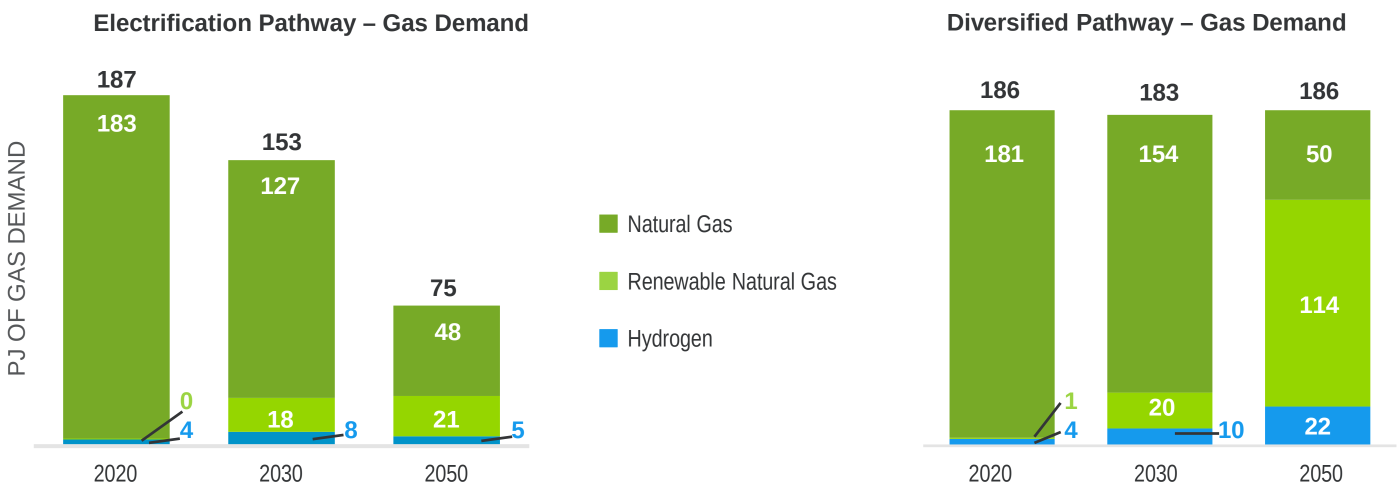


*Peak demand impacts are based on conservative assumptions in both pathways (e.g., majority of MHD vehicle charging occurs in non-peak times)
Source: Guidehouse Analysis

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

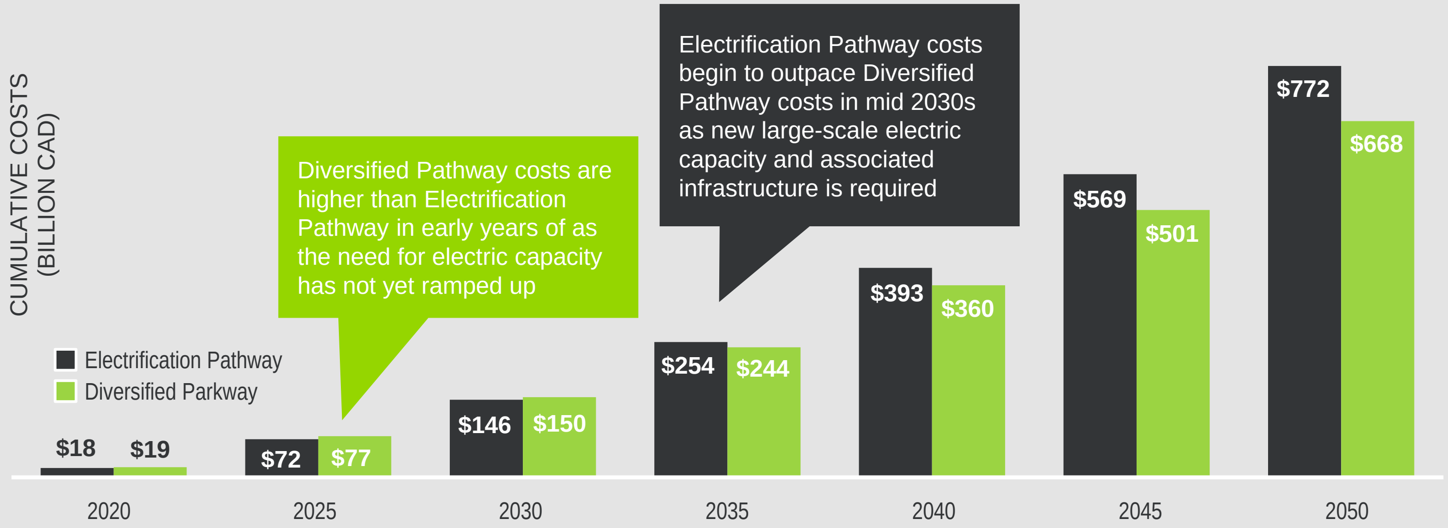
By 2050, the societal value of the Diversified Pathway is expected to be at least $100 billion higher than the Electrification Pathway. The cost of each pathway is roughly the same until the mid-2030s, when the costs of the Electrification Pathway rises much higher than the Diversified Pathway. This 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.

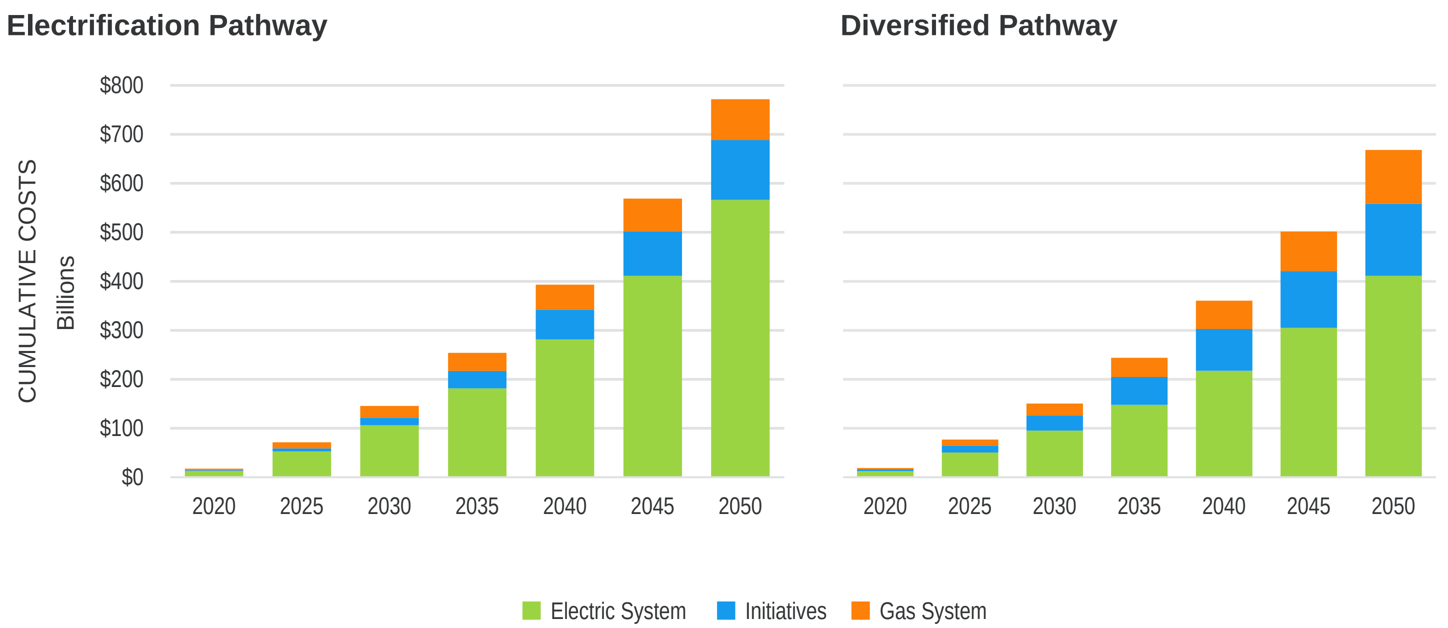
FIGURE 15. PATHWAY COSTS



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.

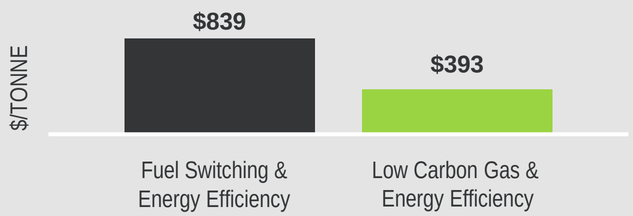
The findings in this analysis suggest drop-in fuels would be more cost-effective than fuel switching to electricity. The cost per tonne of reducing emissions in difficult-to-address sectors like buildings with renewable gases is approximately half that of fuel switching when accounting for the full system 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.