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July 5, 2021

Penticton Indian Band
c/o Mandell Pinder LLP
433 - 1080 Mainland Street
Vancouver, B.C.
V6B 2T4

Attention: Ms. Tarlan Razzaghi

Dear Ms. Razzaghi:

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 Penticton Indian Band (PIB) Information Request (IR) No. 3

On November 16, 2020, FEI filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-166-21 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to PIB IR No. 3.

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

1.0 Topic: Gas Demand

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application; pdf pg. 29

Section 3.3 - Peak Demand is Expected to Increase Resulting in Capacity Shortfall

1.3 Please provide the assumptions FEI is making with respect to future coldest weather events.

Response:

FEI assumes the future coldest weather events through the forecast period would be equivalent to the current design temperatures or design degree days for each region served by the ITS. Please refer to Section 3.3.1.1 of the Updated Application for a description of the extreme value analysis used for determining the design temperature and the values used in the Thompson Okanagan regions served by the ITS. Please also refer to the response to BCUC IR2 43.2.1 for a history of how the design degree day values for the ITS have changed over time.

PIB IR3 1.3.1:

1.3.1a) Please identify the most recent climate science literature or reports that Fortis considered on the predicted changes in climate in the region to calculate its future winter peak demand?

Response:

FEI does not project changes in future climate when calculating the peak demand forecast, and therefore has not applied findings from any recent literature. Extreme weather (as compared to smaller changes in climate averages) in any given year can vary significantly. FEI's believes that a statistical analysis of past extreme events, rather than speculation on future unrealized possibilities, is the most appropriate method for determining the design temperature (extreme weather event) that establishes the peak demand.

Please also refer to the response to BCUC IR3 65.1 for further discussion of FEI's position on future influences on peak demand. Also, please refer to the response to BCUC IR2 43.8 where FEI was asked to comment on the applicability of recent literature prepared for the Okanagan Regional District and to speculate on and illustrate the impacts of climate change on the peak demand forecast.

1.3.1b) Has Fortis identified a threshold at which UPCpeak demand will render the OCU Project not needed? If so, what is the threshold? If not, why not?

Response:

FEI does not identify a peak demand threshold at the use per customer (UPC) level. FEI calculates different UPC_{peak} values for multiple rate schedules in multiple communities served by the ITS. It is the cumulative impact of all communities' peak demand (calculated by summing the products of the UPC_{peak} values times the customer account numbers) that determines the peak demand of the system and where the load is distributed across the system. FEI then determines the capacity of the system by modeling the impact of the forecast peak demand and the distribution of demand system pressures at critical points within the ITS. The UPC_{peak} of a particular rate schedule or in a particular community exceeding a certain threshold is not on its own an indication that the system capacity would be exceeded.

2.0 Topic: Gas Demand

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg. 31

In simple terms, current peak demand is determined by extrapolating the observed variation of existing customers' daily consumption versus temperature to the region's system design temperature.

2.1 How has FEI accounted for climate change in its demand forecasting over the Project's lifespan?

Response:

Please refer to the response to BCUC IR1 8.4.

PIB IR3 2.1.1:

No question was provided.

2.2 How has FEI accounted for government climate policy, such as changes to building codes, subsidies for heat pumps, carbon pricing, or other policy that may have a substantial effect on gas demand?

Response:

FEI forecasts peak demand requirements using current measurements of customer consumption that reflect the impact of existing codes and policy. FEI recognizes there may be a reduction in annual gas demand as a result of the cited policies, but the effect on peak demand is uncertain and so FEI has not speculated on future changes. As a result, FEI applies the currently calculated peak use per customer (UPC_{peak}) to future forecast customers and does not assume a change over time. Please refer to the responses to BCUC IR1 5.2, 5.2.1 and 5.4 for additional discussion on FEI's assumptions related to UPC_{peak} over the forecast.

Please also refer to the response to BCOAPO IR2 14.1 for discussion of how FEI envisions a future where the majority of the energy it delivers through its system, including the Project, will be renewable. Additionally, please refer to the response to CEC IR2 54.2 for discussion on trends in electrification and peak demand.

PIB IR3 2.2.2:

2.2.2a) Please justify FEI's reliance on historical data to inform future trends.

Response:

Please refer to the response to BCUC IR3 65.1.

2.2.2b) Please confirm that CleanBC includes incentives for home and building electrification and energy efficiency, including with respect to heat pumps, windows etc.

Response:

Confirmed, CleanBC provides policy direction for the types of incentives noted in the question.

2.2.2c) Please explain how FEI has addressed the statistical bias against the effects of CleanBC programs on gas demand (i.e. home and buildings incentive programs and the increasing rate of uptake of heat pumps) arising from FEI's method of forecasting peak gas demand upon historical peak demand?

Response:

FEI disagrees with the premise that there is a statistical bias against the effects of CleanBC programs on gas peak demand arising from FEI's method of forecasting peak gas demand by using historical peak demand. CleanBC identifies numerous opportunities within the buildings, industry and transportation sectors for the gas system to materially contribute to GHG reductions and economic growth in British Columbia. For example, the 15 percent minimum renewable gas initiative in the Guidehouse report *Pathways for British Columbia to Achieve its GHG Reduction Goals,* provided as Attachment 14.2.1a in response to PIB IR3 14.2.1a represents 75 percent of anticipated reductions in the buildings sector. In this example, CleanBC assumed fuel switching from conventional natural gas to renewable gas with no reduction in demand.

2.2.2d) Please explain how FEI's aspiration to deliver more renewable gas has any relation to the justification of the OCU Project?

Response:

The OCU Project is needed to meet growing customer demand in the Okanagan region in the near term. While FEI's plans to deliver more renewable gas in the future are not directly related to the need and justification of the OCU Project, those plans support demand for gaseous energy over the longer term and demonstrate the key role that gas delivery infrastructure plays in decarbonization.

3.0 Topic: Project Economic Impacts

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg.84

The Project is expected to result in an overall positive impact to residents and businesses through the creation of additional employment, the procurement of local materials, and the use of local services, such as lodging and dining. Further, the Project will benefit the Okanagan region, by helping to meet long-term capacity requirements for a reliable and safe gas system, as population is forecast to increase for the next 20-year period as described in Section 3.3 of the Application.

3.1 Please provide the analysis undertaken by FEI to make this conclusion, and the data and assumptions relied upon.

Response:

As outlined in Section 3.3 of the Updated Application, FEI's forecast population increase data is based on Statistics Canada data as well as population projections prepared for FEI by BC Stats. These data sources indicate historical annual average population growth rate of 1.6 percent over the 20 year period from 1996 to 2016. The forecast anticipates continued growth over the next 20 years. The Project will provide long-term capacity to meet growing energy demand in the region, thereby supporting continued economic growth.

FEI's expectation that the Project will result in a positive overall economic impact to residents and businesses is based on its experience on past projects and the anticipated economic benefit to local Indigenous and non-Indigenous businesses contracted on the Project, and members of the local Indigenous and non-Indigenous workforce hired for positions on the Project.

For example, between 2014 and 2019, FEI invested approximately $300 million in the Lower Mainland Intermediate Pressure System Upgrades (LMIPSU) project. FEI and its contractors supported more than 350 suppliers in over 40 municipalities and Indigenous communities in Metro Vancouver and across British Columbia. Of this investment, $263 million was spent in goods, materials, and services for the project. LMIPSU project general contractors spent 5.5 percent of their BC-based spend on Indigenous-affiliated businesses.

Finally, FEI's contractors are required to develop participation plans to optimize access and opportunities for local Indigenous and non-Indigenous businesses and for local members of the workforce for major projects. Subsequently, FEI tracks these socio-economic benefits and requires that its contractors and consultants report on local Indigenous and non-Indigenous participation.

PIB IR3 3.1.1:

3.1.1a) Please provide any further evidence in support of FEI's statement of its "expectation that the Project will result in a positive overall economic impact to

residents and businesses is based on its experience on past projects" beyond the statements provided in FEI's response.

Response:

FEI's expectations of overall positive economic impacts are derived from its experience on past projects. Please refer to the response to PIB IR3 4.1.1a for examples of positive economic impacts from past projects.

3.1.1b) Please define "economic impact" in the phrase "expectation that the Project will result in a positive overall economic impact to residents and businesses is based on its experience on past projects" and advise whether this term as used by the FEI is synonymous with "socio-economic benefits" or not.

Response:

FEI defines "economic impact" as a financial effect on a situation, person, and/or entity. This phrase can include benefits and adverse effects. Economic impact can also form a part of socio-economic benefits.

3.1.1c) Please explain how FEI translates spending to an "positive overall economic impact".

Response:

FEI translates spending as a flow-through of economic benefits such as purchasing goods or services, or employment of persons to produce a positive overall economic impact. For example, FEI considers the $74 million contracted to local businesses on the Lower Mainland Intermediate Pressure System Upgrade Projects a positive overall economic impact. Likewise, on the Mt. Hayes LNG Storage Project, FEI considers the $70 million in investment, including in local suppliers for goods and services and direct local employment, a positive overall economic impact.

3.1.1d) Please provide the supporting information that FEI says it has tracked on socio-economic benefits.

Response:

FEI utilizes a third-party consultant to capture and analyze the socio-economic data both from FEI and its contractors related to business details, spend in communities, employment, and

training for the OCU Project. Please refer to the response to PIB IR3 4.1.1a which provides examples of socio-economic benefits that FEI tracks on major projects.

An example of how FEI communicates the socio economic data is through the use of infographics; the image below is one example which was created for FEI's Tilbury LNG expansion project and is utilized on FEI's website for Major Projects, https://talkingenergy.ca/

Figure 1. https://talkingenergy.ca/project/tilbury-LNG-expansion-project

3.2 How have the impacts to Penticton Indian Band been taken into account in this analysis of economic impacts?

Response:

FEI considered the Penticton Indian Band (PIB) in its assessment of local Indigenous businesses and workforce available to participate in anticipated contracting and employment opportunities. FEI has engaged with the PIB development corporation to discuss contracting opportunities and will work with the PIB to identify and address economic impacts as they become known.

PIB IR3 3.2.1:

No follow-up question provided.

4.0 Topic: Project Economic Impacts

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg. 84

Throughout the Project, FEI will endeavor to track the following: Project investment in local Indigenous communities, Project investment in municipalities/regional districts, local employment opportunities, and other community investment activities.

4.1 What does "endeavour" mean, in this context, and what will FEI do in the course of "endeavouring" to track investment and employment?

Response:

In this context, FEI uses "endeavour" to refer to the steps FEI will take to track socio-economic benefits. In this regard, FEI will track local Indigenous and non-Indigenous contracting, employment, and training on the Project. Based on this tracking, FEI will communicate the results through project communications and its sustainability reports. For an example of past project communications please refer to the following web link: https://talkingenergy.ca/topic/ideal-welders-proving-industry-partnerships-are-key-local-growth.

PIB IR3 4.1.1:

4.1.1a) Please provide any similar data tracked from other FEI projects. If none exist, please indicate so.

Response:

FEI has tracked similar data on a number of major projects. For example, in 2012 on the Mt. Hayes LNG Storage Project, FEI partnered with the Stz'uminus (Chemainus) First Nation and Cowichan Tribes. Each Nation invested $5.7 million, creating jobs and economic opportunity in their communities. As a result of the project, the region received $70 million in investment, which included sourcing local suppliers for goods and services, direct local employment during construction, and 12 full-time operations jobs at the facility.

Similarly, FEI spent more than $119 million in BC since 2014 expanding the Tilbury LNG facility in Delta. To date, 365 BC companies from 25 communities and 3 Indigenous Nations have been contracted on the project.

Likewise, FEI's Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) projects delivered approximately $74 million to local businesses between 2014 and 2019. FEI spent $4.2 million on services from 11 Indigenous-affiliated businesses for the LMIPSU projects between 2014 and 2019, including for environmental monitoring and equipment.

5.0 Topic: Project Economic Impacts

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg.119-120

FEI is committed to building strong working relationships with Indigenous groups guided by FEI's Statement of Indigenous Principles (Appendix I-1). FEI recognizes that the potential impacts of the Project on the title, rights, and interests of affected Indigenous groups must be identified and avoided or mitigated as appropriate. To achieve this, FEI recognizes that its engagement approach will need to be thorough, timely, and meaningful. 1 FEI also endeavors to create project benefits for local Indigenous groups, through capacity building and economic opportunities.

5.1 Does FortisBC acknowledge that this application to the BCUC has proceeded before reaching agreements with Penticton Indian Band regarding whether and how to avoid and mitigate project impacts to Syilx title, rights and interests?

Response:

Although an agreement was not reached with PIB regarding potential impacts to PIB's rights and interests prior to FEI filing its Application with the BCUC, FEI will continue to engage with the PIB to find solutions that mitigate any potential impacts to Syilx rights, title, and interests that may be revealed through the development process for the Project. In that regard, FEI has engaged with PIB on the proposed OCU Project since 2019 in an effort to study, understand, and mitigate potential impacts to PIB's rights and interests. This process has included entering a capacity funding agreement with PIB to prepare four reports to assess potential impacts, holding meetings to discuss mitigations, and seeking additional meetings to discuss potential impacts and mitigations. Details of this engagement and FEI's continued efforts to meet with PIB to discuss ways to avoid or mitigate potential impacts to Syilx interests are ongoing and are further described in the responses to BCUC IR2 62.1 and 62.2.

PIB IR3 5.1.1:

5.1.1a) Will FEI agree to a suspension of the BCUC process until PIB and FEI have concluded their discussions and engagements on the OCU Project?

Response:

FEI does not consider it reasonable, or necessary, to suspend the BCUC process until the PIB and FEI have concluded their discussions and engagements on the OCU Project.

The OCU Project is necessary for FEI to continue to maintain safe and reliable gas service to its existing and future customers in the central and north Okanagan regions. As discussed in the Application, due to load growth in the region (specifically around urban centres like Kelowna and

Penticton), FEI predicts that forecast peak demand will exceed the existing capacity of the ITS, and a system upgrade is required to address the expected capacity shortfall prior to the winter peak of 2023/2024. Therefore, given the continuing potential for significant new load, the limitations of existing short-term mitigation measures, and the lead time required for a project of this nature, it would not be prudent to delay the current regulatory review process.

Further, the BCUC regulatory review is a valuable process for determining if the Project is in the public interest. The review process is transparent and open to the public and interveners for comment and input. The BCUC will use the evidence provided by FEI in its Application, together with the responses to multiple rounds of information requests, to make a public interest determination consistent with the *Utilities Commission Act* and the BCUC's practices and guidelines. BCUC review is one of several regulatory approvals required for the Project, and a positive decision from the BCUC does not equate to the Project proceeding to construction.

5.2 What does "endeavour" mean, in this context, and what will FEI do in the course of "endeavouring" to create project benefits?

Response:

In this context, FEI uses "endeavour" to refer to the steps FEI will take to provide opportunities for Project benefits. FEI is seeking to provide opportunities for local Indigenous and non-Indigenous contracting, employment, and training on the Project. At this time, preliminary discussions are ongoing with economic development leads of Indigenous communities, and/or directly with Indigenous community affiliated companies.

PIB IR3 5.2.1:

5.2.1a) Will FEI agree to a suspension of the BCUC process until these ongoing discussions are concluded?

Response:

Please refer to the response to PIB IR3 5.1.1a.

6.0 Topic: Project Economic Impacts

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg.126

FEI will incorporate feedback from Indigenous groups into the Project's procurement plans to identify socio-economic opportunities of mutual interest. FEI will garner detailed reporting on Indigenous employment and socio-economic impacts during this Project lifecycle. Follow-up meetings will be scheduled with Indigenous groups as additional information around employment opportunities, contracting and procurement becomes available.

6.3 Please identify the potential economic costs of the OCU Project and who FEI expects to incur these costs?

Response:

The magnitude and treatment of the Project costs are explained in Section 6 of the Updated Application and are summarized here for convenience:

1. The estimated capital cost to construct the OCU Project is $271.3 million in as-spent dollars.

2. Consistent with FEI's treatment for CPCNs, the capital costs of the Project (i.e., the costs included in the "Sub-Total Construction Cost Estimate (As-spent)"[1] in Table 6-1 referenced above) will be held in Work in Progress, attracting AFUDC during the construction period. Once construction of the Project is completed in 2023, and the specific assets are commissioned and placed in service, FEI will transfer the associated costs to the appropriate plant asset accounts and include them in FEI's rate base on January 1 of the year following their in-service date.

3. Pursuant to sections 59 to 61 of the UCA, FEI is also seeking approval of a new non-rate base deferral account, titled the "OCU Application and Preliminary Stage Development Costs Deferral Account", for deferral treatment of the costs of preparing the Application and Preliminary Stage Development Costs. These deferred costs would be included in rate base and amortized over a three year period beginning January 1, 2022.

Overall, the Project cost will be recovered in customer rates and will result in an estimated delivery rate impact of 2.21 percent in 2024 when all construction is complete and after all assets are placed in service in 2023. For a typical FEI residential customer consuming 90 GJ per year, this would equate to an approximate average bill increase of $9 per year.

[1] The CPCN Application on line 9, page 95 of makes reference to "(i.e., the costs included in the subtotal "Project Capital Budget" in Table 6-1 referenced above)", however Table 6-1 does not have a line item titled such. The wording is updated within this response to correctly reflect the appropriate line item from within Table 6-1.

PIB IR3 6.3.1:

6.3.1a) Has Fortis assessed the economic costs associated with the OCU Project's environmental impacts and impacts on Sylix rights and title and interests? If so, please provide such assessment. If not, why not?

Response:

The economic costs associated with the OCU Project's environmental impacts and impacts on Syilx rights and title and interest have not yet been assessed. FEI intends to engage with Indigenous groups now that the community-led studies and reports are completed, and to use those findings and collaboration with the community to inform the assessment of potential impacts, and the costs associated with them. FEI is committed to continuing to engage with Indigenous groups to understand the potential impacts and costs of the Project.

7.0 Topic: Screening and Evaluation of Alternatives

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg. 46

FEI evaluated all five alternatives on their technical merits and on the basis of high level cost estimates, to screen out those that did not accomplish the objectives of the OCU Project as identified in Section 4.1.

7.5 How were Indigenous groups and/or stakeholders involved in developing the criteria?

Response:

Please refer to the response to PIB IR1 7.4. During the early stages of alternatives screening for the Project, no external groups were engaged to assist in developing the initial Project screening process. This is because early screening is driven by technical requirements which identify feasible alternatives for the Project. Once feasible alternatives have been identified through the screening process, additional information is gathered regarding these alternatives. Feasible alternatives are then evaluated using broader criteria, including both stakeholder and Indigenous impacts, to ensure that the preferred alternative considers all these aspects.

PIB IR3 7.5.1:

7.5.1a) Please confirm that all decision-making criteria in the screening and alternatives evaluation processes were developed by FEI internal staff and thus did not involve any Indigenous communities.

Response:

Confirmed. For the reasons discussed in the preamble above, decision-making criteria and weightings were developed by FEI internal staff.

7.5.1b) Please confirm that all evaluations were undertaken by FEI internal staff and thus did not involve any Indigenous communities.

Response:

Confirmed. For the reasons discussed in the preamble above, initial feasibility screening of alternatives was undertaken by FEI's internal staff. FEI internal staff, who also used information provided by FEI's consultants, undertook scoring of alternatives against evaluation criteria to select a preferred alternative.

7.5.1c) Please provide CVs of the FEI internal staff who developed decision criteria and screened and evaluated alternatives describing their expertise regarding Indigenous knowledge and impacts.

Response:

FEI respectfully declines to name the internal staff individuals involved in developing criteria and/or screening alternatives, or to provide their CVs. The titles of the subject matter experts and subject matter leads who assisted in developing criteria and/or screening alternatives included the following parties:

- Senior Project Manager (P.Eng.);
- Manager, Gas System Assets (P.Eng.);
- Senior Manager, Engineering Projects (P.Eng.);
- Manager, System Capacity Planning (P.Eng.);
- Manager, Regulatory Projects;
- Manager, Indigenous Relations (MA);
- Environmental Program Lead (P.Ag., EP, BC-CESCL);
- Manager, Property Services;
- Manager, Environmental Programs (R.P.Bio.);
- Corporate Communications Adviser;
- Manager, Community Relations (MBA); and
- Community Relations Manager (BBA, MM).

All of the individuals noted have extensive experience on multiple FEI projects, including the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU), Coastal Transmission System Upgrade (CTS), Inland Gas Upgrades (IGU), Eagle Mountain to Woodfibre Gas Pipeline (EGP), and various sustainment capital projects throughout the province. Moreover, many of these individuals have industry experience on various similar projects outside of FEI. Where roles require accreditation (e.g., professional engineer, registered professional biologist), the individuals maintain the appropriate professional designation. These projects, particularly the IGU and EGP Projects, involved significant and ongoing engagement with multiple Indigenous groups.

8.0 Topic: Screening and Evaluation of Alternatives

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg. 46

Evaluation criteria were grouped into three primary categories:

- *Asset Management Capability;*
- *Project Execution and Lifecycle Operation; and*
- *Financial.*

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf. pdf pg.50

Weightings were assigned to the overall categories of evaluation criteria as shown in Table 4-3. Asset Management Capability was weighted the most heavily to reflect the importance of meeting FEI's overall technical objectives. Weighting was split evenly between the other two categories. Both are considered important as they measure various types of impact to the communities affected by the OCU Project. Weightings were also assigned to the criteria within each category, also as summarized in Table 4-3.

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf. Pg. 49

The sole criterion within this category measures the financial impact of the project on FEI's 24 customers. FEI considered the long term rate impact to FEI's non-bypass customers in order to 25 financially compare all three feasible alternatives. This was completed by evaluating the present 26 value of the incremental revenue requirement as well as the levelized delivery rate impact over 27 the 70 year analysis period for each alternative based on the estimated capital cost and 28 operating cost.

8.7 Why do "Environmental, Public, and Indigenous Impacts" receive the lowest weight of all criteria?

Response:

FEI selects and assigns weightings to its evaluation criteria in order to place emphasis on aspects of a project which drive decision making. In other words, criteria that differ noticeably between alternatives are generally more heavily weighted to help with the decision making process. For example, in this case, certain Project alternatives carried very high degrees of schedule risk, while others did not. Selecting an alternative with high schedule risk would have the potential to cause delays to project completion, which would result in negative impacts on FEI's customers, the public, and Indigenous groups. Schedule risk was therefore included as a criteria and weighted highly, whereas in a project with less time-sensitivity or less differentiation between alternatives, this may not be included as a criteria at all.

Conversely, FEI did not highly weight "Environmental, Public, and Indigenous Impacts" on the OCU Project due to the limited differentiation expected between the impacts caused by the three feasible alternatives. This is because each alternative was selected specifically to minimize impacts on the environment, the public, and Indigenous groups. While initially identifying its alternatives, FEI chose to select alternatives which would allow utilization of existing utility rights-of-way wherever possible: Alternative 1 made use of the existing VER PEN 323 right-of-way, while Alternatives 2 and 3 allowed FEI to optimize routing between the VER PEN 323 right-of-way and the FBC powerline right-of-way. No alternative proposes construction of new right-of-way through land not adjacent to existing infrastructure (except potentially for portions of a route, where deviation from existing rights-of-way is unavoidable).

When initially considering the weighting, FEI noted that there would likely be little difference between the impacts on environment, public, and Indigenous groups, and therefore that the scores assigned against this criterion for each of the three feasible alternatives would not differ greatly. Given that all three alternatives make use of existing rights-of-way as much as possible, and that this minimizes the impacts these alternatives may have, FEI determined that weighting this criterion highly would not change the final outcome of the alternative selection, but would instead dilute the impact from other critical evaluation criteria during the selection process.

PIB IR3 8.7.1:

8.7.1a) Please detail the specific factors and impacts FEI assessed in its "Environmental, Public and Indigenous Impacts" criteria.

Response:

The specific factors and impacts FEI assessed were the alternatives' requirements for potential right of way widening, safety, Indigenous impacts, and traffic impacts.

FEI assessed each alternative's requirements for potential widening to existing rights-of-way or clearing of new sections of land. Alternatives which would require additional land to be cleared would score lower due to the long-term impact that clearing land may have on the environment, adjacent landowners and/or Indigenous groups. FEI attempted to mitigate this impact during alternative identification, by planning construction within or adjacent to existing rights-of-way for all three alternatives. For this reason there was no notable difference between the three alternatives from this perspective.

Safety risk to people in the vicinity of the pipeline (which would potentially include both non-Indigenous and Indigenous groups) during execution of the Project was considered.

A desktop study of the various traditional territories through which the proposed alternatives would pass was also completed, which indicated all alternatives would be likely to require engagement with the same Indigenous groups, including the PIB (i.e., there would be no difference in the number of groups impacted). FEI focused on understanding the impacts known at the time. For

example, if the Project alternative crossed known Indigenous cultural sites, reserve lands, or other sensitive areas to Indigenous groups, this information was incorporated into FEI's decision making. Any environmental and archaeological features known at the time were also considered along with the Indigenous impacts.

Finally, traffic impacts were also considered as these can be disruptive to the public during Project execution. There was no notable difference between the three alternatives from this perspective.

8.7.1b) Please provide the assessment conducted by FEI in support of this statement "FEI did not highly weight "Environmental, Public, and Indigenous Impacts" on the OCU Project due to the limited differentiation expected between the impacts caused by the three feasible alternatives."

Response:

The three feasible alternatives for the OCU Project are highly similar in terms of the areas of land which would be disturbed during and after construction. All three would follow existing rights-of-way where possible (the VER PEN 323 right-of-way and/or the FBC power line right-of-way), in order to minimize any lasting impact to the land and to Indigenous groups and stakeholders in the area. All alternatives are geographically close to each other and following a query to the British Columbia Consultative Area Database[2], it was determined that the Indigenous groups affected would remain the same regardless of the alternative selected.

FEI also considered the preliminary archaeological assessment completed for each alternative and focused on understanding the impacts known at the time. For example, if the Project alternative crossed known Indigenous cultural sites, reserve lands, or other sensitive areas to Indigenous groups, this information was incorporated into FEI's decision making.

The only major difference between the alternatives (from the perspective of Environmental, Public, and Indigenous Impacts) which could be identified was the safety risk inherent in hydrotesting the existing VER PEN 323 pipeline. While this risk could be managed and therefore did not automatically eliminate Alternatives 1 and 2, it did cause these alternatives to receive a lower score than preferred Alternative 3.

8.7.1c) Please confirm the alternatives were assessed before FEI received any interim or final traditional and ecological knowledge; use and occupancy and cultural heritage reports from PIB.

Response:

Confirmed.

[2] https://maps.gov.bc.ca/ess/hm/cadb/

10.0 Topic: Screening and Evaluation of Alternatives

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg.62:

Section 5.3.2. Step 2: Feasible Route Options Determination and Evaluation

10.5 How were Indigenous groups and/or stakeholders involved in developing the criteria?

Response:

Please refer to the response to CEC IR1 22.1. To summarize, the evaluation criteria and associated weightings were developed by an internal team of FEI subject matter experts, including representatives from the Asset Management, Engineering, Project Management, Regulatory Affairs, Community and Indigenous Relations, Environmental Management, and Property Services departments.

Please also refer to the response to PIB IR1 8.5.

PIB IR3 10.5.1:

10.5.1a) How were potential knowledge gaps and bias towards FEI interests addressed through this internal process of criteria development, weighting, and evaluation?

Response:

Members of the internal team have extensive experience on multiple projects, including the Inland Gas Upgrades (IGU), Lower Mainland Intermediate Pressure System Upgrade (LMIPSU), Coastal Transmission System Upgrade (CTS), Eagle Mountain to Woodfibre Gas Pipeline (EGP), and various sustainment capital projects throughout the province. The experiences from these projects contributes to FEI's management of potential knowledge gaps and bias during the evaluation criteria, weighting, and evaluation stages.

Moreover, FEI retained various subject matter consultants to provide the necessary input for the evaluation. Please also refer to the response to CEC IR2 59.1.1 for a list of companies used by FEI.

10.6 How did FEI address or adjust for any overlaps among criteria (e.g., between the Socio-Economic, Cultural Heritage, and the Human Environment criteria)?

Response:

FEI addressed any overlaps among criteria by clearly defining the considerations of each criterion. The evaluation considerations for each criterion are outlined in Table 5-2 of the Updated Application. The FEI subject

matter experts relied on their experience on previous projects when developing the scoring and ensured any potential overlaps were identified and addressed.

PIB IR3 10.6.1:

10.6.1a) Please explain the distinction between the description of the Socio-Economic criterion provided in Table 5-2 of the updated application (i.e., "Proximity to populated areas, roadway usage impacts, number of commercial accesses impacted"), the description of the Land Ownership and Use criterion ("Properties directly impacted during construction and nature of impacts"), and the description of the Human Environment criterion which includes "residential accesses impeded, etc."

Response:

The three criteria mentioned above all impact Indigenous groups and local stakeholders and residents in different ways and are considered unique.

The Socio-Economic criterion considers the social and economic impacts including commercial and agricultural industries. For examples, these may include road and traffic impacts to residents and visitors during construction activities.

The Land Ownership and Use criterion considers the direct impacts and restrictions to properties, including residential, during construction activities as well as long-term operations and maintenance activities. An example would be a scenario where the required right of way splits a property which precludes further development opportunities such as a subdivision.

The Human Environment criterion considers aesthetic, noise, emissions, and vibration nuisances that may be observed by residents and visitors to the area during construction as well as long-term operations and maintenance activities. An example would be a valve assembly site causing long-term visual or noise impact to the surrounding area.

13.0 Topic: Public Interest

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf. Pg. 127

Section 46 (3.1) of the UCA states that in considering whether to issue a CPCN, the BCUC must consider:

a) the applicable of British Columbia's energy objectives,

b) the most recent long-term resource plan filed by the public utility under section 44.1, if any, and

c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the Clean Energy Act (CEA).

13.1 Please explain how the Project serves BC energy objective (b), i.e., "to take demand-side measures and to conserve energy"?

Response:

FEI notes that the BCUC's consideration is of the "applicable" energy objectives. Which objectives are applicable will differ for each project, and in some cases, none of the energy objectives will be directly relevant. Where this is the case, FEI seeks to demonstrate that the project is not inconsistent with the energy objectives.

The OCU Project is needed to meet growing customer demand in the Okanagan region and is consistent with BC's energy objectives. While the Project itself does not directly contribute to demand-side measures, FEI notes that the Project is not inconsistent with British Columbia's energy objectives. Please refer to the responses to CEC IR1 44.1 and BCUC IR1 40.1 which describe how FEI's Project advances BC's energy objectives.

PIB IR3 13.1.1:

13.1.1a) Please explain how the OCU Project is not inconsistent with the following BC's energy objectives:

i) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66 percent;

ii) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

iii) to reduce BC greenhouse gas emissions;

iv) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

v) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

vi) to foster the development of first nation and rural communities through the use and development of clean or renewable resources

Response:

As explained in the response to PIB IR1 13.1, the applicable BC government energy objectives will differ for each project. The Project does not deter the advancement of any of these objectives. Therefore, in FEI's view, the OCU Project is not inconsistent with any of the energy objectives.

Please also refer to the response to BCUC IR1 40.1 where FEI explains the extent to which the Project is consistent with and will advance the BC government's energy objectives. This includes how the Project, as part of FEI's overall delivery system, provides the energy delivery infrastructure needed to deliver low carbon energy (i.e. renewable gas) to customers in the province, thereby supporting emissions reductions and the delivery of 15 percent renewable gas content.

13.1.1b) Please explain how the OCU Project specifically will facilitate BC achieving its goal of 15% renewable gas (Reference BCUC IR 1 40.1).

Response:

Please refer to the response to PIB IR3 13.1.1a.

13.8 What incremental volume of natural gas consumption will be attributed to the Project?

Response:

The OCU Project supports growing demand in the region and those changes in demand, regardless of their cause, will impact greenhouse gas emissions. The impact in GHG emissions from the OCU Project will be small relative to the significant GHG reductions expected from FEI's transition to renewable gas, consistent with provincial targets and the CleanBC plan.

FEI estimates that annual demand for energy from its system in the area impacted by the OCU Project will grow by up to 1,800 terajoules[3] (TJ) between 2022 (the year in which current capacity of the system in the Okanagan is

[3] One terajoule is equal to one thousand gigajoules.

expected to be reached) and 2030. The combustion of this gas would result in approximately 90,000 tonnes of CO2 emissions.

The estimated forecast of demand attributable to the OCU Project in 2022 based on the annual demand forecast provided in the 2017 LTGRP is 20,800 TJ. Estimated demand growth is therefore approximately 9 percent over that period. Over the same period, FEI expects to increase renewable gas content to at least 15 percent as stipulated in the provincial climate plan, CleanBC. As such, the transition to renewable gas and the associated GHG emissions reductions are expected to significantly outpace the incremental demand and GHG emissions associated with the OCU Project.

For example, by 2030, FEI anticipates that 30 petajoules[4] (PJ) of renewable gas will be brought online to achieve CleanBC's 15 percent renewable gas target. The transition to 15 percent renewable gas content will achieve at least 1.5 million tonnes of CO2 emissions reductions compared to the 90,000 tonnes associated with the increase in gas demand in the Okanagan region. Furthermore, as described in the response to BCOAPO IR2 14.1, by 2050 FEI intends to transition the majority of its gas portfolio to be renewable in order to reach the Province's legislated 80 percent GHG reduction target.

PIB IR3 13.8.1:

13.8.1a) Please provide an update on FEI's specific actions to foster the use of renewable gas in BC.

Response:

Fostering the use of renewable gas involves acquiring renewable gas supplies, delivering the renewable gas to customers, and ensuring the enabling provincial plans, targets, and policies are in place. The following are examples of work being undertaken by FEI to foster increased use of renewable gas in BC:

- Working with the BC Government to develop policies and regulations that will foster the development and acquisition of renewable gas resources and a renewable gas industry in BC, including supporting recent amendments to the Greenhouse Gas Reduction (Clean Energy) Regulation to accelerate the growth in renewable gas supply.
- Advocating successfully for the important role of renewable gas in CleanBC and the inclusion of the 15 percent renewable gas target.
- Continuing to seek additional supplies of renewable gas through purchase agreements and project development, including working with Indigenous groups to identify opportunities to develop renewable gas supply resources and with industrial customers to identify opportunities to develop and utilize renewable gas in their processes.

[4] One petajoule is equal to one million gigajoules or one thousand terajoules.

- Undertaking market studies that will lead to the development of new renewable gas offerings.
- Developing a hydrogen pathway that identifies key steps in resource acquisition and infrastructure development to rapidly expand the use of hydrogen energy in BC.
- Participating in renewable gas pilot projects such as the REN Energy RNG from wood waste pilot facility near Fruitvale, BC[5].
- Conducting a comprehensive review and assessment of FEI's RNG program including renewable gas supply forecasting, cost recovery mechanisms, and customer program offerings.
- Planning for the supply of renewable gas in FEI's Long Term Gas Resource Plan, to be filed in 2022.

13.8.1b) Please explain how approval of the OCU Project will specifically facilitate FEI's stated involvement in BC achieving its goal of 15% renewable gas by 2030.

Response:

The OCU Project will allow FEI to provide service to existing and new customers in the Okanagan region while also providing access to renewable gas supplies in support the Province's greenhouse gas reduction targets stated in CleanBC. Continuing to maintain and grow a safe and robust gas infrastructure network in the region will also open up opportunities for on-system renewable gas supplies in the region that will be impacted by the OCU Project. In these ways, the OCU Project will not only help to facilitate achieving the 15 percent renewable gas target by 2030, but will also enable larger increases in renewable supply beyond 2030.

13.10 How will air quality in the service region's communities be affected by the increased natural gas combustion associated with the Project?

Response:

The OCU Project supports growing demand in the region and those changes in demand, regardless of their cause, will impact air quality.

Natural gas and renewable natural gas are both clean burning fuels which emit low levels of particulates, oxides of nitrogen and sulphur, and other emissions compared to alternative fuels. The growth in gas demand that is occurring in

[5] https://www.fortisbc.com/news-events/media-centre-details/2020/04/30/fortisbc-first-to-purchase-renewable-natural-gas-made-from-wood-waste

the Okanagan area will result in increases to some emissions. However, where the OCU Project enables the switching from higher carbon-containing or emissions-producing fuels such as oil, wood, or propane for space heating, or diesel or fuel oil for transportation, improvements in gaseous and particulate emissions will occur.

PIB IR3 13.10.1:

13.10.1a) Has FEI conducted assessments, quantitative or otherwise, on the net and cumulative air quality impacts on local air pollution, including an assessment of its claims of users switching to natural gas? If so, please provide the assessments. If not, why not?

Response:

FEI has not conducted air quality studies of the suggested nature in the Okanagan region. Local airshed impacts associated with fuel switching are based on a number of site specific factors that are dependent on the emission source, weather, and geographical considerations. However, a generic qualitative review of information as published by the BC Ministry of Environment and other peer reviewed sources serves as the reference for the cited statement. For example, the benefits of fuel switching from wood burning appliances to natural gas are described by the BC Ministry of Environment:

https://www2.gov.bc.ca/gov/content/environment/air-land-water/air/air-pollution/smoke-burning/wood-burning-appliances

Since these benefits apply across regions, and the widely distributed nature of the natural gas system is able to make such benefits available to customers across the entire service area, FEI has not relied on local air studies to make this claim.

14.0 Topic: Project Lifespan

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application

14.2 What is the expected service life of the Project once construction is completed and the Project is commissioned?

Response:

During the regulatory review of FEI's Application for a CPCN for the Inland Gas Upgrades Project, a similar question was received regarding the expected lifespan of gas transmission pipelines.[6] In order to respond to that question, FEI retained JANA Corporation to provide an expert opinion on the likely maximum physical life of a transmission pipeline. The curriculum vitae of Dr. Ken Oliphant and Wayne Bryce, principals of JANA Corporation, who are primarily responsible for this response, are included as Attachment 14.2. Relevant portions of the response to BCUC IR2 45.1 in the Inland Gas Upgrades Project are reproduced below.

JANA Corporation provided the following response:

JANA's Technical Opinion on Functional Lifetime of a Gas Transmission Pipeline

FEI requested that JANA provide a 3rd Party expert opinion regarding the useful life of a well designed, constructed, operated and maintained transmission pipeline.

Based on JANA's awareness of transmission pipeline historical failure data and available industry literature, JANA's opinion is that there is not currently an industry-recognized finite lifetime for a well-maintained and appropriately assessed pipeline. This opinion is based on:

- *Industry studies demonstrating that there is no time-dependent degradation of the fundamental properties of the steels used in natural gas pipelines[7]. The strength properties of steel pipelines, provided time-dependent threats such as corrosion are managed, will not degrade over time.*

- *An industry study, based on analysis of historical transmission pipeline failures, that concluded that "a well-maintained and periodically assessed pipeline can safely transport natural gas indefinitely[8]" That is, with proper application of Integrity Management approaches, there is no recognized finite lifetime for a transmission pipeline.*

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[6] Refer to the response to BCUC IR2 45.1 (Exhibit B-10) in the Inland Gas Upgrades Project proceeding: https://www.bcuc.com/Documents/Proceedings/2019/DOC_54202_B-10-FEI-Responses-to-BCUC-IR2.pdf.

[7] Clark, E.B., Leis, B.N., and Eiber, R.J., "Integrity Characteristics of Vintage Pipelines," Appendix C, The INGAA Foundation, Inc. 2005.

[8] The Role of Pipeline Age in Pipeline Safety, INGAA Foundation Final Report No. 2012.04.

- *JANA's analysis of PHMSA historical transmission pipeline failure data that confirms the analysis conducted in the above-referenced study.*

FEI provides the following key findings in the report cited by JANA: "The Role of Pipeline Age in Pipeline Safety":

KEY FINDINGS

Ultimately, the safety of a particular natural gas transmission pipeline is not necessarily related to its age because:

1. 85% of pipeline incidents reported to PHMSA from 2002-2009 occurred irrespective of the age of the pipeline, with just 15% related in some way to the age of the pipeline.
2. The properties of the steels which comprise natural gas pipelines do not change with time; that is, pipe does not "wear out."
3. The fitness of a pipeline for service does not necessarily expire at some point in time.
4. The integrity of those pipelines for which the fitness for service may degrade with the passage of time can be assessed periodically. Timely repairs - and other mitigation efforts - based on those assessments will ensure the pipeline's continued fitness for service.
5. A well-maintained and periodically assessed pipeline can safely transport natural gas indefinitely.

The opinion of JANA Corporation and the key findings of the report cited above support FEI's view that the common understanding in the industry is that natural gas transmission pipelines can have an indefinite useful life in the absence of external influences and depending on their design, construction, maintenance, and monitoring.

FEI's natural gas transmission pipelines came into service in British Columbia in 1957, meaning that FEI's oldest pipeline is approximately [64][9] years old. While FEI undertakes site-specific replacements or repairs over the life of its pipelines, there is no indication at this time that any of FEI's pipelines, including those installed in 1957, are approaching the end of their useful life. FEI's expectation is that its integrity management programs can extend the life of its pipelines indefinitely.

PIB IR3 14.2.1:

14.2.1a) Given the apparent longevity of the OCU Project, what will be the series of events and decisions that FEI will face if demand for gas diminishes over the coming decades?

[9] Updated from 62 years as filed in the response to BCUC IR2 45.1 (Exhibit B-10) in the Inland Gas Upgrades Project proceeding, recognizing those responses were filed in 2019.

Response:

FEI believes that, while the demand for conventional natural gas[10] may decline over the coming decades, conventional natural gas will be replaced with renewable natural gas[11] and/or hydrogen which will require ongoing use of FEI's pipelines to transport alternative energy molecules to meet customer energy demand. This would contribute to the Province's goal of reducing GHG emissions while diversifying BC's energy supply options. This is discussed in the Guidehouse report *Pathways for British Columbia to Achieve its GHG Reduction Goals* (provided as Attachment 14.2.1a). Consequently, FEI expects that the pipeline to be constructed as part of the OCU Project will be used and useful well into the future.

[10] Conventional natural gas refers to methane extracted from underground reservoirs and deposits.

[11] Renewable natural gas refers to methane produced from renewable sources such as organic waste from landfills, wastewater treatment plants, and agricultural processes.

18.0 Topic: Project Timeline

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg. 14

18.1 If the Project is approved, FEI will commence construction of the Project in Q1 of 2022. The new pipeline and stations are scheduled to be in service by Q3 of 2023, with Project completion and close-out activities to be completed by Q1 of 2024.

Response:

Should the Project not be approved, FEI would be forced to curtail firm (i.e., non-interruptible) customers on the coldest winter days in the Okanagan region when the system is experiencing its peak demand. The scale and frequency of the gas outages resulting from growing demand without an associated capacity upgrade would increase each year as demand grows. As discussed in Section 3.4 of the Updated Application, the inability to reliably serve customers due to a shortage of capacity on the ITS during an expected 1 in 20 year weather event is considered unacceptable to FEI. Please also refer to the response to PIB IR1 19.1 for a discussion of FEI's statutory obligation to serve customers.

Should the Project approval be delayed, depending on the length of the delay, FEI would investigate other construction methods to shorten the construction schedule. FEI would also re- evaluate the risk and cost associated with working through higher-risk construction seasons (e.g., wildfire season, bird nesting season, etc.), accelerating the work with additional crews, and/or phasing the Project to only install sufficient pipe to meet the 2023/24 winter peak. Any such measures will increase costs to implement and will also increase the environmental and safety risks to the Project, resulting in additional costs to effectively manage the increased risk. If the measures discussed immediately above to reduce the overall construction schedule are insufficient to complete the Project on time, FEI would explore the feasibility of mitigating the resulting short term capacity shortfall with the only remaining option: CNG injection using mobile tankers. CNG injection presents risks and challenges. Please refer to the responses to the BCUC IR1 11 series of questions for a discussion on why FEI considers CNG injection to be an undesirable option, and to the response to BCUC IR2 48.1 for a high-level estimate of the costs associated with attempting to mitigate the shortfall using trucked CNG.

PIB IR3 18.1.1:

18.1.1a) Please explain if FEI believes it would be in breach of its statutory obligations under sections 38 and 39 of the Utilities Commission Act if it was forced to curtail firm customers during peak demand?

Response:

As noted in Section 13 ("Interruption of Service") of the approved General Terms and Conditions for its gas service tariff, FEI uses "best efforts to provide the constant delivery of Gas and the maintenance of unvaried pressures." Although FEI strives to provide an uninterrupted supply of gas to its customers, it is unable to guarantee that supply disruptions will never occur.

However, if FEI was forced to curtail firm customers on a repeated, ongoing, or wide-scale basis due to the capacity shortfall as described in the Application, such curtailments could potentially be contrary to sections 38 and 39 of the UCA.

18.1.1b) Please explain why FEI does not believe it would be obligated to explore further alternatives to services its customers in response to its asserted capacity shortage?

Response:

FEI has thoroughly explored the viable long-term options available to maintain safe and reliable service to its customers in response to the forecast capacity shortfall. These options are the five alternatives which were presented in the CPCN Application. Had FEI identified other potential alternatives, these would have been evaluated and included in the Application. Short-term mitigation measures to address the shortfall are already being implemented where possible, and FEI will continue to undertake these measures as necessary. However, these short-term measures are not practical long-term solutions to address the capacity shortfall.

19.0 Topic: Project Alternatives

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg. 38

DESCRIPTION AND EVALUATION 1 OF ALTERNATIVES

19.1 Please provide the assessments conducted by FEI on alternatives to carrying out the project, including such things as alternative local power and price increases to reduce demand.

Response:

Please refer to Section 4 of the Updated Application that includes detailed assessment and analysis of alternatives to the Project. FEI has not assessed alternatives such as local (i.e., targeted) price increases to reduce demand. Under sections 38 and 39 of the Utilities Commission Act (UCA), FEI must provide service to customers who apply for it without undue discrimination or undue delay. Further, as per sections 59 to 61 of the UCA, the BCUC is charged with setting rates for FEI's customers which must be just, reasonable, and not unduly discriminatory. Targeted rate increases intended to reduce demand in a local area would deviate from the established BC regulatory principle of applying "postage stamp" rates to all customers equally throughout the FEI service area and could be considered unjust and discriminatory.

FEI is unclear what PIB is referring to by "alternative local power" in the context of a natural gas distribution utility. FEI is not a gas producer, nor are there any local gas supplies of significance in the Okanagan area that could be used to offset the demand of local customers.

PIB IR3 19.1.1:

19.1.1a) Has FEI considered "non-local" price increases to reduce demand as an alternative to the OCU Project?

Response:

FEI has not considered "non-local" price increases to reduce demand as an alternative to the OCU Project. As stated in the cited responses, the BCUC is responsible for regulating FEI including setting rates for FEI's customers, which must be just, reasonable, and not unduly discriminatory. Additionally, as many customers rely on natural gas for necessities such as heat and cooking, increasing gas rates may not reliably decrease gas consumption, but rather increase costs for customers.

21.0 Topic: Project Route and Right of Way

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application – pdf pg. 83

The proposed alignment of the preferred alternative is located within or directly adjacent to existing rights of way as much as possible. The proposed route overlaps with watercourses, patches of mature trees, and areas with potential for plant communities at risk. Habitat for wildlife or plant species at risk was identified along the proposed alignment of the preferred alternative and surrounding area. Invasive plants are present in the vicinity of the proposed alignment.

The proposed alignment of the preferred alternative was assessed for potential impacts or effects on the ecological environment. Final routing will be selected to minimize disturbance to sensitive environmental features. Best management practices will be applied to minimize any remaining potential negative impacts or effects on the environment. Invasive plant management will be applied throughout construction to minimize the potential spread or introduction of invasive plants. Some vegetation removal will be required during site preparation and construction.

21.1 Please provide a more detailed description of the new right of away required for the Project, including how much of the line is non-contiguous with adjacent right of way and how much new clearing there will be and quantify the vegetation clearing of the Project.

Response:

The width of the new right of way required for the OLI PEN 406 Extension will be 18 metres. Approximately 80 percent will parallel existing linear corridors, i.e., FBC's 73L power transmission line and FEI's VER PEN 323 transmission line. Areas non-contiguous with adjacent right of way are due to either natural features or landowner negotiations.

Clearing and grading for the Project will take place only in areas designated as temporary work space and permanent right of way, as well as for access to the construction site. The amount of required vegetation clearing will be determined during the detailed design following the completion of land surveys.

PIB IR3 21.1.1:

21.1.1a) Please explain why no reference is made to Indigenous engagement on a factor in determining FEI's route design?

Response:

FEI's cited response describes the technical requirements for the new right of way for the Project and was not intended to list all other factors in determining FEI's route design.

FEI is of the view that the PIB, in its role as leading the engagement of the Project on behalf of the Syilx Nation and its member communities, will continue to provide input on the Project route design. FEI will continue to engage with key stakeholders, landowners, and Indigenous groups, including continuing to engage with PIB directly regarding the Project and how to mitigate impacts.

Information on FEI's engagement activities with Indigenous groups and how these factored in the route determination and evaluation stage are discussed in Section 5.3.2 and Appendix I-4 of the Application, and FEI's responses to BCUC IR2 62.1 and BCUC IR2 62.2.

21.3 Please detail the potential for final routing differ from what is proposed?

Response:

FEI believes it is unlikely the final route will differ from the proposed alignment provided in the Class 3 estimate. Any deviations will be the result from technical or construction challenges determined during detailed engineering design or from continued stakeholder and landowner consultation.

Please also refer to the response to BCUC IR2 54.1.

PIB IR3 21.3.1:

21.3.1a) Please explain why no reference is made to engagement with PIB as a factor in design and construction deviations?

Response:

FEI notes that Indigenous groups including PIB consultation was inadvertently omitted from the list of potential reasons in the response referenced above. FEI is of the view that the PIB, in its role as leading the engagement of the Project on behalf of the Syilx Nation and its member communities, will continue to provide input on the Project route alignment. FEI will continue to engage with key stakeholders, landowners, and Indigenous groups, including continuing to engage with PIB directly regarding the Project and how to mitigate impacts. This view is accurately captured in Section 8 of the Updated Application.

22.0 Topic: Fisheries Act Authorizations

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg. 84

Federal permits, notifications and approvals may be required to comply with the provisions of the Fisheries Act, Species at Risk Act (SARA), and Explosives Act. Notifications and authorizations to comply with the provisions of the Fisheries Act may be required for works associated with geotechnical investigation and construction activities. Fisheries and Oceans Canada is responsible for permitting any federally - regulated waterbody where there is potential for fish and fish habitat alteration disruption and destruction.

22.1 How many federal authorizations will be required from DFO for water crossings and what is the proposed timeline to seek such authorizations?

Response:

FEI's detailed design consultant (IPPL) is currently reviewing all 22 watercourse crossings to confirm or amend the crossing methodology determined during the FEED phase of the Project with input from the Project team, including the environmental consultant, and Indigenous groups. Please also refer to the response to PIB IR1 42.1 regarding the determination of water crossing methodologies.

Once crossing methodologies have been confirmed through detailed engineering, FEI will submit one or more Requests for Project Review to the DFO. The DFO will confirm the actual number of Authorizations required through this process. Currently, FEI anticipates that DFO Authorization may be required for one watercourse crossing, and the duration to obtain an Authorization is a minimum of approximately six months.

PIB IR3 22.1.1:

22.1.1a) Has this six-month timeline been factored into the existing regulatory timeline for the OCU Project?

Response:

Yes, the six month timeline has been factored into the existing regulatory timelines.

23.0 Topic: PIB Rights and Title

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg. 18

Consultation, engagement and communication with public, local government, residents, landowners, businesses, Indigenous groups and other stakeholders are important components of FEI's development plan for the OCU Project.

23.1 What communication has FEI had and received from any Crown entity or Statutory decision-maker regarding the aboriginal consultation and accommodation requirements for this Project?

Response:

The BC Oil and Gas Commission (BCOGC) and FEI held discussions and exchanged emails in February and March 2021 to discuss the Indigenous communities that the BCOGC planned to consult for the proposed OCU Project. The BCOGC indicated that it planned to consult with the following Indigenous communities:

- *Lower Similkameen Indian Band;*
- *Nooaitch Indian Band;*
- *Okanagan Indian Band;*
- *Penticton Indian Band;*
- *Upper Nicola Band; and*
- *Westbank First Nation.*

The BCOGC is a Crown agency and therefore responsible for Indigenous consultation in respect of its decisions. In the course of the regulatory process managed by the BCOGC, FEI is expected to engage Indigenous communities in accordance with the BCOGC's Oil and Gas Activity Application Manual. FEI conducts preliminary discussions with identified Indigenous communities and provides documentation for the BCOGC review process. During the BCOGC permitting and consultation process that will occur prior to authorization for construction, more detailed Project information will be provided to Indigenous communities for review and comment.

PIB IR3 23.1.1:

23.1.1a) Is it FEI's understanding that BCOGC could reject or reroute the OCU Project notwithstanding BCUC's approval of the OCU Project as proposed?

Response:

FEI's understanding is that the BCOGC has the authority to reject the OCU Project based on the information supplied to it. Generally, the BCOGC would first provide feedback to FEI based on

consultation with stakeholders and Indigenous groups and facilitate discussions to reroute the alignment.

25.0 Topic: PIB Rights and Title

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg. 84

5.9 REQUIRED PERMITS AND APPROVALS

25.1 Why is the free prior and informed consent from PIB not listed?

Response:

It is the intention of FEI to engage in discussions with PIB with the aim of obtaining its consent; however, such consent is not a statutory or regulatory requirement for FEI and therefore was not listed in Section 5.9.

PIB IR3 25.1.1:

25.1.1a) Is it FEI's understanding that BCUC is not bound by *Declaration of Rights of Indigenous People Act*?

Response:

FEI's understanding is that as a result of the *Declaration of Rights of Indigenous People Act,* the British Columbia government will undertake all measures necessary to ensure the laws of British Columbia are consistent with the Declaration. Any resulting amendments to the laws of British Columbia may affect FEI, the BCUC, or provincial government and agencies, as the case may be.

26.0 Topic: PIB Rights and Title

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg. 120

At this time, there are no known outstanding issues or concerns with regard to the Project, which cannot be addressed through planned future engagement. FEI continues to engage Indigenous groups on the Project.

26.1 Please identify the outstanding issues or concerns that FEI proposes to address through planned future engagement? Please detail FEI's proposed schedule for such engagement?

Response:

Please refer to the responses to BCUC IR2 62.2 and 63.2 for an updated record of engagement with Indigenous groups. FEI intends to continue to engage with all Indigenous groups on an ongoing and frequent basis throughout the life of the Project.

With respect to the Penticton Indian Band (PIB) specifically, FEI has requested to meet with the PIB to continue discussions regarding its comments, concerns, and to develop mitigation measures. FEI is awaiting two PIB reports identified in the Capacity Funding Agreement to better understand its concerns. These meetings and reports will support future discussions, with the goal of developing a schedule for further engagement in collaboration with the PIB.

PIB IR3 26.1.1:

26.1.1a) Will FEI agree to a suspension of the BCUC process to allow for these discussions to conclude.

Response:

Please refer to the response to PIB IR3 5.1.1a.

26.2 Please confirm Fortis has not been provided with PIB's consent to the Project.

Response:

Confirmed. FEI intends to engage in discussions with PIB with the aim of obtaining consent from PIB. This approach is consistent with the extensive engagement with PIB on the Project to date. Please also refer to the response to BCUC IR2 62.2 that provides further details on FEI's engagement with PIB to date.

PIB IR3 26.2.1:

26.2.1a) Will FEI agree to a suspension of the BCUC process to allow for these discussions conclude to determine if FEI can obtain PIB's consent.

Response:

Please refer to response to PIB IR3 5.1.1a.

28.0 Topic: PIB Rights and Title

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg. 120

28.2 How did FEI incorporate the results of the Penticton Indian Band UOMS INTERIM Report: Fortis BC Okanagan Capacity Upgrade Project into the Project design and application submitted to the BCUC?

Response:

FEI received the UOMS draft interim report on October 28, 2020. FEI acknowledges that the UOMS report does highlight broad areas which are important to the PIB; however, the report was in draft format and lacked sufficient detail to allow FEI to fully understand the nature of any impacts from the presently planned alignment of the Project. As a result of this lack of detail, FEI did not update the Application to reflect this report. Further engagement between FEI and the PIB is required to understand the information contained within the draft report. This will be facilitated by receipt of the final report, which is still forthcoming.

FEI attempted to meet with the PIB since submitting the Application to discuss the UOMS report, however the PIB has not been available for such meetings since January of this year. FEI looks forward to continuing engagement with the PIB on the more detailed, final report when it is provided to FEI by the PIB, and to working to incorporate this information into the Project design.

PIB IR3 28.2.1:

28.2.1a) What specific detail did FEI require in order to incorporate the results of the interim reports into the OCU Project Application?

Response:

FEI required more detailed mapping, and detailed information on where the pipeline intersects with Traditional Land Use (TLU) or Traditional Knowledge (TK) areas. The maps delivered to FEI from the PIB were at a coarse scale between approximately 1:30,000 and 1:50,000, and the report outlined very broad and general areas of importance instead of the specific location of intersection of TLU or TK within the proposed pipeline corridor called for in the work plan.

28.3 How did FEI incorporate the results of the Penticton Indian Band CHRA Report: Fortis BC Okanagan Capacity Upgrade Project (dated July 2020) into its Project design and application submitted to the BCUC?

Response:

FEI received the CHRA draft report on September 29, 2020. FEI acknowledges that the CHRA report highlights broad areas which are important to the PIB; however, the report was in draft format and lacked sufficient detail to allow FEI to fully understand the nature of the impact of the Project. As a result of this lack of detail, FEI did not amend the Application to incorporate this report. However, FEI has included the overarching concerns expressed by the PIB in the CHRA draft report in the Application. Further engagement between FEI and the PIB is required to understand the information contained within the draft report. This engagement will be facilitated by receipt of the final report, which is still forthcoming.

FEI requested to meet with PIB since submitting the Application to discuss the CHRA report; however, the PIB has not been available for such meetings since January 2021. FEI looks forward to continuing engagement with the PIB on the more detailed final report when it is provided to FEI by the PIB, and to working to incorporate this information into the Project design.

PIB IR3 28.3.1:

28.3.1a) What specific detail did FEI require in order to incorporate the results of the interim report into the OCU Project Application?

Response:

FEI required more detailed mapping to better locate features of interest within the proposed pipeline corridor. The maps delivered to FEI from the PIB were at a scale between approximately 1:10,000 and 1:20,000 rather than the level of detail called for in the work plan.

31.0 Topic: Environmental and Archeological Mitigation

Reference: FortisBC Energy Inc. Okanagan Capacity Upgrade Application pdf pg. 100

FEI is committed to delivering safe, reliable energy in an environmentally responsible manner to all the communities that it serves. Based on its preliminary assessment, FEI expects minimal environmental and archaeological impacts for the OCU Project. Potential environmental impacts of the Project can be mitigated through the implementation of standard best management practices and mitigation measures.

31.1 Please specify what standard best management practices and mitigation measures are referred to here.

Response:

The standard best management practices and mitigation measures referred to include, but are not limited to, the following subject areas:

- *Archaeological and cultural areas mitigation and management;*
- *Archaeological monitoring;*
- *Environmental monitoring;*
- *Erosion and sediment control;*
- *Invasive species mitigation and management;*
- *Soil management;*
- *Water mitigation and management;*
- *Vegetation mitigation and management;*
- *Wildlife mitigation and management; and*
- *Restoration planning and management.*

FEI's identification and preliminary assessment of potential effects of the Project is appropriate for the stage of its development and consistent with the level of detail required for a CPCN application. Project development is necessarily an iterative process and FEI believes it would not be in its customers' interest for FEI to advance the development of this Project's detailed plans, including its detailed design and associated environmental management plans and mitigation measures, prior to receiving the BCUC's approval. As a result, project and site- specific management plans will be developed during the detailed engineering phase of the Project. These plans will incorporate standard practices for construction, as well as site and/or sensitivity-specific measures as-needed, dependent on detailed engineering design, which has yet to be developed.

As described in Section 7 of the Updated Application, FEI will undertake further environmental assessments as required, and develop environmental mitigation measures and environmental management plans during the detailed engineering and contractor Request for Proposal (RFP) phases of the Project.

These further assessments, measures and plans are required in order to apply to the BCOGC for an Oil and Gas Activities Act (OGAA) permit, as well as other permits such as Fisheries and Oceans Canada requests for project reviews/authorizations, and species at risk permits (if required).

The Environmental Protection and Management Regulation (EPMR) provides the statutory authority to the BCOGC for the management and protection of environmental values. It is the responsibility of the OGAA permit applicant to satisfy the BCOGC that the proposed activity will not create material adverse effects, as outlined in Sections 4 through 7 of the EPMR, which address water, riparian values, wildlife and wildlife habitat, and old-growth management areas, resource features and cultural heritage resources. The BCOGC's Environmental Protection and Management Guideline7 is included in Attachment 31.1 to this response.

PIB IR3 31.1.1:

31.1.1a) How can the BCUC decide whether the project is in the public interest if the BCOGC's decision on environmental management and protection occurs after the BCUC process?

Response:

The approval of the BCOGC and other permitting bodies is not required to be complete in order for the BCUC to be able to make a determination as to whether the Project is in the public interest and a CPCN should be issued.

Each regulator has a different role in approval. While the BCUC's public interest determination is broad and may take into account aspects that are considered by the other regulators, each of the regulators has a different mandate and specific area of expertise. The Project cannot proceed without all of the required approvals being granted from other regulators with different mandates and expertise.

31.2 Please provide data and all other information used to support conclusion that environmental impacts can be mitigated through the implementation of these management practices.

Response:

FEI's conclusion that environmental impacts can be mitigated through the implementation of best management practices is based on the Environmental Overview Assessment (EOA) prepared by Hemmera Envirochem Inc., FEI's environmental consultant for the Project, and experience from past construction projects.

Section 9.0 of the EOA (included as Appendix F in the Updated Application) lists references reviewed to support the preparation of the EOA. These references, along with field observations and the professional judgement of the environmental consultants aided in the preparation of the EOA and the conclusion that the environmental impacts can be mitigated through the implementation of best management practices.

PIB IR3 31.2.1:

31.2.1a) Please confirm that best management practices require field assessments for wildlife presence and habitat in order to determine mitigation design.

Response:

Mitigation measures can be designed based on desktop reviews of available information and data. For example, if a species has the potential to occur, presence can be assumed and mitigation measures designed from that assumption. However, where possible, field assessments are beneficial to support identification of wildlife and habitat presence or absence to further refine mitigation measures. For example, if a species requires a specific habitat to be present and field assessments determine absence of that habitat type, then previously designed mitigation measures could be excluded. Additional field assessments for the Project are currently underway, with further field activities planned for 2021 and as needed during the ongoing detailed engineering phase of the Project.

31.2.1b) Please provide monitoring and other supporting data from FEI's experience with past projects referenced in FEI's response.

Response:

FEI provides the following example from the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) projects.

Gas line construction across Silver Creek Tributary 1 occurred adjacent to a City of Burnaby Conservation Area and as part of the restoration and enhancement works, FEI removed a hanging culvert and restored a section of Silver Creek Tributary 1. A requirement of the City of Burnaby Access Agreement is to undertake four years of post-construction monitoring. FEI is currently in year three of post-construction monitoring. Please refer to Attachment 31.2.1b for copies of post-construction monitoring reports from year one to three. The presence of invasive species is identified within the monitoring footprint. FEI is currently working with the City of Burnaby and a qualified contractor to treat the invasive species.

In this example, best management practices such as, but not limited to, environmental permitting, erosion and sediment control, site restoration, and invasive species management are all being implemented to mitigate environmental impacts.

35.0 Topic: Land Use

Reference: Appendix F, Table 4.1 pdf pg.170

The selected alignment is located in the City of Penticton along its eastern extent of city limits, and the whole alignment is located entirely within the Regional District of Okanagan-Similkameen. Land ownership through the southern half of the selected alignment is primarily private, with intermittent sections of overlapping unknown, Crown, and municipal lands. The majority of alignment sections north of Naramata are Crown land with some areas of private and municipal lands. The general study area encroaches into 0.17 ha of ALR (soil capability class of 7) located south of Strutt Creek on the west side of the selected alignment. Several Development Permit Areas and planning areas are located over the portion of the selected alignment and general study area within the City of Penticton.

35.1 Is it your understanding that the selected alignment is within Syilx Territory, and in particular the Area of Responsibility of the Penticton Indian Band? If so, why no mention of that here?

Response:

As discussed in Section 8.3.2 and 8.3.3 of the Updated Application, FEI's understanding, based on its discussions with the Penticton Indian Band (PIB), Westbank First Nation, and the BC Oil and Gas Commission, is that the selected alignment is within Syilx Territory, and specifically within the PIB's and Westbank First Nation's areas of responsibility. However, FEI has not been provided with or shown a map of PIB's area of responsibility.

PIB IR3 35.1.1:

35.1.1a) Is FEI aware of the Chiefs Executive Committee resolution that PIB is the lead on the OCU Project?

Response:

Yes, FEI is aware that the Chiefs Executive Council, on behalf of the Okanagan Nation Alliance, passed a Tribal Council Resolution appointing the PIB as the Chiefs Executive Council member lead for engaging with FEI in respect of the Project.

55.0 Topic: Vegetation

Reference: ES p.ii, Table ES.1 - Overview of Potential Effects and Risks to Biophysical Receptors Associated with the Selected Alignment, pdf pg. 151

Vegetation project risk: "moderate"

55.1 How was this risk level determined given that the Project has a high potential to impact at least one red-listed ecological community?

Response:

The "moderate" risk determination for vegetation was for the overall Project, and is not specific to any one vegetation species or ecological community.

PIB IR3 55.1.1:

55.1.1a) Please provide a response to the question posed, which was "how" was risk level determined, in terms of was it based on a specific metric or metrics?

Response:

The risk level was determined based on a review of available information (e.g., desktop and field review) to identify environmental sensitivities (e.g., mapped species at risk occurrence, documented noxious invasive plants species, old growth forest management areas, fish habitat, etc.), and Hemmera's professional judgement to assess potential impacts from the Project (e.g., vegetation clearing, stream crossings).

60.0 Topic: Vegetation

Reference: 3.4 Vegetation, pdf pg. 168

60.3 Please provide rationale why the second field assessment was conducted in August (following the initial one in November, when there was already snow on the ground), especially given that August is also quite late in the season for many plants in that habitat?

Response:

The second field assessment was conducted in August 2020 due to the timing of finalizing the contract between FEI and Hemmera. Consistent with the best management practices and mitigation measures identified in tshe EOA as applicable to the Project, FEI plans to conduct additional field assessment during the detailed design phase of the Project.

Please also refer to the response to PIB IR1 31.1.

PIB IR3 60.3.1:

60.3.1a) Please detail FEI's plans for construction delay of the Project if FEI's misses the field study window for rare vegetation assessments in June/July.

Response:

The rare plant survey is currently being planned for completion in July 2021 preferably under the direction of the PIB. Additional rare plant surveys will be completed, if required, in 2022 and construction plans will be adjusted accordingly prior to construction commencing in those specific areas. At this time, FEI has does not anticipate a delay to construction as this study is expected to be completed as noted above.

60.3.1b) Please detail FEI's plans to ensure this study window is met?

Response:

Please refer to the response to PIB IR3 60.3.1a.

70.0 Topic: Wildlife

Reference: Appendix F Table ES.1 pdf. pg. 151

General - datasets

70.1 Please explain why historical datasets like the BC CDC were used without any stated bias.

Response:

Historical datasets, like the BC CDC, provide a desktop-level resource to identify previously documented and mapped element occurrences within the study area. The review of the BC CDC aids the subsequent species at risk screening review that provides a more comprehensive review of species and ecosystems-at-risk potential occurrence. Potential biases of the dataset were not included as part of the Environmental Overview Assessment (EOA).

Some potential biases within this dataset include:

- *The BC CDC focuses mapping efforts primarily on the most at-risk species and ecosystems or on areas of development. For this reason not all data submitted will result in a mapped element occurrence.*
- *The BC CDC reporting system relies on scientists and knowledgeable naturalists to build the database of the locations of species and ecological communities in BC.*
- *It represents a database of reported and mapped occurrences (i.e., confirmed observations that are then reported and subsequently mapped by the CDC). It does not preclude occurrences of other species at risk that may be present; not all occurrences may be mapped.*
- *It assumes all data reported and to be mapped has been mapped on the database. The review is accurate to the date the desktop review was completed for the EOA.*
- *Occurrences that are not reported and not mapped will not be identified in the BC CDC dataset.*
- *All historical occurrences are provided; current conditions may have changed since the previously identified occurrence to alter habitat conditions and change likelihood of presence (e.g., increase or decrease; expanded or reduced ranges).*
- *The varying level of studies, rigour of assessment, or species detectability will impact the likelihood of occurrences to be documented and reported in this database.*
- *It uses a methodology and ranking system developed by the Ministry of Environment and Climate Change Strategy. Regionally or culturally important species may not be included (e.g., bald eagle).*

FEI notes that multiple data sources were reviewed during the EOA (see Table 3.1 of the EOA for a complete list) to mitigate potential biases. As the Project

progresses through detailed engineering, field assessments will be undertaken to validate the data from desktop sources and where possible, those assessments will account for potential biases in the historical datasets.

PIB IR3 70.1.1:

70.1.1a) How will FEI use the CDC data to detail a species at risk screening review to identify the potential occurrence of species and ecosystems at risk?

Response:

The species at risk review identifying the potential occurrences of species and ecosystems at risk was included in the Environmental Overview Assessment (EOA) in Tables 4.7, 4.8, B.1, B.2 and B.3. As part of the species at risk review, Hemmera reviewed the CDC data for reported and mapped occurrences. Additional information sources such as Species at Risk Public Registry, Committee of the Status of Endangered Wildlife in Canada assessment reports, BC Data Catalogue, BirdLife International, and Hemmera's professional experience and judgement were also utilized as part of the species at risk review.

70.1.1b) Does FEI agree that best practice requires field validation of potential wildlife habitat and presence including Species at Risk?

Response:

In FEI's view, field validation of desktop information is beneficial, but is not always required. If a desktop review identifies the potential for a species at risk to be present, its presence can be assumed and mitigation measures can be applied accordingly, without the need for field validation.

75.0 Topic: Wildlife

Reference: 4.3.3 Wildlife pdf. pg. 184

The wildlife study area is predominantly overlapped by multiple ungulate winter ranges (UWRs) including multiple polygons for U-8-001 (mule deer; M-ODHE), the northernmost section overlaps U-8-006 (moose; M-ALAL), and the southern terminus of the selected alignment overlaps a polygon for U-8-005 (Mountain Goat; M-ORAM) along Ellis Creek.

75.1 FEI correctly identifies the Approved Ungulate Winter Ranges that are near to or intersected by the project footprint. Each of the three UWRs have been established by a legal Order under the authority of sections 12(1) and 9(2) of the Government Actions Regulation. Accordingly, each of those Orders describes the UWR and General Wildlife Measures that prescribe forest harvesting and silviculture practices intended to conserve the habitat value for the species so covered by the Order.

Most of the length of the project is in the core of a Mule Deer UWR; other parts are within a Moose UWR and the southern end is near Mountain Goat UWR. Clearly, the project area is situated in important and valuable ungulate winter habitat.

Please update Appendix F (including Table 6.1) to provide (i) mapping showing the overlap between UWR, (ii) a discussion of the general or specific contents of any UWR Order, (iii) a discussion of any exemptions from the UWR Order that the proponent may be contemplating, (iv) an interpretation of potential impacts [both during construction and operations] of the project on the ungulate species that might manifest via impacts to UWR, and (v) a discussion of measures to be taken to avoid or mitigate impacts of the project on UWR; such measures would be contained within a construction environmental management plan (assuming the proponent is not planning to proceed as exempt from the UWR Orders.

Response:

The Ungulate Winter Range (UWR) polygons were not included in the Environmental Overview Assessment (EOA) figures as they cover the entire area and therefore the extent of the range is not easily visible at the scale of the figures in the EOA. FEI has provided the expanded figure in Attachment 75.1 to address item (i) of this information request.

FEI notes that items (ii) to (v) of this information request are beyond the scope of the EOA. This information will be reviewed and considered during the detailed engineering phase of the Project.

Please also refer to the response to PIB IR1 31.1.

PIB IR3 75.1.1:

75.1.1a) On what information does FEI rely upon to conclude the items (ii) to (v) are beyond the scope of the EOA?

Response:

For clarity, FEI determined the scope of the EOA and in doing so, concluded that items (ii) to (v) were beyond its scope. As noted by Hemmera in the EOA:

> The objective of this EOA report is to provide a high-level overview of the potential adverse effects on environmental receptors that may result from Project construction…For the purposes of this report, risks to the Project include additional costs (e.g., activities requiring further follow-up work or mitigation), timing constraints (e.g., species-specific timing windows), or both (e.g., permits or approvals)… this report identifies environmental receptors in or adjacent to the expected footprint of the Project, potential impacts to those receptors, and environmental factors to be addressed or mitigated prior to or during construction (and in some cases post-construction).

The specifics of the UWR Orders are beyond the level of detail expected in this EOA but will be considered during the detail engineering phase of the Project.

75.1.1b) Please specify and detail the information, reports, assessments created, and their timing, that will be part of FEI's detailed engineering phase referred to by FEI here and throughout its information request responses to PIB.

Response:

FEI assumes this question refers to all environmental information, reports, assessments created, and their estimated timing, not solely Ungulate Winter Range related reports as cited in the preamble. Additional reports and field assessment may be requested by FEI through the detailed engineering phase as the Project scope is further defined and additional environmental information is received.

Deliverable	Estimated Timing
Pre-Construction Habitat Assessment	Completed Q1 2021
Additional Field Assessments such as detailed watercourse/fish and fish habitat assessments, vegetation surveys, and wildlife and habitat surveys (information collected will be used to inform restoration plans, construction scheduling	2021-2022

Deliverable	Estimated Timing
and methodologies, site specific mitigation measures, etc.)	
Environmental Management Plan	Draft - Q3 2021; Final - prior to construction
Restoration Plan(s)	2021-2022

1
2

78.0 Topic: Wildlife

Reference: Table 4.8 pdf pg. 185

Footnote 4 Medium: Hemmera's current understanding of the species range and known species habitat associations suggests that the species is expected to occur in the study area on a temporary or regular (i.e., predictable) seasonal basis and in densities that facilitate persistence of a functional population within the study area. High: Hemmera's current understanding of the species' range and known species habitat associations suggests that the species is expected to occur in the study area regularly, and in densities that would be expected to occur in provincial benchmark habitats.

78.1 Please detail how a species was determined to have a medium or high potential to occur and how data collected during the two field visits (one in November and one in August) or during the desktop exercise support these designations.

Response:

The species at risk screening assessed medium and high potential to occur within the wildlife study area based on confirmed species ranges, habitat associations, and known occurrences or a combination of these factors using professional discretion and knowledge of the species habitat requirements.

Prior to field visits, Hemmera completed the assessment based on desktop review of available resources (as described in Section 3.5 of the EOA) and its professional expertise. Field visits were used to further refine the assessment whereby species at risk were assigned a "high" ranking if the species itself or optimal habitat conditions for the species were observed in the field, while species at risk were assigned at least a "moderate" ranking if suitable habitats were identified in the field.

PIB IR3 78.1.1:

78.1.1a) How was professional discretion and knowledge of habitat applied to determine the species at risk to potentially occur in the Project area and their critical habitat?

Response:

Critical habitat is a regulatory definition under the *Species at Risk Act* that is defined as habitat necessary for the survival or recovery of listed extirpated, endangered, or threatened species, and that is identified as critical habitat in a recovery strategy or action plan.

The ranking assigned to at risk species with the potential to occur was informed by the identification of documented at risk species occurrences, known distribution range of the species, designated critical habitat mapping, and habitat suitability. Habitat suitability was classified into optimal habitats, which yielded a "High" ranking, and suitable habitat, which yielded a "Moderate" ranking, for species at risk to occur (in the absence of confirmed species at risk detection). Optimal

habitat was defined as habitat that provides the necessities for an at risk species to meet life-requisites (e.g., breeding, foraging, hibernating), with habitat features in pristine or fully functional condition; suitable habitat was defined as habitat in partial or semi-functional condition.

Habitat suitability assessment was based on professional discretion and knowledge which is gained through a combination of years of in-the-field observations (i.e., experience), data collection, and literature review (to identify known life-requisites and habitat requirements, and includes review of recovery strategies and action plans). During field assessment, professional knowledge and skills were applied to identify species at risk encountered (e.g., western toad, Lewis's woodpecker), and life-requisite habitat features and functionality.

79.0 Topic: Wildlife

Reference: 5.2.7 pdf pg. 194 5.2.7 Wildlife Act

In general, the BC Wildlife Act provides a regulatory framework for the management of wildlife and, in very limited circumstance and limited to a few specifically designated species, wildlife habitat (i.e., bird nests) in the province. The Wildlife Act protects most native vertebrates from direct harm or harassment, regulates hunting, trapping and sport fishing, protects nesting birds and active nests that are occupied by a bird or its egg(s).

The nests of some bird species are afforded specific consideration under Section 34b of the Wildlife Act regardless of whether they are occupied. These protected nests, as relevant to this Project, include those used seasonally by peregrine falcon, burrowing owl, bald eagle, osprey, and great blue heron.

79.1 Detail the nest assessments conducted and the planned assessments for the construction period, including for habitat used by ground nesters such as Common Nighthawk.

Response:

No assessments specific to nests have been conducted to date. Nest assessment planning will occur during the detailed engineering phase once the Project footprint is better defined. Please also refer to the response to PIB IR1 31.1.

PIB IR3 79.1.1:

79.1.1a) Please detail FEI's plans for construction delay of the Project since FEI has missed the spring field study windows for birds, including migratory birds.

Response:

The nesting period in the Project area is typically from the end of March to mid-August; therefore, the current nesting window has not been missed. Further, a nest survey is currently underway to identify areas of high nesting potential, which will be used to inform the design. Additional pre-construction nest surveys will be undertaken in 2022, if required, and construction plans will be altered accordingly at that time, depending on the findings. At this time, FEI has does not anticipate a delay to construction as this study is expected to be completed as described above.

81.0 Topic: Wildlife

Reference: Appendix F - 6.1 Biophysical Receptors; Table 6.1, pdf pg. 201

Conduct detailed follow-up assessments to determine if critical habitat features or attributes for the following species are present, disturbed or destroyed:

- *Lewis's woodpecker*
- *Great Basin spadefoot*
- *Desert nightsnake*
- *Western rattlesnake*
- *Great Basin gopher snake*

81.1 Please provide when this detailed assessment will be provided and how the results will be presented to Penticton Indian Band and the BCUC?

Response:

The further assessments will be completed during the detailed engineering phase of the Project once the project footprint is further defined. Please refer to the response to PIB IR1 31.1.

PIB members/technicians will be invited to participate in the field component of the assessments. The draft report will be provided to the PIB for its review and comment before the report is finalized, per the existing Capacity Funding Agreement.

Depending on the timeline to complete the assessment report(s), including review by the Indigenous groups, the report likely will not be finalized before the BCUC renders a decision on this Project.

PIB IR3 81.1.1:

81.1.1a) Please detail FEI's plans for construction delay of the Project if FEI misses the August to September field study for snakes.

Response:

FEI is currently working with the PIB to plan snake assessments to commence in August 2021 and this information will be used to inform detailed design and/or construction planning. At this time, FEI has does not anticipate a delay to construction as this study is expected to be completed as noted above.

81.1.1b) Please detail FEI's plans to ensure this study window is met?

Response:

Please refer to the response to PIB IR3 81.1.1a.

83.0 Topic: Wildlife

Reference: Appendix F, 7.2.2.3, Amphibians and Turtle General Least-risk Periods pdf pg. 206

In areas where amphibians and turtles are expected, construction should be avoided during hibernation, breeding, and migration periods, as determined by a QEP.

83.1 Please provided the relevant construction avoidance periods.

Response:

Once the Project footprint and construction methodology are further defined, FEI will assess whether amphibians or turtles are present or have the potential to be present within the footprint. At that time, construction avoidance periods will be prepared for applicable species.

Please also refer to the response to PIB IR1 31.1.

PIB IR3 83.1.1:

83.1.1a) On what basis does FEI continue to refer to the presence of turtles in the Project area?

Response:

As per Table B.1 in the Environmental Overview Assessment, there is low potential for Painted turtle – intermountain - Rocky Mountain population to occur within the Project footprint. Thus, to be conservative, FEI will consider the potential for the presence of this turtle species and its habitat in the Project area at this time.

83.1.1b) Please detail FEI's plans for construction delay of the Project given that FEI has missed the March-April field study for amphibians.

Response:

FEI's environmental consultant, Hemmera, will be undertaking field assessments in 2021, and if amphibian habitat is identified, construction avoidance periods will be included in the construction schedule. FEI notes that the study window for amphibians is broader than the period identified in the question. However, if required, additional surveys can be conducted in March to April 2022, prior to construction in a specific area.

Attachment 14.2.1a

PATHWAYS FOR BRITISH COLUMBIA TO ACHIEVE ITS GHG REDUCTION GOALS

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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

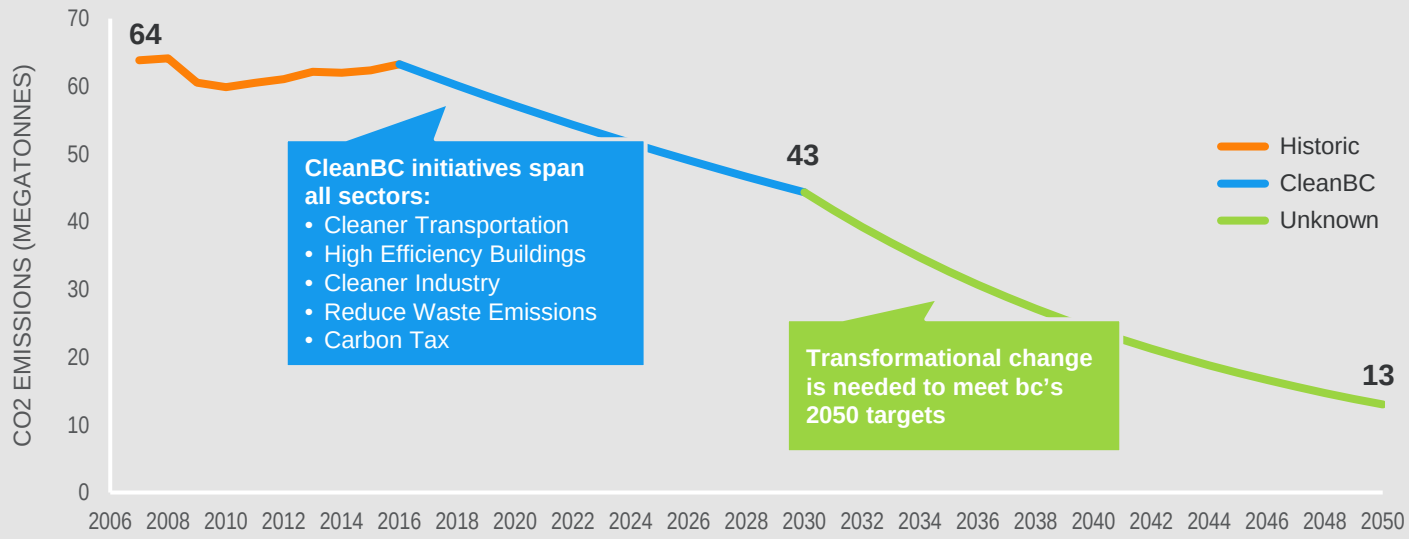
As part of its Climate Change Accountability Act, British Columbia (BC) has committed to reducing greenhouse gas (GHG) emissions to 80% below 2007 levels by 2050. The CleanBC plan puts the province on a path toward this goal, but only sets in action initiatives designed to meet a 2030 target (30% reduction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

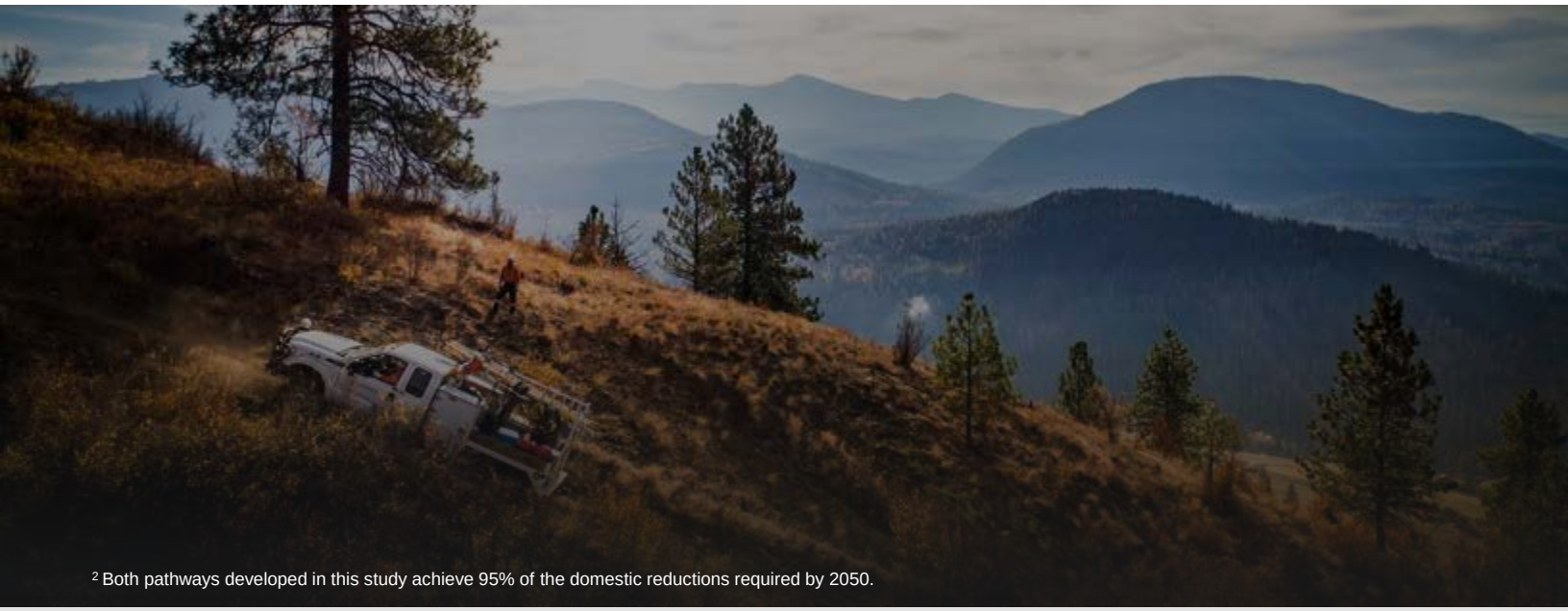


Source: Government of Canada – Canada's Greenhouse Gas Inventory; Government of British Columbia – CleanBC; Guidehouse Analysis

[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.

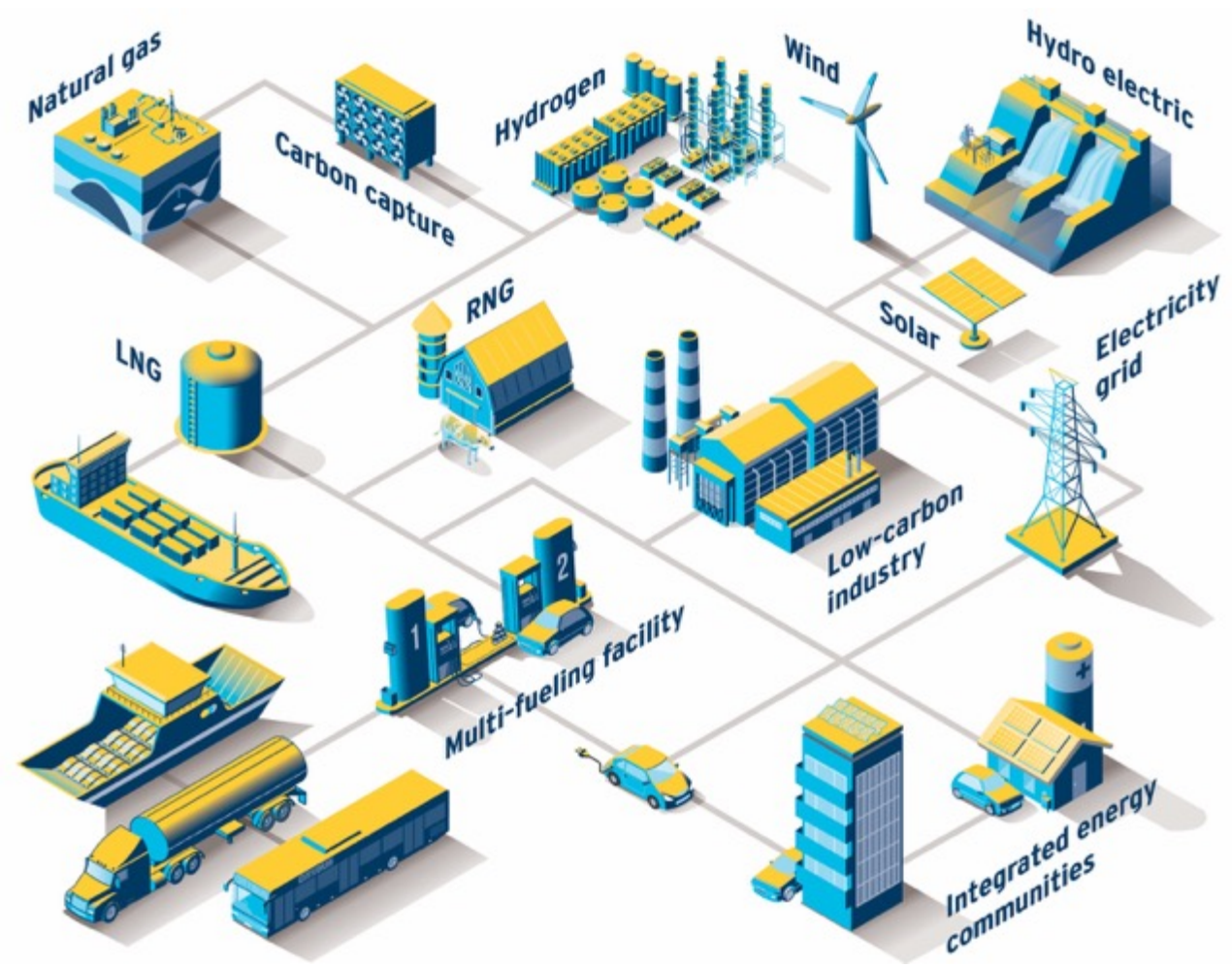


[2] Both pathways developed in this study achieve 95% of the domestic reductions required by 2050.

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.

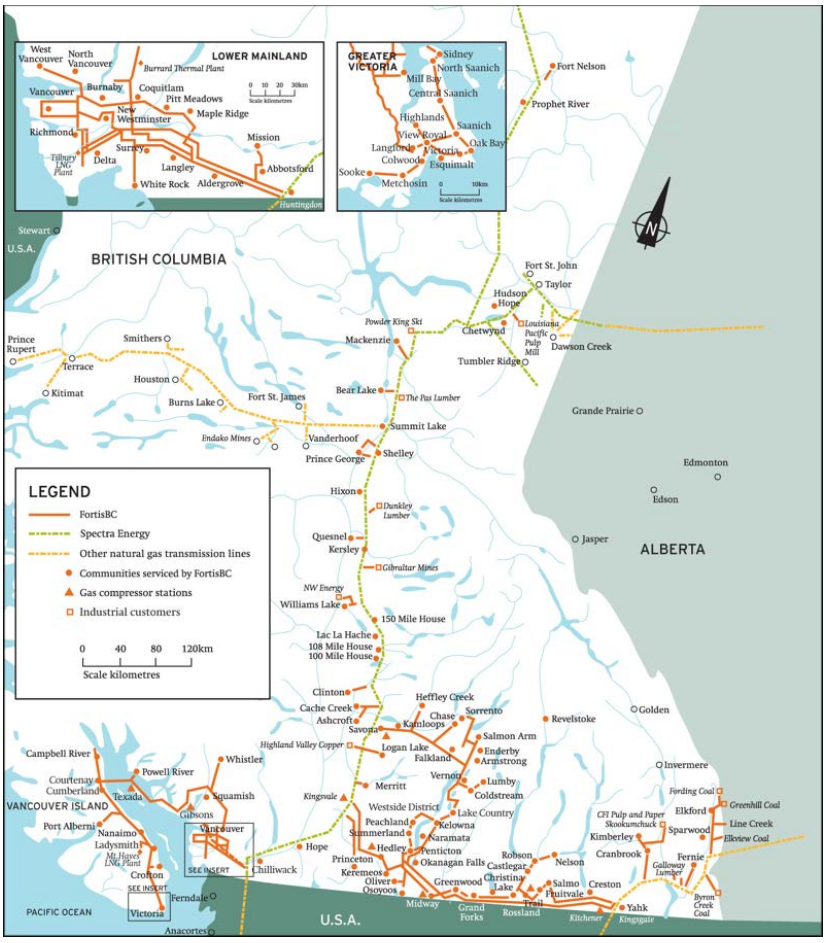
This infrastructure, along with the natural gas pipelines owned by Pacific Northern Gas, TC Energy, Enbridge, and other organizations, spans across the province. The system has multiple import/export points on the borders between Alberta, Yukon, and the US, as well as LNG on the west coast. All of this 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.

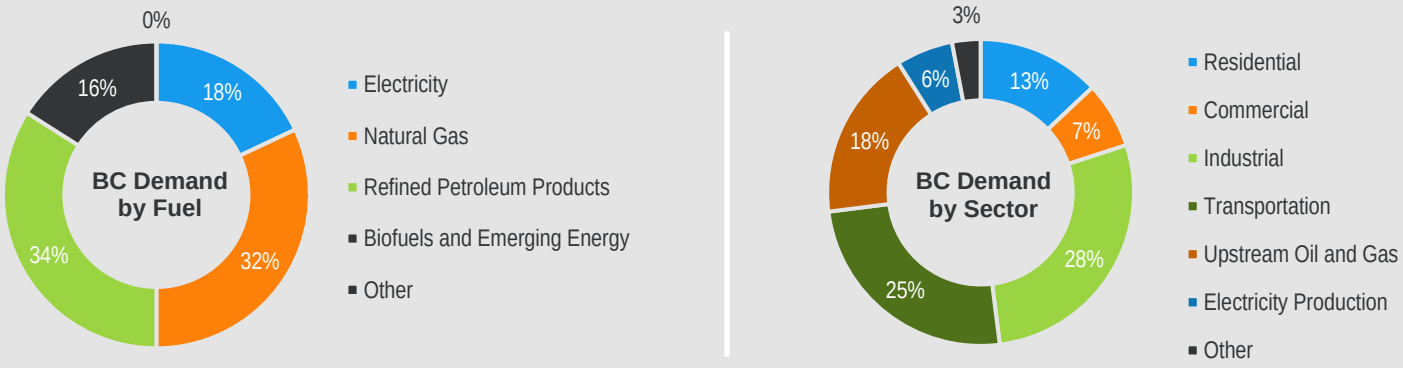
FIGURE 3. NATURAL GAS INFRASTRUCTURE SERVING BC



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.

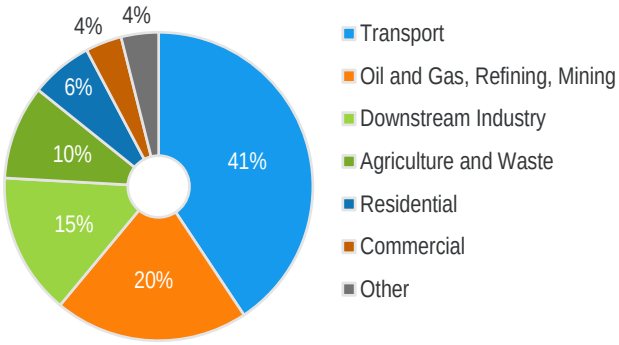
BC has large domestic resources of natural gas and electricity. In 2018, net electricity imports made up 2% of domestic generation. Over 90% of the natural gas consumed in BC is produced in BC (remaining supply is imported from Alberta). However, BC's total natural gas production is greater than its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

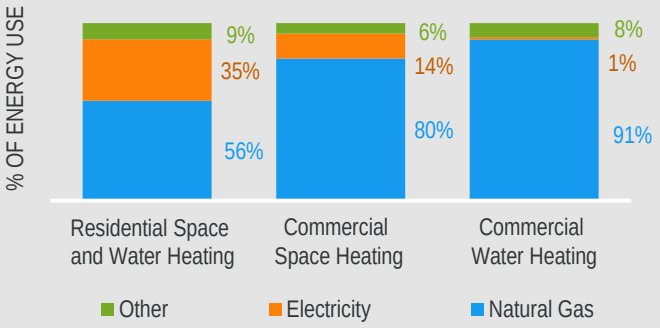
A focus on reduction of emissions across all sectors will be required to achieve the reductions targeted by 2050. Given the significant emissions associated with the transportation and industrial sectors, substantial efforts will be required in these sectors.

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.

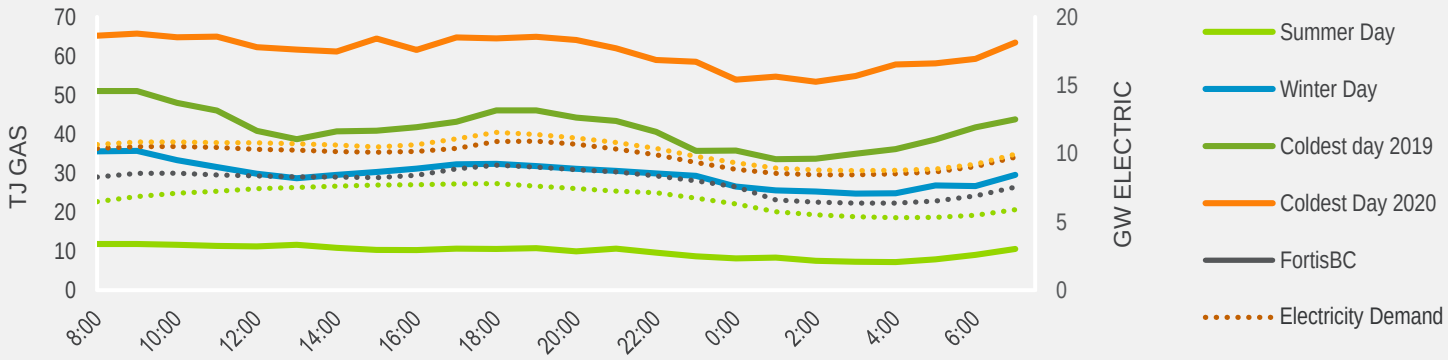
On a very cold day, such as January 14, 2020 when temperatures in the Lower Mainland approached -10°C, the energy delivered by the gas system can be double an average winter day and 50% higher than the coldest day in 2019.

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.

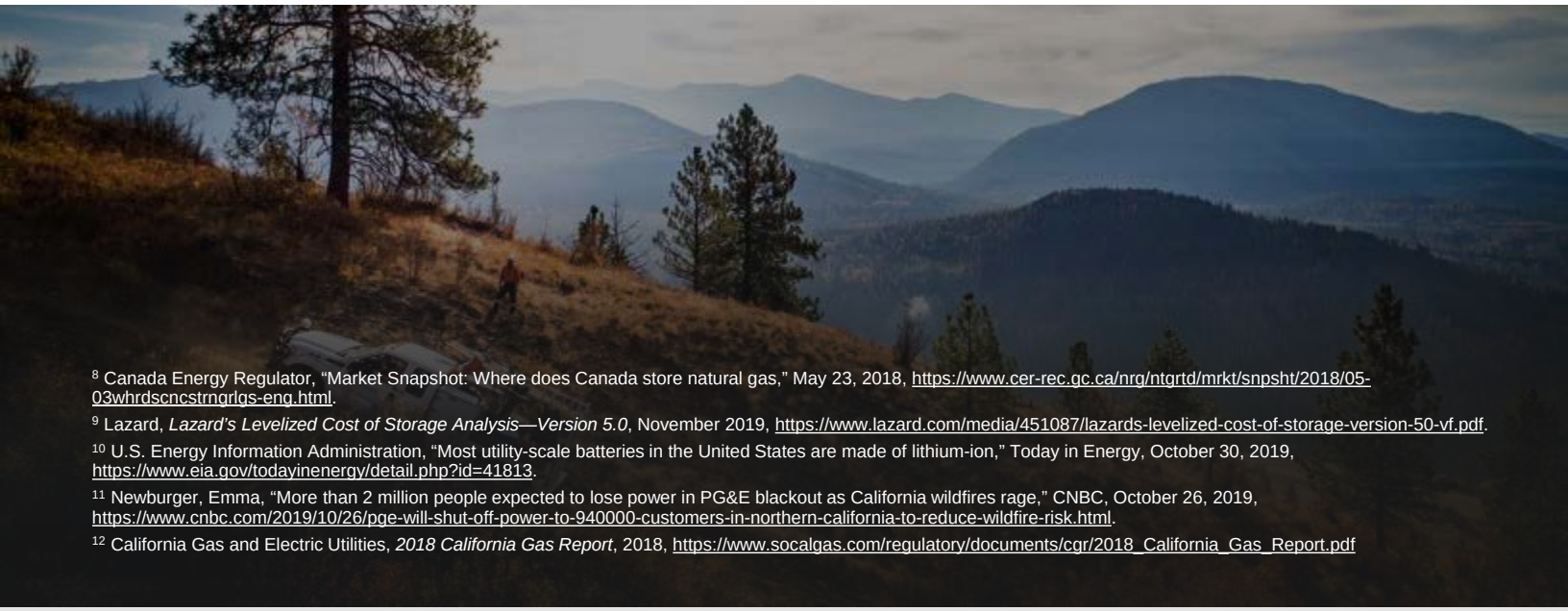
Although electric storage costs are falling significantly, they are still much more costly between $50 and $90 per GJ equivalent comparatively.[9] In addition to Aitken Creek, several smaller natural gas storage facilities exist throughout BC. Natural gas is injected into seasonal storage in summer months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

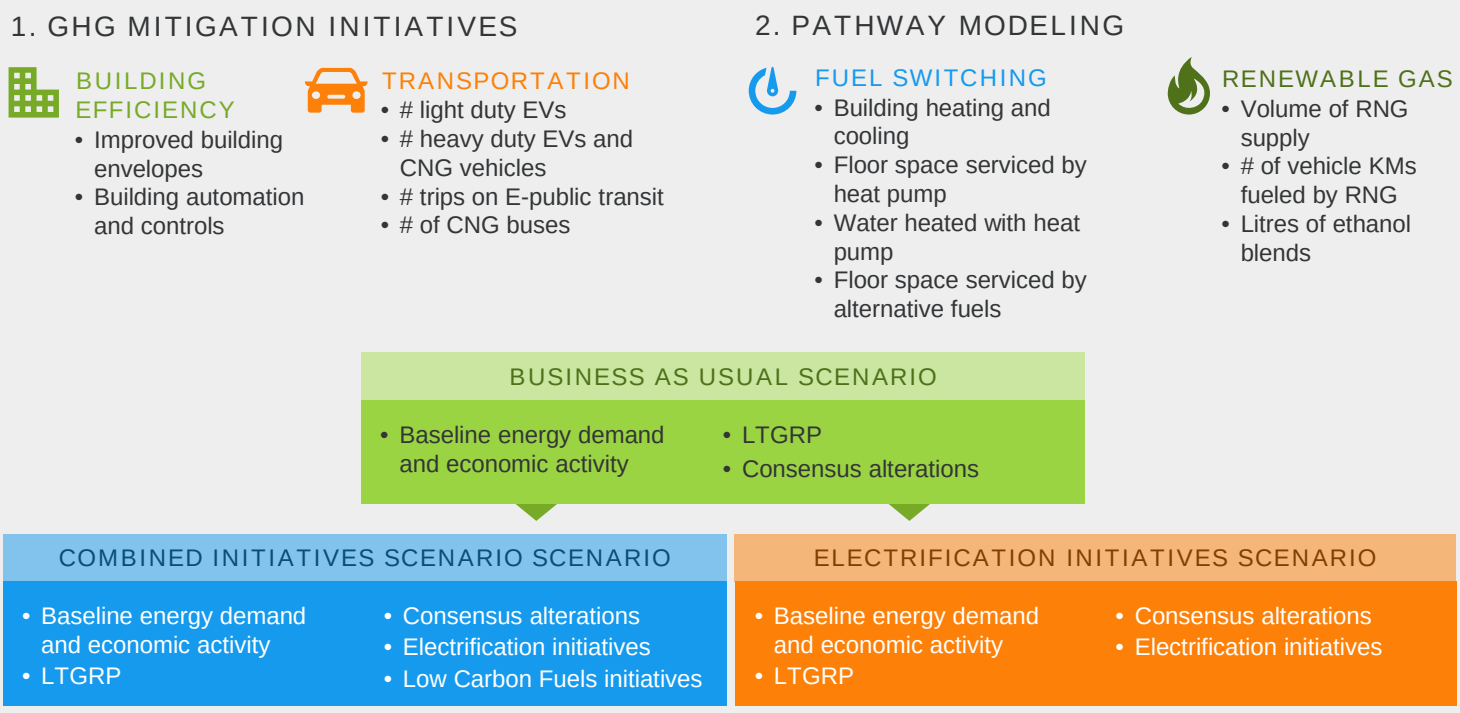
[12] California Gas and Electric Utilities, *2018 California Gas Report*, 2018, https://www.socalgas.com/regulatory/documents/cgr/2018_California_Gas_Report.pdf

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

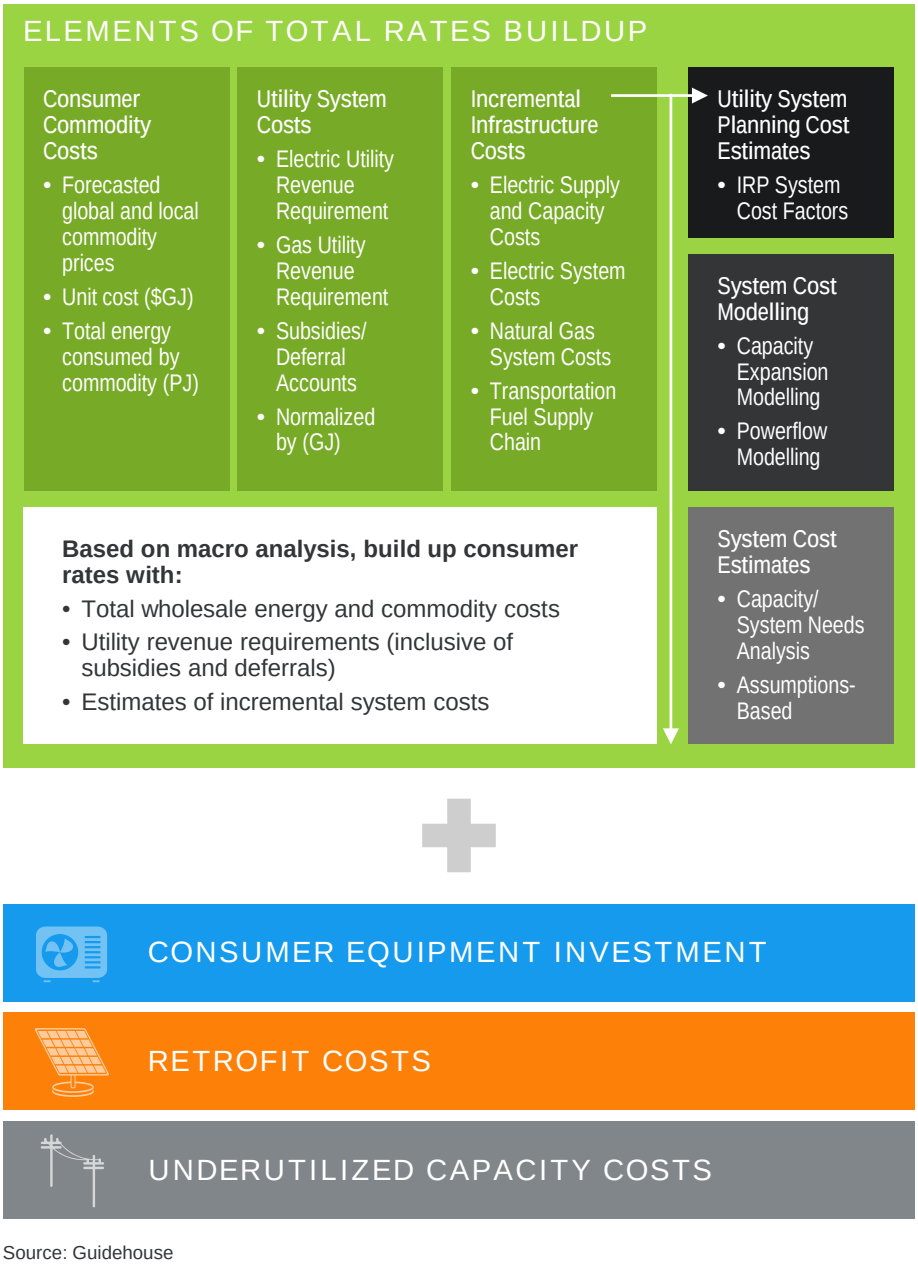


Note: LTGRP refers to FortisBC's Long-Term Gas Resource Plan. Source: Guidehouse

[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.

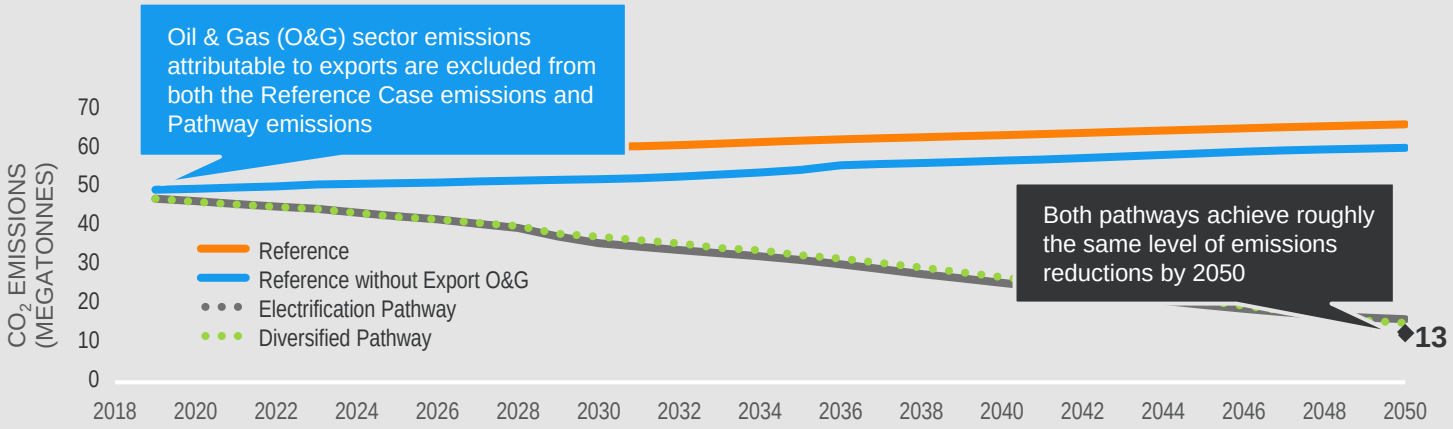
5. STUDY RESULTS – SIDE BY SIDE COMPARISON OF PATHWAYS

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

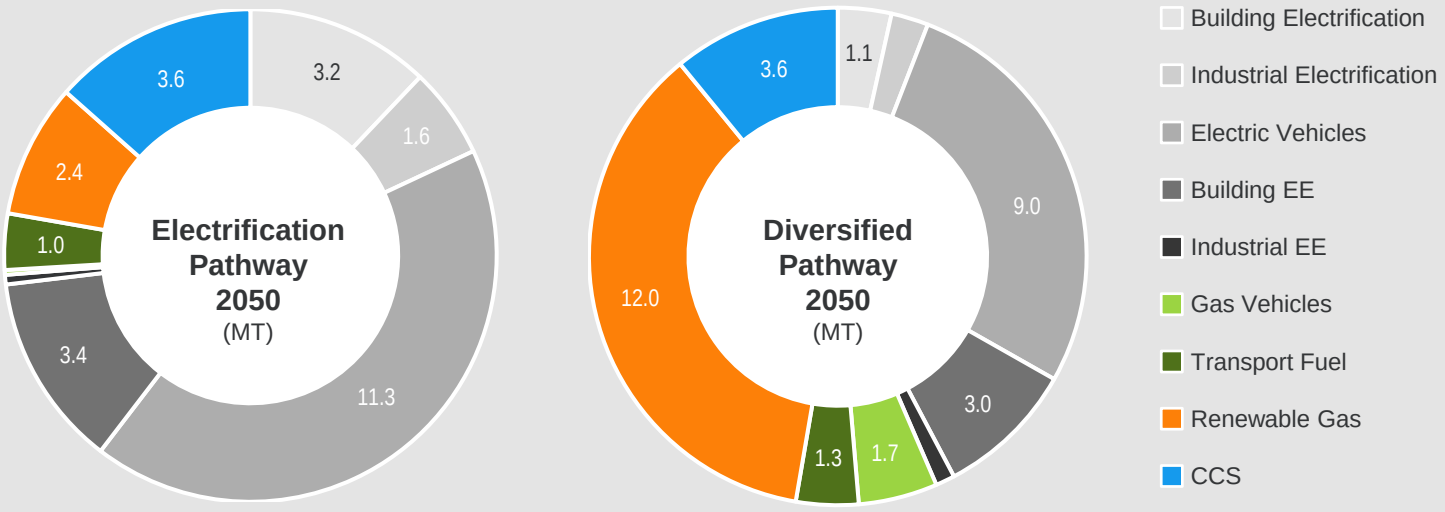
As Figure 11 shows, light duty EVs have a large role to reduce GHG emissions in both pathways, as both pathways were modelled to include the Zero-Emission Vehicles [20] Act; the Zero-Emission Vehicles Act requires 100% of light duty vehicles sold in 2040 to be zero-emissions vehicles.[21] MHD vehicles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

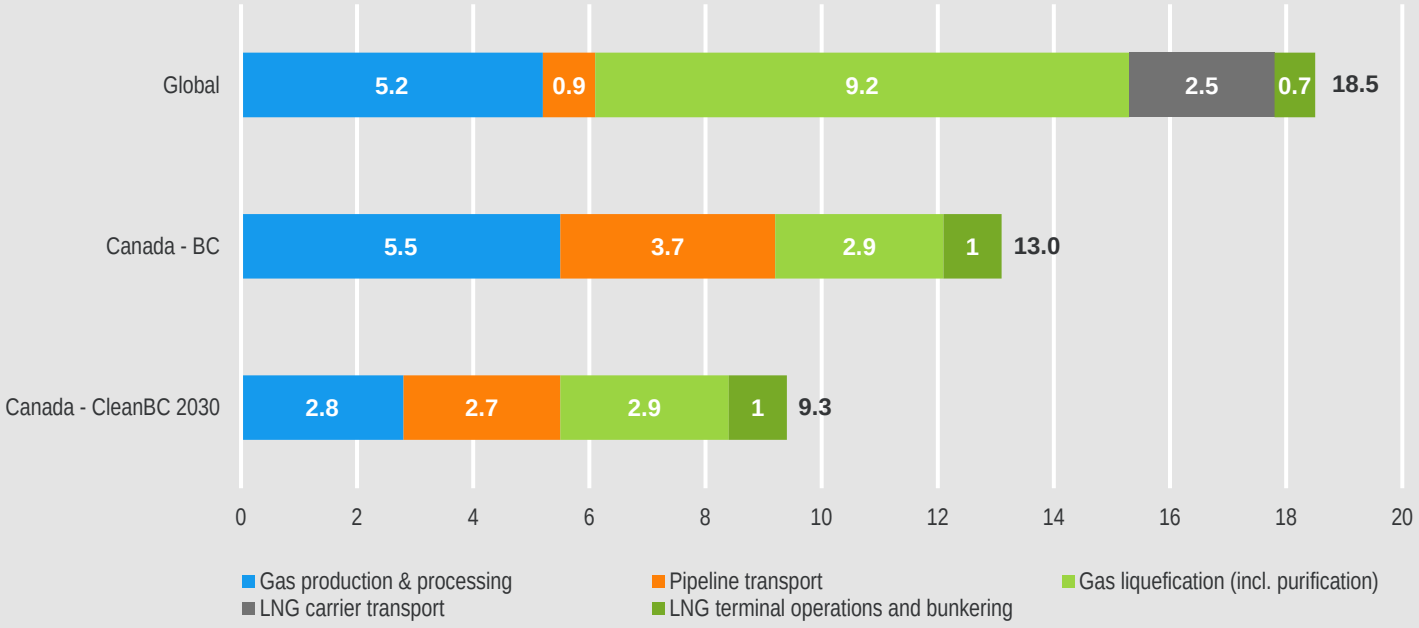
The gas system can also lead to GHG emissions reductions outside of BC. Although these reductions were not evaluated in this analysis, FortisBC has conducted separate evaluations on the role of the gas system to supply LNG to marine vessels and to displace carbon-intensive energy consumption in China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



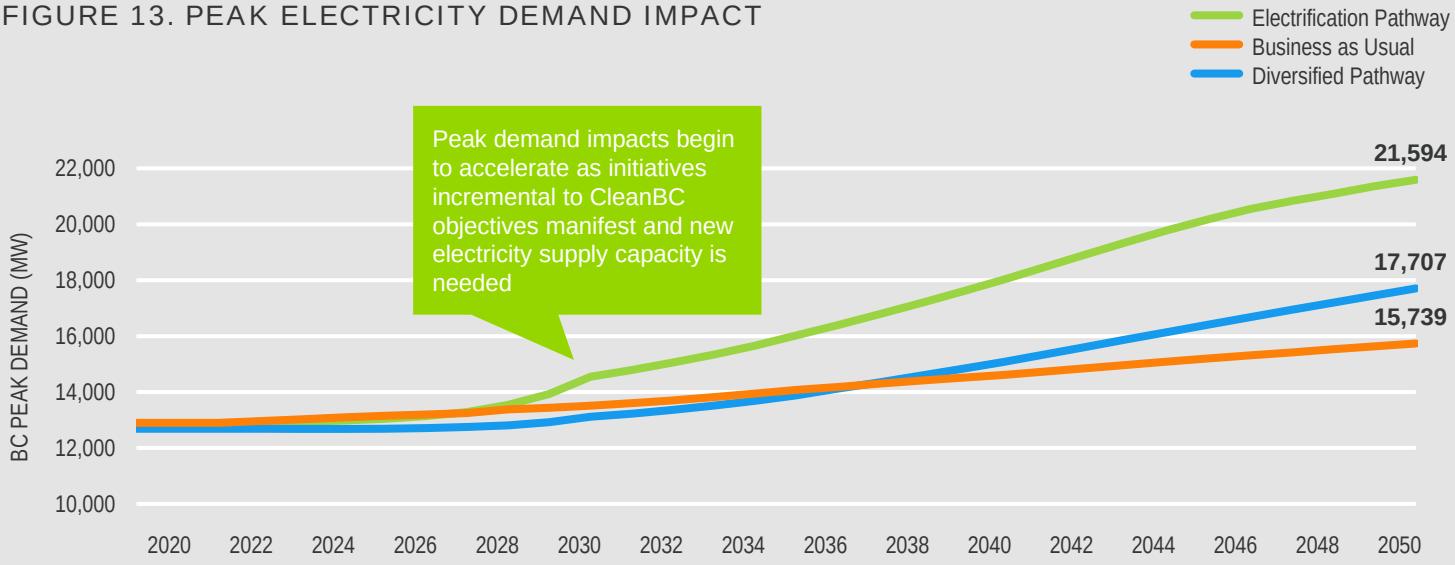
Source: Thinkstep, Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver: 2nd Project Phase, 2020

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

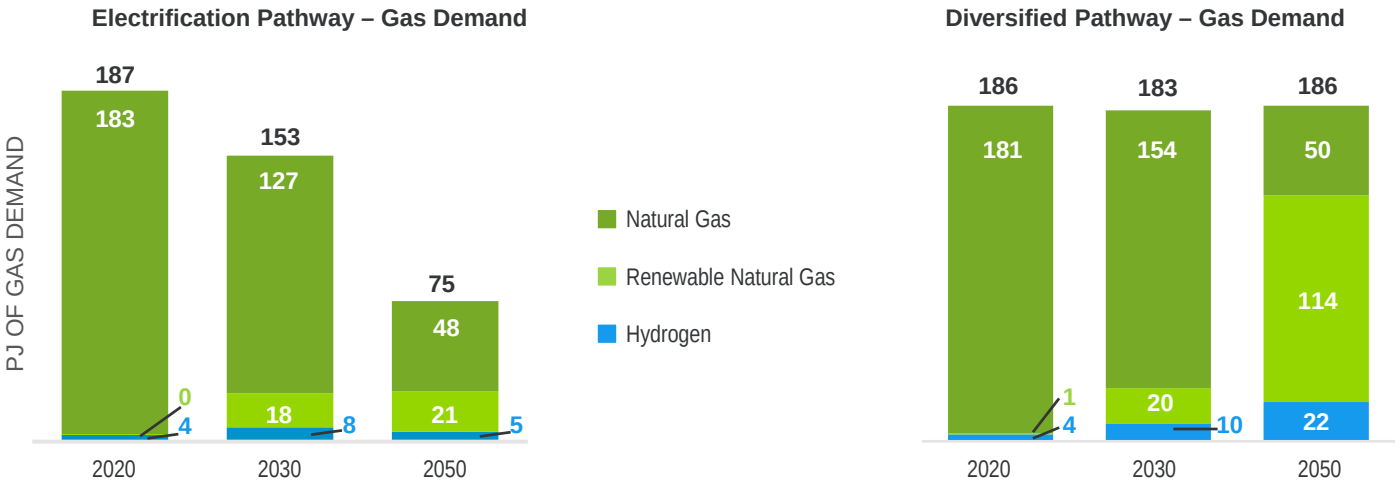


*Peak demand impacts are based on conservative assumptions in both pathways (e.g., majority of MHD vehicle charging occurs in non-peak times)
Source: Guidehouse Analysis

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

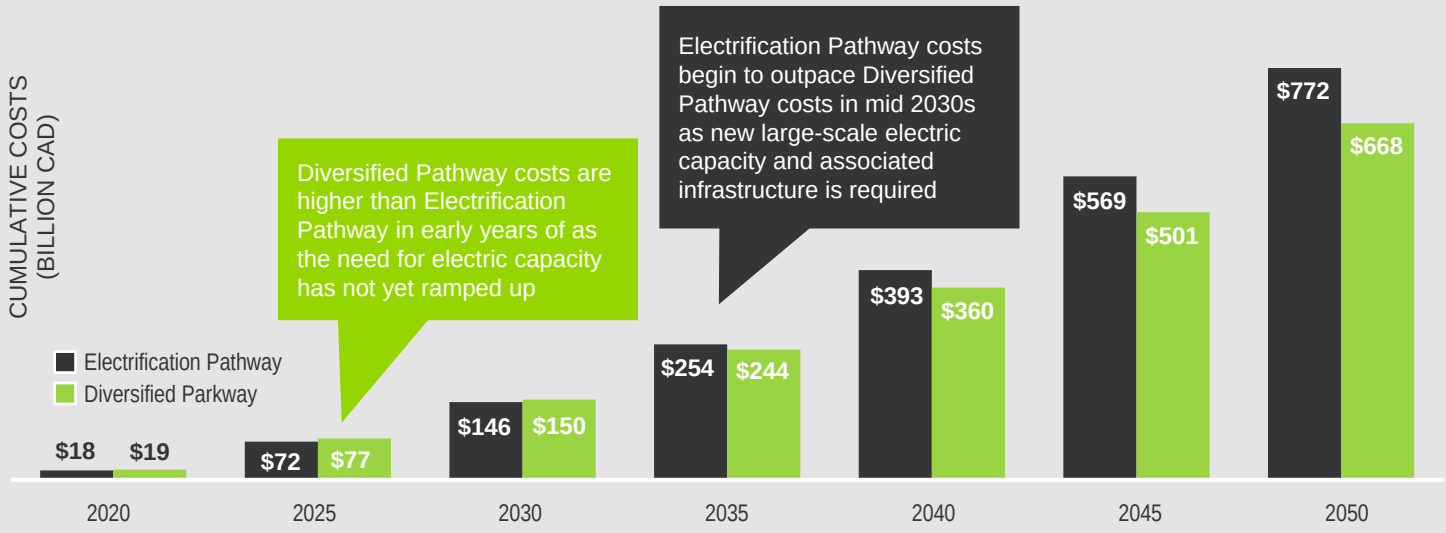
By 2050, the societal value of the Diversified Pathway is expected to be at least $100 billion higher than the Electrification Pathway. The cost of each pathway is roughly the same until the mid-2030s, when the costs of the Electrification Pathway rises much higher than the Diversified Pathway. This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

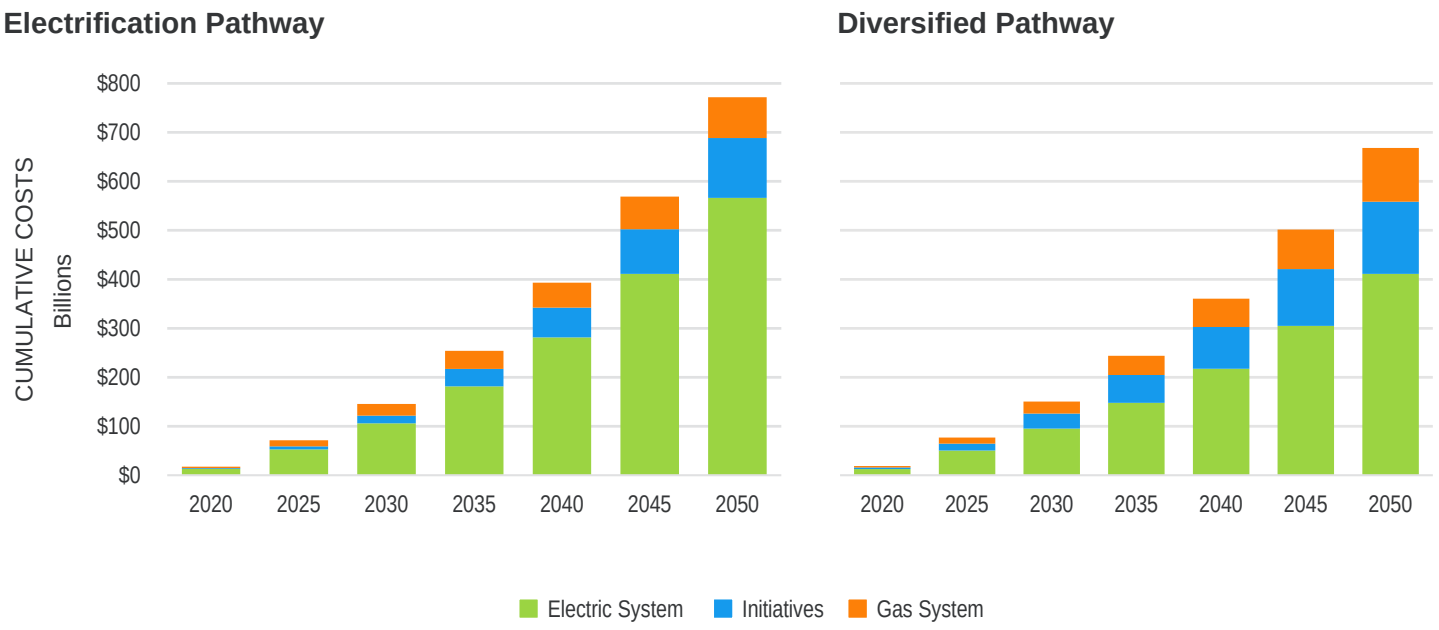
FIGURE 15. PATHWAY COSTS



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.

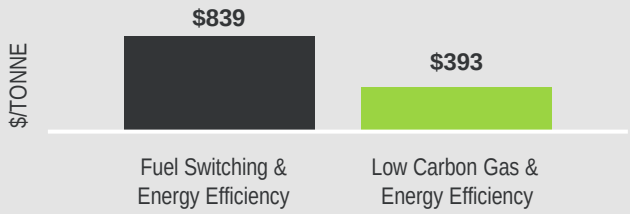
The findings in this analysis suggest drop-in fuels would be more cost-effective than fuel switching to electricity. The cost per tonne of reducing emissions in difficult-to-address sectors like buildings with renewable gases is approximately half that of fuel switching when accounting for the full system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

Attachment 31.2.1b

MEMORANDUM

Date:	June 19, 2019
To:	Colm Kennedy, FortisBC
From:	Caroline Astley, M.Sc., R.P.Bio., CPESC
File:	989772-01
Re:	Silver Creek Trib 1 Restoration Site Monitoring – Year 1

Colm,

As per our discussions with FortisBC, dated March 27, 2019, yearly monitoring of the Silver Creek Tributary 1 restoration area is required to meet the requirements of the City of Burnaby Park Department Conservation Area Access agreement and stream daylighting work completed under the *Water Sustainability Act* in 2018. The purpose of monitoring this area is to assess survivorship of the plants and determine if additional plants or other maintenance is necessary to meet the targets set out in the original restoration plan[1].

1.0 METHODS

An environmental monitor with vegetation identification skills assessed the replanted area at Silver Creek Tributary 1 on May 23, 2019. The purpose of the survey was to survey the plants, determine if any were dead or dying, perform an overview assessment of general health, and identify if invasive species requiring treatment or removal were present.

2.0 RESULTS

Overall, plants in the restoration area are growing well (**Photos 1 to 5**). The hydroseeded areas are providing some ground cover, and the plants have leaves, flowers, and fruit present. Natural recruitment of native species from the surrounding area, such as Pacific bleeding-heart (*Dicentra formosa*), is also evident (**Photo 6**).

[1] Site Restoration Plan, Hemmera (2018), and memo from McTavish (2018).

Photo 1. View of restoration area, west bank

Photo 2. View of restoration area, east bank

Photo 3. Snowberry (*Symphoricarpos albus*) showing good growth

Photo 4. Vine maple (*Acer circinatum*) showing good growth

Photo 5. Rose (*Rosa sp.*) in flower

Photo 6. Pacific bleeding-heart

Invasive species have started to invade the replanting area, with a small patch of Japanese knotweed (*Reynoutria japonica* var. *japonica*), present on the west bank just north of the access road (**Photo 7**).

Photo 7. Japanese knotweed

Himalayan blackberry (R*ubus armeniacus*) has also started to invade the edges of the replanted area (**Photo 8**).

Photo 8. Himalayan blackberry

A few plants are also showing signs of heat or drought stress. The sword ferns (*Polystichum munitum*) planted at the toe of the slope on the west bank are brown and showing signs of stress (**Photo 8**), and at least one western redcedar (*Thuja plicata*) is also showing signs of stress (**Photo 9**).

Photo 8. Stressed sword ferns on the west bank.

Photo 8. Stressed western redcedar.

No movement of the coarse woody debris was noted. It will continue to be monitored to assess the condition of the anchors. Any movement or slippage will be noted and addressed as required.

3.0 RECOMMENDATIONS

Watering through the dry summer months is recommended to support the stressed plants on site and promote growth during drought conditions. Should dead or dying plants be observed during the assessment in 2020, then these plants should be replaced immediately with similar species, or with species approved by the FortisBC Environment team.

Annual monitoring should continue during the maintenance period for next three years as required by Schedule C, Section 7(b) of the City of Burnaby Access Agreement. Inspections should take place during spring months to assess if plants have survived the winter. The timing of annual monitoring will allow for time to replace plants as required.

4.0 CLOSURE

We have appreciated the opportunity of working with you on this project and trust that this report is satisfactory to your requirements. Please feel free to contact the undersigned regarding any questions or further information that you may require.

Report prepared by:
Hemmera Envirochem Inc.

Caroline Astley, M.Sc., R.P.Bio., CPESC
Senior Project Manager

MEMORANDUM

Date:	June 30, 2020
To:	Melissa Graham – Environmental Specialist, FortisBC
From:	Sarah Wyness, M.Sc., R.P.Bio.
File:	989772-01
Re:	Silver Creek Tributary 1 Restoration Site Monitoring – Year 2

1.0 BACKGROUND

In 2018, construction and site restoration activities were undertaken on Silver Creek Tributary 1 as part of the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) project undertaken by FortisBC Energy Inc. (FortisBC). Yearly monitoring of the Silver Creek Tributary 1 restoration area is a requirement of the City of Burnaby Park Department Conservation Area Access Agreement and permits issued for the stream daylighting work under the *Water Sustainability Act* in 2018. The purpose of the site visit was to survey the plants, determine if any were dead or dying, conduct an overview assessment of general plant health, and identify invasive plant species requiring treatment or removal.[1] The Year 1 Restoration Monitoring Assessment was completed by Hemmera in June 2019. This memorandum summarizes the results of the Year 2 Monitoring Assessment undertaken in May 2020.

2.0 METHODS

A Hemmera biologist with vegetation identification skills assessed the replanted area at Silver Creek Tributary 1 on May 11, 2020. The purpose of the site visit was to survey the plants, determine if any were dead or dying, conduct an overview assessment of general plant health, and identify invasive plant species requiring treatment or removal. The Hemmera biologist surveyed the restoration site to identify native species composition and condition, took representative site photos, identified any signs of wildlife, and noted any indicators of human disturbance. Signs of native plant stress were noted.

3.0 RESULTS

Overall, plants in the restoration area were growing well particularly along the upper slope areas (**Photos 1 to 4**). Abundant healthy vegetative growth (i.e., leaves) indicated successful establishment of most plantings. Two western redcedar (*Thuja plicata*) plantings that showed indications of heat or drought stress in Year 1 appeared healthy and viable in Year 2 (**Photo 5**). Two common snowberry (*Symphoricarpos albus*) plantings along the west bank had died. Approximately 20 m^2 of planting along the toe of the slope on the west and east side of Silver Creek tributary, consisting of western sword fern (*Polystichum munitum*) were showing signs substantial heat or drought stress. At these locations, the bank area surrounding the ferns had become exposed and hydroseed had not established (**Photos 6 – 7**). In the remaining hydroseeded areas the hydroseed had become well-established and provided well-developed ground cover. Natural recruitment of native Pacific bleeding-heart (*Dicentra Formosa*) from adjacent areas continued to be observed in Year 2.

[1] Site Restoration Plan, Hemmera (2018), and memo from McTavish (2018).

As was observed during Year 1 monitoring efforts, invasive plant species continued to encroach into the planting area along edge habitats (i.e., adjacent to trail systems and infrastructure). Three patches of Japanese knotweed (*Reynoutria japonica* var. *japonica*) were observed along the west slope of the planting area north of the access road (**Photos 7 and 8**). Field bindweed (*Convolvulus arvensis*) (**Photo 9**) was observed encroaching into the planting area along the southwest and east sides establishing over riprap surfaces and encroaching on the planting area edges, and Himalayan blackberry (*Rubus armeniacus*) was also observed along the edges of the replanted area (**Photos 4 and 7**). A garden variety primrose (*Primula*) species was observed along the west bank of the planting area near the access road.

No movement of the coarse woody debris was noted. It will continue to be monitored in futures years to assess the condition of the anchors, and any movement or slippage will be noted and addressed as required. No wildlife observations were observed; however, the area provides suitable habitat for a variety of small mammals, amphibians, and bird species.

4.0 RECOMMENDATIONS

Continued watering through the dry summer months with targeted watering of the lower southwest and east bank (where western sword fern is showing signs of heat and drought stress) is recommended to promote growth over the summer period. It is recommended that the exposed bank areas along the southwest and east bank are hydroseeded with a native riparian seed to prevent surface erosion and promote the establishment of ground cover, which will provide improved water retention along the slope. Given the successful establishment of vegetation in the remaining sections of the planting area, no additional re-planting is recommended at this time. Should additional dead or dying plants be observed during the assessment in Year 3 resulting in reduced riparian habitat integrity, as determined by a QEP, then additional planting should be completed immediately with similar species approved by the FortisBC Environment team. It is recommended that targeted chemical treatment of the Japanese knotweed occurrences is conducted, and hand removal of the field bindweed is conducted.

Annual monitoring should continue during the maintenance period for the next two years as required by Schedule C, Section 7(b) of the City of Burnaby Access Agreement. Inspections should take place during spring months to assess if plants have survived the winter; this timing of annual monitoring will allow for time to replace plants as required.

5.0 CLOSURE

This Work was performed in accordance with Blanket Order 4500047433 between Hemmera Envirochem Inc. (Hemmera), a wholly owned subsidiary of Ausenco Engineering Canada Inc. (Ausenco), and FortisBC (Client), under a change order dated July 3, 2019 (Contract). This Report has been prepared by Hemmera, based on fieldwork conducted by Hemmera, for sole benefit and use by FortisBC. In performing this Work, Hemmera has relied in good faith on information provided by others, and has assumed that the information provided by those individuals is both complete and accurate. This Work was performed to current industry standard practice for similar environmental work, within the relevant jurisdiction and same locale. The findings presented herein should be considered within the context of the scope of work and project terms of reference; further, the findings are time sensitive and are considered valid only at the time the Report was produced. The conclusions and recommendations contained in this Report are based upon the applicable guidelines, regulations, and legislation existing at the time the Report was produced; any changes in the regulatory regime may alter the conclusions and/or recommendations.

We have appreciated the opportunity of working with you on this project and trust that this report is satisfactory to your requirements. Please feel free to contact the undersigned regarding any questions or further information that you may require.

Report prepared by:
Hemmera Envirochem Inc.

Sarah Wyness, M.Sc., R.P.Bio.
Project Biologist

Report reviewed by:
Hemmera Envirochem Inc.

Renae Mackas, B.Sc.,
Project Manager

6.0 PHOTO DOCUMENTATION

Photo 1 View of restoration area, west bank; looking south (May 11, 2020).

Photo 2 View of restoration area, east bank; looking south (May 11, 2020).

Photo 3 Looking at west bank from east bank.

Photo 4 Western redcedar on west bank; ground-cover well-established and Himalayan blackberry observed along edge.

Photo 5 **Looking at east bank large woody debris placement; western sword fern observed to be stressed and bank exposed.**

Photo 6 **Looking at stressed western sword fern at toe of west bank slope.**

Photo 7 **Looking north along west bank showing good growth; Japanese knotweed observed (circled in red).**

Photo 8 **Japanese knotweed observed on west bank (circled in red).**

Photo 9 Looking north towards east bank; field bindweed observed (yellow circle).

MEMORANDUM

Date:	June 14, 2021
To:	Melissa Graham – Environmental Program Lead, FortisBC
From:	Sarah Wyness, M.Sc., R.P.Bio.
File:	989772-01
Re:	Silver Creek Tributary 1 Restoration Site Monitoring – Year 3

1.0 BACKGROUND

In 2018, construction and site restoration activities were undertaken on Silver Creek Tributary 1 as part of the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) project undertaken by FortisBC Energy Inc. (FortisBC). A four-year maintenance period with annual inspections for the Silver Creek Tributary 1 restoration site is a requirement of the City of Burnaby Park Department Conservation Area Access Agreement and permits issued for the stream daylighting work under the *Water Sustainability Act* in 2018. The purpose of annual monitoring site visits is to survey the plants, determine if any are dead or dying, conduct an overview assessment of general plant health, and identify invasive plant species requiring treatment or removal.[1] The Year 1 and 2 Restoration Monitoring Assessment was completed by Hemmera in May 2019 and May 2020. This memorandum summarizes the results of the Year 3 Monitoring Assessment undertaken in May 2021.

2.0 METHODS

A Hemmera biologist with vegetation identification skills assessed the restoration site at Silver Creek Tributary 1 on May 4, 2021. The purpose of the site visit was to survey the plants, determine if any were dead or dying, conduct an overview assessment of general plant health, and identify invasive plant species requiring treatment or removal. The Hemmera biologist surveyed the restoration site to identify native species composition and condition, took representative site photos, identified any signs of wildlife, and noted any indicators of human disturbance. Signs of native plant stress were noted.

3.0 RESULTS

Overall, plants in the restoration area were growing well particularly along the upper slope areas (**Photos 1 to 4**). Abundant healthy vegetative growth (i.e., leaves) indicated successful establishment of most plantings. Western redcedar (*Thuja plicata*) plantings that showed indications of heat or drought stress in Year 1 and 2 appeared healthy and viable in Year 3 (**Photo 5**). Common snowberry (*Symphoricarpos albus*) plantings appeared to have new growth and were well established along the upper banks (**Photo 6**). Various other native species such as salmonberry (*Rubus spectabilis*), black cottonwood saplings (*Populus trichocarpa*), alder saplings (*Alnus rubra*), Nootka rose (*Rosa nutkana*), and red elderberry (*Sambucus racemosa*) were well established along the banks.

[1] Site Restoration Plan, Hemmera (2018), and memo from McTavish (2018).

Approximately 20 m^2 of planting along the toe of the slope on the west and east side of Silver Creek Tributary 1, consisting of western sword fern (*Polystichum munitum*) continued to show signs of heat or drought stress. At these locations, the bank area surrounding the ferns had become exposed (**Photo 7**). In the remaining hydroseeded areas the hydroseed had become well-established and provided well-developed ground cover.

As was observed in previous monitoring efforts, invasive plant species continued to encroach into the restoration site along edge habitats (i.e., adjacent to trail systems and infrastructure). Five patches of Japanese knotweed (*Reynoutria japonica* var. *japonica*) were observed along the west slope of the restoration site north of the access road (**Photos 8**). Field bindweed (*Convolvulus arvensis*) (**Photo 9**) was observed encroaching into the restoration site along the southwest and east sides establishing over riprap surfaces and encroaching on the restoration site edges, and Himalayan blackberry (*Rubus armeniacus*) was also observed along the edges of the replanted area (**Photo 10**). Additional invasive species that were observed included reed canary grass (*Phalaris arundinacea*), Scotch broom (*Cytisus scoparius*), and creeping buttercup (*Ranuculus repens*). Himalayan blackberry, field bindweed and thistle were observed within the stream channel (**Photo 11**). Natural recruitment of Pacific bleeding heart was documented again in Year 3 along the west slope of the restoration site.

No movement of the coarse woody debris was noted. It will continue to be monitored in Year 4 to assess the condition of the anchors, and any movement or slippage will be noted and addressed as required. No wildlife observations were observed; however, the area provides suitable habitat for a variety of small mammals, amphibians, and bird species.

4.0 RECOMMENDATIONS

Continued watering through the dry summer months with targeted watering of the lower southwest and east bank (where western sword fern is showing signs of heat and drought stress) is recommended to promote growth over the Year 3 summer period. Given the successful establishment of vegetation in the remaining sections of the restoration site, no additional re-planting is recommended at this time. Should additional dead or dying plants be observed during the assessment in Year 4 resulting in reduced riparian habitat integrity, as determined by a QEP, then additional planting should be completed immediately with similar species approved by the FortisBC Environment team. It is recommended that targeted chemical treatment of the Japanese knotweed occurrences is conducted again in Year 3 (i.e., early spring or late summer).

Annual monitoring should continue during Year 4 of the maintenance period at the restoration site as required by Schedule C, Section 7(b) of the City of Burnaby Access Agreement.

5.0 CLOSURE

This Work was performed in accordance with Blanket Order 4500047433 between Hemmera Envirochem Inc. (Hemmera), a wholly owned subsidiary of Ausenco Engineering Canada Inc. (Ausenco), and FortisBC (Client), under a change order dated July 3, 2019 (Contract). This Report has been prepared by Hemmera, based on fieldwork conducted by Hemmera, for sole benefit and use by FortisBC. In performing this Work, Hemmera has relied in good faith on information provided by others, and has assumed that the information provided by those individuals is both complete and accurate. This Work was performed to current industry standard practice for similar environmental work, within the relevant jurisdiction and same locale. The findings presented herein should be considered within the context of the scope of work and project terms of reference; further, the findings are time sensitive and are considered valid only at the time the Report was produced. The conclusions and recommendations contained in this Report are based upon the applicable guidelines, regulations, and legislation existing at the time the Report was produced; any changes in the regulatory regime may alter the conclusions and/or recommendations.

We have appreciated the opportunity of working with you on this project and trust that this report is satisfactory to your requirements. Please feel free to contact the undersigned regarding any questions or further information that you may require.

Report prepared by:
Hemmera Envirochem Inc.

Annette Bosman, M.Sc., BIT
Project Biologist

Report reviewed by:
Hemmera Envirochem Inc.

Sarah Wyness, M.Sc., R.P.Bio.
Project Biologist

PHOTOGRAPHS

6.0 PHOTO DOCUMENTATION

Photo 1 View of restoration site conditions growing along the east and west slope looking north (Photo taken: May 4, 2021).

Photo 2 View of west slope looking south-west (Photo taken: May 4, 2021).

Photo 3 View of the restoration site east slope looking east (Photo taken: May 4, 2021).

Photo 4 Looking south towards restoration site from the stream channel (May 4, 2021).

Photo 5 Western redcedar planted on the west slope; plantings in good health (Photo taken: May 4, 2021).

Photo 6 Common snowberry well-established through restoration site along west slope (Photo taken: May 4, 2021).

Photo 7 View of the ground conditions around western sword fern near toe of slope; sword fern plantings showing signs of stress (Photo taken: May 4, 2021).

Photo 8 Japanese knotweed growing on the west slope of the restoration site (Photo taken: May 4, 2021).

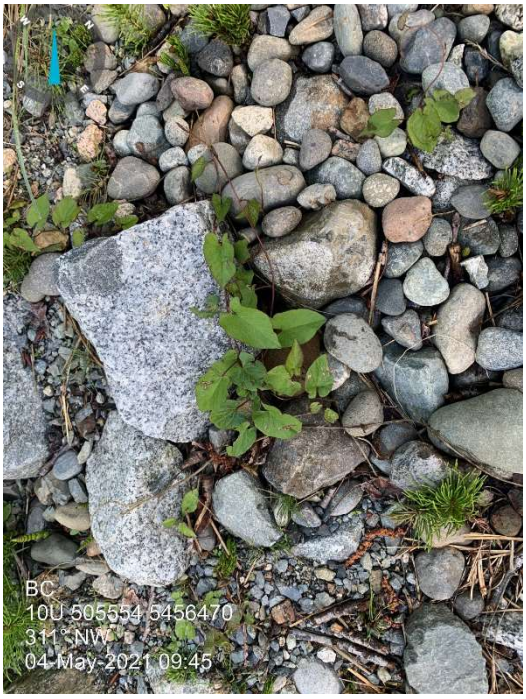


Photo 9 Field bindweed encroaching into the restoration site along south extent (Photo taken: May 4, 2021).

Photo 10 View of the Himalayan blackberry that was observed encroaching into the restoration site along the west slope (Photo taken: May 4, 2021).

Photo 11 View of the invasive plant species within the stream channel.