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May 3, 2023

My Sea to Sky
P.O. Box 2668
Squamish, BC
V8B 0B8

Attention: Eoin Finn, B.Sc., Ph.D., MBA

Dear Eoin Finn:

Re: FortisBC Energy Inc. (FEI)

2022 Long Term Gas Resource Plan (LTGRP) – Project No. 1599324

Response to the My Sea to Sky (MS2S) Information Request (IR) No. 2

On May 9, 2022, FEI filed the LTGRP referenced above. In accordance with the amended regulatory timetable established in British Columbia Utilities Commission Order G-99-23 for the review of the LTGRP, FEI respectfully submits the attached response to MS2S IR No. 2.

In its responses, FEI has identified responses which were provided by, contributed to, or developed with its consultants, the Posterity Group and Guidehouse.

For convenience and efficiency, if FEI has provided an internet address for referenced reports instead of attaching the documents to its IR responses, FEI intends for the referenced documents to form part of its IR responses and the evidentiary record in this proceeding.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Parties

ISSUE 11: Hydrogen Blending-Impact on Emissions

Reference: LTGRP <u>Exhibit A2-2</u>: Letter dated March 16, 2022 - BCUC staff submitting BC Centre for Innovation and Clean Energy's report on Carbon Intensity of Hydrogen Production Methods[1]

P. 9 The Executive Summary of that report states:

> **"Hydrogen blending and its impact on emissions**
>
> The report also analyzed the GHG emissions reductions that would be possible by blending hydrogen into BC's natural gas network. Four scenarios were developed: a high efficiency scenario, an electrolysis-only scenario, a mixed reduction scenario, and a scenario using proven technology alone.
>
> Using these scenarios, analysis shows that blending hydrogen at approximately 20% by volume(2 l.5 million GJ of hydrogen) into the province's natural gas network for utility heating can achieve emission reductions of 350,000 - 815,000 tonnes/year CO2e. This results in a 0.5% - 1.3% reduction in overall BC GHG emissions, and a 1.7% - 4% reduction in emissions from BC's utility natural gas system."

Questions:

11.1 Does FEI concur that blending hydrogen at approximately 20% by volume would result in a 1.7% to 4% reduction in emissions from BC's utility natural gas system? If not, what overall emission reduction does FEI anticipate by 2030?

<u>Response:</u>

Please refer to the response to BCUC IR2 106.12.

11.2 What GHG reductions are anticipated to result from each of the following by 2030?:

(a) FEI blending hydrogen gas into the gas supply

(b) RNG

(c) Small scale demand-side measures

(d) Energy efficiency improvements.

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1 https://docs.bcuc.com/Documents!Proceedings/2023/DOC70568A2-2-CICE-Carbon-Intensity-of-HydrogenProduction-Methods.pdf.

Response:

Please refer to the response to CEC IR2 56.2 for an overview of the annual GHG end use emission reductions FEI anticipates by 2030, 2040 and 2042 for the requested initiatives.

For clarity, FEI interprets the question as referring to annual end use emission reductions achieved in 2030 for each of the following:

a) Emission reductions contributed via hydrogen (all types of hydrogen-related activity, not just blending and CCUS);

b) RNG including syngas and lignin;

c) Small scale demand-side measures as represented by residential and commercial customer types; and

d) Energy efficiency improvements as those related to industrial customer types.

ISSUE 12 : Hydrogen Blending - Impact on Emissions

Reference: Exhibit A2-2: Letter dated March 16, 2022 - BCUC staff submitting BC Centre for Innovation and Clean Energy's report on Carbon Intensity of Hydrogen Production Methods

P. 35, of Exhibit A2-2 states: "The potential for (global) warming due to hydrogen leakage is not considered. Currently, the United Nations Intergovernmental Panel on Climate Change (IPCC) does not have a GWP (global warming potential) for hydrogen, but emerging research in the UK[2] indicates it might have a GWP of about 11. There is also work on potential leakage rates for hydrogen systems (Frazer Nash, 2022), and initial results indicate rates around 5% for some production activities. However, further investigation is required".

Questions:

12.1 While hydrogen (H2) is itself not a GHG, scientific research[3] suggests that it increases the longevity of methane in the upper atmosphere. Which makes it, in effect, also a radiative forcer2. Has FEI incorporated this effect in its estimation of GHG reductions resulting from hydrogen blending into the gas stream?

Response:

As noted in the preamble, further investigation is required to determine the trade-off between the increased use of low-carbon intensity hydrogen and resulting reduction in methane emissions and products of natural gas combustion. This includes consultation between industry and provincial and federal regulators on the topic.

For the purposes of the LTGRP, FEI has not adopted the indirect global warming potential in the lifecycle GHG emission factors provided. FEI refers to the British Columbia report on the Carbon Intensity of Hydrogen Production Methods recently published as the most up to date reference on lifecycle carbon intensity for hydrogen production methods.[4]

Hydrogen leakage along supply chains will be an important consideration and additional analysis may be required to understand potential environmental impacts from deploying hydrogen,

[2] Nicola Warwick, Paul Griffiths, James Keeble, Alexander Archibald, John Pyle, and Keith Shine, Atmospheric implications of increased hydrogen use, Department for Business, Energy and Industrial Strategy, 2022, 75.

[3] Risk of the hydrogen economy for atmospheric methane: https://www.nature.com/artic1es/s41467-022-35419-7; The abstract of the paper states "Hydrogen (H2) is expected to play a crucial role in reducing greenhouse gas emissions. However, hydrogen losses to the atmosphere impact atmospheric chemistry, including positive feedback on methane (CRi), the second most important greenhouse gas. Here we investigate through a minimalist model the response of atmospheric methane to fossil fuel displacement by hydrogen. We find that CH4 concentration may increase or decrease depending on the amount of hydrogen lost to the atmosphere and the methane emissions associated with hydrogen production. Green H2 can mitigate atmospheric methane if hydrogen losses throughout the value chain are below 9 ± 3%. Blue H2 can reduce methane emissions only if methane losses are below 1 %. We address and discuss the main uncertainties in our results and the implications for the decarbonization of the energy sector.

[4] https://cice.ca/2023/03/16/carbon-intensity-of-hydrogen-production-methods-report/.

particularly at large scale into the future. FEI proposes that into the future, two important aspects of the gas system need to be considered in the context of hydrogen leakage:

1) Hydrogen will initially be deployed at relatively low percentage blend concentrations which will not result in significant hydrogen emissions, and

2) As more hydrogen is deployed over time, gas networks will be upgraded and therefore less likely to leak.

12.2 Has FEI incorporated leakage rates for hydrogen in its estimates of GHG reductions in customer emissions?

Response:

No. Please refer to the response to MS2S IR2 12.1.

12.3 Is FEI aware of recent peer-reviewed research (published in the prestigious science journal Nature Communications3) showing that, for blue hydrogen, any leakage rates for hydrogen exceeding 1% will actually result in increased- not decreased - GHG impact from blending hydrogen into gas distribution networks?

Response:

FEI is aware of the report mentioned in the question. FEI understands that the lifecycle carbon intensity of blue hydrogen production pathways will depend on the technology used to produce the hydrogen and the manner in which the technology is deployed in the design, construction and operation of low-carbon hydrogen production facilities. FEI will take all steps to ensure the lifecycle carbon intensity of any prospective blue hydrogen production or procurement by FEI aligns with the carbon reduction goals of the provincial and federal governments and any potential targets or policies that prescribe the carbon intensity of this pathway.

ISSUE 13: Hydrogen Blending-Pipeline Embrittlement

Reference: Exhibit A2-2: Letter dated March 16, 2022 - BCUC staff submitting BC Centre for Innovation and Clean Energy's report on Carbon Intensity of Hydrogen Production Methods

P. 48 of Exhibit A2-2 states: "Transportation is a significant contributor to the lifecycle CI (Carbon Intensity) for hydrogen production pathways that involve greater distances between the point of production and the point of use. This is especially clear with respect to the SMR (Steam-Methane Reforming) plus CCS (Carbon Capture & Sequestration) pathway, which assumes that hydrogen is produced in northeastern BC and transported 1,200 km to the Lower Mainland. The modelling also shows that truck transportation makes a far larger contribution to lifecycle CI than transport by either rail or pipeline. Pipeline transportation is the least carbon intensive, but building a dedicated hydrogen pipeline from the production source to the demand centre is cost-prohibitive. Another option would be to blend hydrogen into the existing natural gas pipeline from the production source, but this would require significant blending of hydrogen at the transmission pressure. This would introduce several challenges, including the potential for catastrophic failure due to hydrogen embrittlement. See Section 6.1 for additional challenges and issues for blending into the transmission infrastructure". [acronyms expanded]

Section 6.1 (P. 63) of Exhibit A2-2 states: "One of these challenges is hydrogen embrittlement, a phenomenon that causes catastrophic failures in metal and non-metallic materials that are constantly exposed to hydrogen and is often a limiting factor to the quantity of hydrogen that can be accommodated in natural gas infrastructure. Embrittlement is also specific to the pressures and materials under exposure, which means that its impact on transmission and distribution pipelines varies. Furthermore, embrittlement considerations apply to key infrastructure components, such as compressors, that play an important role in natural gas transportation".

P. 29, Figure 7 of Exhibit A2-2 states: "(Australia) agrees not to support the blending of hydrogen in existing gas transmission networks until further evidence emerges that hydrogen embrittlement issues can be safely addressed" .

P. 53 of exhibit A2-2 states: "Another challenge involves the separation of blended hydrogen in transmission lines prior to US export- specifically, limitations in the applicability of separation technologies at scale and increased energy requirements. These limitations are typically associated with the levels of selectivity (i.e., how much hydrogen can be separated) and purity (i.e., how pure the separated hydrogen is) achievable from separation technologies. This separation would likely require processing large volumes of natural gas, up to the entire export volume; which would result in significant energy and cost implications due to pressure losses from depressurization during separation, and subsequent post-separation re-pressurization for export".

P. 53 of Exhibit A2-2 states: "In the early 2010s, the National Renewable Energy Laboratory (NREL) estimated the cost of hydrogen extraction using PSA units to be between US$3.3 and US$8.3 per kg of hydrogen (~ US$0.40-US$1/GJ energy), not including the cost of natural gas re- compression for subsequent export. The NREL's estimate was based on extracting hydrogen from a 300-psi pipeline at 10% concentration".

Questions:

13.1 What would be the cost of constructing a dedicated hydrogen pipeline from Northeast BC to the Lower Mainland and onward to Vancouver Island?

<u>Response:</u>

FEI has not investigated the scope and cost of constructing a dedicated hydrogen pipeline from Northeast BC to the Lower Mainland and onward to Vancouver Island. This initiative could be assessed in the future as the production of hydrogen as a mainstream fuel source evolves over time.

13.2 Has FEI considered constructing a dedicated hydrogen pipeline from Northeast BC to the Lower Mainland? If not, why not?

<u>Response:</u>

FEI has not yet considered the construction of a dedicated hydrogen pipeline from Northeast BC to the Lower Mainland in detail because the hydrogen market, including the supply and demand outlook, is not sufficiently mature to indicate if or when such a large pipeline transport infrastructure would be required. However, this concept for a hydrogen pipeline was suggested in the BC Hydrogen Study report published in 2019 which was supported by the Province of BC and FEI, among others.[5] The relevant details from the report are copied below for ease of reference:

> The Peace Region of BC, with extensive gas reserves, CO_2 sequestration potential, hydroelectric generation capacity and wind resources, coupled with an abundant fresh water supply, could become a centralized large-scale producer of clean hydrogen supplying not only BC, but also the US Pacific Northwest and California. There is potential to use the existing NG grid and inject large amounts of hydrogen and create a blended NG / H_2 gas stream. Liquefaction coupled with rail or road transport would enable delivery of pure hydrogen. A 'big bold goal' would be to construct a dedicated hydrogen pipeline that runs from the Peace Region right down to California. This would be built with a view to future energy systems, rather than one retrofitted to the hydrocarbon energy systems of the past. There could also be potential to run the pipeline east into Alberta. This carbon-free

[5] Exhibit B-1, Appendix A-6.

energy pipeline could provide a means for both provinces to transmit carbon-free energy derived either from renewable resources or fossil resources where the carbon is sequestered directly at the source of extraction, thereby alleviating many of the environmental concerns connected to existing pipeline projects under development.[6]

13.3 At what point(s) in the gas transmission network is FEI considering injecting the (up to) 20% Hydrogen?

Response:

FEI expects that it will be further out in the forecasting period when, as hydrogen begins to support more of the core demand, that load will be displaced and the transmission pipeline network would likely be required to support increasing hydrogen demand and to transport supply to demand nodes on the distribution network.

FEI expects to initially blend hydrogen into the distribution pressure pipeline network at a lower blend concentration and then expand hydrogen-blended service across more of the distribution network, at higher blend concentrations up to approximately 20 percent hydrogen by volume, with the potential for segments within the distribution network to expand to include hydrogen networks that can distribute higher shares of hydrogen. FEI expects that local hydrogen production facilities interconnected to the distribution system will be sufficient to meet demand from hydrogen blending and as potential demand emerges in other sectors such as transportation.

Beyond that point, FEI expects it may become necessary to expand, upgrade or repurpose some components of the transmission network to support and enhance the capacity of the blended systems, while still supporting the remaining dedicated natural gas requirements. Over the longer term and as supply and demand for hydrogen grows, FEI expects to transition the transmission network through retrofitting, upgrading and expansion to transport an increasing share of hydrogen and RNG, which will include supply delivered from outside FEI’s main service territories which will likely include import of hydrogen by pipeline.

[6] Ibid., p. 59.

13.4 Is FEI aware of the recent publication[7] _by CB&I engineers in LNG Industry Magazine?

Response:

FEI is aware of this report.

13.5 The CB&I engineers article outlines severe hydrogen intolerance in the methane liquefaction process, and strongly recommends providing a pure methane gas supply to LNG liquefaction plants (i.e. injecting hydrogen in the gas stream only downstream of LNG plants). Does FEI concur that hydrogen should only be injected into the gas stream downstream of LNG plans? If not, why not?

Response:

The referenced report does not state that hydrogen should only be injected in the gas stream downstream of LNG plants. Rather, the report says: "When possible, it is highly recommended that hydrogen injection be located downstream of an LNG peak shaving facility to avoid issues with liquefaction". When possible, the simplest solution is, of course, to inject hydrogen downstream of an LNG peak shaving facility. As stated in the referenced report, installation of a separation process is a solution where this is not possible:

> Over time, it is possible that hydrogen will become prevalent in many of the pipelines feeding peak shaving facilities. This will require mitigations to keep these important facilities operational.
>
> For existing liquefiers, hydrogen removal is recommended prior to the liquefaction process. The simplest arrangement may be to install a separation process prior to the gas pre-treatment system (Figure 3). A solution for an existing LNG facility is membrane separation.

[7] **Hydrogen blending and LNG, LNG Industry Magazine, October 2022**
Jeffery J. Baker and Randall W. Redman, CB&I, USA, details how hydrogen can impact LNG peak shavers, outlining the solutions to keep LNG peak shavers operational. An excerpt from this states: "Though a limited presence of hydrogen in natural gas has minimal effects on residential appliances and industrial burners, even a small percentage of hydrogen in the feed gas to an LNG peak shaving facility will affect the liquefaction process. When possible, it is highly recommended that hydrogen injection be located downstream of an LNG peak shaving facility to avoid issues with liquefaction". Note: CB&I (Chicago Bridge & Iron) is a construction subsidiary of McDermott International, the company contracted by Woodfibre LNG to construct its LNG plant near Squamish, BC.

13.6 Would the costs of separating methane from hydrogen be borne by (i) the LNG plants or (ii) all ratepayers?

Response:

The recovery of costs related to separating methane from hydrogen has not been determined at this point. It is feasible that low carbon hydrogen, if delivered as a blend in the gas stream, could be separated at the plant gate and used by the LNG plant facility to decarbonize its plant operations or provided as a fuel to decarbonize the downstream gas system. However, it is anticipated the costs would be borne by all non-bypass customers.

13.7 Does FEI propose to deliver a hydrogen/ methane blend to its own LNG plants (i) on Tilbury Island and (ii) at Mount Hayes on Vancouver Island? If so, how does FEI propose to remove hydrogen from a hydrogen/ methane blend delivered to those plants?

Response:

The strategy to deliver a hydrogen/methane blend over FEI's complete system is still under development. Should a hydrogen/methane blend be introduced into the transmission system upstream of the Tilbury Island and/or Mount Hayes plants, facilities would need to be installed to remove the hydrogen from the methane. Current technologies that could be considered for applications to separate hydrogen from a blend with natural gas include PSA, cryogenic and membrane separation technologies. If hydrogen was separated from the gas supply upstream of the LNG plant facilities, this may provide opportunities to supply hydrogen to other local markets, including transportation, that may take advantage of the purer hydrogen supply. The facilities have not been designed at this point in time.

13.8 What is the additional cost of that removal of hydrogen from a hydrogen/methane blend for each of the LNG plants at Tilbury Island and Mount Hayes?

Response:

FEI has not yet undertaken facility design or cost estimating work to quantify the costs associated with hydrogen separation facilities. FEI plans, as part of an ongoing integrated program of work, to evaluate all of its gas system assets and gas customers' installations, in order to establish the requirements and overall strategy to blend hydrogen throughout FEI's service territories. FEI expects to advance its hydrogen roadmap over the coming two to three years as part of the broader program of work that will also include developing a hydrogen deployment strategy to guide FEI's roll out of hydrogen in the near-term and the longer-term which will include developing FEI's understanding of the feasibility and additional cost of removal of hydrogen from a hydrogen/methane blend for LNG facilities.

13.9 Is FEI aware that the Certified Project Description[8] for the Eagle Mountain Gas pipeline(s) specifies that "The pipelines must transport sweet natural gas only"?

Response:

Confirmed.

13.10 Does FEI agree that the Eagle Mountain Gas pipeline(s) are the only pipelines serving gas customers from the Eagle Mountain compressor station in Coquitlam through to Southern Vancouver Island? If no, list the other pipelines that serve these gas customers.

Response:

The Eagle Mountain Gas pipeline, together with the existing Vancouver Island Transmission System, are the only pipelines capable of serving gas customers from the Eagle Mountain compressor station in Coquitlam through to Southern Vancouver Island.

13.11 Would FEI agree that this restriction on transporting sweet natural gas only bars any transmission of hydrogen/methane blend through that linked 24" and 10" pipeline pair, which are the only pipelines serving gas customers from the Eagle Mountain compressor station in Coquitlam through to Southern Vancouver Island?

[8] https://projects.eao.gov.bc.ca/api/public/document/58869121e036fb0105768ee0/download/Schedule%20A%20-%20Certified%20Proj%20ect%20Description.pdf.

Response:

If both the restriction on transporting sweet natural gas, and the definition of sweet natural gas remain unchanged, then FEI agrees that transmission of a hydrogen/methane blend may not be permissible.

Regardless, FEI expects that, instead of transporting a blend of natural gas and hydrogen through the linked 24" and 10" pipelines, a more practical approach would be to utilize available resources to produce hydrogen locally (i.e., closer to downstream customers) that could then be supplied to customers served by the Vancouver Island Transmission System (VITS) downstream of the linked 24" and 10" pipelines.

13.12 How else would FEI propose to deliver a hydrogen/methane blend to customers downstream of the Eagle Mountain compressor station in Coquitlam?

Response:

Please refer to the response to MS2S IR2 13.11.

ISSUE 14: Hydrogen Blending - Impact on LNG Plants Reference: FEI response to MS2S IR#1, Issue 1.2

MS2S' preamble to the questionl.1 : "Hydrogen and LNG plants. We note that, in its submission to BCUC for a new biomethane rate structure Project, FEI proposed increasing the proportion of Hydrogen (H2) in all three transmission regions - CTS, VITS and ITS - over time. Table 3 below (from FEI's August 12, 2022 "Energy Scenarios- Stage 2 Report, P.9) shows, in FEI's preferred "FEI Diversified Energy (Planning) scenario, a ten-fold increase in Hydrogen in the 2025-2042 interval.

Table 3: Forecast of Hydrogen Supply by Scenario (PJ/Year)

	2025	2030	2035	2040	2042
FEI Diversified Energy (Planning)	5.4	20.0	33.8	47.5	53.0
BC Hydro Accelerated Electrification	0.5	2.1	2.4	3.2	3.5
BC Hydro Reference Case	0.7	1.7	2.4	2.7	2.9
FEI Economic Stagnation	0.1	0.5	1.1	1.7	1.9
FEI Deep Electrification	0.0	0.0	0.0	0.0	0.0

However, in the LTGRP (Section 7 and pp. ES 9-14, Table ES-3 reproduced below), and FEI's August, 2022 "Energy Scenarios- Stage 2 Report, FEI highlights some of the challenges it will face in offering blends of hydrogen and fossil gas in its service offerings.

FORTISBC ENERGY INC.
2022 LONG TERM GAS RESOURCE PLAN

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

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

Notable among those are the effects of having downstream LNG plants (Tilbury, possibly Woodfibre, and Mount Hayes on Vancouver Island) in the pipeline circuit. These LNG plants have no use, nor any current approved plans to cope with an unrequited hydrogen supply. Plants would have to separate and dispose of any hydrogen in their feedstock. We note that FEI is contemplating (as in Table ES3 above) a "dedicated hydrogen backbone", on the CTS system at least, to deal with this issue".

MS2S' Question 1.1: What impact would this Hz blending have on methane supply to these plants?"

"FEI's Response:

In the event the hydrogen supply is blended into the supply of natural gas feeding the LNG plants, modifications and equipment retrofits, such as hydrogen removal equipment upstream of the liquefaction equipment, would need to be installed to extract hydrogen. This is because hydrogen does not liquefy at the minus162°C temperatures at which LNG is produced. There are two potential options available to mitigate the impact on LNG operations from increasing hydrogen content in the gas system:

- Hydrogen would be removed by separating it from the gas supply upstream of the LNG facility and then redirected to a different part of the gas network; or
- Hydrogen would enter the LNG facility but would be extracted prior to liquefaction and stored separately onsite for use in gaseous or liquid form (e.g. for fuel cell electric vehicle refueling). Both options would remove the hydrogen from the gas stream prior to liquefaction and hence the LNG tank would only store liquid natural gas. The extracted hydrogen would then be used for LNG plant fuel or for higher value applications, such as transportation, or might be re-blended with any downstream natural gas streams flowing past the facilities to other consumers on the system."

Questions:

14.1 To FEI's knowledge, did the environmental assessment of any of these LNG plants (Tilbury, Woodfibre and Mount Hayes) consider and approve hydrogen/methane separation capabilities? If so, please identify how the environmental assessment considered these capabilities for each LNG plant.

Response:

There was no requirement for an environmental assessment for the existing Tilbury or Mount Hayes plants. At the time of installation, hydrogen was not considered as part of feed gas for the projects. For the Woodfibre LNG project, FEI is not aware whether hydrogen has been considered as part of the Woodfibre LNG project environmental assessment. However, as stated in the preamble, technology is available to separate hydrogen from natural gas.

14.2 Please describe FEI's experience with currently-available technologies (including pressure swing adsorption (PSA), cryogenic distillation, or membrane separation) to separate/remove hydrogen from hydrogen/methane blends?

Response:

FEI has operating experience with multiple gas separation technologies at RNG facilities as well as LNG facilities; however, FEI does not yet have operating experience with commercial scale technologies to remove hydrogen from natural gas specifically, as these facilities are not required in FEI's current LNG operations.

14.3 Please describe FEI's knowledge of and estimate for:

(i) the cost of such techniques (per Gigajoule of methane)?

(ii) the feasibility of implementing any one of them on a pipelined gas blend operating at pressures of the order of 2160 PSI and flow rates of~ 0.28 billion cubic feet/day (the specifications of the EGP pipeline)?

Response:

FEI has not studied the feasibility or costs of separating hydrogen from methane in its transmission systems. FEI notes that while the maximum operating pressure of the EGP pipeline is 2,160 psi, the pressure will be reduced at the inlet of the Woodfibre LNG facility prior to liquefaction.

14.4 Please describe FEI's knowledge of other gas utilities and LNG plants that have implemented this separation technology at the scale of a multi-megatonne LNG export plant.

Response:

FEI is unaware of other gas utilities that have implemented hydrogen separation technology at this scale. These are early days in low carbon hydrogen development, and at this point in time low carbon hydrogen has not been introduced at scale requiring such facilities. The technologies that may be used, however, including PSA, membrane separation, and cryogenic distillation, are utilized in gas processing facilities of similar scale.

ISSUE 15: Meeting BC's Climate Targets

Reference: FEI response to British Columbia Utilities Commission (BCUC) Information Request (IR) No. 1, Q. 28.0, Pp. 154-155

FEI stated that "With or without the [Renewables Gas Connections] service, FEI expects to take the steps necessary so that its total GHG emissions from the use of natural gas by residential, commercial and industrial customers will meet the 2030 GHG emissions cap expected to be implemented by the Province. The availability of Renewable Gas Connections service will inform the strategies FEI must employ to meet the GHG emissions cap".

15.1 Given the climate effects of hydrogen radiative forcing and limits on the acquisition and use of low-carbon gases, what "additional steps" can FEI take to ensure that its service meets BC's 2030 GHG emissions cap and the objectives of the GHGRS?

<u>Response:</u>

Please refer to the response to BCUC IR1 74.2 for an overview of FEI’s emission reduction initiatives to meet the proposed 2030 GHGRS. Please refer to the response to GNAR IR1 1.0 and 1.1 for a discussion on radiative forcing of hydrogen.

ISSUE 16: Meeting BC's Climate Targets

Reference: FEI response to BC Climate Alliance and First Things First Okanagan (BCCA- FTFO) Information Request (IR) No. 1, Q.4.3, Pp.13-14

In this response FEI states:

> "According to the latest analysis by the International Energy Agency (IEA), natural gas emits between 45% and 55% lower greenhouse gas emissions than coal when used to generate electricity. Going forward, technologies like Carbon Capture Utilization and Storage (CCUS), renewable gases and hydrogen can help further minimize carbon content of natural gas, by as much as 90%."

On P.8 of the response, FEI states that "Industries such as pulp mills and cement manufacturing are among the largest industrial contributors to GHG emissions in BC and good candidates as hydrogen projects".

Questions:

16.1 Please provide the carbon-capture efficiencies of examples of CCUS in association with each gas-powered electricity generation, pulp mills and cement manufacturing.

Response:

The carbon-capture efficiencies of CCUS in association with gas-powered electricity generation, pulp mills or cement manufacturing will depend on the carbon capture and sequestration technologies that will be applied to decarbonize GHG emissions from industrial process fuel combustion. This is a complex, emerging topic. Please refer to the findings from three recent studies for relevant examples and further background.

1. The IEA Report - The Role of CCUS in Low-Carbon Power Systems[9] shows that gas-fired power plants can usually achieve a 90% capture rate. More than 90 percent of CO2 capture rate can be achieved at low additional marginal cost in gas-fired power plants equipped with carbon capture technologies.
2. The UN Climate Technology Center & Network Report - CCS from Cement Production [10] cited that CCS could capture between 85-95 percent of all CO2 produced.
3. Finally, the IEA Report - Achieving Net Zero Heavy Industry Sectors in G7 Members [11] provides further and complete up to date reference materials.

[9] IEA, "The role of CCUS in low-carbon power systems" (Paris, July 2020) online at: https://www.iea.org/reports/the-role-of-ccus-in-low-carbon-power-systems.

[10] UN Climate Technology Centre & Network, "CCS from cement production" online at: https://www.ctc-n.org/technologies/ccs-cement-production#:~:text=As%20stated%20above%2C%20CCS%20could,et%20al.%2C%202007).

[11] IEA, "Achieving Net Zero Heavy Industry Sectors in G7 Members" (Paris, May 2020) online at: https://www.iea.org/reports/achieving-net-zero-heavy-industry-sectors-in-g7-members.

16.2 Does this 2019 statement (quoted by the IEA but authored by the IGU-International Gas Union) incorporate the recent scientific findings of the radiative forcing effects of hydrogen as a power source - displacing fossil gas? If not, does FEI agree that hydrogen has radiative forcing effects?

Response:

Please refer to the response to GNAR IR1 1.1.

16.3 Please confirm that the IEA analysis uses the 100-year GWP (Global Warming Potential) figures for GHGs. How would the results change if the 20-year GWP figures were used?

Response:

Confirmed. The IEA, along with organizations like the IPCC, use the 100-year GWP. When GWP-20 is used instead of GWP-100, the results will change. The 20-GWP measures the effects of greenhouse gases over a shorter period, so it gives greater weight to activities that generate shorter-term warming.

16.4 How would tradeable (per COP21 "Paris" Climate Agreement - Article 6) emission reductions associated with LNG exports be agreed, measured and verified?

Response:

Article 6 of the Paris Agreement establishes a framework for voluntary international cooperation for countries to reduce emissions and meet their individual country-level pledges (often called nationally determined contributions or NDCs). Article 6 of the agreement permits a signatory country, either through bilateral or multilateral agreements, to cooperate with other countries to reduce its GHG emissions in exchange for voluntarily transferred emission credits. Signatory countries are expected to adhere to the principles of environmental integrity and transparency and implement carbon accounting procedures to ensure that double counting of emission reductions is avoided. However, precise operational details regarding the implementation of ITMOs are not yet specified.

FEI believes that ITMOs could be a potential opportunity to address GHG emissions associated with the manufacturing and corresponding benefits from the use of LNG but that high degrees of bi-lateral, commercial, policy, and technological alignment would be needed.

16.5 Please confirm that the IEA has estimated[12] the cost of capturing CO2 from coal-fired power plants at between US$50 and US$100/tonne, with an additional US$12-US$24 for transport and storage costs.

Response:

As stated in the IEA document provided:

> CCUS applications do not all have the same cost. Looking specifically at **carbon capture**, the cost can vary greatly by CO2 source, from a range of USD 15-25/t CO2 for industrial processes producing "pure" or highly concentrated CO2 streams (such as ethanol production or natural gas processing) to USD 40-120/t CO2 for processes with "dilute" gas streams, such as cement production and power generation. [Emphasis added]

The correct value as listed in the reference for cement production and power generation is between $40 and $120 per tonne of CO_2.

16.6 Please comment on the incentive for power producers in Asia and elsewhere (including BC) to invest in CCUS when their local-currency cost of carbon emissions is either absent or significantly below that range.

Response:

FEI understands this question to be asking why regions would invest in CCUS if there is no carbon price or a low carbon price. Many regions are implementing carbon pricing which will incentivize CCUS. Depending on the jurisdiction, the adoption of CCUS could be driven by specific policy directives for certain industries rather than carbon pricing. For example, in Canada, under the proposed federal clean electricity standard, a specific GHG performance benchmark is being proposed for electricity generators which will mandate that fossil-fired generation adopt CCUS. This approach, which could be used in other countries, does not use carbon pricing to see investments in CCUS. Furthermore, the most recent IPCC report (AR6) says the world will need a portfolio of carbon removal options.

[12] https://www.iea.org/commentaries/is-carbon-capture-too-expensive.

16.7 Is Fortis Inc. or FortisBC currently involved/investing in any CCS/CCUS projects? If yes, please provide details.

Response:

Yes, FEI has a carbon capture pilot program to help BC businesses save energy and decrease GHG emissions associated with natural gas use. FEI provides a rebate to offset the cost of purchasing and installing small-scale carbon capture units to program participants. The carbon capture unit attaches to a natural gas boiler or hot water tank and captures carbon dioxide emissions, which would otherwise be vented into the atmosphere, and turns them into potassium carbonate, a versatile mineral and solid by-product used in making pharmaceuticals, soap, and manufacturing glass. The unit also saves energy by capturing heat and redistributing it for heating needs around the building.

Additionally, as described in the response to BCOAPO IR2 12.2, FEI is investigating projects that involve carbon capture and will be funding pilot projects that have the potential of storing significant amounts of CO_2 in BC through its Clean Growth Innovation Fund.

16.8 (in reference to the statement on P. 8 of the above noted reference (i.e. FEI response to BC Climate Alliance …etc.): Please outline the current status of FEI's efforts to provide hydrogen as a fuel alternative for "industries such as pulp mills and cement manufacturing" in BC.

Response:

FEI has ongoing engagement with BC-based industries that consume large amounts of natural gas and are undertaking early-stage exploratory work to understand their decarbonization goals and determine the optimum role that renewable gases such as RNG and low-carbon intensity hydrogen could play in meeting their greenhouse gas emissions reduction targets. FEI considers that decarbonizing energy intensive industry is a potentially significant opportunity for the gas system, and is developing project concepts and business cases along with engaging with policy makers and industrial consumers. For example, FEI is working directly with industrial gas users in BC to pilot and demonstrate the use of hydrogen to displace natural gas in industrial fuel systems and will partner to support the demonstration of hydrogen use to replace natural gas in lime kilns at Nanaimo Forest Products – Harmac Pulp and Paper operations.

ISSUE 17: LNG as a Marine Fuel:

Reference: In Section 3.6 of the LTGRP Application, FEI discusses its investment in LNG to lower GHG emissions in marine fueling and global markets. It states:

"BC's LNG can also power large ocean vessels, which would displace higher-emissions fuels like diesel and heavy oil. Adoption of liquified natural gas as a marine fuel for the global marine vessel market is growing as a result of the implementation of global environmental regulations that support a shift away from higher carbon fuels that have traditionally been consumed by the global marine market".

Questions:

17.1 How much bunkered LNG does FEI expect to be supplied to Port of Vancouver vessels in 2023, 2025, and 2030?

Response:

Based on current market conditions, FEI continues to believe the most likely outcome will be somewhere between the Base Case (i.e., FEI's Planning setting) and the High Case (i.e., FEI's High setting) forecasts in the PoV Study. Please refer to the table below for the forecast volumes of LNG marine bunkering under the Planning Scenario and the High Scenario:

Marine Bunkering (PJ/year)	2023	2025	2030
Planning	8.34	27.21	54.25
High	10.22	36.79	72.52

17.2 Does FEI plan to provide LNG, via bunker vessel, to vessels in the Port of Vancouver? If not, who would provide LNG bunker fuel to vessels?

Response:

No, FEI does not plan on providing LNG bunkering service. Rather, FEI expects to supply LNG to a bunkering service provider at the marine jetty, under a BCUC-approved tariff. The bunkering service provider would then fuel vessels in the Port of Vancouver.