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October 13, 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. 3 on Rebuttal Evidence

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-150-23 for the review of the LTGRP, FEI respectfully submits the attached response to MS2S IR No. 3 on Rebuttal Evidence.

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

1. FEI Rebuttal Evidence - Pipeline Embrittlement and Leakage Risks of Hydrogen Blending

FEI's Rebuttal Evidence (Exhibit B-38, p. 7) notes that the risks of hydrogen blending, including from pipeline embrittlement and leakage, can be addressed. It provides an example (p. 2): "*Hawaii Gas has been blending an average of 12 percent hydrogen into its gas network for over 50 years*."[1]

MS2S's evidence (Exhibit C16-6) also notes that leakage and embrittlement issues are proportional to the ambient pressure in the pipeline - i.e. at lower pressures, such effects are greatly diminished. Indeed, FEI's rebuttal evidence concurs with MS2S' observation, stating on p. 8 that "*hydrogen embrittlement is a well-understood phenomenon. When certain metal piping is exposed to hydrogen over long periods, particularly at higher concentrations and pressures, it can degrade*".

Hawaii Gas' (grey) hydrogen, which is sourced from naphtha from a local refinery, maintains a pipeline pressure of up to ~65psi (50 psig) in its network - i.e. Hawaii's gas network operates at very low pressure compared to FEI's.[2] In the Hawaii Gas network, Mooney regulators are typically used in district regulator stations fed by a gas supply of up to 50 psig (3.45 bar). The regulators deliver gas to the distribution system at 12 to 17 psig (0.83 to 1.17 bar).

FEI's Rebuttal Evidence states that the operating pressures of its backbone pipeline systems are: 583psi (Lower Mainland) and 2,160psi (Sea to Sky and Vancouver Island regions).

Information Requests

1.1 Do you agree that Hawaii Gas maintains a pipeline pressure of up to ~65psi in its pipelines that transport a hydrogen natural gas blend? If not, what pipeline pressure does Hawaii Gas maintain in pipelines that transport a hydrogen natural gas blend?

<u>Response:</u>

FEI respectfully disagrees that Hawaii Gas maintains a pipeline pressure of up to ~65 psi in its pipelines that transport a hydrogen natural gas blend. The synthetic natural gas (SNG) that contains a blend of hydrogen is transported through a 22-mile, 16-inch nominal diameter transmission pipeline on the island of O'ahu at pressures of 350-450 pounds per square inch gauge (psig), with a maximum allowable operating pressure (MAOP) of 500 psig.[3] Regulator

[1] Exhibit B-38, FEI Rebuttal Evidence to MS2S, p, 2 PDF 4. (https://docs.bcuc.com/documents/proceedings/2023/doc_73113_b38feims2sevidencerebuttalevidenceresponse.pdf).

[2] https://pgjonline.com/magazine/2023/february-2023-vol-250-no-2/features/say-aloha-to-new-trend-of-hydrogen-blending-with-hawaii-gas#:~:text=In%20the%20Hawaii%20Gas%20network,(0.83%20to%201.17%20bar).

[3] https://uploads-ssl.webflow.com/618c69307382fa36b31ac896/642f89e3171648bf86e7135e_Dkt%202022-0009%20Hawaii%20Gas%20Final%20IRP%20Report%20and%20Action%20Plan%2C%20filed%204-6-2023.pdf.

stations along the transmission pipeline step down the pressure of the SNG to residential, commercial, and industrial customers. The distribution pressure network consists of approximately 912 miles of pipeline that operates at an MAOP of 50 psig.

FEI's low-pressure gas distribution pipelines operate at or below 100 psig pressure which is close to the 50 psig pressure at which Hawaii Gas operates its low-pressure SNG distribution system.

The 500 psig MAOP of the Hawaii Gas transmission pressure system is equivalent to the MAOP of FEI's Coastal Transmission System which has an MAOP of 583 psig. FEI's Interior Transmission System maximum MAOP and FEI's Vancouver Island Transmission System MAOP are approximately 3 times and 4 times the MAOP of the Hawaii Gas transmission system, respectively.

1.2 Do you agree that FEI maintains a pipeline pressure of 583 psi in the Lower Mainland and 2,160 psi in the Sea to Sky and Vancouver Island regions? If not, please state what pressure is maintained in these systems.

Response:

FEI does not define a "Sea to Sky" region for its infrastructure. Geographic and technical descriptions of FEI's transmission and distribution infrastructure systems are explained in Section 7.3 of the 2022 LTGRP Application. As previously clarified in FEI's Rebuttal Evidence to MS2S,[4] FEI maintains a pipeline pressure of 583 psig in the Lower Mainland Transmission System and 2,160 psig in the Vancouver Island Transmission System. The Lower Mainland *distribution systems* operate between 420 kPag and 700 kPag, equivalent to 61 psig and 101.5 psig. The Vancouver Island *distribution systems* operate at 550 kPag, equivalent to 80 psig.

1.3 Does FEI maintain a pressure in its BC systems that are 9-33 times higher than the pressure in pipelines that transport a hydrogen blend in Hawaii? If not, how does the pressure in FEI's BC pipelines compare to that of Hawaii Gas?

Response:

FEI does not maintain a pressure in its BC system that is 9-33 times higher than the pressure in pipelines that transport a hydrogen blend in Hawaii. Please refer to the response to MS2S IR3 1.1 for further explanation.

[4] Exhibit B-38, FEI Rebuttal Evidence to MS2S, A9, p. 7.

1.4 At what pressure does FEI propose to transport a methane/hydrogen blend in its Lower Mainland, Seak to Sky and Vancouver Island Regions?

Response:

If FEI were to transport a methane-hydrogen blend in its infrastructure serving the Lower Mainland and Vancouver Island regions,[5] FEI expects that the infrastructure would continue to operate at the same pressure as prior to the introduction of the hydrogen blend. However, this will be studied and verified through detailed analysis prior to introducing hydrogen for transport in this infrastructure.

5 For clarity, "Sea to Sky" as mentioned in the IR, is not a distinct region to the Lower Mainland and Vancouver Island.

2. Hydrogen – Equipment changes to accommodate Hydrogen blending

On p.9 of its Rebuttal Evidence, FEI states:

> "Some components of the distribution network may need to be upgraded or replaced beyond a certain hydrogen blend concentration, but this equipment is relatively easily upgraded or replaced, if required".

Information Requests

2.1 Please provide a list of these components. If possible, provide an indication of the complexity and cost of upgrading and replacing them.

Response:

If present, components such as gas chromatographs (GC) and cast-iron fittings would need to be replaced prior to introducing hydrogen; however, FEI does not have any GCs operating in its distribution network and all cast iron has also already been removed from FEI's distribution networks. At lower hydrogen blend concentrations, FEI expects that the existing distribution network components will be hydrogen compatible (subject to FEI completing due-diligence validation review). At higher hydrogen blend concentrations, FEI would need to examine all components for hydrogen compatibility. It is expected that the components that need to be upgraded or replaced would likely be above ground and easily accessed. Given that FEI has not yet completed this analysis, FEI is unable to provide more detailed project scope and costs at this time.

2.2 At what hydrogen blend concentration will these changes to components be required?

Response:

Please refer to the response to MS2S IR3 2.1.

2.3 The p.9 statement, above, is made with reference to the distribution network. Please provide a statement with reference to the mainline/backbone network, including:

a) how much of FEI's mainline network will need to be upgraded/replaced to accommodate hydrogen blending?

b) Describe what components may need to be upgraded or replaced, and specify at what hydrogen blend concentration those changes to components will be required?

c) If possible, indicate the complexity and cost of any upgrades or replacements?

Response:

The concept of a mainline/backbone network is to enable the transport of large volumes of hydrogen in the gas system from point of production to the point of consumption/demand. The infrastructure to support a backbone system will likely comprise of existing gas infrastructure that is repurposed, or new infrastructure constructed along existing pipeline corridors, which is designed to transport high hydrogen blend concentrations or 100 percent hydrogen service. FEI is currently planning to progress early-stage techno-economic work to examine the feasibility of a hydrogen backbone in the Lower Mainland where there is an emerging market need to connect potential large scale centralized green hydrogen production to a number of difficult-to-decarbonize end-user market segments. At this early stage of the feasibility work, FEI is not able to address the specific technical questions posed in the IR.

3. Hydrogen – LNG plants

On p. 10 of its Rebuttal Evidence, FEI states:

> "FEI's development of infrastructure to integrate hydrogen supply will be planned taking LNG plants into consideration, and FEI expects that it will either avoid LNG facilities or separate the hydrogen before it reaches them. It is important to note that the current and planned LNG facilities are not connected to FEI's distribution system, where hydrogen is likely first to be introduced".

MS2S understands that the Vancouver Island Transmission System (VITS) mainline, that serves all customers in Squamish, Whistler and Vancouver Island, starts as a single 12" pipe in Coquitlam - branching off the Lower Mainland's Coastal Transmission System (CTS). It will also serve the proposed Woodfibre LNG plant, and the Mount Hayes LNG plant near Ladysmith – there is no other gas source.

Information Requests

3.1 Describe the connection between FEI's distribution system and Woodfibre and Mount Hayes LNG plants. Through what lines do they receive gas? Please describe the size of pipe and number of lines that distribute, or will distribute, gas to both LNG plans.

Response:

The Mt. Hayes LNG plant, the proposed Woodfibre LNG plant and all of the Vancouver Island distribution systems receive gas from the Vancouver Island Transmission System (VITS) pipeline that originates at FEI's Eagle Mountain Compressor Station and terminates in Langford, BC.

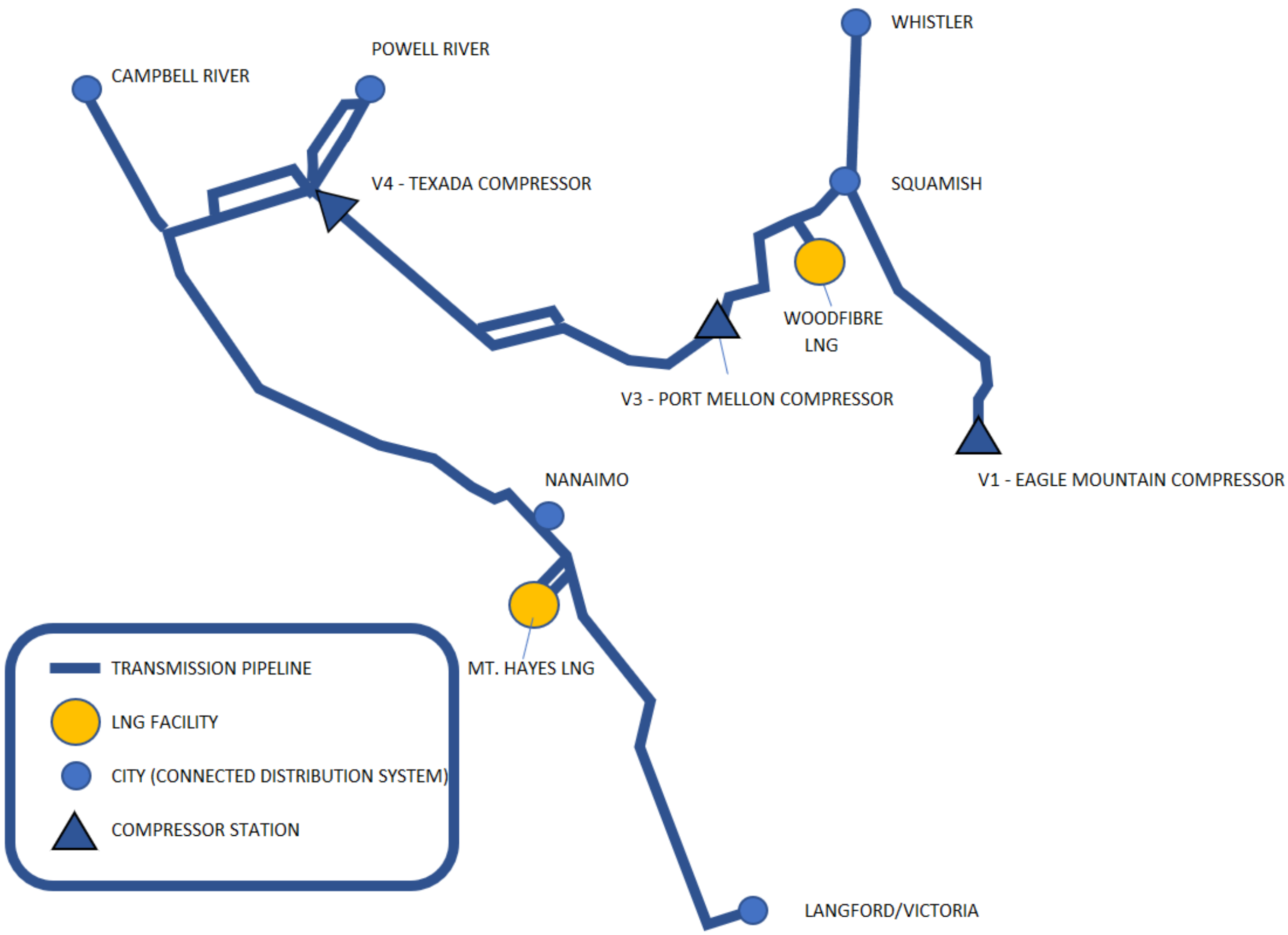
Regulating stations are used to reduce pressure from the transmission pipeline and feed gas into the distribution systems at lower pressure. This occurs at numerous locations throughout the VITS both upstream and downstream of the above-mentioned LNG plants.

The Woodfibre LNG plant is planned to be constructed approximately 10 kilometers southwest of Squamish, BC. It will receive gas from the VITS through a combination of 20-inch and 24-inch diameter pipes.

The Mt. Hayes LNG plant is approximately 15 kilometers south of Nanaimo, BC. It receives gas from the VITS through two lateral pipelines. One lateral pipeline is 10 inches in diameter, and the other is 4 inches in diameter. Both pipelines are approximately 7 kilometers in length.

Figure 1 below is a simplified schematic of the VITS pipelines showing the relative location of the Mt. Hayes and future Woodfibre LNG plants, as well as some of the larger communities supplied by the VITS. The relationship between distribution systems, transmission pipelines and LNG facilities is further and more generally described in the response to MS2S IR3 3.2.

Figure 1: Simplified Vancouver Island Transmission System Schematic

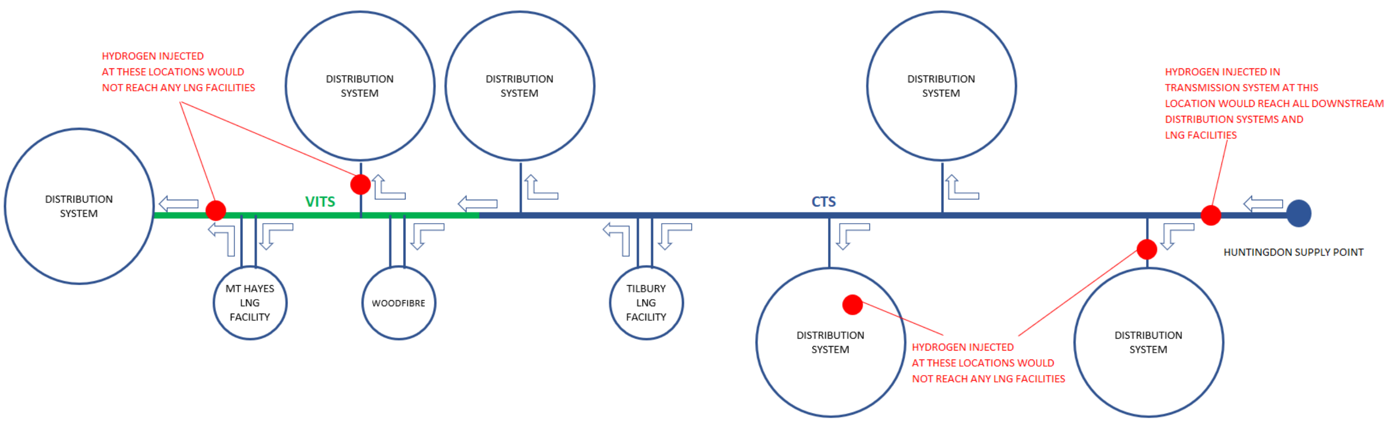


3.2 Please explain how, if FEI introduces a hydrogen blend to CTS to serve its Lower Mainland customers, how the Woodfibre and Mount Hayes LNG plants are "*not connected to FEI's distribution system*" and can avoid having to deal with separating out the hydrogen in the blend?

<u>Response:</u>

For clarity, and as presented in Section 7.3 of the 2022 LTGRP Application, for design, maintenance and operational purposes, FEI generally classifies its energy delivery pipeline network into transmission and distribution systems. If FEI introduces a hydrogen blend to serve its Lower Mainland customers, and the hydrogen is supplied by injection into the gas distribution systems serving FEI's Lower Mainland customers which are strictly downstream of transmission pressure pipes, then the hydrogen would be physically unable to reach any of the LNG facilities because they are supplied by connections to the gas transmission system rather than any of FEI's distribution pipelines. The figure below illustrates the relationship between the transmission, distribution and LNG assets.

Figure 1: Simplified Illustration of CTS and VITS LNG Facilities and Distribution Systems



FEI's distribution systems are the direct feed for the vast majority of FEI's customers throughout the Lower Mainland. The distribution systems in the Lower Mainland are supplied by higher pressure transmission pipelines, namely the CTS and the Enbridge T-South pipelines. Similarly, gas for existing and proposed LNG facilities is delivered to and received from the existing transmission pipelines and these facilities have no direct connection to any distribution systems.

To the extent hydrogen is injected into a distribution system, being strictly downstream of the transmission system, it will be physically unable to reach any of the LNG facilities. If FEI elects to inject hydrogen into the CTS or receive hydrogen blended natural gas into the CTS then, depending on the location, it is possible that it would be delivered to the LNG facilities and may require separation.

It is possible that in certain locations hydrogen could be injected into the transmission system and, based on the direction of flow, will not reach LNG facilities. For example, hydrogen injected at any location south/downstream of the Mt. Hayes LNG facility on the VITS would avoid all LNG facilities. Similar locations may exist in other areas of FEI's transmission pipeline networks.

3.3 In the above case, please explain how hydrogen would get to the local distribution system in Squamish and Whistler? Describe what distribution infrastructure will be used.

<u>Response:</u>

Local production in the Squamish and Whistler areas could be used to deliver hydrogen to those communities. As noted in the response to MS2S IR3 3.2, hydrogen delivered directly into distribution systems is physically unable to reach the existing and planned LNG facilities connected to FEI's transmission pipelines. Further, an injection of hydrogen into the 8" intermediate pressure transmission pipeline that originates near Squamish and supplies gas to Whistler could, based on the direction of flow, deliver a hydrogen blend to the community of Whistler without impacting any LNG facilities.

4. Hydrogen - Backbone Pipeline

On pp. 11-12 of its Rebuttal Evidence, FEI states (emphasis added):

> "FEI has been clear that, beyond 2030, a hydrogen backbone pipeline would likely be required to operate in parallel with the CTS pipelines, transporting hydrogen to the distribution systems in the Lower Mainland into which the hydrogen would be blended. With respect to the CTS, the presence of LNG facilities, and delivery of hydrogen to customers in the Lower Mainland, FEI's preliminary analysis as described in the Application is as follows:
>
> > To keep the blended hydrogen from the upstream pipelines out of the CTS as it begins to arrive in more significant quantities after 2030 **would require a hydrogen separation facility at Huntingdon and a dedicated hydrogen pipeline** that would ultimately connect to FEI's initial hubs. This pipeline would share a common alignment with FEI's existing CTS pipelines so that hydrogen could be blended directly into the distribution systems at the gate stations served by the CTS. This would allow the distribution system to receive a controlled blend of conventional gas, hydrogen and RNG, while leaving the CTS to deliver natural gas and RNG to the LNG production at Tilbury and the VITS-supplying Woodfibre LNG project via the Eagle Mountain Compressor facility in Coquitlam. This approach to introducing hydrogen along a dedicated "backbone" that connects earlier established local hubs allows some flexibility to control the increasing delivery of hydrogen in the system."
>
> An alternate approach would be to accept gas-hydrogen blends at Huntingdon into the CTS and install multiple separation facilities throughout the CTS at locations such as Tilbury LNG. This would require the re-blending of hydrogen collected at these locations back into the CTS downstream of the LNG facility. As stated in the Application and in responses to IRs from MS2S, given the greater complexity of this approach and other concerns such as the impact of hydrogen blends on CTS capacity, implementing the hydrogen backbone option described above would avoid these issues".

On p. 13 of its Rebuttal Evidence, FEI states:

> "While the hydrogen backbone can play an important role, it is not a necessary component of FEI's hydrogen strategy at this time; GHG targets could be met through blending and local dedicated systems (hubs).[51] that connect decentralized hydrogen production to local demand. As discussed throughout FEI's evidence, FEI has undertaken preliminary analysis but is continuing to develop its overall hydrogen deployment strategy and has yet to determine the optimum strategy to integrate hydrogen".

Information Requests

4.1 What, in FEI's opinion, will be the threshold conditions to deciding that a "Hydrogen Backbone" is required?

Response:

There are several independent variables that will support any decisions regarding a hydrogen backbone in FEI's hydrogen deployment strategy. These variables include, but are not limited to, the physical locations of downstream hydrogen end-users, end-use hydrogen purity requirements and hydrogen pressure requirements. Consequently, a single threshold cannot be provided at this time. Analysis of the costs and benefits associated with a hydrogen backbone would be included as part of future CPCN applications concerning hydrogen infrastructure projects.

4.2 Would trucking hydrogen (in its gaseous phase) from production points to local injection points into local distribution systems be an interim step toward a "Hydrogen Backbone" pipeline?

Response:

Trucking hydrogen in high pressure tube trailers is referred to as a "virtual pipeline". This mode of energy delivery is suitable for small volume demand customers in the higher priced market segments such as vehicle refueling, or as a temporary measure to deliver fuel before a more cost effective permanent physical pipeline solution can be installed. The concept of a hydrogen backbone is to provide an embedded high-volume service integrated into the gas distribution system to replace natural gas supply to customers that require the reliability and resiliency of a physical energy delivery system to support a growing market. Therefore, trucking hydrogen would not be a logistically or economically feasible interim step toward a hydrogen backbone.

4.3 What would be the likely geographic extent of the "Hydrogen Backbone" pipeline? Would it run all the way from Huntingdon to Vancouver Island? Please describe.

Response:

The FEI hydrogen deployment strategy, including the specific near term and long-term requirements for hydrogen transport and distribution capacity, is still under development and specific terminal stations have not been selected at this time.

5. Hydrogen - Strategy

On pp. 10-11 of its Rebuttal Evidence, FEI states:

> "Given that the strategy to deliver a hydrogen/methane blend over FEI's system is still under development, and the responsibility for operating hypothetical separation facilities would depend on where the facilities are constructed, it would not be reasonable to expect LNG facilities to have "published plans to cope with the added hydrogen" at this time".

Information Requests

5.1 When will FEI finalize and publish its methane/hydrogen blend strategy?

Response:

FEI intends to commence the project to execute the scope of work to develop its hydrogen deployment strategy in Q1, 2025. The strategy will be completed in tandem with, and informed by, the BC Gas System Hydrogen Blending Feasibility Study and Technical Assessment which is expected to run from 2025 to 2028. FEI will develop its overall methane/hydrogen blend strategy in a sequential fashion over that period starting with the low-pressure gas distribution system and moving onto the higher-pressure transmission system. FEI has not yet confirmed when the results of this will be publicly available but anticipates that it will be in conjunction with and supportive of future BCUC submissions related to hydrogen supply and infrastructure.

5.2 The locations (Tilbury, Woodfibre, Kitimat x 2, Naas Valley) of the five proposed multi- billion dollar BC LNG plants are established. As these cannot operate with a methane/hydrogen mix under current plans, it would seem prudent to expect that at least three of them (Tilbury, Woodfibre and Mount Hayes) would have made inquiries of FEI's plans to introduce hydrogen to its gas supply. Have they? If so, describe which LNG proponents have made those inquiries and how FEI responded.

Response:

FEI owns and operates the Tilbury and Mt. Hayes LNG facilities. FEI does not expect to blend hydrogen into the gas feedstock supply to Woodfibre LNG. For the FEI-owned LNG facilities, the potential integration of hydrogen into the feedstock supply to these facilities will be examined as part of the system-wide technical analysis.

6. Hydrogen – Indirect GHG effect, sources

On p. 15 of its Rebuttal Evidence, FEI states:

> "MS2S cites three reports for the proposition that hydrogen fugitive emissions (i.e., from hydrogen production or pipeline leakage) prolong the lifetime of methane in the upper atmosphere, impacting climate warming. FEI has acknowledged that hydrogen leakage along supply chains will be an important consideration and additional analysis may be required to understand potential environmental impacts from deploying hydrogen, particularly at large scale into the future. However, FEI refers to the British Columbia report on the Carbon Intensity of Hydrogen Production Methods as the most up to date reference on lifecycle carbon intensity for hydrogen production methods, and notes that, to FEI's knowledge, there has been no guidance provided on any potential indirect global warming potential of hydrogen, including by a leading world authority, the Intergovernmental Panel on Climate Change, or from the British Columbia or federal governments. FEI expects that future policy developments will consider any contribution of hydrogen leakage as Scope 1 emissions and compare it to the reduction of emissions from the use of hydrogen to displace fossil fuels.
>
> FEI will monitor the changing state of climate science to minimize indirect warming potential associated with all GHGs. With respect to developing its plan to evaluate the integration of hydrogen, FEI will rely on the emission factors for hydrogen as established by government authorities where available".

On p.16, FEI states:

> "FEI intends to only source renewable and low-carbon gas supplies that meet the prevailing government-specified carbon intensity threshold. This means that FEI would not acquire hydrogen supplies that do not offer meaningful emissions reductions, such as grey hydrogen".

Information Requests

6.1 Does FEI dispute the science quoted by MS2S in regard to the role of hydrogen as an indirect GHG prolonging the lifetime of methane in the upper atmosphere? If so, describe the basis for FEI's dispute.

<u>Response:</u>

FEI does not dispute that there is a body of scientific research, including the reference quoted by MS2S, that alludes to the potential effects from hydrogen leakage to the atmosphere from incremental production. FEI's acquisition of low-carbon hydrogen will be executed as per applicable standards and in alignment with all required policy and regulations in BC. As stated in A16 of FEI's Rebuttal Evidence, FEI expects that future policy developments will consider the global warming potential of hydrogen emissions in the context of the overall reduction of emissions associated with the use of low carbon hydrogen to displace emissions from natural gas.

6.2 Could FEI please describe its experience with CCS (Carbon Capture & Storage)?

Response:

FEI is exploring opportunities to source low-carbon hydrogen produced from natural gas using CCS and abated natural gas that uses CCS to capture upstream emissions associated with the production of the natural gas (beyond regulated requirements), which lowers the overall lifecycle carbon intensity.

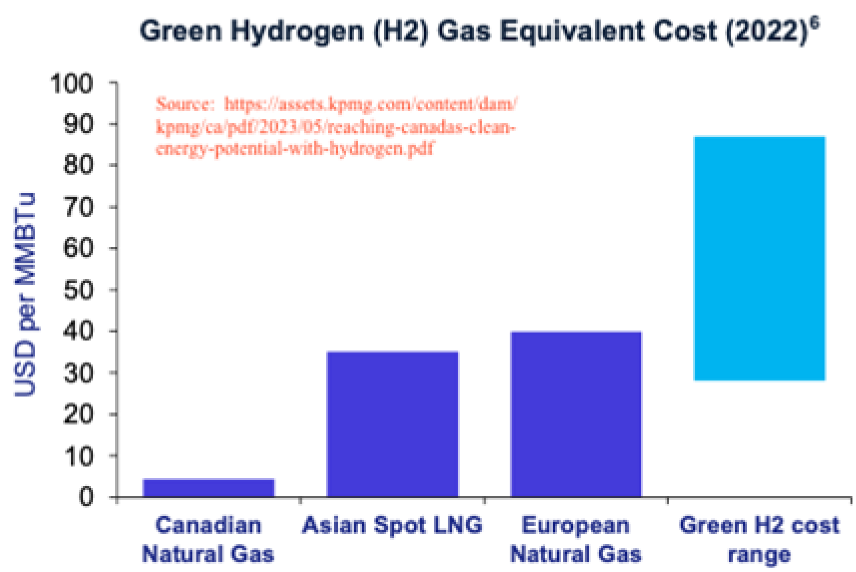
Please also refer to the response to BCUC IR1 9.1.

7. Hydrogen – cost of Green Hydrogen

FEI criticizes MS2S's evidence that the cost of green hydrogen exceeds current allowable prices on the basis that MS2S takes an inappropriate "static view of policy". On p.4 of its Rebuttal Evidence, FEI states that while the maximum allow price for green hydrogen was $31/GH in 2021/22, "*the maximum allowable price for 2023/2024 is approximately $35.50 per GJ"*.

MS2S states (at page 4) that the cost of green hydrogen would exceed the current allowable maximum of C$31/GJ specified by the GGRR and (on p. 5) that it would be an expensive alternative to natural gas, citing green hydrogen costs of approximately $38/GJ at average BC Hydro rates and approximately $14/GJ, which MS2S says is three times that of fossil gas.

A May 2023 report by KPMG, titled "Reaching Canada's clean energy potential with Hydrogen[6]" estimates the cost range of producing green hydrogen by various means at US$30- US$85/GJ:[7]



Information Requests

7.1 Does FEI agree that the cost of producing green hydrogen can vary significantly?

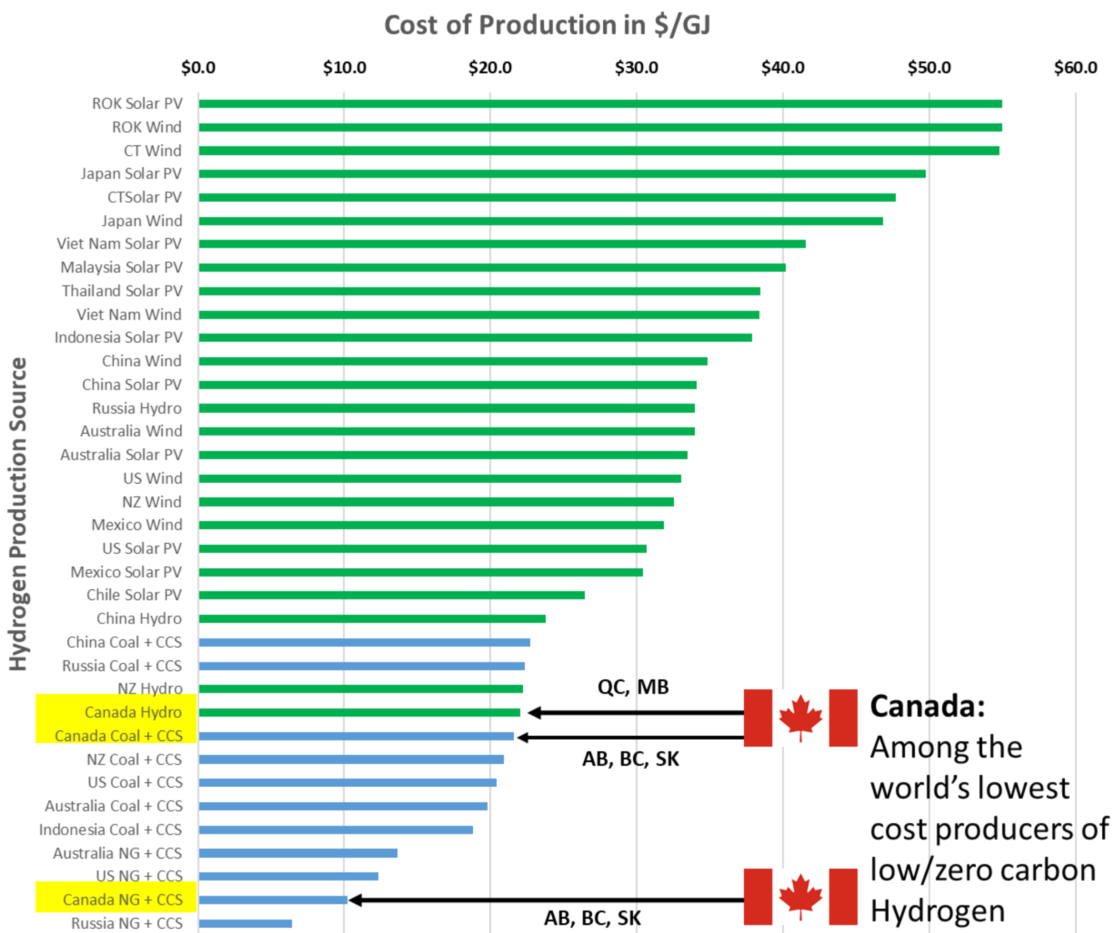
Response:

Yes, FEI expects that the cost of producing green and low-carbon intensity hydrogen will vary in price between countries, regions, and regional markets. The cost of production will depend on the cost of available low-carbon resources to produce the hydrogen (for example, the price of clean

6 https://assets.kpmg.com/content/dam/kpmg/ca/pdf/2023/05/reaching-canadas-clean-energy-potential-with-hydrogen.pdf.

7 P. 4, Figure "Green Hydrogen (H2) Gas Equivalent Cost (2022), available online: https://assets.kpmg.com/content/dam/kpmg/ca/pdf/2023/05/reaching-canadas-clean-energy-potential-with-hydrogen.pdf.

electricity to produce hydrogen derived from water electrolysis), the scale at which hydrogen is produced, its geographic location and access to market, and regional clean energy policy and support mechanisms to stimulate nascent market demand in different jurisdictions. The following chart indicates that Canada is internationally recognized as among the world's lowest cost sources of 'blue' and 'green' hydrogen.[8]



7.2 Does FEI agree that the cost of producing green hydrogen can be as high as US$85/GJ?

Response:

FEI has not completed analysis to determine what the maximum cost to produce green hydrogen across all global jurisdictions might be and therefore, cannot agree that the cost of producing green hydrogen can be as high as $85 per GJ. The BC Renewable Gas Supply Potential Study[9] indicates a maximum green hydrogen production cost of approximately $50 CAD per GJ, and the

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8 Layzell DB, Young C, Lof J, Leary J and Sit S, "Towards Net-Zero Energy Systems in Canada: A Key Role for Hydrogen", *Transition Accelerator Reports: Vol 2, Issue 3*, (2020), online at https://transitionaccelerator.ca/towards-net-zero-energy-systems-in-canada-a-key-role-for-hydrogen.

9 Exhibit B-1, Application, Appendix D-2.

chart included in the response to MS2S IR3 7.1 indicates that across Canada that cost could be significantly lower. However, the 2023 GGRR price cap for green hydrogen is approximately $34/GJ and FEI is only seeking to acquire the lowest cost and lowest carbon intensity green hydrogen available to the market under this price cap. As a result, any green hydrogen supply that FEI acquires will likely be the lowest cost in the market which will translate to the best value for customers and mitigate the risk of any significant price escalation.

7.3 Would FEI agree that, should it supply Customers with a gas blend containing significant amounts of green hydrogen, their costs would escalate significantly? If not, why not?

Response:

FEI acknowledges that gas costs relative to current levels will increase as renewable gas content increases; however, gas costs will be influenced by several factors including the mix and cost of all gases in FEI's gas portfolio. Please also refer to the response to MS2S IR3 7.2.

8. LNG as a Marine Fuel – methane slip

On p.15 of its Rebuttal Evidence, FEI states:

> "There are LNG engine solutions available today with negligible methane slip, and these account for over 50 percent of LNG vessels in the DNV newbuilds order book. For those older engine technologies for which slip remains an issue (predominantly in the short-sea and coastal shipping subsegments of the marine market), manufacturers have identified pathways to eliminate it by 2030".

A recent article[10] highlighted the sharp increase in newbuild orders for methanol-fuelled ships, according to DNV's Alternative Fuels Insight platform.

Further, according to DNV's 2023 publication "Alternative Fuels for Containerships",[11] there has been a notable increase in the use of LNG for tankers (83) and bulk carriers (39). Out of the 1,376 ships currently on order with alternative fuels, 306 are LNG-fuelled LNG carriers, 523 are other types of LNG-fuelled ships, and 295 are using battery/hybrid propulsion.

Indeed, DNV states in the "Alternative Fuels for Containerships" report (quoted by FEI in its rebuttal evidence as Reference 89 on P. 22) that:

> "There is potential for improvement in the areas of greatest energy loss; for example, by reducing hull friction and recovering energy from the engine exhaust and cooling water. These measures generally have a substantial investment cost and potentially significant emission-reduction effects. Many technical measures are limited to application on new ships, due to the difficulties or high costs of retrofitting existing ships".

A 2021 retrofit (to use LNG as a fuel) of the 15,000TEU Hapag-Lloyd container ship Brussels Express is reported to have cost in excess of US$35 Million.[12]

Information Requests

8.1 FEI's statement that "these [engine solutions] account for over 50 percent of LNG vessels in the DNV newbuilds order book" (p. 15) requires clarification and context. Can FEI state what percentage of the global commercial fleet this equates to?

Response:

FEI is not able to compare orders of LNG fueled ships to the global commercial fleet in operation, as the size of the global fleet is difficult to assess. The size would depend on what vessels were

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10 J. Guerrlich, "Methanol-Fueled Ship Orders Surge in July", available online: https://gcaptain.com/methanol-fueled-ship-orders-surge-in-july/#:~:text=A%20total%20of%2062%20alternative,AFI%20platform%2C%20including%2015%20retrofits.

11 https://www.dnv.com/expert-story/maritime-impact/methanol-as-an-alternative-fuel-for-container-vessels.html.

12 LNG Prime, "Hapag-Lloyd's converted LNG containership in new Rotterdam bunkering op", available online: https://lngprime.com/lng-as-fuel/hapag-lloyds-converted-lng-containership-in-new-rotterdam-bunkering- op/28228/.

being included. However, data from Clarksons Research show that, in 2022, LNG dual-fueled orders were over half of all newbuilding tonnage ordered.[13]

8.2 Can FEI indicate the probability that, by 2030, vessels transiting the Port of Vancouver will be those with low-methane-slip, LNG-fueled engines? (this statistic will be crucial to its meeting LNG bunker sales and climate targets).

Response:

FEI anticipates that most of its demand growth for LNG as a marine fuel is expected to come from transoceanic ships calling on the Port of Vancouver, which are predominantly two-stroke vessels with negligible methane slip.[14]

8.3 Does FEI concur that methanol, ammonia and biodiesel are low-carbon competitors for LNG?

Response:

All marine fuels with a low production and utilization carbon intensity (CI) are potential competitors with LNG. Alternatives to conventional marine fuels face common challenges of developing low carbon production pathways, the necessary safety frameworks both onboard the vessel to be bunkered and for bunkering, production, transportation and storage of the fuel, and bunkering infrastructure, all at a competitive price to conventional marine fuels. These elements all exist for LNG as a marine fuel, but they do not yet exist for other fuels today. This was discussed at a recent conference by a Shell executive:[15]

> Karrie Trauth, SVP for maritime and shipping at Shell, addressed the future of the shipping industry's energy requirements in a panel session at the London International Shipping Week headline conference on Wednesday.
>
> "Any fuel choice we make for shipping is really going to come on the back of a low- or zero-carbon fuel for energy, the global energy system," she said.
>
> "Shipping isn't going to get to choose, in many locations and in many ways, what our future fuel is; it's going to be driven by global energy trends."

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13 Online at: https://en.portnews.ru/news/341460/.
14 Exhibit B-38, FEI Rebuttal Evidence to MS2S, p. 18, A19.
15 Online at: https://shipandbunker.com/news/world/935865-lisw23-shipping-isnt-going-to-get-to-choose-what-our-future-fuel-is

> Shell has previously expressed scepticism over the idea of ammonia becoming the dominant future marine fuel, citing reservations over how it can be safely handled at sea.
>
> Trauth said for any alternative bunker fuel market, the key to its emergence would be having it available in significant quantities at locations where the demand would be.
>
> "It comes to just seeing that demand, and having a line of sight to being able to produce and supply," she said.
>
> "I'll take the example of LNG as a marine fuel.
>
> "LNG as a marine fuel came about because we had LNG supply in multiple ports around the world; the fuel was already in the port, and we were able then to convert it to be a marine fuel.
>
> "When you look at ammonia, when you look at methanol, when you look at any of the alternatives that are being considered right now, none of those are a meaningfully globally traded energy commodity whereby we can simply do that last quarter-mile of bunkering the vessel.
>
> "Those require the development of the infrastructure in the port, the development of the fuel-production infrastructure.
>
> "This is a huge chick-and-egg question."

In the specific case of biodiesel, a significant investment to increase production of biodiesel would be needed to meet the needs of the marine industry. DNV estimates that if shipping is to decarbonize completely by 2050 in line with the IMO strategy, a total of 250 million tonnes of oil equivalent (Mtoe) per year is needed, an increase from a current production of 11 Mtoe per year.[16]

Additionally, marine Classification Societies Lloyds Register and American Bureau of Shipping have raised concerns about methanol as a fuel source to decarbonize the shipping industry. Both Class Societies forecast methanol production from renewable and even from fossil fuel sources might not meet the demand quantities due to its high production cost and limited availability.[17]

8.4 Does FEI know what DNV's newbuild numbers for the methanol, ammonia and biodiesel fuel types are?

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[16] DNV Maritime, "Exploring the potential of biofuels in shipping" (June 22, 2023), online at: https://www.dnv.com/expert-story/maritime-impact/Exploring-the-potential-of-biofuels-in-shipping.html.

[17] S&P Global, "Methanol's status as top future marine fuel in doubt due to cost, availability" (September 11, 2023), online at: https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/shipping/091123-methanols-status-as-top-future-marine-fuel-in-doubt-due-to-cost-availability.

Response:

FEI is not able to comment about order numbers for methanol, ammonia and biodiesel fuel types as FEI only has access to DNV's LNG vessel sales and order numbers. FEI notes that biodiesel is a drop-in fuel for marine diesel so there are no "biodiesel newbuilds".

Please also refer to the response to MS2S IR3 8.3 for a discussion of the challenges associated with the fuels noted in the information request.

8.5 To what does FEI attribute the sharp decline in port LNG bunker sales in the 2020-23 interval, as described in MS2S' evidence in Exhibit C16-6?

Response:

FEI assumes the question is referring to MS2S's evidence in Exhibit C16-8, rather than Exhibit C16-6.[18] It is FEI's understanding that the decline in LNG bunker sales in Rotterdam during the 2020-23 period is directly related to the COVID-19 pandemic and the Ukrainian War. Specifically, the Ukrainian War created a significant impact on European gas markets in 2022. The IEA refers to 2022 as being in a "gas crisis" in Europe as the uncertainty of Russian supply created significant demand for alternative sources of supply.[19]

The fact that LNG was the only bunkering fuel to see bunkering demand reduce during the period highlights that LNG is a versatile fuel and LNG that would have been used for bunkering was instead shifted to conventional gas uses to support the energy crisis. FEI does not expect that the temporary reductions in LNG demand in Europe due to the pandemic and the Ukrainian War will have any impact on the long-term demand for LNG as a marine fuel. FEI has previously provided evidentiary support for an expected increase in LNG bunker sales. Specifically, FEI itself has seen exponential growth in its truck-to-ship LNG bunkering in the Port of Vancouver between 2018 and 2023.[20] Additionally, DNV predicts that due to the IMO adoption of the 2023 IMO Strategy on the Reduction of GHG Emissions from Ships in July 2023, 37 percent of the marine fuel mix will be derived from LNG by 2030.[21]

18 FEI could not identify any passages in Exhibit C16-6 related to a "sharp decline in port LNG bunker sales in the 2020-23 interval". However, MS2S discusses LNG bunkering sales at various ports in Europe and Asia in Exhibit C16-8, MS2S Response to BCUC IR 3.1.

19 IEA, "Gas Market Report, Q4-2022", (October 2022), online at: https://www.iea.org/reports/gas-market-report-q4-2022.

20 Exhibit B-1, Application, Figure 3-9.

21 Exhibit B-38, FEI Rebuttal Evidence to MS2S, A22.

8.6 Can FEI confirm that the 2021 retrofit (to use LNG as a fuel) of the 15,000TEU Hapag- Lloyd container ship referenced above cost in excess of US$35 Million?

Response:

FEI can confirm that the article cited above states “Total costs for the containership conversion to LNG power reached about $35 million, according to Hapag-Lloyd.” Error! Bookmark not defined. However, FEI cannot confirm the validity of that claim nor the broad applicability of these costs to other retrofits.

8.7 Does FEI agree that retrofits converting ships to consume LNG as a fuel can be costly?

Response:

There are many factors affecting the costs to retrofit a ship to be able to be powered by LNG. Further, the concept of “costly” is relative and must be considered in light of the options available to a ship owner, including the relative cost of alternatives such as replacing existing fleets with new builds or continuing to use higher emitting and often costly traditional fuels. Retrofitting ships’ fuel handling systems and power units to be able to consume any alternative fuel are often more expensive than designing and building a new vessel for a specific fuel.

8.8 Does FEI agree that the high cost of retrofitting ships to consume LNG as fuel can be may cause others contemplating such action to pursue alternatives to reduce GHG emissions?

Response:

FEI is not able to comment on the financial decisions of vessel owners and operators looking to reduce their GHG emissions. Please refer to the response to MS2S IR3 8.7.