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August 18, 2023

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

Re: FortisBC Energy Inc. (FEI)

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

FEI Rebuttal Evidence

In accordance with the regulatory timetable established in British Columbia Utilities Commission Order G-150-23, please find enclosed FEI's Rebuttal Evidence in response to the intervener evidence filed by My Sea to Sky[1] (MS2S) on May 16, 2023.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

cc (email only): Registered Interveners

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[1] Exhibit C16-6.

2022 Long-Term Gas Resource Plan

Rebuttal Evidence
of FortisBC Energy Inc.

to the Intervener Evidence filed by
the My Sea to Sky (MS2S)

August 18, 2023

1. REBUTTAL TO THE EVIDENCE OF MS2S

Q1: What is the purpose of this Rebuttal Evidence?

A1: In this Rebuttal Evidence, FEI responds to the evidence of My Sea to Sky (MS2S) in Exhibit C16-6 and MS2S's responses to information requests. The capitalized terms in this Rebuttal Evidence are defined in the Application. For example, "FEI" or the "Company" refers to FortisBC Energy Inc.

Although FEI has addressed a number of matters in this Rebuttal Evidence, FEI's silence on any particular matter should not be construed as agreement.

Q2: Please summarize the evidence of MS2S.

A2: MS2S has filed evidence on two topics: hydrogen blending and LNG as a marine fuel. On the topic of hydrogen blending, MS2S lists six challenges or implications of blending hydrogen into the natural gas distribution system, ranging from cost to GHG emissions. On the topic of LNG as a marine fuel, MS2S claims that using LNG to power large ocean vessels will not result in the reduction of GHG emissions that FEI suggests, due to an underestimation of emissions from LNG in the marine sector and an overestimation of anticipated demand for LNG as a marine fuel.

Q3: Please summarize FEI's response.

A3: MS2S's evidence on hydrogen blending and LNG as a marine fuel does not present a balanced view of the potential for these applications to reduce GHG emissions. MS2S overstates the challenges of hydrogen blending and underestimates the potential for LNG to decarbonize the marine sector.

MS2S has not filed any evidence suggesting FEI will be unable to overcome the technical, logistic and economic challenges of acquiring and distributing hydrogen. FEI's plans for hydrogen blending in its natural gas distribution system are supported by government policy, and the engineering challenges noted by MS2S can and will be addressed as FEI develops its hydrogen strategy in accordance with relevant standards and with oversight from regulatory bodies. Given that FEI's hydrogen deployment strategy is still under development, the evidence it has filed in this proceeding is reasonable and appropriate for the nature and purpose of long-term resource planning.

FEI's forecast of LNG as a marine fuel is reasonable and supported by reliable sources of information, as is its assessment of its GHG reduction potential. FEI's evidence on demand for LNG as a marine fuel is based on Port of Vancouver demand forecasts and LNG vessel orders reported by DNV, the leading classification society for the maritime industry. For calculating potential GHG reductions from the use of LNG as a marine fuel, FEI uses BC-specific emissions factors, considers recent and reliable data and industry knowledge in assessing the impact of methane slip, follows accepted standards for emissions accounting, and relies on independent, peer-reviewed lifecycle emissions assessments.

Q4: How is the remainder of this Rebuttal Evidence organized?

A4: FEI has organized this Rebuttal Evidence as follows:

- Section 2 rebuts MS2S's evidence on the blending of hydrogen in the natural gas distribution system.
- Section 3 rebuts MS2S's evidence on the use of LNG as a marine fuel.
- Section 4 concludes this Rebuttal Evidence.

2. FEI PLANS FOR HYDROGEN BLENDING

Q5: Has MS2S fairly characterized the state of industry knowledge of hydrogen blending in natural gas distribution systems?

A5: No. MS2S does not present a balanced view of the feasibility of hydrogen blending, but rather presents "challenges" to hydrogen based on a selective reading of FEI's evidence and third-party reports, without any attempt to acknowledge the existence of solutions. For instance, MS2S lists the challenges of blending hydrogen into existing natural gas infrastructure that were identified in the BC Renewable and Low-Carbon Gas Supply Potential Study (Supply Potential Study), but does not acknowledge any of the potential solutions. In fact, and as detailed in this Rebuttal Evidence, the "challenges" to hydrogen blending identified by MS2S are well understood and can be addressed. For instance, Hawaii Gas has been blending an average of 12 percent hydrogen into its gas network for over 50 years,[1] and Hydrogen blending has been successfully demonstrated in various jurisdictions including Markham, Ontario, and Fort Saskatchewan, Alberta in Canada, as well as in various countries in Europe. These demonstrations emphasize safety and monitoring to ensure the successful integration of hydrogen into existing energy systems. Close collaboration between public stakeholders and a strong body of supporting technical evidence has been key to the success of these pilots.

While transitioning to a low-carbon energy future will require a level of innovation and development of new technologies to overcome initial challenges, there is significant policy

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1 Kevin Topolski et al., "Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology" (Golden, CO: National Renewable Energy Laboratory, 2022) online at: https://www.nrel.gov/docs/fy23osti/81704.pdf.

and industry support for the development of a hydrogen economy, including hydrogen blending. The Province of British Columbia and the Government of Canada have both published hydrogen strategies, and a number of leading organizations evaluating global climate action, including the International Energy Agency, have indicated that hydrogen will be an important part of the overall global decarbonization transition.[2] The Province's Hydrogen Strategy specifically highlights the potential for hydrogen to be distributed in B.C.'s existing natural gas pipeline infrastructure to meet the requirements of CleanBC, and identifies several actions the Province will take to support blending hydrogen with natural gas.[3] This policy direction reflects the finding of the BC Hydrogen Study that hydrogen blending in the natural gas system will be required to achieve the GHG reductions outlined in CleanBC.[4]

As described in this Rebuttal Evidence, FEI is aware of and taking steps to appropriately consider and manage the challenges referenced by MS2S. Hydrogen technology is currently still in early stages of development, and FEI's LTGRP acknowledges and accounts for its attendant uncertainties, as well as its potential. As FEI develops its hydrogen blending strategy in line with government policy, FEI will continue to rely on government regulation and evolving industry standards, and the most reliable sources of information available, which is reflected in FEI's long-term resource planning.

Q6: On page 4 of its evidence, MS2S states that the proportion of hydrogen in FEI's gas stream by 2030 would be far too little to meet the 47% reduction in customer emissions specified in the CleanBC Roadmap. How does FEI respond?

A6: MS2S conflates FEI's 2022 LTGRP with the Supply Potential Study. MS2S refers to Figure 2 of the Supply Potential Study as FEI's "plan" for the 2030 maximum scenario mix of renewable gases in FEI's supply.[5] However, Figure 2 does not represent FEI's plan to meet emissions reductions targets, does not account for out-of-province supply, nor does it represent FEI's planned or forecast portfolio of renewable and low-carbon gases in 2030.

For clarity, the Supply Potential Study, filed as Appendix B-1 to FEI's Application, is a report prepared for FortisBC, BC Bioenergy Network, and the Provincial Government by Envint Consulting and Canadian Biomass Energy Research Ltd. It was commissioned to "estimate the technical supply potential of renewable and low-carbon gases in B.C., Canada and the United States".[6] In contrast, FEI's LTGRP provides a long-term outlook or forecast for its total supply of renewable and low-carbon gas.[7] FEI has not developed a separate 20-year forecast for each individual component of its renewable and low-carbon gas supplies (RNG, hydrogen, syngas and lignin).[8] The amount of each resource to be

2 Exhibit B-13, GNAR IR1 1.0.
3 Exhibit B-1, Appendix A-4, p. 13, 19-20.
4 Exhibit B-1, Appendix A-6, p. 27.
5 Exhibit C16-6, pp. 3-4.
6 Exhibit B-1, Appendix D-2, p. 1.
7 Exhibit B-1, Application, Figure 6-3.
8 Exhibit B-6, BCUC IR1 52.6.1, BCUC IR1 71.8.1; Exhibit B-10, BCSEA IR1 16.1.

acquired and delivered to customers throughout the planning period will ultimately be predicated by several variables, including quantity and timing of resource availability, resource development and delivery, and location.[9]

As a high-level outlook, FEI suggests that 20 PJs of its supply may be hydrogen in 2030.[10] This supply has not been broken out further into separate hydrogen types within the supply portfolio, since hydrogen supply development is still in early stages and insufficient information exists with which to forecast the volume of individual hydrogen supply types.[11] Contrary to MS2S's suggestion,[12] RNG, and not hydrogen, is expected to make up a larger portion of the renewable and low-carbon gas supply in the earlier years of the planning horizon.[13] Hydrogen supply is not expected to gain momentum until beyond 2030.[14]

While there is still significant work to be done to better understand and define the pathways to comply with the CleanBC Roadmap, limitations on hydrogen supply will not pose a significant challenge to achieving the overall GHG reductions required by 2030. As discussed in the Application, hydrogen will make only a small overall contribution to GHG abatement to 2030. In the shorter term, RNG and DSM are the largest categories of carbon reductions that FEI will leverage to align with the 2030 GHG reduction goals.[15]

Q7: MS2S states (at page 4) that the cost of green hydrogen would exceed the current allowable maximum of $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. How does FEI respond?

A7: MS2S's evidence applies a static view of the price for green hydrogen, and a static view of policy, which is inappropriate during a time of rapid technological and policy development. FEI makes the following five points in further reply to MS2S.

First, the maximum allowable price for hydrogen under the GGRR varies with the annual average All-items Consumer Price Index for British Columbia, as published by Statistics Canada. While the maximum amount in effect for 2021/2022 was $31 per GJ, for subsequent years, the maximum amount is calculated by multiplying the maximum amount in effect for the preceding year, and the sum of 1 plus the annual percentage change in the Consumer Price Index for the previous year. Appling this formula, the maximum allowable price for 2023/2024 is approximately $35.50 per GJ, not $31 per GJ as noted by MS2S.

9 Exhibit B-1, Appendix D-3, pp. 1-2.
10 Exhibit B-6, BCUC IR1 71.8.1.
11 Exhibit B-14, MetroVan IR1 2.2; Exhibit B-10, BCSEA IR1 6.5; Exhibit B-6, BCUC IR1 62.10.
12 Exhibit B-1, Appendix C16-6, p. 3.
13 Exhibit B-6, BCUC IR1 52.6.1.
14 Exhibit B-6, BCUC IR1 52.5.
15 Exhibit B-16, MS2S IR1 1.8.

Second, the relevance of the current allowable maximum under the GGRR is limited in terms of predicting the accessibility of green hydrogen supply in the long-term. Policy and regulations are subject to change within the 20-year horizon of the LTGRP, and the GGRR may be adjusted to support and expand decarbonization initiatives. Other policy tools may also be implemented to support the development of the hydrogen economy. In any event, the costs of hydrogen generally, and green hydrogen in particular, are likely to decrease over time as production technologies advance and the market matures. Indeed, certain hydrogen supplies already meet the prescribed price limits under the GGRR.

Third, the cost of green hydrogen is not representative of the cost of the overall hydrogen supplies FEI anticipates acquiring. FEI has not developed a separate forecast for each individual component of its renewable and low-carbon gas supplies (i.e. RNG, hydrogen, syngas and lignin), and FEI did not develop a cost projection for green hydrogen for the purposes of the LTGRP.[16] Instead, FEI developed only one cost outlook for hydrogen, and the cost estimates included in the Supply Potential Study, which MS2S cites, were only one consideration in FEI's early cost outlook.[17]

Fourth, since reducing GHG emissions is an imperative, FEI views affordability and affordable rates through the lens of FEI's ability to transition to low carbon fuels at the lowest reasonable cost. Thus, the cost of green hydrogen should be compared to other renewable and low carbon sources of supply, not natural gas.

Fifth, FEI's Clean Growth Pathway demonstrates a cost-effective alternative to other GHG reduction pathway scenarios.[18] Decarbonization will require the use of innovative technologies that are initially more expensive than conventional technologies. These costs are expected to decline over time. FEI's Clean Growth Pathway would allow British Columbians to benefit from an overall reduced level of costs by maintaining both BC's gas and electric infrastructure, while sharing the costs of ongoing innovation and acceleration of decarbonization to both systems.[19]

Q8: MS2S states (on p. 4) that hydrogen blending will result in increased risk of pipeline leaks resulting from the increased operating pressure required to transport hydrogen. What is FEI's response?

A8: MS2S has not filed any evidence to support its contention that hydrogen blending will result in increased risk of pipeline leaks, and has not filed any evidence that suggests FEI will be unable to mitigate risk of pipeline leaks if FEI proceeds with introducing hydrogen into its existing infrastructure. FEI's evidence, which MS2S cites, is that: "As hydrogen is less dense, it will require somewhat larger pipes and more compression to deliver similar

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16 Exhibit B-6, BCUC IR1 62.9.

17 Exhibit B-6, BCUC IR1 71.8.1. FEI estimates that under all planning scenarios, the cost of hydrogen would be \$15/GJ by 2030.

18 Exhibit B-9, BCOAPO IR1 9.1, 9.2.

19 Exhibit B-12, CEC IR1 7.2.

amounts of energy."[20] However, MS2S failed to also reference FEI's evidence on the extensive due diligence that will be conducted prior to blending hydrogen into existing systems, as well as FEI's preliminary plans to mitigate risks of pipeline leakage, which will be further developed as the technical considerations relevant to blending hydrogen are further studied and understood.

As FEI stated in response to MS2S IR1 6.4:

> FEI will consider the energy density of hydrogen, just as it currently considers the properties of natural gas, in the planning and operation of its gas transportation and distribution systems . . . This information will be considered by FEI in the planning of hydrogen blending locations and any system improvements to transport the hydrogen blended gas. Upstream pipeline companies would similarly consider and address these impacts on their systems.

This work is part of FEI's broader efforts to ensure the safe and reliable delivery of hydrogen blends:

> Any plans to introduce hydrogen into systems for the first time, be it customer facilities behind the gas meter or into FEI's pipeline systems, will be preceded by due diligence technical assessments and fitness-for-service studies to ensure the systems and end-use equipment may be safely and reliably operated with the proposed hydrogen blends. This will be confirmed with structured and monitored pilot programs to demonstrate the safe operation of hydrogen blends.[21]

FEI's response to BCUC IR1 61.9 provides a discussion of the next major steps prior to introducing hydrogen into its systems.

Further, managing pipeline integrity is already a central aspect of FEI's business, and FEI has the experience, expertise, and systems in place to mitigate pipeline leaks, that will be advanced and adapted to suit the technical properties of the gas it transports. For instance, FEI has provided evidence on its Integrity Management Program, and the development of leak monitoring and prevention processes suited to delivering hydrogen blends:

> FEI has an Integrity Management Program (IMP) which includes leak management, and covers surveying for leaks, the classification of identified leaks, and their associated repair. FEI recognizes that FEI may need to adjust aspects of its leak management policy to ensure leakage is minimized. FEI also expects codes, standards, and regulatory requirements will also advance with market development and ensure safety and

[20] Exhibit B-1, Application, Appendix B-1, p. 3-16.
[21] Exhibit B-16, MS2S IR1 6.2.

> environmental considerations are adequately addressed as the adoption of hydrogen and hydrogen blends progresses, including leak monitoring and prevention processes.[22]

The integrity of FEI's gas infrastructure is also subject to regulatory oversight. FEI expects that regulatory approvals will be required from Technical Safety BC and the BC Energy Regulator prior to blending hydrogen into its existing natural gas transmission or distribution system networks,[23] and FEI will proceed with hydrogen blending in accordance with all Canadian Standards Association (CSA) standards.[24]

In conclusion, MS2S has provided no evidence to suggest that FEI's due diligence assessments, mitigation measures, leak prevention systems, and regulatory oversight, will be insufficient to mitigate any risk of pipeline leaks as a result of hydrogen blends.

Q9: In response to CEC's IR1 1.2, requesting that MS2S "confirm that the FEI existing system would not be permitted to operate with pressures in excess of its specific pipeline limits", MS2S states that it does not know which regulator is responsible for regulating the operating pressures of FEI's system, but says that FEI's "Lower Mainland CTS/VTS/EGP transmissions system operates well above" the typical pressure of US interstate pipelines, at 2,160 PSI. MS2S states that "The Canadian Standards Association (CSA) publishes a biennial update to its pipeline standards, but these are guidelines developed in concert with the oil and gas industry - not binding, enforced government regulations." What is FEI's response?

A9: First, the operating pressure of FEI's transmission and distribution pipelines is regulated under the Oil and Gas Activities Act25 (OGAA) framework. FEI must operate its pipelines in accordance with the OGAA Pipeline Regulation,[26] which incorporates the Canadian Standards Association (CSA) "CSA Z662, Oil and Gas Pipeline Systems" standard.[27]

Second, MS2S is incorrect that the "Lower Mainland" system operates at 2,160 PSI. The Coastal Transmission System (CTS), which serves Lower Mainland and Fraser Valley customers, operates at a maximum of 583 PSI. The Vancouver Island Transmission System (VITS) serves customers on Vancouver Island, Squamish, Sunshine Coast and Whistler, and operates at a maximum of 2,160 PSI. The operating pressures of these individual transmission systems are set in accordance with CSA Z662 as required by the *Pipeline Regulation.*

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[22] Exhibit B-13, GNAR, IR1 1.3.
[23] Exhibit B-6, BCUC IR1 61.12; see also: 61.3.
[24] Exhibit B-23, BCUC IR2 106.4.
[25] S.B.C. 2008, c. 36.
[26] B.C. Reg. 289/2020.
[27] Through the BC Energy Regulator's participation in the Western Regulator's Forum, British Columbians are provided with no-fee access to the CSA Petroleum and Natural Gas standards: https://www.csagroup.org/store/petroleum-and-natural-gas/.

Third, MS2S is incorrect that the CSA standards are not "binding, enforced government regulations". The *Pipeline Regulation*, which is binding on pipeline operators in BC, incorporates CSA Z662 by reference. Compliance with this standard is enforced by the BC Energy Regulator, who refers to it as "the main safety standard for designing, building and operating pipelines in Canada."[28] In the most recent edition of CSA Z662, changes have been made throughout with respect to handling unique design, material, construction, and operational requirements for pipelines containing hydrogen.

Q10: MS2S states (on p. 4) that hydrogen blending will result in increased risk of pipeline ruptures and cracks due to vulnerability of existing infrastructure to embrittlement, which MS2S claims is "largely-unresearched" (MS2S Response to BCSSIA IR1 2.2). What is FEI's response?

A10: MS2S appears to misunderstand the cause of hydrogen embrittlement, the materials that are and are not vulnerable to embrittlement, the influence of operating parameters such as operating pressure on embrittlement, and the prevalence of those materials and operating pressure environments in FEI's distribution and transmission system. As described further below, most of FEI's system is likely not vulnerable to hydrogen embrittlement due to the low operating pressure, and in any event, technical assessments are being conducted to ensure the safety and compatibility of hydrogen blends in FEI's infrastructure, which will specifically evaluate the potential for hydrogen embrittlement. MS2S has offered no evidence to suggest that FEI will be unable to safely mitigate the risk of hydrogen embrittlement where relevant to its system.

Contrary to MS2S's evidence, 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.[29] This is because hydrogen gas molecules can disassociate into hydrogen atoms, which are the smallest atoms, and when exposed to the inside surface of a steel pipe, they have some propensity to adsorb into the steel lattice and compromise the pipe body and welds. This can degrade the mechanical properties of the steel, and, in simple terms, can cause it to become more brittle and result in the formation or growth of cracks.

However, as described in the Carbon Intensity of Hydrogen Production Methods Report filed by BCUC Staff, "Embrittlement is specific to materials and pressures under exposure, meaning that its impact on transmission and distribution pipelines varies."[30] Canada's Hydrogen Strategy, published by Natural Resources Canada, also confirms that "Embrittlement effects depend on the type of steel and on operating conditions and must be assessed on a case-by-case basis."[31]

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[28] BC Energy Regulator, "Legislative Framework – Standards Relevant to OGAA", https://www.bc-er.ca/how-we-regulate/legislative-framework/.

[29] Exhibit B-1, Application, Appendix A-2, p. 60.

[30] Exhibit A2-2, p. 53.

[31] Exhibit B-1, Application, Appendix A-3, p. 60; see also: Appendix A-6, British Columbia Hydrogen Study, p. 66.

FEI expects to initially blend hydrogen into the distribution pipeline network,[32] which is considered less vulnerable to the effects from hydrogen embrittlement, and constitutes 94 percent of FEI's total pipeline infrastructure.[33] Approximately 65 percent of the distribution lines are made of polyethylene materials, which are not compromised by the presence of hydrogen in the gas stream.[34] The remaining 35 percent of the distribution lines are made from a type of steel that is less susceptible to hydrogen embrittlement.[35] Based on the combination of materials and low operating pressures of the distribution system, distribution lines are generally considered compatible with hydrogen blend concentrations well beyond that of appliances and potentially compatible with up to 100 percent hydrogen. 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.[36] FEI will execute system-wide technical analysis and community level demonstration projects, as well as secure all necessary regulatory approvals, before blending hydrogen into its gas infrastructure.[37]

Q11: In Appendix A of its evidence, MS2S quotes from Exhibit A2-2, Carbon Intensity of Hydrogen Production Methods, to support its concern regarding hydrogen embrittlement. Does FEI have any comments on MS2S's use of this report?

A11: The Carbon Intensity of Hydrogen Production Methods Report does not suggest that hydrogen blending is not feasible or not advisable due to the well-understood concept of hydrogen embrittlement. Rather, the purpose of the report is to "provide data and insights that support the determination of the lifecycle CI [Carbon Intensity] for selected hydrogen pathways, and to explore the highest potential for CI reductions", in recognition that "Hydrogen plays a critical role in helping British Columbia achieve its commitment to net-zero emissions by 2050, by enabling the province to decarbonize energy systems and

32 Exhibit B-16, MS2S IR1 13.3.

33 Exhibit B-14, MetroVan IR1 4.1.1.

34 There is a large body of research on the negligible impacts of hydrogen on common polyethylene components. For example, in one study of hydrogen exposure to polyethylene 100, no change to mechanical behaviour, including tension and ductile fracture, was found: Klopffer et al, "Polymer Pipes for Distributing Mixtures of Hydrogen and Natural Gas: Evolution of their Transport and Mechanical Properties after an Ageing under an Hydrogen Environment" (2010) online at: https://www.researchgate.net/publication/48693261_Polymer_Pipes_for_Distributing_Mixtures_of_Hydrogen_and_Natural_Gas_Evolution_of_their_Transport_and_Mechanical_Properties_after_an_Ageing_under_an_Hydrogen_Environment. The findings of this study have been substantiated by several internal studies commissioned by FEI.

35 Canada's Hydrogen Strategy confirms (Exhibit B1-1, Appendix A-3, p. 61) that "[t]he steels used for natural gas distribution systems are not generally susceptible to hydrogen induced embrittlement under normal operation." See also: Exhibit B1-1, Appendix A-6, BC Hydrogen Study, p. 66. Distribution pipeline steel is typically low strength, which is less brittle compared to the higher strength steel used in transmission pipelines. Distribution pipelines operate well under the maximum limits for the materials, and there are fewer pressure fluctuations than for transmission pipelines, which minimizes the potential for material fatigue.

36 Exhibit B-14, MetroVan IR1 4.1.1; see Exhibit B-11, BCSSIA IR1 5.5 for a breakdown of the pipeline materials used in FEI's distribution system by Zone; see Exhibit B-11, BCSSIA IR1 5.7 for a discussion of the critical pipeline components that are required to operate the pipeline system and that will be considered in technical assessments of hydrogen blending.

37 Exhibit B-14, MetroVan IR1 4.1.1; see also: Exhibit B-6, BCUC IR1 61.3, Exhibit B-11, BCSSIA 5.7, Exhibit B-16, MS2S IR1 6.1, for more information on FEI's actions and plans to ensure the safe blending of hydrogen into its gas system.

facilitate transition to a low-carbon economy."[38] The report also analyzes the GHG emissions reductions that would be possible by blending hydrogen into BC's natural gas network,[39] and provides a jurisdictional scan of the perspectives on and funding incentives offered for hydrogen blending in select jurisdictions.

MS2S quotes an excerpt from the report that indicates Australia's agreement not to support the blending of hydrogen in existing gas transmission networks until further evidence emerges that hydrogen embrittlement issues can be safely addressed.[40] This quote, taken alone, may provide the impression that Australia does not support hydrogen blending in general. However, the report also notes that Australia's HyP Murray Valley project, if completed, will be the largest hydrogen blending project in the world, and is one of several hydrogen blending projects in Australia.[41] Australia has also initiated regulatory reforms to bring hydrogen blends under the national gas regulatory framework, in order to ensure regulatory barriers would not restrict proposed investments in renewable gas projects such as hydrogen blending, and to ensure existing regulatory protections apply.[42]

Q12: MS2S states (at p. 4) that hydrogen blending will create issues for LNG plants downstream of where hydrogen is injected into the system. MS2S says that none of the plants (Tilbury, Woodfibre, or Mount Hayes) have published plans to cope with hydrogen. Further, in Appendix B, MS2S says that the Tilbury, Woodfibre and Mount Hayes LNG facilities do not "have, propose to have, or want to have" the capability to separate and remove hydrogen. MS2S also says that Enbridge also "won't want" hydrogen. How does FEI respond?

A12: 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. As such, the LNG facilities will not impact FEI's ability deliver a hydrogen blend to the majority of its customers via its distribution networks. If hydrogen is to be blended into the transmission system supplying LNG plants, then measures such as hydrogen separation will be implemented to accommodate those plants.

Given that the strategy to deliver a hydrogen/methane blend over FEI's system is still under development,[43] and the responsibility for operating hypothetical separation facilities would depend on where the facilities are constructed,[44] it would not be reasonable to

[38] Exhibit A2-2, p. 6.
[39] Exhibit A2-2, pp. 8-9.
[40] Exhibit C16-6, p. 12, referring to Exhibit A2-2, p. 30.
[41] Exhibit A2-2, p. 33.
[42] Australian Department of Climate Change, Energy, the Environment and Water, "Extending the national gas regulatory framework to hydrogen blends and renewable gases" (October 31, 2022) online at: https://www.energy.gov.au/government-priorities/energy-and-climate-change-ministerial-council/priorities/gas/extending-national-gas-regulatory-framework-hydrogen-blends-and-renewable-gases.
[43] Exhibit B-31, MS2S IR2 13.7.
[44] Exhibit B-6, BCUC IR1 63.1.1.

expect LNG facilities to have "published plans to cope with the added hydrogen" at this time.

In response to MS2S's comment that Enbridge won't want hydrogen, Enbridge is in fact a proponent of hydrogen blending. Enbridge's website states:[45]

> Hydrogen gas, whether it's created through electrolysis ("green hydrogen") or a steam methane reforming process ("blue hydrogen"), can be blended with natural gas into existing utility pipeline networks, harnessed for peak power generation, used in heavy-haul trucking and shipping, applied to industrial processes or stored for future use.
>
> Enbridge will be a key player in the development of this low-carbon energy solution, given the sheer size of our gas pipeline network, our prowess in building and operating pipelines and storage, and our current hydrogen production and blending expertise. Our gas utility, Enbridge Gas, helped establish North America's first utility-scale power-to-gas (P2G) facility in Markham, ON, and has established North America's first hydrogen blending initiative by injecting that renewable hydrogen gas into its natural gas distribution network.

Q13: In Appendix B of MS2S's evidence, MS2S says that "unless FortisBC can complete the twinning of the Eagle Mountain- Woodfibre pipeline, or figure out how to economically manufacture and inject hydrogen in multiple downstream locales, there won't be any hydrogen in what FortisBC will supply to Squamish, Whistler, Vancouver Island etc." In MS2S's response to BCSSIA IR1 on MS2S's evidence, MS2S states that due to the need to separate hydrogen-gas blends at Huntingdon, "it is unlikely that FEI's over 700,000 Lower Mainland customers and those Vancouver Island customers upstream of Ladysmith will receive a hydrogen: fossil gas blend." What is FEI's response?

A13: MS2S mischaracterizes the nature and extent of the challenges to delivering a hydrogen-natural gas blend to customers in the Lower Mainland, Squamish, Whistler and Vancouver Island. As noted above, LNG facilities are not connected to the distribution systems, and therefore would have no impact on FEI's ability to deliver a hydrogen blend to the majority of its customers.

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.[46] 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:

45 https://www.enbridge.com/about-us/new-energy-technologies/clean-hydrogen.
46 Exhibit B-16, MS2S IR1 6.

> 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.[47]

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.

With respect to Vancouver Island, FEI does not view the presence of the Mt. Hayes LNG facility as particularly relevant to decision making on system design:

> The rate of LNG production on the VITS downstream of the Woodfibre LNG facility is relatively small compared to the LNG production that currently exists and that is projected to develop on the CTS at Tilbury and on the VITS at Woodfibre LNG. The scale of facilities that would be required to separate hydrogen at the Mt. Hayes LNG facility is also relatively minor, making blending hydrogen into the VITS downstream of Woodfibre LNG facility more feasible.[48]

As was true for its electric and natural gas systems, the delivery of hydrogen will be adapted to the unique features and requirements of FortisBC's service territories and implemented incrementally and iteratively.

Q14: In Appendix B, MS2S says that FEI has left the economic feasibility, extent and timing of a CTS hydrogen backbone pipeline wholly unspecified. What is FEI's response?

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[47] Exhibit B-1, Application, pp. 7-39.
[48] Exhibit B-6, BCUC IR1 61.7.

A14: FEI is not requesting approval in this proceeding to construct and operate a hydrogen backbone pipeline in BC. Rather, FEI has filed a long-term resource plan, and the evidence it has filed is reasonable and appropriate for the nature and purpose of such a plan. For instance, FEI has identified the hydrogen backbone as:

> . . . a potential future scenario towards the latter part of the planning period when hydrogen may need to be delivered in bulk supply from remote production centres to FEI's distribution networks in much the same way that natural gas is delivered today. The infrastructure to operate a hydrogen "backbone" could comprise repurposing and upgrading of existing transmission pressure pipelines or developing new dedicated hydrogen infrastructure to integrate sufficient hydrogen as part of a deeply decarbonized provincial gas system.[49]

And

> . . . a likely and flexible way that the system can be expanded later in the forecast period considering the number of factors, yet be fully determined, that may need to be defined and managed.[50]
>
> [Emphasis added.]

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.[52] When and if FEI files for approval to construct and operate such a hydrogen backbone pipeline, FEI will provide the necessary information to support approval of the project.

Q15: MS2S claims that hydrogen is explosive over all (0-100%) concentrations in air. Is MS2S's evidence accurate?

A15: No.

The flammability or explosive range of pure hydrogen in atmospheric air refers to the range of concentrations within which hydrogen can form a flammable or explosive mixture with air. For hydrogen, the lower flammability limit (LFL) is 4 percent volume. The upper

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49 Exhibit B-14, MetroVan IR1 4.2.1.
50 Exhibit B-1, Application, p. 7-40.
51 Exhibit B-14, MetroVan IR1 4.2.1.
52 Exhibit B-15, MoveUp IR1 4.2.1.

flammability limit (UFL) is 75 percent volume. If the concentration of hydrogen in air falls within this range, there is the potential for combustion if an ignition source is present.

Compared to natural gas, which is mainly methane, hydrogen has a wider flammability range; however, hydrogen is less likely to create and maintain a combustible environment, because of its unique characteristics. Hydrogen gas is very light (~14 times lighter, or more buoyant, than air), and rises through the atmosphere quickly (~6 times faster than methane, with an escape velocity of 20 metres per second).[53] For a fire to occur, an adequate concentration of hydrogen must first be confined, and the presence of an ignition source and the correct amount of oxygen must be present.

The explosive range of hydrogen is narrower compared to the flammability range of hydrogen in atmospheric air, from a lower explosive limit (LEL) of 18 percent volume to an upper explosive limit (UEL) of 59 percent volume. However, similar to flammability, there is a low likelihood that hydrogen will explode in open air due to its tendency to rise quickly, unlike for propane or gasoline fumes. Like existing natural gas processing, transmission and distribution systems, adequate ventilation and leak detection are important elements in the design of safe hydrogen systems.

The impact of blending hydrogen with natural gas on the flammability characteristics can vary depending on the pressure, flow rate and operating temperature, which dictate the homogeneous or even distribution of hydrogen in the stream. Due to the turbulence present in natural gas transmission and distribution networks, an even distribution of hydrogen is expected.

When hydrogen is blended with natural gas, the LFL of the mixture tends to lower slightly compared to the LFL of natural gas. One study conducted by the National Renewable Energy Laboratory (NREL)[54] found that blending hydrogen with natural gas at concentrations up to 20 percent volume can decrease the LFL of the mixture by approximately 1 to 2 percentage points compared to pure natural gas. This reduction is minimal and can be detected within the tolerances of existing flame and gas leakage detection equipment.

The upper flammability limit (UFL) of the blended supply is primarily determined by the flammability properties of natural gas, which are not significantly influenced by the addition of hydrogen up to a 20 percent blend. The NREL study found the UFL to remain at ~17 percent volume. Subsequent research published by the International Journal of Hydrogen Energy[55] found the UFL to increase by 4 percentage points to 20.9 percent volume.

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53 US Department of Energy & the National Hydrogen Association, Hydrogen Safety Fact Sheet 1.008, online at: https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/h2_safety_fsheet.pdf.

54 MW Melaina, O Antonia, M. Penev, "Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues" (National Renewable Energy Laboratory: March 2013) online at: https://www.nrel.gov/docs/fy13osti/51995.pdf.

55 H Miao, L Lu, Z Huang, "Flammability limits of hydrogen-enriched natural gas", Vol. 36, Issue 11 (June 2011) online at: https://www.sciencedirect.com/science/article/abs/pii/S0360319911005672.

Thus, for the blended conditions expected for the transmission and distribution of hydrogen-natural gas mixtures, there is a minor impact to flammability with hydrogen blends of up to 20 percent.

Q16: MS2S claims that hydrogen prolongs the lifetime of methane in the upper atmosphere, effectively making it a GHG (page 16). How does FEI respond?

A16: For clarity, MS2S does not challenge the well-established fact that hydrogen is carbon-neutral at the point of combustion. Rather, 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.[56] 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,[57] 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.[58] 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.

Q17: MS2S claims that there are additional GHG emissions implications of the source ("colour") of the hydrogen used. Has FEI taken into account the lifecycle emissions of different sources of hydrogen?

A17: Yes. Lifecycle emission factors represent the GHG emissions from upstream fuel production to fuel consumption at the end use appliance.[59] In Table 1-2 of the Application, FEI provides an estimate of the lifecycle GHG intensity associated with green hydrogen and blue hydrogen. Green hydrogen was assumed to have a lifecycle emission factor of close to zero, as it was assumed to be made from a low-carbon source of electricity (hydro, wind or solar). Blue hydrogen's lifecycle emissions estimate was based on the emissions from producing natural gas, the efficiency of conversion to hydrogen, and energy inputs

[56] Exhibit B-16, MS2S IR2 12.1.
[57] Exhibit A2-2.
[58] Exhibit B-13, GNAR IR1 1.0.
[59] Exhibit B-6, BCUC IR1 71.1.

required to run the hydrogen production facility and sequester carbon. The lifecycle emission factor is based on generic assumptions and actual lifecycle emissions may ultimately vary by facility.[60] For hydrogen and other renewable and low-carbon gas supplies, FEI would quantify the life cycle intensities as supply is acquired.[61]

FEI intends to only source renewable and low-carbon gas supplies that meet the prevailing government-specified carbon intensity threshold.[62] This means that FEI would not acquire hydrogen supplies that do not offer meaningful emissions reductions, such as grey hydrogen.

3. FEI IS SERVING THE MARKET FOR LNG AS A MARINE FUEL

Q18: Has MS2S fairly represented the state of industry knowledge on LNG as a marine fuel?

A18: No. MS2S's evidence does not present a balanced view on the state of industry knowledge of marine vessel emissions, on carbon accounting, or on demand for LNG as a marine fuel. MS2S's position is contrary to the conclusions of credible and reliable industry experts and market participants, all of whom recognize the potential for natural gas as a fuel to reduce GHG emissions in the marine transportation sector.

Q19: M2S2 asserts (on p. 6) that its evidence brings into doubt FEI's claim of an up to 27% reduction in GHG emissions associated with the use of LNG as propulsion fuel in marine transportation. Please explain the basis of FEI's estimate of potential reductions in GHG emissions from the use of LNG as a marine fuel, and why the assumptions that FEI has used in its analysis are reasonable.

A19: As expanded on further below, FEI's estimate of potential GHG reductions from the use of LNG as a marine fuel is reasonable because:

a) FEI has used BC-specific emission factors;

b) FEI considers recent and reliable data and industry knowledge in assessing the impact of methane slip;

c) FEI follows accepted standards for measuring global warming potential; and

d) FEI relies on independent, peer-reviewed lifecycle well-to-wake emissions assessments.

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[60] Exhibit B-6, BCUC IR1 71.4.
[61] Exhibit B-6, BCUC IR1 71.1.1.
[62] Exhibit B-16, MS2S IR1 8.1.

When estimating potential reductions in GHG emissions from the use of LNG as a marine fuel, FEI used third-party carbon intensity measurements specific to FEI's LNG production facility at Tilbury. The ICCT reports that MS2S relies on for its lifecycle emissions analysis are not specific to the BC LNG supply chain or the Tilbury facility, but rather are based on global LNG input factors.[63] Using BC-supply factors is important in ascertaining emissions, as Tilbury is the only LNG facility currently operating in western North America that powers its liquefaction process with renewable electricity, and because BC's upstream natural gas production emissions management regime is one of the most stringent in the world.[64] According to the independent consultancy Sphera, the carbon intensity of LNG from FEI's Tilbury facility is 29 percent lower than the global average.[65] With the CleanBC Plan initiatives implemented by 2030, the carbon intensity of LNG produced in BC in 2030 can be about 50 percent lower than the current global LNG supply average.[66] The low emissions factor of BC's upstream natural gas production was recently recognized by a US regulator, when the Puget Sound Clean Air Agency required the owner of a new LNG project in Washington to ensure its sole source of natural gas supply comes from BC or Alberta.[67]

Contrary to MS2S's suggestion that methane slip is a little-known disadvantage of LNG as a marine fuel,[68] methane slip is a recognized issue for LNG powered shipping and has fallen four-fold over the past two decades since LNG-fuelled engines were first introduced.[69] 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

63 Bryan Comer, Jane O'Malley, Lludmlla Oslpova, Nikita Pavlenko, "Comparing the Future Demand for, Supply of, and Life-Cycle Emissions from Bio, Synthetic, and Fossil LNG Marine Fuels in the European Union" (2022, International Council on Clean Transportation) online at: https://theicct.org/wp-content/uploads/2022/09/Renewable-LNG-Europe_report_FINAL.pdf (ICCT EU Report); Bryan Comer, Lludmlla Oslpova, "Update: Accounting for well-to-wake carbon dioxide equivalent emissions in maritime transportation climate policies" (August 2021, International Council on Clean Transportation) online at: https://theicct.org/wp-content/uploads/2021/08/update-well-to-wake-co2-aug21-1.pdf (ICCT Emissions Factors Report) (together, the "ICCT Reports").

64 Exhibit B1-16, MS2S IR1 4.6; see also: Affinity, "Study on the Air Quality Benefits to the Part of Vancouver by Adopting LNG as a Marine Fuel", (October 2022), p. 5, (Affinity Report) online at: http://tilburypacific.ca/wp-content/uploads/2022/10/Affinity-Study-Vancouver-Air-Quality-Report-02.09.2022.pdf.

65 Exhibit B-16, MS2S IR1 4.6; Sphera, "Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver – Final Results" (March 2020) (Sphera Port of Vancouver Report) online at: https://www.cdn.fortisbc.com/libraries/docs/librariesprovider5/sustainability-in-all-we-do/lifecycle-ghg-emissions-of-the-lng-supply-at-the-port-of-vancouver-footnote-8.pdf.

66 Tilbury Detailed Project Description, p. 2-6, online at: https://www.projects.eao.gov.bc.ca/api/public/document/6138dcca17ba3b0022913ab0/download/FortisBC_Tilbury_DPD_Package.pdf.

67 Canadian Energy Centre, "New US LNG project required to use natural gas from Canada to lower GHGs" (December 16, 2020) online at: https://www.canadianenergycentre.ca/new-us-lng-project-required-to-use-natural-gas-from-canada-to-lower-ghgs/.

68 Exhibit C16-8, MS2S Response to BCUC IR1 3.1 on Intervener Evidence.

69 S&P Global, "LNG still a viable solution for maritime decarbonization despite hurdles" (September 23, 2022) online at: https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/092322-lng-still-a-viable-solution-for-maritime-decarbonization-despite-hurdles#:~:text=Addressing%20methane%20slip&text=Later%20during%20the%20same%20month,improvements%20made%20in%20engine%20technologies.

identified pathways to eliminate it by 2030. MS2S's own references highlight the extensive work that industry participants are undertaking to reduce methane slips from engines. For instance, MAN Energy Solutions[70] has been working on methane slip solutions for over a decade. In addition, a local UBC study has demonstrated the potential for engine calibration to improve the efficiency and emissions performance of local ferries.[71] The Sphera lifecycle analysis on which FEI relies, using BC-specific emissions data, states that for two-stroke slow speed engines, GHG emissions are reduced by 20 to 27 percent compared to Heavy Fuel Oil, and that for four-stroke medium speed engines, GHG emissions are reduced by 12 – 21 percent compared with Heavy Fuel Oil, both on well-to-wake basis. FEI anticipates that most of its demand growth for LNG as a marine fuel will come from transoceanic ships calling on the Port of Vancouver,[72] which are predominantly two-stroke vessels with negligible methane slip.[73]

FEI has followed the convention of leading authorities such as the UN's Intergovernmental Panel on Climate Change (IPCC) in measuring greenhouse gas emissions using 100-year GWP. FEI believes that 100-year GWP strikes an appropriate balance between consideration of short-lived vs. long-lived gases and provides common parameters for climate change discussions, as it accounts for the long-lasting warming effects of carbon dioxide and the shorter-term effects of gases like methane.

Using a 20-year GWP emissions factor attaches more weight to short-lived greenhouse gases, such as methane, as opposed to CO2, which is a long-lived greenhouse gas that stays in the atmosphere for hundreds of years, continuing to cause warming. Methane slip is an identified short-term issue associated with the release of emissions from shipping that is being addressed. LNG bunkering in marine shipping represents a structural move away from diesel and heavy fuel oil to reduce CO2 emissions over the long term and FEI considers it a more appropriate measure when accounting for long term impacts.

FEI is not aware of any country that uses the 20-year GWP as their sole representative measure for greenhouse gas reporting and accounting. Using the 20-year GWP and focusing on short-lived GHGs, would disincentivize the required deep reductions of long-

[70] Exhibit C1-16, Footnote 9.

[71] Rochussen et al, "Development and demonstration of strategies for GHG and methane slip reduction from dual-fuel natural gas coastal vessels", *Fuel*, Issue 349 (2023) online at: https://www.sciencedirect.com/science/article/pii/S0016236123010463.

[72] Exhibit B-21, Confidential Port of Vancouver Study.

[73] These 2-stroke engines are used in deep sea shipping where 70%-80% of marine fuel is burned and the majority of GHG emissions generated. Of the 2-strokes on order, about 70% are high pressure diesel technologies which have negligible methane slip: SEA-LNG, "ICCT Report on LNG Pathway Makes Flawed Assumptions Based on Outdated Data" (September 20, 2022) online: https://sea-lng.org/2022/09/icct-report-on-lng-pathway-makes-flawed-assumptions-based-on-outdated-data/.

lived carbon dioxide emissions, resulting in higher carbon dioxide concentrations and ocean acidification.[74]

FEI has reviewed the ICCT Reports in detail and has identified issues with the reliability of their data and analysis. Neither the ICCT EU Report nor the ICCT Emissions Factors Report claim to meet the leading international standards on lifecycle assessment (ISO 14040/14044) or claim to be peer-reviewed. With respect to the prevalence of high methane slip engines, the ICCT EU Report uses outdated vessel fleet data that is dominated by older, obsolete 4-stroke low pressure dual fuel diesel electric engine technologies which have relatively high levels of methane slip. This technology has been and will continue to be upgraded by engine manufacturers to further reduce methane slip, and is largely limited to short-sea, coastal vessels. SEA-LNG, a multi-sector industry coalition, has raised the same concerns with the ICCT EU Report in the past.[75] The ICCT EU Report also fails to acknowledge the aggressive technical measures being implemented by marine engine manufacturers to minimize and eliminate methane slip.

For its global emission factors, FEI relies on the "Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel" Report by independent consulting firm Sphera.[76] This Report was commissioned by industry groups, conducted according to ISO standards (the leading international standards on lifecycle GHG assessment), and was peer-reviewed by a panel of independent academic experts. In a report commissioned by the Vancouver Fraser Port Authority and FortisBC, Sphera extended this study by analyzing the Port of Vancouver-specific supply.[77] A described above, using BC-supply factors is important in measuring GHG emissions from LNG sourced from Tilbury, as is using the most recent and relevant data on methane slip.

Q20: On page 7, MS2S states "FortisBC points to bio and renewable synthetic LNG as options for replacing fossil methane & LNG", and cites the ICCT EU Report for the proposition that "using 100% bio and renewable synthetic LNG would result in the doubling of well-to-wake methane emissions from LNG-fueled ships between 2019 and 2030 because of growing demand for LNG marine fuel and continued methane slip". What is FEI's response?

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[74] See: United States Environmental Protection Agency, "Understanding Global Warming Potentials" (2023) online at: https://www.epa.gov/ghgemissions/understanding-global-warming-potentials; Climate Analytics, "Why using 20-year Global Warming Potentials (GWPs) for emission targets is a very bad idea for climate policy" (2017) online at: https://climateanalytics.org/briefings/why-using-20-year-global-warming-potentials-gwps-for-emission-targets-is-a-very-bad-idea-for-climate-policy/.

[75] Exhibit B-16, MS2S IR1 4.6.

[76] Thinkstep (now Sphera), "Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel: Final Report" (2019) Commissioned by SEA-LNG limited and Society for Gas as a Marine Fuel Limited (SGMF), (Sphera GHG Report) online at: https://sea-lng.org/wp-content/uploads/2020/06/19-04-10_ts-SEA-LNG-and-SGMF-GHG-Analysis-of-LNG_Full_Report_v1.0.pdf. Sphera has since released an updated report: Sphera, "2nd Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel: Final Report" (2021) Commissioned by SEA-LNG Limited and SGMF, online at: https://sphera.com/wp-content/uploads/2021/04/Sphera-SEA-LNG-and-SGMF-2nd-GHG-Analysis-of-LNG_Full_Report_v1.0.pdf.

[77] Sphera Port of Vancouver Report.

A20: MS2S cites the British Columbia Hydrogen Study for FEI's suggestion that "bio and renewable synthetic LNG" may be used to displace natural gas and LNG. However, for clarity, the British Columbia Hydrogen Study is an independent study that is appended to the 2022 LTGRP Application to supplement FEI's evidence on the potential for hydrogen to decarbonize BC's energy system. It was not authored by FEI. In any event, the Hydrogen Study discusses synthetic methane in the context of comparing the uses of hydrogen in meeting the objectives of CleanBC, not in the context of decarbonizing FEI's marine LNG supply.

While MS2S does not define "bio LNG" or "renewable synthetic LNG", FEI assumes that bio LNG refers to RNG,[78] and renewable synthetic LNG refers to synthetic methane derived from the synthesis of carbon dioxide and hydrogen.[79]

RNG is a low-carbon biofuel. When used as a marine fuel, RNG can reduce emissions by up to about 92 percent in the combustion cycle compared to conventional LNG and has the potential for negative emissions.[80]

Synthetic methane, also called "e-methane", is carbon neutral if the hydrogen used in the methanation process is produced from water electrolysis using renewable electricity, and the carbon dioxide is "recycled" from the ambient air or industry flue gas.[81]

The diminishing issue of methane slip in modern vessels with newer engines has been addressed above.

Q21: On pages 8 to 9, in response to the Environmental Assessment Office's draft assessment report on the Tilbury Marine Jetty project, MS2S claims that emissions from LNG-fueled ships could be 75 percent higher than the EAO is estimating. Is MS2S's analysis correct?

A21: No. As described in response to A19 above, MS2S's analysis is based on assumptions derived from the flawed and unreliable ICCT Reports, and uses the 20-year GWP, which is not a method accepted by leading climate change authorities. The EAO draft assessment report presents the results of the project proponent's analysis, which was scrutinized by technical experts from Indigenous groups and federal, provincial and local

[78] RNG is a biofuel made by processing organic waste flows, such as organic household and industrial waste, manure, and sewage sludge. When anaerobic digestion of organic waste occurs, biogas is emitted in the process.

[79] Exhibit B-1, Application, Appendix A-6, British Columbia Hydrogen Study, p. 65.

[80] European Biogas Association, "Reversing the trend with Bio-LNG: Best option to cut emissions from shipping" (2023) online at: https://www.europeanbiogas.eu/reversing-the-trend-with-bio-lng/#:~:text=Compared%20to%20fossil%20LNG%2C%20BioLNG,the%20potential%20for%20negative%20emissions; "Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel: Final Report" (2019), p. 97, online at: https://sphera.com/wp-content/uploads/2023/06/Life-Cycle-GHG-Emission-Study-on-the-Use-of-LNG-as-Marine-Fuel.pdf.

[81] Faber et al, "Availability and costs of liquefied bio- and synthetic methane: The maritime shipping perspective" CE Delft (March 2020), pp. 6-7, online at: https://cedelft.eu/wp-content/uploads/sites/2/2021/03/CE_Delft_190236_Availability_and_costs_of_liquefied_bio-_and_synthetic_methane_Def.pdf.

government agencies. The Affinity Air Quality Report, which is an independent expert study commissioned by the proponent for the purposes of the Tilbury Marine Jetty Project environmental assessment process, found that Tilbury LNG has the potential to reduce carbon emissions from marine vessels by up to 27 percent.[82]

Q22: MS2S states (on p. 9) that the "investment space looks very poor" for LNG as a marine fuel and raises the specter of LNG infrastructure and LNG vessels becoming stranded assets. How does FEI respond to MS2S's claims and the sources it cites in support?

A22: First, for clarity, FEI is not requesting approval in its LTGRP of any infrastructure or rates to serve LNG to marine vessels. In any event, there is credible and reliable evidence that the use of LNG as a marine fuel will continue to rise, including FEI's own bunkering experience in BC, recent and independent Port of Vancouver demand forecasts, vessel order data from DNV, and local market research.

FEI has already had initial success advancing the LNG bunkering market in BC, evidenced by the exponential growth in bunkering events between 2018 and 2023.[83] This growth has been and is expected to continue to be supported by the provincial government, as the use of LNG to displace marine diesel by domestic BC customers is eligible for credit generation under the BC-LCFS and emissions are included in BC Emissions Inventory.[84]

FEI's LNG marine bunkering forecast is based on an independent 2019 Port of Vancouver study. This study provides a reasonable range of potential LNG marine bunkering demand in the Port of Vancouver—it is based on local shipping and LNG marine bunkering market data, and includes details specific to key market subsegments in BC.

In July 2023, the IMO adopted the "2023 IMO Strategy on the Reduction of GHG Emissions from Ships".[85] The Strategy provides a policy imperative to reduce emissions from global shipping[86] and builds on earlier policies, including a sulfur cap regulation,[87] that have precipitated a transition away from heavy fuel oil and diesel. LNG is currently the only economically feasible, commercially viable, scalable alternative to heavy marine fuels and diesel.[88] The transition to LNG is illustrated by the rapid growth in LNG-fuelled vessel orders, which have more than doubled from 2019 to 2022. The figure below shows

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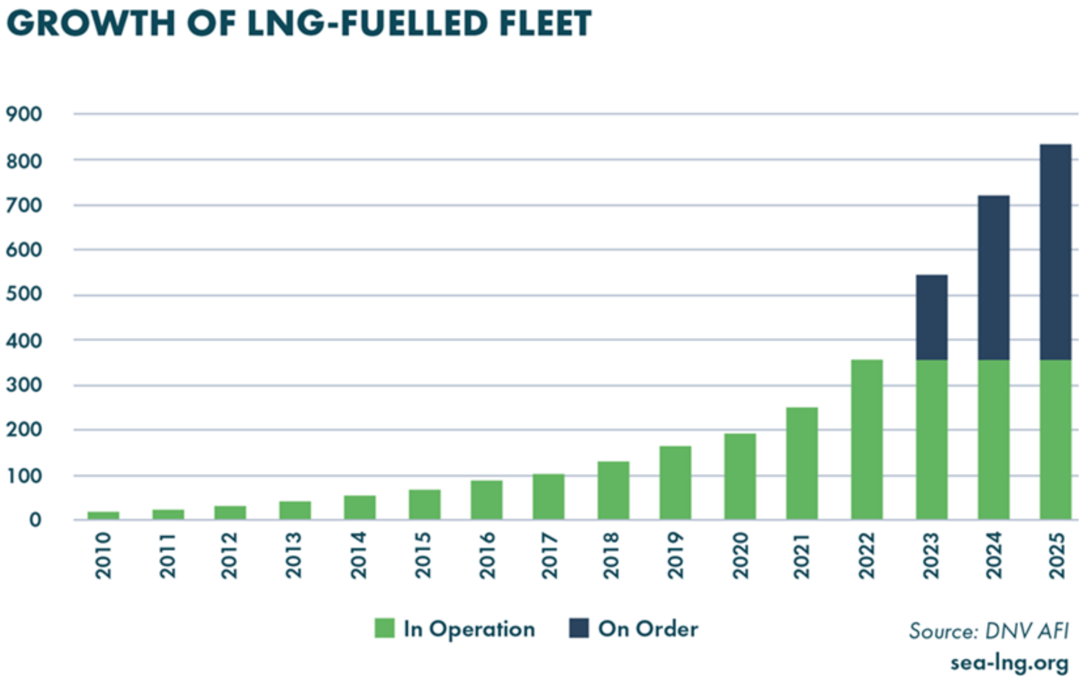
[82] Affinity Report, p. 4.
[83] Exhibit B-1, Application, Figure 3-9; see also: Exhibit B-12, CEC IR1 26.2.
[84] Exhibit B-10, BCSEA IR1 8.5.
[85] IMO, "Revised GHG reduction strategy for global shipping adopted" (July 20, 2023) online at: https://www.imo.org/en/MediaCentre/PressBriefings/pages/Revised-GHG-reduction-strategy-for-global-shipping-adopted-.aspx.
[86] While it is too early to determine with precision the impacts of the Strategy on the LNG bunkering industry, at a high level, a primary feature of the Strategy is that it requires lifecycle GHG emissions accounting for the marine industry, which includes accounting for methane slip. We note that methane slip is already been accounted for in FEI's independent lifecycle emissions analysis of LNG as a marine fuel (Sphera GHG Report).
[87] Exhibit B-1, Application, Appendix B-3, p. 17; Exhibit B-6, BCUC IR1 33.10; Exhibit B-7, BCCA-FTFO IR1 4.1, 4.2.
[88] Exhibit B-12, CEC IR1 26.2; Exhibit B-13, GNAR IR1 3.5; Exhibit B-24, BCUC Conf IR2 1.4.

the LNG vessels in operation and on order based on information from DNV.[89] In addition to the data found in this figure, FEI notes that 91 LNG dual-fuelled vessels were delivered in 2022, and a record 124 LNG dual-fuelled vessels will be delivered in 2023. DNV predicts that the global maritime fuel mix will shift rapidly away from fuel-oil towards LNG, estimating that by 2030, 37 percent of the marine fuel mix will be derived from LNG.



As an example of one rapidly growing market sub-segment, LNG-powered Pure Car Truck Carrier (PCTC) vessel orders have increased significantly in recent years, as demonstrated below.[90] The car carrier shipping industry has invested heavily in LNG as a marine fuel, with vessels on order surpassing 119 in 2022.

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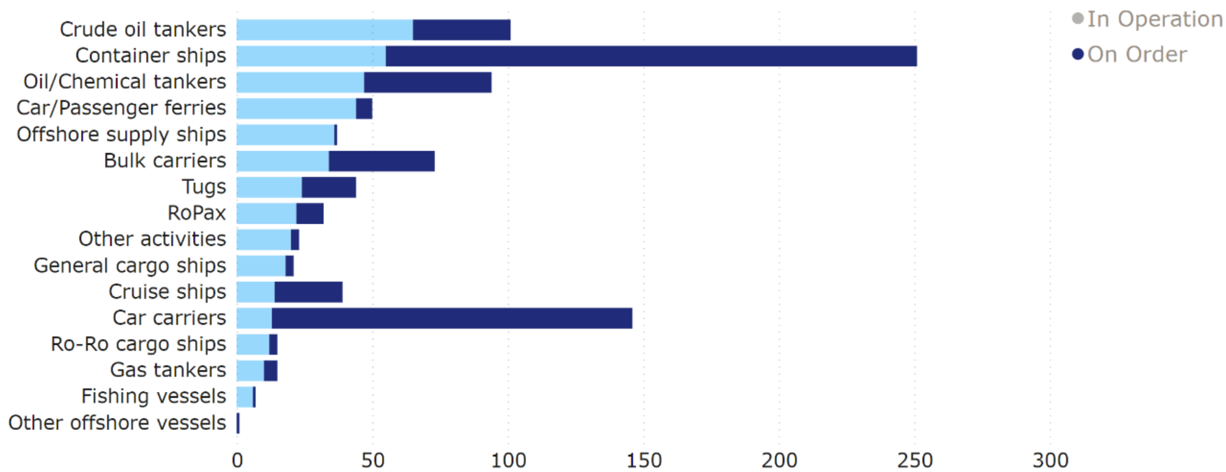
89 DNV Maritime, Alternative Fuels Insight, online at: https://store.veracity.com/alternative-fuels-insight-platform-afi. DNV is an international maritime service company, and is a leading and authoritative source of data for the maritime industry: https://www.dnv.com/about/index.html.

90 DNV Maritime, Alternative Fuels Insight, online at: https://store.veracity.com/alternative-fuels-insight-platform-afi.



Given that the Port of Vancouver receives almost 100 percent of all Asian-manufactured vehicles destined for Canada,[91] FEI expects that this increase in LNG-fuelled car carrier orders will translate into higher LNG demand in the Port of Vancouver, once LNG marine bunkering infrastructure is in place. In fact, NYK's LNG-powered PCTC, the Sakura Leader, has already called at the Port of Vancouver.[92] As described in a report by Affinity on the air quality benefits of adopting LNG as a marine fuel:

> Bunkering stations suitable for trans-Pacific routes are being developed in Australia, China, Indonesia, the port of Long Beach and Seattle, Singapore and Japan . . . The availability of LNG marine fuel in Vancouver is likely to attract a greater number of LNG-fueled vessels, now confident they can complete a round voyage by refueling in Vancouver.[93]

This positive shift in the car carrier market sub-segment has not yet been incorporated into FEI's forecasts.

Q23: In support of its contention that the investment space for LNG looks very poor, MS2S claims that container shipping lines have "opted to leapfrog over LNG for carbon-neutral fuels", and experts are calling for directing investments towards, among other things, direct electrification. What is FEI's response?

A23: LNG is the leading candidate amongst the various alternative fuel options. To FEI's knowledge, there are no trans-oceanic battery vessels that are considered pure electric, and those ships with hybrid systems on-board use the battery technology for ancillary loads (hoteling) while docked or anchored at port. Any increase in the electric ship market size is expected to happen mostly in the hybrid-electric segment and with voyages from 50 to 100 km. Given the absence of alternative fuels in the transoceanic shipping

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91 Port of Vancouver, Automobiles (2023), online at: https://www.portvancouver.com/cargo-terminals/automobiles/.
92 https://shippingmatters.ca/nyks-first-lng-fueled-and-data-smart-vessel-makes-inaugural-call-to-port-of-vancouver/
93 Affinity Report, p. 5.

marketplace, FEI has not included hydrogen, methanol or ammonia in its LNG bunkering forecasts, nor has the Port of Vancouver forecast an uptake in hydrogen-fuelled vessels calling at the port.[94]

Q24: What fuel does LNG typically displace when it is used as a marine fuel?

A24: When LNG is used as a marine fuel, it displaces some of the world's highest carbon intensity fuels, such as marine gas oil, marine diesel oil, intermediate fuel oil and heavy fuel oil,[95] and offers air pollutant emissions reductions of SOx emissions by 98 percent, of NOx emissions by 76 percent, of black carbon emissions by 96 percent and of particulate matter emissions by 90 percent.[96] The IMO links air pollutant emissions produced by the marine shipping industry to premature deaths, stroke, asthma, lung cancer, cardiovascular and pulmonary disease.[97]

As an example, in 2019, 177 tonnes of particulate matter were emitted in the Port of Vancouver area. This would be reduced by 159 tonnes per year if LNG fully substituted for marine gas oil, and by 67 tonnes under DNV's projection of LNG being approximately 37 percent of the maritime fuel mix by 2030. The reduction in pollutants would notably improve the air quality in the Port of Vancouver and would consequently offer health benefits to British Columbians.[98]

Switching to LNG as a fuel in marine vessels has atmospheric and environmental benefits. It reduces air pollution and acid deposition impacts associated with traditional marine fuels, contributing to the reduction of impacts on human health, acidification, decarbonization, and sustainability of the shipping industry.

4. CONCLUSION

Q25: Does this conclude your rebuttal to MS2S?

A25: Yes.

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94 Exhibit B-16, MS2S IR1 1.6.
95 Exhibit B-1, Application, p. 3-23.
96 Affinity Report, p. 15; Exhibit B-12, CEC IR1 26.1; Exhibit B-16, MS2S IR1 4.6. See generally: Exhibit B-1, Application, Section 3.6.
97 IMO, "IMO 2020 – cutting sulphur oxide emissions" (2020) online: https://www.imo.org/en/MediaCentre/HotTopics/Pages/Sulphur-2020.aspx.
98 Affinity Report, p. 4.