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December 22, 2022

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

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

Dear Mr. 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. 1

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-287-22 for the review of the LTGRP, FEI respectfully submits the attached response to MS2S IR No. 1.

FEI notes that, in some instances, the manner in which MS2S has framed its information requests (IRs) appears to be an attempt to provide intervener evidence through the preambles to its IRs. In other proceedings, the BCUC has set out its expectations regarding the appropriate style and substance of IRs under Rules 13.01-13.02 of the Rules and Practice and Procedure. In particular, the BCUC stated:[1]

> The BCUC reminds all interveners that the purpose of IRs is not to enable the author of the IR to introduce evidence. The purpose of IRs is to elicit relevant information on the evidentiary record or to clarify or test existing evidence to contribute to a better understanding by the BCUC of the relevant issues in the proceeding. Any statements that are included in the preamble to an IR should be restricted to providing context for a question relevant to the proceeding submitted by the party to whom the IR is directed.
>
> Finally, whereas letters of comment are intended to provide for any member of the public to contribute views, opinions, and impact or potential impact, with respect to a matter before the BCUC, IRs must not be letters of comment.

[1] In the matter of the *FEI Application for a CPCN for the Advanced Metering Infrastructure Project*, in its letter dated September 28, 2021 (Ex. A-15).

FEI has responded to the information requests by focusing on the questions themselves, rather than parsing and rebutting each preamble. However, FEI wishes to be clear that the preambles contain inaccuracies and characterizations that FEI does not accept. As such, FEI's silence regarding any part of the content of a preamble should not be interpreted as agreement. FEI will object to any attempt by MS2S to rely on the content of preambles to its information requests in final argument.

For convenience and efficiency, FEI has occasionally provided an internet address for referenced reports instead of attaching lengthy 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:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

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

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

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

However, in the LTGRP (Section 7 and Pps. ES 9-14, Table ES-3- reproduced below) and FEI's August, 2022 "<u>Energy Scenarios- Stage 2 Report</u> , FEI highlights some of the challenges it will face in offering blends of Hydrogen and fossil gas in its service offerings. Notable among those are the effects of having downstream LNG plants (Tilbury, possibly Woodfibre, and Mount Hayes on Vancouver Island) in the pipeline circuit. These LNG plants have no use, nor any current approved plans to cope with an unrequited hydrogen supply, which they would have to separate and dispose of. We note that FEI is contemplating (see Table ES3 following) a "dedicated hydrogen backbone", on the CTS system at least, to deal with this issue. Our questions:

1.1 What impact would this H2 blending have on methane supply to these plants?

<u>**Response:**</u>

In the event the hydrogen supply is blended into the supply of natural gas feeding the LNG plants, modifications and equipment retrofits, such as hydrogen separation equipment upstream of the liquefaction equipment, would need to be installed to extract hydrogen. This is due to the inability of hydrogen to liquefy at the temperatures at which LNG is produced.

There are two potential options available to mitigate the impact on LNG operations from increasing hydrogen content in the gas system:

- Hydrogen would be removed by separating it from the gas supply upstream of the LNG facility and then redirected to a different part of the gas network; or
- Hydrogen would enter the LNG facility but would be extracted prior to liquefaction and stored separately onsite for use in gaseous or liquid form (e.g., for fuel cell electric vehicle refueling).

Both options would remove the hydrogen from the gas stream prior to liquefaction and hence the LNG tank would continue to only store liquid natural gas. The extracted hydrogen would then be used for LNG plant fuel or for higher value applications, such as transportation, or might be re-blended with any downstream natural gas streams flowing past the facilities to other consumers on the system.

1.2 If, as FEI suggests, local hubs will produce hydrogen for injection into the fossil gas system, how can the issue of unwanted hydrogen in the LNG projects' supply be addressed without bypassing most, if not all of the 585,000 CTS customers and some of the 200,000 VITS customers?

Response:

Please refer to the response to MS2S IR1 IR1 1.1.

1.3 (i) What are the practical economics of separating upstream hydrogen at Huntingdon/Sumas, and then adding it back downstream of the Mount Hayes LNG facility? (ii) How would it get from A to B? (iii) What impact would that effort have on customer rates? and (iv) What would FortisBC do with the Hydrogen?

Response:

FEI would not propose separating hydrogen for separate transport and subsequent injection downstream of the Mt Hayes LNG facility. FEI has not determined if separating hydrogen at Huntingdon/Sumas would be necessary to supply a possible hydrogen-capable backbone serving hydrogen-capable end uses in the Lower Mainland. FEI notes that it is too early in the feasibility phase to determine the cost recovery of hydrogen infrastructure and the rate impact it may have on customers.

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

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

FORTISBC ENERGY INC.
2022 LONG TERM GAS RESOURCE PLAN

Fuel Type / Other Considerations	Regional Transmission and Distribution Line Considerations		
	VITS	CTS	ITS
System Upgrade Requirements	• Scope and location of system upgrades not yet feasible to determine as supply volumes and locations are currently in early stages of development	• Local supply hubs and small dedicated systems eventually connected to upstream by dedicated hydrogen "backbone" • Scope and location of system upgrades not yet feasible to determine as supply volumes and locations are currently in early stages of development	• Renewable and low-carbon projects could offset the need for upgrades • RGSD project under development could provide significant support for delivery of hydrogen and other renewable gas • Scope and location of system upgrades not yet feasible to determine as supply volumes and locations are currently in early stages of development

1.4 What are the economics of not separating upstream hydrogen at Huntingdon/Sumas, but instead separating out the Hydrogen downstream of Mount Hayes? What impact would that effort have on customer rates?

Response:

Please refer to the response to MS2S IR1 1.3.

1.5 Alternatively, what do LNG plants (FEI owns and operates two of them- Tilbury and Mount Hayes) plan to do with the unwanted H2 if delivered to them? (We note that neither of the Environmental Assessments and detailed project descriptions for the Tilbury and Woodfibre LNG projects include a hydrogen separation function).

Response:

Please refer to the response to MS2S IR1 1.1.

1.6 What proportion of FEI's LNG bunkering volumes will be devoted to providing hydrogen (in some form- possibly ammonia or methanol) as a fuel to hydrogen-capable vessels in the Port of Vancouver?

Response:

FEI has not included hydrogen, methanol or ammonia in its LNG bunkering forecasts, nor has the Port of Vancouver forecasted an uptake in hydrogen fuelled vessels calling at the port.

1.7 As FEI is currently proposing a new BERC rate structure for blends of hydrogen, RNG and fossil gas, how will customers upstream of these plants (those who cannot be served with any hydrogen in their FortisBC pipelined supply) be rated and charged?

Response:

FEI notes that the rate design being proposed as part of its Revised Renewable Gas Application is only applicable to RNG at this time, and not the other renewable and low-carbon gases referenced in the question. Regardless, FEI can confirm that customers upstream of the potential hydrogen and RNG facilities will be charged at the same rates as those customers downstream of these facilities in the same way that customers today are charged the same rate for natural gas and electricity irrespective of where the energy they use is sourced from in relation to their specific location.

1.8 What is the likely impact of restricted hydrogen delivery on FEI's ability to meet its own (30by30) and CleanBC Roadmap (47% GHG reduction in Customer emissions by 2030) GHG emission targets?

Response:

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

1.9 If, because of LNG projects, FEI cannot deliver a Hydrogen: fossil gas blend to the majority of its customers, what are the implications for its plans to make Hydrogen a significant low-carbon component of its gas supply?

Response:

FEI does not consider the LNG projects to preclude the ability to deliver a hydrogen blend to the majority of its customers. The development of infrastructure to integrate hydrogen supply will be planned taking into consideration the LNG facilities. Isolation of the hydrogen supply from the LNG facilities, or separation of the hydrogen from the natural gas supply to the facilities, will be required and will be taken into consideration in the planning of the gas system.

Issue 2: VITS expansion. In Section 7, the LTGRP states, in relation to prospective demand from the Woodfibre LNG plant near Squamish (on the VITS segment): "To accommodate this load addition, there is a need to reinforce the existing VITS with pipeline looping and added compression near Squamish. This infrastructure expansion would match the Firm Transportation capacity contracted by Woodfibre LNG Limited under peak demand, preserving available capacity for existing customers, but would allow large volumes of interruptible capacity to be available for much of the year. The Woodfibre LNG project will help reduce costs for firm service on FEI systems providing benefits to FEI's existing customers.

Woodfibre LNG project's toll will recover the cost of the Woodfibre LNG project and provide an additional contribution to FEI's other customers over time".

Our questions:

2.1 How will VITS customers benefit from FEI's action to "reinforce the existing VITS with pipeline looping and added compression near Squamish" ?

Response:

FEI will construct, own and operate the EGP pipeline, thereby necessitating its addition to FEI's rate base. The $350 million included in Fortis Inc.'s capital plan is the net amount of capital expended to construct the EGP, which is effectively equal to the capital cost of the project less the contributions in aid of construction (customer contribution) made by the customer. Woodfibre LNG will be charged a rate that fully recovers the annual cost of service associated with adding the EGP assets to FEI's rate base, including an additional toll component that will provide revenue that lowers all of FEI's non-bypass customers' rates.

2.2 A BC Order In Council (749 /2013)[1] allows FEI to charge the cost of the Eagle Mountain Pipeline (EGP) Project to ratepayers without any BC Utilities Commission scrutiny. If the costs of the above actions are to be included in FEI's

[1] EGP project
(1) Within 60 days of the date this section comes into force, the commission must, by regulation under section 45 (4) of the Act, exclude the EGP project from the operation of section 45 (1) of the Act.
(2) In setting rates under the Act for FortisBC Energy (Vancouver Island) Inc., the commission must:
(a) on January 1 of the year immediately following the year in which the EGP project is completed, include in the utility's natural gas class of service rate base the capital costs, construction carrying costs and feasibility and development costs for the EGP project,
(b) allow the utility to earn a return on the costs referred to in paragraph (a), and
(c) include in the calculation of rates for applicable customers
(i) the annual operating costs of the EGP project, and
(ii) the capital costs, construction carrying costs, sustaining capital costs, decommissioning and salvaging costs and feasibility and development costs respecting the EGP project.

rate base, won't VITS customers be paying in their rates for this system expansion constructed to benefit one (large) industrial customer?

Response:

Please refer to the response to MS2S IR1 2.1.

2.3 If Woodfibre LNG is to be charged a rate to fully recover the cost of the added EGP infrastructure, why does this capital project appear in Fortis Inc.'s capital planning for 2022-28 as "Eagle Mountain Pipeline Project (EGP) …… $350 million ….. net of Customer contributions"?

Response:

Please refer to the response to MS2S IR1 2.1.

2.4 What are the "Customer contributions" to the capital and operating costs of the EGP?

Response:

Please refer to the response to MS2S IR1 2.1.

Issue 3 : In Section 7.4 INTEGRATION OF RENEWABLE AND LOW-CARBON GAS , FEI states:

"Although FEI is securing about as many contracts for supply within BC as outside of BC, the larger producers, in the near term, are outside of the province. Therefore, in the early years of the 11 planning horizon, FEI's supply will predominantly be acquired and used outside of FEI's service territory …. " Gases with physical properties within the range of conventional gas, such as RNG, will have no net impact on delivery capacity. Delivering hydrogen or a blend of hydrogen and natural gas or hydrogen and RNG, where the gas density and energy content are different from traditional natural gas supply, will change the energy delivery capacity". Our questions:

3.1 Over 80% of the biomethane FEI is proposing to contract and offer to BC customers will be sourced "in the near-term" from facilities outside BC. Is this not contrary to the stated aim of the 2010 Clean Energy Act, which stressed the goal of energy independence for BC?

Response:

No. British Columbia's energy objectives in the *Clean Energy Act* (CEA) were aimed at achieving electricity self-sufficiency, which is different from energy independence and did not include reference to gaseous energy. Further, the requirement that BC Hydro achieve electricity self-sufficiency is a requirement for planning purposes, but is not a requirement for operational purposes. Under section 6 of the CEA , BC Hydro is required to hold the rights to an amount of electricity that meets its electricity supply obligations solely from electricity generating facilities within BC. Operationally, however, BC Hydro (through Powerex) engages in significant electricity trade and uses imports from the United States and Alberta to meet portions of its annual electricity demand.

The combination of in-province and out-of-province renewable gas supply maximizes the opportunity for GHG reductions, reduces risk and cost, allows for the expansion of BC's renewable gas infrastructure and capacity, and fosters a competitive domestic industry in BC.

3.2 If hydrogen, with an energy content one-third that of methane, is also to be blended into the fossil gas /RNG mix, what effects will various blends of that have on the energy capacity of, especially, high- pressure gas lines such as those segments of VITS downstream of the Eagle Mountain compressor station?

Response:

The introduction of large quantities of hydrogen would impact the energy transporting capacity of transportation pipelines such as the VITS downstream of the Eagle Mountain compressor station. The volume of hydrogen supply and proposed blending locations will need to be considered when assessing the energy delivery capacity and the scope of any system upgrades to deliver the required customer energy demand in the future. For example, in Table 7-2 of the Application, FEI describes that in the VITS, green hydrogen hubs will reduce upstream supply requirements and improve available capacity, but reduce available capacity downstream. In Table D3-1 of Appendix D-3 of the Application, FEI illustrates how different blends of hydrogen could affect the energy delivery capacity of a simple transmission system. As supply options and possible locations for hydrogen production are still developing, FEI cannot be specific about the net effect on capacity on the VITS or other FEI systems until those details become more defined.

3.3 In what timeframe does FEI plan to source the majority of RNG from BC facilities?

Response:

Achieving a significantly larger share of RNG from BC facilities will depend on innovation, particularly of technologies that convert wood waste to RNG. Since this pathway requires further research and development to achieve the technical readiness for large-scale deployment, FEI estimates that the required technological advances may occur in the mid- to long-term of the planning horizon.

3.4 Is it economically practical for FEI to source the majority of its biomethane from BC sources?

Response:

No. At this time, it is not economically practical for FEI to source the majority of biomethane from BC sources because out-of-province sources of biomethane supply are often more cost-effective. Also, as stated in Appendix D-2, importing RNG from outside BC can hedge against future high costs to keep BC's industry competitive and protect ratepayers.

3.5 Is supplying "100% biomethane" preferentially to new buildings (as proposed in the BERC rate submission) really the "highest and best use" for the energy? Why not preferentially to difficult-to- decarbonize industries like cement, steelmaking and long-haul truck and rail transport?

Response:

As discussed in the Pathways Report and the Application, RNG will be needed in all sectors as part of a diversified energy pathway for BC to cost-effectively achieve its 2030 and 2050 GHG reduction goals. FEI believes that buildings, industry and transport will all have unique and significant challenges with respect to decarbonization, especially taking into account challenges like market adoption and upstream energy system impacts of electrification. For these reasons, FEI is working to expand its supply of renewable and low-carbon gases throughout the planning period to supply all sectors.

Issue 4: LNG as a Marine Fuel. In Section 3.6.2, Figure 3-9: Timeline of FEI's Annual Bunkering Milestones (2018-2023) shows an expected frequency of bunkering episodes at 5,000 by the end of this year. It also states that the more dangerous ship-to-ship bunkering of LNG marine bunkering "is most frequently performed via an LNG bunkering vessel that pulls up alongside the vessel requiring fuel, and the fuel is transferred from the bunkering vessel to the receiving vessel." (We had understood that the large European ports of Rotterdam and Marseilles have just last year commenced using this method). Our questions:

4.1 What proportion of the almost 5,000 bunkering episodes the LTGRP claimed to date were (i) shore- to-ship, (ii) truck-to-ship and (iii) ship-to ship?

Response:

The reference to "the more dangerous ship-to-ship bunkering of LNG" in this information request is incorrect. In fact, the use of LNG as a marine fuel has an excellent safety record, with no major incidents on record. For example, Viking Grace's cruise ferry has bunkered, ship-to-ship, without incident, more than 2,000 times in Stockholm since its entry into service in 2013[2] and Gasum's bunker barge Coralius has safely completed over 500 ship-to-ship LNG bunkering operations since 2017.[3]

In order to receive approval for a bunkering operation, a risk assessment process is conducted for each section of the transfer process and each individual operation, considering internal and external environmental, societal, technical and economical factors. For instance, LNG operations in the Port of Vancouver LNG Operations must comply with international, federal/Transport Canada, and Vancouver Fraser Port Authority requirements.

In addition, the operation would be conducted in reference to all other applicable regulations such as Class Society requirements, Flag and Marine Technical Review Board requirements, as well as the International Code of Safety for Ships using Gases or other Low-flashpoint Fuels and the Society for Gas as a Marine Fuel guidelines and checklists.

All of the 5 thousand LNG bunker events referenced in the Application used on-board truck-to-ship bunkering, and at the time of writing, the number of bunker events performed without any incidents affecting the safety of the public is now 5,229. As with any fuel, procedures for the handling and transfer of LNG are rigorous, and are subject to the approval and oversight of regulatory bodies such as Transport Canada, as noted above.

[2] SEA-LNG, "Safety: LNG as a marine fuel has a proven safety record with well-established standards, guidelines and operating protocols" (2020) online at: https://sea-lng.org/why-lng/safety/.

[3] Ship & Bunker, "Gasum Sees 500 LNG Bunker Operations in Five Years with Coralius Barge" (November 29, 2022) online at: https://shipandbunker.com/news/world/874103-gasum-sees-500-lng-bunker-operations-in-five-years-with-coralius-barge.

4.2 At which PoV anchorages will ship-to-ship bunkering be allowed/ disallowed?

Response:

The Vancouver Fraser Port Authority is the federal agency responsible for the stewardship of the lands and waters that make up the Port of Vancouver. This includes the approval of bunkering operations within its jurisdiction. Currently, to FEI's knowledge, the Port of Vancouver has not received any applications, nor issued any licenses, for LNG bunkering within its jurisdiction.

4.3 What tonnage of LNG (or PJ of energy) does FEI expect to be (i) bunkered from Tilbury and (ii) exported from Tilbury in the planning horizon 2022-2027?

Response:

The following table shows the amount of LNG that FEI is forecasting to be (i) bunkered from Tilbury and (ii) exported from Tilbury in the 2022-2027 Planning Scenario.

Planning Scenario	2022	2023	2024	2025	2026	2027	Total (PJ)	Total (%)
(i) Bunkering (PJ)	1.36	8.34	18.70	27.21	33.18	39.15	127.93	84%
(ii) Export (PJ)	3.33	3.66	3.99	4.32	4.65	4.98	24.93	16%
Total	4.69	12.00	22.69	31.53	37.83	44.13	152.86	

4.4 What proportions of that tonnage would be (i) fossil gas, (ii) RNG and (iii) Hydrogen and (iv) other?;

Response:

FEI expects the majority of the volumes forecast to be (i) bunkered from Tilbury and (ii) exported from Tilbury in the 2022-2027 timeframe to be LNG from conventional sources. However, FEI expects that RNG could increase to approximately 10 percent of the total domestic bunkering volume by 2027. FEI does not expect any RNG usage for LNG export before 2027 and has no plans to deliver hydrogen from Tilbury for bunkering or export.

4.5 How would local hydrogen hubs deliver that energy to (i) a PoV-anchored ships? (ii) Heavy-industry customers not close to a main supply line?

Response:

FEI expects that as hydrogen hubs initially develop, the hydrogen supply chain will include delivery as a compressed gas in short pipeline infrastructure when hydrogen production is located in proximity to high demand volume customers, and as a compressed gas in tube trailer by road transport, or as a cryogenic liquid in tank trailer by road transport for non-pipeline connected customers or customers that need to store hydrogen onsite in liquified form. FEI is also progressing plans to deliver hydrogen as a blend in the existing gas supply using the existing main supply lines, and could separate the hydrogen from the supply mix at vehicle refueling points adjacent to the existing gas network. FEI is not investigating solutions for hydrogen delivery to Port of Vancouver anchored ships.

4.6 FEI is loudly touting LNG as a marine fuel, stating that it will reduce GHG emissions in this sector "by up to 27%" over alternative fuels. Is FEI aware of the recent peer-reviewed research (published by the International Council on Clean Transportation)[4] showing the opposite – that using LNG as a fuel for all of the common engine types in the world's commercial vessel fleet (including cruise ships, ferries, tankers and freighters) emits more – not fewer – GHGs than alternatives MGO, VLSFO or HFO?

Response:

Yes, FEI is aware of the ICCT report and acknowledges that there are issues to be resolved by the marine transportation industry, including with respect to upstream and downstream emissions, and regarding methane slip, as indicated in the report. It must be noted, however, that the ICCT report was not specific to FEI's LNG production facility at Tilbury but was based on global LNG input factors. British Columbia's upstream natural gas production emissions management regime is one of the most stringent regimes in the world. Further, FEI's Tilbury facility produces LNG that is among the lowest carbon intensity in the world. According to the independent consultancy Sphera[5], the carbon intensity of LNG from FEI's Tilbury facility is 30 percent lower than the global

[4] The January 2020 publication, titled "The Climate Implications of using LNG as a Marine Fuel", states that "*Using a 20-year GWP, which better reflects the urgency of reducing GHGs to meet the climate goals of the International Maritime Organization (IMO), and factoring in higher upstream emissions for all systems and crankcase emissions for low-pressure systems, there is no climate benefit from using LNG, regardless of the engine technology". "Given this, we conclude that using LNG does not deliver the emissions reductions required by the IMO's initial GHG strategy, and that using it could actually worsen shipping's climate impacts. Further, continuing to invest in LNG infrastructure on ships and on shore might make it harder to transition to low-carbon and zero-carbon fuels in the future*".

[5] Source: Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver. 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

average. Downstream, future shore-to-ship and ship-to-ship LNG bunkering systems will be designed so there is zero methane emitted during operations in order to be allowed to operate within the Vancouver Fraser Port Authority jurisdiction.

Regarding methane slip, global players in the LNG industry including Maran Gas Maritime, Mediterranean Shipping Company (MSC), Carnival Corporation, Seaspan, Shell, Lloyd's Register and Knutsen have joined an initiative called Methane Abatement in Maritime to identify, accelerate and advocate technology solutions for the maritime industry to measure and manage methane emissions activity. Additionally, two of the largest marine engine manufacturers (MAN Energy Solutions[6] and Wärtsilä[7]) have been and continue to be engaged in aggressive technical measures to minimize and eliminate methane slip. MAN is confident methane slip will not become a barrier for the continued expansion of natural gas as a transition fuel towards IMO's commitment to reducing GHG emissions from international shipping. Finally, according to SEA-LNG[8], a multi-sector coalition, the lifecycle or well-to-wake emissions estimated by the ICCT report for 2030 are based on historical data that has been dominated by 4-stroke engines with old technology. This technology has been and will continue to be upgraded by the top engine manufacturers to further reduce methane slip. The maritime classification society DNV's data[9] on the current vessel order book shows 75 percent of the LNG powered vessels will have 2-stroke engines as that is the type of engine used by ocean-going ships. Of those vessels on order using 2-stroke engines, 70 percent are high pressure engines which have negligible methane slip.

Further, GHG emissions cannot be the only consideration when discussing marine fuels. Air contaminant emissions must be considered as well. As noted in the response to CEC IR1 26.1, switching from marine diesel fuels to LNG provides the following reductions:

- SOx reduction: 99 percent.
- NOx reduction: 95 percent.
- PM reduction: 99 percent.[10]

6 MAN Energy Solutions, "Managing methane slip" online at: https://www.man-es.com/marine/campaigns/methane-slip.
7 Wärtsilä, "A strong track record of reducing methane slip" (2022) online at: https://www.wartsila.com/services-catalogue/engine-services-4-stroke/a-strong-track-record-of-reducing-methane-slip.
8 SEA-LNG, "ICCT Report on LNG Pathway Makes Flawed Assumptions Based on Outdated Data" (September 20, 2022) online at: https://sea-lng.org/2022/09/icct-report-on-lng-pathway-makes-flawed-assumptions-based-on-outdated-data/.
9 Alternative Fuels Insight https://store.veracity.com/alternative-fuels-insight-platform-afi
10 Society for Gas as a Marine Fuel, LNG as a Marine Fuel: Fuel Lifecycle Analysis Graphic (2021) online at: a49de2307fe2e907892cd4b190bef4ee.pdf.

Issue 5: Demand from the expanded Tilbury LNG plant: The LTGRP states that supplying 2.1 million tonnes per annum (MTPA) of methane gas to the Woodfibre LNG plant, when/if in production by 2025, will be a significant logistical challenge for the CTS and VITS pipeline segments. Yet, the LTGRP makes little mention of the 3.8 MTPA Tilbury LNG/ Tilbury Jetty expansion , planned for much the same the 2023-28 timeframe as the smaller 2.1 MTPA Woodfibre LNG plant. Our questions:

5.1 Where in the LTGRP is the demand from the Phase 2 Tilbury expansion represented? Figure 7-8 shows Tilbury peak demand unchanged in the 2021-28 interval – should it not show increases for the liquefaction/ bunkering/ LNG exports expected in that timeframe?

<u>Response:</u>

Tilbury expansions beyond the currently operating T1A are discussed in Section 7.3.2.4 of the Application and represented in Figures 7-11 and 7-12 and in Table 7-1.

5.2 Will the additional capacity (from Fig. 7.6 :Woodfibre: up to 237 MMscf/day on VITS , proportionately, Tilbury LNG would be ~ 430 MMscf/day on CTS) to handle one or both of these plants be available on the Spectra/Enbridge pipeline, which is currently taxed, especially in the Winter months, to cope with current demand?

<u>Response:</u>

As discussed in Section 6.3.1 of the Application, regional resources are fully contracted and the Westcoast T-South pipeline has run at or near its maximum capacity available each winter season over the past several years. The Woodfibre LNG project has already secured firm transportation capacity on the T-South system for a significant portion of their demand requirements. When the LNG facility is operational, Woodfibre LNG will require its contracted T-South capacity to produce LNG, effectively removing this gas supply from the Huntingdon market.

FEI believes that new pipeline infrastructure is required in order meet load growth, support the transition to a lower carbon economy, and enhance gas supply resiliency in the region. Further, the higher prices at Sumas for the winter seasons, as shown and explained in the response to CEC IR1 5.1, are also an indication that a pipeline expansion in the region is required.

This is one of the reasons why FEI is developing the Regional Gas Supply Diversity (RGSD) project. For more detail, please refer to the responses to BCSEA IR1 19.1 and 19.3. For more detail on Enbridge's recent announcement to expand the Westcoast T-South pipeline, please refer to the response to BCSEA IR1 19.2.

Issue 6: Hydrogen supply logistics, blends: The LTGRP suggests (Section 3.3.3) a number of pathways FEI can undertake for hydrogen distribution, including:

- Supplying the existing gas grid at low concentrations or blends;
- Directly supplying to hydrogen ready customers (initially, large commercial & industrial end users);
- Delivering supply to end users through purpose-built pipeline systems;
- Combusting directly or converting to electricity using fuel cells;
- Utilizing power-to-gas technologies that could strategically couple the gas and electric grids to convert electrical energy to chemical energy in the form of hydrogen or methanized hydrogen for storage and delivery; and
- Supplying for transportation applications;

The LTGRP introduces a longer-term plan to create a separate Hydrogen "backbone" in the gas supply. An overview is shown in Figure 3-6 , and is referenced in Table ES-3. Also, Section 3.3.4 states: "Currently, there is an opportunity to start transitioning pulp mills and cement manufacturing facilities to using low- carbon hydrogen. This transition can be initiated with minimal upgrades and process impacts by blending low-carbon hydrogen into the end user's existing natural gas supply, starting at as low as 2 percent by volume. An industrial hydrogen blending test program will be conducted, administering appropriate safety and impact assessments in order to allow for safe incremental increases of hydrogen blending, by up to 20 percent. Our questions:

6.1 Is FEI aware of the research conducted by Sandia National Laboratories[11] and elsewhere on the Hydrogen embrittlement and rupture risk issue with blends – even low-pressure, small H2 proportion ones – of hydrogen in pipelines built for natural gas transmission ?

Response:

FEI has conducted thorough literature reviews to inform ongoing research and technical assessment of its gas system to transport hydrogen and is aware of the research conducted by Sandia National Laboratories and elsewhere on the potential impacts of hydrogen on the

[11] Sandia's summary conclusions, published in https://www.osti.gov/servlets/purl/1646101, "Hydrogen Effects on Pipeline Steels and Blending into Natural Gas", are:

What is hydrogen embrittlement and when is it important?	Hydrogen degrades mechanical properties of most metals.
How does gaseous hydrogen affect fatigue and fracture of pipeline steels?	Fatigue is accelerated by >30x and fracture resistance is reduced by >50%
Is there a threshold below which hydrogen effects can be ignored?	No, even small amounts of hydrogen have large effects
Can the effects of hydrogen be masked by other physics?	Oxygen can mitigate the effects of hydrogen in some cases, which perhaps can be exploited

properties of steel pipelines. Prior to injecting hydrogen into a pipeline system, FEI must ensure that it would adhere to codes and standards, and a system would be engineered to avoid any risk of metallurgical degradation. Please refer to BCUC IR1 61.3 for further discussion of the past and ongoing analysis that FEI has undertaken to identify its overall hydrogen deployment strategy.

6.2 In the shorter (pre-hydrogen backbone) period, how does FEI plan to deal with this risk?

Response:

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. Please refer to BCUC IR1 61.9 for a discussion of the next major steps required prior to introducing hydrogen into its systems.

6.3 Would the new "hydrogen backbone" duplicate/replace the existing fossil gas piping? To what extent? (i.e. to customer premises or just mainline piping)?

Response:

The "hydrogen backbone" would operate in parallel to the existing natural gas transmission system, connecting upstream hydrogen supplies with hydrogen hubs and FEI gate stations where blending into the distribution system could occur. Some hydrogen backbone pipelines could appear within the distribution system and provide supply directly to hydrogen-ready customers through dedicated hydrogen lines.

6.4 In LTGRP Section 3.3.3, FEI states "As hydrogen is less dense, it will require somewhat larger pipes and more compression to deliver similar amounts of energy. Introducing hydrogen into the existing gas network, the potential impacts on end users, and supporting the development of codes, standards, and regulations are all areas FEI is evaluating". How does FEI plan to deal with capacity issues when using significant proportions of Hydrogen (with one-third the heating value of methane per unit volume) on tight capacity constraints on several key pipeline segments (SCT, EGP, Spectra- Enbridge)?

Response:

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. FEI provided examples of the capacity impacts on the transmission and distribution system in Appendix D-3 of the Application. 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.

Issue 7: In the LTGRP, FEI goes to some lengths to explain why the "Deep Electrification" scenario is an uneconomic proposition, citing cost, reliability and capacity issues with high-elecrification of the BC economy.

7.1 For balance, why is there not a corollary "Deep Gasification" scenario which examines the pros and cons of that approach?

Response:

Fuel switching from electricity to gas for loads that can be served by gas is a consideration in the Application. The current policy environment, however, suggests that modelling significant electricity to gas fuel switching in buildings and industry is an unwarranted exercise at this time. Yet it remains possible that as the renewable and low-carbon gas supply and marketplace in BC and across North America evolves and the existing electricity planning surplus in BC is used up by 2030, electricity load avoidance through encouraging more gas use may well be a prudent long-term planning consideration for utilities and the Province again. FEI will continue to monitor this consideration and include such in its demand forecasting scenarios if and when appropriate for future LTGRPs.

In the Application, the Upper Bound Scenario, in which the settings for all critical uncertainties are intentionally set to result in demand increases, is the practical opposite to the Deep Electrification Scenario in terms of energy demand forecasting. FEI has examined the implications of the Upper Bound Scenario for its system and presented these in Section 7 of the Application.

Issue 8: GHG emissions from Grey, Blue and Turquoise Hydrogen: In Figure 3.7 (Section 3.3.5), FEI estimates that steam-reformed (Turquoise or Blue) Hydrogen is expected to be ~60% (29.6 of 48.8 PJ) of the potential "renewable and low-carbon" gas supply by 2030. Our questions:

8.1 Given that the steam reforming (SMR) process is by far the predominant current method of generating Hydrogen from methane, and is a large emission source[12] (it produces 7 tonnes of CO2 for every tonne of Methane), how would the inclusion of hydrogen in FEI's customer gas supply represent an improvement over methane in meeting BC's climate goals? (1 tonne methane combusts to at least 2.75 tonnes CO2 ?

Response:

To consider how any fuel might provide a climate benefit over another, one must consider the fuels' lifecycle carbon intensities. Table ES-2 shows the GHG emissions intensity of producing hydrogen using SMR and CCS as 20.0 gCO_2e per MJ versus 59.8 gCO_2e per MJ for natural gas.[13] If BC's policy and regulatory framework were to enable FEI to include turquoise or blue hydrogen, FEI would only source renewable and low-carbon gas supplies that meet the prevailing government-specified carbon intensity threshold, which is likely to be well below the carbon intensity of natural gas. As an example, in the federal government's Fall Economic Statement, an investment tax credit for hydrogen production was introduced. To qualify for the tax credit, the carbon intensity of hydrogen production would have to be approximately 33 gCO_2e per MJ (or at least 4 kg CO_2 per kg H_2).

The carbon intensity of any hydrogen that FEI includes in its supply portfolio will be an improvement over natural gas and will contribute to meeting BC's climate goals.

8.2 If, as FEI suggests (LRTP Appendix A-3 Figure 35: Aggregate Demand Opportunity for Hydrogen in Canada), the majority of the hydrogen supply will be "grey" (i.e. from methane with no CCS), or "blue" (i.e. from methane with CCS) , what is the net GHG effect of producing hydrogen from both of of those sources, which are both known to be large emitters of Carbon Dioxide (and are also endothermic processes requiring much power to execute)?

[12] Steam methane reforming (SMR) is currently the main hydrogen production process in industry, but it has high emissions of CO_2, at almost 7 kg CO_2/kg H_2 on average, and is responsible for about 3% of global industrial sector CO_2 emissions. Source: https://www.researchgate.net/publication/267623573_Assessment_of_CO2_capture_options_from_various_points_in_steam_methane_reforming_for_hydrogen_production.

[13] For comparison, the federal government has recommended 36.4 gCO2e/MJ as the carbon intensity threshold for low carbon hydrogen in Canada's Hydrogen Strategy. Source: https://www.nrcan.gc.ca/sites/nrcan/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf.

Response:

Please refer to page 83 of the Hydrogen Strategy for Canada in Appendix A-3 of the Application, Figure 43 – Hydrogen Decarbonization Potential, as published by the Government of Canada.

8.3 How does this approach assist FEI in meeting its own "30by30" and/or CleanBC Roadmap's 48% reduction in customer GHG emissions, each by 2030, a scant seven years hence?

Response:

FEI interprets this question as asking how blue and turquoise hydrogen assist FEI in meeting the 30BY30 target and/or CleanBC Roadmap's proposed GHG cap on emissions from natural gas use in the buildings and industry sectors (47 percent reduction by 2030).

As described in Section 3.3.3 of the Application, FEI believes that developing and delivering hydrogen (green, blue, and turquoise) through or enabled by existing gas infrastructure will enable FEI to displace conventional natural gas, and therefore assist FEI in achieving the 30BY30 target and CleanBC GHG cap on natural gas utilities.

By 2030, FEI envisions blending some hydrogen (green, blue or turquoise) across the low-pressure gas distribution system and potentially serving localized customers 100 percent hydrogen through hydrogen hubs, where possible. Please refer to Figure 3-6 of the Application for a visual representation of some of the ways that FEI's infrastructure can facilitate the incorporation of hydrogen production, transmission and use.

Issue 9: Capture and Storage. Section 3.3.5 the LTGRP states that "Natural gas feedstocks in this analysis require carbon capture and sequestration or other technologies that ensure that the hydrogen is low-carbon".

To date, published results show that CCS technologies have struggled to achieve anything higher than (i) a 30% capture ratio, and (ii) an economic business case for those facing the alternative of paying the carbon tax for venting or combusting their high-carbon emissions. Our questions:

9.1 Quantitatively, how much CCS will be needed to fulfil FEI's requirement to meet CleanBC's 47% reduction in customer GHG emissions by 2030.

Response:

FEI is unable to specify how much CCS will be needed to fulfil CleanBC's 47 percent GHG emission reduction target from buildings and communities by 2030. The level of CCS adoption required, if any, to meet the 47 percent emission reduction target will depend on the amount of renewable gas used to displace conventional gas, as well as uptake of other GHG emission reduction activities such as adoption of energy efficiency and conservation measures, and fuel switching from higher to lower carbon fuels in industry. The potential interchangeability of these types of solutions highlights the importance of a diversified energy future in keeping all options 'on the table'. Please refer to BCUC IR1 64 series for further discussion of FEI's CCUS support for on-system low-carbon gas supply.

9.2 To FEI's knowledge, how much of this CCS technology is currently in place in BC?

Response:

CCS technology is currently used at small scale by upstream gas processing facilities in the acid gas disposal process. FEI is aware of proposed plans for upstream gas processing facilities to install CCS technology for large-scale carbon capture and storage; however, FEI is not aware of any such large-scale projects currently in operation in B.C.

9.3 Per Gigajoule, what is your working estimate for the cost of CCS in BC?

Response:

FEI does not currently have a working estimate for the cost of CCS in BC. FEI envisions that the relative costs of the various renewable and low-carbon gas solutions will in part drive how much of each supply resource will be acquired.

9.4 Where will these CCS facilities most likely be located?

Response:

Given the high concentration of carbon emissions in the flue gas of upstream natural gas processing facilities, FEI expects that large-scale CCS facilities will most likely be located where large point-source emitters, such as upstream natural gas processing facilities, are located in relative proximity to suitable underground carbon storage formations. Over time and as the industry scales, carbon dioxide transportation pipeline infrastructure may emerge to transport the CO_2 from multiple geographically dispersed CCS facilities to a suitable storage formation.

9.5 Will FEI be providing financial incentives for (gas-fired) (i) homeowners (ii) commercial enterprises and (iii) heavy industrial emitters to install and operate CCS technologies?

Response:

FEI is not currently considering providing financial incentives for residential or commercial customers that invest in CCS technologies. However, FEI is exploring how the utility might play a role in providing financial incentives for industrial emitters such as gas producers to install and operate CCS technologies. FEI would contractually obtain the associated environmental attributes, provided that a rate-recovery mechanism exists and that FEI would be able to count the associated GHG emissions reductions toward its GHG reduction obligations.

FEI is investigating some projects that involve carbon capture through its Clean Growth Innovation Fund; however, most of these technologies are relatively small scale. CCS may have a role in the medium- to long-term for those customers that cannot transition from natural gas, and FEI is interested in supporting the development and deployment of these technologies, but it is too early to say if an incentive program is required and what such program would look like.

If FEI were to pursue providing incentives for CCS, FEI expects that it would first file an application to the BCUC requesting related approvals.

9.6 Can FEI indicate where, and to what effect, other gas utilities have successfully implemented CCS programs with their customers?

Response:

FEI is not aware of any gas utilities implementing CCS programs with their customers.

Issue 10: Additional compressors = additional GHG emissions: The LTGRP (suggests that expanding the Langley compressor station - by adding more compression horsepower (to handle population-driven demand growth and downstream LNG demand) - will be necessary in the shorter term. Our questions:

10.1 Will these be electric- not gas -powered compressors?

<u>Response:</u>

The scope of the potential capacity upgrade in the Coastal Transmission System to handle additional load has not yet been determined. Multiple options are being considered at this time, including:

1. Expansion of the Langley Compressor Station through the additional gas-fired compressors;
2. Expansion of the Langley Compressor Station through the addition of electric-drive compressors;
3. Expansion of the Langley Compressor Station through the removal of the existing gas-fired compressors and addition of electric-drive compressors; and
4. Pipeline upgrades downstream of the Huntingdon Control Station.

Any alternative that includes electric-drive compressors will require the construction of between 5 and 10 kilometres of high-voltage power lines through Langley to connect the station to BC Hydro's transmission system.

For any gas-fired alternative at the Langley Compressor Station, FEI will evaluate modern emissions reduction and carbon capture technology and, if feasible, apply such technology to any gas-fired alternative proposed to ensure compliance with local emissions regulations and the CleanBC plan.

The following are key considerations for FEI in determining which of the options to proceed with:

1. Rate impacts: Projects with a lower rate impact over their useful life are preferable, all else equal.
2. Reliability: These facilities will be required to supply gas to BC residents and businesses on the coldest days of the year. Only alternatives that meet the reliability needs of the area will be considered.
3. Regulatory Compliance: Only alternatives that meet regulatory requirements, including emissions limitations, will be considered.
4. Community, Indigenous, and Stakeholder Impacts: Alternatives that require construction of new linear infrastructure (pipelines or power lines) will have a higher negative impact on adjacent communities during construction compared to alternatives that are limited to the Langley Compressor Station site. Alternatives with

less negative impact or more positive impact on the local community, Indigenous groups, and other stakeholders will have a higher weight than others.

10.2 If gas-powered, what will be the incremental GHG emissions attributable to this expansion?

Response:

Please refer to the response to MS2S IR1 10.1. Incremental GHG emissions will depend on the scope of the project and cannot be provided at this time.

10.3 Post expansion(s), what will then be the total GHG emissions attributable to the Langley station?

Response:

Please refer to the response to MS2S IR1 10.1. Post-expansion GHG emissions attributable to the Langley Compressor Station will depend on the finalized scope and cannot be determined at this time.

Issue 11: Re the Envint et al. consulting report (Appendix D-2 of the LTGRP- Growth in Renewable Gas Supply - Long-Term Supply Forecast: 2027-2032) conclusions (Note: this is somewhat related to a question – 16.0, as yet unanswered) posed by the City of Richmond et al. in its Biomethane rate hearing letter of Aug. 12, 2022 – see Exhibit C 26-2.

FEI has included this report, prepared by Envint Consulting and others, as Appendix D-2 of the LTGRP. This version of the report was labeled "FINAL REPORT" and dated January 28, 2022. The relevant section (colouration is added) begins on page 112 and reads:

"Demand-side management and technology switching:

This study focuses on the supply potential for renewable and low-carbon gas production pathways. Pathways beyond renewable and low-carbon gas are outside the scope of this report. A more comprehensive approach would compare primary energy use of various pathways in a 'well-to-heat' manner. Currently, 45% of natural gas consumed in B.C. is used by the residential and commercial sector. [Footnote omitted] The residential sector alone uses around 48 petajoules per year of natural gas for low- temperature space heating. [Footnote omitted] This need for low-temperature heat can be met more effectively by pathways other than low-carbon gas.

For example, green hydrogen can be produced with a conversion efficiency of 65% to 75% of the electricity used. Methanation of syngas to produce RNG is expected to have 95% conversion efficiency. A downstream household may use renewable gas in its furnace or boiler at a seasonal efficiency of 80% to 85%. The total system efficiency multiplies to 46% to 61% of the electricity input. In comparison, an air- source heat pump used in the climate of southern coastal B.C., where most of the population is located, can achieve a coefficient of performance (equivalent to an efficiency) of 300% to 350% of the electricity used, i.e. it is six to eight times more efficient than heating with gas.

The life expectancy of residential buildings in Canada ranges from 42 years for apartment buildings with less than five storeys to 65 years for single detached and row houses and 80 years for large apartment buildings. [Footnote omitted] Assuming an average age of the residential housing stock of 36 years [footnote omitted] (in 2021), a large share of B.C.'s building stock will be replaced within the 29 years between 2021 and 2050. This offers opportunities to switch from natural gas to alternative forms of heating. The goal of 15% renewable gas may be achieved more easily by switching technologies than by switching to low-carbon gas."

11.1 The technical argument, and its conclusion (the coloured sentence), appear quite logical. Does FEI agree with it, and, if not, why not?

Response:

FEI does not agree with the technical argument or its conclusion, which is not substantiated. FortisBC's Pathways Report,[14] as well as the study conducted by the University of Victoria's Institute for Integrated Energy Systems,[15] involved in-depth energy system modelling to better understand the costs and tradeoffs of decarbonization pathways for heat. The conclusions of these analyses do not support the claims made in the referenced section. Moreover, FEI has already secured long-term supply of 10 percent RNG, which was achieved more rapidly, cost-effectively, and reliably than switching technologies.

Further, this information request references a version of the BC Renewable and Low-Carbon Gas Supply Potential Study that has since been updated. The update was initiated by the steering committee composed of the BC Bioenergy Network, the Ministry of Energy, Mines and Low Carbon Innovation, and FEI. The 2022 BC Renewable and Low-Carbon Gas Supply Potential Study may be found in Appendix D-2 of the Application.

14 Exhibit B-1, 2022 LTGRP Application, Appendix A-2.
15 Exhibit B-1, 2022 LTGRP Application, Appendix A-9.5.