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February 4, 2021

Sent via email/eFile

FEI CPCN APPLICATION FOR OKANAGAN CAPACITY UPGRADE PROJECT EXHIBIT A-3

Ms. Diane Roy
Vice President, Regulatory Affairs
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
gas.regulatory.affairs@fortisbc.com

Re: FortisBC Energy Inc. – Application for a Certificate of Public Convenience and Necessity for the Okanagan Capacity Upgrade Project – Project Number 1599152 – Information Request No. 1

Dear Ms. Roy:

Further to your November 16, 2020 filing of the above noted application, enclosed please find British Columbia Utilities Commission Information Request No. 1. In accordance with Order G-335-20 establishing the regulatory timetable for this proceeding, please file your responses on or before Thursday, March 4, 2021.

Sincerely,

Original signed by:

Marija Tresoglavic
Acting Commission Secretary

PS/dg
Enclosure

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FortisBC Energy Inc.
Application for a Certificate of Public Convenience and Necessity
for the Okanagan Capacity Upgrade Project

INFORMATION REQUEST NO. 1 TO FORTISBC ENERGY INC.

Table of Contents **Page no.**

A. PROJECT NEED AND JUSTIFICATION

1.0 Reference: PROJECT NEED AND JUSTIFICATION
Exhibit B-1-2 (Updated Application), pp. 18, 28, 29
Impacts of COVID-19

On page 18 of the Updated Application, FortisBC Energy Inc. (FEI) states, "FEI's system capacity planning team refreshes its forecast annually, based on the most recently available customer addition and consumption data."

On page 28 of the Updated Application, FEI states:

> FEI's peak demand forecast was prepared in 2019, before the onset of the COVID-19 pandemic. As of the date of filing, there is insufficient data to quantify the COVID-19 impact, to forecast its future impacts on energy consumption or, more importantly for system planning, its impact on peak loads. FEI acknowledges that the immediate and near-term impacts of the pandemic may be significant for some types of customers and economic sectors. However, FEI presently has insufficient information to quantify these impacts.

On page 29 of the Updated Application, FEI states:

> In summary, given the lack of firm information on COVID-19 related impacts on the peak load in 2023/2024 and future years, the continuing potential for significant new loads in urban centres like Kelowna, the limitations of existing short-term mitigation measures,

and the lead time required for a project of this nature, FEI concludes that it would not be prudent to delay the addition of ITS [Interior Transmission System] capacity and that the OCU [Okanagan Capacity Upgrade] Project should proceed as set out in this Application.

1.1 Please discuss when FEI expects its 2020 peak demand forecast will be available, and whether FEI expects to file an updated demand forecast as part of this proceeding.

1.2 Please provide a detailed discussion of the work FEI is undertaking with respect to estimating the impact of the COVID-19 pandemic upon peak demand forecasting, including any timelines for such work.

2.0 Reference: PROJECT NEED AND JUSTIFICATION
Exhibit B-1-2, pp. 24, 25, 28
Minimum Inlet Pressure at Gate Stations

On page 24 of the Updated Application, FEI states:

> FEI designs the ITS to deliver a minimum inlet pressure of 2415 kPag (350 psig) into the major gate stations serving downstream Intermediate Pressure (IP) systems on a peak day. This minimum pressure is the parameter that defines the ITS capacity limit. This minimum pressure is identified as the primary capacity constraint for this region in order to maintain a 350 kPag (50 psig) working pressure differential across Polson Gate Station and Kelowna #1 Gate Station that supply IP systems that operate at 2070 kPag (300 psig), supplying thousands of customers. This minimum delivery pressure ensures a reasonable working pressure across the station always exists to accommodate effective sizing and operation of the station regulators and other station equipment.

On page 25 of the Updated Application, FEI states:

> These pressure-controlled regions are identified in Table 3-1 above, with the segments most relevant to the OCU Project listed in rows 2 to 5. These portions of the pipeline can provide a local constraint on capacity. The most significant constraint on maintaining minimum pressure into the north and central Okanagan is the pressure limitation to 5171 kPag (750 psig) between Ellis Creek Control Station in Penticton and the SN9-3 Control Station south of Kelowna. The OCU Project will address this constraint by providing the ability to supply gas into the NPS 12 Savona to Penticton mainline at the maximum 5171 kPa at a point more than 28 kilometres closer to the major load centres on the ITS in the Central Okanagan.

On page 28 of the Updated Application, FEI states:

> The first regions to experience a capacity shortfall would be the communities of West Kelowna, Lavington, and Lumby (shown in Figures 3-9 and 3-10 above). The systems in these communities are supplied by the Kelowna #1 Gate Station and the Polson Gate Station, which require inlet pressures sufficient to maintain an adequate pressure differential between transmission inlet pressure and discharge pressure. Due to their approximate midpoint location on the ITS mainline, the inlets of both stations experience the lowest pressures experienced on the ITS, and current forecasts indicate that the inlet pressures would be insufficient to operate the stations in the case of extreme cold conditions during the winter of 2023/2024. Customers served by the Kelowna #1 Intermediate Pressure system currently number approximately 16,300 in West Kelowna and the customers served by the Polson Intermediate Pressure system in Vernon number over 2,000 in Lavington and Lumby.

2.1 Please explain if the minimum inlet pressure of 2415 kPag (350 psig) is uniform for all major gate stations on the ITS.

2.1.1 If not, please explain the factors that contribute to variations in minimum inlet pressure.

2.2 Please discuss whether there have been any instances in the past ten years where inlet pressure into the into the major gate stations on the ITS has been below the minimum inlet pressure of 350 psig.

2.2.1 If so, please describe the circumstances causing such instances, and the impacts upon the downstream system.

2.3 Please explain the extent to which the inlet pressure observed at the Kelowna #1 Gate Station and the Polson Gate Station is affected by (i) the peak demand on the entirety of the ITS system, and (ii) the peak demand in localized areas of the ITS system.

2.4 Please discuss whether the minimum inlet pressure at major gate stations may be affected by future increases in demand.

2.5 Please provide graphs for the Kelowna #1 Gate Station and the Polson Gate Station which show from 2019 to 2039 the forecasted inlet pressure under forecasted peak day conditions in the absence of the OCU Project.

2.6 Please confirm or explain otherwise that the OCU Project is not solely designed to address the potential capacity shortfall in the communities of West Kelowna, Lavington, and Lumby.

2.6.1 Please discuss whether FEI considered alternatives that would specifically address the forecasted capacity shortfall in the communities of West Kelowna, Lavington, and Lumby only.

2.6.1.1 Please discuss the pros and cons of such an approach.

2.7 Please provide a table which identifies for each major gate station on the ITS; the first year in the forecast period where, in the absence of the OCU Project, forecasted inlet pressure would fall below the minimum inlet pressure of 350 psig under peak day conditions at the gate station; and the number of customers served downstream of the gate station.

2.7.1 Please also provide this information in the scenario where the OCU Project is constructed but no other capacity upgrades are undertaken in the forecast period (if applicable).

3.0 Reference: PROJECT NEED AND JUSTIFICATION
Exhibit B-1-2, p. 25
FEI 2017 Long Term Gas Resource Plan proceeding, Exhibit B-1, pp. 152, 153
Line Pack

On page 25 of the Updated Application, FEI states:

> The successful application of line pack to supplement the system capacity relies on sufficient periods of lower system demand to occur where input into the system can exceed current demand and rebuild the line pack within the system to be available for future periods of peak demand. The ITS experiences continuous daily cycles in demand where line pack is constantly in flux alternating between periods of depletion followed by periods of regeneration. FEI accounts for this capability by applying the transient factor to the peak demand. The transient factor adjusts the magnitude peak load used for system design to a value lower than the hourly peak demand actually experienced on the system on a peak day, reflecting that the balance can be provided by the system line pack.

On pages 152 to 153 of the FEI 2017 Long Term Gas Resource Plan (LTGRP), FEI stated:

> Designing transmission systems to meet peak demand. Core demand varies on an hourly basis and typically exhibits a morning peaking period between six and ten a.m. and an evening period between five and nine p.m. The peak hour demand for these customers can be more than 40 percent above the hourly average (daily demand/24 hours). Transmission systems are designed to meet this peak demand condition.
> …
>
> The amount of line pack within a transmission system determines whether it should be designed to meet peak day or peak hour conditions. A pipeline system with a large relative line pack can temporarily support increased demand out of the system that exceeds the supply into the system. As demand exceeds supply the amount of gas "packed" in the pipeline (i.e. line pack) is reduced and pressure in the pipeline is drawn down , until such time that the demand drops below the supply into the system, at which point pressure (and line pack) can recover. Pipeline length and operating pressure determine the amount of line pack available in the system. Typically, longer, larger diameter systems operating at higher pressures with high line pack are designed to peak day conditions; conversely, systems with lower amounts of line pack (due to factors such as lower pressures and smaller volumes) are designed to meet peak hour loads.

3.1 Please confirm, or explain otherwise, that the peak demand forecasts presented in the Updated Application (e.g. in Figures 3-6 to 3-8) reflect the application of the transient factor.

3.1.1 Please discuss whether the transient factor is applied at a system wide level or at a more granular localized level.

3.1.2 Please show a comparison of the peak day forecast for the ITS adjusted for the transient factor and unadjusted for the transient factor, for the forecast period. If available, please also provide the peak hour forecast for the ITS.

3.2 Please discuss why peak day is a more appropriate measure for capacity planning on the ITS than peak hour.

3.2.1 Please explain whether periods of low line pack coincide with periods of highest demand on the ITS.

3.2.2 Please discuss whether there are any localized points on the ITS with typically low line pack where peak hour demand may be more relevant for capacity planning purposes than peak day.

3.2.3 Please describe the line pack characteristics of the pipelines feeding the Kelowna #1 Gate Station and the Polson Gate Station.

3.3 Please explain whether FEI must consider the duration of a peak winter event beyond the peak day in its system capacity planning on the ITS.

3.3.1 Please provide a load duration curve showing the daily peak demand on the ITS for the year with the coldest peak day observed in the last five years.

4.0 Reference: PROJECT NEED AND JUSTIFICATION
FEI 2017 LTGRP proceeding, Exhibit B-1, p. 154
End-use Peak Load Forecasting

On page 154 of the 2017 LTGRP, FEI stated:

> FEI has since commissioned Posterity, a consultant, to develop an exploratory process linking peak demand forecasts to the end-use scenarios used in the annual demand

forecasts. At this point, the exercise is theoretical in nature and unsupported by direct measurement. As such, FEI's infrastructure planning continues to rely on the Traditional Peak Method. The exploratory end-use method does, however, provide a means of assessing a range of peak demand forecast possibilities and the impact on system capacity upgrade project scope and timing.

4.1 Please explain whether FEI has conducted analysis of the link between end-use demand forecasts and peak demand for the ITS system as part of its assessment of the need for the Project.

4.1.1 If yes, please provide a summary of this analysis, and explain the extent to which it supports the peak demand forecast used in the Application.

4.1.2 If no, please compare the peak demand forecast presented in the Updated Application with the end-use peak demand analysis provided for the ITS in the FEI 2017 LTGRP, and discuss any significant differences between the two forecasts.

4.1.3 Please briefly explain the strengths and weaknesses of end-use peak demand forecasting with respect to system capacity planning.

5.0 Reference: PROJECT NEED AND JUSTIFICATION
Exhibit B-1-2, pp. 20, 21
BC Office of Housing and Construction, Provincial Policy: Local Government Implementation of the BC Energy Step Code, p. 4
Use Per Customer

On page 20 of the Updated Application, FEI provides the formula used for forecasting peak day demand:

> The calculation of the forecast peak day demand in any year can be described by the following formula:
>
> $$Peak\ Day\ Demand_{(Year\ N)} = \sum_{i=1}^{3} (\sum \text{Current Accounts} \times UPC_{peak} + \sum \text{Forecasted Accounts to Year N} \times UPC_{peak})_{(rate\ schedule\ i)} + \sum \text{Industrial Customer Maximum Demand} + \sum \text{Contract Obligations for Interruptible Customers}$$

On page 21 of the Updated Application, FEI states:

> FEI determines the peak demand of residential and commercial customers connected to and consuming gas on the ITS by multiplying the three-year average peak use per customer (UPCpeak) for each rate schedule by the number of current customers in the system in each residential and commercial rate schedule. FEI then multiplies the three-year average UPCpeak for each of the rate schedules by the forecast number of new customer accounts in each rate schedule for each year of the forecast, and adds this to the peak demand for current customers. FEI does not modify the UPCpeak values over the forecast period.

5.1 Please explain the rationale for selecting a three-year average UPCpeak, rather than an average over some longer or shorter period.

5.2 Please provide a detailed explanation of why the UPCpeak for current customers is assumed to be constant over the forecast period.

5.2.1 Please describe the main factors FEI considers may contribute to an increase or decrease in the UPCpeak in the forecast period.

5.3 Please provide the UPCpeak for residential and commercial customers by rate schedule for the last 10 years for customers served by the ITS. Please provide a description and explanation of any observable trends.

5.4 Please explain why the UPCpeak for new customers is assumed to be the same as existing customers.

Page 4 of the BC Office of Housing and Construction document titled "Provincial Policy: Local Government Implementation of the BC Energy Step Code"[1] states:

> The BC Energy Step Code is a voluntary roadmap that establishes progressive performance targets (i.e., steps) that support market transformation from the current energy-efficiency requirements in the BC Building Code to net zero energy ready buildings. It establishes a set of incremental performance steps for new buildings that aims to communicate the future intent of the Building Code and improve consistency in building requirements across British Columbia (B.C.) to transition to net zero energy ready buildings by 2032. It is a voluntary tool local governments across B.C. can use to encourage—or require—the construction of more energy-efficient buildings in their communities, and do so in a consistent, predictable way.

5.5 Please discuss whether FEI assumes the number of new customer accounts to be directly correlated with new buildings.

5.6 Please provide any analysis FEI has undertaken with respect to the actions adopted by local governments in the ITS service area to implement the BC Energy Step Code, such as mandatory building requirements.

5.7 Please discuss the extent to which the BC Building Code and implementation of the Energy Step Code in BC represents a known and measurable impact upon peak load forecasting for new customers in the forecast period, particularly in municipalities who have adopted mandatory approaches to implementing the Energy Step Code.

6.0 Reference: PROJECT NEED AND JUSTIFICATION
Exhibit B-1-2, p. 23
Exhibit B-1-2-1, Appendix L-3, "ITS Inc. Acct Growth" tab; "ITS Peak Day Demand" tab
Peak Demand Forecasting by Customer Class

On page 23 of the Updated Application, FEI states:

> To maintain consistency with FEI's rate setting forecast, FEI "trues up" each year of the more granular BC Stats/LHA forecast to the regional rate-setting forecast. For residential customers, the rate-setting forecast uses the single family/multi-family growth rates from the Conference Board of Canada (CBOC) forecast. The CBOC forecast is applied province-wide and does not provide the regional granularity of the BC Stats/LHA method. The commercial rate-setting forecast uses a three-year average of customer additions. To "true up" the forecast, FEI factors the municipal forecasts up or down so that the aggregate sum by region matches the CBOC method, but the differences by LHA

[1] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/construction-industry/building-codes-and-standards/guides/baguide_c2_sc_april2017.pdf

remain. This has the advantage of maintaining consistency with FEI's rate-setting aggregate forecast, while also providing a granular forecast that is reflective of the growth patterns forecast by the BC Stats/LHA method.

6.1 Please clarify the difference (if any) between the terms "household formation" as defined by BC Stats/LHA and "housing starts" as defined by CBOC.

6.2 Please explain whether the trueing-up of the residential forecast (using the CBOC forecast results) in higher or lower growth rates for the ITS than the BC Stats/LHA forecast.

6.3 Please explain why consistency is needed with the rate-setting forecast for the purposes of capacity planning.

6.3.1 Please identify any key differences in the objectives of forecasting for rate-setting and forecasting for capacity planning.

6.4 Please explain why a three-year average of customer additions is used to true-up the forecast for commercial customers.

6.4.1 Please explain whether the trueing-up of the commercial customer forecast (using the three year average of customer additions) results in higher or lower growth rates for the ITS than the BC Stats/LHA forecast.

An excerpt of the "ITS Inc. Acct Growth" tab of Appendix L-3 to Exhibit B-1-2-1 is provided below, showing the growth rate for Rate Schedule 3 (RS 3) customers on the Total ITS System:

2018 YE Accounts	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
628	9.1%	8.5%	8.1%	7.7%	7.1%	6.7%	1.1%	1.1%	1.0%	1.1%	1.0%

6.5 Please explain why the forecasted growth rate for RS 3 customers is higher than other customer classes in the period 2019 to 2024.

6.5.1 Please explain the reason for the significant drop in the forecasted growth rate between 2024 and 2025.

In the "ITS Peak Day Demand" tab of Appendix L-3 to Exhibit B-1-2-1, Row 151 shows a forecast peak industrial demand of 62.23 TJ/d for the forecast period.

6.6 Please confirm which rate schedules comprise the "industrial demand."

6.7 Please confirm, or explain otherwise, the industrial demand figure of 62.23 TJ/d represents firm demand from industrial customers only.

6.7.1 If interruptible demand is included, please provide a breakdown of the 62.23 TJ/d figure by firm and interruptible demand.

7.0 Reference: PROJECT NEED AND JUSTIFICATION
Exhibit B-1-2, p. 21
Industrial demand

On page 21 of the Updated Application, FEI states:

> Maximum Demand from Firm Industrial Customers: For firm industrial customers with available hourly consumption data, FEI determines the UPCpeak for each customer

directly from the hourly data. The peak day demand is determined based on the maximum demand observed in the hourly consumption of the customer and assumes that consumption would be sustained over a day. The peak day demand is therefore equivalent to a peak day flow. If an industrial customer has made a contractual commitment to increase their future firm load, this incremental load is included in the peak day demand forecast. Otherwise, FEI does not include any change in industrial customer numbers or demand due to the uncertainty associated with the location and magnitude of consumption needs of future customers in industrial rate schedules.

7.1 Please explain why FEI does not use daily consumption data to determine the UPCpeak for firm industrial customers.

7.2 Please discuss whether the assumption that an industrial customer's maximum hourly demand is sustained over a day is supported by metered data.

7.2.1 If not, please explain why FEI makes this assumption.

7.2.2 Please provide the total hourly load profile of FEI's firm industrial customers in the ITS in the peak day observed in the last three years.

7.3 Please discuss whether FEI considers further capacity upgrades would likely be required in the forecast period to accommodate any additional firm industrial customers.

8.0 Reference: PROJECT NEED AND JUSTIFICATION
Exhibit B-1-2, p. 22
1 in 20 Weather Event

On page 22 of the Updated Application, FEI states:

> FEI's DDD [Design Degree Day] temperature for any system operating within a region is the coldest day that is statistically likely to occur only once in any given 20 year period. In determining the DDD value, FEI uses an extreme value statistical method called the Gumbel Method of Moments. This method returns the expected extreme value for a given historical data set based on a specified return period. FEI uses a 1 in 20 return period on a data set that represents the coldest recorded daily mean temperature at the region's weather station each winter over a 60 year period.
>
> The DDD temperature values for weather zones in the ITS range from a 46.7 Degree Day (DD) 16 (corresponding to minus 28.7°C mean daily temperature) in the Thompson region, to a 43.9 DD (corresponding to minus 25.7°C mean daily temperature) in the North and Central Okanagan region, to a 39.1 DD (corresponding to minus 21.7°C mean daily temperature) in the South Okanagan region. The regional DDD values are based on a 60 year weather history as reported by Environment Canada at the Kamloops Airport, Kelowna International Airport, and Penticton Regional Airport weather stations, respectively.

8.1 Please compare the DDD values for the Thompson region, North and Central Okanagan region and South Okanagan region against the coldest day observed in the last 20 years.

8.1.1 Please outline the number of days in the last 60 years where the observed mean daily temperature was colder than the DDD, and the dates of these occurrences.

8.2 Please explain whether the Gumbel Method of Moments places greater weight on observed temperatures in more recent years.

8.2.1 Please explain why a 60 year data set is used instead of the most recent 20 year period.

8.3 Please discuss at a high level any observed trends in the frequency and severity of extreme cold events in the last 60 years.

8.4 Please explain whether FEI makes any adjustments to the DDD due to climate change, for example based on observed or expected trends in the frequency and severity of extreme cold events.

9.0 Reference: PROJECT NEED AND JUSTIFICATION
Exhibit B-1-2, pp. 25, 51
Class Locations

On page 25 of the Updated Application, FEI states:

> The ITS serving the Thompson Okanagan region has several regions where pressure is controlled below the original MOP [maximum operating pressure] to ensure pipeline safety factors associated with CSA Z662 class locations requirements. These pressure-controlled regions are identified in Table 3-1 above, with the segments most relevant to the OCU Project listed in rows 2 to 5.

On page 51 of the Updated Application, FEI states:

> The class location of a pipeline is related to the population density in the surrounding area. As population in an area increases, the class location can change, and a pipeline operator must take action to ensure the pipeline meets the requirements of the new class location. This can mean reducing MOP or modifying the pipeline.

9.1 Please explain whether FEI anticipates any class location changes will be required to FEI's pipelines in the ITS during the forecast period as a result of the expected population growth discussed in section 3.3 of the Updated Application.

B. SHORT TERM MITIGATION MEASURES

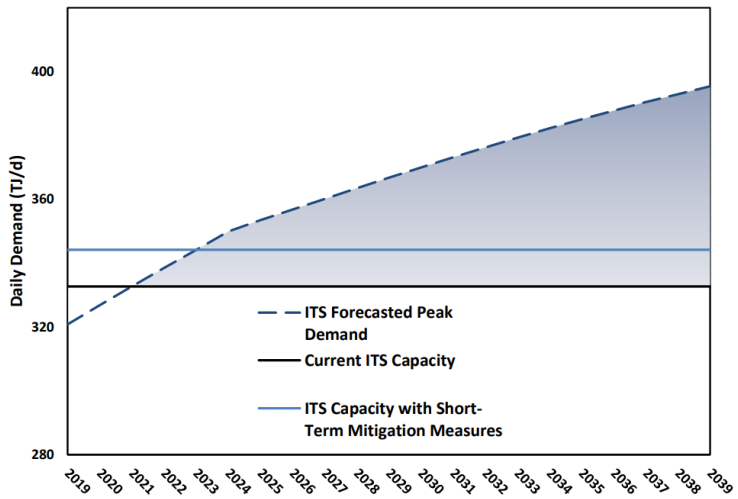
10.0 Reference: SHORT TERM MITIGATION MEASURES
Exhibit B-1-2, pp. 34, 35, 37
Description of Short Term Mitigation Measures

In sections 4.2.1 to 4.2.4 on pages 34 to 35 of the Updated Application, FEI describes the following short term mitigation measures: contractual minimum pressure increase, temporary load shifting, station modifications, and additional mitigation measures.

With respect to additional mitigation measures, FEI states, "In addition, throughout the period prior to completion of the OCU Project, FEI will manage load additions within system capacity limitations, and identify and manage existing customer loads under peak conditions."

Figure 4-1 on page 37 shows the ITS capacity with the short term mitigation measures:

Figure 4-1: ITS Capacity with Mitigation Measures



10.1 For each of the four short term mitigation measures FEI is planning to undertake, please explain the following:

- Whether there are any reliability concerns with respect to the measure's ability to provide dependable capacity during a peak demand event (assuming overall system capacity was sufficient to meet demand);
- The extent to which potential exists for increased capacity by further expansion of the measure at the location(s) described and/or elsewhere on the ITS, and any implications of expanding the measure;
- The potential longevity of the measure as a reliable capacity solution (assuming overall system capacity was sufficient to meet demand).

10.2 Please provide a breakdown of the estimated capacity increases shown in Figure 4-1 by measure.

10.3 Please further explain how FEI intends to "identify and manage existing customer loads under peak conditions."

11.0 Reference: SHORT TERM MITIGATION MEASURES
Exhibit B-1-2, pp. 35, 36
Compressed Natural Gas

On pages 35 to 36 of the Updated Application, FEI states:

> To mitigate the forecast capacity shortfall, 1 to 2 large truckloads of CNG [compressed natural gas] per hour (up to 4 – 6 truckloads per day) would be required during a peak demand event by the winter of 2022/2023. With growing demand in the region, the capacity shortfall and corresponding amount of CNG or LNG [liquefied natural gas] required will increase over time. CNG trucks would be required to travel from a filling point outside of the central Okanagan, where the system has a sufficient gas surplus to allow trucks to fill, to an effective injection point in the central Okanagan. LNG trucks would be supplied from FEI's Tilbury LNG facility in Delta, approximately 400 km from the shortfall region. This CNG/LNG truck traffic would be required during a peak demand event, which corresponds to the most severe winter weather in B.C.

Transporting fuel by truck during severe winter weather is a less cost effective and reliable method of gas transportation than appropriate and adequate pipeline infrastructure. The reliability concerns could be mitigated through staging of sufficient additional trucks, but this would come at an increased cost. CNG and LNG supplementation would not provide a lasting improvement to FEI's system, as CNG/LNG supplementation is not a viable long-term solution to the capacity shortfall in the Okanagan and will not decrease the cost associated with this required pipeline installation.

11.1 Please provide any analysis that FEI has performed to assess the potential costs of CNG and/or LNG against the potential benefits of deferring the OCU Project (for example, by one to five years).

11.2 Please provide an estimate of the number of CNG truckloads per hour and per day that would be required to meet peak demand in winter 2023/24 and 2024/25.

11.3 Please discuss whether temporarily introducing CNG and/or LNG as a short term measure from 2022/23 could enhance the viability of any of the Project alternatives not selected by FEI, as outlined in section 4 of the Updated Application.

11.4 Please describe in detail the reliability concerns associated with using a) CNG supplementation and b) LNG supplementation to meet demand on a peak day event.

11.4.1 Please discuss FEI's experience with using CNG and LNG supplementation to meet peak demand elsewhere on its system.

C. DESCRIPTION AND EVALUATION OF ALTERNATIVES

12.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1-2, Section 3.1, p. 11
ITS gas supply strategy

On page 11 of the Updated Application, FEI states:

> FEI's ITS interconnects the gas supply from the Enbridge owned Westcoast Energy System in the west (Westcoast system) and the TC Energy-owned Foothills Pipeline in the east (TC Energy pipeline). Under typical conditions, gas is taken from the Westcoast system at the Savona Compressor Station to supply FEI's customers in the Thompson and north Okanagan Regions, while FEI's customers in the south and central Okanagan Regions are supplied primarily by the Southern Crossing Pipeline (SCP) supplying Oliver, which, in turn, supplies pipelines delivering gas through the Penticton area.

12.1 Please describe FEI's current natural gas supply strategy for the ITS and how this strategy is expected to evolve over the medium and long term.

12.1.1 Please explain how each alternative for the OCU Project aligns with this gas supply strategy.

12.1.2 Please discuss whether FEI's broader gas supply strategy for its entire system is a consideration when planning capacity upgrades on the ITS.

13.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1-2, Section 3.3, pp. 19-20
Capacity with the OCU Project

On page 20 of the Updated Application, FEI provides the Figure 3-8 illustrating both the current capacity and the capacity of the ITS following completion of the OCU Project.

13.1 Please provide a graph similar to Figure 3-8 illustrating the capacity of the ITS with each Alternative.

13.2 Please describe the methodology and assumptions that FEI uses to calculate the ITS capacity with each Alternative.

FEI states on page 19 of the Updated Application that the Figure 3-8 shows that, with the OCU Project, there will be enough capacity to support peak demand until the winter of 2029/2030. FEI explains in Section 3.3.2.4 the compression upgrades that would be undertaken at that time to further support peak demand to the end of the 20 year forecast period without extending the OCU Project pipeline.

13.3 Please describe any assessments to determine the feasibility of upgrading the compression capability to support peak demand to the end of the 20 year forecast period, including engineering and cost studies and provide the results of these assessments.

14.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1-2, Section 3.3.2.4, p. 26
Future Compressor Upgrades

On page 26 of the Updated Application, FEI states:

> Based on the current forecast, by the summer of 2029 FEI will need to upgrade the compression capability on the SCP to improve capacity into the Central and North Okanagan. FEI is currently considering several possible options to increase compression capability on the SCP to meet a variety of possible future needs. As the compression requirement to address future capacity needs in the Okanagan is several years beyond the immediate need for the OCU Project, and the optimal location and extent of required additional compression cannot yet be determined, FEI did not include a compressor upgrade in the OCU Project. Compressor requirements to satisfy the longer term capacity needs would be included, as needed, as part of any expansion project contemplated on the SCP.

14.1 Please explain when FEI expects to be able to provide additional information about any future project(s) to increase compression capability on the SCP, including project overview, timing, or anticipated cost.

14.2 Please discuss whether any FEI options to increase the compression capability on the SCP would require new transmission pipelines or recertification of any existing transmission pipelines to a higher pressure.

14.2.1 If so, please provide details of any new pipelines required and any existing pipelines requiring recertification.

14.3 Please explain why compression upgrades on the SCP are planned to address future capacity needs in the Okanagan (beyond 2029) and not the immediate need identified for the OCU Project.

14.4 If the Updated Application were not approved as applied for, what would the implications be, if any, on the need or timing of future compressor upgrades on the SCP? Please discuss.

14.5 Please discuss how the future expansion of compression capability on the SCP and FEI's overall vision for expanding system capacity in the Okanagan factored in FEI's decision-making when determining which alternative should be proposed for the OCU Project.

15.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1-2, Section 4.1.2, p. 32
Compression Option

On page 32 of the Updated Application, FEI states:

> In order to meet the Project's objectives, FEI identified and investigated five alternatives, including four pipeline installation options and an LNG (Liquefied Natural Gas) storage/peak shaving option.

15.1 Please discuss whether FEI considered adding compression to the ITS in the Okanagan area as a possible alternative to meet the OCU Project's objectives.

15.1.1 If yes, please describe any assessments to determine the feasibility of installing compression on the existing ITS, including engineering and cost studies and provide the results of these assessments.

15.1.2 If yes, please explain why FEI did not identify a compression option as a Project alternative.

16.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1-2, Section 4.2.1, p. 34
Savona Compressor Station

On page 34 of the Updated Application, FEI states:

> FEI has established a working agreement with Enbridge to maintain a minimum delivery pressure into Savona of 4480 kPag (650 psig) on peak days. This is 345 kPag (50 psig) higher than FEI's normal expected minimum delivery pressure at Savona. This will improve pressure into the north and central Okanagan and is required in the winter of 2021-22 and 2022-23 in advance of the completion of the OCU Project, but is not sufficient on its own to mitigate forecast peak demand in those winters.

16.1 Please provide the historical minimum delivery pressure into Savona on peak days for the past five years.

16.1.1 Please provide the current capacity of Savona Compressor Station. Please provide any assumptions made in determining current capacity, including the inlet pressure to the compressor station.

17.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1-2, Section 4.3.2, pp. 39-40
Alternative 2 – Modified ITS Upgrades to VER PEN 323

On pages 39 and 40 of the Updated Application, FEI provides the following description of Alternative 2:

> This alternative proposes the installation of a 6 km 406 mm pipeline extension of OLI PEN 406 (SONG pipeline built in 1994) around the City of Penticton. The 6 km long extension proposed under this alternative eliminates the requirement to replace and/or retest multiple segments from the southern end of Alternative 1….
>
> This alternative would require a new regulating station with a 406 mm receiving barrel to be built at the northern end of the extension where the new 406 mm pipeline would tie-in to the existing VER PEN 323, as the two pipelines do not operate at the same MOP. All upgrades that are part of Alternative 1 which are located north of the tie-in would still be required under Alternative 2; this equates to replacement of 3.9 km of existing VER PEN 323 with new higher strength 323 mm pipeline followed by hydrotesting of the VER PEN 323 located north of the tie-in location to the proposed end point of upgrades so that the pipeline can be recertified to operate at a MOP of 6,619 kPa.

Further on page 40, FEI states that Alternative 2 would need to be completed in its entirety prior to the winter of 2023/2024 to avoid a capacity shortfall.

17.1 Please explain how FEI determined that Alternative 2 would need to be completed in its entirety prior to the winter of 2023/2024 to avoid a capacity shortfall.

17.1.1 Please describe any assessments to determine the ITS capacity with only the 6 km 406 mm pipeline extension and the new regulating station completed prior to the winter of 2023/2024.

17.2 Please discuss the feasibility of completing the 6 km 406 mm pipeline extension and the new regulating station prior to the winter of 2023/2024 and upgrading VER PEN 323 later.

18.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1-2, Section 4.3.3, p. 41
Alternative 3 – OLI PEN 406 Extension

On page 41 of the Updated Application, FEI states Alternative 3 involves the addition of approximately 30 km of 406 mm pipeline running from OLI PEN 406 (SONG pipeline built in 1994) east of Ellis Creek near Penticton to Chute Lake northeast of Naramata.

18.1 Please explain how FEI determined the pipeline length for Alternative 3.

18.1.1 Please describe any assessments to determine the optimal pipeline length of the OLI PEN 406 Extension, including engineering and cost studies and provide the results of these assessments.

18.2 Please discuss whether there is an opportunity for FEI to extend the OLI PEN 406 beyond the OCU Project to further support peak demand on the ITS.

18.2.1 If yes, please explain whether this option is identified in the Updated Application.

18.2.1.1 If not, why not?

18.3 Please discuss whether there is an opportunity for FEI to reduce OCU Project costs by reducing the length of OLI PEN 406 Extension, while still meeting the primary project objectives.

18.4 Please discuss any potential OCU Project scheduling risks (permitting or construction) that factored in FEI's decision making when determining the pipeline length for Alternative 3.

19.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1-2, Section 3.3.2.1, p. 24, Section 4.3.4, p. 42
Alternative 4 – 508 mm Loop from Savona

On page 24 of the Updated Application, FEI states:

> FEI designs the ITS to deliver a minimum inlet pressure of 2415 kPag (350 psig) into the major gate stations serving downstream Intermediate Pressure (IP) systems on a peak day. This minimum pressure is the parameter that defines the ITS capacity limit. This minimum pressure is identified as the primary capacity constraint for this region in order to maintain a 350 kPag (50 psig) working pressure differential across Polson Gate Station and Kelowna #1 Gate Station that supply IP systems that operate at 2070 kPag (300 psig), supplying thousands of customers.

On page 42 of the Updated Application, FEI states, "The fourth alternative to address the capacity constraint involves the installation of a 508 mm loop starting at the Savona Compressor Station and running eastward for approximately 68.4 km before terminating east of Kamloops."

19.1 Please explain how FEI determined the 508 mm diameter and 68.4 km length for the pipeline starting at Savona Compressor Station proposed as Alternative 4.

19.1.1 Please provide the capacity of the pipeline solution proposed in Alternative 4, in both mmscfd and TJ/d units.

19.1.2 To the extent it is feasible, for each year in the forecast period (2021-2039), please provide the forecasted inlet pressures on a peak day at each major gate station within the ITS if the pipeline proposed in Alternative 4 were to be installed.

20.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1-2, Section 4.4.2.1, p. 45
Alternative 4 Discussion and Analysis

On page 45 of the Updated Application, FEI states:

> Alternative 4 would meet one of the objectives for this project: to increase the capacity of ITS. However, the length and diameter of this pipeline would trigger an environmental assessment (EA). The anticipated timeline for completion of an EA is three years.

20.1 Please describe the regulatory process and associated time frame for completion of each stage of an EA, from early consultation to project approval, and compare this to the regulatory process for the same project if the pipeline would not trigger an EA.

20.2 Please explain how FEI determined that the anticipated timeline for completion of an EA is three years.

20.2.1 Please compare FEI's anticipated timeline for completion of an EA with any legislated timelines within the Environmental Assessment Act or with any timelines proposed by the Environmental Assessment Office for the completion of an EA.

21.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1-2, Section 4.4.2.2, p.45
Alternative 5

On page 45 of the Updated Application, FEI states:

> Alternative 5 would meet the capacity objective for this project. However, preliminary research indicates that this alternative would be significantly too complex to design and construct prior to the winter of 2023/2024. An estimated minimum of five years is required to design and execute construction of such a facility following CPCN approval, pushing the completion date to 2027, or likely later.

21.1 Please describe the design and construction process and associated time frame for completion of each stage of Alternative 5, from early consultation to project commissioning.

21.2 Please explain whether FEI had considered any additional benefits associated with on-system LNG storage that may be possible for Alternative 5.

21.2.1 If not, please explain why not.

21.2.2 If yes, please describe any studies FEI conducted and provide the results of these assessments.

22.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1-2, Section 4.1, p. 32; Section 4.6.1, p. 49
Asset Management Capability Alternative Evaluation

On page 32 of the Updated Application, FEI states that the OCU Project has the following project objectives:

1. Increase the delivery capacity of the ITS to meet peak demand requirements and to maintain safe and reliable gas service to FEI customers in the central and north Okanagan regions; and
2. Ensure all construction related activities are completed in time for the winter of 2023/2024 to avoid service interruptions to customers.

On page 49, FEI provides Table 4-5 which shows Asset Management Capability Alternative Evaluation criterion and associated weighting.

Table 4-5: Asset Management Capability Alternative Evaluation

Criterion	Weighting	Alternative 1: ITS Upgrades Score	Alternative 2: Modified ITS Upgrades Score	Alternative 3: OLI PEN 406 Extension Score
System Capacity Increase	50%	5	5	5
Operational Flexibility	50%	2	3	4
Weighted Total:*	**100%**	**3.5**	**4.0**	**4.5**

3.

22.1 Please provide further details on FEI's OCU Project objective of increasing the delivery capacity of the ITS to meet peak demand requirements. For example, is the objective of the OCU Project to meet peak demand requirements in the winter of 2023/2024, winter of 2029/2030 or over the entire 20 year forecast period?

22.2 Please explain how FEI defines and measures "operational flexibility" in its Alternative evaluation.

22.3 Please discuss whether FEI considered including resiliency of the ITS as a criterion in its evaluation of alternatives.

22.3.1 If not, why not?

22.4 Please explain in detail FEI's rationale for the System Capacity Increase weighting of 50 percent, given that the primary objective of the OCU Project is to meet peak demand requirements.

22.5 Please discuss how the Asset Management Capability Alternative Evaluation criterion and associated weighting were determined.

22.6 Please discuss whether FEI applies the criterion and associated weighting shown in the preamble to its other capacity upgrade projects.

22.6.1 If not, please provide the Asset Management Capability Alternative Evaluation criterion and associated weighting FEI used in other capacity upgrade projects.

23.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1-2, Section 4.6.2.2, p. 53
Alternative 1 & 2 – VER PEN 323 retesting

On page 53 of the Updated Application, FEI states:

> Testing this pipe to a significantly higher level of stress than in 1957 leads to uncertainty about FEI's ability to successfully carry out the requalification tests. This presents a significant scheduling risk to the implementation of Alternative 1 or Alternative 2. Retesting promotes opening of existing cracks that are near failure so that they fail during the test and can be removed from the system. However, to complicate matters, it may also promote growth of small cracks that would have otherwise been acceptable, resulting in a new set of critical cracks left in the system after completion of the repairs. These new critical cracks may fail during the subsequent attempt at a successful test, resulting in a cycle of leak detection, repair and testing.

23.1 Please confirm whether FEI is able to conduct inline inspections on the VER PEN 323 pipeline.

23.1.1 If confirmed, please discuss the overall integrity of the VER PEN 323 pipeline based on the inline inspection results.

23.2 Please discuss FEI's assessment of the likelihood that the VER PEN 323 pipeline has "existing cracks that are near failure so that they fail during the test."

D. PROJECT DESCRIPTION

24.0 Reference: PROJECT DESCRIPTION
Exhibit B-1-2, Section 5.6.1, p. 78
Project delivery method

On page 78 of the Updated Application, FEI states:

> Given the scale and scope of the Project, FEI will use a project delivery method that utilizes separate contracts for engineering design, construction management and

inspection, and construction. The engineering design will be completed using a services contract for the complete design and development of bid packages. These bid packages will then be used to seek competitive pricing from contractors for the construction of the works.

24.1 Please discuss whether FEI has used the selected project delivery method for other projects of this scale and scope.

24.1.1 If no, please explain the rationale for the selection of the OCU Project delivery method.

24.1.2 Please discuss the pros and cons of the selected delivery method with respect to the allocation of risks related to cost escalation and schedule between FEI and its consultants or contractors.

25.0 Reference: PROJECT DESCRIPTION
Exhibit B-1-2, Section 5.4.2.8, p.72
Water Crossings

On page 72 of the Updated Application, FEI states:

> All pipeline crossings within the Project will be constructed using open cut methods with the exception of Penticton Creek. In general, the types of crossings identified along the proposed OLI PEN 406 pipeline route include:
>
> - Road Crossings;
> - Water Crossings; and
> - Pipeline and Utility Crossings.

25.1 Please identify all Water Crossings along the proposed OLI PEN pipeline route.

25.2 Please describe the construction methods FEI considered for each Water Crossing along the OLI PEN pipeline route and explain the primary reason(s) for choosing the proposed crossing method.

26.0 Reference: PROJECT DESCRIPTION
Exhibit B-1-2, Section 5.6.5, p.79; Section 5.10.4.4, p.90
Penticton Creek Horizontal Directional Drill (HDD) Installation

On page 79 of the Updated Application, FEI states:

> The main objective of the early works construction phase is to complete the HDD [horizontal directional drill] work. While the feasibility study concluded that HDD is a feasible option to cross Penticton Creek, there is still a risk that the HDD installation could be unsuccessful. FEI plans to address the risk as soon as possible in the Project to allow adequate time to implement the contingency plan of using an open trenching method across the drainage within the mainline contractor's scope of work.

On page 90, FEI explains:

> There is a high risk to the Project should the HDD fail, as the contingency plan consists of attempting a subsequent drill, and failing that the plan is to open trench across a very steep ravine. FEI and SMCI have identified an open trench route across Penticton Creek and this option is currently under evaluation. FEI will proceed with the design and

permitting of both the HDD and the open trench options to minimize delays should the HDD prove not feasible. Table 5-12 outlines the range of possible outcomes stemming from an unsuccessful HDD across Penticton Creek.

26.1 Please provide details of any construction challenges with the proposed Penticton Creek HDD installation and explain how these challenges factored into FEI's decision to complete the HDD as part of its early works construction phase.

26.2 Please discuss any potential environmental and public impacts associated with an HDD failure.

26.3 Please describe how the drill hole would be abandoned if HDD installation is unsuccessful and quantify any associated abandonment costs.

26.4 Please discuss any changes to the pipeline alignment crossing Penticton Creek should the HDD fail.

27.0 Reference: PROJECT DESCRIPTION
Exhibit B-1-2, p. 82
Kettle Valley Rail Trail

On page 82 of the Updated Application, FEI states:

> The Kettle Valley Rail Trail (KVR) is a national historical site located in Naramata and runs in parallel with some sections of the OCU Project route. The KVR is a popular among cyclists who want to bike from Naramata to Kelowna. As such, FEI has recognized the importance of this historical site in its Project planning.

27.1 Please provide a summary of any permits or land access agreements which will be required for any segments of the OLI PEN 406 proposed pipeline that cross or run parallel to the KVR.

27.1.1 Please provide an update on the status of these permits or land access agreements.

27.1.2 Please discuss the risk of delay to the Project Schedule due to permitting regarding the KVR.

28.0 Reference: PROJECT DESCRIPTION
Exhibit B-1-2, Section 5.9.6, p.85
Other Pending or Anticipated Application/Conditions

On page 85 of the Updated Application, FEI states that it "expects the Project will not require an Environmental Assessment Certificate under the BC Environmental Assessment Act."

28.1 Please explain why FEI expects the OCU Project will not require an Environmental Assessment Certificate.

28.2 Please discuss the potential impact to OCU Project schedule if an Environmental Assessment Certificate is required.

29.0 Reference: PROJECT DESCRIPTION
Exhibit B-1-2, Section 5.10.4.4, p. 90
Market risk

On page 90 of the Updated Application, FEI states, "FEI identified that there is a market risk to the Project due to factors such as contractor capacity, the availability of qualified pipeline contractors in 2022 and 2023 and market risk where bids are uncompetitive."

29.1 Please elaborate on the information or experience FEI relied upon in identifying this market risk.

29.1.1 Please explain whether FEI has re-evaluated the market risk since its initial risk analysis. If yes, please discuss any changes to market risk. If not, why not.

29.2 Please explain what impact the identified market risks may have on the OCU Project schedule.

29.2.1 Please discuss whether any risks to the OCU Project schedule are accounted for in the assessment of the Management Reserve amount. If so, how?

30.0 Reference: PROJECT DESCRIPTION
Exhibit B-1-2, Section 5.4.4, p. 74
Pipeline Deactivation

On page 74 of the Updated Application, FEI states:

> A 1,200 m section of the existing OLI PEN 406 will be deactivated between the Ellis Creek tie-in point and the existing Ellis Creek Pressure Control Station.
>
> This will include removing a section of pipe at the tie-in location, welding a cap onto the deactivated section, installing a blind at the inlet to the Ellis Creek Pressure Control Station, purging the line and maintaining a low pressure blanket with nitrogen.
>
> Deactivation of this section of OLI PEN 406 was chosen over abandonment to minimize ecological and socio-economic disturbance to the area and allow re-establishment of gas supply to the Ellis Creek Pressure Control Station if required in the future to support forecast peak demand beyond the 20 year planning window. Deactivation will follow all regulatory and code requirements.

30.1 Please confirm, or explain otherwise, that, after the deactivation of this section of OLI PEN 406, this portion of the assets will also be removed from FEI's ratebase.

30.2 Please provide the amount of depreciation remaining to be recorded on this section of pipeline and the remaining useful life of the asset.

30.3 Please provide the costs of deactivation and on-going maintenance of OLI PEN 406.Please discuss the ecological and socio-economic disturbance to the area that would occur if the pipeline was abandoned.

30.4 Please clarify whether FEI undertook an assessment of the costs associated with deactivating this section of pipeline compared to abandonment.

30.4.1 If yes, please provide the financial assessment.

30.4.2 If not, please explain why no assessment was undertaken.

30.5 Please discuss under what circumstances that FEI would reactivate this section of the OLI PEN 406 pipeline.

30.6 Please explain the factors that could cause FEI to consider abandonment of the deactivated pipeline in future.

31.0 Reference: PROJECT DESCRIPTION
Exhibit B-1-2, Section 5.10.4.3, pp. 90–92
Contingency Estimate

On page 91 of the Updated Application, FEI states, "Contingency is normally funded at the P50

confidence level. Based on FEI's risk tolerance, the Project contingency will be $25.1 million (13 percent) at the P50 confidence level."

On page 90 of the Updated Application, FEI provides the following table showing the results of the Monte Carlo analysis:

Figure 5-6: Quantitative Risk Analysis - Monte Carlo Simulation

Base Estimate:	$187,960	Currency:	$CAN
Probability of Underrun	Indicated Funding Amount	Contingency	
		Costs (thousands)	Percent of Base Est.
5%	171,500	(16,500)	-9%
10%	179,500	(8,500)	-5%
15%	185,200	(2,800)	-1%
20%	190,100	2,100	1%
25%	194,800	6,800	4%
30%	198,700	10,700	6%
35%	202,400	14,400	8%
40%	206,100	18,100	10%
45%	209,700	21,700	12%
50%	213,100	25,100	13%
55%	217,000	29,000	15%
60%	220,400	32,400	17%
65%	224,400	36,400	19%
70%	228,400	40,400	21%
75%	233,200	45,200	24%
80%	238,600	50,600	27%
85%	244,700	56,700	30%
90%	252,900	64,900	35%
95%	265,000	77,000	41%

31.1 Please discuss how FEI determined the P50 confidence level to be the appropriate contingency for the OCU Project.

31.2 Please explain whether FEI considered any alternative confidence level, other than the P50 confidence level.

31.2.1 If yes, please discuss the alternative(s) considered by FEI, including the advantages and disadvantages of each and please explain why each alternative was rejected.

31.2.2 If not, please explain why not.

On page 91 of the Updated Application, FEI states:

> The probability of both management reserve risks occurring is low, therefore, FEI will hold one reserve fund to cover the impact should either of the risks occur. Given there are two risks covered by a single management reserve, FEI has chosen to fund the P70 value of the larger risk or $23.6 million.

On page 92 of the Updated Application, FEI states, "FEI will fund escalation at $11.6 million which corresponds to the P50 level of confidence."

31.3 Please discuss FEI's rationale for selecting the P50 confidence level to estimate escalation. Please discuss why FEI considers the P50 level to be appropriate to estimate escalation for the OCU Project.

31.4 Please explain whether FEI considered any alternative confidence levels to estimate escalation, other than the P50 confidence level.

31.4.1 If yes, please discuss the alternative(s) considered by FEI, including the advantages and disadvantages of each and please explain why each alternative was rejected.

31.4.2 If not, please explain why not.

31.5 Please provide the total OCU Project cost estimate if the P70 confidence level was used to estimate contingency and escalation, as well as the management reserve.

E. PROJECT COST ESTIMATE

32.0 Reference: PROJECT COST ESTIMATE
Exhibit B-1-2, Section 6.2, p. 83
Summary of Project Costs

On page 83 of the Updated Application, FEI provides the following table showing a summary of the total cost estimate of the OCU Project:

Table 6-1: Summary of Forecast Capital and Deferred Costs ($millions)

Line	Item	Amount	Reference
1	Construction Cost Estimate (Contractor)	$153.4	Appendix A-3 [30]
2	Construction Cost Estimate (FEI)	$34.5	Appendix B
3	*Owner Costs ($25.1M)*		Appendix B
4	*Inspection Services ($8.6M)*		Appendix B
5	*AC Mitigation, Cathodic Protection, Deactivation ($0.7M)*		Appendix B
6	Sub-Total Construction Base Cost Estimate (2020$)	$187.9	Section 5.10.3
7	Project Development Costs (Capitalized Estimate)	$6.2	Section 6.2
8	Contingency	$25.1	Section 5.10.4.5
9	Sub-Total Cost Estimate (2020$)	$219.2	
10	Management Reserve	$23.6	Section 5.10.4.5
11	Cost Escalation Estimate	$11.6	Section 5.10.4.6
12	Sub-Total Construction Cost Estimate (As-spent)	$254.4	
13	AFUDC	$16.8	
14	Grand Total Project Cost Estimate (As-spent)	$271.3	

32.1 Please discuss the accuracy range of the OCU Project cost estimate.

32.2 Please explain how FEI developed FEI's portion of the construction base cost estimate of $34.5 million, including the sources of information used to develop the cost estimate.

Further, on page 83 of the Updated Application Update, FEI states, "Project development costs include all of the costs associated with developing an AACE Class 3 cost estimate in accordance to AACE International Recommended Practices Nos. 18R-97 and 97R-18 as required by the CPCN Guidelines and are estimated to be $6.2 million (2020$)."

32.3 Please provide a detailed breakdown and explanation of the Project Development costs of $6.2 million by line item and year incurred.

33.0 Reference: PROJECT COST ESTIMATE
Exhibit B-1-2, Section 6.3.2, p. 96, footnote 35, p. 96
Application and Preliminary Stage Development Costs

On page 96 of the Updated Application, FEI states:

FEI is seeking BCUC approval under Sections 59-61 of the UCA for deferral treatment of the Application and Preliminary Stage Development costs. The Application costs are based on a written hearing process and include expenses for legal review, consultant costs, BCUC costs and BCUC-approved intervener costs. The Preliminary Stage Development costs are related to expenses incurred for engaging third-party consultants for feasibility evaluation, preliminary development and assessment of the potential design and alternatives as required to complete this Application. … FEI proposes to transfer the balance in the deferral account to rate base on January 1, 2022 and commence amortization over a three-year period.

Table 6-3 below shows the December 31, 2020 net-of-tax balance for the Application costs and the Preliminary Stage Development costs is forecast to be a credit of $795 thousand.

Table 6-3: Forecast Application Costs and Preliminary Stage Development Costs ($000s)

Particulars	Application Costs	Preliminary Stage Development Costs	Total
Pre-tax Costs	$400	$902	$1,302
Income Tax Recovery:			
Costs held in deferral account[34]	$(108)	$(244)	$(352)
Capitalized Costs[35]		$(1,682)	$(1,682)
Total Tax Offset	$(108)	$(1,926)	$(2,034)
Financing, WACC after tax	$10	$(73)	$(63)
Total	$302	$(1,097)	$(795)

In footnote 35 to Table 6-3 on page 96 of the Updated Application, FEI states, "Income tax recovery on the development costs that were capitalized but are deductible for tax purposes. The amount shown is equal to the costs capitalized of $6.2 million times the income tax rate of 27%."

33.1 Please provide a breakdown of the Application costs of $400,000 and the Preliminary Stage Development costs of $902,000 by each activity (e.g. consultant costs, legal costs etc.) for each year incurred.

33.2 Please clarify whether the income tax recovery of the capitalized costs relates to the Capital Cost Allowance (CCA) deduction of the capitalized Project Development Costs.

33.3 Please explain why FEI proposes to include the income tax recovery of the capitalized costs of $6.2 million in the deferral account.

33.4 Please provide FEI's rationale for proposing to amortize the deferral account over a three-year period.

33.5 Please explain whether FEI considered any alternative amortization periods, other than three years.

33.5.1 If yes, please discuss the alternative amortization period(s) considered by FEI, including the advantages and disadvantages of each and please explain why each alternative was rejected.

33.5.2 If not, please explain why not.

34.0 Reference: PROJECT COST ESTIMATE
Exhibit B-1-2, Section 6.4, pp. 96–97
Rate Impact

On page 97 of the Updated Application, FEI provides the following table showing the annual delivery rate impact compared to the 2021 applied for non-bypass revenue requirement and the incremental annual delivery rate impact in percentage in 2024:

Table 6-4: Summary of Rate Impact for the Project

Particulars	Impact
Incremental Revenue Requirement ($000s)	$19,448
% Increase to 2021 Applied for Revenue Requirement, Non-Bypass (August, 2020)[37]	2.21%
Delivery Rate Impact (2024) $ / GJ	$0.100
Levelized Rate Impact $ / GJ (**2019 – 2088**)	$0.073

Further, on page 97 of the Updated Application, FEI states that "the Project will result in an estimated delivery rate impact of 2.21 percent in 2024 when all construction is complete and after all assets are placed in service in 2023."

34.1 Please discuss the assumptions used to calculate the rate impact, including the assumptions associated with the load forecast including growth in customer accounts and rationale for each assumption.

34.2 Please clarify whether FEI considered any potential increase in volumes sold, as a result of the OCU Project, when determining the rate impact provided in Table 6-4.

34.2.1 If yes, to what extent to does the increased revenue offset the rate impact of the project?

34.2.2 If no increase in volumes is reflected in the rate impact, please explain why not.

F. ENVIRONMENT AND ARCHEOLOGY

35.0 Reference: ENVIRONMENT AND ARCHEOLOGY
Exhibit B-1-2, Section 7.1, p. 98
First Nations engagement and consultation

FEI states on page 98 of the Updated Application that draft versions of both the Environmental Overview Assessment (EOA) and Archaeological Overview Assessment (AOA) were provided to Indigenous communities who requested drafts for their review and comment. At the time of writing, FEI had not received any comments; however, any comments that are received will be incorporated during the detailed engineering phase of the Project.

35.1 Please provide an update on engagement with Indigenous communities with regards to the EOA and the AOA, including anticipated timelines for future engagement.

36.0 Reference: ENVIRONMENT AND ARCHEOLOGY
Exhibit B-1-2, Appendix F, Table 6.1, p. 42
Overview of Potential Effects and Risks

Table 6.1 of Appendix F identifies several follow-up activities to mitigate project risks related to Land

Use and the use of public roadways including engagement with the Ministry of Transportation and Infrastructure.

36.1 Please describe the engagement that has occurred with the Ministry of Transportation and Infrastructure to date.

Table 6.1 identifies several Moderate to High project risks related to Surface Water Quality and Quantity, noting "construction timing (i.e., avoid periods of heavy precipitation" as a possible follow up activity.

36.2 Please discuss any adjustments to the construction schedule to mitigate these project risks.

Table 6.1 notes high project risks associated with Fish and Fish Habitat, and follow-up activities include:

- Conduct instream works within reduced risk work window.
- To the extent practicable, undertake construction within the least-risk timing windows for applicable species.

36.3 Please discuss how FEI has adjusted its plan for instream works to align with the reduced risk work window.

37.0 Reference: ENVIRONMENT AND ARCHEOLOGY
Exhibit B-1-2, Section 7.2.1.2, p. 100; Appendix F, Table 6.2, p. 44
Contaminated Sites and Environmental Permitting

FEI states on page 100 of the Updated Application:

> Locations where there is a medium to high potential for encountering soil or groundwater contamination within the Project footprint may impact construction cost, and timelines. These areas are defined as APECs [area of potential environmental concern]. One high risk and one low risk APEC were identified in the contaminated sites study area. … The high risk APEC is associated with an active landfill that includes operations dating back to 1972.

Hemmera recommends on page 44 of Appendix F that planning and construction be coordinated with the Campbell Mountain Landfill to comply with conditions of their landfill operating permit.

37.1 Please discuss what steps FEI has taken to engage with the operators of the Campbell Mountain Landfill to date.

37.2 Please discuss the potential impact of this high risk APEC (VP1) on construction cost and timelines.

38.0 Reference: ENVIRONMENT AND ARCHEOLOGY
Exhibit B-1, Section 7.2.3, p. 103; Appendix F, Table 6.3, p. 45
Permitting

FEI states on page 103 of the Updated Application that all required environmental permits and approvals for the Project will be identified and applied for during the detailed engineering phase of the Project.

A list of anticipated permits and approvals along with the estimated timeframe for issuance is provided in Table 6.3 of Appendix F.

38.1 Please confirm if FEI has submitted a request for project review to Fisheries and Oceans Canada yet, including the date of submission if applicable. If not, please indicate when FEI intends to submit the request.

38.2 Please confirm if FEI has submitted an application for the Waste Discharge Authorisation to the BC Oil and Gas Commission, including the date of submission if applicable. If not, please indicate when FEI intends to submit the application.

38.3 Please confirm if FEI has received formal confirmation of the exemption from the Regional District of Okanagan-Similkameen for:

- the Environmentally Sensitive Area Development Permit; and
- the Watercourse Development permit.

G. CONSULTATION AND ENGAGEMENT

39.0 Reference: CONSULTATION AND ENGAGEMENT
Exhibit B-1-2, Section 8.2.5.3 pp. 113, 114
Consultation with Landowners

FEI notes on page 113 of the Updated Application that as a result of consultation with landowners, FEI was able to make adjustments to the route which ultimately decreased the number of directly impacted landowners from 57 to 38. Of the 57 original landowners to whom FEI sent the initial notification letter, five of those landowners responded. FEI subsequently followed up with landowners that did not respond to the initial notification letter.

FEI states on page 114 of the Updated Application that it began negotiations to acquire the necessary land rights in August and September 2020. The landowners were given a document package that included an independent real estate market appraisal of their property based on the latest IOP, the standard form of Agreement to Grant Statutory Right of Way and Temporary Work Space.....FEI is committed to negotiating fair agreements with landowners along the route and will continue to engage with landowners post CPCN filing to acquire the requisite land rights. Should FEI be unable to reach agreement with landowners, FEI will follow the internal escalation procedure outlined in the Land Acquisition Plan, including pursuing its rights to expropriate land in accordance with applicable legislation. As at the filing date FEI has come to agreement with 13 of 38 private landowners. [*Emphasis added*]

39.1 Of the 38 directly impacted landowners, please confirm if all of them have now responded to FEIs notification. If not confirmed, please clarify how many have not responded, and outline the steps FEI is taking to ensure notifications have been received.

39.2 Please provide an update with regard to the signing of agreements with the 38 private landowners.

39.2.1 If applicable, please discuss the possible impact of an expropriation process on the project schedule.

39.3 Please discuss what steps FEI takes to ensure the independence of the real estate company.

39.4 Please clarify where the budget for all payments associated with property acquisition (including both statutory rights of way and temporary work space) appears in the project cost estimate. Responses can be provided confidentially if necessary.

H. PROVINCIAL GOVERNMENT ENERGY OBJECTIVES

40.0 Reference: PROVINCIAL GOVERNMENT ENERGY OBJECTIVES
Exhibit B-1-2, Section 9.2, p. 125
Policy Considerations

FEI states on page 125 of the Updated Application that the OCU Project will support the British Columbia energy objective found in section 2(k) of the CEA "to encourage economic development and the creation and retention of jobs."

Section 2 of BC's Clean Energy Act outlines BC's energy objectives, including:

…
(b)to take demand-side measures and to conserve energy,…
…
(g)to reduce BC greenhouse gas emissions
…
(iii)by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,
(iv)by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and
(v)by such other amounts as determined under the *Climate Change Accountability Act*;
(h)to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;
(i)to encourage communities to reduce greenhouse gas emissions and use energy efficiently;
(j)to reduce waste by encouraging the use of waste heat, biogas and biomass;
(k)to encourage economic development and the creation and retention of jobs;…"

40.1 Please discuss the extent to which project is consistent with and will advance the BC government's energy objectives as set out above.