Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St
Vancouver BC, Canada
V6E 4A4

February 11, 2021

Marija Tresoglavic

Acting Commission Secretary

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC, V6Z 2N3

Commission.Secretary@bcuc.com

Re: FortisBC Energy Inc. – Application for a Certificate of Public Convenience and Necessity for the Okanagan Capacity Upgrade Project – Project Number 1599152 – Residential Consumer Intervenor Group (via its agent Midgard Consulting Incorporated) Information Request (IR) No. 1 to FortisBC Energy Inc.

Dear Ms Tresoglavic,

In accordance with the Regulatory Timetable set by the British Columbia Utilities Commission (BCUC) Order G-335-20, please find enclosed the Residential Consumer Intervenor Group (RCIG) IR No. 1 to FortisBC Energy Inc. on the above noted Application.

If further information is required, please contact the undersigned.

Sincerely,

Original signed by:

Sam Mason
Consultant on behalf of the Residential Consumer Intervenor Group

REQUESTOR NAME: **Residential Consumer Intervener Group (RCIG)**

INFORMATION REQUEST ROUND NUMBER: **1**

TO: **FortisBC Energy Inc. (FEI)**

DATE: **February 11, 2021**

APPLICATION NAME: **Certificate of Public Convenience and Necessity (CPCN) Application for Okanagan Capacity Upgrade (OCU)**

Table of Contents **Page Number**

A. Project Need and Justification

1. Reference: Exhibit B-1-2 Section 3 p.18, 22 (pdf 30, 34)

The footnote states "System design temperature is determined for each region by calculating the coldest day which is statistically likely to occur once in a 20-year period. FEI's system is designed to meet the peak demand which would occur during this extreme cold weather event. The statistical 20-year low is calculated using information from local weather stations, and is updated as weather trends change."

1.1 When was the last time the 20-year low used to establish the peak demand in the Central Okanagan was updated?

1.2 Is the 20-year low the same as the 1-in-20 year Design Degree Days referenced on page 22?

2. Reference: Exhibit B-1-2 Section 3 p.20 (pdf 32)

"The peak day demand forecast methodology that FEI used to assess the need for the OCU Project is consistent with the methodology FEI has used in previous CPCN applications and long-term resource plans filed with the BCUC."

2.1 If the peak day demand forecast methodology is not exactly as previously used, identify any differences in the methodology and explain why these changes were made.

3. Reference: Exhibit B-1-2 Section 3 p.22,23

"FEI then prepares a 20-year account forecast for all residential and commercial rate schedules at the municipal, LHA [Local Health Authority], and FEI region level. The forecast uses the 20-year household formation (HHF) forecast prepared by BC Stats at the LHA level. The HHF forecast is the forecast of household formations in each LHA. The HHF forecast is provided in terms of year over-year growth rates for each LHA. FEI applies the relevant LHA growth rates to the customer counts in each municipality to develop a 20 year customer forecast for each municipality."

3.1 Confirm whether there is an implicit assumption in the residential customer forecast that the proportion of new households taking gas service matches the current proportion of households taking gas service. If confirmed, justify this assumption. If not confirmed, explain how FEI determines the proportion of new households that take gas service for the purposes of the residential customer forecast at the Local Health Authority level (that is, prior to trueing up with the rate-setting forecast).

3.2 Confirm whether, in the first step of FEI's commercial customer forecasting process, FEI applies the household formation growth rate to the numbers of commercial accounts. If confirmed, explain and provide support for the relationship between household formation rates and commercial customer growth rates. If not confirmed, clarify the process.

3.3 Has FEI tried to include other explanatory variables in its forecast of commercial customer growth rates, such as forecasts of GDP growth, as opposed to continuing the recent trend? Explain any FEI analysis in this area and why an approach that includes other explanatory variables is not used.

4. Reference: Exhibit B-1-2 Section 3 p.19,20,37 (pdf 31,32,49) Figures 3-7, 3-8, and 4-1

4.1 Confirm whether the ITS forecasted peak demand reflects the impacts of demand-side management initiatives as well as energy efficiency improvements mandated by codes and standards. If not confirmed, provide updated Figures 3-7, 3-8, and 4-1 reflecting the ITS forecasted peak demand <u>net</u> of expected DSM and energy efficiency improvements mandated by codes and standards.

4.2 How does the ITS peak demand forecast incorporate trends of decarbonization of energy systems?

5. Reference: Exhibit B-1-2 Section 3 p.21,22 (pdf 33,34)

"…the customer billing information and temperature information from the local weather zone index weather stations is reduced to a daily average demand (for the customer in each billing period) and an average mean daily temperature for the corresponding billing period… A linear regression for each customer is performed on this data and the base load and slope (standard meters^3/ day/degree Celsius) is calculated."

5.1 Provide the weather sensitivity (m^3/day/°C) by rate class (or other grouping as used by FEI in the calculation of weather sensitivity) for each region (Thompson, North and Central Okanagan, and South Okanagan) and as calculated for each of the past five years. A table such as this may be used:

	Thompson		North and Central Okanagan		South Okanagan	
	Residential	Commercial	Residential	Commercial	Residential	Commercial
2015/16						
2016/17						
2017/18						
2018/19						
2019/20						

5.2 Explain any significant year-over-year variation in the weather sensitivity.

6. Reference: Exhibit B-1-2 Section 3 p.24,34 (pdf 36,46)

At page 24: "Under peak demand conditions, gas flows into the central Okanagan from the north from the Westcoast system at Savona where FEI assumes[12] a minimum delivery pressure of 4135 kPa (600 psig) and from the south from gas supplied originally from TC Energy at Yahk where FEI assumes a minimum delivery pressure of 4480 kPa (650 psig)."

At page 34: "FEI has established a working agreement with Enbridge to maintain a minimum delivery pressure into Savona of 4480 kPag (650 psig) on peak days."

6.1 Clarify the minimum delivery pressure on peak days into Savona from the Westcoast/Enbridge system.

6.2 Confirm whether the Current ITS Capacity shown elsewhere in the application, including in Figures 3-7 and 3-8, reflects a delivery pressure of 600 psi or 650 psi at Savona.

6.3 Does "working agreement" mean a firm contractual obligation on Enbridge to deliver gas at 650 psi on peak days, or is it on a "best efforts"

basis?

6.4 When does the "working agreement" terminate?

6.5 Has FEI had discussions with Enbridge or TC Energy about contractually increasing delivery pressures to Savona or Yahk for an extended timeframe? Summarize the results of those discussions.

6.6 How do increased delivery pressures at Savona or Yahk or both affect the ITS capacity? Explain whether increased delivery pressures affect the need date for the new ITS capacity from the OCU.

6.7 What are the minimum tariff pressures that Westcoast and TC Energy are each obligated to deliver at Savona and Yahk, respectively?

6.8 Until what year would the proposed OCU result in sufficient ITS capacity if either Westcoast or TC Energy delivered gas at the minimum tariff pressures to Savona or Yahk, respectively? For how many years would the OCU result in sufficient ITS capacity if both Westcoast and TC Energy delivered at the minimum tariff pressures? What would the next ITS capacity upgrade or upgrades be to address FEI receiving gas at minimum tariff pressures?

7. Reference: Exhibit B-1-2 Section 3 p.24 (pdf 36)

"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."

7.1 Does FEI have a minimum distribution pressure criterion (or criteria) at the system extremities? Provide this minimum pressure criterion and explain why FEI established this as the criterion.

7.2 Based on the minimum pressure criterion at the distribution system extremities, for each of the Lumby, Lavington, and West Kelowna distribution systems, provide the years when this criterion is no longer met, with and without the proposed mitigation measures in Section 4.2.

7.3 Does FEI have a minimum intermediate pressure criterion at the inlet to IP regulating stations? Provide this minimum pressure criterion and explain why FEI established this as the criterion.

7.4 Based on the minimum pressure criterion to the inlet of IP regulating stations, for each of Lumby, Lavington, and West Kelowna, provide the year when this criterion is no longer met, with and without the proposed mitigation measures in Section 4.2.

7.5 Confirm whether bypass of IP regulating stations in Lumby, Lavington, and West Kelowna is feasible to maintain sufficiently high outlet pressures into the distribution system. If not, explain why not.

7.6 Provide additional details of what happens with the operation of the IP and DP systems when the inlet pressures to the transmission pressure regulating stations (Kelowna #1, Polson) drop below 350 psi.

7.7 Provide FEI's gas planning criteria document or manual, which describes the pressure and velocity criteria used to identify when capacity upgrades are required.

7.8 Explain the processes, steps taken, and measured inputs used by FEI to verify the accuracy of its hydraulic system models.

8. Reference: Exhibit B-1-2 Section 3 pp.25,51 (pdf 37,63)

8.1 Provide a map of the VER PEN 323 line that shows the class locations along its length.

8.2 Explain whether any further class location changes on VER PEN 323 will result in further MOP reductions. Are any further class location changes anticipated within the 20-year forecast period?

8.3 If the MOP on VER PEN 323 line is reduced further, confirm whether further upgrades following the proposed OCU are required within the forecast period and explain what those upgrades would entail.

9. Reference: Exhibit B-1-2 Section 3 p.26 (pdf 38)

9.1 With the proposed compression increase on the Southern Crossing Pipeline in 2029-30, and assuming the proposed OCU proceeds, are there any other capacity projects expected anywhere on the ITS within the 20-year planning horizon? If so, what are they?

B. <u>Short-Term Mitigation Measures</u>

10. Reference: Exhibit B-1-2 Section 4 p.33 (pdf 45); 2017 Long Term Gas Resource Plan p.ES-8

"Each proposed Project alternative relies on the implementation of short-term mitigation measures to meet forecasted capacity shortfalls in the winters of 2021/2022 and 2022/2023. Following recent years of high growth in customer accounts, FEI's forecasts indicate that the capacity to meet peak demand would be exhausted in the winter of 2021-22 if FEI took no interim measures. This timeframe is prior to the projected completion of the OCU Project. As a result, FEI has examined a number of measures that could assist in managing the projected shortfall and provide some capacity margin without impacting customers served by the system."

10.1 If FEI was aware of the impending capacity shortfall in 2022 on the ITS in its 2017 Long-Term Gas Resource Plan, why is FEI bringing an

application for a Certificate of Public Convenience and Necessity now, and not one or more years ago, in order that short-term mitigation measures would not be required or that other alternatives would not be screened out due to lengthy construction schedules?

11. Reference: Exhibit B-1-2 Section 4 p.35 (pdf 47)

"To mitigate the forecast capacity shortfall, 1 to 2 large truckloads of CNG per hour (up to 4 – 6 truckloads per day) would be required during a peak demand event by the winter of 2022/2023"

"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." [emphasis added]

11.1 How many CNG trucks per hour and per day would be required to meet a peak demand event in the winter of 2029/30 if OCU does not proceed?

11.2 How many LNG trucks per hour and per day would be required to meet a peak demand event in the winter of 2022/23? How many LNG trucks per hour and per day would be required to meet a peak demand event in the winter of 2029/30 if OCU does not proceed?

11.3 Confirm whether LNG (or CNG) shipments would be required in years when design day weather is not experienced (or closely approached).

11.4 Explain whether CNG trucks could be filled on the peak day at the terminus of the Southern Crossing Pipeline in Oliver (which appears to have surplus capacity). Would this materially affect the capacity and pressure available to Kelowna #1 Gate Station or Polson Gate Station?

11.5 Explain and provide cost details (for example, the approximate capital cost of the required fleet and the approximate cost per journey excluding the commodity cost of the cargo) that show why the costs of trucked CNG or LNG would be less cost effective than the proposed project.

11.6 Explain why trucked CNG or LNG is not feasible to provide a medium-term solution to the identified capacity shortfalls that would defer the OCU project for five, ten, or more years.

12. Reference: Exhibit B-1-2 Section 3 p.26,32, (pdf 38,44)

At page 26: "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. … 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."

At page 32: "All Project alternatives rely on the implementation of short-term mitigation measures to address the possibility of a capacity shortfall during the winters of 2021/2022 and 2022/2023. … While these measures are adequate to provide some capacity margin in the winter of 2021/2022 and 2022/2023, they do not represent a viable long-term solution, and do not provide FEI with sufficient and reliable system capacity starting from the winter of 2023/2024."

12.1 Would the SCP compression upgrade be sufficient on its own to increase capacity of the ITS system, without the OCU Project? Please explain why or why not. If yes, for how many years would the compression upgrade be sufficient?

12.2 What is FEI's best estimate of the shortest timeframe in which the SCP compression upgrade project could be completed?

12.3 Does Section 4.2 represent a comprehensive list of all possible short-term mitigation measures that could increase ITS system capacity? If yes, please justify. If no, what others are available?

12.4 Did FEI analyze the possibility of advancing the timeframe of the SCP compression upgrade such that short-term mitigation measures could support the ITS system until the SCP compression upgrade is completed (thereby eliminating the need for the OCU Project)? If yes, please provide the conclusions of the analysis. If no, why not?

C. <u>Description and Evaluation of Alternatives</u>

13. Reference: Exhibit B-1-2 Section 4 p.52

"The requalification tests are to be performed in accordance with the requirements of CSA Z662:19. These requalification strength tests per the current requirements of chapter 8 of CSA Z662 require a minimum test pressure of 125 percent of the MOP but are limited to a maximum test pressure that results in stresses equivalent to 110 percent SMYS for pipe installed in areas of class location 1 or 2. Similarly, for pipe installed in areas of class location 3 or 4, CSA Z662:19 requires a minimum test pressure of 140 percent of the desired MOP, but are limited to a maximum test pressure that results in stresses equivalent to 110 percent SMYS. However, as the pipe installed in 1957 was subjected to requalification testing only up to 90 percent SMYS at the time of manufacture, FEI's subject matter experts have recommended a maximum test

pressure corresponding to pipe stresses of no more than 95 percent SMYS."

13.1 Provide the pipeline test pressures for the VER PEN 323 line that correspond to: 110% SMYS, 95% SMYS, and 90% SMYS.

13.2 What are the pipe grade (i.e. API 5LX42? 5LX46?) and wall thickness(es) of VER PEN 323?

14. Reference: Exhibit B-1-2 Section 4 pp.38-40 (pdf 50-52)

"In order to meet the pressure reinforcement required to avoid capacity shortfalls currently forecast for the winter of 2023/2024, this alternative proposes the replacement of fifteen segments of the existing VER PEN 323 pipeline with new higher strength 323 mm pipeline. The replacement segments would total almost 7.6 km in length, and include multiple road crossings. All replacement segments would be designed such that they would be able to operate at a MOP of 6,619 kPa."

14.1 Are there segments of the VER PEN 323 line that would not be replaced under Alternatives 1 or 2 that could experience a class location change in the future (due to residential, commercial, or industrial development)? Would this force FEI to reduce the MOP back down to 5171 kPa?

15. Reference: Exhibit B-1-2 Section 4 pp. 51-53 (pdf 63-65)

FEI raises the concern that a hydrostatic test could open cracks that weaken the pipe, but do not fail until a subsequent hydrostatic test. This results in a test-fail-repair-test repetition.

"Due to limitations on allowable elevation difference on a test section, thirty-three requalification tests would be required in addition to six tests for the replacement segments."

15.1 How many re-tests (e.g. test-fail-repair-test) would FEI consider before re-testing of that segment was abandoned and an alternative approach was implemented? For example, if the same test segment of pipe failed twice, would FEI continue to repair and re-test this segment or would it consider alternative approaches, such as pipe replacement? Would multiple failures cause FEI to reconsider hydrostatic testing of the remaining test segments?

15.2 Do the cost estimates for Alternatives 1 and 2 include the cost to repair any damage from failed hydrostatic testing as well as the cost of subsequent tests?

15.3 What is the approximate cost to repair one failed pipe joint and conduct an additional test on that segment?

15.4 How many other transmission pipelines has FEI subjected to in-service testing?

15.5 What has been FEI's experience with these in-service tests? Have there been failures and if so, did the test segment successfully pass the re-test? If the number of tests is large, refine the request by indicating the number of low frequency induction seam welded pipes that have been requalified after having been in service.

16. Reference: Exhibit B-1-2 Section 4 Tables 4-3, 4-4, 4-6 pp.47-56 (pdf 59-68)

FEI provides the Alternative Evaluation Scoring Definitions and Evaluation Criteria Weighting.

"Asset Management Capability: Criteria within this category measure the success of the alternative in achieving the technical goals of the project now and into the future. As this category assesses the efficacy of the solution in meeting the project objectives, FEI considers this category to be relatively more important, which is reflected in the weighting discussed below."

"System Capacity Increase: Ability of an alternative to increase capacity in the ITS such that supply can be maintained to the Okanagan region under peak demand conditions. Alternatives that provide the greatest capacity increase will score the highest. If two or more alternatives provide a similar capacity increase, the same score is assigned."

"Operational Flexibility: Ability of a project to provide FEI with greater operational flexibility to perform inspection and repair work on its system assets. Projects which extend the window during which FEI can complete such work on sections of the ITS will score the highest."

"Schedule Risk: Ability for an alternative to be completed on schedule, with few identified risks to achieve the scheduled in-service date. Alternatives which can be completed on time will score the highest. Other alternatives are scored lower."

"Financial Evaluation: FEI considered the long term rate impact to FEI's customers to compare the financial impact of the three feasible alternatives. This was completed by evaluating the present value of the incremental revenue requirement as well as the levelized delivery rate impact over the 70-year analysis period for each alternative based on the estimated capital cost and operating cost. For a fair comparison, future incremental sustainment capital and operating expenditures over the 70-year analysis period for each feasible alternative were included in the analysis."

16.1 Confirm whether the same scoring definitions and weightings in Tables 4-3 and 4-4 have been consistently used by FEI in prior pipeline projects. For example, have Ratepayer Impacts been weighted as 30% in prior projects? If not confirmed, explain why not and provide scoring definitions and weightings used in prior projects.

16.2 Considering that only Alternatives that meet the project objectives reach the scoring evaluation stage, why is the Asset Management

Capability category given the greatest weight?

16.3 Considering that only Alternatives that meet the project objectives reach the scoring evaluation stage, and one of those objectives is the ability to provide sufficient capacity for the 20-year forecast period, confirm whether any advantage that one Alternative has over another in the Asset Management Capability scoring category relates to additional capacity that is only expected to be needed beyond the 20-year forecast period.

16.4 Confirm whether the scoring for Operational Flexibility is solely related to FEI's ability to perform maintenance on the OLI PEN 406 and VER PEN 323 lines and stations, and specifically to the time available to perform this maintenance. If not confirmed, clarify and provide additional details of the factors that affect the scoring for Operational Flexibility.

16.5 Provide the estimated annual cost savings that are expected as a result of the additional Operational Flexibility that is expected with Alternative 3 compared with Alternatives 1 and 2.

16.6 Operational Flexibility has a scoring weight of 20% of the total scoring evaluation (50% of 40%). Given the magnitude of the cost savings (if any) provided by additional operational flexibility, justify why this criterion is given only marginally less weight than Financial (Rate Impact) which has a scoring weight of 30%.

16.7 How would approval and construction of Alternative 1 affect the next capacity upgrade for the ITS? That is, what would change in terms of the next capacity additions (e.g. pipeline expansion, compression addition) compared with the construction of Alternative 3?

16.8 Explain whether the three alternatives would have achieved higher, and possibly the same, scores for Schedule Risk if FEI had brought this CPCN application earlier such that there would have been sufficient time to complete all activities without substantial risk to the schedule.

16.9 Is there a risk that hydrotesting of the VER PEN 323 line would not ultimately be successful? How should such a possibility be reflected in the evaluation scoring?

16.10 Provide the justification for the use of a 70-year period for the financial evaluation.

16.11 Over what period (for example in a discounted cash flow analysis) does FEI evaluate the economic feasibility of system expansion to serve new customers?

16.12 Recalculate Table 4-7 (PV of Annual Revenue Requirement, Levelized Rate Impact) using an evaluation period that matches the one used to evaluate economic feasibility for system expansion. Does the different evaluation period change the scoring?

17. Reference: Exhibit B-1-2 Sections 3,4 Figures 3-6, 3-7, 3-8, 4-1, pp.18-20,37, (pdf 30-32, 49)

17.1 Provide tables with the data points used to create Figures 3-6, 3-7, 3-8, 4-1, and the response to BCUC Information Request 1.13.

D. <u>Project Description</u>

18. Exhibit B-1-2 Section 5 p.62 (pdf 74)

"Each of the evaluation criterion was given a weighted score as outlined in Table 5-2, in order to quantify the relative merits of each option."

18.1 Confirm whether the route selection evaluation criteria and weighting are consistent with other FEI pipeline projects of similar scope or magnitude as OCU.

18.1.1. If not confirmed, explain how and why the criteria or weighting have changed.

18.1.2. If not confirmed, provide the weighting factors used in recent FEI pipeline projects of similar scope or magnitude as OCU.

18.1.3. If there are no pipeline projects with similar scope and magnitude as OCU, then provide the weighting factors used in pipeline projects with a construction value greater than $10 million undertaken by FEI in recent years.

19. Reference: Exhibit B-1-2 Section 5 pp.70,71 (pdf 82,83)

"It is expected that the existing CP system could be used to provide protection to the new OLI PEN 406 extension; this will be confirmed during detailed design."

19.1 What is the cost impact if the existing cathodic protection system is found to be inadequate to protect the proposed extension to OLI PEN 406 and additional cathodic protection is required? Provide both the capital cost, the ongoing operating and maintenance costs, and the present value of the annual revenue requirement of the additional cathodic protection (on a comparable basis to the annual revenue requirements shown in Table 4-7).

20. Reference: Exhibit B-1-2 Section 5 pp.72,74 (pdf 84,86)

"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."

20.1 Describe the purpose(s) and function(s) of the Ellis Creek Pressure Control Station.

20.2 Provide the cost of the control station that will be constructed at the terminus of the OLI PEN 406 line near Chute Lake, with a breakdown showing the cost of the pressure regulating equipment (shown separately for each pressure reduction run), line heaters, inlet and outlet valves, pig receiver, filters, telemetry, and overpressure protection.

20.3 Provide station design details for the Ellis Creek station in a similar format as Table 5-10 for the portion of the station that reduces the pressure from the OLI PEN 406 line.

20.4 Confirm whether FEI considered relocating and repurposing the station equipment at the Ellis Creek Station to be used at the Chute Lake station. Provide FEI's analysis of the advantages and disadvantages of this approach.

21. Reference: Exhibit B-1-2 Section 5 p.74 (pdf 86); BCUC IR 1.30.1

"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."

21.1 If the deactivated OLI PEN 406 assets will be removed from rate base, confirm whether the Ellis Creek station assets used to interconnect with the OLI PEN 406 line will also be removed from FEI's rate base.

22. Reference: Exhibit B-1-2 Section 5 pp.89-91 (pdf 101-103)

"The risk identification process identified a number of risks which were tabulated in the risk register included in Appendix 4 to YPCI's Risk Report (Confidential Appendix C-1)."

22.1 Has FEI undertaken any pipeline projects of similar scope or magnitude as OCU in the past five years? If so, identify them and provide a brief description. If FEI has not undertaken any pipeline projects of similar scope or magnitude as OCU, then identify pipeline projects and provide brief descriptions for projects with capital costs in excess of $50 million.

22.2 For the projects in 22.1, if Monte Carlo simulations of the contingency, management reserve, and escalation reserve amounts were undertaken, provide the probabilities of underrun for each of contingency, management reserve, and escalation reserve assumed in each CPCN application. If Monte Carlo simulations were not undertaken, provide the contingency, management reserve, and escalation reserve as proportions of the base estimate assumed in each CPCN application.

22.3 For the projects in 22.2, provide the amounts of contingency,

management reserve, and escalation reserve that were ultimately used to complete the projects, as well as the final costs of the projects in comparison with the costs presented in the corresponding CPCN applications.

22.4 For FEI's most recent pipeline project of similar scope and magnitude to the OCU, provide the risk register or similar consultant's report on the project risks.

23. Reference: Exhibit B-1-2 Section 5 p.90-92 (pdf 102-104)

"During the cost validation process outlined in Section 5.10.3, 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. FEI considered market prices as a risk that could impact the Project cost and undertook additional analysis."

"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."

"Escalation per AACE is 'a provision in costs or prices for uncertain changes in technical, economic, and market conditions over time. Inflation (or deflation) is a component of escalation.'"

23.1 If FEI is addressing the risk of market prices and uncompetitive contractor bids through the management reserve, explain whether addressing the escalation of economic and market conditions with the escalation reserve results in a duplicate provisioning for this risk.

E. <u>Project Cost Estimate</u>

24. Reference: Exhibit B-1-2 Section 6 pp.96-97 (pdf 108-109)

24.1 Explain whether there are any opportunities to reduce the delivery rate impact on consumers through additional cost deferrals or extensions to the amortization periods of proposed cost deferrals. Discuss the advantages and disadvantages of these opportunities.

F. <u>Consultation and Engagement</u>

25. Reference: Exhibit B-1-2 Section 8 p.113

"As a result of FEI's 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."

25.1 Was FEI able to resolve all the concerns of landowners with respect to the project routing? If not, what concerns expressed by landowners remain unresolved?

26. Reference: Exhibit B-1-2 Appendix H-2 Stakeholder Consultation Log (pdf 318-322)

Appendix H-2 is a log of stakeholder consultation and identifies a number of communications (letters and emails) that were sent to landowners, residents, and other stakeholders.

26.1 Provide copies of the responses received by FEI to the communications sent to landowners and stakeholders detailed in Appendix H-2.