OWEN·BIRD
LAW CORPORATION

PO Box 49130
Three Bentall Centre
2900-595 Burrard Street
Vancouver, BC
Canada V7X 1J5

Telephone 604 688-0401
Fax 604 688-2827
Website www.owenbird.com

Direct Line: 604 691-7557
Direct Fax: 604 632-4482
E-mail: cweafer@owenbird.com
Our File: 23841/0203

May 7, 2019

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Sirs/Mesdames:

Re: FortisBC Inc. ("FBC") Certificate of Public Convenience and Necessity Application for the Grand Forks Terminal Station Reliability Project ~ Project No. 1598987 (the "Application")

We are counsel to the Commercial Energy Consumers Association of British Columbia (the "**CEC**"). Attached please find the CEC's Final Submissions with respect to the above-noted matter.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jj
cc: CEC
cc: FortisBC Inc.
cc: Registered Interveners

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA

FINAL SUBMISSIONS

FortisBC Inc. Certificate of Public Convenience and Necessity Application for the Grand Forks Terminal Station Reliability Project
Project No. 1598987

May 7, 2019

Commercial Energy Consumers Association of British Columbia

FortisBC Inc. Certificate of Public Convenience and Necessity Application for the Grand Forks Terminal Station Reliability Project
Project No. 1598987

Table of Contents

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA

FINAL SUBMISSIONS

FortisBC Inc. Certificate of Public Convenience and Necessity Application for the Grand Forks Terminal Station Reliability Project
Project No. 1598987

The Commercial Energy Consumers Association of BC ("**CEC**") represents the interests of ratepayers consuming energy under commercial tariffs in applications before the BC Utilities Commission ("**BCUC**" or the "**Commission**").

FortisBC Inc. ("**FBC**") applies for a Certificate of Public Convenience and Necessity ("**CPCN**") for its Grand Forks Terminal Station Reliability Project ("**GFT Reliability Project**" or the "**Project**").

The CEC has participated in the proceeding and reviewed the public and confidential information available on the evidentiary record.

The CEC provides the following Final Submissions for the Commission's review and consideration.

I. SUMMARY POSITION

1. The CEC has reviewed the evidence and submits the Project should be found to be in the public interest.

2. The CEC recommends that the Commission approve the Project as filed with the Commission, but would not object to a Project deferral if so determined by the Commission.

II. SUBMISSIONS

A. PROJECT NEED

3. The CPCN is intended to address transmission system reliability issues in the Grand Forks area supplied by the Grand Forks (GFT T3), Ruckles (RUC T3), Christina Lake (CHR T1) and Bradford/Roxul (BRA T1) distribution transformers. The normal 63 kV supply for these substations is from Grand Forks Terminal 1 transformer ("**GFT T1**")[1]; and the reliability requirements for the Grand Forks area load (GFT, RUC, CHR, BRA) are critically dependent on the availability of this transformer.[2]

---

[1] Exhibit B-5, CEC 1.16.1

[2] Exhibit B-2, BCUC 1.1.1

N-1 Planning

4. FBC cannot meet its single contingency (N-1) planning criteria for the 63 kV system in the Grand Forks area under peak load conditions[3] since parallel operation of 9L and 10L cannot be relied upon.[4] The Grand Forks area's peak loads are such that having only one of the 9L or 10L lines in service during peak periods would not suffice to provide the 63kV backup supply.[5]

5. FBC transmission lines operating at voltage levels below 160 kV are, for the most part, operated in radial mode and do not meet N-1 planning criteria. For higher density load centers, this radial transmission is configured to provide substations with two sources of dual radial supply. Plans to operate important load centres for N-1 planning contingencies are justified on a case-by-case basis.[6]

6. However, the Grand Forks area is part of the interconnected system, and therefore its N-1 planning criteria apply.[7]

7. FBC states that although there are other areas (Kaslo, Crawford Bay, Coffee Creek substations) that do not meet N-1 planning criteria, the Grand Forks area was prioritized because the recorded seasonal peak load has been above the backup supply capacity limitation (27 MW with a single line in service) several times in the past five years, because the area includes industrial loads and because 9L and 10L back up supply is in poorer condition than the other areas.[8]

8. The CEC submits that it is reasonable for FBC to strive to meet its N-1 planning criteria for areas that are part of the interconnected system.

9. The CEC also finds that FBC's prioritization of Grand Forks is reasonable.

Equipment Condition

10. The likelihood of a failure to GFT T1 and FBC's ability to restore customers are further impacted by the poor condition of the existing facilities at the Grand Forks Terminal station ("**GFT**") including GFT T1, spare transformer ("**OLI T1**") and the transmission lines 9L and 10L.[9]

---

[3] FBC Final Submissions page 1

[4] Exhibit B-2, BCUC 1.1.1

[5] FBC Final Submissions page 1

[6] Exhibit B-5, CEC 1.5.1

[7] Exhibit B-10 BCOAPO 2.20.1 and 2.20.1.1

[8] Exhibit B-5, CEC 1.5.1.1

[9] FBC Final Submissions page 1

11. FBC notes that the poor condition of existing facilities poses additional reliability risks.[10]

12. FBC has provided evidence of the deterioration of the relevant equipment currently in place in the Grand Forks area.

13. The GFT T1 Transformer is now 53 years old which is significantly higher than the most common end of life time period for such transformers, which is 35 to 45 years.[11]

14. The GFT T1 condition assessment found the remaining useful life to be 15 years.[12]

15. FBC notes that GFT T1 has operated with abnormal levels of dissolved hydrocarbon and hydrocarbon gases since 2002. The dissolved hydrocarbon and hydrocarbon gases may be considered as fault gases and FBC considers them as indicators of transformer condition. FBC has taken corrective measures however the GFT T1 dissolved gas levels stabilized only after the load tap changer was switched to manual.[13]

16. FBC expects that the GFT T1 dissolved Gas Signature and unit health will be stable as long as the load tap changer operation is not required.[14]

17. FBC considers the risk of failure ("**RoF**") for the GFT T1 to be 2.6%.[15] This is on the high side compared with a typical utility population[16], and FBC expects this to increase to approximately 3.5% over 30 years.

18. The RoF cannot be improved since all recommended practices were in place at the time the RoF was calculated.[17]

---

[10] FBC Final Submissions page 5

[11] Exhibit B-1, page 15

[12] FBC Final Submissions, page 5

[13] Exhibit B-5, CEC 1.6.1

[14] Exhibit B-5, CEC 1.6.1

[15] 2.6% applies to Transformer and is assumed for the entire station due to the single 161/163 transformer BCUC 2.17.1

[16] Exhibit B-1, page 15

[17] Exhibit B-2, BCUC 1.2.4

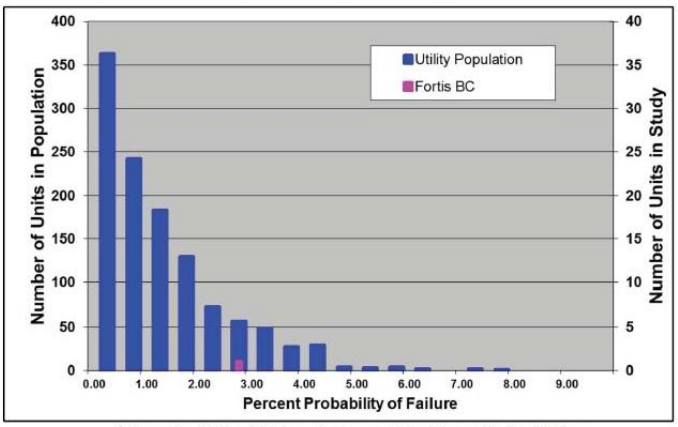


Figure 6 – Risk of Failure Compared to a Transmission Utility

18

Year	Risk of Failure
2018 (00 years)	2.60
2028 (10 years)	3.05
2033 (15 years)	3.26
2038 (20 years)	3.47
2043 (25 years)	3.49
2048 (30 years)	3.50

Table 9 – Projected Future Risk of Failure

19

19. FBC considers that an acceptable risk of failure for a transmission station should be no higher than 2% based on industry standards[20] but does not expect the transformer will fail in the near term.[21]

20. FBC based their RoF of 2.6% on an ABB report filed in Appendix B in the application.

21. The ABB report provided the following table for the RoF. The 2.6% RoF was calculated based on the existing presence of C2H2 in oil and assuming no inhibitor in oil.

Risk of Failure (%)	Condition
2.600	Transformer as is (C2H2 in oil and assuming no inhibitor)
0.524	Considering no acetylene in oil and inhibitor in oil.
0.262	New transformer design. (No gas in oil, inhibitor in oil, better short circuit withstand design)

22

[18] Exhibit B-1, Appendix B, page 17

[19] Exhibit B-5, CEC 1.10.3

[20] Exhibit B-2, BCUC 1.2.3

[21] FBC Final Submissions page 5

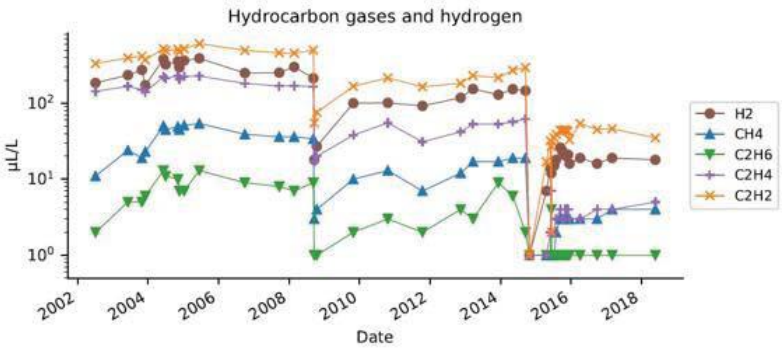
[22] Exhibit B-1, Appendix B, page 17

22. ABB speculated in the report that 'the C2H2 in oil is the result of oil leaking from the Load Tap Changer ("**LTC**") and not an active arcing issue in the active part and probably there is still some inhibitor in the oil'. They also calculated the RoF at this condition, as well as for a new transformer. These results show RoF of 0.524% and 0.262% respectively.[23]

23. Additionally, FBC assumes that GFT T1 Dissolved Gas Signature and unit health will be relatively stable as long as the load tap changer operation is not required.[24]

24. FBC states that they selected the worst case scenario for the RoF because:

> "GFT T1 has had high acetylene (C2H2) levels since 2002 as shown in the figure below. FBC replaced the diverter tank-barrier board to try and address this issue. However, replacing this equipment did not lower the acetylene levels. FBC has operated the GFT T1 load tap changer in manual control since April 2016, which appears to have resulted in stable dissolved hydrocarbon and hydrogen gases. However, the load tap changer may not be the actual cause of the high acetylene levels. Therefore, FBC selected the worst case scenario for the risk of failure (RoF) as 2.6 percent."



[25]

25. FBC also states that:

> "Since the likely cause of the abnormal fault gases has not been determined and given the fact that GFT T1 is now 53 years old, exceeding the expected transformer lifespan of 40 years, FBC considered the risk of failure of 2.6 percent calculated by ABB to be appropriate."[26]

26. The CEC is of the view that a 2.6% RoF is likely high given FBC's acknowledgement that there is uncertainty surrounding the reason for the fault gases, there appears to be evidence that operating the load tap changer in manual has stabilized the situation, and ABB's speculation as to its potential source.

---

[23] Exhibit B-1, Appendix B, page 17

[24] Exhibit B-5, CEC 1.6.1

[25] Exhibit B-2, BCUC 1.2.2

[26] Exhibit B-2, BCUC 1.2.2

27. The CEC submits that it would not be unreasonable to discount the RoF to between 1% and 2%, which recognizes ABB's speculative RoF of 0.524% and FBC's experience replacing certain equipment as well as recognizing FBC's concerns regarding uncertainty.

28. Such a determination would place the RoF below FBC's threshold of acceptability of 2%.

29. The CEC notes that there are other additional areas of concern.

30. If the GFT T1 were to fail during peak conditions then customer load would be restricted until the OLI T1 could be installed as a replacement or 10L could be energized.[27]

31. OLI T1 is 47 years old[28], has a 10 to 15 year remaining life[29] and is the only designated emergency spare for two other stations in FBC's system.[30] FBC does not own any other spare transformers with a similar size and voltage level.[31]

32. There are several known issues with OLI T1, including an oil leak and issues with the load tap changer and gear mechanisms.[32] FBC does not calculate the RoF for all equipment or stations.[33]

33. FBC's assessment of 9L and 10L found that they are generally in poor condition and that 37% of the structures on 9L and 69% of the structures on 10L require replacement.[34]

34. FBC de-energized 10L in 2010 because it is in poor condition and was creating an operational challenge.[35]

35. There are a large number of poles on 9L and 10L between CHR and CSC that are well beyond their average life expectancy, which is up to 46 years with stubbing.[36] FBC provides a Pole Vintage chart in BCUC 1.1.1 which demonstrates this fact.

---

[27] FBC Final Submission page 6

[28] Exhibit B-2, BCUC 1.1.1

[29] Exhibit B-2, BCUC 1.1.1

[30] Exhibit B-2, BCUC 1.2.10.

[31] Exhibit B-9, BCUC 2.19.1.3

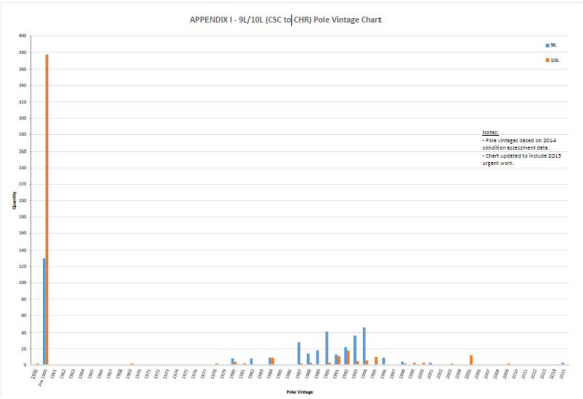
[32] FBC Final Submissions page 6

[33] Exhibit B-5, CEC 1.10.2

[34] Exhibit B-2, BCUC 1.1.1

[35] Exhibit B-5, CEC 1.3.1

[36] Exhibit B-2, BCUC 1.1.1



[37]

36. Additionally, there are significant access issues for the 9L and 10L between CHR and CSC remain challenging.[38]

<u>Impacts</u>

37. The Grand Forks area has 3,750 residential and commercial customers; 2,200 City of Grand Forks customers and 2 industrial customers.[39]

38. The GFT Reliability Project as proposed in the application will reduce risk and improve the outage restoration time for customers.[40]

39. The CEC inquired as to the likely impact under a GFT T1 outage if only 9L could be placed into service. FBC is not able to provide the number of customers that would likely experience an outage as it would depend on the time of year the outage occurred and the Grand Forks area load at the time. However, with only a single line of service the maximum load that can be supported is 27 MW, and this peak load if often exceeded.[41] The peak load reached 34 MW in winter (2016/2017) and 33 MVA in summer 2018.[42]

40. FBC provides the seasonal peak load data for GFT 1 in CEC 1.7.1.

41. FBC provided the number of direct and indirect customers that were affected in each outage on 9L and 10L over the last five years in CEC 1.13.1. This showed numbers in the order of 2,000 customers affected on several occasions.

42. The CEC notes that FBC does not appear to have conducted a cost-benefit analysis of the value of the risk reduction versus the cost of the Project.

---

[37] Exhibit B-2, BCUC 1.1.1

[38] Exhibit B-2, BCUC 1.1.1

[39] Exhibit B-5, CEC 1.7.1

[40] Exhibit B-2, BCUC 1.3.1

[41] Exhibit B-5, CEC 1.7.2

[42] Exhibit B-5, CEC 1.7.1

43. The CEC submits that such analysis could potentially be useful in determining when a capital project is optimally undertaken.

CEC Conclusions

44. The CEC has reviewed the need for the Project and submits that there is a significant need for the Project given the lack of N-1 redundancy and the poor condition of the existing equipment.

45. The CEC does not find that there is a strong urgency for the Project at this time given the remaining life of the GFT T1 and OLI T1 and the CEC's view of the lower RoF of GFT T1.

46. The CEC submits that given the capital cost of the Project ($12 million in 2018$[43]) a deferral would create savings, but could also serve to increase risks. FBC has not quantitatively analysed the trade-offs for deferral.

47. Accordingly, the CEC submits that it is reasonable to undertake the Project at this time, but would not oppose a delay in the Project based on the CEC's quantitative assessment of the expected values in this case.

B. ALTERNATIVES ANALYSIS

48. FBC evaluated three alternatives as outlined in Table 3-3 of the Application.

49. Each alternative would meet the Company's N-1 transmission planning criteria for 63kV supply in the Grand Forks area. Alternatives A and B include the installation of a second transformer at GFT and Alternative C includes rehabilitation of line 9L and 10L instead. FBC selected Alternative B.[44]

50. FBC's Technical criteria included:

- Meeting the N-1 planning criteria;
- Operations accessibility and operability;
- Lifecycle utilization;
- Project Risk; and
- System reliability.

51. The CEC submits that these are reasonable criteria for technical consideration.

[43] Exhibit B-1, page 40

[44] FBC Final Submission page 9

52. Financial criteria included:

- O&M and sustainment capital costs;
- Present value incremental revenue requirement; and
- Rate impact.

53. FBC provides full financial summaries of each of the alternatives in Confidential Appendix J (J.1; J.2 and J.3).

54. The CEC submits that these are reasonable financial criteria.

55. The CEC notes that no quantification of risk reduction was used in the financial assessment of the alternatives.[45]

56. The CEC submits that it would be reasonable for FBC to provide a quantification of the risk reduction in its evaluation of alternatives.

57. The CEC notes that FBC calculated the present value and levelized rate impact assuming that GFT T1 has a useful remaining life of 10 years; a 40 year life for a new transformer; and future capital requirements in Years 10, 15 and 25 which are not being requested for approval in this application.[46]

58. FBC assigned a 10 year lifespan to GFT T1, although ABB recommended that the transformer not be kept in service for more than 15 years. FBC considered that an additional 10 year lifespan was the most appropriate since the cause of the abnormal fault gases had not been determined and the transformer is 53 years.[47]

59. The CEC submits that the ABB report would reasonably have considered the age and condition of the transformer in its evaluation of the transformer life and that the 15 year lifespan is the more appropriate assessment.

60. The CEC submits that FBC's assessment is very conservative and that the remaining useful life of GFT T1 should be 15 years

61. Additionally, the CEC notes that FBC's transformers examined in the current application have exceeded their original expected life by several years.

---

[45] Exhibit B-5, CEC 1.19.2

[46] FBC Final Submissions page 9

[47] Exhibit B-2, BCUC 1.2.5

Alternative A

62. Alternative A includes installing OLI T1 as a second transformer on site at GFT (GFT 2); removing 44.6 km of the 9L and 10L transmission lines and repurposing 20.8 km of the 9L and 10L transmission lines for use as distribution lines. The second transformer, previously designated as OLI T1, would be designated as GFT T2. FBC outlines Alternative A at pages 21-22 of its application including the advantages and disadvantages.

63. In Alternative A, FBC would replace the GFT T1 with a new transformer in Year 10 and the OLI T1 with a new transformer in year 15.[48]

64. The capital cost of Alternative A is $11.3 million ($2018) and the Present Value of Alternative A is $9.959 million at 40 year cost of service[49]. It has a levelized rate impact of 0.18%.[50]

Alternative B (selected Alternative)

65. Alternative B includes the purchase and installation of a new second transformer as opposed to installation of the on-site spare (in Alternative A). A new transformer will reduce the risk that GFT 1 and GFT 2 could fail simultaneously[51]. OLI T1 remains as an onsite spare.[52]

66. The CEC does not consider simultaneous failure to be a highly significant risk, particularly given the CEC's view on the RoF, but does note that there is a limited expected life to the OLI T1 which would be longer with a new transformer.

67. In Alternative B FBC would replace GFT 1 with OLI T1 in Year 10 and replace OLI T1 with a new transformer in year 25.

68. The capital cost of Alternative B is $12,196 million (2018$)[53] and the Present Value is $9.960 million at 40 year cost of service.[54] The PV is only $1000 higher than Alternative A. It has a levelized rate impact of 0.18%.[55]

---

[48] Exhibit B-1, page 24

[49] Exhibit B-1-2, page 26

[50] Exhibit B-1-2, page 26

[51] FBC Final Submissions page 10

[52] Exhibit B-1 page 25

[53] Exhibit B-1, page 40

[54] Exhibit B-1-2, page 26

[55] Exhibit B-1-2, page 26

Alternative C

69. Alternative C includes the rehabilitation of 9L and 10L transmission lines with a like-for-like replacement of the existing facilities and with all work completed to FBC standards. In this alternative no second transformer would be installed at GFT and 9L and 10L would remain as the secondary 63 kV back supply for GFT.[56]

70. Alternative C has the lowest initial capital cost of the alternatives but is the most costly option on a PV basis.

71. The capital cost of Alternative C is $9.034 million,[57] and the Present Value is $13.940 million at 40 year cost of service.[58] It has a levelized rate impact of 0.25%.[59]

72. Although Alternative C has the lowest initial capital cost, it has the highest PV cost because of higher O&M and sustainment capital costs for 9L and 10L. Additionally, Alternative C would not meet forecast load growth in the Grand Forks area over the 20-year planning horizon, even with the addition of reactive compensation for voltage support.[60]

CEC Conclusions on Alternatives Analysis

73. The CEC agrees with FBC that Alternative B represents the preferred solution, of the alternatives analysed by FBC, in that the capital costs for all alternatives are within approximately $3 million and the PV is nearly identical between Alternatives A and B, which are both significantly lower than Alternative C.

74. The CEC submits that the Commission would have benefited from an FBC quantitative assessment of the values related to short term deferrals.

75. The CEC submits that a new transformer has the potential to add significant benefit in that the new GFT T2 life expectancy could be increased beyond 40 years all else being equal.[61]

C. PROJECT DETAILS

76. In addition to purchasing a new transformer, FBC plans to remove 44.6 km of 9L and 10L transmission lines from CHR to CSC. A portion will be removed, sold for scrap and

[56] Exhibit B-1, page 23

[57] Exhibit B-1-2, page 23

[58] Exhibit B-1-2, page 26

[59] Exhibit B-1-2, page 26

[60] FBC Final Submissions page 10

[61] Exhibit B-2, BCUC 1.2.7.1

retired from plant. 20.8 km of transmission lines 9L and 10L will be repurposed to distribution lines.[62]

77. FBC does not expect there to be any limitations associated with utilizing the repurposed lines for distribution[63] and FBC has repurposed transmission lines to distribution lines in the past.[64] The repurposed lines are intended to be used immediately to provide service to customers between CHR and CSC.[65]

78. FBC also expects to generate salvage from the sale of the scrap portion of the transmission lines.[66]

79. The CEC submits that repurposing assets where possible is a reasonable and likely cost-effective approach.

Project Cost Estimate

80. The Project is estimated to have a capital cost of $13.171 million in as-spent dollars, including AFUDC of $0.531 million and net removal costs of $4.528 million.[67]

81. FBC obtained major material quotes from two different suppliers known to conform to FBC equipment standards. FBC also relied on actual data from ongoing capital projects and pricing from the FBC procurement department.[68]

82. A contingency of 17.7% was used for the stations component and a contingency of 20% was used for the distribution component.[69]

83. There is a contingency of $427 thousand for the Construction cost and an additional $866 thousand in Construction for Net Removal[70].

84. FBC provided, rationales and cost bases for various contingencies in CEC 1.21.2, 1.21.3, 1.23.1 and 1.23.2, most of which were provided confidentially.

---

[62] Exhibit B-1, page 39 and page 43

[63] Exhibit B-5, CEC 1.25.1

[64] Exhibit B-5, CEC 1.25.5

[65] Exhibit B-5, CEC 1.25.2

[66] Exhibit B-5, CEC 1.25.4, see also CEC Confidential 1.25.4

[67] Exhibit B-1, page 39

[68] Exhibit B-5, CEC 1.21.4

[69] Exhibit B-1, page 42

[70] Exhibit B-1, pages 39-40

85. The contingency of 20% for the transmission and distribution portion of the Project was selected by the independent contractor who performed the condition assessment.[71]

86. The CEC has reviewed the evidence and is satisfied with the calculation of contingencies.

87. The CEC has reviewed the evidence related to the Project Cost Estimate overall and is satisfied with the costing.

Risks

88. FBC has provided roject risk assessments and the CEC is satisfied with this analysis.

Land Rights

89. FBC will attempt to negotiate with private property owners for sufficient land rights. Crown rights will be applied for through the standard FrontCounterBC process.[72]

90. Project and construction management will be undertaken by FBC and external personnel will not be required. Civil/structural engineering, geotechnical and grounding studies will be completed externally.[73]

91. The CEC has reviewed the evidence and is satisfied with FBC's approach to land rights.

Consultation

92. FBC has consulted with indigenous communities.

93. FBC 'submits that no public consultation is required due to the Project's minimal impact[74], but intends to contact residents and commercial enterprises that are expected to experience impacts during the Project[75]. Additionally, FBC has mitigated noise and light concerns expressed by residents.[76]

94. The CEC has reviewed FBC's approach to consultation and finds it acceptable.

III. CONCLUSION

95. The CEC has reviewed the evidence for the FBC Grand Forks Terminal Station Reliability Project and submits that the Project is in the public interest.

---

[71] Exhibit B-5, CEC 1.23.2

[72] Exhibit B-5, CEC 1.22.1

[73] Exhibit B-5, CEC 1.20.1

[74] FBC Final Submissions page 18

[75] FBC Final Submissions page 17

[76] FBC Final Submissions pages 18-19

96. The CEC would not be opposed to a Project deferral for a short time period.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

David Craig

David Craig, Consultant for the Commercial Energy Consumers Association of British Columbia

Christopher P. Weafer, Counsel for the Commercial Energy Consumers Association of British Columbia