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

January 31, 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. Certificate of Public Convenience and Necessity Application for the Grand Forks Terminal Station Reliability Project ~ Project No. 1598987

We are counsel to the Commercial Energy Consumers Association of British Columbia (the "CEC"). Attached please find the CEC's first set of Information Requests 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

INFORMATION REQUEST NO. 1

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

January 31, 2019

---

1. Reference: Exhibit B-1, page 5

> **1.4 *REGULATORY HISTORY***
>
> FBC first proposed the installation of a second 161/63 kV transformer at GFT and the removal of 9L and 10L between CSC and CHR in its 2012-2013 Capital Expenditure Plan. In that application, the transformer addition project was linked to the Grand Forks to Warfield Fibre Project as the infrastructure required to integrate the transformer into the substation would be greatly reduced by the availability of a secure fibre-optic communications link to the remote substations. At that time, FBC also sought approval for expenditures related to the relocation and storage of a spare transformer at GFT.
>
> In its Decision and Order G-110-12, the BCUC endorsed the relocation of the spare transformer, but rejected the proposed expenditures related to the installation of the second transformer because the need for increased reliability was not apparent. The BCUC also directed FBC to apply for a separate CPCN for approval of the project.

1.1 Please explain whether or not FBC considers the need for increased reliability to be more apparent now than it was when the BCUC issued its decision, and provide quantification for any evidence FBC is able to provide in terms of new vs historical information that the Commission was previously relying upon in its decision.

2. Reference: Exhibit B-1, page 6 and page 43

> With respect to the CPCN threshold, FBC is directed to apply to the BCUC for a CPCN for projects that require in excess of $20 million in capital expenditures. The total forecast cost of the Project is not expected to exceed $20 million, and FBC does not anticipate any significant public concerns with the proposed solution. On that basis, the Company would not typically file a CPCN application for a project of this nature.
>
> As mentioned above, FBC first proposed this project in its 2012-2013 Capital Expenditure Plan application. In that application, FBC sought approval to recover only engineering/estimating expenditures with a subsequent application to propose procurement and installation of the fibre cable. At the time, the BCUC denied approval for the preliminary costs and directed that a CPCN be filed for the project.
>
> The BCUC confirmed the requirement for a CPCN application in Order G-80-16. FBC is therefore filing this CPCN Application to ensure that the regulatory process can proceed in a timely manner to accommodate the Project schedule and in-service date.
>
> **6.4 *RATE IMPACT***
>
> The Project construction period is between 2019 – 2021 with assets going into service in 2021 and 2022. A 40 year cost of service model was used to evaluate this option (Alternative B) against the others described in section 3. The levelized 40 year rate impact is 0.18% or $0.20 per MWh. The annual bill impact for an average residential customer using 11,500 KWh at the 40 year levelized rate would be $2.14. The rate impact in 2022 the year when all assets have been transferred into plant asset accounts will be 0.26 percent. This would equate to annual bill increase of $3.36 for an average residential customer using 11,500 KWh.

2.1 Under the current PBR ratemaking, costs for projects below the CPCN threshold are normally included in formula capital and O&M, whereas costs included in a CPCN are flowed through to ratepayers. Please explain how FBC is proposing to handle the costs for this CPCN in its PBR given that FBC has been directed to file a CPCN for a project well below the CPCN threshold.

2.1.1 If costs are being treated as flow through, please describe the impact if costs were not flowed through, but instead included in formulaic spending.

2.1.2 Would FBC undertake the project if a CPCN were not required and costs were to be included in formulaic spending? Please explain why or why not.

3. Reference: Exhibit B-1, page 12 and 13

> The 63 kV transmission lines 9L and 10L were originally constructed in 1908 and supplied power from the West Kootenay to customers in the Boundary and South Okanagan. Taps off these transmission lines were later built to supply a number of substations including CHR and RUC. In 1965, Grand Forks Terminal was constructed and GFT T1 was installed to connect the 63 kV transmission facilities to the 161 kV system via 11L. After GFT T1 was installed, it became the primary 63 kV supply for the Grand Forks area with 9L and 10L remaining as the backup supply. Both 9L and 10L each cover a total distance of 62.4 km between WTS and GFT. A geographic map of 9L and 10L is provided below in 3-2.

Figure 3-2: Geographic Map of 9L and 10L

In normal operation, 9L is open and 10L is de-energized between the CHR tap and CSC substation. As well, in normal operation, approximately 32.7 km of 10L is de-energized between the CHR tap and CSC substation due to its poor condition, and must be visually assessed and confirmed to be in suitable condition (and rehabilitated to minimum standards if necessary) before it can be placed in service. The condition of 9L and 10L will be discussed further in Section 3.2.1.3. Please refer to Appendix A for the existing 9L and 10L circuit arrangement.

Over the years, underbuilt distribution circuits were constructed on portions of both 9L and 10L to serve customers in the vicinity of the lines right of way. There are currently 46 customers supplied from distribution underbuild on 9L and 10L transmission structures as highlighted in Figure 3-3. Along 10L, 9.8 km of distribution underbuild serves 26 customers from CHR Feeder 1 (8.5 km single phase and 1.3 km three phase). Along 9L, 11.0 km of distribution underbuild serves 20 customers from CSC Feeder 3 (10.5 km single phase and 0.5 km three phase).

3.1 Would 10L normally be de-energized if it there were no portions that were in poor condition? Please explain.

3.2 Please provide FBC's plans for 10L regarding where rehabilitation might occur and the quantitative benefits reasons for doing so (i.e. Value of N-1 capability).

4. Reference: Exhibit B-1, page 13 and 14

Over the years, underbuilt distribution circuits were constructed on portions of both 9L and 10L to serve customers in the vicinity of the lines right of way. There are currently 46 customers supplied from distribution underbuild on 9L and 10L transmission structures as highlighted in Figure 3-3. Along 10L, 9.8 km of distribution underbuild serves 26 customers from CHR Feeder 1 (8.5 km single phase and 1.3 km three phase). Along 9L, 11.0 km of distribution underbuild serves 20 customers from CSC Feeder 3 (10.5 km single phase and 0.5 km three phase).

4.1 Please explain why underbuilt distribution circuits were constructed on portions of 9L and 10L over the years.

5. Reference: Exhibit B-1, page 14 and page 15

The maximum load that can be supplied by either 9L or 10L is 27 MW, which is insufficient to meet peak load conditions for the Grand Forks area.[8] If both lines are operated in parallel, the maximum load that can be supplied increases to 45 MW. During seasonal peaks, both lines must operate in parallel to meet the load requirements in the event of an outage or failure to GFT T1. However, mountainous terrain, particularly in winter, can make it impossible to operate 9L and 10L in parallel since the lines traverse the Rossland Mountain Range, restricting physical access and making it extremely difficult to visually assess and rehabilitate 10L before it can be energized. As such, 9L and 10L are not a reliable secondary 63 kV supply for the Grand Forks area.

ability to restore customers is further impacted by the condition of the existing facilities at GFT and transmission lines 9L and 10L.

The purpose of the Project is to ensure FBC customers continue to receive safe and reliable service in the event of an outage or failure of GFT T1.

3.2 *PROJECT NEED*

The GFT Reliability Project is a reliability-driven project, as FBC cannot meet the single contingency (N-1) criteria for the 63 kV system in the Grand Forks area since parallel operation of 9L and 10L cannot be relied upon. As will be explained below, the likelihood of failure and the

ability to restore customers is further impacted by the condition of the existing facilities at GFT and transmission lines 9L and 10L.

The purpose of the Project is to ensure FBC customers continue to receive safe and reliable service in the event of an outage or failure of GFT T1.

5.1 Please discuss if there are other similar areas of the system that also do not have N-1 contingency at this point and the length of such lines vs the length of all lines.

5.1.1 If there are other similar areas of the system that also do not have N-1 contingency, please explain why this area is a priority.

6. Reference: Exhibit B-1, page 15

3.2.1 Facilities Condition Assessment

3.2.1.1 GFT T1 Condition

GFT T1 is of 1965 vintage and is now 53 years old, exceeding the expected transformer lifespan of 40 years. In recent years, the load tap changer (LTC) tanks have been replaced and the oil has been processed. The unit is closely monitored and recent Dissolved Gas Analysis (DGA) results have been relatively stable.

ABB, a qualified transformer design contractor, performed a comprehensive condition assessment in 2018 for GFT T1 on behalf of the Company, which is provided in Appendix B. Based on the analysis, ABB recommends GFT T1 should not be kept in service for more than 15 years.[9]

The condition assessment calculated the Risk of Failure (RoF) for this transformer to be 2.6 percent based on the most recent DGA and the available test/maintenance data.[10] The RoF for this unit is on the high side when compared to a typical utility population.

ABB's report identifies the second most failed component for this type of transformer is the LTC and the single most common cause of failure is inadequate short circuit strength. Both of these components are weak in this unit. Also, based on the age profile for over 7 thousand units in a particular subset of in-service transformers contained in the Transformer Industry-Wide Database (IDB), the most common end of life for a transformer occurs in the 35 to 45 year portion of the population. This unit is 53 years old. With each passing year, the probability of failure of this unit increases.

6.1 Please provide a brief discussion of the relevance of the Dissolved Gas Analysis being relatively stable.

7. Reference: Exhibit B-1, page 12 and page 17

Over the past five years, the maximum winter and summer peak loads on GFT T1 were approximately 34 MW and 29 MW, respectively. GFT T1, with a nominal rating of 45/60 MVA, has sufficient capacity to meet the forecasted distribution demand for the Grand Forks area load over the system planning horizon of 20 years. The characteristics of the four distribution transformers from which GFT T1 serves the local customer base are as follows:

If there is a GFT T1 outage or failure, customers will be left without power until the system is reconfigured to the backup 63 kV supply from 9L and 10L. The reconfiguration can result in lengthy restoration times and energization of 10L may not be possible if the line cannot be accessed. With only 9L in service, the maximum load that can be supplied is only 27 MW, which is insufficient to meet the seasonal peak loads for the Grand Forks area. In order to use 9L and 10L as the secondary 63 kV supply for the Grand Forks area, extensive rehabilitation work will be required to ensure both lines are available when needed.

7.1 Please provide the dataset demonstrating the seasonal peaks for the relevant area, including the size, timing and duration of peak periods.

7.2 Please provide a discussion of the number of customers that would be left without power under a GFT T1 outage or failure if only 9L could be placed into service.

8. Reference: Exhibit B-1, Appendix B page 7-8

- The transformer maintenance records provided by the customer indicate that 3 LTC diverter tubes were replaced in October 2014 due to their leaks. The high concentration of Hydrogen (H2), Ethane (C2H4), and Acetylene (C2H2) shown in DGA sampled before October 2014 was from the diverter contamination. The 33 ppm to 54 ppm of Acetylene (C2H2) were found the years after the new oil was filled in October 2014, which were believed from the residual Acetylene (C2H2)

in the insulations. Note: Normally a level of 46 ppm Acetylene corresponds to an unacceptable high probability of failure. Additional monitoring is required to monitor the gassing trend.

8.1 Has FBC been able to confirm that the 33 ppm to 54 ppm of Acetylene were from the residual Acetylene in the insulations? Please explain.

8.2 Please confirm that FBC is currently or has conducted additional monitoring of the gassing trend and provide any updated information available to FBC.

9. Reference: Exhibit B-1, Appendix B, page 8

- The carbon oxides levels were below the IEEE C57.104-2008 guide Condition Level 1 for the last few years. It is to be noted however that in 2014 this unit had the oil replaced and some of the markers of normal or abnormal aging were probably erased in the process. This observation is triggered by increased DGA levels recorded between 2003 and 2005. The CO_2/CO ratio is between 4 and 10. The normal CO_2/CO ratios are typically in the range of 5 to 9. The ratio of the carbon oxides suggests that these gas concentrations are likely due to the normal aging process of the transformer. For free breathing transformers with an ample supply of oxygen, there are typically high levels of carbon oxides generated under normal loading conditions. It is also typical that some of the CO will be converted to CO_2 in the presence of large quantities of oxygen. Oxygen acts as a catalyst to increase the generation rates of CO, CO_2 and combustible gases.

9.1 Please discuss the significance of the CO2/CO ratio being between 4 and 10 whereas the normal CO2/CO ratios being in the range of 5-9.

10. Reference: Exhibit B-1, page 15 and Appendix B, page 17

The condition assessment calculated the Risk of Failure (RoF) for this transformer to be 2.6 percent based on the most recent DGA and the available test/maintenance data.[10] The RoF for this unit is on the high side when compared to a typical utility population.

ABB's report identifies the second most failed component for this type of transformer is the LTC and the single most common cause of failure is inadequate short circuit strength. Both of these components are weak in this unit. Also, based on the age profile for over 7 thousand units in a particular subset of in-service transformers contained in the Transformer Industry-Wide Database (IDB), the most common end of life for a transformer occurs in the 35 to 45 year portion of the population. This unit is 53 years old. With each passing year, the probability of failure of this unit increases.

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)

Table 8 – Risk of Failure

The results above indicate a high risk of failure (2.6) for this transformer based on the current DGA in oil and available test and maintenance data. The below figure shows the Risk of Failure (RoF) compared to a transmission utility population. It can be seen that RoF is on the high side for this unit.

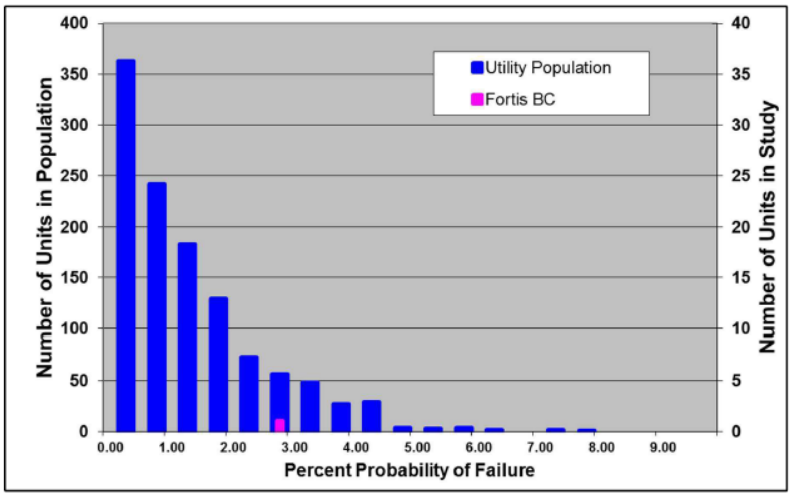

Figure 6 – Risk of Failure Compared to a Transmission Utility

10.1 Please confirm that the 2.6 percent probability of failure identified in the chart is FBC's Risk of Failure for this individual unit, and not for FBC's units as whole.

10.2 If confirmed, please provide an estimate of the average probability of failure for these units for all of FBC, if possible.

10.3 Please provide FBC's assessment of how much the risk of failure will increase 'with each passing year'.

10.4 Does FBC have pre-established criterion for itself regarding the risk of failure for transformers such as this? Please explain and provide the criterion if applicable.

11. Reference: Exhibit B-1, page 15 and 16

3.2.1.2 OLI T1 On-site Spare Transformer Condition

Oliver T1 (OLI T1) is a cold standby (normally de-energized) spare transformer located at GFT. It is a 161/63 kV transformer with a nominal rating of 45/60 MVA. The transformer was previously located at the Oliver Terminal, but was disconnected in 2011 as part of the Okanagan Transmission Reinforcement Project and relocated to GFT in 2014. The unit is of 1971 vintage and is now 47 years old, exceeding the expected transformer lifespan of 40 years.

In the event GFT T1 fails, it would likely take more than a year to repair or replace the unit based on historical procurement timelines. In the interim, FBC could install OLI T1 until a replacement unit could be procured. Although OLI T1 is on-site, it may take several weeks to install due to substation reconfiguration and civil work required to accommodate the spare transformer.

A field inspection assessment of OLI T1 was performed in 2013 by ABB prior to its relocation to GFT. The field inspection assessment report is included as Appendix D. The report concluded the tensile strength of the insulation paper is in the upper "Mid-Life" category.[11] Therefore, once refurbished, this indicates the unit could be used for another 10 to 15 years.

Given that OLI T1 is normally de-energized, there is always some uncertainty with the condition of the unit and its availability for service. Further, if the transformer were damaged in the process of installing it in the location of the failed GFT T1, then both transformers could be unavailable for an extended period. This would leave FBC with no alternative but to attempt to serve whatever load it could in the Grand Forks area using only the aging 9L and 10L.

11.1 Does FBC have any reason to believe that the transformer was damaged in the process of installing it? Please explain.

11.2 Does FBC normally run the risk of uncertainty regarding condition when transformers are used as back up and de-energized? Please explain.

12. Reference: Exhibit B-1, page 18

3.2.2 Reliability

Typical industry transmission planning standards require the system to be planned such that all projected customer loads are served during both normal (N-0)[12] operation and single contingency (N-1)[13] operation. As such, FBC transmission planning criteria specifies that firm customer load should be able to be supplied in N-0 and N-1 conditions.

[12] Normal operation, also referred to as N-0 reliability, means that with all major elements of the power system in service, the network can be operated to meet projected customer demand in order to avoid a load loss (customer outage).

[13] Single contingency, also referred to as N-1 reliability, means that an outage of a single element with all other elements of the power system in service (a single transmission line, transformer, generating unit, power conditioning unit like a shunt capacitor bank, a shunt reactor bank, a series capacitor, a series reactor, etc.) results in no load loss.

12.1 Is the CEC's interpretation correct that all of FBC's transmission infrastructure is planned to N-1 contingency or does some part of the system have radial lines at N-0 contingency? Please explain.

13. Reference: Exhibit B-1, page 18 and 19

FBC's transmission outage statistics show there have been a combined total of 54 outages on 9L and 10L over the past five years. The table below categorizes the total 9L and 10L outages by cause and shows the average duration, minimum duration, and maximum duration. Most outages to 9L and 10L are caused by snow unloading and lightning.

Table 3-1: 9L and 10L Outage Statistics (June 2013 - June 2018)

Description of Cause	Number of Outages	Avg Duration (hrs)	Min Duration (hrs)	Max Duration (hrs)
Snow	18	1.839	0.001	16.159
Tree Into Line	5	12.451	0.002	27.847
Equipment Failure	3	22.069	5.680	39.378
Pole Issue	5	9.096	1.176	17.052
Lightning	12	0.061	0.001	0.230
Human Interference	1	5.286	5.286	5.286
Conductor Issue	3	83.098	5.240	152.361
Flood	1	1.198	1.198	1.198
Forest Fire	2	0.914	0.127	1.701
Unknown	4	6.356	0.001	15.088
Total	**54**			

FBC's transmission outage statistics show there has been only a single outage to GFT T1 over the past five years, which was caused by lightning. The table below provides the outage cause and outage duration.

Table 3-2: GFT T1 Outage Statistics (June 2013 - June 2018)

Description of Cause	Number of Outages	Avg Duration (hrs)	Min Duration (hrs)	Max Duration (hrs)
Lightning	1	0.003	0.003	0.003
Total	**1**			

13.1 Please provide the number of customers that were affected in each outage if the information is available.

14. Reference: Exhibit B-1, page 20

Do nothing or Status Quo was not considered an option because FBC cannot currently meet the N-1 transmission planning criteria in the event of a GFT T1 failure during seasonal peaks.

FBC also considered consolidating 9L and 10L into a single circuit using 477 ACSR (Aluminium Conductor Steel-Reinforced) but rejected this option because the capacity of the new line could not support the Grand Forks area load.

14.1 Please provide further elaboration on the need for FBC to meet N-1 transmission planning criteria.

14.2 Please discuss whether or not FBC has been able to meet this need in the last several years.

15. Reference: Exhibit B-1, page 24

The comparative merits of the alternatives, including the financial impact, are summarized in the table below. The criteria that were evaluated are as follows:

1. Meets Single Contingency N-1 Transmission Planning Criteria: Ability to continue to serve all load during the outage of a single element.
2. Operations Accessibility and Operability: Considers the accessibility and operability of the facilities by FBC employees and contractors working on system repairs, performing routine maintenance, or transferring load during real-time outages.
3. Lifecycle Utilization: Considers the full lifecycle of the existing assets.
4. Project Risk: Considers Project risks, such as schedule, lands, and unforeseen environmental and archeological discoveries.
5. System Reliability: Refers to the availability of electrical supply on the transmission, distribution and substation facilities.
6. O&M and Sustainment Capital Costs: Costs related to maintaining the assets in place.
7. Present Value Incremental Revenue Requirement: The discounted value of the revenue requirement over 40 years.
8. Rate Impact: The levelized rate impact over the 40 year period.

15.1 Did FBC apply any weighting and provide scoring to the comparative merits in its analysis?

15.1.1 If yes, please provide.

15.1.2 If no, please explain why not.

16. Reference: Exhibit B-1, page 25 and 26

Table 3-3: Grand Forks Reliability Project Alternatives Comparison

Criteria	Alternative A	Alternative B	Alternative C
Technical			
Meets N-1 Transmission Planning Criteria	• Second transformer at GFT provides alternate 161/63 kV supply at GFT.	• Second transformer at GFT provides alternate 161/63 kV supply at GFT.	• 9L and 10L provide alternate 63 kV supply from WTS for Grand Forks area.
Operations	• GFT T1 load transfer can be transferred to GFT T2, and vice versa, remotely by System Control Centre (SCC).	• GFT T1 load transfer can be transferred to GFT T2, and vice versa, remotely by SCC. • OLI T1 remains as an onsite spare which can be used in the event either GFT T1 or GFT T2 fail.	• Field staff must manually close switches on 9L and 10L to reconfigure for 63kV supply from WTS. • OLI T1 remains as an onsite spare which can be used in the event GFT T1 fails.
Lifecycle Utilization[21]	• Makes use of remaining life of OLI T1 (15 years). • Removes portions of the legacy transmission lines 9L and 10L. • Given the condition of GFT T1 and OLI T1, both units could fail within a year of each other. This is considered to be a low risk.	• OLI T1 remains as on-site spare and available for future use. • Removes portions of the legacy transmission lines 9L and 10L.	• OLI T1 remains as on-site spare and available for future use. • Rehabilitates legacy transmission lines 9L and 10L.

Criteria	Alternative A	Alternative B	Alternative C
Project Risk	• Schedule Risk: Construction and removal window for 9L and 10L is impacted seasonally. • Lands Risk: Confirm distribution ROW for portion of 9L and 10L that will be repurposed for distribution. Considered to be low risk. • Environmental and Archeological Risk: Considered to be low risk.	• Schedule Risk: Construction and removal window for 9L and 10L is impacted seasonally. Lead time for a new transformer can be up to a year. • Lands Risk: Confirm distribution ROW for portion of 9L and 10L that will be repurposed for distribution. Considered to be low risk. • Environmental and Archeological Risk: Considered to be low risk.	• Schedule Risk: Construction window impacted seasonally. • Lands Risk: None, no changes to transmission or distribution routes. • Environmental and Archeological Risk: Considered to be low risk.
System Reliability	• Fewer outages are associated with transformers.	• Fewer outages are associated with transformers.	• More frequent outages are associated with transmission lines.
Financial			
O&M and Sustainment Capital Costs	• Reduces 9L and 10L transmission O&M costs. • Reduces 9L and 10L transmission rehabilitation capital costs. • Reduces 9L and 10L urgent repairs.	• Reduces 9L and 10L transmission O&M costs. • Reduces 9L and 10L transmission rehabilitation capital costs. • Reduces 9L and 10L urgent repairs.	• No reduction in 9L and 10L transmission O&M. • No reduction in transmission rehabilitation capital costs. • Reduces 9L and 10L urgent repairs
Present Value of 40 year Cost of Service	$9.959 million	$9.960 million	$14.004 million
Levelized Rate Impact	0.18 % $0.20 $/MWh ($0.00020 $/KWh)	0.18% $0.20 $/MWh ($0.00020 $/KWh)	0.26% $0.28 $/MWh ($0.00028 $/KWh)
Alternative Evaluation			
Ranking	2	1	3

16.1 Please briefly state the total number of customers who will be impacted and the expected improvements in system reliability/outages etc. that will arise for them.

16.2 Please quantify the expected benefits in system reliability for each Alternative.

17. Reference: Exhibit B-1, page 27

Alternative B provides an additional benefit over Alternative A. Because Alternative B includes installation of a new second transformer at this time as opposed to installing the on-site spare, it reduces the risk that both GFT T1 and GFT T2 could fail simultaneously. As mentioned in section 3.2.1, GFT T1 has a useful remaining life of 10 years and the on-site spare has a useful remaining life of 10 to 15 years, whereas a new transformer would have a useful remaining life of at least 40 years.

17.1 What circumstances might cause both transformers to fail simultaneously? Please explain and discuss the likelihood of such an event occurring.

17.2 Has FBC ever encountered a situation in which two transformers of similar remaining useful life failed simultaneously?

18. Reference: Exhibit B-1, page 27

All three alternatives have Project risks associated with them. The schedule risk is lowest for Alternative A since OLI T1 is already on site, Alternative B is dependent on the approximately one year lead time for procurement of a new transformer, and Alternative C has a greater likelihood of being impacted by seasonal construction windows. The lands risk is lowest for Alternative C since the distribution and transmission routes will not be changing, while Alternative A and Alternative B both require distribution rights-of-way to be confirmed for the portions of 9L and 10L that will not be removed. All alternatives have low unforeseen environmental and archaeological discovery risk during the construction phase based on FBC's historical experience in the GFT and along the 9L and 10L right-of-way.

Alternative A and Alternative B further improve system reliability by reducing exposure to transmission line outages through the removal of 9L and 10L, compared to Alternative C which rehabilitates the lines.

Based on the technical evaluation, Alternative A and Alternative B better address the technical criteria by supplying a second 161/63 kV supply at GFT as compared to Alternative C. However, Alternative B offers improved reliability compared to Alternative A since it includes installation of a new second transformer at GFT as opposed to installation of the on-site spare, thereby addressing the existing condition of GFT T1, which has exceeded the expected transformer lifespan of 40 years. This is because the on-site spare has a useful remaining life of only 10 to 15 years, whereas a new transformer would have a useful remaining life of 40 years. Furthermore, Alternative B is a more reliable option for the additional reason that OLI T1 would remain as an on-site spare at GFT. Therefore, Alternative B is the preferred solution as it best addresses the issue of transmission reliability for the Grand Forks area.

18.1 How did FBC value and/or account for 'schedule risk' in its evaluation? Please explain.

18.2 How did FBC value and/or account for 'system reliability' in its evaluation? Please explain.

19. Reference: Exhibit B-1, page 4 and page 28 and page 43

Financial Criteria

1. O&M and Sustainment Capital Costs;
2. Present Value of Incremental Revenue Requirement; and
3. Rate Impact.

Based on these criteria, the Company submits that the best alternative for the Project is Alternative B, i.e., to provide a second transformer at GFT (GFT T2) by purchasing and installing a new 161/63 kV transformer, remove 44.6 km of the 9L and 10L transmission lines between CHR and CSC, and repurpose 20.8 km of the 9L and 10L transmission lines to distribution lines. Alternative B best addresses the condition of existing facilities and reliability issues for the Grand Forks area. The evaluation of the alternatives and selection of the recommended solution will be discussed in detail in Section 3.4 and Section 3.5.

3.5.2 Financial Evaluation

Alternative A and Alternative B will have a net reduction in O&M costs since a large portion of 9L and 10L will be removed. There will be no change in O&M costs for Alternative C. In addition, FBC transmission condition assessment and rehabilitation (sustainment capital) occurs on an eight-year cycle; removal of a portion of 9L and 10L will reduce these costs in Alternative A and Alternative B. All three alternatives will see a reduction in urgent repairs on 9L and 10L, with the largest reduction in Alternative A and Alternative B since a portion of the lines will be removed.

Although the initial capital cost of Alternative A is less than Alternative B, the present value of the incremental cost of service between Alternative A and Alternative B is substantially equal, since the levelized rate impact percentage and the $ / MWh is the same (the present value for Alternative A is only $1 thousand lower than Alternative B). Even though Alternative C has the lowest initial capital cost, its present value of incremental cost of service is highest because of the higher O&M and sustainment capital costs for 9L and 10L.

Based on the financial analysis, both Alternative A and Alternative B better minimize the financial impact of the Project than Alternative C. Of these two options, the Company prefers Alternative B since it results in the same rate impact to customers as Alternative A based on a levelized lifecycle analysis over a 40 year period and was the preferred alternative based on the technical criteria as explained above.

6.5 *SUMMARY*

In this section, FBC has described the Project cost estimate, the financial evaluation, accounting treatment, and the rate impact. The Project will cost $12.2 million in 2018 dollars including net removal costs of $4.3 million. The levelized rate impact of Alternative B is projected to be 0.18% or $0.20 per MWh, and will add $2.32 to the annual bill for the average customer using 11,500 KWh.

19.1 Please provide a full financial summary for each alternative which depicts FBC's financial analysis of the three options or indicate where this is provided in the

application. Please include initial capital costs, sustainment capital, O&M, allowance for funds used during construction, any other relevant expenditures, present value calculations, all assumptions and any other inputs and calculations used to develop the financial assessment for each alternative. Please file confidentially if necessary.

19.2 Please discuss any quantification of risk reduction that was used in the financial assessment of the alternatives. Please file confidentially if necessary.

19.3 What value was assigned to the repurposing of 9L and 10L? Please provide and file confidentially if necessary.

20. Reference: Exhibit B-1, page 36

5.5 *PROJECT RESOURCES*

5.5.1 Project Management

FBC plans to have an FBC Project Manager who will manage all aspects of the Project, including, but not limited to, engineering, procurement, and construction. The Project Manager is responsible for coordinating all Project activity.

Additionally, FBC plans to have an FBC Construction Manager on site who will manage both internal and external construction resources. The Construction Manager is responsible for coordinating all on-site activity.

5.5.2 Engineering

FBC plans to have an FBC Project Engineer and an FBC Design Technologist manage the engineering component of the Project. External engineering support may be required to complete design for the foundations and transformer pad/containment.

5.5.3 Construction Services

The construction activities will be managed directly on site by FBC. Construction will be performed by qualified construction workers and supervisors.

20.1 Does FBC require any additional personnel in product management, engineering, construction services or other roles in order to undertake the project? Please explain why or why not.

20.1.1 If yes, please quantify.

20.2 Have the costs for project resources been included in the financial analysis? Please explain.

21. Reference: Exhibit B-1, page 39 and 40 and page 43

6.1 *PROJECT CAPITAL COST ESTIMATE*

Table 6-1: Summary of Estimated Project Capital Costs ($000)

Particular	2018 $	As–spent $
Pre-Approval Costs	257	257
Construction	6,414	6,630
Contingency	1,184	1,225
AFUDC		400
Subtotal – Construction	**7,855**	**8,512**
Net Removal Costs	3,475	3,625
Contingency	866	903

Particular	2018 $	As–spent $
AFUDC		131
Subtotal – Net Removal	**4,341**	**4,659**
Total Project	**12,196**	**13,171**

The Project capital cost estimate was developed based on consideration of the substation upgrade work and the transmission/distribution work. FBC requested quotes from potential suppliers to compile the station upgrade estimate. FBC engaged DBS Energy, an engineering consulting company, to provide the 9L and 10L transmission lines estimate as part of the condition assessment. FBC's estimate for the station upgrade can be found in Confidential Appendix H, and the DBS estimate for the 9L and 10L work can be found in the condition assessment report in Confidential Appendix C.[22]

Table 6-4: Schedule of Completion Inclusion in Rate Base (excluding AFUDC)

Year of Construction Complete	Construction Work to be completed	Estimated amount of capital (As-Spent $) transfer to Plant-in-Service ($ millions)	Date transfer to Opening Balance of Plant-in-Service
2020	Station	$ 5.3	January 1, 2021
2020	Distribution Rebuild	$ 1.4	January 1, 2021
2021	Distribution Rebuild	$ 1.4	January 1, 2022
2020	Station Removal	$ 0.1	January 1, 2021
2020	Transmission Removal	$ 2.2	January 1, 2021
2021	Transmission Removal	$ 2.3	January 1, 2022
	TOTAL	**$12.7**	

21.1 Please provide a breakdown for the Net Removal Costs of $3,475,000. Please provide confidentially if necessary.

21.2 Please provide the basis for the Contingency of $1,184,000. Please provide confidentially if necessary.

21.3 Please provide the basis for the Contingency of $866,000 in Net Removal. Please provide confidentially if necessary.

21.4 From how many suppliers did FBC request quotes to compile the station grade estimate?

22. Reference: Exhibit B-1 page 41

6.1.2 Transmission and Distribution

Transmission and distribution work will begin in 2020 after GFT T2 is installed. It is expected to take two years for 9L and 10L to be removed or have a portion repurposed for distribution. Work will occur primarily outside of winter. Transmission line work activities will be confined to existing FBC rights-of-way (ROW) and access roads. Distribution ROW will need to be acquired for the 9L and 10L distribution repurposing work.

Table 6-3 details the Project estimate which includes transmission line and conductor removal, distribution repurposing, recommended urgent work to stabilize the lines, and access road re-establishment. Conductor salvage credits are included in the net removal cost; based on $2.50 per pound of copper which is subject to market changes.

The detailed cost estimate for the transmission and distribution work is provided in the 9L and 10L condition assessment report in Confidential Appendix C.[23]

Table 6-3: Transmission and Distribution Capital Cost Summary ($000)

Particular	2018 $	As–spent $
Pre-Approval Costs	87	87
Construction	2,137	2,229
Contingency	427	446
AFUDC		90
Subtotal – Construction	**2,652**	**2,852**
Net Removal Costs	3,429	3,578
Contingency	857	894
AFUDC		128
Subtotal – Net Removal	**4,286**	**4,600**
Total T&D Costs	**6,938**	**7,452**

22.1 Please explain how FBC will acquire the Distribution ROW need for the 9L and 10L distribution work and provide quantification for costs. Please provide confidentially if necessary.

23. Reference: Exhibit B-1, page 42

6.1.3 Project Contingency Model and Determination of Project Contingency

Contingency has been applied to the Project to account for certain items, conditions, or events which may occur throughout the Project lifecycle. A contingency of 17.7 percent (including Project loadings) was used for the stations component and a contingency of 20 percent was used for the transmission and distribution component.

23.1 Please provide the rationale for the Contingency of 17.7% for the stations component. Please provide confidentially if necessary.

23.2 Please provide the basis for the Contingency of 20% for the transmission and distribution equipment and explain why it differs from the stations component. Please provide confidentially if necessary.

24. Reference: Exhibit B-1, page 42

6.2 *Operation and Maintenance*

FBC expects that the retirement of 9L and 10L transmission lines will reduce transmission line O&M expenditures by approximately $60 thousand per year and reduce brushing costs by an average of $31 thousand per year. However, it is expected that O&M expenditures related to substation equipment will increase by approximately $5 thousand per year. Overall, the Project is expected to reduce net O&M expenditures by approximately $85 thousand[24] annually starting in 2021.

24.1 Please provide the sources of information that FBC used to develop its O&M expenditure reduction assessment.

24.2 Why are O&M expenditures related to substation equipment likely to rise by $5000? Please explain.

25. Reference: Exhibit B-1, page 39 and page 43

As previously discussed, the recommended alternative for the Project is Alternative B, which includes:

- Installing a second transformer at Grand Forks Terminal Station (GFT) by purchasing a new 161/63kV transformer as described in the Application; and
- Removing 44.6 km of the transmission lines 9 Line (9L) and 10 Line (10L) from CHR to CSC, and repurposing 20.8 km of transmission lines 9L and 10L to distribution lines.

6.3.1 Retirement of Existing Assets

As described in Section 3.3.2, a portion of the 9L and 10L transmission lines will be removed, sold for scrap and retired from plant. The gross book value of the electric plant related to transmission lines 9L and 10L that is being retired from electric plant in service and also from accumulated depreciation is $3.22 million. This retirement has been planned in two phases and will be recorded when the distribution conversion work enters rate base. The book value of the remaining portions of the 9L and 10L transmission lines that are to be repurposed as distribution lines will be reclassed as distribution assets. This reclassification has no impact on the financial analysis.

25.1 Are there functional, life expectancy, or other limitations associated with utilizing repurposed lines such as the 9L and 10L for distribution? Please explain and provide quantification of such limitations.

25.2 Will the repurposed lines likely be used immediately or go into inventory for some period? Please explain.

25.3 If the lines are not expected to be used immediately, when does FBC expect that it will use them?

25.4 Please provide quantification of the revenue FBC expects to receive from the sale of the scrap portion of the transmission lines.

25.5 Please provide a brief discussion of FBC's experience using repurposed transmission lines.

26. Reference: Exhibit B-1, page 44

7.1 *Reliability Considerations*

Typical industry transmission planning standards require the system to be planned such that all projected customer loads are served during normal operation (N-0)[25] and single contingency (N-1).[26] As such, FBC transmission planning criteria ensure customer load can be supplied in N-0 and N-1 conditions.

Mandatory Reliability Standards (MRS) do not apply to the 9L and 10L transmission lines or the GFT transformers since these elements are not included as part of the Bulk Electric System (BES). To be included as part of the BES, transmission lines need to be operated at 100 kV or higher and transformers require the primary terminal and at least one secondary terminal operated at 100 kV or higher.

26.1 Please describe the significance of the inapplicability of the MRS to the 9L and 10L transmission lines or GFT transformers in this application.