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October 3, 2017

Industrial Customers Group
c/o #301 – 2298 McBain Avenue
Vancouver, BC V6L 3B1

Attention: Mr. Robert Hobbs

Dear Mr. Hobbs:

Re: FortisBC Inc. (FBC)

Project No. 1598920

Multi-Year Performance Based Ratemaking Plan for 2014 through 2019 approved by British Columbia Utilities Commission (Commission) Order G-139-14 – Annual Review for 2018 Rates (the Application)

Response to the Industrial Customers Group (ICG) Information Request (IR) No. 1

On August 10, 2017, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-116-17 setting out the Regulatory Timetable for review of the Application, FBC respectfully submits the attached response to ICG IR No. 1.

If further information is required, please contact Joyce Martin at 250-368-0319.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1. Reference: Exhibit B-2, Section 1.4.3.1, pp. 6-9, Table 1-2

1.1 Please reproduce Table 1-2 specifically identifying the amount of Contributions in Aid of Construction in each year.

Response:

Please refer to the response to BCUC IR 1.8.1.

1.2 Please identify the amount of increased capital expenditures in 2017 attributable to each of the following main pressures: 1) System improvements to accommodate customer growth; 2) Forced relocation of transmission and distribution infrastructure due to the widening of Highway 97 near Kelowna by the Ministry of Transportation and Infrastructure; 3) Customer- driven modifications at RG Anderson Terminal associated with the City of Penticton's distribution voltage conversion project; and 4) Increased cost of equipment and supplies purchased from the United States due to the unfavourable exchange rate.

Response:

Please refer to the responses to BCUC IRs 1.10.1.

2. Reference: Exhibit B-2, Section 1.4.3.4, page 13

"It is clear that the capital spending is required and it is the right thing to do to limit increasing risk exposure in the system, and avoid unplanned and urgent capital work that reduces productivity and drives up project costs by reducing FBC's ability to plan and execute the work."

2.1 Please explain more fully why the capital spending above forecast is "the right thing to do" and describe the analysis has FortisBC performed to identify the increased risk exposure to the system by deferring such capital spending.

Response:

FBC considers capital spending above forecast is the right thing to do in order to manage risk exposure, to reduce the cost of equipment replacement and other work by completing it on a planned basis rather than on a more-costly urgent basis, and to realize more productivity efficiencies and operational savings.

Please refer to the response to BCUC IR 1.11.1 which describes the manner in which FBC has prioritized its capital work.

3. Reference: Exhibit B-2, Section 3.3, page 22

"DSM savings and other savings are forecast on an incremental basis (to savings embedded in historical loads to 2016).

The DSM savings forecast is deducted from the before-savings forecast for all customer classes."

3.1 Please provide the "before savings" data for Table 3-3, and a table of the difference between "before savings" and "after savings".

Response:

The requested information is provided in the table below.

Before and After Savings	Before-Savings Forecast		After-Savings Forecast		Difference	
Energy (GWh)	**2017S**	**2018F**	**2017S**	**2018F**	**2017S**	**2018F**
Residential	1,296	1,293	1,290	1,280	7	13
Commercial	915	930	908	912	7	18
Wholesale	587	589	585	586	1	2
Industrial	371	382	370	379	1	2
Lighting	16	16	16	15	0	1
Irrigation	41	41	41	41	0	0
Net	3,226	3,251	3,209	3,213	17	38
Losses	281	283	275	272	6	10
Gross	3,506	3,534	3,484	3,485	22	48
System Peak (MWh)						
Winter Peak	714	719	710	712	4	7
Summer Peak	582	586	580	581	2	5

The before-savings historical loads are not included as FBC is unable to accurately determine this. Exhibit B-2, Appendix A-2, page 7, Table 5.3 shows historical savings estimates, but FBC is unable to validate the actual savings embedded in the annual historical loads.

Note: The 2017S Net DSM and other savings without losses in Appendix 2, Table 5.3 is 17 GWh and not 27 GWh. A corrected version of Table 5.3 can be found in the response to BCOAPO IR 1.8.1. There is no impact to the net load or gross load forecasts as a result of this error.

4. Reference: Exhibit B-2, Section 3.5.7, pp. 30-31

"The 8 percent loss rate was based on a loss study that was conducted in 2012, which is still in line with the loss rate that FBC is seeing on an annual basis (averaging 7.88 percent over the previous three years, after DSM and AMI impacts)."

4.1 Please provide the 2012 loss study.

Response:

The 2012 loss study is provided in Attachment 4.1 as requested. The loss study was based on the years 2011 and 2012 after the Okanagan Reinforcement Project was completed, since the project lowered system losses from transmission and distribution. The loss study uses CIS billing information and the actual gross load from the System Control Center (SCC) to calculate the loss rate.

FBC bills most customers every second month, which results in some meter readings containing load from three months. For example, the GWh volume billed in January 2011 (cell B7) includes consumption from November 2010 (cell B4), December 2010 (cell B5) and January 2011 (cell B6), and so on for each month's billings. Energy consumed in January 2011 (cell B8) is billed in each of January (cell B6), February (cell C5), and March (cell D4). Therefore, energy consumed during 2011 is the sum of the monthly values in row 8 (found in cell P8). The difference between 2011 consumption and gross load (cell Q8) is losses and the gross loss rate is expressed as losses divided by gross load.

The uncertainties associated with the three-month allocation process make looking at losses for any individual month unreliable. However, if the time frame is much longer, such as over a couple of years, the uncertainties are reduced. FBC is currently in the process of analyzing the AMI loss data in order to update the loss projections.

5. Reference: Exhibit B-2, Section 3.5.7.1, pp. 31-32

"FBC is beginning to leverage the tamper detection functionality of the AMI system for theft identification and has also begun to implement its energy balancing program."

5.1 Please provide the specific details (cost, scope, schedule, etc.) associated with the energy balancing program.

Response:

FBC's AMI-enabled theft detection and deterrence strategy involves two primary components:

1. Leveraging AMI meter data (events and alarms) for identifying possible instances of theft; and

2. Deploying portable "feeder meters" on the primary system for the purposes of reconciling customer meter data downstream (energy balancing).

With respect to FBC's energy balancing program, capital expenditures of $0.345 million were incurred in 2015 and 2016 related to the procurement of portable feeder meters for use in conducting energy balancing analyses, with full implementation of FBC's energy balancing program completed in Q2 2017.

2018 O&M expenditures related to FBC energy balancing program are budgeted at $0.251 million, and include a 0.5 FTE Revenue Protection Analyst as well as the use of a contract powerline technician resource for deploying feeder meter sensors and conducting secondary audits to support energy balancing analyses.

6. Reference: Exhibit B-2, Section 4.2, pp. 35-36

6.1 Please provide the average cost per MWh and total MWh for the energy sourced from "small Independent Power Producer (IPP) contracts" and the "number of market purchase arrangements". What is the number of small IPP contracts?

Response:

IPPs include Distributed Generation, which is an individual-use generation resource, such as run of river, and small scale utility distribution supply. Self-Generators refer to large power produced by self-generating customers that can provide electricity to FBC. Due to the small number of IPP facilities and self-generators, FBC has aggregated the data to preserve the confidentiality of the contracts.

In 2017, FBC purchased energy from eight customers that are included in the IPP and Self-Generator categories. The average cost per MWh and total MWh embedded in the 2017 Approved, 2017 Projected, and 2018 Forecast are outlined in the table below.

	Approved 2017	Projected 2017	Forecast 2018
IPP and Self-Generator (MWh)	3,422	3,521	3,092
Average Rate ($CDN/MWh)	$ 58.73	$ 44.93	$ 47.03

7. Reference: Exhibit B-2, Section 4.5, pp. 37-38, Table 4-2; Section 4.6, page 38, Table 4-3

7.1 Please provide the approved and projected 2017 energy volumes associated with the values in Table 4-2.

Response:

Please refer to the response to BCOAPO IR 1.16.1.

7.2 Please explain the reasons for the reduction between the approved and projected amounts for Independent Power Producers in Table 4-2.

Response:

The 2017 Approved expense for Independent Power Producers (IPP) includes both IPP and Self-Generating customers. In the 2017 Projected figure, the IPP customers and the Self-Generators have been split into separate categories. Therefore, to compare like figures, the 2017 Approved IPP expense of $0.201 million should be compared with the IPP expense plus the Self-Generator expense from the 2017 Projected totaling $0.158 million. The decrease of $0.043 million is the result of slightly lower purchase volumes along with lower contract rates.

7.3 Please explain how Independent Power Producers differ from Self-Generators in Tables 4-2 and 4-3.

Response:

Please refer to the response to ICG IR 1.6.1.

8. Reference: Exhibit B-2, Section 5.3, page 43

8.1 Please provide the amount of transmission access revenue recovered in 2016 (actual), 2017 (projected) and 2018 (forecast), broken out by each of the applicable tariffs under which the amounts are recovered.

Response:

The requested amounts are provided below.

	2016 Actual	2017 Projected	2018 Forecast
Rate 110	895	807	799
Rate 103	188	182	182
Rate 104	195	190	189
Total Transmission Access Revenue	**1,278**	**1,179**	**1,170**

9. Reference: Exhibit B-2, Section 6.3.2, page 47

9.1 Please explain in detail why the 2018 insurance premiums are lower than the 2017 premiums even after factoring in five percent escalation is based on a combination of historical increases in premiums, increases in the value of assets year over year and the expectations of Fortis Inc.'s insurance broker on future premiums.

Response:

FBC's insurance renewal occurred on July 1, 2017 for the period to June 30, 2018; therefore the 5 percent escalation was only applied to the last six months of 2018. Premiums for the insurance renewal effective July 1, 2017 were less than anticipated and this reduction in premiums extends to the first six months of 2018. With regard to the 2017 renewal, insurance pricing for the Power/Energy market was more competitive than expected and, more specifically, the Fortis account has had a clean claims record over the period resulting in lower premiums. FBC has also taken advantage of its involvement in the growing Fortis Inc. insurance program resulting in insurance premium savings.

10. Reference: Exhibit B-2, Section 6, p. 51 and Order G-18-17

"In Order G-139-14 the Commission confirmed that as a non-recurring expenditure, MRS audits should not be included in Base O&M."

"Z-factor treatment for the 2017 incremental operations and maintenance expenses and capital expenditures related to the Mandatory Reliability Standards Assessment Report No. 8 is approved."

"… MRS incremental capital expenditures related to BC Hydro's Assessment Reports No. 8 and No. 10, which qualify for exogenous treatment as discussed in Section 12.2 of the Application."

10.1 Please explain the differences, if any, between the Commission treatment of O&M expenses related to MRS audits, including 2018 Compliance Audit, and MRS Report No. 8.

Response:

O&M Expenses associated with the 2018 compliance audit and MRS Reports No. 8 and No. 10 are all treated as forecast O&M outside of the formula. For the reasons explained in the response to BCUC IR 1.1.1, the compliance audit does not meet the criteria for Z-factor treatment, therefore the 2018 compliance audit is treated in the same manner as the 2015 compliance audit. MRS Assessment Reports No. 8 (and No. 10) do meet the Z-factor criteria as explained in section 12.2 of the Application and are also outside of formula O&M Expense.

In both cases, all variances between forecast and actual expenses are trued up by way of the Flow-through deferral account, and the variances are either returned to or recovered from ratepayers in the following year.

10.2 Please identify any 2017 and 2018 capital expenditures related to MRS compliance? If any, does FortisBC propose Z-factor treatment for all such capital expenditures?

Response:

FBC proposes Z-factor treatment only for capital expenditures related to events that qualify as exogenous factors. FBC projects capital expenditures of $1.349 million in 2017 and $0.050 million in 2018 related to Assessment Report No. 8, shown in Table 7-3 of the Application. Capital expenditures beyond 2018 related to Assessment Reports No. 8, No. 10 and future events triggering costs that meet the Z-factor criteria will be addressed in future applications.

Any other capital expenditures related to ongoing MRS compliance are included in the formula capital envelope.

10.3 Please explain the proposed treatment of the costs of $0.350 million related to the 2018 audit? Is this amount in addition to or included in the forecast expenditures for 2018 of $0.540 million?

Response:

Please refer to the responses to BCUC IR 1.1.1 and ICG IR 1.10.1 explaining the treatment of the costs associated with the 2018 compliance audit.

The audit costs are not included in the $0.540 million forecast for Assessment Report No. 8. Table 6-6 of the Application, reproduced below, shows the 2018 forecast costs associated with the compliance audit in addition to Assessment Reports No. 8 and No. 10.

Table 6-6: MRS Incremental O&M Expense ($ millions)

Line No.	Description	Approved 2017	Projected 2017	Forecast 2018
1	Assessment Report No. 8	$ 0.050	$ 0.050	$ 0.540
2	Assessment Report No. 10	-	-	0.180
3	2018 Compliance Audit	-	-	0.350
4	Forecast O&M	$ 0.050	$ 0.050	$ 1.070

10.4 Please identify costs, if any, related to MRS compliance that the Company would include in Base O&M? At what point should the costs and activities associated with MRS compliance become part of Base O&M? Are the costs and activities associated with MRS compliance expected to continue into the foreseeable future? When was FortisBC's compliance with MRS first required in British Columbia?

Response:

MRS took effect on November 1, 2010. MRS compliance is part of the Company's ongoing requirements to operate and maintain the electrical grid and the costs will continue into the

foreseeable future. The standards will continually evolve and FBC will continue to evaluate any changes and identify impacts through future applications to the Commission.

Already included in Formula O&M are all costs related to maintaining compliance with the standards in effect when the PBR Plan was established, in addition to incremental costs associated with any new or revised standards since that time, other than those associated with the Z-factor events or the triennial compliance audits. If FBC were to enter into a new PBR plan at the expiration of the existing one and to rebase its formula O&M Expense, that would be an appropriate time to incorporate into formula O&M the costs of ongoing MRS compliance. FBC expects that incremental MRS costs such as those associated with annual assessment reports which meet the Z-factor criteria, or infrequent or nonrecurring costs such as the triennial compliance audits, would remain outside of formula O&M.

10.5 Please identify all Commission decisions, if any, about capital expenditures related to BC Hydro's Assessment Report No. 10?

Response:

FBC is not aware of any decisions about capital expenditures related to BC Hydro's Assessment Report No. 10. FBC does not anticipate any capital expenditures related to Assessment Report No. 10 in 2018.

10.6 Please explain why the Draft Order, Appendix F, seeks Z-factor treatment of 2018 capital expenditures related to MRS Report No. 8? Please identify when MRS Report No. 8 capital expenditures are expected to be complete and explain all forecast 2018 capital expenditures related to MRS Report No. 8?

Response:

Z-factor treatment for costs related to Assessment Report No. 8 has been approved in 2016 and 2017 by Orders G-202-15 and G-8-17, respectively. Consistent with these Orders, FBC seeks approval for this treatment in 2018.

As part of the Annual Review for 2017 Rates, FBC forecast a one-time capital expenditure of $1.350 million to add hardware and software systems to existing infrastructure to comply with Assessment Report No. 8. FBC also identified in its Annual Review for 2017 Rates that

sustaining capital would be required beyond 2017. The 2018 capital expenditures are part of the sustaining capital required for ongoing support for the hardware and software additions, including annual upgrades and minor additions that will be required to the initial infrastructure and systems being implemented in 2017. The sustaining capital expenditures will continue for the life of the hardware and software solutions implemented until end of life of the components.

10.7 Have the MRS audits now become recurring expenditures (triennial), and as such, should the costs now be incorporated in Base O&M?

Response:

No, the costs should not be incorporated into Base O&M. The PBR Plan does not contain a provision to amend the Base O&M Expense during the PBR term. The costs of the compliance audits should continue to be forecast for each occurrence and variances trued up by way of the Flow-through deferral account.

11. Reference: Exhibit B-2, Section 6, p. 51

"The O&M reduction related to the annual unit inspections is a one-time reduction to O&M Expense in the year that a unit is refurbished. … For this reason, the O&M reduction is outside of the formula O&M amount."

11.1 Please explain why the one-time reduction to O&M Expense referred to above should not benefit customers through a one-time reduction in 2018 to Base O&M Expenditure.

Response:

The PBR Plan does not contain any provisions for temporary reductions to base (formula) O&M.

The result of decreasing total O&M (see Table 6-3) is to reduce revenue requirements by the $0.040 million. Therefore, customers receive the full benefit of the lower O&M expense. This is the same result as if formula O&M were lower by $0.040 million.

12. Reference: Exhibit B-2, Section 7, p. 62

"Although not identified in the proceeding to review 2017 rates, the 2016 forecast was lower than usual due to an error when certain uncollectable account balance provisions in the general ledger were omitted from the forecast."

12.1 Please explain why the uncollectable accounts in the general ledger that were omitted from the 2016 forecast should now be recovered from customers?

Response:

The discussion of uncollectable accounts in section 7 concerns the calculation of the working capital component of rate base in 2016. The omission of certain of the general ledger accounts from the forecast had the effect of reducing the working capital allowance and hence rate base, thereby reducing revenue requirements for 2016 through a lower return on rate base. There is no true-up to actuals for this item, so the lower 2016 return is not being recovered from customers.

13. Reference: Exhibit B-2, Section 7, p. 63

"These include shortening the timeline for sending payment reminder notices, using reminder calls on overdue payments more frequently, and the implementation of AMI meters with the ability to remotely disconnect and reconnect meters."

13.1 Please explain whether the timeline for disconnection for late payment has been shortened with the implementation of AMI meters?

Response:

In the circumstances where a disconnection is required for non-payment, the timeline is approximately three months from when the bill was due to when the disconnection occurs. This timeline has not changed as a result of AMI meters.

Further, FBC regards the discontinuation of service as a last resort and as such, works with each customer individually to consider the various alternatives available, such as bill payment options (i.e., flexible payment plans and pre-authorized payment plans) based on their individual situation.

13.2 Please identify how long payments can be overdue for a customer in each rate class before FortisBC remotely disconnects service to the customer? If there is not a specific length of time a residential customer can be overdue, even if the customer has not been contacted, before FortisBC remotely disconnects service, please explain why not?

Response:

Please refer to the response to ICG IR 1.13.1.

To the extent that discontinuation of service is deemed necessary, FBC makes every reasonable attempt to contact the necessary parties before doing so.

14. Reference: Exhibit B-2, Section 8, p. 67

Based on the above information, FBC's AFUDC Rate for 2018 (which is equal to its after-tax weighted average cost of capital) is 5.91%.

14.1 Please confirm that the WACC of 5.91% is a forecast and the actual WACC can be expected to either more or less than the forecast of 5.91%. If confirmed, please explain if the AFUDC is based on the actual or forecast WACC?

Response:

Confirmed. 5.91 percent is the forecast WACC which is used in determining FBC's AFUDC. The actual WACC may differ during the year due to the timing, yield, and amount of long term debt issued during the year, as well as the actual short term balances and rates. As AFUDC is calculated using the approved forecast WACC, the actual WACC would not impact AFUDC amounts during the year.

14.2 Please comment on whether the AFUDC for a project is included in rate base before the capital expenditures for the project are included in rate base? if capital expenditures are not included in rate base until the project is used and useful and AFUDC is included in rate base before the project is used and useful, please explain why this is the appropriate treatment of AFUDC?

Response:

AFUDC goes into rate base at the same time as the project expenditures go into rate base.

15. Reference: Exhibit B-2, Section 12.4.1.1, p. 119

15.1 Please explain whether FortisBC expects to recover the costs of the Community Solar Pilot Project Application from customers if the Commission denies the Application.

Response:

Yes. The recovery of costs associated with bringing an Application before the Commission is not contingent upon whether the Application is ultimately approved.

16. Reference: Exhibit B-2, Section 13.2.3, pp. 134-137

16.1 Please provide the annual actual operating hours, idle hours, and forced outrage hours for each of FortisBC's generating units for the years shown in Table 13-13. If possible, please provide the comparable CEA statistics for the hydro-electric sector. Do the quoted CEA statistics include all generation or specifically hydro-electric generation?

Response:

The annual actual operating hours, idle hours, and forced outage hours for each of FBC's generating units for the years 2009 to June 2017 YTD are presented in Tables 1 to 9 below. Please note that FBC calculates the Operating and Idle hours yearly in the April – May period of the following year and as such the June 2017 YTD hours are not provided. The Forced Outage Rate reported for June 2017 YTD was calculated using an estimated number for the operating hours. The CEA Forced Outage Rate presented in Table 13-13 is provided in the annual CEA reports that can be obtained from CEA; the CEA reports do not contain the operating hours, idle hours, and forced outrage hours. The quoted CEA Forced Outage Rate presented in Table 13-13 includes hydro-electric generation only.

Table 1: 2009

	Operating (hrs.)	Idle (hrs.)	Forced Outage (hrs.)
Lower Bonnington - 01	8299.36	455.46	0.00
Lower Bonnington - 02	5547.83	3199.63	4.69
Lower Bonnington - 03	5688.40	3065.37	4.17
Upper Bonnington - 01	1933.23	6596.48	1.47
Upper Bonnington - 02	1260.74	7281.38	2.10
Upper Bonnington - 03	842.59	7042.48	624.95
Upper Bonnington - 04	785.82	7772.28	1.63
Upper Bonnington - 05	8496.45	39.50	0.25
Upper Bonnington - 06	1651.06	6889.60	0.00
South Slocan - 01	4640.35	582.83	0.00
South Slocan - 02	6977.39	796.96	5.96
South Slocan - 03	6147.08	741.01	0.00
Corra Linn - 01	8407.49	333.40	0.30
Corra Linn - 02	7447.14	1312.83	0.00
Corra Linn - 03	3385.45	5372.09	2.40

Table 2: 2010

	Operating (hrs.)	Idle (hrs.)	Forced Outage (hrs.)
Lower Bonnington - 01	8359.34	314.10	0.00
Lower Bonnington - 02	3233.36	5440.57	1.65
Lower Bonnington - 03	6852.70	1823.08	0.00
Upper Bonnington - 01	854.77	7628.36	25.53
Upper Bonnington - 02	897.47	7755.87	0.00
Upper Bonnington - 03	815.91	7622.88	0.00
Upper Bonnington - 04	816.49	7864.73	0.00
Upper Bonnington - 05	8583.16	47.90	26.91
Upper Bonnington - 06	1142.72	7537.33	2.20
South Slocan - 01	6027.30	1662.72	5.89
South Slocan - 02	6798.32	1746.40	0.90
South Slocan - 03	5496.30	3122.30	0.00
Corra Linn - 01	4373.51	886.80	0.00
Corra Linn - 02	8467.76	189.91	3.23
Corra Linn - 03	5493.96	3080.41	3.36

Table 3: 2011

	Operating (hrs.)	**Idle (hrs.)**	**Forced Outage (hrs.)**
Lower Bonnington - 01	7566.00	1116.61	0.00
Lower Bonnington - 02	3879.30	4761.28	42.03
Lower Bonnington - 03	8598.45	82.93	0.17
Upper Bonnington - 01	2271.97	6403.88	0.00
Upper Bonnington - 02	2412.67	6242.45	0.00
Upper Bonnington - 03	2269.67	6387.98	0.00
Upper Bonnington - 04	2486.22	6170.62	0.00
Upper Bonnington - 05	7956.12	697.18	0.00
Upper Bonnington - 06	3411.23	5102.07	1.18
South Slocan - 01	4651.17	4020.70	0.00
South Slocan - 02	6730.55	1924.20	0.00
South Slocan - 03	8275.67	406.27	1.22
Corra Linn - 01	6993.47	55.08	27.93
Corra Linn - 02	4078.32	57.33	0.30
Corra Linn - 03	7061.68	1586.58	0.00

Table 4: 2012

	Operating (hrs.)	Idle (hrs.)	Forced Outage (hrs.)
Lower Bonnington - 01	6079.45	2392.49	96.38
Lower Bonnington - 02	5948.68	2643.62	4.73
Lower Bonnington - 03	7951.58	733.52	3.98
Upper Bonnington - 01	3146.57	5426.53	50.25
Upper Bonnington - 02	2427.53	5515.00	5.68
Upper Bonnington - 03	2911.90	5116.48	7.08
Upper Bonnington - 04	2790.15	5644.78	195.88
Upper Bonnington - 05	6401.83	2162.62	25.87
Upper Bonnington - 06	5253.17	3385.40	30.88
South Slocan - 01	7195.63	1497.93	1.77
South Slocan - 02	6099.90	2571.75	1.95
South Slocan - 03	7006.35	1675.57	0.20
Corra Linn - 01	8005.93	648.87	0.00
Corra Linn - 02	7645.59	888.53	0.85
Corra Linn - 03	3742.92	3582.20	5.88

Table 5: 2013

	Operating (hrs.)	**Idle (hrs.)**	**Forced Outage (hrs.)**
Lower Bonnington - 01	6021.97	2649.68	3.88
Lower Bonnington - 02	7356.27	1305.22	0.00
Lower Bonnington - 03	6397.08	2276.12	2.60
Upper Bonnington - 01	2108.62	6643.87	5.10
Upper Bonnington - 02	2098.12	6546.13	5.97
Upper Bonnington - 03	0.00	2167.65	0.00
Upper Bonnington - 04	1967.62	6785.98	6.38
Upper Bonnington - 05	5622.32	2909.93	1.05
Upper Bonnington - 06	5335.10	3384.75	8.08
South Slocan - 01	4742.35	4016.77	0.87
South Slocan - 02	8631.33	119.68	2.28
South Slocan - 03	6403.87	2356.12	0.00
Corra Linn - 01	8680.10	0.00	8.78
Corra Linn - 02	4615.24	15.17	4120.78
Corra Linn - 03	5622.72	3051.77	0.00

Table 6: 2014

	Operating (hrs.)	Idle (hrs.)	Forced Outage (hrs.)
Lower Bonnington - 01	8397.83	252.92	0.00
Lower Bonnington - 02	7279.43	918.50	0.00
Lower Bonnington - 03	5589.48	3067.10	2.28
Upper Bonnington - 01	3367.20	4948.50	1.82
Upper Bonnington - 02	3734.40	4824.98	66.17
Upper Bonnington - 03	29.43	0.00	0.00
Upper Bonnington - 04	2777.65	5134.57	3.48
Upper Bonnington - 05	7405.52	1251.87	1.73
Upper Bonnington - 06	4952.63	3606.43	0.85
South Slocan - 01	3722.02	4131.50	824.50
South Slocan - 02	8605.85	0.00	75.88
South Slocan - 03	8369.48	257.23	53.68
Corra Linn - 01	6189.76	2159.82	0.30
Corra Linn - 02	7155.42	933.63	422.77
Corra Linn - 03	7456.07	1206.93	1.22

Table 7: 2015

	Operating (hrs.)	**Idle (hrs.)**	**Forced Outage (hrs.)**
Lower Bonnington - 01	6660.03	1966.75	6.02
Lower Bonnington - 02	6433.33	2226.20	0.12
Lower Bonnington - 03	5286.43	3396.13	1.67
Upper Bonnington - 01	613.78	7318.67	7.43
Upper Bonnington - 02	717.13	7938.68	3.27
Upper Bonnington - 03	675.75	6201.05	1.68
Upper Bonnington - 04	480.05	8174.63	3.42
Upper Bonnington - 05	7402.77	1239.93	3.90
Upper Bonnington - 06	3575.93	5080.97	0.28
South Slocan - 01	4272.85	4319.43	3.73
South Slocan - 02	7440.60	1203.77	2.15
South Slocan - 03	6438.52	2130.15	0.00
Corra Linn - 01	4752.40	3884.45	14.63
Corra Linn - 02	7975.43	230.90	0.10
Corra Linn - 03	4927.68	3020.17	3.15

Table 8: 2016

	Operating (hrs.)	Idle (hrs.)	Forced Outage (hrs.)
Lower Bonnington - 01	5962.93	1930.30	3.95
Lower Bonnington - 02	7157.23	1604.68	4.23
Lower Bonnington - 03	6635.15	1893.65	3.20
Upper Bonnington - 01	2029.05	6130.80	0.00
Upper Bonnington - 02	1995.63	6732.60	0.80
Upper Bonnington - 03	1862.28	6195.75	673.67
Upper Bonnington - 04	2219.65	5692.33	0.00
Upper Bonnington - 05	5936.28	2798.13	3.35
Upper Bonnington - 06	5752.18	2824.42	1.33
South Slocan - 01	5073.25	3425.12	1.05
South Slocan - 02	7216.45	1502.83	0.00
South Slocan - 03	8084.13	425.73	0.00
Corra Linn - 01	5942.03	2104.33	1.77
Corra Linn - 02	8184.23	355.13	5.75
Corra Linn - 03	6137.13	2488.07	1.97

Table 9: June 2017 YTD

	Operating (hrs.)	Idle (hrs.)	Forced Outage (hrs.)
Lower Bonnington - 01	-	-	10.08
Lower Bonnington - 02	-	-	0.00
Lower Bonnington - 03	-	-	0.00
Upper Bonnington - 01	-	-	231.78
Upper Bonnington - 02	-	-	69.25
Upper Bonnington - 03	-	-	1.17
Upper Bonnington - 04	-	-	34.22
Upper Bonnington - 05	-	-	12.76
Upper Bonnington - 06	-	-	15.10
South Slocan - 01	-	-	0.00
South Slocan - 02	-	-	0.00
South Slocan - 03	-	-	1.08
Corra Linn - 01	-	-	0.00
Corra Linn - 02	-	-	0.00
Corra Linn - 03	-	-	0.00

17. Reference: Exhibit B-2, Appendix B, Order G-139-14, p. 80

17.1 Please describe the consultations that have taken place regarding the selection of a mutually acceptable consultant to perform the benchmarking study.

Response:

In compliance with the Commission's directive regarding the Benchmarking Study, FEI/FBC consulted with stakeholders, including ICG, in May/June of 2017 on the choice of a mutually acceptable consultant to complete the benchmarking study and the broad terms and parameters of the study.

Please refer to the response to BCOAPO IR 1.26.3 for a summary of the Benchmarking Study progress to date and suggested next steps. Included in the response is a document entitled "Summary of Stakeholder Comments Regarding the Benchmarking Study" which lists the stakeholders consulted and the representatives and summarizes stakeholders' comments provided on the choice of a mutually acceptable consultant to complete the benchmarking study and the broad terms and parameters of the study.

18. Reference: Exhibit B-2, Appendix C, Ruckles project, Section 1.3.1, pp. 2-3

18.1 Please provide the civil and structural design tender package for the Ruckles project, and a summary of the bids received.

Response:

Please refer to Attachment 18.1, which is a copy of FBC's civil and structural design tender package, excluding the attachments identified in section 5.2 of the tender package. A complete copy of FBC's tendering documents would contain detailed information on FBC's facilities that are security sensitive, as well as commercial terms and conditions that are commercially sensitive to FBC. Release of the security and commercially sensitive information in these documents would compromise the security of FBC's facilities and systems, and harm FBC's negotiating position in the future to the detriment of FBC's ratepayers.

The responses to FBC's tenders are also confidential and commercially sensitive to both FBC and its contractors. FBC can report that it received bids from two engineering consultants, both of which were below $50 thousand and within 10 percent of each other. The contractor that submitted the best bid and was best resourced to complete the work was selected.

18.2 Please provide the electrical design tender package for the Ruckles project, and a summary of bids received.

Response:

The majority of the electrical design has been completed using FBC staff and hence no overall electrical design tender package for the project was prepared. Some small studies were prepared by contractors.

19. Reference: Exhibit B-2, Appendix D, UBO Refurbishment project, Section 4.2, page 10

19.1 Please provide the criteria used by FortisBC to determine whether stator core condition is acceptable or not.

Response:

To evaluate the condition of the generator stator core, FBC used the Electromagnetic Core Imperfection detection (EL-CID) method. This method was used to check for any significant damage to the inter-laminar insulation system and to identify areas and features on the core which may require further investigation and possible remedial measures.

In short, this method generates a magnetic field throughout the entire stator core. The amount of magnetic field through the stator core is measured to ensure uniformity throughout the stator. Any non-uniformity indicates a potential flaw in the stator core laminations which is then investigated further.

A visual inspection of the stator core was also completed following blast cleaning to detect any surface problem areas and visible burned or damaged laminations.

Results from the testing and inspection of the Unit 3 stator core were reviewed by FBC and by a third party consultant and the condition was determined to be acceptable.

19.2 Why is the condition of the stator core of Unit 2 not an issue?

Response:

The Unit 2 stator core was replaced as part of the repairs completed after the unit failed in 1995. Therefore, rewinding of Unit 2 was not included in the project scope.

19.3 Was the condition stator core of Unit 3 acceptable?

Response:

Please refer to the response to ICG IR 1.19.1.

19.4 What is the potential cost risk associated with unacceptable condition of the remaining stator cores?

Response:

The potential cost risk associated with unacceptable condition of the remaining stator cores is dependent on whether the cores of the unit can be repaired or have to be replaced.

The capital cost of repairing stator cores for Units 4 and 1 could range from $200 thousand to $300 thousand per unit, and could delay the in-service date three to four weeks for each unit. These figures are difficult to predict since the magnitude of repairs can range significantly.

The estimated capital cost of replacing a stator core is approximately $700 thousand and could delay the in-service date of the respective unit by three to four months.

Attachment 4.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 18.1

ENGINEERING
SCOPE of WORK

Ruckles Substation 2017 Upgrade
Site Prep & Civil Design

Prepared: **John McIntosh**
Checked: **Anjuman Shahriar**
Approved:

Date	Revision	Description	Checked	Approved
Jan 17/17	R0	Issued for Proposal	AS	
Jan 31/17	R1	Updated supporting docs, revised dates and added additional detail		

1.0 INTRODUCTION

The existing Ruckles substation has numerous operational issues which require substantial expenditure to rectify, and the station is also located in a flood zone which could see 2m (+/-) of water cover the site in a 20 year flood event. As a result, the station will be completely rebuilt in situ and its elevation increased to rectify the noted concerns at the station.

This broadly involves:

- Site preparation for new foundations, retaining walls and perimeter fencing
- Provision of new equipment foundations
- Staged re-grading of the station to permit construction of the new site, while leaving existing equipment in place and operational
- Install and commission new equipment in a staged manner to re-supply the existing 13kV and 4kV loads.
- Once all new equipment is in service and old equipment removed, complete the grading of the site, retaining walls and new approach road.

Staging of the project will be very important and must be considered for all parts of the design and construction. Proposed staging is outlined in the included Staging drawings. It is currently expected that all foundations for the project will be completed by the fall of 2017. However, the balance of the site work, grading, fences and retaining walls may not be completed until fall 2018.

2.0 PROJECT WORK SUMMARY

The following broad tasks are required, but the level of effort and detail is to be assessed and determined by the consultant to meet the needs of the scope outlined:

(a) Review and assess existing flood hazard data and preliminary site drawings then finalize the grade elevations required to meet the needs of the substation and data presented;
(b) Finalize the preliminary station road approach to ensure grading, drainage and the design proposed is acceptable. The Mobile Transformer access is of key importance;
(c) Arrange for any additional survey work as deemed necessary;
(d) Assess existing geotechnical information and arrange for further investigations if necessary;
(e) Complete detailed site preparation design including grading, profiles, drainage, fencing and retaining walls with sufficient detail that Contractors can accurately assess and cost the project with minimal exposure to claims for extras. Develop civil staging drawings if considered necessary.
(f) Complete all required equipment foundation designs based on standard Fortis designs, but taking into consideration the specific needs of the station and construction;
(g) Field reviews during construction to ensure the installation is completed in accordance with the design and;
(h) Complete Record drawings at the completion of the project.

The Consultant shall complete all necessary site preparation and civil design and engineering required for the station. This shall include, but is not limited to the following:

i. Construction drawings
ii. Technical specifications
iii. Technical studies
iv. Reports
v. Completing all relevant project Record drawings

2.1 *Deliverables*

i. Review geotechnical, flood hazard data, preliminary drawings and other related information completed to date and provide feedback on applicability, recommended improvements or revisions on or before **February 17, 2017.**
ii. Complete preliminary site plan and grading profiles for FortisBC review on or before **March 3, 2017.**
iii. Complete preliminary foundation and civil designs on or before **March 21**, **2017.**
iv. Issue final IFC packages including drawings, specifications and work summary for site and Civil Construction on or before **April 7, 2017.**
v. Complete and issue Record drawings no later than **6 weeks** after the receipt of project as-built drawing markups.

3.0 ENGINEERING AND DESIGN WORK

The Consultant shall utilize FortisBC standards. Unless otherwise approved by FortisBC, all deliverables shall be prepared in accordance with FortisBC standards. When standards are not provided by FortisBC for specific work, the Consultant shall submit draft designs or specifications for FortisBC approval.

3.1 *Site Development.*

Site development design work shall include but not be limited to the following:

(a) Review geotechnical data, flood hazard report and preliminary site preparation design drawings and provide recommendations to address any concerns with Fortis prior to proceeding with detail design;

(b) Review the site survey data, existing and preliminary drawings and complete all new drawings required for the site development. Fortis preference is to develop an AutoCad Civil 3D model to produce the site plan and profile drawings;

(c) Review and update if considered necessary the preliminary Construction Staging Area drawing with any information required to provide adequate construction access and work surface;

(d) Design all site drainage and grading requirements;

(e) Calculations of the expected cut, fill, imports and spoils for use in both the tender and construction;

(f) Detailed design of required retaining walls including requirements for temporary shoring. Include designs to accommodate station fencing and grounding. It is anticipated that copper ground conductors will need to pass through the retaining walls at 2-4 meter intervals to allow connection to the station perimeter ground conductor located 1m outside station fencing;

(g) Detailed design of new access road into the station;

(h) Detailed design of new station fencing;

(i) Design requirements for site finishing including: topsoil, grading, hydro seeding and landscaping to the satisfaction of FortisBC and Interfor (adjacent land owner);

(j) Provide detailed drawings and specifications for construction. FBC standards to be utilized where applicable. All construction documentation must be sealed by an Engineer who is a member in good standing with APEGBC;

(k) Provide engineering technical support and assist with quality assurance during the course of construction;

(l) Complete field reviews as deemed necessary for the work involved and;

(m) Complete review of as-built markups and develop Record drawings.

3.2 *Civil and Foundation Works.*

The detailed civil design work shall include but not be limited to the following:

(a) Participation in weekly design meetings (or as required).

(b) Assist FortisBC in the preparation and submission of schedules as maybe required for a building permit for the control building. It is anticipated that a prefabricated type building will be utilized. FortisBC will draft the building specification based on previous building specifications, but will require the Contractor to review and provide technical input to this document;

(c) Design of an appropriate oil containment system for the power transformer sized for 110% containment as per FortisBC standards. The oil containment system shall be designed to accommodate the future addition of a sound wall on at least three sides. The design shall utilize fire retardant rock and include drainage utilizing “petro-pipe” type barriers;

(d) Design of oil containment systems for two step-down transformers. The design shall utilize fire retardant rock and include drainage. Include a fire protection wall or walls to meet the requirements of NFPA 850. Expected Transformer oil volume is approximately 2600L each. The Contractor may explore a combined containment system for the two step-down transformers so long as the design meets the intent of IEEE 980;

(e) Detailed design of all other civil works and foundation design for the substation including, but not limited to:

i. 60kV line termination A-frame and switch structure foundation;

ii. 60kV breaker foundation;

iii. 60kV bus supports;

iv. T3 foundation and containment;

v. 13kV distribution structure;

vi. 5 – 13kV breaker foundations;

vii. 4 – 13kV egress structures;

viii. 2 – 13kV feeder bypass switch structures;

ix. Foundations and containment for 2 – 5MVA, stepdown, padmount transformers;

x. Control building foundation and cable entry system;

xi. 13kV capacitor bank foundations and;

xii. 60kV mobile termination switch foundation.

(f) Consideration of demolition needs of existing station structures and foundations;

(g) During construction provide engineering support, answer construction RFI’s and complete any site visits to ensure that construction generally conforms to the design;

(h) Provide detailed drawings and specifications for construction. FBC standards to be utilized where applicable. All construction documentation must be sealed by an Engineer who is a member in good standing with APEGBC.

(i) Complete field reviews as deemed necessary for the work involved and;

(j) Complete review of as-built markups and develop Record drawings.

4.0 ENGINEERING EXPECTATIONS

FortisBC requires regular Engineering project meetings (to be scheduled by FortisBC). The Consultant's Project Design Lead shall attend the regular meetings and bring other Consultant resources as required. The intent of the meetings is to provide a forum to discuss issues and concerns surrounding the project. The Consultant shall record and issue minutes from the meeting prior to the end of the next business day.

The Consultant shall obtain FortisBC approval in the form of a change order prior to any change in design or construction which functionally deviates from the agreed scope or previously approved design drawings or where additional costs may be incurred.

4.1 *Engineering Correspondence*

All Engineering correspondence, formal submittals, e-mails or telephone calls should be directed to the attention of the FortisBC Project Engineer. In addition to the scheduled meetings, the Consultant is encouraged to contact the Project Engineer via telephone or e-mail regarding project specifics. Any decisions, action items or other project clarifications resulting from informal discussions/e-mails must be summarized and submitted as a formal document. The requirement for the submittal shall be at the discretion of the FortisBC Project Engineer.

4.2 Engineering Standards

Engineering and design principles must generally conform to the following standards:

(a) FortisBC Station Engineering standards

(b) Standard utility practice

(c) Current edition of the Canadian Electrical Code where applicable

For clarification on the application of standards contact the FortisBC Project Engineer. Where appropriate standards are not in place, the Consultant shall propose a Standard for FortisBC consideration prior to proceeding with design. Where practical, FortisBC will also provide a typical design application that can be used as a template or starting point in this situation.

4.3 *Design Records*

The Consultant shall maintain and retain his own design records. In the event backup information is required (telephone logs, correspondence, design calculations, sketches etc), these shall be made available to FortisBC on request.

5.0 TECHNICAL DOCUMENTATION

Drawings supplied by FortisBC are attached as Annex A Reference Drawing List. An electronic copy of FortisBC Engineering and Drafting Standards can be provided on request.

5.1 Drawing List

The Consultant shall provide a preliminary list of all anticipated site drawings required for the project.

5.2 Attachments

The following attachments form part of the consultant's contract:

Annex A	Reference Drawing List
Annex B	Flood Assessment Documents, Ruckles substation (November 2, 2012)
Annex C	Engineering Change Notice
Annex D	Staging Drawings
Annex E	Geotechnical Report.

ANNEX A

Reference Drawing List

Drawing Number	Description	Rev
2645-0-TOPO	McElhanney Survey Drawing for Ruckles Station (2007)	
Site Topo with Poles	Survey Drawing (2015)	
3-271-0104	Foundation Plan	3
3-271-1004	General Arrangement *(Existing)*	5
3-271-8010	Site Grading Plan (Option 2)	P
3-271-8011	Site Grading Sections (Option 2)	P
3-271-8101	General Arrangement – Option 2 *(Proposed)*	P4
3-271-8102	Sections (Option2)	P1
N/A	Construction Staging Area	P0
3-271-8201	Proposed SLD – Option 2	P1