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May 8, 2018

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

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Re: FortisBC Inc. (FBC)
Project No. 1598939
2017 Cost of Service Analysis and Rate Design Application (the Application)
Errata dated May 8, 2018

On December 22, 2017, FBC filed the Application referenced above. Concurrent with this Errata filing, FBC submitted its responses to Information Requests (IR) No. 1.

During the course of responding to IRs, FBC determined a few corrections are required to the Application. The following outlines the corrections made as part of this Errata.

IR Reference:	Affected Pages (Exhibit B-1)	Correction
BCUC IR 1.17.1	<ul style="list-style-type: none">Application, page 50, Line 27	Correction to table reference.
BCUC IR 1.17.2	<ul style="list-style-type: none">Application, page 50, Line 29	Correction to percentage.
BCUC IR 1.38.8	<ul style="list-style-type: none">Application, page 66, Tables 6-3 and 6-4	Corrections to certain values.
BCUC IR 1.40.1	<ul style="list-style-type: none">Application, pages 67 and 68, Tables 6-5 and 6-6	Corrections to certain values.

IR Reference:	Affected Pages (Exhibit B-1)	Correction
BCUC IR 1.51.1 and 1.51.2	<ul style="list-style-type: none"> • Application, page 12, Line 9 • Application, page 79, Line 22; • Appendix G, page R-21.2 • Appendix H, page R-21.2 	Correction to certain values.
BCUC IR 1.56.1	<ul style="list-style-type: none"> • Application, page 12, Lines 26 and 27 • Application, page 32, Table 3-2 • Application, page 86, Table 6-24 • Application, page 87, Lines 4 to 9 • Appendix G, page R-40.1 • Appendix H, page R-40.1 • Appendix L, page 1 	Correction to certain values and revisions to wording.
BCUC IR 1.68.2	<ul style="list-style-type: none"> • Application, page 98, Table 7-6 	Correction to certain values.
BCUC IR 1.68.5; BCOAPO IR 1.54.1; KSCA IR 1.7.1	<ul style="list-style-type: none"> • Application, page 98, Line 23 	Corrections to certain values.
BCUC IR 1.69.5	<ul style="list-style-type: none"> • Appendix G, page R-104.1 • Appendix H, page R-104.1 	Correction to certain values.
BCUC IR 1.71.2 and 1.71.3	<ul style="list-style-type: none"> • Application, page 102, Lines 15 and 26 	Corrections to formula.
BCUC IR 1.73.3	<ul style="list-style-type: none"> • Appendix G, page R-109.1 • Appendix H, page R-109.1 	Corrections to certain values.
BCUC IR 1.76.2	<ul style="list-style-type: none"> • Application, page 108, Line 32 	Addition of a rate schedule.
BCUC IR 1.80.8	<ul style="list-style-type: none"> • Application, pages 114 and 115, Tables 8-9 and 8-10 • Appendix G, page R-22A.1 • Appendix H, page R-22A.1 	Corrections to certain values.
BCOAPO IR 1.21.1	<ul style="list-style-type: none"> • Application, page 51, Line 2 	Wording revision.
BCOAPO IR 1.56 series	<ul style="list-style-type: none"> • Application, page 113, Line 3 	Correction to the year.
CEC IR 1.45.1	<ul style="list-style-type: none"> • Application, page 32, Table 3-2 • Appendix L, page 1 	Correction to certain values.

These corrections do not result in any impacts to the results or recommendations contained in the Application. In the case of corrections to values, the correct values were used in the COSA model.

FBC has attached the blacklined version of the affected pages.

FBC apologizes for any inconvenience this may have caused to the Commission and Interveners in reviewing the Application.

If further information is required, please contact Corey Sinclair at (250) 469-8038.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachment

cc (email only): Registered Parties



- 1 3. In order to better reflect COSA allocations on a unit cost basis and to improve consistency
2 among rate classes, approval of the following revenue neutral change for Commercial (RS
3 21):
- 4 • An increase in the monthly Customer Charge from \$16.48 to \$54.00.
 - 5 • A flat energy rate of \$0.06875 per kWh for all consumption to replace the current
6 declining block rate structure.
 - 7 • An increase in the per-kVA Demand Charge from \$7.72 to \$10.22 in consideration of the
8 COSA fixed costs on a unit cost basis.
 - 9 • An update to the transformation discount from \$0.53 per kW of Billing Demand to \$0.32
10 per kW of Billing Demand
- 11 4. For RS 30, an update to the transformation discount from \$2.676 per kVA of Billing Demand
12 to \$5.26 per kVA of Billing Demand.
- 13 5. In consideration of COSA fixed costs (customer-related and demand-related) and to improve
14 consistency among rate classes, approval of the following revenue neutral change for Large
15 Commercial – Transmission (RS 31):
- 16 • An increase in the monthly Customer Charge from \$3,116.03 to \$3,195.00.
 - 17 • A decrease in the energy rates from \$0.05516 per kWh to \$0.05367 per kWh.
 - 18 • An increase in the per-kVA Power Supply Demand Charge from \$2.77 to \$3.45.
- 19 6. Approval of the following revenue neutral changes to RS 60 – Irrigation and Drainage:
- 20 • An increase in the Customer Charge from \$20.06 per month to \$22.09 per month in
21 consideration of the COSA unit costs and to improve consistency among rate classes.
 - 22 • A decrease in the energy rates from \$0.07259 per kWh to \$0.07240 per kWh.

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23 Wholesale Rate Schedules

- 24 7. Approval of the addition of a discount available to Wholesale Customers served on RS 40
25 that take delivery at Transmission voltage.
- 26 7(a) Approval of an increase in the Customer Charge for RS 40 from \$2,645.03 to \$4,522.46
27 and a decrease in the energy rates for RS 40 from \$0.05441 per kWh to \$0.05338 per kWh.

28 Optional Time of Use Rates

- 29 8. Approval of the revised optional TOU rates as described in Section 8 of the Application.

30 Transmission Service Rates

- 31 9. With respect to Transmission Service Rates:
- 32 • Removal of RS 102 from the Tariff as FBC has no need for Non-Firm PTP Rates and the
33 RS 102 pricing is identical to that contained in RS 101.
 - 34 • Changes to the anti-pancaking language contained in RS 101 and RS 102 (should RS
35 102 remain open) in order to prevent the possibility of zero dollar rates noted in those

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33 RS 102 pricing is identical to that contained in RS 101.
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35 102 remain open) in order to prevent the possibility of zero dollar rates noted in those

1 Table 3-2 below shows the current fixed cost recovery embedded in the current rates when
2 assessed against the 2017 COSA unit costs.

3 **Table 3-2: Current Fixed Cost Recovery Detail**

	Current Customer Charge (\$/mo)	Customer Charge COSA Unit Cost (\$/mo)	Customer Charge Recovery Percent	Current Demand Charge (\$/kVA) ³²	Customer Demand COSA Unit Cost(\$/kVA)	Demand Charge Recovery Percent
Residential (RCR)	16.05	35.60	45%	n/a	n/a	n/a
Residential (Exempt)	18.70	35.60	53%	n/a	n/a	n/a
Small Commercial	19.40	41.75	46%	n/a	n/a	n/a
Commercial	16.48	96.38	17%	7.72	15.73	49%
Large Commercial Primary	945.04	1,474.98	64%	9.19	14.00	66%
Large Commercial Transmission	3,116.03	5,810.78	54%	4.93	7.34	67%
Irrigation	20.96	40.17	52%	n/a	n/a	-
Wholesale Primary	2,645.03 ³³	8,222.83	32%	8.98	15.05	60%
Wholesale Transmission	5,974.48	7,892.14	76%	6.24	6.39	98%

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5 While in the 2017 RDA there is a directional move to better align rates with the COSA unit costs,
6 and in particular to have the fixed charge rate components recover fixed costs more
7 consistently, there are opposing views as to the appropriateness of shifting the burden of cost
8 recovery between the fixed and volumetric charges within a rate. FBC seeks a better balance
9 between the impacts of customer behaviour on their bills, such as through the opportunity to
10 reduce bills by reducing consumption, and the recognition that the changing energy supply
11 landscape can produce equity challenges between users of the utility system that may have
12 very different requirements from the grid, both now and in the future.

13 The increase in the Customer Charge to a minimum of 55 percent of the COSA customer-
14 related unit cost, along with an increase in the demand-related charges in certain rate
15 schedules, will help to mitigate the transfer of costs between customers on both an inter-class
16 and intra-class basis. These changes are all part of the current Application, and if approved

³² Demand Charges shown for Large Commercial Transmission and Wholesale rates are for "Wires" Demand

³³ Customer Charge for Wholesale – Primary is assessed on a per POD/month basis.

1 As noted in Table 5-7, Distribution costs were split between demand and customer according to
2 a minimum system approach. This approach reflects the philosophy that the system is in place
3 in part because there are customers to serve throughout the service territory, and that a
4 minimally sized distribution system is needed to serve these customers even if they only use 1
5 kWh of energy per year. The concept follows that any costs associated with a system larger
6 than this minimum size are due to the fact that customers “demand” a delivery quantity greater
7 than the minimum unit of electricity and that therefore, those costs should be treated as
8 demand-related,

9 While the minimum system is, in theory, designed to carry only a minimal amount of load, the
10 actual facilities designated as the minimal size are actually capable of carrying some amount of
11 demand. The actual amount of demand capability within the minimum system is a function of
12 load density, minimum required clearances, minimum equipment standards, temperature, and
13 other engineering considerations. Using only the minimum system allocation technique, each
14 customer/connection attracts an equal allocation of the minimum system, plus each customer
15 class is allocated demand costs based on the total customer class’ non-coincident peaks. As
16 such, it has been argued that a customer class’ non-coincident demand allocator is too large,
17 because a portion of these peak demand-related costs is being covered through the per
18 customer/connection minimum system allocation.

19 The correction of the problem of over allocating demand can be achieved by the application of a
20 Peak Load Carrying Capability (PLCC) adjustment. This adjustment was first introduced in the
21 2009 COSA. The precise amount of a PLCC adjustment should match the definition of the
22 minimum system adopted. In the FBC case, it was determined that the average PLCC for the
23 FBC system is 1.09 kW per customer. Appendix B to the EES Consulting Report provides a
24 more detailed discussion of the PLCC and how the amount was calculated.

25 In addition to those shown in Table 5-7, there are number of other, small Rate Base items
26 included in the classification process. These are as follows:

- 27 • **General Plant** - after being functionalized to the three areas shown in Table 5-4 above,
28 General Plant was classified using the resulting classification as total rate base for each
29 function. For example, the 28 percent of General Plant assigned to generation was split
30 between demand and energy in the same manner as the generation rate base.
- 31 • **Accumulated depreciation accounts and working capital** accounts - classified in the
32 same fashion as the corresponding Gross Plant accounts. Customer contributions were
33 assigned to classes on the basis of poles, conductors and transformers.
- 34 • **Plant acquisition adjustment and deferred costs** - classified on the same basis of
35 Gross Plant prior to General Plant.
- 36 • **Construction Work in Progress (CWIP) not earning Allowance for Funds used**
37 **during Construction (AFUDC)** - assigned to each function and classified in the same
38 manner as the rate base for each function.

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- **DSM** - classified as 72 percent power supply energy, 17 percent power supply demand and 12 percent transmission and distribution. This split is consistent to that used by FBC in the cost/benefit analyses performed for DSM spending.

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5.1.2.2.2 PRODUCTION/POWER SUPPLY EXPENSES

Classifying power supply costs to demand and energy components depends on the use of the generation and the pricing for power supply purchases. For FBC, the power supply resources include FBC-owned generation, long-term power purchase contracts including a tariff-based purchase from BC Hydro, and a small amount of market purchases. All of the resources used by FBC have both an energy and peaking component to them.

Table 5-8: Production / Power Supply Expense Classification

	2017 Costs (\$ Millions)	Classification	Notes
Kootenay River Plants	\$16.0	20% Demand 80% Energy	On the basis of Generation Rate Base
Columbia Power Corporation (Brilliant) and Waneta Expansion	\$81.0	31% Demand 69% Energy	Using BC Hydro 3808 as a proxy each month
BCH 3808 Purchases	\$49.0	20% Demand 80% Energy	As Charged
Net Market Purchases	\$6.2	100% Energy	All Energy Purchases
Total System	\$152.2	27% Demand 73% Energy	Sum of all Resources

5.1.2.2.3 OTHER EXPENSES

There are a number of additional expense categories that require classification. This section of the Application summarizes those cost areas and how they are treated within the COSA.

- **Transmission Services** - FBC purchases wheeling services from BC Hydro in the Okanagan and Creston areas to supplement its own transmission. The cost of providing transmission service to a customer is considered to be directly proportional to the demand that customer imposes on the system. All transmission expense accounts are classified on the same basis as transmission rate base.
- **Distribution Expenses** - Many of the distribution expense accounts correspond to a rate base account and follow the treatment of the rate base item. For example, account 583.10 is for distribution line maintenance, corresponding to rate base account 365-conductors and devices. Since the distribution rate base uses a minimum system approach, the expenses will also follow the splits resulting from that analysis. Street lighting expenses are directly assigned to the lighting class. Account 598 – other distribution plant is classified on the basis of total distribution rate base.

1 Changes within the options (referring to the option numbering in the top row of Table 6-4) are
2 summarized below.

3 **Table 6-3: Options for Changing RCR Components**

Option	Customer Charge	Tier 1 Rate	Tier 2 Rate	Threshold
Option 3	Unchanged	Increased	<u>Unchanged</u>	Increased
Option 4	Increased	Increased	<u>Decreased</u>	Increased
Option 5	Unchanged	Increased	Decreased	Unchanged
Option 6	Increased	Increased	Decreased	Unchanged
Option 7	Increased	Increased	Decreased	Unchanged
Option 8	Increased	Increased	Decreased	Unchanged

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5 **Table 6-4: July 2017 Open House RCR Option Comparison**

	Current RCR	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8
Customer Charge (\$/mo)	16.05	16.05	18.00	16.05	<u>18.00</u>	17.00	18.25
Tier 1 Rate (\$/kWh)	0.10117	0.10700	0.10770	0.10750	0.10220	0.10850	0.10800
Tier 2 Rate (\$/kWh)	0.15617	0.15617	0.1460	0.14420	0.14800	0.13900	0.13600
Threshold	800	1,000	1,000	800	800	800	800
Annual Consumption (kWh)	Percent of Total Customers	Average Percent Bill Difference					
Above 35,000	2%	(1%)	(6%)	(6%)	(4%)	(8%)	(10%)
30,000 – 35,000	1%	(1%)	(5%)	(4%)	(3%)	(7%)	(8%)
25,000 – 30,000	2%	(1%)	(5%)	(4%)	(3%)	(6%)	(7%)
20,000 – 25,000	5%	(2%)	(4%)	(3%)	(2%)	(4%)	(5%)
15,000 – 20,000	10%	(2%)	(3%)	(1%)	(1%)	(2%)	(3%)
10,000 – 15,000	22%	(1%)	0%	1%	(1%)	2%	2%
5,000 – 10,000	37%	3%	6%	4%	3%	6%	7%
0 – 5,000	21%	3%	9%	4%	6%	7%	10%
Percent > 10%		0%	2%	0%	1%	0%	4%

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7 At the July open houses, FBC indicated that if it were to recommend a change to the RCR as
8 part of the Application given the information available at the time, these changes would include:

- 9
- 10 • A moderate increase to the Customer Charge to better reflect the appropriate fixed charges indicated through the COSA;
 - 11 • A reduction in the spread between the Tier 1 and Tier 2 rates which would best be accomplished through a moderate increase in the Tier 1 rate and a more dramatic decrease in the Tier 2 rate; and
 - 12 • No change in the Threshold since any change in bill impact a threshold change would cause can effectively be managed through changes in the other rate components.
- 13

14
15 Of the options presented in Table 6-4, those labelled 6, 7, and 8 would meet all of these criteria.
16
17 Option 8 would come closest to having the Customer Charge set at a minimum of 55 percent of
18

1 the COSA unit cost. FBC was open to having this preliminary conclusion informed or altered
2 based on the input received through the consultation process that was ongoing at the time.

3 **6.1.4.3 Declining Block Rate**

4 The Company modelled a sample declining block rate in response to a customer request,
5 though FBC does not support the implementation of such a rate and did not receive any
6 supporting comments from consultation participants. This option was not explored in further
7 detail or seriously considered given that it may discourage conservation and offers no
8 advantage over the options considered.

9 **6.1.4.4 Changes to the Customer Charge**

10 Changes to the existing Customer Charge were discussed during consultation activities, where
11 FBC explained that the Customer Charge could be maintained at its current level, increased or
12 decreased; however, reducing the Customer Charge would exacerbate the issue of inadequate
13 fixed cost recovery and this option was not considered.

14 In examining a change in the Customer Charge, a logical change is to align the current RS 01
15 Customer Charge to that of the Exempt Residential Rates (RS 03 and RS 03A), currently
16 \$18.70 per month. At \$18.70, the Customer Charge collects 53 percent of the associated fixed
17 COSA charges. This is just below the target of 55 percent, but as this is the change discussed
18 during consultation no additional increase is being proposed. There is no cost-based rationale
19 for having the Customer Charges of the two residential rates differ.

20 An increase in the RCR Customer Charge from its current level of \$16.05 per month to \$18.70
21 requires a reduction in the overall revenue recovered from the Tier 1 and Tier 2 Energy Charges
22 in order to maintain revenue neutrality to current rates. The Tier 1 and Tier 2 rates must be
23 adjusted in order for this to occur. In the analysis that follows, FBC has set the Tier 1 and Tier
24 2 rates such that the overall residential revenue recovered is the same as under current rates,
25 and the differential between the Tier 1 and Tier 2 remains as it is today. This results in a rate as
26 shown in Table 6-5.

27 **Table 6-5: RCR with RS 03 Customer Charge**

RCR Charge	Current RCR	Equivalent RCR
Customer Charge (\$ per month)	16.05	18.70
Tier 1 Rate (\$ per kWh)	0.10117	0.09880
Tier 2 Rate (\$ per kWh)	0.15617	0.15254
Threshold (kWh / mo.)	800	800

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28
29 This rate option was selected from among a number of alternatives based on the range of billing
30 impacts for customers at different consumption levels, if the change was effected in a single
31 year.

1 The bill impact of implementing this change is shown in Table 6-6 below.

2 **Table 6-6: RCR with RS 03 Customer Charge - Bill Impact**

Annual Consumption (kWh)	Percent of Customers	Average Bill Difference (%)	Average Annual Bill Difference (\$)
Above 35,000	2%	(2%)	(161)
30,000 - 35,000	1%	(2%)	(73)
25,000 - 30,000	2%	(1%)	(55)
20,000 - 25,000	5%	(1%)	(36)
15,000 - 20,000	10%	(1%)	(18)
10,000 - 15,000	22%	0%	0
5,000 to 10,000	37%	2%	15
0 to 5,000	21%	6%	29

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4 In the above scenario 96 percent of customers have an annual bill increase of less than 10
5 percent, however, the immediate bill impact on low consuming customers is a cause for
6 concern.

7 As part of the analysis of an increase to the Customer Charge, FBC also examined the impact
8 of phasing in the increase such that the RS 01 and RS 03 Customer Charges were equivalent
9 after five years.

10 Using the same assumptions regarding the Tier 1 to Tier 2 differential and revenue equivalency,
11 and assuming that rates become effective on January 1 in each year, rates would be as shown
12 in Table 6-7 below. The Customer Charge increase has been spread evenly over the 5 years.

1

Table 6-17: RS 21 Bill Impact by Percentage

Annual Bill Impact	# of Customers	Percent of Customers	Percent
Greater than 10% Increase	66	4.8	4.8%
5-10% Increase	73	5.3	5.3%
0-5% Increase	311	22.7	22.7%
0-5% Decrease	424	30.9	30.9%
5-10% Decrease	369	26.9	26.9%
Greater than 10% Decrease	127	9.3	9.3%
Total	1,370	100.0	100.0%

2 **6.2.2.3 Transformation Discount**

3 The Commercial rate is designed on the basis that customers receive service at secondary
4 voltage. However, some customers choose to own the transformation equipment required to
5 convert their service voltage from the Primary level to the Secondary level. In these cases, the
6 customer is actually taking service at the Primary voltage available at the location of the
7 interconnection, and the customer is entitled to a discount from the demand charge rate in the
8 rate schedule as transformation and secondary costs would normally be included in the rate.

9 There are currently thirty-one RS 21 customers that receive the transformation discount.

10 In looking at the appropriate discount for taking service at a higher voltage level, the COSA
11 results were used to establish the difference in costs. The COSA is set up to account for the
12 voltage level associated with each customer class. That allows the allocation of costs to the
13 class for the specific facilities used by customers within the class.

14 To determine the difference in costs solely on the basis of a change in voltage level, the COSA
15 was recalculated assuming a higher voltage level for the class in question. The difference was
16 calculated independently for each class where such a discount is offered, but assumed the
17 entire class rather than specific customers was served at the higher voltage level.⁵³ None of the
18 load data or allocation factors were changed for the various classes when completing the
19 calculation. The only difference would be that certain costs were no longer assigned to the
20 class. The resulting difference in the unit costs for each class was then taken from the COSA to
21 determine the appropriate discount level of a per kVA basis.

22 For RS 21, the 2017 COSA indicates that a transformation discount of \$0.32 per kW of Billing
23 Demand should be applied to the Demand Charge portion of the rate. The current
24 transformation discount is \$0.53 per kW of Billing Demand. FBC is proposing to include the
25 updated amount as the transformation discount in the delivery and metering voltage discounts
26 section of RS 21.

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⁵³ The transformation is currently available only to RS21 and RS30 customers as they have a Demand-related billing component and a higher than standard delivery voltage may be available.

6.3 WHOLESALE RATES

Wholesale rates are fully bundled services offered to the municipalities located within the FBC service territory that also operate electric utilities, as well as at a number of points of interconnection with BC Hydro. In all cases, the Wholesale customers purchase electricity in order to resell to end-use customers.

In the COSA, there are seven wholesale customers that represent approximately 17 percent of energy sales.

6.3.1 Current Wholesale Rates

FBC offers two Default rate schedules as part of its Wholesale rates:

- **RS 40, Wholesale Service – Primary** – available to the municipal utilities of Grand Forks, Penticton, Summerland, and BC Hydro for service near Lardeau and Yahk.
- **RS 41, Wholesale Service – Transmission** – available to the City of Nelson.

A summary of 2017 Wholesale rates and COSA-derived unit costs is shown in the table below.

Table 6-24: Wholesale Rate Details

Rate	Existing Rate	COSA Value	COSA Unit Cost Percentage	Proposed rate
Wholesale Primary (RS 40)				
Energy Charge (\$/kWh)	0.05441	0.03887		0.05388
Customer Charge (\$/POD/mo)	2645.03	8222.83	32%	4522.46
Wires Charge (\$/kVA)	8.98	15.05	60%	8.98
Power Supply Charge (\$/kVA)	4.82	6.13	77%	4.82
Wholesale Transmission (RS 41)				
Energy Charge (\$/kWh)	0.04501	0.03903		0.04501
Customer Charge (\$/mo)	5,974.48	7892.14	78%	5,974.48
Wires Charge (\$/kVA)	6.34	6.29	101%	6.34
Power Supply Charge (\$/kVA)	4.77	4.66	102%	4.77

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6.3.2 Optional Wholesale Rates

The Wholesale Rates currently have an optional TOU rate available. These rates are discussed in Section 8 of the Application which deals with TOU rates in detail.

- **RS 42, Wholesale Service – Primary, Time of Use**
- **RS 43, Wholesale Service – Transmission, Time of Use**

1 The TOU rate schedules are available to the same utilities as the respective underlying rate
2 schedule. FBC does not have any wholesale customers taking service on a TOU rate.

3 **6.3.3 Wholesale Rates Discussion and Proposals**

4 FBC is proposing few structural or rate level changes to the default Wholesale rates. In terms of
5 fixed cost recovery, the only rate components that falls short of either the 55 percent Customer
6 Charge or 65 percent Demand Charge threshold are, the Wires Charge and Customer Charge
7 rates under RS 40, which are, at 60 percent and 32 percent, respectively.

8 The result of increasing the Customer Charge (and corresponding decrease in the Energy rate)
9 is shown in Table 6-24 above. The additional change being proposed for the Wholesale rates is
10 the addition of a discount to RS 40 for those customers that receive delivery at one or more
11 points of interconnection where the available voltage is at a transmission level (60,000 volts or
12 above). This is discussed in the following section.

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Deleted: While there are some variances between the individual COSA-derived unit costs and the rates currently charged to Wholesale customers, in aggregate, the recovery of fixed costs is at a level that is acceptable using the criteria being applied to other rate classes. For this reason, no change is proposed for these rates.

Deleted: only

13 **6.3.4 Transmission Discount**

14 FBC is proposing to add a transmission discount to RS 40. The inclusion of a transmission
15 discount is consistent with a similar provision found in both RS 21 and RS 30 that allows a
16 customer that does not meet the eligibility criteria for the rate schedule offering service at a
17 higher voltage to receive a lower rate based on providing their own transformation.

18 Currently the only Wholesale Transmission rate in the FBC tariff is RS 41 which is derived from
19 the specific load and cost information for Nelson Hydro and is exclusively for the use of the
20 Nelson Hydro. This discount is based on the COSA and effectively excludes some allocated
21 costs for elements of service that are no longer used by the customer. Wholesale-Primary
22 customers are unable to take service under the existing Wholesale Transmission rate (RS 41)
23 since this rate is specific to the service characteristics of the City of Nelson and has no general
24 application to other utilities.

25 During the consultation that preceded this Application, FBC received correspondence from the
26 City of Grand Forks that it is considering a change to the voltage at which it takes service from
27 FBC. The addition of a transmission discount would facilitate this change without the need for
28 process outside of this RDA, and the discount would then be available for other wholesale
29 customers.

30 The discount available for Wholesale customers served under RS 40 is determined in the same
31 manner as described for the RS 21 and RS 30 customers (see Sections 6.2.2.3 and 6.2.3.1)
32 and results in rates as follows:

- 1 • Reactive Supply and Voltage Control - Rate Schedule 104.

2
3 In addition, the Transmission Customer may elect to obtain the following Ancillary Services from
4 FBC, or with FBC acting as its agent, obtain the services from a third party, or by self-supply:

- 5 • Regulation and Frequency Response Service - Rate Schedule 105;
- 6 • Energy Imbalance Service - Rate Schedule 106;
- 7 • Operating Reserve – Spinning - Rate Schedule 107;
- 8 • Operating Reserve – Supplemental - Rate Schedule 108;
- 9 • Loss Compensation - Rate Schedule 109

10
11 As part of the Application, FBC has reviewed the Ancillary services and updated the rate
12 schedules as shown in Appendix G, the Black-lined Tariff. A brief description of each of the
13 above-listed Ancillary Services is contained in the following sections.

14 **7.4.1 Rate Schedule 103 – Scheduling, System Control and Dispatch Service**

15 Scheduling, System Control and Dispatch Service is required to schedule the movement of
16 power through, out of, within, or into FBC’s service territory.

17 The Transmission Customer must purchase this service if taking supply under RS 100, RS 101
18 or RS 102.

19
20 FBC has reviewed the costs associated with this service and has determined that a single rate
21 for all classes of customers is most appropriate as the cost of providing the service is not
22 dependent on the customer class.

23 The existing rate for RS 103 is \$0.00126 per kWh. The proposed rate is \$0.00023, per kW of
24 Reserved Capacity per hour. The units are changed from energy to capacity per hour to more
25 closely follow industry practise including the BC Hydro tariff RS 03.

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26 The rates are derived directly from the 2017 COSA utilizing the costs associated with the
27 System Control Centre that provides the service, divided by the sum of the non-coincident
28 system peaks. The COSA values, derivation, and COSA Schedule reference are shown in
29 Table 7-6 below.

30 **Table 7-6: Derivation of RS 103**

Description	Value	Reference
Expenses for System Control (Acct 556)	\$2,298,000	COSA Schedule 3.1
Non-Coincident Peak (Sum of 12 months)	13,768,020 kVA	COSA Schedule 2.1
Resulting Rate103 per kW-month	\$0.1669 / kW	Row 1 divided by Row 2

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31

- 1 The revised structure and charges for Energy Imbalance Service are set forth below.
- 2 1. A positive imbalance will be credited as the lower of:
- 3 (a) the Tranche 1 Energy Price set out in BC Hydro Rate Schedule 3808 as of January
4 1 in the calendar year in which the available surplus power is delivered; and
- 5 (b) The hourly Powerdex Mid-Columbia (Mid-C) index price for the hour in which the
6 positive Energy Imbalance Service is taken by the Customer. In hours in which the
7 Mid-C price is negative, the negative value will be used resulting in a charge to the
8 transmission customer for those hours.
- 9 plus
- 10 (c) an administrative premium of 10 percent will be subtracted from the credited
11 amount or added to the charged amount if the index price was negative.
- 12 2. A Negative Energy Imbalance Service will be charged as follows:
- 13 a) For hourly negative Energy Imbalance Service less than or equal to 4 MW,
14 the charge will be:
- 15 (i) The amount of negative Energy Imbalance Service ~~±~~ (1 x loss
16 compensation % as per RS 109) multiplied by
- 17 (ii) The hourly Powerdex Mid-Columbia (Mid-C) per kWh price for the hour
18 in which the negative Energy Imbalance Service is taken by the
19 Customer. In hours in which the Mid-C price is negative, a zero value
20 will be used; plus
- 21 (iii) The Bonneville Power authority's (BPA) wheeling rate from B.C.-U.S.
22 Border to Mid-C. per kWh; plus
- 23 (iv) An administrative premium of 10 percent.
- 24 b) For hourly negative Energy Imbalance Service greater than 4 MW, the
25 charge will be:
- 26 (i) The amount of negative Energy Imbalance Service ~~±~~ (1 x loss
27 compensation % as per RS 109) multiplied by
- 28 (ii) The greater of
- 29 a. \$50/MWh, or
- 30 b. 150 percent of the hourly Powerdex Mid-Columbia (Mid-C) per
31 kWh price for the hour in which the negative Energy Imbalance

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1 **8. OPTIONAL TIME OF USE RATES**

2 TOU rates are generally intended to incent customers to shift the time of consumption in a
3 manner that allows a utility to reduce costs or generate incremental revenue such that a rate
4 benefit will accrue to all customers.

5 FBC currently offers time-differentiated, or time of use, rates for all of its retail rate classes,
6 although the rate for residential customers has been closed to new participants since 2012. The
7 closure of this rate coincided with the implementation of the RCR as the default rate for
8 residential customers.

9 As part of the 2017 COSA and RDA process, FBC has completed the first comprehensive
10 review of these rates in 20 years. FBC has updated the assumptions and cost allocations
11 associated with the rates and is proposing to reconfigure and reprice the TOU rates for all
12 classes, and to reintroduce a TOU rate for the residential class as an optional rate for eligible
13 customers.

14 The development of the updated TOU rates requires analysis of data apart from the typical cost
15 allocations by customer classes, since the information and data contained in a typical COSA is
16 not differentiated on the basis of time. The additional analysis on which FBC's present
17 proposals built was enabled by the Company's Advanced Metering Infrastructure (AMI), which
18 provides accurate hourly consumption data for FBC's customers and allows for the derivation of
19 the appropriate TOU time periods and the optional billing option itself. This information is
20 required so that TOU rates will, to the extent possible, be cost-based, and not simply designed
21 as a behaviour modification tool. Unless the changes in behaviour caused by the rate result in
22 the desired financial benefit, the rate will not have achieved its objective.

23 **8.1 CURRENT TOU RATES**

24 The current TOU rates offered by FBC are:

- 25 • RS 2A - Residential TOU rate (as noted above, closed to new customers since 2012);
- 26 • RS 22A - Commercial Service - Secondary - Time of Use;
- 27 • RS 23A - Commercial Service - Primary - Time of Use;
- 28 • RS 32 - Large Commercial Service - Primary - Time of Use;
- 29 • RS 33 - Large Commercial Service - Transmission - Time of Use;
- 30 • RS 42 - Wholesale Service - Primary - Time of Use; Deleted: and
- 31 • RS 43 - Wholesale Service - Transmission - Time of Use; and
- 32 • RS 61 – Irrigation and Drainage – Time of Use.
- 33

1 Costs for power supply do, however, differ by time-period and were therefore used as the basis
2 for the analysis.

3 For this purpose, power supply costs for 2017, were split into several different categories to
4 cover capacity-related costs, energy purchases and baseload costs. The capacity costs that
5 are considered variable included the capacity charges related to purchased power and would
6 apply only to the on-peak period. The capacity-related costs are generally associated with
7 ensuring there is sufficient capacity available at the time of the system peaks in the winter and
8 summer. They are charged on the basis of the peak demands in the peak winter and summer
9 months. The on-peak TOU period reflects the timeframe in which that peak demand could
10 occur. While the general hours when a system peak could occur are known, it could occur on
11 any given weekday in the month depending on weather circumstances. For that reason those
12 capacity costs are divided by all of the hours in the on-peak period.

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13 The variable energy costs included the energy charges from power purchases from BC Hydro
14 and the market and apply to both the on-peak and mid-peak period. These charges are
15 incurred for the time periods when loads are higher than what can be generated by FBC's own
16 generation and contractual resources like the Brilliant plant. These charges best match the mid-
17 peak TOU period where loads are expected to be higher than the base load of the system and
18 the load during the potential on-peak hours. All other power costs are considered base costs
19 that would apply to all TOU periods.

20 The capacity-related costs divided by the on-peak loads yields a per unit cost of 10.57 cents per
21 kWh. This amount was used to reflect the necessary adder for on-peak rates relative to mid-
22 peak rates. The costs and energy amounts used to derive this adder are shown in Table 8-8
23 below. The variable energy costs are similarly divided by the mid-peak period energy. The
24 result is a per unit cost of 2.59 cents per kWh, which reflects the additional amount for mid-peak
25 rates when compared to off-peak rates. The proposed off-peak rate would be set so that the
26 total forecast revenues collected are revenue neutral with the proposed non-TOU rates and the
27 revenue requirement for each class. The annual cost of the on-peak and mid-peak power supply
28 resources, as well as the energy associated with each is shown in Table 8-8 below. The
29 resulting cost differential is shown in the right-most column.

30 **Table 8-8: TOU Rate Differential Derivation**

	Annual Cost	Energy Amount	Cost Differential per kWh
On-Peak Peak Capacity Cost of Both Purchased and Owned Resources	\$56 million	530 GWh On-Peak	\$0.1057
Mid-Peak Energy Purchases Beyond Output from Owned Resources	\$42 million	1,092 GWh Mid-Peak	\$0.0259

31

1 These pricing differentials form the basis of the TOU rates and are the same for all classes. For
2 each customer class, since the amount of load that falls within each period varies, as does the
3 class revenue requirement, the rates that apply to each class are different.

4 An elasticity factor was applied to the load in each time-period to account for the assumed
5 impacts in usage associated with TOU rates. The elasticity factor accounts for the assumption
6 that the price difference associated with the time periods will affect customer behaviour.
7 Elasticity estimates were based on the most current data specific to FBC residential customers
8 – those developed for the 2014 RIB report to the BCUC. There, an analysis found an elasticity
9 of -0.14 for block 2 which as a proxy was applied to the on-peak period. The elasticity for the
10 block 1 use was -0.07 (although not statistically significant) and was applied to the mid-peak
11 and off-peak periods. Elasticity was applied to the usage levels and comparing the TOU rates
12 in each period to the average energy rate. The result was a decrease in the on-peak period and
13 on an overall basis. This in turn led to rates that needed to be slightly higher to maintain
14 revenue neutrality to current rates. Additionally, the reduced power supply cost associated with
15 overall reduced consumption was applied as an offset to the revenue when looking at revenue
16 neutrality. The savings was based on the variable energy rate of \$0.04863 per kWh from the
17 BC Hydro RS 3808 PPA.

18 8.3 PROPOSED TOU RATES

19 TOU pricing during the periods described above is built upon a base energy price for each rate
20 class, which is then adjusted based on the time-delineated cost differentials developed as
21 described in the previous section.

22 Based on the TOU time-periods, the distribution of load into the time periods was developed.
23 The residential breakdown was calculated based on a sample of residential load data. The
24 following shows the split by time period in terms of the percent of load for each class.

25 **Table 8-9: Breakdown of Load to TOU Periods**

Rate Class	On-Peak Use	Mid-Peak Use	Off-Peak Use
Residential	15.8%	28.5%	55.8%
Small Commercial	16.0%	35.9%	48.1%
Commercial	14.4%	34.1%	51.5%
Large Commercial	14.0%	33.5%	52.5%
Wholesale Primary	12.4%	32.3%	55.4%
Wholesale Transmission	12.4%	33.8%	53.8%
Irrigation	20.2%	25.8%	54.0%
Total System	14.9%	30.7%	54.4%

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26

Appendix G

BLACKLINED FBC ELECTRIC TARIFF

RATE SCHEDULE 21 - COMMERCIAL SERVICE (Cont'd)

- (b) A discount of ~~32.0¢~~ per kW of Billing Demand will be applied to the above rate if the Customer supplies the transformation from the primary to the secondary voltage.
- (c) If a Customer is entitled to both of the above discounts, the discount applicable to the metering at a primary voltage is to be applied first.

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POWER FACTOR: If at FortisBC's option, the Demand is measured in kVA instead of kW then;

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40 kW will become 45 kVA
~~32.0¢~~ per kW will become ~~29.0¢~~ per kVA
~~\$11.35~~ per kW will become ~~\$10.22~~ per kVA
where used in this schedule.

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BILLING CODES:

The following letter designations may appear on Customer's bills:

- "A" – Demand measured in kW, FortisBC owned transformation from primary to secondary distribution voltage, metering at secondary distribution voltage
- "B" – Demand measured in kVA, FortisBC owned transformation from primary to secondary distribution voltage, metering at secondary distribution voltage
- "C" – Demand measured in kW, Customer owned transformation from primary to secondary distribution voltage, metering at primary distribution voltage
- "D" – Demand measured in kVA, Customer owned transformation from primary to secondary distribution voltage, metering at primary distribution voltage

Deleted: Company

OVERDUE ACCOUNTS:

A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE

ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 22 A - COMMERCIAL SERVICE – SECONDARY – TIME OF USE

APPLICABLE: To Commercial Customers whose electrical Demand is less than 500 kW and is supplied at a secondary distribution voltage through one meter. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

- Deleted:** non-residential
- Deleted:** the Company
- Deleted:** month
- Deleted:** month

RATES BY PRICING PERIOD:

	<u>Summer</u> July-August	<u>Shoulder</u> March-June September-November	<u>Winter</u> December-February	<u>¢/kW.h</u>
<u>On-Peak</u>	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	20.495
<u>Mid-Peak</u>	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	9.929
<u>Off-Peak</u>	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	7.340

- Deleted:** 675
- Deleted:** 10.109
- Deleted:** 520

plus:

CUSTOMER CHARGE:

\$23.00 per Month

- Deleted:** 16.48
- Deleted:** month

BILLING:

FortisBC may, at its option, bill this rate bimonthly in which case the Customer Charge will be doubled.

- Deleted:** The Company
- Deleted:** shall

OVERDUE ACCOUNTS:

A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT:

Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 40 - WHOLESale SERVICE - PRIMARY

AVAILABLE: In Grand Forks, Kelowna, Penticton, Princeton, Summerland, Lardeau and Yahk.

APPLICABLE: To service for resale, subject to written agreement.

MONTHLY RATE: A Wires Charge of:
\$8.98 per kVA of Billing Demand

plus:

A Power Supply Charge of:

\$4.82 per kVA of maximum Demand in current billing Month

plus:

An Energy Charge of:

All kW.h @ 5,388¢ per kW.h

CUSTOMER CHARGE: \$4,522.46 per Point of Delivery per Month

"Billing Demand"

The greatest of:

- i. eighty percent (80%) of the Contract Demand, or
- ii. the maximum Demand in kVA for the current billing Month, or
- iii. eighty percent (80%) of the maximum Demand in kVA registered during the previous eleven Month period.

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RATE SCHEDULE 104 - REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICES

PREAMBLE: In order to maintain Transmission Voltages on transmission facilities within acceptable limits, generation facilities under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain Transmission Voltages within limits that are generally accepted in the region.

The Transmission Customer must purchase this Service if taking supply under Rate Schedules 100, 101, and 102.

RATE: ~~\$0.825~~ per ~~MW~~ of Reserved Capacity per Hour

NOTE: A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.

PERMANENT RATE

ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

- Deleted:** Wholesale Service-Transmission: .
- Deleted:** 00141
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- Deleted:** kW.h
- Deleted:** Wholesale Service-Primary: . \$0.00132 per kW.h
- Deleted:** Large Commercial Service-Transmission: \$0.00132 per kW.h

RATE SCHEDULE 109 - TRANSMISSION LOSSES

APPLICABLE: All transactions under Rate Schedules 100 and 101, will incur real power losses as follows:

Wholesale Service - Transmission 2.86%

Wholesale Service - Primary 4.26%

Large Commercial Service - Transmission 2.86%

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Appendix H

CLEAN FBC ELECTRIC TARIFF

RATE SCHEDULE 21 - COMMERCIAL SERVICE (Cont'd)

- (b) A discount of 32.0¢ per kW of Billing Demand will be applied to the above rate if the Customer supplies the transformation from the primary to the secondary voltage.
- (c) If a Customer is entitled to both of the above discounts, the discount applicable to the metering at a primary voltage is to be applied first.

POWER FACTOR: If at FortisBC's option, the Demand is measured in kVA instead of kW then;

40 kW will become 45 kVA
32.0¢ per kW will become 29.0¢ per kVA
\$11.35 per kW will become \$10.22 per kVA
where used in this schedule.

BILLING
CODES:

The following letter designations may appear on Customer's bills:

- "A" – Demand measured in kW, FortisBC owned transformation from primary to secondary distribution voltage, metering at secondary distribution voltage
- "B" – Demand measured in kVA, FortisBC owned transformation from primary to secondary distribution voltage, metering at secondary distribution voltage
- "C" – Demand measured in kW, Customer owned transformation from primary to secondary distribution voltage, metering at primary distribution voltage
- "D" – Demand measured in kVA, Customer owned transformation from primary to secondary distribution voltage, metering at primary distribution voltage

OVERDUE
ACCOUNTS:

A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE

ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 22 A - COMMERCIAL SERVICE – SECONDARY – TIME OF USE

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RATES BY PRICING PERIOD:

	Summer July-August	Shoulder March-June September-November	Winter December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	20.495
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	9.929
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	7.340

plus:

CUSTOMER CHARGE: \$23.00 per Month

BILLING: FortisBC may, at its option, bill this rate bimonthly in which case the Customer Charge will be doubled.

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

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plus:

A Power Supply Charge of:
\$4.82 per kVA of maximum Demand in current billing Month

plus:

An Energy Charge of:
All kW.h @ 5.388¢ per kW.h

CUSTOMER CHARGE: \$4522.46 per Point of Delivery per Month

"Billing Demand"

The greatest of:

- i. eighty percent (80%) of the Contract Demand, or
- ii. the maximum Demand in kVA for the current billing Month, or
- iii. eighty percent (80%) of the maximum Demand in kVA registered during the previous eleven Month period.

RATE SCHEDULE 104 - REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICES

PREAMBLE: In order to maintain Transmission Voltages on transmission facilities within acceptable limits, generation facilities under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain Transmission Voltages within limits that are generally accepted in the region.

The Transmission Customer must purchase this Service if taking supply under Rate Schedules 100, 101, and 102.

RATE: \$0.825 per MW of Reserved Capacity per Hour

NOTE: A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 109 - TRANSMISSION LOSSES

APPLICABLE: All transactions under Rate Schedules 100 and 101 will incur real power losses as follows:

Wholesale Service - Transmission 2.86%

Wholesale Service - Primary 4.26%

Large Commercial Service - Transmission 2.86%

Appendix L

2017 PROPOSED RATE CHANGE SUMMARY

1 FortisBC Inc. Fully Bundled Rates

Rate Class	Code	Current FortisBC Rates			Proposed FortisBC Rates						
		Basic Charge (\$/month)	Energy Rate (cents/kWh)		Demand Rate (\$/kVA)	Basic Charge (\$/month)	Energy Rate (cents/kWh)		Demand Rate (\$/kVA)		
Residential RCR[1]	RS01	16.05	Tier 1	10.117	n/a	16.58	Tier 1	10.394	n/a		
			Tier 2	15.617			Tier 2	14.915			
Residential Exempt	R03	18.70	11.749		n/a	18.70	11.749		n/a		
Small Commercial	RS20	19.40	10.195		n/a	23.00	10.000		n/a		
Commercial	RS21	16.48	Tier 1	8.663	7.72	54.00	6.875	10.22			
			Tier 2	7.191							
Large Commercial - Primary	RS30	945.04	5.571		9.19	945.04	5.571		9.19		
Large Commercial - Transmission	RS31	3116.03	5.516		Wires	PS	3195.00	5.367		Wires	PS
					4.93	2.77				4.93	3.45
Irrigation	RS60	20.06	7.259		n/a	22.09	7.240		n/a		
Primary Wholesale	RS40	2645.03 / POD / mo.	5.441		Wires	PS	4522.46 / POD / mo.	5.388		Wires	PS
					8.98	4.82				8.98	4.82
Transmission Wholesale	RS41	5974.48	4.501		Wires	PS	5978.48	4.501		Wires	PS
					6.34	4.77				6.34	4.77

- 2
- 3 Figures in red are higher than the equivalent current rate. Figures in green are lower than the
- 4 equivalent current rate.
- 5 [1] Proposed RCR Rate shown is for the first year of the phase-in period.