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March 26, 2021

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Application to Amend Residential Inclining Block Rate Pricing Principles for Fiscal 2021 and Fiscal 2022 - Rate Schedules 1101, 1121 - Compliance with BCUC Order No. G-62-20 Directive 2
Rate Design Progress Report

BC Hydro writes in compliance with Directive 2 of BCUC Order No. G-62-20 and Directive 66 of BCUC Order No. G-246-20 to provide its Rate Design Progress Report.

For further information, please contact Anthea Jubb at 604-623-3545 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

rz/ma

Enclosure

BC Hydro Residential Inclining Block Rate Pricing Principles Extension for Fiscal 2021 and Fiscal 2022 Application Compliance with BCUC Order No. G-62-20 Directive 2

Rate Design Progress Report

March 26, 2021

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1 Executive Summary

In the decisions on BC Hydro's Fiscal 2021 and Fiscal 2022 Residential Inclining Block (**RIB**) Rate Pricing Principles Extension Application (Order No. G-62-20, Directive 2) and Fiscal 2020 to Fiscal 2021 RRA (Order No. G-246-20, Directive 66), the British Columbia Utilities Commission (**BCUC**) directed BC Hydro to file a report by March 26, 2021 that describes our progress and plans on rate design and to provide an update on our fully allocated cost of service (**FACOS**) study and methodology. This report is provided for information purposes in compliance with the above noted directives.

BC Hydro's overall rate design objectives are to move us towards rates that are affordable, economically efficient by reflecting our marginal costs, supportive of decarbonization and that are flexible. Below we provide a summary of recent and planned activities for residential, commercial, non-integrated area and industrial customer rate design as well as our fully allocated cost of service studies.

For residential customer rate design, activities to date include:

- Completing a comprehensive evaluation of the current Residential Inclining Block Rate Schedule 1101 in 2018;
- Phasing out the Residential Dual Fuel Rate Schedule 1105 effective 2019;
- Conducting customer research and updating our residential rate design jurisdiction review in 2020 and 2021; and
- Development of a stakeholder and customer communications and engagement plan to be conducted in 2021 commencing in the spring.

Planned activities for residential customer rate design include modeling residential rate design concepts, conducting communications and engagement to gain customer input on rate design concepts, and preparing a residential rate design application planned to be filed with the BCUC in February 2022.

For commercial customers taking General Service, activities to date include:

- Redesigning the Small, Medium and Large General Service Rate Schedules 13xx, 15xx and 16xx effective 2017;
- Phasing out the General Service Dual Fuel Rate Schedules 1205, 1206 and 1207 effective 2020;
- Implementing two new optional Large General Service Rate Schedules 164x and 165x in 2020 and 2021 to encourage decarbonization through the electrification of fleet vehicles and vessels; and
- Conducting preliminary customer and stakeholder meetings on rate design for commercial customers and updating our jurisdictional review.

Planned activities for commercial customer rate design include conducting customer research in 2021 to gauge interest and preference on rate design concepts for commercial customers. BC Hydro will determine the appropriate timing and scope for a commercial rate design application based on the results of this research.

For industrial customers taking Transmission Service, activities to date include:

- Implementing the optional Transmission Service Freshet Energy Rate Schedule 1892 in 2016 and the optional Transmission Service Incremental Energy Rate Pilot Rate Schedule 1893 in 2020;
- Implementing two new Clean B.C. Industrial Electrification Rate Schedules 1894 and 1895 to encourage switching to electricity from carbon-based fuels and to promote new clean industry into the province; and

- Commencement of customer and stakeholder engagement on Transmission Service Rate Schedule 1823 restructuring with a public engagement workshop on February 9, 2021.

Planned activities for industrial customer rate design include a Rate Schedule 1823 restructuring application in 2021, as described in BC Hydro's Transmission Service Rate Fiscal 2022 and Fiscal 2023 Pricing Principles Application, filed with the Commission on March 2, 2021. We will also be conducting additional customer consultation sessions in the spring and summer of 2021.

For customers in BC Hydro's Non-Integrated Area (**NIA**), activities to date include updating our jurisdictional review and holding preliminary discussions with stakeholders. Planned activities for NIA rate design include NIA customer and stakeholder consultation to be undertaken within the scope of the broader residential rate design communication and engagement. A decision on whether to file a rate design application for service to the NIA will follow based on the outcome of that engagement.

BC Hydro notes that rate design is being considered as important inputs to two other BC Hydro initiatives, which are BC Hydro's December 2021 Integrated Resource Plan and BC Hydro's F2023 Electrification Plan. In the development of the 2021 Integrated Resource Plan, BC Hydro has and will continue to analyze and conduct public and stakeholder engagement on optional time-varying rates across all customer segments, as a potential capacity resource option. In the development of the Electrification Plan, which will be included in BC Hydro's next Revenue Requirements Application to be filed with the BCUC in summer 2021, BC Hydro will consider how rate design can be used to encourage electrification and greenhouse gas emission reductions. The rate design activities described in this report will be coordinated with and be complementary to any future proposals for optional time-varying rates to deliver on the longer-term resource needs identified through the Integrated Resource Plan, and to actions arising from the F2023 Electrification Plan.

BC Hydro filed our most recent FACOS study, which includes results for fiscal 2020, with the BCUC on February 11, 2021. This study is included as Appendix A. BC Hydro has completed two recent reviews of our FACOS study methodology. The first review was conducted by BC Hydro staff in response to the issues raised in the 2016 Negotiated Settlement Agreement. This work is documented in BC Hydro's F2019 Cost of Service Study[1] filed with the BCUC on March 29, 2019. Additionally, in 2020 BC Hydro retained external experts to provide a review of cost of service methodology with a focus on marginal cost of service. BC Hydro concludes from this review that our current methodology, referred to as the embedded cost of service approach, remains appropriate and is consistent with common utility practice. However, further work could be undertaken in the future to explore whether there may be value in incorporating aspects of marginal cost of service in our fully allocated cost of service studies. In addition, BC Hydro views marginal costs as an important consideration and input to rate design and pricing, consistent with the Bonbright rate design criteria of economic efficiency.

After the proceedings for the transmission and residential rate design applications planned for the coming year, BC Hydro anticipates that it will need to consider, among other things, the BCUC's decisions in regard to those applications and the feedback received from customers and stakeholders.

[1] Available here: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-filings/reports/00-2019-03-29-bchydro-f2019-cost-of-service-study-ff.pdf.

2 Introduction

2.1 Regulatory Context and Scope of this Report

In the recent decisions on BC Hydro's Fiscal 2021 and Fiscal 2022 RIB Rate Pricing Principles Extension Application (Order No. G-62-20, Directive 2) and Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (Order No. G-246-20, Directive 66), the BCUC directed BC Hydro to file a report by March 26, 2021 that describes our progress and plans on rate design, as follows:

> BC Hydro must file a report with the BCUC .... that discusses its progress regarding developing its next residential rate design application and the anticipated filing date of that application. The report must also include details of its activities to date and its planned activities regarding the development of that application…the Panel directs BC Hydro to also include in that report, a discussion of its progress regarding the development of its next rate design application (RDA) for commercial and industrial customers, as well as for customers in the non-integrated areas. The report should also include results of the most recent fully allocated cost of service, and a discussion on whether BC Hydro's COS methodology should be adjusted and if not, its rationale for not doing so.

This report is provided for information purposes in compliance with the above noted directives.

2.2 BC Hydro's Rate Design Approach

BC Hydro's rate design proposals are guided by the statutory "just and reasonable" standard, our rate design objectives and the Bonbright rate design criteria.

BC Hydro's rate design objectives are to implement rates that are affordable, economically efficient, supportive of decarbonization and that are flexible. Our objectives are consistent with the "just and reasonable" standard and the Bonbright criteria, which can be broadly grouped into four categories: economic efficiency, practicality, fairness and stability. BC Hydro considers and assesses potential rate designs against the "just and reasonable" standard, our rate design objectives and the Bonbright criteria through the process of developing and conducting stakeholder and customer engagement on rate design.

2.3 Government Policy Context

The Government of B.C.'s CleanBC plan outlines its goals, actions and targets to reduce greenhouse gas emissions while transitioning to a low-carbon economy. Electrification is a key component of the plan and BC Hydro's clean electricity can support the transition away from fossil fuels. Rate design is one of the ways in which we can support electrification efforts by designing rates that encourage fuel switching and the efficient use of electricity.

Affordability is also one of government's key policy priorities and rate design directly impacts customer bills. While BC Hydro currently has some of the lowest rates in North America, affordability of electricity bills remains a concern for some customers and will be a consideration during the engagement process. Any rate design proposal put forth by BC Hydro must take affordability into consideration to align with government's policy priorities.

2.4 BC Hydro's 2021 Integrated Resource Plan and F2023 Electrification Plan

Optional time-varying rates are expected to provide an important capacity resource option for BC Hydro in its 2021 Integrated Resource Plan (**IRP**). Optional time-of-use and critical-peak pricing rate design concepts are being analyzed as complementary resource options for inclusion in the draft IRP to be filed in June and the final IRP to be filed in December 2021. These rate concepts have been modelled for the IRP and continue to be the subject of consultation.

Rate design communications, engagement and applications to the BCUC will be coordinated with, and complementary to, planned activities for the IRP.

Rate design is also expected to play a role in BC Hydro's F2023 Electrification Plan, which will be included in our next Revenue Requirements Application to be filed with the BCUC in summer 2021.

3 Residential Rate Design

BC Hydro will be examining alternatives to the default rate design under which the majority of our residential customers currently take service, which is the Residential Inclining Block Rate Schedules 1101 and 1121 (**RIB Rate**). We plan to submit a rate design application to the BCUC on this matter by February 2022. Background on the rate, activities to date and planned activities are summarized in sections that follow.

3.1 Background

The RIB Rate was established in 2008 by BCUC Order No. G-124-082 in response to the 2007 Energy Plan's objective of encouraging additional electricity conservation. Since January 2011, all three charges that apply to the RIB Rate have increased by the approved RRA through BCUC Order Nos. G-180-10, G-13-14, G-5-176 and G-214-181. In Order No. G-5-17, the BCUC approved BC Hydro's proposal in its 2015 RDA regarding the RIB Rate pricing principles for fiscal 2017 to fiscal 2019.

Order No. G-214-181 extended the RIB Rate Pricing Principles as established in Order No. G-5-176 to March 31, 2020. One of the reasons for the extension was to allow BC Hydro and its stakeholders to fully consider the outcomes of Phase 1 of the Government of B.C.'s 2018 Comprehensive Review of BC Hydro, the scope of which included BC Hydro's rates, prior to the next rate design application.

In February 2020, BC Hydro requested to extend the pricing principles by another two years, from April 1, 2020 to March 31, 2022. There were two reasons for the extension request. First, to allow for the completion of Phase 2 of the Government of B.C.'s Comprehensive Review of BC Hydro so that the conclusions and directions from the review could inform pricing principles for the next Residential Rate Design Application. The second reason was to allow for rate stability for our customers and stakeholders. The extension request was approved by BCUC as part of Order No. G-62-20 and this approval is in effect until March 31, 2022.

3.2 Activities Completed to Date

3.2.1 Jurisdictional Review

We recently updated our residential rate design jurisdictional review to better understand how other utilities have structured their residential rates and to further define potential rate design concepts to explore with our customers and stakeholders. Our review found that many utilities that have inclining block rates are transitioning away from this rate design, typically to either flat or some form of time-varying energy charges. For example, Hydro Quebec has a residential inclining block rate and in 2017 they increased the Step 1/Step 2 energy charge threshold such that only high usage accounts are in Step 2 during the heating season. FortisBC received approval from the BCUC in 2019 for a five-year transition of their residential inclining block rate design to a rate design with a lower flat energy charge and higher basic charge. Various U.S. based utilities such as Colorado's Xcel Energy and California's Sacramento Municipal Utilities District are transitioning their residential customers from inclining block to time of use rates.

3.2.2 Rate Perception Survey

A survey to gauge the public's perception of current rate designs and potential changes to the way rates are structured was delivered to BC Hydro residential customers in December 2020. The survey was sent to 8,000 BC Hydro residential customers and had over 950 completions, for a response rate of 12 per cent. The response rate and number of completions are sufficient to ensure the results are representative of the views of our customers. Below are some key findings:

- While 38 per cent of customers say the current residential rate design works for them, support for change is just over half with 56 per cent of respondents preferring no change to how they are charged for electricity;
- In terms of optional rates, 42 per cent indicated they are likely to sign up for an optional time-of-use rate, 32 per cent for an electric vehicle rate and 33 per cent for a heat pump rate; and
- Many customers responded to rate design questions with “no opinion” or “don’t know”. For example, 30 per cent of respondents indicated “no opinion”/ “don’t know” when asked whether the current residential rate design works for them, and 25 per cent of respondents indicated “no opinion”/ “don’t know” regarding their support for a flat residential rate design.

The finding that many BC Hydro residential customers do not know or have no opinion about how they are charged for electricity is of interest. This result is consistent with prior residential rate design surveys conducted. BC Hydro customer surveys conducted in 2012 and 2017 found that customers’ unaided awareness that BC Hydro charges household consumption of electricity on an inclining block rate measured 49 per cent in 2012 and 47 per cent in 2017 with only approximately 50 per cent of residential customers being aware of how they are charged for electricity. These customer surveys were very robust with 3,307 responses to the 2017 survey and 2,468 responses to the 2012 survey.

3.3 Next Steps

3.3.1 Communications and Engagement

Over the next ten months, BC Hydro will embark on a customer engagement and communication process to explore redesign of our residential rates.

The objectives of customer communication and engagement are to:

- Build customer understanding of how electricity is used and charged today as well as of alternative rate options that may better meet the needs of customers in the future;
- Shape and develop a broader story of how rate design can address climate change, reduce the overall cost of electricity, and help individual customers make the right energy choices for their households;
- Reach a range of residential customers, including those who will benefit from a change in rate design and those who will not;
- Build trust that BC Hydro, working with our customers, is making the right decisions about the future of rates; and
- Better understand potential customer impacts and /or benefits of a change to our rate designs to inform the rate design process and any potential support programs and initiatives around the implementation of a new rate design.

BC Hydro will seek support for new rate design concepts by providing customers, customer groups, intervenors and stakeholders an opportunity to give feedback on those concepts. BC Hydro will engage residential customers representing a broad range of consumption; including customers living in urban and rural housing across many dwelling types and geographies. The customers engaged will also include those who rely upon electric heat.

BC Hydro will seek customer input in three stages of engagement over the next nine to 10 months:

1. ***Concepts Consultation*** (April to May 2021): At the broadest level, we will introduce rate design concepts to residential customers and seek input on options for consideration. We will discuss principles behind these designs, and what other utilities do, and seek input on which concepts are viewed most favourably;
2. ***Options Consultation*** (August to September 2021): At a more detailed level, we will share illustrative pricing of what some new rate designs might look like, including optional time-of-use rates for feedback and refinement. We will use rates input received during the consultation on the draft Integrated Resource Plan in June to July 2021 to inform this stage of consultation; and
3. ***Proposals*** (November to December 2021): Present BC Hydro's rate proposals in detail and seek feedback on their details.

A number of rate design concepts may be explored in the concepts consultation phase, including:

- Concepts that maintain the inclining block rate design;
- Concepts that eliminate the inclining block rate design;
- Concepts that segment the residential rate class;
- Optional rate design concepts, such as an optional time-of-use rate; and
- Optional end-use rates, such as such electric vehicle charging and heat-pump rates.

Each concept has sub-concepts and trade offs which need to be further examined. Feedback obtained from customer engagement, implementation costs and practicality, and alignment with our rate design objectives and the Bonbright criteria all need to be considered in determining preferred options.

3.3.2 Residential Rate Design Application

We plan to file a Residential Rate Design Application with the BCUC in February 2022. The application will be informed by the results of our customer communication and engagement.

4 General Service Rate Design

4.1 Background

Most of BC Hydro's commercial customers are served under one of the three General Service Rate Schedules – Large General Service Rate Schedules 16xx (**LGS**), Medium General Service Rate Schedules 15xx (**MGS**) or Small General Service Rate Schedules 13xx (**SGS**).

All three General Service rates were redesigned through BC Hydro's 2015 Rate Design Application (**RDA**), approved by BCUC Order No. G-5-17 and implemented in 2017.

In March 2020, BC Hydro received BCUC approval for two new optional rates to encourage decarbonization through the electrification of fleet vehicles and vessels. The two rates are the Demand Transition Rate Schedule 165x, effective April 1, 2020, and the Overnight Rate Schedule 164x, effective April 1, 2021, both approved under BCUC Order No. G-67-20.

4.2 Activities Completed to Date

4.2.1 Jurisdictional Review

BC Hydro has recently updated our commercial customer rate design jurisdictional review. BC Hydro's general service rate designs for larger commercial customers are similar to that found for most other electric utilities, being a three-part rate design with a fixed daily charge, an energy charge and a demand charge. However, some utilities also offer economically efficient and flexible optional rates to encourage electrification or manage utility costs. Some examples from comparable Canadian electric utilities are listed below.

Yukon Energy, Manitoba Hydro and Hydro Quebec each have an interruptible rate option available to larger commercial customers to encourage sales of hydroelectricity and additional electricity use during periods of surplus. Hydro Quebec offers commercial customers of all sizes a dynamic pricing rate to help manage the cost of electricity service during winter peak demand periods. Manitoba Hydro and Hydro Quebec also offer a load curtailment rate to commercial customers under which the customer receives a discount or credit in exchange for curtailing their load during peak events. Manitoba Hydro's offer is restricted to large commercial customers while Hydro Quebec's offer is available to all commercial customers.

4.2.2 Customer and Stakeholder Feedback

BC Hydro held a virtual WebEx meeting in February 2021 with commercial customers and stakeholders. The purpose of the meeting was to discuss the current General Service rates and identify potential rate design concepts that warrant further examination. BC Hydro received valuable feedback from meeting participants on potential rate designs of interest to commercial customers.

4.3 Next Steps

The next steps on customer and stakeholder engagement on commercial rate design is to conduct more extensive customer research later in 2021 to gauge interest and preference on rate designs. BC Hydro will determine if and when to make an application for commercial rate design pending the outcome of this research.

5 Transmission Service Rate Design

5.1 Background

BC Hydro's Transmission Service Rate Fiscal 2022 and Fiscal 2023 Pricing Principles Application, filed with the Commission on March 2, 2021, describes our activities to date and planned activities on transmission service rate design. A summary is also included in the sections that follow.

5.2 Activities Completed to Date

5.2.1 Jurisdictional Review

We have updated our jurisdictional review of electricity rate design for large industrial customers. Our research indicates that BC Hydro's existing transmission (industrial) rate design appears to be unique in North America. The aspects that make it unique are that it is a mandatory rate design that combines a tiered inclining block energy charge with individual customer baseline loads.

5.2.2 Public Rate Design Workshop

On February 9, 2021, BC Hydro held a virtual WebEx workshop with customers and stakeholders to discuss Rate Schedule 1823 restructuring concepts. At the workshop, BC Hydro discussed possible impacts on other related rate schedules for both firm and non-firm transmission service if RS 1823 is restructured. BC Hydro also asked for customer and stakeholder feedback on whether they support the extension of existing RS 1823 pricing principles.Feedback obtained to date is provided in section 5 of the Transmission Service Rate Fiscal 2022 and Fiscal 2023 Pricing Principles Application.

5.3 Next Steps

5.3.1 Communications and Engagement

As described in BC Hydro’s Transmission Service Rate Fiscal 2022 and Fiscal 2023 Pricing Principles Application, BC Hydro plans to conduct analysis, communication and engagement throughout 2021 on potential rate restructuring options for RS 1823.

5.3.2 Rate Schedule 1823 Restructuring Application

As further described in BC Hydro’s Transmission Service Rate Fiscal 2022 and Fiscal 2023 Pricing Principles Application, BC Hydro intends to file a Transmission service (industrial) rate restructuring application in fall 2021. The application will be informed by customer and stakeholder feedback.

6 Non-Integrated Area Rate Design

6.1 Background

BC Hydro’s Non-Integrated Area has two rate zones, Zone 1B (District of Bella Bella) and Zone II (all other non-integrated communities).[2] Zone 1B residential customers are served under the Zone 1 residential flat rate, while Zone 2 residential customers have a tiered rate with a higher priced second tier price. Electricity supply

[2] BC Hydro provides service to several communities that are not connected to our integrated system. Most of these Non-Integrated Area communities are served under our Zone 2 rates, which are inclining block rates. The rate schedules in Zone 2 apply the electricity rates up to a threshold, above which a much higher rate applies. For example, the Zone 2 residential rate is 11 c/kWh up to 1,500 kWh in a month, and 19 c/kWh above this threshold.

in the NIA is a mix of diesel generation, hydro electric and some biomass. While most of our customers in the Non-Integrated Areas are Residential, there are also some General Service accounts.

6.2 Activities Completed to Date

6.2.1 Jurisdictional Review

BC Hydro recently updated our jurisdictional review of NIA rates. The review found that our Zone II rate design is consistent with that of other electric utilities that serve remote communities.

In each of Manitoba, Ontario, Quebec, Newfoundland and Labrador and Alaska customers pay an initial energy charge generally based on what residential customers on the integrated system pay and they are then charged higher rates for electricity use above set thresholds, to reflect the higher cost of electricity generation in remote northern communities. Manitoba Hydro and Hydro Quebec discourage the use of electricity for space heating in northern remote communities. Manitoba Hydro does so by limiting residential electrical service levels and Hydro Quebec does so by charging an electricity rate for space heating that is higher than the standard rate.

6.2.2 Customer and Stakeholder Feedback

In 2017, a series of workshops were conducted by BC Hydro on the topic of NIA rate design. The purpose of the workshops was to educate customers on rate design and to gather feedback. In February 2021, BC Hydro met with the Low Income Advisory Council (**LIAC**). The purpose of the session was to gather ideas and feedback from the council on potential rate options to explore.

6.3 Next Steps

To explore rate design concepts and options for NIA rate design, BC Hydro will include the NIA in the scope of the residential rate design communication and engagement work. A decision on whether and when to file an NIA Rate Design Application with the BCUC will be made following the outcome of this work.

7 Fully Allocated Cost of Service

7.1 Background and Regulatory Context

Fully allocated cost of service studies are used in the assessment of the fair allocation of costs, which is a longstanding and widely accepted Bonbright rate design criteria. Two main outputs of the studies are unitized cost of service (e.g., cost of energy in c/kWh, and cost of demand in $/kW-year), as well as revenue to cost (**R/C**) ratios. BC Hydro uses the unitized costs for pricing and rate design, for example to assess how cost reflective the fixed, demand or energy charges are. R/C ratios compare the revenues received from a rate class to the costs allocated to it. While R/C ratios may be used for rate rebalancing, consistent with section 58.1 of the *Utilities Commission Act*, BC Hydro has not undertaken rate rebalancing for several years and currently has no plans to apply to the BCUC for rate rebalancing.

BC Hydro's FACOS studies use the known accounting costs from BC Hydro's Revenue Requirements Applications and related compliance filings as a basis. Revenue Requirement Application cost items are allocated to rate classes using the widely-adopted three-step process: costs are first functionalized into four functions (Generation, Transmission, Distribution and Customer Care); costs in each function are then classified as customer, energy, or demand related; finally, the classified costs are allocated to rate classes based on the various allocation factors (e.g., proportion of energy, coincident peak (**CP**), non-coincident peak (**NCP**), or number of customers).

Commission Order No. G-111-07 issued September 18, 2007, directs the use of embedded costs (i.e., revenue requirements), along with other key methodological approaches for BC Hydro's FACOS studies. With the exception of fiscal 2015, BC Hydro has completed FACOS studies annually since fiscal 2008. BC Hydro's most recent FACOS was filed on February 11, 2021 covering up to fiscal 2020.

The methodologies applied in BC Hydro's FACOS study were thoroughly examined during BC Hydro's 2015 Rate Design Application. As part of that proceeding, a negotiated settlement process for BC Hydro's cost of service study and rate class segmentation was held on March 7 and 8, 2016. On April 11, 2016, Commission Order No. G-47-16 approved the 2016 negotiated settlement agreement. On March 29, 2019, BC Hydro filed our Fiscal 2019 Cost of Service Study, with the BCUC in which the fourteen identified topics in the 2016 negotiated settlement agreement were further examined. For example, BC Hydro examined if 4CP, 1CP or 12CP is the appropriate demand allocator. Based on the analysis undertaken, in our F2019 Cost of Service Study BC Hydro concluded that BC Hydro's FACOS methodologies remain appropriate for the determination of cost causation and we have not made any changes to the FACOS methodology.

7.2 F2020 Fully Allocated Cost of Service Study Results

BC Hydro completes an updated FACOS study annually. The F2020 FACOS study was filed with the BCUC February 11, 2021 and is included as Appendix A.

The revenue to cost ratios from fiscal 2016 to fiscal 2020 are shown below. In fiscal 2020 the unitized cost of energy was 3.9 cents kWh, and the unitized generation and transmission demand related cost was $219.2/kW-year.

Table 1 F2020 Cost of Service Study Results

	Revenue to Cost Ratios						
Rate Class	F2016 Actual (%)	F2017 Actual (%)	F2018 Actual (%)	F2019 Actual (%)	F2020 Actual (%)	Percentage Point Change (F2019 Actual to F2020 Actual) (%)	Percentage of Energy at Customer Meter in F2020 (%)
Residential	90.8	93.2	93.8	94.6	93.3	-1.3	35.0
GS < 35 Kw	122.6	123.6	121.3	120.9	116.4	-4.5	7.8
MGS	123.5	115.1	114.3	115.1	113.7	-1.4	6.7
LGS	103.9	103.9	102.9	102.4	103.7	1.3	21.9
Irrigation	95.1	89.5	72.0	83.4	77.2	-6.2	0.1
Street Lighting – BC Hydro Owned	183.6	198.4	210.5	211.9	200.2	-11.7	0.1
Street Lighting – Customer Owned	101.8	95.1	92.8	88.4	84.9	-3.5	0.3
Transmission	98.8	95.4	96.1	94.9	99.3	4.4	28.1
Total BC Hydro	100.0	100.0	100.0	100.0	100.0	0	100.0

7.3 Methodology Discussion

As noted above in section 7.1, BC Hydro conducted a thorough review of our FACOS study methodology as described in our Fiscal 2019 Cost of Service Study and concluded at that time that no methodological changes were warranted. In consideration of recent feedback from interveners during BC Hydro's Revenue Requirements Applications, in 2020 BC Hydro retained external experts[3] in cost of service to provide a review of cost of service methodology with a focus on marginal cost of service. The results of that review are summarized below. BC Hydro

[3] Agustin J. Ros, Philip Q. Hanser and Sai Shetty from the Brattle Group.

concludes from this review that our current methodology remains appropriate and is consistent with common utility practice. However, further work could be undertaken in the future to explore whether there may be value in incorporating aspects of marginal cost of service in our fully allocated cost of service studies. In addition, BC Hydro views marginal costs as an important consideration and input to rate design and pricing, consistent with the Bonbright rate design criteria of economic efficiency.

The fully allocated cost of service methodology used by BC Hydro, being the embedded cost approach, is a widely accepted cost of service study approach that has been adopted by many Canadian Utilities (e.g., BC Hydro, Fortis BC, Manitoba Hydro, Hydro-Quebec, Hydro One, New Brunswick power, Newfoundland Power, Nova Scotia Power and SaskPower). This approach is the standard for rate setting and discussions surrounding rate rebalancing. An advantage of the embedded cost of service approach is that it is calibrated to the utility's revenue requirements and historic accounting reports, which improves transparency of inputs.

Another approach is a marginal cost of service study which is a forward-looking study based on future costs. The marginal cost study estimates the resource costs to the utility in providing the last unit of production. The marginal costs are calculated as the ratio of the change in production costs to a change in total quantity. The use of marginal costs is widely accepted in the electric utility industry as having the potential to provide economically efficient price signals to encourage efficient use of electricity.

Since the marginal cost approach deals with future costs, the implicit revenue requirement from a marginal cost of service study is unlikely to match a utility's authorized, embedded cost revenue requirement which is based on historic accounting reports. Marginal cost of service studies may be applied in three ways in rate cases – pure marginal cost framework, marginal cost with reconciliation, or cost allocators with marginal cost framework – and these approaches are described below:

- The pure marginal cost framework focuses on the principle that pricing at marginal cost produces an optimal outcome. Any shortfall or surplus compared to the revenue requirement is made up for in subsidies or taxes. Embedded cost studies may serve as a means of comparison, but the marginal cost framework's results drive final cost and rate decisions;
- The marginal cost with reconciliation framework follows the pure marginal cost framework but includes a reconciliation of revenues calculated from the marginal cost study to the utility's authorized, embedded revenue requirement. Therefore, the final allocation deviates from that indicated by the pure marginal cost framework; and
- The cost allocators from the marginal cost framework uses the marginal costs to provide the cost shares for each class, as opposed to their absolute level. These shares are then applied to the authorized, embedded revenue requirement to give a fully allocated cost of service study result based on the revenue requirements.

The use of marginal cost of service for rate setting and rate rebalancing is not widespread in either Canadian nor U.S. jurisdictions. No Canadian utility company and very few U.S. states require marginal cost of service studies for rate-setting purposes. California, Oregon and Nevada are the few U.S. states that require utilities to allocate cost based on marginal cost allocators, which is the third approach described above.

Even though marginal costs are not commonly used in general rate setting and rate rebalancing, marginal costs can be valuable to form the basis for pricing in rate design. For example, marginal costs are an important input to the pricing of economically efficient rates, and in particular time-varying rates.

BC Hydro concludes from this review that our current methodology, referred to as the embedded cost of service approach, remains appropriate and is consistent with common utility practice. However, further work could be undertaken in the future to explore whether there may be value in applying the cost allocators from marginal cost approach to our fully allocated cost of service studies as an alternative methodology.

BC Hydro intends to examine this approach and if sufficient data is available, to include a summary of its outcomes in our F2021 FACOS filing to the BCUC.

8 Conclusion

This report is filed for information purposes and to comply with BCUC Order No. G-62-20, Directive 2 and Order No. G-246-20, Directive 66. In these directives, the BCUC directed BC Hydro to file a report by March 26, 2021 that describes our progress and plans on rate design and provides an update on our fully allocated cost of service study and methodology.

As described in this report, BC Hydro has completed a number of activities on rate design for all of our customer segments. We are planning to file a transmission rate design application in 2021 and a residential rate design application in 2022. These applications will be preceded by extensive customer and stakeholder engagement activities and BC Hydro invites all interested parties to participate in and contribute to these efforts.

BC Hydro Residential Inclining Block Rate Pricing Principles Extension for Fiscal 2021 and Fiscal 2022 Application Compliance with BCUC Order No. G-62-20 Directive 2

Rate Design Progress Report

Appendix A

F2020 Fully Allocated Cost of Service Study

BC Hydro
Power smart

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February 11, 2021

Ms. Marija Tresoglavic
Acting Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Tresoglavic:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2020 Fully Allocated Cost of Service (FACOS) Study

BC Hydro writes to file, attached as Appendix A to this letter, its F2020 FACOS study reflecting fiscal 2020 actual results pursuant to Commission Directive No. 2 of the 2007 Rate Design Application (**2007 RDA**) Decision (page 206).[1]

This compliance filing uses the same methodology as the fiscal 2016, fiscal 2017, fiscal 2018 and fiscal 2019 FACOS studies. The F2019 study was filed with BCUC on May 13, 2020.

The table below shows Revenue-to-Cost (R/C) ratios for all rate classes in fiscal 2020, as compared to the results since fiscal 2016, and the percentages of energy consumption of individual rate classes in fiscal 2020.

	Revenue to Cost Ratios						
Rate Class	F2016 Actual (%)	F2017 Actual (%)	F2018 Actual (%)	F2019 Actual (%)	F2020 Actual (%)	Percentage Point Change (F2019 Actual to F2020 Actual) (%)	Percentage of Energy at Customer Meter in F2020 (%)
Residential	90.8	93.2	93.8	94.6	93.3	-1.3	35.0
GS < 35 Kw	122.6	123.6	121.3	120.9	116.4	-4.5	7.8
MGS	123.5	115.1	114.3	115.1	113.7	-1.4	6.7

1 https://www.bcuc.com/Documents/Proceedings/2007/DOC_17004_10-26_BCHydro-Rate-Design-Phase-1-Decision.pdf.

	Revenue to Cost Ratios					
LGS	103.9	103.9	102.9	102.4	103.7	1.3	21.9
Irrigation	95.1	89.5	72.0	83.4	77.2	-6.2	0.1
Street Lighting – BC Hydro Owned	183.6	198.4	210.5	211.9	200.2	-11.7	0.1
Street Lighting – Customer Owned	101.8	95.1	92.8	88.4	84.9	-3.5	0.3
Transmission	98.8	95.4	96.1	94.9	99.3	4.4	28.1
Total BC Hydro							100.0

BC Hydro notes the following when comparing FACOS results in fiscal 2020 to the results in fiscal 2019:

- The R/C ratios for the Residential, MGS, and LGS Class changed by less than 1.5 per cent in fiscal 2020;
- The approximate 4.5 per cent decrease in the R/C ratio for the SGS Class (i.e., GS < 35 Kw) was due to its slight increase of Coincident Peak and Non-Coincident Peak Factors, which are used to allocate demand related cost to customer classes[2];
- The R/C ratio for the Irrigation Class decreased 6.2 per cent in fiscal 2020 due to its considerable increase of peak demand in winter months;
- The 11.7 per cent decrease in the R/C Ratio for the Street Lighting – BC Hydro Owned Rate Class in fiscal 2020 was due to the reduction of revenue attributable to attrition of a closed rate RS 1755 and a one-time back billing due to the adjustment of the number of street lights for a customer;
- The approximate 3.5 per cent decrease in the R/C Ratio for the Street Lighting – Customer Owned Rate Class reflects the further revenue reduction caused by the replacement of old technologies with LED energy efficient lights by customers;
- The 4.4 per cent increase in the R/C Ratio for the Transmission Class was due to the additional revenue of RS 1891 (Transmission Service – Shore Power Service), and RS 1893 (Transmission Service -Incremental Energy Rate). RS 1893 is a new rate that started during fiscal 2020.

2 “Coincident Peak” is the individual customer class’ demand during the time of system peak demand; “Non-Coincident Peak” is the maximum demand of an individual customer class regardless of time of occurrence.

For further information, please contact Anthea Jubb at 604-623-3545 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

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Enclosure

Copy to: BCUC Project No. 3698781 (2015 RDA) Registered Intervener Distribution List.

Appendix A

F2020 Cost of Service - Actual Cost

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Note: All costs are in $ X 1 million unless otherwise noted.
Some numbers may not add up due to rounding.

Appendix A

F2020 Cost of Service - Actual Cost
Functionalization Details

Revenue Requirement Schedule (F2020 Actual) [1]

		F2020 Revenue Requirement	Generation	Transmission	Distribution	Customer Care
Cost of Energy						
Sched 4, L23	Water Rentals	331.6	331.6	0.0	0.0	0.0
Sched 4, L24	Natural gas for thermal generation	7.1	7.1	0.0	0.0	0.0
Sched 4, L25	Domestic Transmission (Heritage)	24.8	0.0	24.8	0.0	0.0
Sched 4, L26	Non-treaty storage and Libby Coordination agreements	37.7	37.7	0.0	0.0	0.0
Sched 4, L27	Remissions and Other	-42.4	-42.4	0.0	0.0	0.0
Sched 4, L 41	HDA Additions	82.4	82.4	0.0	0.0	0.0
Sched 4, L 43	Deferred Operating HDA	-1.4	-1.4	0.0	0.0	0.0
Sched 4, L 49	HDA Recoveries	-280.6	-280.6	0.0	0.0	0.0
	Total IPPs and Long-term Commitment	1,451.7	1,451.7	0.0	0.0	0.0
Sched 14, L 21	Reduction of COE due to transations under an energy supply contract under IPP [2]	-5.4	-5.4	0.0	0.0	0.0
Sched 4, L 30	NIA Generation	31.3	31.3	0.0	0.0	0.0
Sched 4, L 31	Gas & Other Transportation	4.5	4.5	0.0	0.0	0.0
Sched 4, L 32	Water Rentals (Waneta 2/3)	3.3	3.3	0.0	0.0	0.0
Sched 4, L 42	NHDA Additions	-100.1	-100.1	0.0	0.0	0.0
Sched 4, L 44	Deferred Operating NHDA	0.0	0.0	0.0	0.0	0.0
Sched 4, L45	Deferred Amortization NHDA	0.4	0.4	0.0	0.0	0.0
Sched 4, L46	Deferred Taxes NHDA	0.0	0.0	0.0	0.0	0.0
Sched 4, L47	Deferred Provision NHDA	0.0	0.0	0.0	0.0	0.0
Sched 4, L48	Deferred Waneta 1/3 Costs	0.0	0.0	0.0	0.0	0.0
Sched 4, L 50	NHDA Recoveries	40.9	40.9	0.0	0.0	0.0
Sched 4, L 34	Market Electricity Purchases	133.1	133.1	0.0	0.0	0.0
Sched 4, L 35	Surplus Sales	-1.0	-1.0	0.0	0.0	0.0
Sched 4, L36	Net purchases (sales) from Powerex	-35.2	-35.2	0.0	0.0	0.0
Sched 4, L 37	Domestic Transmission -Export (Market Energy)	2.0	2.0	0.0	0.0	0.0
Total		1,684.8	1,660.0	24.8	0.0	0.0
O M & A Expenses						
sched 5.0, L111	Intergarated Planning	432.2	132.7	149.0	150.0	0.5
sched 5.0, L112	Capital Infrastructure Project Delivery	111.6	57.0	37.9	13.6	3.2
sched 5.0, L113	Operations	318.3	70.2	77.4	164.0	6.7
sched 5.0, L114	Safety	55.2	15.8	15.8	17.2	6.4
sched 5.0, L117	Finance, Technology, Supply Chain	269.5	75.3	76.2	87.1	31.0
sched 5.0, L118	People, Customer, Corporate Affairs	150.2	15.1	14.8	16.0	104.4
Sched 5.0, L117	Other	-10.4	-3.0	-3.0	-3.2	-1.2
Sched 5.0, L120 (Sched3.13, L31)	Non-Current PEB - Pension	56.8	16.2	16.3	17.7	6.6
Sched 5.0, L121	PEB Current Pension Costs	-0.9	-0.2	-0.3	-0.3	-0.1
Total		1,382.6	379.1	384.1	462.1	157.4
Depreciation & Amortization						
Sched 7.0, L1	Amortization of Capital Assets - Generation	262.7	262.7	0.0	0.0	0.0
Sched 7.0, L2	Amortization of Capital Assets - Transmission	229.2	0.0	229.2	0.0	0.0
Sched 7.0, L3	Amortization of Capital Assets - Distribution	207.3	0.0	0.0	207.3	0.0
Sched 7.0, L4	Amortization of Capital Assets - Business Support	186.6	39.2	121.3	26.1	0.0
Sched 7.0, L13	Amortization - Other Leases	2.6	0.7	0.8	0.8	0.3
Sched 7.0, L14, L18	Defferal Account Additions - Transfers to NHDA	0.0	0.0	0.0	0.0	0.0
Sched 7.0, L19	Transfer to Regulatory Account - Amortization on Additions Variance	0.4	0.1	0.1	0.1	0.0
Sched 7.0, L22 - L25	Regulatory Account Recoveries - DSM Amortization	103.3	93.0	5.2	5.2	0.0
Sched 7.0, L31	Pre-1996 CIAC Amortization	5.1	0.0	0.0	5.1	0.0
Sched 7.0, L32	Capital Additions Regulatory Account - Business Support	9.7	2.0	6.3	1.4	0.0
Total		1,007.0	397.7	362.9	246.0	0.4
Taxes						
Sched 6, L 24	Generation	44.2	44.2	0.0	0.0	0.0
Sched 6, L 25	Transmission	158.4	0.0	158.4	0.0	0.0
Sched 6, L 26	Distribution	28.6	0.0	0.0	28.6	0.0
Sched 6, L27 minus L10	Customer Care	0.9	0.0	0.0	0.0	0.9
Sched 6, L 28	Business Support	17.7	3.4	12.1	2.2	0.1
Total		249.7	47.6	170.5	30.7	0.9
Finance Charges						
Sched 8,	Generation	371.0	371.0	0.0	0.0	0.0
Sched 8,	Transmission	265.2	0.0	265.2	0.0	0.0
Sched 8,	Distribution	166.8	0.0	0.0	166.8	0.0
Sched 8, L21	Total Finance Charge Regulatory Acct. Additions	-0.9	-0.7	-0.1	-0.2	0.0
Sched 8, L22	Site C Project (IFRS 14 IDC impact)	1.9	1.4	0.1	0.4	0.0
Sched 8, L23	Interest on Deferral Accounts	15.9	11.5	1.1	3.3	0.0
Sched 8, L24	Interest on Other Reg Accounts	-32.6	-23.5	-2.3	-6.8	0.0
Sched 8, L31	Regulatory Account Recoveries	-100.3	-46.3	-33.1	-20.8	0.0
Total		687.0	313.3	231.0	142.7	0.0
Allowed Net Income (return on equity)						
Sched 9, L41 - L 44	Total ROE	704.9	325.6	232.8	146.4	0.0
Total		704.9	325.6	232.8	146.4	0.0
Miscellaneous Revenues						
Sched 15, L1	Amortization of Contributions (Generation)	-0.3	-0.3	0.0	0.0	0.0
Sched 15, L2	Other (Generation)	-2.2	-2.2	0.0	0.0	0.0
Sched 15, L4	External OATT (Transmission)	-10.7	0.0	-10.7	0.0	0.0
Sched 15, L5	FortisBC Wheeling Agreement (Transmission)	-5.2	0.0	-5.2	0.0	0.0
Sched 15, L6	Secondary Revenue (Transmission)	-7.1	0.0	-7.1	0.0	0.0
Sched 15, L7	Interconnections (Transmission)	-6.4	0.0	-6.4	0.0	0.0
Sched 15, L8	Amortization of Contributions (Transmission)	-14.6	0.0	-14.6	0.0	0.0
Sched 15, L9	NTL Supplemental Charge (Transmission)	-2.3	0.0	-2.3	0.0	0.0
Sched 15, L11	Secondary Use Revenue & Other (Distribution)	-17.0	0.0	0.0	-17.0	0.0
Sched 15, L12	Amortization of Contributions (Distribution)	-49.1	0.0	0.0	-49.1	0.0
Sched 15, L14	Meter/Trans Rents & Power Factor Surcharges (Customer Care)	-16.1	0.0	0.0	0.0	-16.1
Sched 15, L15	Smart Metering & Infrastructure Impact (Customer Care)	-2.2	0.0	0.0	0.0	-2.2
Sched 15, L16	Diversion Net Recoveries (Customer Care)	-0.2	0.0	0.0	0.0	-0.2
Sched 15, L17	Other Operating Recoveries (Customer Care)	-4.1	0.0	0.0	0.0	-4.1
Sched 15, L18	Customer Crisis Fund Rider Revenue (Customer Care)	-4.4	0.0	0.0	0.0	-4.4
Sched 15, L19	Other (Customer Care)	-3.1	0.0	0.0	0.0	-3.1
Sched 15, L20	Waneta Lease revenue from Teck (Customer Care)	-75.2	0.0	0.0	0.0	-75.2
Sched 15, L21	Waneta 2/3Teck portion of operating costs (Customer Care)	-5.4	0.0	0.0	0.0	-5.4
Sched 15, L22	Waneta 2/3Teck portion of water rentals (Customer Care)	-3.3	0.0	0.0	0.0	-3.3
Sched 15, L23	Waneta 2/3 Teck portion of property taxes (Customer Care)	-0.9	0.0	0.0	0.0	-0.9
Sched 15, L26	Corporate General Rents (Business Support)	-3.9	-1.1	-1.1	-1.2	-0.5
Sched 15, L27	Late Payment Charges (Business Support)	-7.1	-2.0	-2.0	-2.2	-0.8
Sched 15, L28	MMBU Secondary Revenue (Business Support)	-3.9	-1.1	-1.1	-1.2	-0.5
Sched 15, L29	Other (Business Support)	-1.4	-0.4	-0.4	-0.4	-0.2
Total		-246.0	-7.2	-51.1	-71.1	-116.7
Revenue Offsets & Other						
Sched 3.1 L14,L15; Sched 3.4 L18, L19	Total Inter-Segment Revenue	-72.0	-0.6	-70.5	-0.6	-0.2
Sched 1.0,L17; Sched 2.1, L16, L18	Powerex Net Current Income	-284.8	-284.8	0.0	0.0	0.0
Sched 3.0, L64	Powertech Net Income	-3.4	-3.4	0.0	0.0	0.0
Sched 3.0, L65	Other Utilities Revenue	-29.7	-29.7	0.0	0.0	0.0
Sched 3.0, L66	liquefied Natural Gas Revenue	-1.3	-1.3	0.0	0.0	0.0
Sched 3.0, L67	Deferral Account Rate Rider Revenue	-0.2	-0.2	0.0	0.0	0.0
Sched 3.2, L9	GRTA Allocation	0	43.3	-43.3	0.0	0.0
Sched 3.2, L10	Generation Real Time Dispatch	0	2.4	-2.4	0.0	0.0
Sched 3.4, L10	Distribution Real Time Dispatch	0	0.0	-20.8	20.8	0.0
Sched 3.4, L11	SDA Allocation to Distribution	0	0.0	-127.0	127.0	0.0
Sched 3.4, L12	PTP Allocation to Distribution	0	0.0	-23.9	23.9	0.0
Sched 3.2, L11	Generation Ancillary Services	0	-2.1	2.1	0.0	0.0
Sched 3.2, L12	Generation Capitalized Overhead	0	-6.7	2.7	2.9	1.1
Sched 3.4, L14	Transmission Capitalized Overhead	0	4.6	-11.5	5.0	1.9
Sched 3.5, L11	Distribution Capitalized Overhead	0	13.0	13.1	-31.3	5.3
Sched 3.1, L9 - L11	Generation RSRA Write-off	0.0	0.0	0.0	0.0	0.0
Sched 3.2, L14	Waneta 2/3 Lease revenue form Teck	0	-75.2	0.0	0.0	75.2
Sched 3.2, L15	Adj to align with prior approved RRA	0	0.0	0.0	0.0	0.0
Total		-391.3	-340.7	-281.4	147.6	83.2
Total Revenue Requirement		**5,078.6**	**2,775.5**	**1,073.5**	**1,104.4**	**125.2**

1. As included in Attachment A to Revised Financial Schedules of BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Applicaiton dated December 1, 2020.
2. The difference of total revenue requirement between Cost of Service Study and Fiscal 2020 to Fiscal 2021 Revenue Requirements Application is due to the non-cash transactions under an energy supply contract which allowed an IPP customer to borrow and return water to BC Hydro. This revenue offset the cost of energy in Cost of Service.

Classification of Generation Function
(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Energy Related	Demand Costs	Energy Costs
Cost of Energy					
Water Rentals	331.6	10.0%	90.0%	33.2	298.4
Natural gas for thermal generation	7.1	0.0%	100.0%	0.0	7.1
Domestic Transmission (Heritage)	0.0	100.0%	0.0%	0.0	0.0
Non-treaty storage and Libby Coordination agreements	37.7	0.0%	100.0%	0.0	37.7
Remissions and Other	-42.4	0.00%	100.0%	0.0	-42.4
HDA Additions	82.4	7.1%	92.9%	5.9	76.5
Deferred Operating HDA	-1.4	7.1%	92.9%	-0.1	-1.3
HDA Recoveries	-280.6	7.1%	92.9%	-20.0	-260.6
Total IPPs and Long-term Commitment	1451.7	7.0%	93.0%	101.6	1350.1
Reduction of COE due to transations under an energy supply contract under IPP	-5.4	7.0%	93.0%	-0.4	-5.0
NIA Generation	31.3	0.0%	100.0%	0.0	31.3
Gas & Other Transportation	4.5	0.0%	100.0%	0.0	4.5
Water Rentals (Waneta 2/3)	3.3	10.0%	90.0%	0.3	3.0
NHDA Additions	-100.1	7.1%	92.9%	-7.1	-93.0
Deferred Operating NHDA	0.0	7.1%	92.9%	0.0	0.0
Deferred Amortization NHDA	0.4	7.1%	92.9%	0.0	0.3
Deferred Taxes NHDA	0.0	7.1%	92.9%	0.0	0.0
Deferred Provision NHDA	0.0	7.1%	92.9%	0.0	0.0
Deferred Waneta 1/3 Costs	0.0	7.1%	92.9%	0.0	0.0
NHDA Recoveries	40.9	7.1%	92.9%	2.9	37.9
Market Electricity Purchases	133.1	0.0%	100.0%	0.0	133.1
Surplus Sales	-1.0	0.0%	100.0%	0.0	-1.0
Net purchases (sales) from Powerex	-35.2	0.0%	100.0%	0.0	-35.2
Domestic Transmission -Export (Market Energy)	2.0	100.0%	0.0%	2.0	0.0
Total	1,660.0	7.1%	92.9%	118.3	1,541.7
O M & A Expenses					
Intergarated Planning	132.7	55.0%	45.0%	73.0	59.7
Capital Infrastructure Project Delivery	57.0	55.0%	45.0%	31.4	25.7
Operations	56.7	55.0%	45.0%	31.2	25.5
Burrard	5.4	100.0%	0.0%	5.4	-
Fort Nelson	7.4	26.0%	74.0%	1.9	5.5
Prince Rupert	0.7	40.0%	60.0%	0.3	0.4
Thermal Generation	13.5	56.1%	43.9%	7.6	5.9
Safety	15.8	55.0%	45.0%	8.7	7.1
Finance, Technology, Supply Chain	75.3	55.0%	45.0%	41.4	33.9
People, Customer, Corporate Affairs	15.1	55.0%	45.0%	8.3	6.8
Other	(3.0)	55.0%	45.0%	(1.6)	(1.3)
Non-Current PEB - Pension	16.2	55.0%	45.0%	8.9	7.3
PEB Current Pension Costs	(0.2)	55.0%	45.0%	(0.1)	(0.1)
Total	379.1			208.6	170.4
Depreciation & Amortization					
Generation	262.7	55.0%	45.0%	144.5	118.2
Transmission	-	55.0%	45.0%	-	-
Distribution	-	55.0%	45.0%		
Business Support	39.2	55.0%	45.0%	21.6	17.6
Amortization - Other Leases	0.7	55.0%	45.0%	0.4	0.3
Transfer to Regulatory Account - Amortization on Additions Variance	0.1	55.0%	45.0%	0.1	0.1
Regulatory Account Recoveries - DSM Amortization	93.0	28.1%	71.9%	26.1	66.9
Pre-1996 CIAC Amortization	-	55.0%	45.0%	-	-
Capital Additions Regulatory Account - Business Support	2.0	55.0%	45.0%	1.1	0.9
Total	397.7			193.7	204.0
Taxes					
Generation	44.2	55.0%	45.0%	24.3	19.9
Transmission	-	55.0%	45.0%	-	-
Distribution	-	55.0%	45.0%	-	-
Customer Care	-	55.0%	45.0%	-	-
Business Support	3.4	55.0%	45.0%	1.9	1.5
Total	47.6			26.2	21.4
Finance Charges					
Generation	371.0	55.0%	45.0%	204.0	166.9
Transmission	-	55.0%	45.0%	-	-
Distribution	-	55.0%	45.0%	-	-
Total Finance Charge Regulatory Acct. Additions	(0.7)	55.0%	45.0%	(0.4)	(0.3)
Site C Project (IFRS 14 IDC impact)	1.4	55.0%	45.0%	0.7	0.6
Interest on Deferral Accounts	11.5	7.1%	92.9%	0.8	10.7
Interest on Other Reg Accounts	(23.5)	55.0%	45.0%	(12.9)	(10.6)
Regulatory Account Recoveries	(46.3)	55.0%	45.0%	(25.5)	(20.9)
Total	313.3			166.8	146.5
					-
Allowed Net Income					-
Generation	325.6	55.0%	45.0%	179.1	146.5
Total	325.6			179.1	146.5
					-
Miscellaneous Revenues					-
Amortization of Contributions	(0.3)	55.0%	45.0%	(0.2)	(0.1)
Other	(2.2)	55.0%	45.0%	(1.2)	(1.0)
External OATT	-	55.0%	45.0%	-	-
FortisBC Wheeling Agreement	-	55.0%	45.0%	-	-
Secondary Revenue	-	55.0%	45.0%	-	-
Interconnections	-	55.0%	45.0%	-	-
Amortization of Contributions	-	55.0%	45.0%	-	-
NTL Supplemental Charge	-	55.0%	45.0%	-	-
Secondary Use Revenue & Other	-	55.0%	45.0%	-	-
Amortization of Contributions	-	55.0%	45.0%	-	-
Meter/Trans Rents & Power Factor Surcharges	-	55.0%	45.0%	-	-
Smart Metering & Infrastructure Impact	-	55.0%	45.0%	-	-
Diversion Net Recoveries	-	55.0%	45.0%	-	-
Other Operating Recoveries	-	55.0%	45.0%	-	-
Customer Crisis Fund Rider Revenue	-	55.0%	45.0%	-	-
Other	-	55.0%	45.0%	-	-
Waneta Lease revenue from Teck	-	55.0%	45.0%	-	-
Waneta 2/3Teck portion of operating costs	-	55.0%	45.0%	-	-
Waneta 2/3Teck portion of water rentals	-	55.0%	45.0%	-	-
Waneta 2/3 Teck portion of property taxes	-	55.0%	45.0%	-	-
Corporate General Rents	(1.1)	55.0%	45.0%	(0.6)	(0.5)
Late Payment Charges	(2.0)	55.0%	45.0%	(1.1)	(0.9)
MMBU Secondary Revenue	(1.1)	55.0%	45.0%	(0.6)	(0.5)
Other	(0.4)	55.0%	45.0%	(0.2)	(0.2)
Total	(7.2)			(3.9)	(3.2)
					-
Revenue Offsets & Other					-
Total Inter-Segment Revenue	(0.6)	55.0%	45.0%	(0.32)	(0.26)
Powerex Net Income	(284.8)	28.1%	71.9%	(80.01)	(204.76)
Powertech Net Income	(3.4)	28.1%	71.9%	(0.96)	(2.45)
Other Utilities Revenue	(29.7)	55.0%	45.0%	(16.34)	(13.37)
liquefied Natural Gas Revenue	(1.3)	0.0%	100.0%	-	(1.26)
Deferral Rider Revenue	(0.2)	7.1%	92.9%	(0.02)	(0.20)
GRTA Allocation	43.3	55.0%	45.0%	23.82	19.49
Generation Real Time Dispatch	2.4	55.0%	45.0%	1.31	1.07
Distribution Real Time Dispatch	-	55.0%	45.0%	-	-
SDA Allocation to Distribution	-	55.0%	45.0%	-	-
PTP Allocation to Distribution	-	55.0%	45.0%	-	-
Generation Ancillary Services	(2.1)	55.0%	45.0%	(1.15)	(0.94)
Generation Capitalized Overhead	(6.7)	55.0%	45.0%	(3.68)	(3.01)
Transmission Capitalized Overhead	4.6	55.0%	45.0%	2.53	2.07
Distribution Capitalized Overhead	13.0	55.0%	45.0%	7.12	5.83
Gneration RSRA Write-off	-	55.0%	45.0%	-	-
Waneta 2/3 Lease revenue form Teck	(75.2)	55.0%	45.0%	(41.36)	(33.84)
Adj to align with prior approved RRA	-	55.0%	45.0%	-	-
Total	(340.7)			(109.1)	(231.6)
Total Generation Costs	**2,775.5**	**28.1%**	**71.9%**	**779.8**	**1,995.7**

Appendix A

Classification of Transmission Function

(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Demand Costs
Cost of Energy			
Water Rentals	-	100%	-
Natural gas for thermal generation	-	100%	-
Domestic Transmission (Heritage)	24.8	100%	24.8
Non-treaty storage and Libby Coordination agreements	-	100%	-
Remissions and Other	-	100%	-
HDA Additions	-	100%	-
Deferred Operating HDA	-	100%	-
HDA Recoveries	-	100%	-
Total IPPs and long-term Commitment	-	100%	-
NIA Generation	-	100%	-
Gas & Other Transportation	-	100%	-
Water Rentals (Waneta 2/3)	-	100%	-
NHDA Additions	-	100%	-
Deferred Operating NHDA	-	100%	-
Deferred Amortization NHDA	-	100%	-
Deferred Taxes NHDA	-	100%	-
Deferred Provision NHDA	-	100%	-
Deferred Waneta 1/3 Costs	-	100%	-
NHDA Recoveries	-	100%	-
Market Electricity Purchases	-	100%	-
Surplus Sales	-	100%	-
Net purchases (sales) from Powerex	-	100%	-
Domestic Transmission -Export (Market Energy)	-	100%	-
Total	24.8		24.8
O M & A Expenses			
Intergarated Planning	149.0	100%	149.0
Capital Infrastructure Project Delivery	37.9	100%	37.9
Operations	77.4	100%	77.4
Safety	15.8	100%	15.8
Finance, Technology, Supply Chain	76.2	100%	76.2
People, Customer, Corporate Affairs	14.8	100%	14.8
Other	3.5	100%	3.5
Non-Current PEB - Pension	0.2	100%	0.2
PEB Current Pension Costs	9.4	100%	9.4
Total	384.1		384.1
Depreciation & Amortization			
Generation	-	100%	-
Transmission	229.2	100%	229.2
Distribution	-	100%	-
Business Support	121.3	100%	121.3
Amortization - Other Leases	0.7	100%	0.7
Transfer to Regulatory Account - Amortization on Additions Variance	0.1	100%	0.1
Regulatory Account Recoveries - DSM Amortization	5.2	100%	5.2
Pre-1996 CIAC Amortization	-	100%	-
Capital Additions Regulatory Account - Business Support	6.3	100%	6.3
Total	362.9		362.9
Taxes			
Generation	-	100%	-
Transmission	158.4	100%	158.4
Distribution	-	100%	-
Customer Care	-	100%	-
Business Support	12.1	100%	12.1
Total	170.5		170.5
Finance Charges			
Generation	-	100%	-
Transmission	265.2	100%	265.2
Distribution	-	100%	-
Total Finance Charge Regulatory Acct. Additions	(0.1)	100%	(0.1)
Site C Project (IFRS 14 IDC impact)	0.1	100%	0.1
Interest on Deferral Accounts	1.1	100%	1.1
Interest on Other Reg Accounts	(2.3)	100%	(2.3)
Regulatory Account Recoveries	(33.1)	100%	(33.1)
Total	231.0		231.0
Allowed Net Income			
Transmission	232.8	100%	232.8
Total	232.8		232.8
Miscellaneous Revenues			
Amortization of Contributions	-	100%	-
Other	-	100%	-
External OATT	(10.7)	100%	(10.7)
FortisBC Wheeling Agreement	(5.2)	100%	(5.2)
Secondary Revenue	(7.1)	100%	(7.1)
Interconnections	(6.4)	100%	(6.4)
Amortization of Contributions	(14.6)	100%	(14.6)
NTL Supplemental Charge	(2.3)	100%	(2.3)
Secondary Use Revenue & Other	-	100%	-
Amortization of Contributions	-	100%	-
Meter/Trans Rents & Power Factor Surcharges	-	100%	-
Smart Metering & Infrastructure Impact	-	100%	-
Diversion Net Recoveries	-	100%	-
Other Operating Recoveries	-	100%	-
Customer Crisis Fund Rider Revenue	-	100%	-
Other	-	100%	-
Waneta Lease revenue from Teck	-	100%	-
Waneta 2/3Teck portion of operating costs	-	100%	-
Waneta 2/3Teck portion of water rentals	-	100%	-
Waneta 2/3 Teck portion of property taxes	-	100%	-
Corporate General Rents	(1.1)	100%	(1.1)
Late Payment Charges	(2.0)	100%	(2.0)
MMBU Secondary Revenue	(1.1)	100%	(1.1)
Other	(0.4)	100%	(0.4)
Total	(51.1)		(51.1)
Revenue Offsets & Other			
Total Inter-Segment Revenue	(70.5)	100%	(70.5)
Powerex Net Income	-	100%	-
Powertech Net Income	-	100%	-
Other Utilities Revenue	-	100%	-
liquefied Natural Gas Revenue	-	100%	-
Deferral Rider Revenue	-	100%	-
GRTA Allocation	(43.3)	100%	(43.3)
Generation Real Time Dispatch	(2.4)	100%	(2.4)
Distribution Real Time Dispatch	(20.8)	100%	(20.8)
SDA Allocation to Distribution	(127.0)	100%	(127.0)
PTP Allocation to Distribution	(23.9)	100%	(23.9)
Generation Ancillary Services	2.1	100%	2.1
Generation Capitalized Overhead	2.7	100%	2.7
Transmission Capitalized Overhead	(11.5)	100%	(11.5)
Distribution Capitalized Overhead	13.1	100%	13.1
Gneration RSRA Write-off	-	100%	-
Waneta 2/3 Lease revenue form Teck	-	100%	-
Adj to align with prior approved RRA	-	100%	-
Total	(281.4)		(281.4)
Total Transmission Costs	**1,073.5**		**1,073.5**

Appendix A

Classification of Distribution Function
(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Customer Related	SMI Energy Related	Streetlighting Costs (Direct Assigned)	Demand Costs	Customer Costs
Cost of Energy							
Water Rentals	-					-	-
Natural gas for thermal generation	-					-	-
Domestic Transmission (Heritage)	-					-	-
Non-treaty storage and Libby Coordination agreements	-					-	-
Remissions and Other	-					-	-
HDA Additions	-					-	-
Deferred Operating HDA	-					-	-
HDA Recoveries	-					-	-
Total IPPs and Long-term Commitment	-					-	-
NIA Generation	-					-	-
Gas & Other Transportation	-					-	-
Water Rentals (Waneta 2/3)	-					-	-
NHDA Additions	-					-	-
Deferred Operating NHDA	-					-	-
Deferred Amortization NHDA	-					-	-
Deferred Taxes NHDA	-					-	-
Deferred Provision NHDA	-					-	-
Deferred Waneta 1/3 Costs	-					-	-
NHDA Recoveries	-					-	-
Market Electricity Purchases	-					-	-
Surplus Sales	-					-	-
Net purchases (sales) from Powerex	-					-	-
Domestic Transmission -Export (Market Energy)	-					-	-
	-					-	-
O M & A Expenses							
Intergarated Planning	150.0	80%	20%		2.0	118.5	29.6
Capital Infrastructure Project Delivery	13.6	80%	20%			10.9	2.7
Operations	164.0	80%	20%			131.2	32.8
Safety	17.2	80%	20%			13.8	3.4
Finance, Technology, Supply Chain	87.1	80%	20%			69.7	17.4
People, Customer, Corporate Affairs	16.0	80%	20%			12.8	3.2
Other	-3.2	80%	20%			(2.6)	(0.6)
Non-Current PEB - Pension	17.7	80%	20%			14.1	3.5
PEB Current Pension Costs	-0.3	80%	20%		-	(0.2)	(0.1)
Total	462.1				2.0	368.1	92.0
Depreciation & Amortization							
Generation	0.0	80%	20%			-	-
Transmission	0.0	80%	20%			-	-
Distribution	207.3	80%	20%		0.9	165.2	41.3
Business Support	26.1	80%	20%			20.9	5.2
Amortiation - Other Leases	0.8	80%	20%			0.7	0.2
Transfer to Regulatory Account - Amortization on Additions Variance	0.1	80%	20%			0.1	0.0
Regulatory Account Recoveries - DSM Amortization	5.2	80%	20%			4.1	1.0
Pre-1996 CIAC Amortization	5.1	80%	20%			4.1	1.0
Capital Additions Regulatory Account - Business Support	1.4	80%	20%			1.1	0.3
Total	246.0				0.9	196.1	49.0
Taxes							
Generation	0.0	80%	20%			-	-
Transmission	0.0	80%	20%			-	-
Distribution	28.6	80%	20%		0.1	22.7	5.7
Customer Care	0.0	80%	20%			-	-
Business Support	2.2	80%	20%			1.7	0.4
Total	30.7				0.1	24.5	6.1
Finance Charges							
Generation	0.0	80%	20%			-	-
Transmission	0.0	80%	20%			-	-
Distribution	166.8	80%	20%		0.7	132.9	33.2
Total Finance Charge Regulatory Acct. Additions	-0.2	80%	20%			(0.2)	(0.0)
Site C Project (IFRS 14 IDC impact)	0.4	80%	20%			0.3	0.1
Interest on Deferral Accounts	3.3	80%	20%			2.7	0.7
Interest on Other Reg Accounts	-6.8	80%	20%			(5.5)	(1.4)
Regulatory Account Recoveries	-20.8	80%	20%			(16.7)	(4.2)
Total	142.7				0.7	113.6	28.4
Allowed Net Income							
Distribution	146.4	80%	20%		0.6	116.6	29.2
Total	146.4				0.6	116.6	29.2
Miscellaneous Revenues							
Amortization of Contributions	0.0	80%	20%			-	-
Other	0.0	80%	20%			-	-
External OATT	0.0	80%	20%			-	-
FortisBC Wheeling Agreement	0.0	80%	20%			-	-
Secondary Revenue	0.0	80%	20%			-	-
Interconnections	0.0	80%	20%			-	-
Amortization of Contributions	0.0	80%	20%			-	-
NTL Supplemental Charge	0.0	80%	20%			-	-
Secondary Use Revenue & Other	-17.0	80%	20%			(13.6)	(3.4)
Amortization of Contributions	-49.1	80%	20%			(39.2)	(9.8)
Meter/Trans Rents & Power Factor Surcharges	0.0	80%	20%			-	-
Smart Metering & Infrastructure Impact	0.0	80%	20%			-	-
Diversion Net Recoveries	0.0	80%	20%			-	-
Other Operating Recoveries	0.0	80%	20%			-	-
Customer Crisis Fund Rider Revenue	0.0	80%	20%			-	-
Other	0.0	80%	20%			-	-
Waneta Lease revenue from Teck	0.0	80%	20%			-	-
Waneta 2/3Teck portion of operating costs	0.0	80%	20%			-	-
Waneta 2/3Teck portion of water rentals	0.0	80%	20%			-	-
Waneta 2/3 Teck portion of property taxes	0.0	80%	20%			-	-
Corporate General Rents	-1.2	80%	20%			(1.0)	(0.2)
Late Payment Charges	-2.2	80%	20%			(1.8)	(0.4)
MMBU Secondary Revenue	-1.2	80%	20%			(1.0)	(0.2)
Other	-0.4	80%	20%			(0.3)	(0.1)
Total	-71.1				-	(56.9)	(14.2)
Revenue Offsets & Other							
Total Inter-Segment Revenue	-0.6	80%	20%			(0.5)	(0.1)
Powerex Net Income	0.0	80%	20%			-	-
Powertech Net Income	0.0	80%	20%			-	-
Other Utilities Revenue	0.0	80%	20%			-	-
liquefied Natural Gas Revenue	0.0	80%	20%			-	-
Deferral Rider Revenue	0.0	80%	20%			-	-
GRTA Allocation	0.0	100%	0%			-	-
Generation Real Time Dispatch	0.0	80%	20%			-	-
Distribution Real Time Dispatch	20.8	80%	20%			16.6	4.2
SDA Allocation to Distribution	127.0	100%	0%			127.0	-
PTP Allocation to Distribution	23.9	80%	20%			19.1	4.8
Generation Ancillary Services	0.0	80%	20%			-	-
Generation Capitalized Overhead	2.9	80%	20%			2.3	0.6
Transmission Capitalized Overhead	5.0	80%	20%			4.0	1.0
Distribution Capitalized Overhead	-31.3	80%	20%			(25.0)	(6.3)
Gneration RSRA Write-off	0.0	80%	20%			-	-
Waneta 2/3 Lease revenue form Teck	0.0	80%	20%			-	-
Adj to align with prior approved RRA	0.0	80%	20%			-	-
Total	147.6				-	143.5	4.1
Total Distribution Costs	**1104.4**	**82.0%**	**17.6%**		**4.3**	**905.5**	**194.6**

Appendix A

Classification of Customer Care Function
(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Customer Related	Demand Costs	Customer Costs
Cost of Energy					
Water Rentals	-	0%	100%	-	-
Natural gas for thermal generation	-	0%	100%	-	-
Domestic Transmission (Heritage)	-	0%	100%	-	-
Non-treaty storage and Libby Coordination agreements	-	0%	100%	-	-
Remissions and Other	-	0%	100%	-	-
HDA Additions	-	0%	100%	-	-
Deferred Operating HDA	-	0%	100%	-	-
HDA Recoveries	-	0%	100%	-	-
Total IPPs and Long-term Commitment	-	0%	100%	-	-
NIA Generation	-	0%	100%	-	-
Gas & OtherTransportation	-	0%	100%	-	-
Water Rentals (Waneta 2/3)	-	0%	100%	-	-
NHDA Additions	-	0%	100%	-	-
Deferred Operating NHDA	-	0%	100%	-	-
Deferred Amortization NHDA	-	0%	100%	-	-
Deferred Taxes NHDA	-	0%	100%	-	-
Deferred Provision NHDA	-	0%	100%	-	-
Deferred Waneta 1/3 Costs	-	0%	100%	-	-
NHDA Recoveries	-	0%	100%	-	-
Market Electricity Purchases	-	0%	100%	-	-
Surplus Sales	-	0%	100%	-	-
Net purchases (sales) from Powerex	-	0%	100%	-	-
Domestic Transmission -Export (Market Energy)	-	0%	100%	-	-
Total	-			-	-
O M & A Expenses					
Intergarated Planning	0.5	0%	100%	-	0.5
Capital Infrastructure Project Delivery	3.2	0%	100%	-	3.2
Operations	6.7	0%	100%	-	6.7
Safety	6.4	0%	100%	-	6.4
Finance, Technology, Supply Chain	31.0	0%	100%	-	31.0
People, Customer, Corporate Affairs	104.4	0%	100%	-	104.4
Other	(1.2)	0%	100%	-	(1.2)
Non-Current PEB - Pension	6.6	0%	100%		6.6
PEB Current Pension Costs	(0.1)	0%	100%		(0.1)
Total	157.4			-	157.4
Depreciation & Amortization					
Generation	-	0%	100%	-	-
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Business Support	-	0%	100%	-	-
Amortization - Other Leases	0.3	0%	100%	-	0.3
Transfer to Regulatory Account - Amortization on Additions Varia	0.0	0%	100%	-	0.0
Regulatory Account Recoveries - DSM Amortization	-	0%	100%	-	-
Pre-1996 CIAC Amortization	-	0%	100%	-	-
Capital Additions Regulatory Account - Business Support	-	0%	100%	-	-
Total	0.4			-	0.4
Taxes					
Generation	-	0%	100%	-	-
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Customer Care	0.9	0%	100%	-	0.9
Business Support	0.1	0%	100%	-	0.1
Total	0.9			-	0.9
Finance Charges					
Generation	-	0%	100%	-	-
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Total Finance Charge Regulatory Acct. Additions	-	0%	100%	-	-
Site C Project (IFRS 14 IDC impact)	-	0%	100%	-	-
Interest on Deferral Accounts	-	0%	100%	-	-
Interest on Other Reg Accounts	-	0%	100%	-	-
Regulatory Account Recoveries	-	0%	100%	-	-
Total	-			-	-
Allowed Net Income (return on equity)					
Customer Care	-	0%	100%	-	-
Total	-			-	-
Miscellaneous Revenues					
Amortization of Contributions	-	0%	100%	-	-
Other	-	0%	100%	-	-
External OATT	-	0%	100%	-	-
FortisBC Wheeling Agreement	-	0%	100%	-	-
Secondary Revenue	-	0%	100%	-	-
Interconnections	-	0%	100%	-	-
Amortization of Contributions	-	0%	100%	-	-
NTL Supplemental Charge	-	0%	100%	-	-
Secondary Use Revenue & Other	-	0%	100%	-	-
Amortization of Contributions	-	0%	100%	-	-
Meter/Trans Rents & Power Factor Surcharges	(16.1)	0%	100%	-	(16.1)
Smart Metering & Infrastructure Impact	(2.2)	0%	100%	-	(2.2)
Diversion Net Recoveries	(0.2)	0%	100%	-	(0.2)
Other Operating Recoveries	(4.1)	0%	100%	-	(4.1)
Customer Crisis Fund Rider Revenue	(4.4)	0%	100%	-	(4.4)
Other	(3.1)	0%	100%	-	(3.1)
Waneta Lease revenue from Teck	(75.2)	0%	100%	-	(75.2)
Waneta 2/3Teck portion of operating costs	(5.4)	0%	100%	-	(5.4)
Waneta 2/3Teck portion of water rentals	(3.3)	0%	100%	-	(3.3)
Waneta 2/3 Teck portion of property taxes	(0.9)	0%	100%	-	(0.9)
Corporate General Rents	(0.5)	0%	100%	-	(0.5)
Late Payment Charges	(0.8)	0%	100%	-	(0.8)
MMBU Secondary Revenue	(0.5)	0%	100%	-	(0.5)
Other	(0.2)	0%	100%	-	(0.2)
Total	(116.7)			-	(116.7)
Revenue Offsets & Other					
Total Inter-Segment Revenue	(0.2)	0%	100%	-	(0.2)
Powerex Net Income	-	0%	100%	-	-
Powertech Net Income	-	0%	100%	-	-
Other Utilities Revenue	-	0%	100%	-	-
liquefied Natural Gas Revenue	-	0%	100%	-	-
Deferral Rider Revenue	-	0%	100%	-	-
GRTA Allocation	-	0%	100%	-	-
Generation Real Time Dispatch	-	0%	100%	-	-
Distribution Real Time Dispatch	-	0%	100%	-	-
SDA Allocation to Distribution	-	0%	100%	-	-
PTP Allocation to Distribution	-	0%	100%	-	-
Generation Ancillary Services	-	0%	100%	-	-
Generation Capitalized Overhead	1.1	0%	100%	-	1.1
Transmission Capitalized Overhead	1.9	0%	100%	-	1.9
Distribution Capitalized Overhead	5.3	0%	100%	-	5.3
Gneration RSRA Write-off	-	0%	100%	-	-
Waneta 2/3 Lease revenue form Teck	75.2	0%	100%	-	75.2
Adj to align with prior approved RRA	-	0%	100%	-	-
	83.2	0%	100%	-	83.2
Total Customer Care Costs	**125.2**			**-**	**125.2**

Appendix A

Allocation of Generation Costs

(Classified Costs from Schedule 2.0)

Cost Classification	Generation Demand	Generation Demand-Related Costs	Generation Energy	Generation Energy Related Costs
Allocation Basis	4 CP Demand including losses (Sched 5.1)	779.8	Energy Including Loss (Sched 5.0)	1,995.7
Residential	45.3%	352.9	35.7%	712.3
GS Under 35 kW	8.0%	62.7	7.9%	157.8
MGS < 150 kW	6.3%	49.0	6.8%	136.0
LGS > 150 kW	19.0%	148.0	22.0%	439.3
Irrigation	0.0%	0.1	0.1%	2.9
Street Lighting BCH	0.1%	1.0	0.1%	1.8
Street Lighting Cust	0.4%	3.3	0.3%	6.6
Transmission	20.9%	162.8	27.0%	539.0
Total	100.0%	779.8	100.0%	1995.7

Appendix A

Allocation of Transmission Costs

(Classified Costs from Schedule 2.1)

Cost Classification	Transmission Demand	Demand Related Costs (Sched 2.1)
Allocation Basis	4 CP demand including losses (Sched 5.1)	1,073.5
Residential	45.3%	485.9
GS Under 35 kW	8.0%	86.3
MGS < 150 kW	6.3%	67.5
LGS > 150 kW	19.0%	203.7
Irrigation	0.0%	0.1
Street Lighting BCH	0.1%	1.4
Street Lighting Cust	0.4%	4.6
Transmission	20.9%	224.1
Total	100%	1,073.5

Appendix A

Allocation of Distribution Costs

(Classified Costs from Schedule 2.2)

Cost Classification	Distribution Demand Related	Distribution Demand-Related	Distribution Secondary Demand Related	Distribution Secondary Demand-Related	Distribution Transformer Related	Distribution Transformer Related	Distribution Customer Related	Distribution Customer Related	Distribution Metering Related	Distribution Metering Related	Street Light Customer	Street Light Customer Related
Allocation Basis	NCP (Sched 5.1)	729.8	NCP w/o Primary (Sched 5.1)	75.8	Transformer Allocator (Sched 5.4)	199.8	Customer Count (Sched 5.2)	76.8	Metering Allocator (Sched 5.2)	18.0	Street Light Direct Assignment	4.3
Residential	55.6%	405.9	67.8%	51.4	65.5%	130.9	89.1%	68.4	77.6%	13.9	0.0%	0.0
GS Under 35 kW	10.9%	79.3	13.3%	10.0	16.8%	33.6	9.1%	7.0	15.8%	2.8	0.0%	0.0
MGS < 150 kW	8.5%	61.8	8.2%	6.2	10.7%	21.5	0.8%	0.6	4.4%	0.8	0.0%	0.0
LGS > 150 kW	23.9%	174.1	9.3%	7.0	5.4%	10.8	0.4%	0.3	1.9%	0.3	0.0%	0.0
Irrigation	0.5%	3.5	0.6%	0.4	0.5%	1.1	0.2%	0.1	0.3%	0.0	0.0%	0.0
Street Lighting BCH	0.2%	1.1	0.2%	0.1	0.3%	0.7	0.2%	0.2	0.0%	0.0	100.0%	4.3
Street Lighting Cust	0.6%	4.0	0.7%	0.5	0.7%	1.3	0.3%	0.2	0.0%	0.0	0.0%	0.0
Transmission	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0
Total	100.0%	729.8	100.0%	75.8	100.0%	199.8	100.0%	76.8	100.0%	18.0	100.0%	4.3

Appendix A

Allocation of Customer Care Costs

(Classified Costs from Schedule 2.3)

Cost Classification	Customer Care Demand	Customer Care Demand Related Costs	Customer Care Customer	Customer Care Customer Related Costs
Allocation Basis	NCP Sched 5.1	0.0	Blended Customer Count & Revenue Sched 5.3	125.2
Residential	55.6%	0.0	83.1%	104.1
GS Under 35 kW	10.9%	0.0	9.1%	11.3
MGS < 150 kW	8.5%	0.0	2.3%	2.8
LGS > 150 kW	23.9%	0.0	2.7%	3.3
Irrigation	0.5%	0.0	0.1%	0.1
Street Lighting BCH	0.2%	0.0	0.4%	0.5
Street Lighting Cust	0.6%	0.0	0.6%	0.7
Transmission	0.0%	0.0	1.8%	2.3
Total	100.0%	0.0	100.0%	125.2

Appendix A

Summary of Costs by Functions and Revenue to Cost Ratios

Rate Class	Generation Costs	Transmission Costs	Distribution Costs	Customer Care Costs	Total Cost	Total Revenue	Revenue - Cost ($ million)	Revenue:Cost Ratios	R/C Ratios last filed (F2019)	R/C Ratio change from last filed
Residential	1,065.2	485.9	670.5	104.1	2,325.7	2,168.8	-156.9	93.3%	94.6%	-1.3%
GS Under 35 kW	220.5	86.3	132.8	11.3	450.9	525.0	74.1	116.4%	120.9%	-4.4%
MGS < 150 kW	185.1	67.5	90.9	2.8	346.2	393.7	47.4	113.7%	115.1%	-1.4%
LGS > 150 kW	587.3	203.7	192.6	3.3	987.0	1,023.3	36.3	103.7%	102.4%	1.3%
Irrigation	2.9	0.1	5.2	0.1	8.3	6.4	-1.9	77.2%	83.4%	-6.2%
Street Lighting BCH	2.8	1.4	6.4	0.5	11.0	22.1	11.1	200.2%	211.9%	-11.8%
Street Lighting Cust	9.9	4.6	6.1	0.7	21.3	18.1	-3.2	84.9%	88.4%	-3.4%
Transmission	701.8	224.1	0.0	2.3	928.2	921.2	-7.0	99.3%	94.9%	4.4%
Total	2,775.5	1,073.5	1,104.4	125.2	5,078.6	5,078.6	0.0	100.0%		

Note: The difference of total revenue requirement between Cost of Service Study and Fiscal 2020 to Fiscal 2021 Revenue Requirements Application is due to the non-cash transactions under an energy supply contract which allowed an IPP customer to borrow and return water to BC Hydro. This revenue offset the cost of energy in Cost of Service.

Appendix A

Summary of Costs by Classification

Rate Class	Energy Related Costs	Generation Demand Related Costs	Transmission Demand Related Costs	Distribution Demand Related Costs	Total Demand Related Costs	Customer Related Costs	Total
Residential	712.3	352.9	485.9	522.8	1,361.6	251.9	2,325.7
GS Under 35 kW	157.8	62.7	86.3	106.2	255.1	37.9	450.9
MGS < 150 kW	136.0	49.0	67.5	78.7	195.2	15.0	346.2
LGS > 150 kW	439.3	148.0	203.7	186.6	538.3	9.4	987.0
Irrigation	2.9	0.1	0.1	4.5	4.7	0.8	8.3
Street Lighting BCH	1.8	1.0	1.4	1.6	4.0	5.3	11.0
Street Lighting Cust	6.6	3.3	4.6	5.2	13.1	1.6	21.3
Transmission	539.0	162.8	224.1	0.0	386.8	2.3	928.2
Total	1,995.7	779.8	1,073.5	905.5	2,758.8	324.1	5,078.6

Appendix A

Percent of Costs by Allocator

Rate Class	Generation Energy (kWh)	Generation & Transmission Demand (4CP)	Distribution Demand (NCP)	Customer (Various)
Residential	31%	36%	22%	11%
GS Under 35 kW	35%	33%	24%	8%
MGS < 150 kW	39%	34%	23%	4%
LGS > 150 kW	45%	36%	19%	1%
Irrigation	34%	2%	54%	9%
Street Lighting BCH	16%	21%	15%	48%
Street Lighting Cust	31%	37%	24%	7%
Transmission	58%	42%	0%	0%
Total	39%	36%	18%	6%

Appendix A

Energy Allocators

Rate Class	Energy @ Customer Meter	Distribution Loss Factor	Energy @ Transmission Interface	Transmission Loss Factor	Energy @ Generation Interface	Energy by Rate Class	Energy at Generator Allocation Factor
	(MWh)		(MWh)		(MWh)		
Residential	17,993,281	6.0%	19,072,878	5.7%	20,154,310	20,154,310	35.7%
GS Under 35 kW	3,986,200	6.0%	4,225,372	5.7%	4,464,950	4,464,950	7.9%
MGS < 150 kW Primary	109,871	3.4%	113,651	5.7%	120,095		
MGS < 150 kW Secondary	3,329,594	6.0%	3,529,370	5.7%	3,729,485		
MGS						3,849,580	6.8%
LGS > 150 kW Primary	6,942,074	3.4%	7,180,881	5.7%	7,588,037		
LGS > 150 kW Secondary	4,323,892	6.0%	4,583,326	5.7%	4,843,200		
LGS						12,431,237	22.0%
Irrigation	72,147	6.0%	76,475	5.7%	80,812	80,812	0.1%
Street Lighting BCH	45,244	6.0%	47,958	5.7%	50,678	50,678	0.1%
Street Lighting Cust	167,184	6.0%	177,215	5.7%	187,263	187,263	0.3%
Transmission	14,433,343	0.0%	14,433,343	5.7%	15,251,714	15,251,714	27.0%
Total	51,402,830		53,440,469		56,470,544	56,470,544	100.0%

Appendix A

Demand Allocators

Rate Class	4 CP	NCP w/o T	NCP w/o Prim
Residential	45.3%	55.6%	67.8%
GS Under 35 kW	8.0%	10.9%	13.3%
MGS < 150 kW	6.3%	8.5%	8.2%
LGS > 150 kW	19.0%	23.9%	9.3%
Irrigation	0.0%	0.5%	0.6%
Street Lighting BCH	0.1%	0.2%	0.2%
Street Lighting Cust	0.4%	0.6%	0.7%
Transmission	20.9%	0.0%	0.0%
Total	100%	100%	100%

Appendix A

F2020 Cost of Service - Actual Cost Allocator by Customer, Bill and Revenue

Total BC Hydro - F20

Rate Class	Actual Number of Accounts F20	Annual bills per account	Annual bills per rate class	# of Bills Allocator
Residential	1,863,569	6	11,181,414	87.6%
GS Under 35 kW	189,756	6	1,138,536	8.9%
MGS < 150 kW	17,678	12	212,136	1.7%
LGS > 150 kW	7,629	12	91,548	0.7%
Irrigation	3,286	2	6,572	0.1%
Street Lighting BCH	4,211	12	50,532	0.4%
Street Lighting Cust	6,164	12	73,968	0.6%
Transmission	306	12	3,672	0.0%
Total	2,092,599		12,758,378	100.0%

Rate Class	Actual Number of Accounts F20	Distribution Customer Count	Distribution Customer Allocator
Residential	1,863,569	1,863,569	89.1%
GS Under 35 kW	189,756	189,756	9.1%
MGS < 150 kW	17,678	17,678	0.8%
LGS > 150 kW	7,629	7,629	0.4%
Irrigation	3,286	3,286	0.2%
Street Lighting BCH	4,211	4,211	0.2%
Street Lighting Cust	6,164	6,164	0.3%
Transmission	306	306	0.0%
Total	2,092,599	2,092,599	100.0%

Rate Class	Actual Number of Accounts F20	Distribution Customer Count	Distribution Metering Allocator
Residential	1,863,569	1,863,569	77.6%
GS Under 35 kW	189,756	189,756	15.8%
MGS < 150 kW	17,678	17,678	4.4%
LGS > 150 kW	7,629	7,629	1.9%
Irrigation	3,286	3,286	0.3%
Street Lighting BCH	4,211	4,211	0.0%
Street Lighting Cust	6,164	6,164	0.0%
Transmission	306	306	0.0%
Total	2,092,599	2,092,599	100.0%

Rate Class	Revenue ($millions)	Revenue Allocator
Residential	$2,168.8	42.7%
GS Under 35 kW	$525.0	10.3%
MGS < 150 kW	$393.7	7.8%
LGS > 150 kW	$1,023.3	20.1%
Irrigation	$6.4	0.1%
Street Lighting BCH	$22.1	0.4%
Street Lighting Cust	$18.1	0.4%
Transmission	$921.2	18.1%
Total	$5,078.6	100.0%

Rate Class	90% # of Bills Allocator	10% Revenue Allocator	Blended Customer Care Allocator
Residential	78.9%	4.3%	83.1%
GS Under 35 kW	8.0%	1.0%	9.1%
MGS < 150 kW	1.5%	0.8%	2.3%
LGS > 150 kW	0.6%	2.0%	2.7%
Irrigation	0.0%	0.0%	0.1%
Street Lighting BCH	0.4%	0.0%	0.4%
Street Lighting Cust	0.5%	0.0%	0.6%
Transmission	0.0%	1.8%	1.8%
Total			100.0%

Appendix A

Distribution Classification by Sub-Functionalization

F20 updated

Sub-Function	F20 Year-End Assets (NBV)	% of assets (excluding Substation)	% of assets without Streetlighting	Demand-related %	Customer-related %	Demand % of Total Costs	Customer % of Total Costs	% of total Demand costs	% of total Customer costs
Primary	3,773.3	61.8%	62.1%	100%	0%	62.1%	0.0%	77.5%	0.0%
Secondary/Services	946.8	15.5%	15.6%	50%	50%	7.8%	7.8%	9.7%	39.1%
Meters	111.6	1.8%	1.8%	0%	100%	0.0%	1.8%	0.0%	9.2%
Transformers	1,248.4	20.4%	20.5%	50%	50%	10.3%	10.3%	12.8%	51.6%
Substation	148.9			100%	0%				
Streetlighting	26.0	0.43%							
Total	6,255.0	100%	100%			80.1%	19.9%	100.0%	100.0%