2009 FortisBC Rate Design Application

October 30, 2009

FortisBC Inc.

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1.0 The Application

1.1 Introduction and Regulatory Background

FortisBC Inc. ("FortisBC" or the "Company") is an investor-owned, integrated utility engaged in the business of generation, transmission, distribution and sale of electricity in the southern interior of British Columbia. The Company serves more than 158,000 customers directly and indirectly, and employs approximately 560 full time and part time people. FortisBC was incorporated in 1897 and is regulated under the *Utilities Commission Act*, R.S.B.C. 1996, c.473 ("UCA").

FortisBC owns assets with a gross book value in excess of $1 billion, including four hydroelectric generating plants located on the Kootenay River with a combined capacity of 223 megawatts, as well as approximately 7,000 circuit kilometres of transmission and distribution power lines for the delivery of electricity to major load centers and customers in its service area.

This Application, which incorporates the results of a 2009 Cost of Service Analysis ("COSA"), a proposal for the revision of Rate Schedules for select customer classes, (the "Rate Design"), and general revisions to other Tariff sheets, is being filed both as a result of and in consideration of Commission directives and Provincial policy and legislation.

FortisBC believes that the proposals contained within this Application are required to address the realities in which it operates while continuing to provide service to its customers fairly and cost-effectively.

1.2 Proposals to Address Current Environment

Since 1997, significant changes have taken place that materially affect FortisBC's business and its ability to effectively and fairly serve evolving customer needs. In evaluating the requests in this Application, the Company submits that the Commission should bear in mind the following factors detailed below.

First, the Commission itself has ordered an updated Rate Design to be filed (as outlined in section 1.2). As part of this process it was essential that FortisBC evaluate current cost allocation and rate structures.

Second, in conducting the required COSA it became clear that costs were not appropriately allocated among customer classes. Customers have indicated in consultation that they are supportive of a move to greater equity.

Third, in the years preceding this filing, provincial energy policy has become increasingly focused on conservation. The BC Energy Plan as well as other policies has encouraged utilities to find ways to reduce usage; this priority was consequently an influential factor in rate design.

Fourth, the FortisBC system has become increasingly capacity constrained. The growing constraints are reflected in the emergence of the rapidly increasing summer peak (outlined in section 6.3 of this Application). Finding ways to encourage conservation is a benefit to all customers through reductions in power purchase and infrastructure costs. It should also be pointed out that the Company's system is distinct from BC Hydro, and efforts we take to foster conservation may be unique as well.

Fifth and finally, FortisBC intends to file an AMI application in 2010 with the intention of making interval data readily available, and thereby permitting the introduction of new rates that take advantage of this new data.

Together these five factors indicate the need for the requests made within this Application.

1.3 Background

Order G-115-07, issued on September 21, 2007, contained the following relevant Commission directives;

> "*FortisBC is directed to file a Cost of Service ("COS") Study on, or before, June 30, 2008.*
>
> *FortisBC is directed to file a Rate Design application on or before September 1, 2008. The Rate Design application should include a proposal for Time-of-Use rates that will apply to all customers within the merged PLP/FortisBC service area. "*

Both the COSA and the Rate Design Application are required pursuant to Commission Order G-115-07. The filing date was amended by Orders G-83-08, G-147-08, and G-164-08. As a result of these later Orders, FortisBC was required to file the Application by September 30, 2009.

FortisBC filed its draft COSA Report with the Commission on June 30, 2009 in response to Order G-115-07 as amended.

On September 28, 2009, the Company requested a further extension to filing its final COSA and RDA in order to continue discussions with a customer group (the BC Municipal Electric Utilities or "BCMEU"). As stated in the extension request, the BCMEU had identified some areas where they have concerns with elements of the Company's COSA and RDA proposals and in the Company's opinion, allowing sufficient time to continue with meaningful consultation and fully explore stakeholder concerns would make the regulatory process more efficient and potentially less contentious. Wholesale class consultation is discussed in more detail in Section 4.5.

By Order G-115-09, the Commission granted an extension of the required filing date to October 30, 2009.

On December 11, 2008, the Commission issued Order G-193-08, approving the terms of the Negotiated Settlement Agreement ("NSA") following the review and discussions held pursuant to the filing by the Company of its 2009 Revenue Requirement Application.

Appendix A to Order G-193-08 contains issues and resolutions that pertain directly to this Application. These are as follows:

Issue	Resolution
Stakeholder engagement	FortisBC will engage in meaningful stakeholder engagement before the Rate Design Application (RDA), Cost of Service, Advanced Meter Infrastructure, DSM Study and Net Metering applications are submitted to the BCUC.
Rate Design Application	FortisBC will reallocate $50,000 of the RDA budget to stakeholder engagement.
Rate Design Application and the 2007 BC Energy Plan	The Rate Design Application will address the 2007 BC Energy Plan policy #4 and will include general tariffs for customers to sell power back to FortisBC.

The 2007 BC Energy Plan: A Vision for Clean Energy Leadership ("Energy Plan") policy action #4 states "Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation."

Each of these Commission Decisions and directives is considered and incorporated into this Rate Design Application and is addressed in a later section.

Additionally, FortisBC sets rates in consideration of the UCA, particularly Sections 59 and 60, which state in part;

Section 59

1) A public utility must not make, demand or receive

a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or

b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

And;

Section 60

1) In setting a rate under this Act

(a) the commission must consider all matters that it considers proper and relevant affecting the rate,

(b) the commission must have due regard to the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59,

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and

(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance

1.4 Approvals Sought

The 2009 FortisBC Rate Design Application proposes the most significant set of changes and updates to the Company's rate structures and customer service guidelines since 1997. The Company anticipates considerable interest in the outcome of the Application by a variety of stakeholders, which is reflected in the amount of public consultation that has preceded the filing of the Application. Given the extent of the proposed changes, the Company expects that the proposals contained in the Application could reasonably take effect on January 1, 2011. The Company believes the approvals sought are prudent and essential if it is to continue to meet the needs of its customers fairly and effectively.

Accordingly, pursuant to the *Utilities Commission Act*, R.S.B.C. 1996, c.473, as amended, and in particular to Sections 58 and 61 thereof, FortisBC hereby applies for an order of the BCUC approving the following items which are detailed in the sections mentioned:

- Rate Rebalancing - A rebalancing of rates across the customer classes as described in Section 8 of the Application and specifically to achieve revenue-to-cost ratios of between 95 percent and 105 percent;
- Small General Service rates - Exclusive of any rebalancing, the changes to the Small General Service rate as described in Section 11 of the Application, in particular, the elimination of the declining blocks;
- General Service Rates - Exclusive of any rebalancing, the changes to the General Service rate as described in Section 11 of the Application, including adjustments to the demand portion of the rates and the flattening of the declining blocks;

- Large General Service Rates - Exclusive of any rebalancing, the changes to Large General Service rates as described in Section 12 of the Application, including adjustments to the demand portion of the Rates and the separation of the demand charge into a wires and power supply component for transmission customers;
- Wholesale Rates - Exclusive of any rebalancing, changes to Wholesale rates as described in Section 13 of the Application including the separation of each municipal wholesale customer into a distinct customer class;
- Time-of-Use (“TOU”) rates - Changes to TOU rate structures as discussed in Section 14 including the harmonization of the residential TOU rate as required by Commission Order G-115-07, issued on September 21, 2007 and the introduction of a wires-based charge to the Wholesale and Large General Service-Transmission TOU rates;
- Green rates - The introduction of a Green rate rider to replace separate eleven Green Rates as described in Section 15;
- Changes to Schedule 50 – Lighting as discussed in Section 16 and detailed in Appendix C;
- Changes to Schedule 74 – Extensions, as discussed in Section 17 and detailed in Appendix D;
- Changes to Schedule 80 – Charges for Connection or Reconnection of Service or Account, Testing of Meters and Various Customer Work, as discussed in Section 18 and detailed in Appendix E;
- The removal of Schedule 81 – Time-of-Use Charges, as the Company seeks to remove financial barriers to participation in time-based rates;
- Changes to Schedule 82 – Charges for Installation of New/Upgraded Services, as discussed in Section 20 and detailed in Appendix F;
- Changes to Schedule 90 – Energy Management, as discussed in Section 21 and detailed in Appendix G; and
- Changes to the FortisBC Terms and Conditions for Electrical Service as discussed in Section 22 of the Application and detailed in Appendix H.

The rationale for these proposals is outlined more fully in the following pages of the Application.

1.5 Process for the Application

FortisBC believes that its 2009 Cost of Service and Rate Design Application can best proceed by way of the process set out below involving a negotiated settlement process ("NSP"). If the NSP is unsuccessful in reaching an agreement, in whole or in part, any further process can determined by a procedural conference.

The following is a proposed regulatory timetable for this application.

Item	**Date**
Filing of COSA & Rate Design Application by FortisBC	October 30, 2009
Commission Information Request No. 1	November 25, 2009
Registration of Intervenors and Interested Parties	November 27, 2009
Responses to Commission Information Request No. 1	December 15, 2009
Technical Workshop	December 17, 2009
Commission Information Request No. 2 and Intervenor Information Requests No. 1 Issued to FortisBC	January 8, 2010
Responses to Commission Information Requests No. 2 and Intervenor Information Request No. 1 by FortisBC	February 5, 2010
Negotiated Settlement Process	March 3, 2010
Procedural Conference (if necessary)	March 17, 2010

The Company believes an NSP is a valuable part of this process given the nature of this application. The COSA and RDA application is a process of balancing interests among all customers. An NSP would provide a forum for each customer class to participate in negotiations with the other customer classes.

2.0 Executive Summary

The 2009 FortisBC Rate Design Application represents the Company's first comprehensive review of its cost to serve, rate structures, and tariff schedules since 1997. Because of the consideration taken in developing the Rate Design, and the extensive consultation process FortisBC has led, the Company feels that its submission reflects a prudent and measured approach to meeting customer needs.

This Executive Summary shows this by looking at how the Application:

- Supports and is in line with Provincial energy policy, which is increasingly focused on promoting conservation.
- Was put forward only after extensive consultation with stakeholders.
- Includes an RDA and COSA that are both based on sound guiding principles.
- Takes a measured and reasonable approach to phasing in rate changes.

These points are elaborated upon below.

2.1 BC Government Energy Objectives

This Application is at the front end of a forward-looking rate design and demand-side management ("DSM") program development that incorporates the COSA information and stakeholder input and will produce a set of rates and DSM initiatives that will meet the Government's Energy Objectives and the needs of the Company and its customers. This Application meets the Government's Energy Objectives as defined in the UCA as well as the BC Energy Plan. FortisBC believes that achievement of these objectives will be supported through DSM initiatives, electrical rates and codes and standards. The Company has proposed rate structures that encourage energy efficiency and conservation. This is the first step down the path of the Company's commitment to the wide scale implementation of time-based conservation and efficiency rates. This RDA is a key component of FortisBC's energy conservation and efficiency strategy. In conjunction with the enhanced DSM Power Sense program, articulated in the Company's 2008 Strategic DSM Report, 2009 and 2010 Capital Expenditure Plan, 2009

Resource Plan and the forthcoming 2011 DSM Plan, FortisBC is confident that it will meet the conservation and efficiency objectives as set out in the BC Energy Plan. Over the next several years, FortisBC will be well positioned to further support the energy conservation goals of the Province as identified by the Energy Plan and UCA. Further discussion of the longer term implementation of FortisBC's future rate strategy is located in Section 3 of the Application.

2.2 Public Consultation

Due to the time since the last such submission and the impact that changes resulting from the process were likely to entail, FortisBC embarked on an extensive public consultation process.

This consultation included seven public open houses in four different municipalities, as well as individual meetings with every municipal utility and most municipal governments in the FortisBC service area. Company representatives visited and extended invitations to every large customer in its Large General Service customer base. A variety of consumer and industry groups received the Cost of Service Analysis and Rate Design materials, and were invited to either meet with Company representatives or provide comment. In addition, two "Super Group" focus groups were convened in order to gauge public opinion and preference for a variety of rate rebalancing and design options presented by the Company. At a technical workshop attended by each municipal utility and representatives from the Residential and Large General Service classes, the Company answered questions on the COSA study. All materials were readily available on the FortisBC website including a working copy of the COSA model as soon as it was available. A more detailed account of the public consultation with a summary of findings is located in Section 4 of the Application.

FortisBC engaged in this degree of consultation in consideration of the complex nature of a COSA and Rate Design and the desire to hear and address stakeholder issues. In addition, as the Company was proposing a number of departures from the methodology employed in 1997, some level of education of the customer groups was desirable in order to get the most effective input possible. The most discussion from these groups was in regard to the change in methodology used to allocate the transmission and distribution costs to the Wholesale and Large General Service Transmission customers on the basis of their contracted capacity reservation. A full discussion of the COSA Study including the methodology, assumptions and considerations is contained in Sections 5 and 6 of the Application.

The outcome of the public consultation regarding the COSA and the resulting revenue-to-cost ("R/C") ratios for each customer class resulted in a plan to rebalance rates in order to achieve interclass equity. The Company is proposing to rebalance any rate class that is outside of a 95 percent to 105 percent R/C ratio range. Detail of this proposal is contained in Section 8. The resulting revenue-to-cost ratios appear in Table 2 below.

Table 2.2 - COSA Revenue-to-Cost Ratios

Rate Class	**Ratio**
Residential	98.3%
Small General Service (20)	113.4%
General Service (21)	138.9%
Large General Service Primary (30)	122.4%
Large General Service Transmission (31)	109.9%
Large General Service Transmission TOU (33)	23.5%
Lighting	81.9%
Irrigation	78.6%
Kelowna Wholesale	89.9%
Penticton Wholesale	78.0%
Summerland Wholesale	96.6%
Grand Forks Wholesale	68.1%
BC Hydro Lardeau Wholesale	101.8%
BC Hydro Yahk Wholesale	103.5%
Nelson Wholesale	80.0%
Total	**100.0%**

2.3 COSA and RDA Guiding Principles

The COSA and RDA processes were guided by a set of principles (the “Principles”) based on those articulated by Dr. James Cummings Bonbright. As well, the Company considered a number of other factors such as future plans and technical restrictions as it sought to arrive at a set of rates that is logical, workable, and acceptable to customers. A discussion of these principles can be found in Section 5 of the Application.

Particular consideration within the Application is given to the conservation objectives contained within the Utilities Commission Act and the Energy Plan. In this Application, FortisBC pursued the Government’s Energy Objectives. The Company has proposed rate structures that encourage energy efficiency and conservation. This is the first step down the path of the Company’s commitment to the wide scale implementation of time-based conservation and efficiency rates. This RDA is a key component of FortisBC’s energy conservation and efficiency strategy. In conjunction with the enhanced DSM Power Sense program, articulated in the Company’s 2008 Strategic DSM Report, 2009 and 2010 Capital Expenditure Plan, 2009 Resource Plan and the forthcoming 2011 DSM Plan, FortisBC is confident that it will meet the conservation and efficiency objectives as set out in the Energy Plan.

Where possible, rates have been redesigned to either embed conservation objectives or to set the stage for their implementation when supportive technology is in place. Future plans including the implementation of an Advanced Metering Infrastructure (“AMI”) system and time-based rates are discussed in Section 3.

A summary of the proposed changes to customer rates and rate structures, exclusive of any rate rebalancing, can be found in Table 2.3 below.

Table 2.3 - Summary of Rate Changes

Rate Class	Current FortisBC Rates				Proposed FortisBC Rates				
	Basic Charge[1]	Energy Rate (¢ / kWh)		Demand (/ kVA)	Basic Charge	Energy Rate (¢ / kWh)		Demand (/ kVA) [3]	
Residential	$24.26 *	7.627		N/A	$24.26 *	7.627		N/A	
Small General Service	$29.24 *	Tier 1	8.694	N/A	$29.24 *	8.571		N/A	
		Tier 2	6.601						
		Tier 3	4.900						
General Service	$14.61	Tier 1	8.694	$7.21 /kW	$14.61	Tier 1	8.571	$7.70/kW	
		Tier 2	6.601			Tier 2	6.333		
		Tier 3	4.900			Tier 3	N/A		
Large General Service Primary	$748.73	4.539		$6.79	$748.73	4.383		$7.25	
								Wires	PS
Large General Service Transmission	$2,246.22	3.993		$5.49	$2,246.22	3.938		$3.50	$2.00
Irrigation	$14.62	5.650		N/A	$14.62	5.650		N/A	
								Wires	PS
Kelowna Wholesale	$1,729.08	3.838		$7.48	$1,729.08	2.290		$6.70	$3.54
								Wires	PS
Penticton Wholesale	$1,729.08	3.838		$7.48	$1,729.08	1.990		$5.52	$3.17
								Wires	PS
Summerland Wholesale	$1,729.08	3.838		$7.48	$1,729.08	2.465		$6.74	$3.60
								Wires	PS
Grand Forks Wholesale	$1,729.08	3.838		$7.48	$1,729.08	1.728		$4.76	$2.85
								Wires	PS
BCH Lardeau Wholesale	$1,729.08	3.838		$7.48	$1,729.08	2.707		$6.82	$3.01
								Wires	PS
BCH Yahk Wholesale	$1,729.08	3.838		$7.48	$1,729.08	2.555		$8.76	$3.49
								Wires	PS
Nelson Wholesale	$3,952.23 [2]	3.779		$4.44	$1729.08	1.923		$4.59	$3.28

1 1 – Basic Charge is monthly unless denoted as bi-monthly by “*”

2 2 – Nelson Basic Charge is per customer on existing rate only. All others are per point of delivery (POD)

3 3 – Wires = Wires related component based on Contract Demand. PS = Power Supply Component based on actual demand

A full explanation of the rationale for each change is located in a later section of the Application: Section 10 covers Residential rates; Section 11 covers General Service rates; Large General Service rates are covered in Section 12; Wholesale rates and a general discussion on time-of-use rates are contained in Sections 13 and 14 respectively. None of the rate tables or discussion includes any assumptions on the amount of rebalancing adjustments, which are covered in Section 8.

2.4 Prudent Changes in Timing and Structure of Rates

The Company has taken care to manage the impact of rate changes to all customers. A full and detailed explanation of the rationale for each change is located in a later section of the Application: Section 10 covers Residential rates; Section 11 covers General Service rates; Large General Service rates are covered in Section 12; Wholesale rates and a general discussion on Time-of-Use rates are contained in Sections 12 and 15 respectively. None of the rate tables or discussion includes any assumptions on the amount of rebalancing adjustments, which are covered in Section 8.

After an examination of rate structures, the Company believes that Residential rates should move toward time-based rates that promote energy efficiency after the implementation of AMI. Given the relatively short time period between the decision on this application and the proposed implementation of AMI, the Company does not recommend introducing an interim rate such as an inclining block structure. There are three reasons for this recommendation. First, the effective implementation of energy conservation rate structures requires that customers be provided with additional education allowing them to understand the new pricing signals. Since the Company intends to introduce time-based rates after the implementation of an AMI, customers would have to be re-educated in order to understand and adjust to the time-based pricing signals. This could cause customer confusion and stranded customer investment in conservation infrastructure. Second, certain types of energy conservation rates, inclined block in particular, require real-time energy consumption information to be available to customers for maximum effectiveness. This information will not be available until an AMI is implemented. Third, energy conservation rate structures do not directly address the fundamental power supply issue at FortisBC, which is an increasing capacity constraint. This issue is discussed in more detail in Section 3. In addition to supporting conservation, time-based rates can be designed to directly address the Company's capacity constraints.

General Service rates have been adjusted such that disincentives to conservation have been reduced. These classes, (Rates 20 and 21) currently have declining block rates that do not discourage higher energy consumption. The blocks have either been flattened, as in the case of Rate 20, or reduced from three tiers to two, as in the case of Rate 21. In both cases, the demand portion of the rate has been slightly increased in order to move the collection of demand charges closer to the COSA-derived level and to recognize the capacity constraints. These rate adjustments have been made in a manner that manages the impact on individual customers.

FortisBC proposes an increase in the Large General Service - Primary rate schedule (31) demand charge with an offsetting reduction in the energy rate; again, intended to move the collection of demand charges closer to the COSA-derived level and to recognize the capacity constraints.

Both the Large General Service - Transmission and Wholesale rate schedules will have the demand charges separated into a “wires” and “power supply” portion. This change more appropriately reflects the nature of cost causation; that rates should be based upon the extent to which the various rate classes contribute to the overall cost of operating the utility. It also recognizes the capacity reservations that are contained in the individual contracts that are in place with these customers. These rate structures have been designed to encourage efficient use of the Company's transmission and distribution infrastructures.

Four municipalities and two BC Hydro points of delivery previously served under a common wholesale tariff rate have been separated into individual rate classes in recognition of their unique operating characteristics and cost drivers upon the FortisBC System.

As part of the Application, FortisBC is proposing a number of other changes to its Electric Tariff as follows:

Green Rates – the replacement of class-specific Green rates with a Green Power Rider applicable to all rates – Section 15;

Lighting – Changes to the repair charge provisions to better reflect current costs and practices – Section 16;

Extensions – Changes to Schedule 74 that make the schedule easier to apply and understand, that better reflect current costs and impacts of customer additions - Section 17;

Standard Charges - Changes to Schedules 80, 81 and 82 which specify charges for standard work performed by the Company are discussed in Sections 18, 19, and 20 and associated Appendices;

Energy Management - Schedule 90, which governs the administration of the demand side management or “PowerSense”, has been streamlined to allow for more flexibility in its application as described in Section 21; and

Terms and Conditions - Changes were made for clarity and ease of administration. This discussion can be found in Section 22 and Appendix H.

FortisBC believes that this Application will result in an improved tariff that complies with legislation, adheres to provincial government energy policy and is fair and equitable to the Company’s customers.

Table 2.4 below provides a summary of rate design changes.

Table 2.4 - Changes to Rate Classes

Rate Class	Existing Schedule	Status	Description
Residential Service	1	No Change	No change to existing rate structure.
Residential TOU	2	Deleted	5 customers on this rate that can choose between Schedule 1 or 2 A
	2 A	No Change	No change to existing rate structure.
Residential - Green	3	Deleted	Converted to common Green rate rider (Refer to Section 15)
Residential TOU - Green	4	Deleted	Converted to common Green rate rider
Small General Service	20	Modified	Changed from three-step declining block to flat. Rebalancing adjustments to be applied to energy rate only.
General Service	21	Modified	Demand charge increased. Changed from three-step declining block to two-step declining block. Rebalancing adjustments to be applied to energy rate only.
General Service - Secondary - Time of Use	22	Deleted	5 customers on this rate that can choose between Schedule 20, 21 or 22A
General Service - Secondary - Time of Use	22 A	Modified	Added metering discount for primary metering.
General Service - Primary - Time of Use	23	Deleted	No customers on this rate.
General Service - Primary - Time of Use	23 A	Added	Updating of Rate 23
Small General Service - Green Power	24	Deleted	Converted to common Green rate rider
General Service - Green Power	25	Deleted	Converted to common Green rate rider
General Service - Secondary - Time of Use - Green Power	26	Deleted	Converted to common Green rate rider
General Service - Primary - Time of Use - Green Power	27	Deleted	Converted to common Green rate rider

Table 2.4 - Changes to Rate Classes (cont'd)

Rate Class	Existing Schedule	Status	Description
Large General Service - Primary	30	Modified	Demand charge increased. Rebalancing adjustments to be applied to energy charges only.
Large General Service - Transmission	31	Modified	Demand charge now split between contract demand-based wires charge and actual demand-based power supply charge.
Large General Service - Primary - Time of Use	32	Modified	Rebalancing adjustments to be applied to energy charges only.
Large General Service - Transmission - Time of Use	33	Modified	Implement contract demand-based wires charge
Large General Service - Primary - Time of Use - Green Power	34	Deleted	Converted to common Green rate rider
Large General Service - Transmission - Green Power	35	Deleted	Converted to common Green rate rider
Large General Service - Transmission - Time of Use -Green Power	36	Deleted	Converted to common Green rate rider
Wholesale Service - Primary	40	Closed	Wholesale Customers each have COSA based rate. (See Schedules 40A – 40E)
Wholesale Service – Primary	40A	New	Available to the City of Grand Forks Demand Charge Based on Demand Limit
Wholesale Service – Primary –Time of Use	40A –TOU	New	Available to the City of Grand Forks Implement Contract Demand based Wires Charge
Wholesale Service - Primary	40B	New	Available to the District of Summerland COSA Based rates Demand Charge Based on Demand Limit
Wholesale Service – Primary –Time of Use	40B - TOU	New	Available to the City of Summerland COSA Based rates Implement Contract Demand based Wires Charge
Wholesale Service - Primary	40C	New	Available to the City of Penticton Demand Charge Based on Demand Limit
Wholesale Service – Primary –Time of Use	40C - TOU	New	Available to the City of Penticton Implement Contract Demand based Wires Charge
Wholesale Service - Primary	40D	New	Available to the City of Kelowna Demand Charge Based on Demand Limit

Table 2.4 - Changes to Rate Classes (cont'd)

Rate Class	Existing Schedule	Status	Description
Wholesale Service – Primary –Time of Use	40D - TOU	New	Available to the City of Kelowna Implement Contract Demand based Wires Charge
Wholesale Service - Primary	40E	New	Available to the BC Hydro services at Yahk. Demand Charge Based on Demand Limit
Wholesale Service – Primary –Time of Use	40E - TOU	New	Available to the City of BC Hydro services at Yahk. Implement Contract Demand based Wires Charge
Wholesale Service - Primary	40F	New	Available to the BC Hydro services at Lardeau Demand Charge Based on Demand Limit
Wholesale Service – Primary –Time of Use	40F - TOU	New	Available to the City of BC Hydro services at Lardeau Implement Contract Demand based Wires Charge
Wholesale Service – Transmission (Nelson)	41	Modified	Demand Charge Based on Demand Limit Updated with new COSA information
Wholesale Service - Primary - Time of Use	42	Deleted	No customers on this rate. Wholesale Customers each have modified TOU rate
Wholesale Service - Transmission - Time of Use (Nelson)	43	Modified	COSA Based Basic Charge Implement Contract Demand based Wires Charge
Wholesale Service - Primary - Green Power	44	Deleted	Converted to common Green rate rider
Wholesale Service - Primary - Time of Use - Green Power	45	Deleted	Converted to common Green rate rider
Wholesale Service - Transmission - Green Power	46	Deleted	Converted to common Green rate rider
Wholesale Service - Transmission - Time of Use - Green Power	47	Deleted	Converted to common Green rate rider
Lighting – All Areas	50	No change	No change to existing rate structure.
Lighting - Green Power	50	Deleted	Converted to common Green rate rider
Irrigation and Drainage	60	No change	No change to existing rate structure.
Irrigation and Drainage - Time of Use	61	No change	No change to existing rate structure.
Irrigation and Drainage - Green Power	62	Deleted	Converted to common Green rate rider
Irrigation and Drainage - Time of Use - Green Power	63	Deleted	Converted to common Green rate rider
Green Power Rider	85	New	Applies to specific rates

3.0 Rate Design Strategy

As identified in the FortisBC 2009 Resource Plan, FortisBC is experiencing increasing capacity constraints. This capacity constraint is an important consideration not only within the Cost of Service model which determines inter-class equity, but also Rate Design, which affects intra-class equity. The Company supports the provincial energy consumption conservation goals through increased investment in its DSM programs and the move towards time-based conservation rates which will also help address the Company's capacity constraints that drives decision making during rate design.

Given the growing capacity constraints, it is important for FortisBC to consider the introduction of rates and other incentives that encourage customers to reduce their electric use, particularly when the system is most constrained. Simply put, the Company must endeavor to reduce its customers overall energy consumption while also reducing peak demand.

3.1 Time-Based Rates that Encourage Conservation and Reduce Peak Demand

Two types of rate design that accomplish this goal are TOU and critical peak pricing ("CPP") rates, which charge higher rates for energy at times when the system loading is at its highest.

Rates such as inclined block would be expected to have only a minimal impact in reducing system peak demand while having a questionable effect on energy conservation. The inclined block rates modeled as part of this application had a pricing differential between blocks of 40 percent, resulting in an upper block rate that is approximately 17 percent higher than current flat rates. Using a price elasticity ratio of -0.1, this price increase could be expected to reduce energy consumption in the upper block by 1.7 percent. Peak demand reduction could be expected to approximate the same percentage.

Time-based rates, on the other hand, have been shown to reduce overall energy consumption by up to 6 percent. In addition, time-based rates could reduce peak demand by up to 25%. An Ontario pricing pilot[1] reached similar conclusions, summarized in the following table:

Table 3.1 – Effect of Time Based Rates

Period	**Time-of-Use only**	**Critical Peak Pricing**	**Critical Peak Rebate**
Energy Conservation	6.0%	4.7% (n/s)*	7.4%
Critical peak hour (3 or 4 hours during the peak)	5.7% (n/s)*	25.4%	17.5%
Entire On-Peak period (6 hours)	2.4% (n/s)*	11.9%	8.5%

Pecentage shift in load during the four summertime critical peak days of the pilot.

* *The percentage reductions for the TOU-only customers are not statistically significant at a 90% confidence level and can therefore not be as readily generalized to a large population. They do represent actual reductions recorded for that group. Had there been more critical peak days, it is likely these results would be statistically significant*.

A 2008 Brattle Group study[2] concludes that "For the average customer, time-of-use rates are likely to induce a drop in peak usage of under 5% while critical-peak pricing tariffs [induce] a drop of around 10-25%." Since properly designed time-based rates support the reduction of system peak demand, it is the current intention of FortisBC, after adequate consultation and consideration, to introduce mandatory time-based conservation rates, once electric usage interval data is made available through the implementation of an AMI, for all metered customer classes. The Company will continue to evaluate and consult upon all conservation rate structures including residential incline block, the results of which will be included in the next rate design application. During consultation, FortisBC indicated its intention to move customers to time-based rates when feasible to do so. Generally, stakeholders were supportive of this direction and few dissenting opinions were expressed. Closer to implementation, further public consultation will be conducted to aid in designing rates that best balance the needs of customers and FortisBC.

[1] Ontario Energy Board. *Ontario Energy Board Smart Price Pilot: Final Report*, July 2007.
[2] Ahmad Faruqui and Sanem Sergici, The Brattle Group *The Power of Experimentation: New Evidence on Residential Demand Response*, April 11, 2008.

This type of demand conservation has the added benefit of energy conservation since a customer choosing to use less electricity during the more expensive peak periods, will likely not use more electricity during the off-peak period to compensate.

The majority of meters installed throughout the FortisBC service territory do not collect electric usage interval data. The bulk of meters installed continuously record total energy use and, for certain customer classes, the peak electrical consumption rate ("peak demand") since the last meter reset, compared to an interval meter which takes measurement of energy use at regular intervals. Therefore, potential changes to existing rates are confined to adjustments to the Basic Charge, the rate charged for total energy used between successive meter readings, and for certain customer classes, the rate charged for peak demand measured between successive meter readings.

At this time, electric usage interval data will not be available for all metered customer classes until the implementation of an AMI system is complete. FortisBC intends to file an AMI application in 2010 with the intention of making interval data readily available, and thereby permitting the introduction of time-based rates.

FortisBC intends to prepare for the implementation of time-based rates in four stages as outlined below:

1. Commission a study during 2009 and 2010 that examines the typical effects of time-based rates on energy and demand, as experienced by utilities that have already implemented or piloted them.

2. File an application for a Certificate of Public Convenience and Necessity ("CPCN") for AMI in 2010.

3. Conduct a study after the implementation of AMI to determine the extent to which education and real-time consumption information can best influence customer conservation behaviour.

4. Submit Rate Design Application supporting results of consultation and study.

Once the above steps are complete, the Company will be able to implement wide-scale time-based rates.

The future plans outlined in this section of the Application were given strong consideration in Section 9 regarding Rate Design.

4.0 Public Consultation

FortisBC engaged in a broad consultation process for both the COSA and RDA which included the following:

- Face-to-face customer meetings – During the week of May 26, 2009, representatives from the Company met individually with each of its five municipal wholesale utility customers, as well as each of its transmission customers, to review the COSA methodology, highlight changes in cost allocation methods and review revenue-to-cost ratios;
- Municipal / Large General Service Meetings – During the week of June 1, 2009, FortisBC met with several other non-wholesale municipalities and Large General Service customers to advise them of the ongoing COSA process and the consultation that the Company was undertaking. The COSA methodology, changes in cost allocation methods and current revenue-to-cost ratios were also reviewed by the parties and invitations were extended to attend the public consultation sessions;
- Between May 25 and July 31, 2009, the Company held 7 public open houses on COSA and Rate Design in Creston, Castlegar, Kelowna and Osoyoos, which were open to all customer classes with key stakeholder groups receiving personal invitations;
- The Company met twice with its DSM Advisory group, offered one First Nations workshop (which was cancelled due to lack of attendance), and held two facilitated Super Groups (focus groups);
- At the request of its municipal wholesale customers, a stakeholder technical workshop was held and attended primarily by the municipal utilities despite being open to all Interested persons; and

- The ten customers taking service under closed Schedules 2 and 22 will be advised by FortisBC that a regulatory Application that proposes to remove these Schedules is being filed.

The consultation process was advertised in local news media across FortisBC's service territory and on the Company's website, as well as through direct mail and email to customer and government stakeholders as well as to First Nations.

Each of these activities encouraged all customer groups including Residential, General Service, Large General Service, Lighting, Irrigation and Wholesale to learn more about the COSA and RDA, to ask questions and to provide meaningful input. More detail on these activities is included in the next Section.

The extent of the consultation activities was lengthy as both the COSA and RDA are not only complex, but also affect all customer classes. Customer input provides balance to the financial and conservation considerations that are reflected in the recommendations.

The Company recognizes the need to develop an RDA that balances the interests of all customer groups and understands that rates charged to its customers need to be fair and equitable. An overview of public consultation activities for the COSA and RDA is provided in the next section.

4.1 Cost of Service Analysis Consultation

In recognition of the complex nature of the cost of service study process, and the potential misunderstanding or misinterpretation of the results among customers, FortisBC focused its initial stages of public consultation on awareness and education. Public education was also undertaken in an effort to improve the breadth and quality of input that would be received during the development of the COSA and subsequent RDA.

FortisBC arranged a series of face-to-face meetings and public open houses where a high level overview of the COSA was presented and draft results discussed. This included a complete review of the changes and their rationale as compared to previous COSA methodology and the revenue-to-cost ratios that resulted were presented and discussed. While a strategy for adjusting the rates to re-establish equity between the classes had not been determined, the intention of the Company to rebalance the rates was clearly indicated.

In an effort to reach as many stakeholders as possible, and to engage a wide range of customers, the open houses were advertised in local media and over 230 notifications were sent by direct mail and email to First Nations, intervenors from previous regulatory processes, as well as local government, provincial and federal elected officials, Chambers of Commerce, customer organizations and major customers. The presentation was also reviewed with the FortisBC Demand Side Management Advisory Committee in advance of the open houses.

Three public open houses focusing on COSA education and preliminary study results were held during the week of May 26, 2009. These included a PowerPoint presentation and an opportunity for open house participants to ask questions. The first open house was at the Sandman Hotel in Castlegar on May 26, 2009, the second was at the Ramada Hotel in Kelowna on May 27, 2009 and the third was at the Best Western Sunrise Inn in Osoyoos on May 28, 2009.

In addition to the open houses, representatives of FortisBC met in person with each customer taking service under Rates 31 and 33, and the wholesale municipalities of Nelson, Grand Forks, Kelowna, Penticton and Summerland to provide an overview of the COSA and review the preliminary study results. Individual meetings or phone calls were also conducted with non-wholesale municipalities throughout the service area to inform them of the COSA and RDA process and results. At each meeting, customers were notified of the potential for the COSA results to be reflected in rebalancing and the Rate Design process, and provided with information on future participation in the COSA and RDA process.

The draft COSA study as well as copies of all open house materials were posted to the FortisBC website on June 12, 2009. The draft report was subsequently filed with the Commission and posted to the FortisBC website on June 30, 2009.

4.2 Rebalancing and Rate Design Consultation

A second set of public open houses was held to review rebalancing and rate design options being considered by the Company. The rate design options presented at the open houses are those Residential and General Service scenarios that are detailed in Section 8 and the presentation materials are attached in the Public Consultation Report appended to this Application as Appendix I.

Four open houses were held in July 2009 that were directly focused on rate rebalancing and rate design options with a brief review of the COSA. Each open house provided a PowerPoint presentation and an opportunity for participants to ask questions and provide input. Surveys were collected at the end of each open house in Creston, Castlegar, Kelowna and Osoyoos. Representatives from the Residential, General Service, Large General Service and Municipal rate classes signed into the sessions.

In addition to the public open houses, invitations were sent to the Bands and Nations within the FortisBC service area for a First Nations open house scheduled for July 21, 2009. This open house was not held as no Bands or Nations confirmed attendance and no written feedback was received on either the COSA or RDA.

4.3 Super Group Consultation

In order to gather additional feedback and ensure input from a representative sample of FortisBC customer groups concerning the COSA and RDA, FortisBC hired Environics Research Group to conduct two large focus groups, called “Super Groups”. The first Super Group was conducted in Castlegar on August 17 and the second in Kelowna on August 18, 2009.

In each case, a representative sample of customers was recruited at random, being told only that they would be participating in a focus group, but if they inquired were told that the subject matter was electricity rates for FortisBC. Participants were paid an honorarium for their attendance.

Participation by 58 customers in Castlegar and 56 customers in Kelowna resulted in 114 complete surveys with in-depth feedback. Participants were asked to complete a short entrance survey and a more detailed survey subsequent to the open house presentation by FortisBC staff. The exit survey enabled participants to provide their feedback on COSA, rebalancing and rate design. The Environics surveys and summary report are provided in Appendix I to this Application.

4.4 Technical Workshop

Invitations were sent to First Nations, stakeholders and prior open house attendees for a COSA technical workshop hosted in Kelowna on August 31, 2009. Invitees were provided with the option to attend in person or by teleconference. Those in attendance were representatives of the Residential, General Service, and the five Wholesale municipal utilities.

The workshop provided participants an opportunity to discuss the COSA model, and to directly question the model's assumptions and functionality.

4.5 Wholesale Class Consultation

Discussions with the Wholesale classes, Rates 40 and 41, began at the earliest stages of COSA consultation as the Company recognized that this customer class would be negatively impacted by rate rebalancing and needed to be informed of the COSA and RDA process as soon as practicable. COSA consultation began with visits to each municipal Wholesale customer during the week of May 26, 2009, where the COSA methodology and changes to cost allocation methods was reviewed, and current revenue-to-cost ratios were presented.

In August of 2009, the municipal Wholesale customers, through their umbrella group, the British Columbia Municipal Electrical Utilities ("BCMEU") took a position against certain aspects of the methodology used in the COSA. The primary issue was the methodology by which certain transmission and distribution costs were allocated to the wholesale and industrial transmission customers.

The methodology used for the allocation in the COSA model relies on the contractual demand limits prescribed in the existing contracts with these customers. The Company is contractually obligated to provide electrical service up to those prescribed limits and believes it is appropriate to allocate costs on that basis.

Given that the current Agreements are to expire during the proposed COSA and RDA Application regulatory process, the Company and the municipalities attempted to reach agreement on several key terms relating to the contractual demand limits prior to filing the Application so that they may be reflected in this Application.

On September 29, 2009, the Commission issued Order G-115-09, extending the filing date of the COSA and RDA Application to October 30, 2009 so that these discussions could continue in the hope of reaching a resolution. The discussions focused on the renewal of the Wholesale contracts - specifically related to the contracted demand obligations - intended to reflect the capacity requirements of the Wholesale class and to ensure that other customer groups do not continue to unduly subsidize the municipal customers. These terms included the existing demand limits at the points of delivery, as well as new nominations for transmission capacity, to be provided by the individual municipal Wholesale customers to be used for both cost allocation within the COSA and as billing determinants. Also included was an automatic adjustment mechanism to correct for under-nominations.

Had the parties been able to agree upon terms for renewal of the contracts, including new transmission capacity nominations, this would have been reflected in a revised RDA. As at the time of the deadline for submission of this Application, the parties had not yet agreed to any amendments to the existing Wholesale contracts. The Company filed the Application based on the terms contained in the Wholesale contracts that are currently in effect.

The Company remains committed to addressing the concerns of all stakeholders, however, the adoption of the BCMEU position would have significant impacts to other customer classes and therefore should be dealt within the proposed NSP attended by all intervenors.

4.6 Consultation Results

This section summarizes the feedback received at each of the consultation sessions held by FortisBC regarding the COSA and rate design options.

4.6.1 Open House Surveys and Written Submission

FortisBC collected 20 surveys and four written submissions as a result of the mail and email notifications of the process and open houses.

Within the 9 COSA-related surveys, all but one indicated that the COSA information was presented in a balanced manner, provided a better understanding, and explained the opportunity to stay involved in the process. In addition the surveys indicated that the methodology and principles used in the COSA appeared reasonable.

Within the 11 RDA-related surveys, all but one agreed that rebalancing is needed but there were mixed responses as to whether five years is an appropriate timeframe for rebalancing, and whether a cap of five percent per year for rebalancing is reasonable. The surveys also showed no strong preference for one particular rate option of the four presented.

4.6.2 Face-to-Face meetings and Technical Workshop

The face-to-face meetings and technical workshop were primarily attended by Wholesale municipalities and Large General Service customers. Concern was expressed by the Wholesale municipalities regarding the use of the contract demand methodology (as discussed in Section 6.3.5) and its effect on the resulting revenue-to-cost ratios within the COSA. In general, the Large General Service customers were supportive of the contract demand methodology.

4.6.3 Super Group Results

The Super Groups served to collect input from a representative sample of customer classes and to solicit feedback from a greater number of individuals. In total 114 surveys were collected. The results are included in Appendix I.

A summary of the opinions in the surveys collected is as follows:

- 85 percent of participants support rebalancing;
- Most participants agree that capping increases at five percent per year is reasonable when customers' revenue-to-cost ratio is below 100 per cent;
- 70 per cent agree that rate structures that encourage conservation are important;
- The implementation of inclining block rates to promote energy conservation and maintaining the status quo until Advanced Metering Infrastructure is implemented received mixed responses;
- The primary reason for supporting inclining block rate structures is energy conservation;
- Supporters for maintaining the existing rate structures often cited the implementation of Advanced Metering Infrastructure or a lack of reason to change as the rationale for preferring that option;
- Participants are mixed concerning the idea of recovering fixed costs by raising the Basic Charge; and
- General Service participants are not generally in favour of the proposal to flatten the blocks and increase the Basic Charge. Many believe their electricity bills would increase as a result of this change to electricity billing.

5.0 Principles and Objectives

The content of this Application adheres to a set of principles (the "Principles") that influence rate rebalancing and rate design. This ensures that decisions made as part of COSA, rebalancing and rate design appropriately consider provincial energy policy and FortisBC customer interests.

The fundamental principles applied in the development of this Application are generally based on those identified by Dr. James Cummings Bonbright[3]. FortisBC has attempted to balance the following principles in the development of this Application.

Principle 1	Recovery of the revenue requirement;
Principle 2	Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates);
Principle 3	Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy);
Principle 4	Customer understanding and acceptance;
Principle 5	Practical and cost-effective to implement (sustainable and meet long-term objectives);
Principle 6	Rate stability (customer rate impact should be managed);
Principle 7	Revenue stability; and
Principle 8	Avoidance of undue discrimination (interclass equity must be enhanced and maintained).

The Company proposes rate rebalancing that most closely aligns rates with the costs to serve each rate class as much as is reasonable. The principal of cost causation, reflected in Principle 2 and Principle 8, is well established and accepted as appropriate in determining rates. Cost causation, the primary driver of the assumptions contained in the cost of service study, leads to the allocation of costs that when compared to

[3] James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961

revenues by class indicates that cross-subsidization between rate classes exists under current rates. Interclass revenue adjustments are proposed to ensure that the amount of revenue collected from each customer class more appropriately recovers the costs of serving that class.

FortisBC supports the need, as embodied in the Energy Plan and the UCA, to conserve energy as a basic consideration in utility planning. In order to provide price signals that encourage efficient use and discourage inefficient use (Principle 3), the options presented in the Application were developed to ensure that the energy efficiency and conservation goals of the Company, the Commission, and the Province as contained in the Utilities Commission Act and the Energy Plan are supported. The decision to flatten existing declining block General Service rates, maintain the Basic Charges at current rates, increase demand charges and consider inclining block rates is a direct outcome of this principle.

During rate design, a direct conflict between the principle of promoting energy efficiency (Principle 3) and the principle of using COSA-based costs (Principle 2) occurred in some instances. In particular, the COSA-based customer costs were generally higher than the current fixed monthly charges, but it was determined that raising the monthly Basic Charge results in a lower energy rate and therefore a lower marginal cost of energy, which ultimately does not encourage energy efficiency. Where such conflicts arose, the Company favoured Principle 3 encouraging the efficient use of electricity.

The review of rates included in the Application explored options that provide customers with price signals reflecting current energy policy and helps to address the growing capacity constraints faced by FortisBC. In the recent past, FortisBC's growing capacity and energy requirements were supplied primarily by purchases from B.C. Hydro under tariff rates. As load continues to grow across the service area, new and existing sources of supply and the associated transmission system enhancements bring higher incremental commodity costs that call for rate design changes to reflect these pressures.

The Company must also consider evolving technologies and medium-term plans in the rate design options considered. The advent of AMI would provide for the wide application of time-based rates such as time-of-use, critical peak pricing or load control which would better address FortisBC's capacity gap in the longer term. Easing the capacity requirement will also have a positive effect on related energy consumption.

FortisBC is committed to the energy conservation and demand reduction goals that both the Company and the Province have identified as priorities in meeting increasing electric demands. The COSA and the associated rate proposals contained in this Application reflect both current needs and the future direction of the Company. The use of technology in meeting these goals is paramount, and in particular FortisBC is of the opinion that AMI must be considered in future rate design plans.

FortisBC believes it has satisfied all of the aforementioned principles in the completion of its Cost of Service Study and Rate Design recommendations.

6.0 Cost-of-Service and Rate Rebalancing

6.1 Overview

This section summarizes the background, process, and results of the 2009 Cost of Service Analysis completed by EES Consulting Inc. ("EES") for FortisBC. The COSA component of the Application is important as not all current rates adequately reflect the cost of providing service. In response to this current situation, FortisBC is proposing to rebalance rates for all rate classes in a manner described in Sections 10.0 to 14.0.

6.2 The Cost of Service Study

FortisBC engaged EES Consulting Inc. to assist in completing the Company's Cost of Service Study and in the development of FortisBC's Rate Design Application. While EES provided technical expertise and input for the completion of the study, and provided the model used to gather and analyze the various data, FortisBC provided the necessary information and policy level guidance that produced the study results. The complete EES COSA Report ("2009 COSA Report") is attached to this Application as Appendix A.

A COSA is a process used to assign or allocate a fair share of total cost or revenue requirement of a utility to its various customer rate classes or schedules. The primary output of the study is the cost to be collected by rate class, which is used as a basic input for rate design.

The outcome of the COSA and Rate Design process is revenue neutral and the primary concern for the Company is that the principles of cost-causation and equity are upheld within the cost allocation methodologies and assumptions while considering and balancing the Principles set forth in Section 5.

6.3 Consideration for the 2009 COSA

6.3.1 Regulatory Environment

The environment in which FortisBC operates has seen significant change since the last COSA was filed in 1997. The Provincial Government has released comprehensive energy plans in 2002 and more recently with the 2007 Energy Plan, and made changes to the UCA that has shifted industry focus towards a greater consideration of objectives related to conservation, efficiency, adequate capacity availability and self sufficiency.

Assumptions contained within the 2009 COSA Report have been made to reflect the inherent value of system capacity and the responsibility of each customer class for the costs that it imposes upon the system as a whole.

As noted in the 2009 COSA Report, the 1997 COSA served as the starting point for the 2009 study. In most cases, basic assumptions remain consistent with those used in 1997 and therefore the bulk of the 2009 COSA Report is devoted to explaining those assumptions in greater detail, and identifying the adjustments from previous practice, along with the rationale and impact of these changes.

Generally speaking, the methodologies used in the 1997 study were the same as those employed in the completion of the 2009 version. Within each basic methodology, assumptions must be made based upon the circumstances that exist at the time of the study. Where these specific assumptions differ between the two studies, it has been noted in the 2009 COSA Report and is also summarized below.

6.3.2 Capacity Constraints

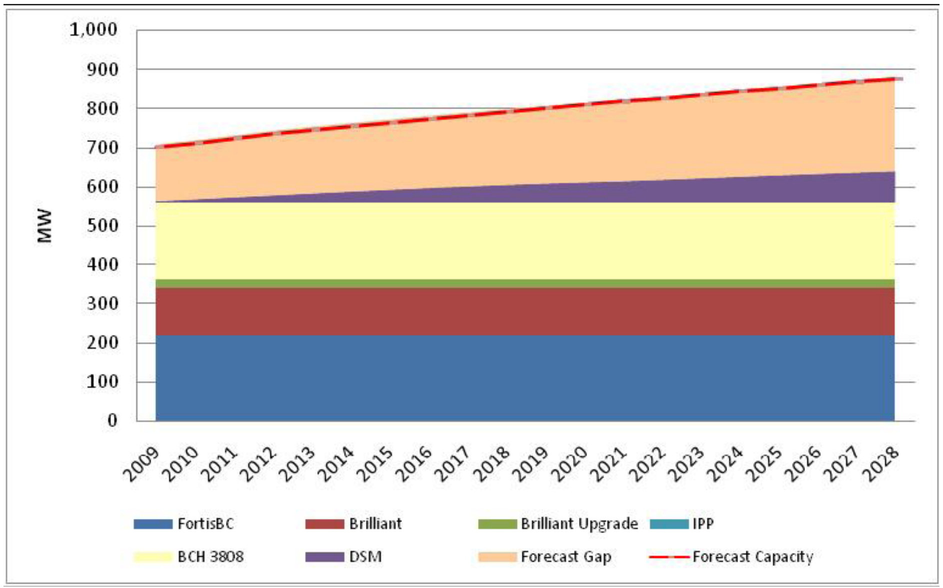
In its 2009 Resource Plan filed with the Commission on May 29, 2009, the Company stated;

> "*The FortisBC Plants and the power purchase agreements with BC Hydro and Brilliant Power Corporation together constitute the bulk of the Company's existing power supply resources,*

providing a total winter peak capacity of approximately 551MW. In 2008 these resources served about 74% of FortisBC's December 2008 winter peak of 746 MW, resulting in a shortfall of 195 MW which was met through short term, market based contracts. In 2009, FortisBC's load forecast predicts a capacity shortfall of about 145 MW."

This situation is shown graphically in Figure 6.3.2 which is also taken from the 2009 Resource Plan. It can be seen that the existing capacity gap from existing resources increases steadily over time.

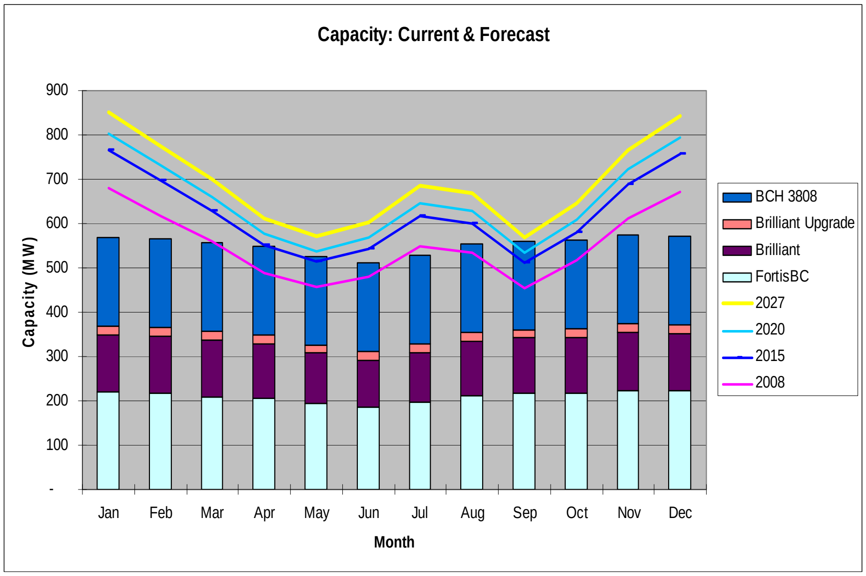
Figure 6.3.2 – FortisBC Load-Resource Gap



6.3.3 Dual Peaking Load

Related to capacity concerns is the relatively rapid increase in the summer peak where now both the summer and winter peak play a significant role in system planning. The chart below shows the pronounced 2008 summer peak which FortisBC believes is caused primarily by the large air conditioning load developing in the FortisBC service area.

Figure 6.3.3 – FortisBC System Peak Demand



6.3.4 System Investment

As noted in the EES Report (Appendix A) on page 12, FortisBC has increased the gross value of its Rate Base by over 200 percent since the 1997 COSA Study. Capital Expenditures in 2007 and 2008 were approximately $130 million and $110 million respectively. These levels of investment are driven by the infrastructure required for system expansion and replacement which is required to accommodate ongoing capacity constraints on the transmission and distribution systems. The Kootenay 230 kV Transmission Project, completed in 2003, is an example of one such project required to keep pace with growth and manage issues related to the age of existing plant. The allocation of costs related to transmission and distribution plant tends to affect certain classes of customers to a greater extent than others.

Transmission plant accounted for 24 percent of the rate base in 1997 versus 29 percent today, while production was 9 percent of the rate base in 1997 but now comprises 12 percent of the total in the 2009 study. The shift in investment towards generation and transmission results in widening gaps in the revenue-to-cost ratios between the customer classes.

6.3.5 Resulting Changes to Study Methodology

Several key assumptions used in the 2009 study reflect the facts discussed above. With the exception of the use of contractual demand limits as an allocation factor (discussed below), these assumptions have a minimal impact on the study results.

For customers served under Large General Service Transmission Schedules 31 and 33 and Wholesale Schedules 40 and 41, FortisBC has in place negotiated contracts for supply. These agreements contain “demand limits” which represent the load that FortisBC is contractually obligated to supply at each point of delivery. In effect, these demand limits are capacity reservations, and there is a cost attributable to the planning and constructing of infrastructure required to satisfy these contractual arrangements. The COSA utilizes these amounts as an allocation factor for transmission and distribution costs where these demand limits exceed the actual demand.

In the discussion of this methodology in the draft COSA report filed with the Commission on June 30, 2009, and during the public consultation, the obligation to meet the supply requirements at these points of delivery was referred to alternately as contractual demand, contract demand, contracted demand, or demand limit. Regardless of the nomenclature, the Company must have the ability at each supply point identified in the contracts to simultaneously provide electric service to the contractual limit specified, and to allocate the costs of doing so to those parties who see the benefit. The concept of cost causation as captured in the second principle guiding this Application is reflected through the use of the demand limits as an allocation factor.

To contrast, the 1997 study took only measured demand into consideration. The current approach better reflects both the contractual obligations and the capacity costs associated with those obligations, and prevents those costs from being inappropriately absorbed by the broader customer base. As noted in the report, the Energy Plan encourages all utilities to promote efficiency and conservation, and therefore it is imperative that customers are provided price signals that reflect the true cost of the facilities used to serve them. The use of firm capacity reservations as a COSA assumption supports the Energy Plan by ensuring that capacity nominations are accurate.

FortisBC has power supply agreements in place with each of its municipal Wholesale customers, all of which will expire in the near term. The Company expects to continue pursuing conservation objectives upon renewal of the Agreements, by taking into consideration the importance of cost-causation, capacity and energy constraints, insulating other customers from the potential risk of stranding assets and the appropriate placement of utility risk.

In consideration of the capacity-constrained nature of the FortisBC system, the allocation of generation rate base was changed from the 1997 Study assumption that 100 percent of the cost amount was energy related. The 2009 COSA Report assumes an 80 percent energy, 20 percent demand split, the derivation of which is discussed in detail on page 18 of the EES Report (Appendix A). The recognition that the FortisBC plants provide both energy and capacity results in value being attributed to capacity in the system. The effect on the revenue-to-cost ratios from this change alone is small, causing a drop in the ratio for the Large General Service Transmission class of less than three percentage points, and an even smaller rise in the ratios for the General Service and Large General Service Primary classes.

The dual-peaking nature of the FortisBC system load is reflected in the decision to use the sum of two winter and two summer peaks for the two critical peak (“2 CP”) method for allocating demand related transmission costs. The 2 CP method was also employed in the 1997 COSA and the incorporation of the additional peak data has a minor effect on the outcome of the study. A full discussion on the selection of the 2 CP method is contained in the EES Report beginning at page 26 of Appendix A.

Investment in the system since the 1997 COSA changes the relative weightings of the generation, transmission and distribution values within the total rate base, broadly affecting COSA results.

For the classification of distribution plant, a minimum system study was performed in order to determine the split between customer and demand-related costs. A similar approach was taken in the 1997 COSA, however, the 2009 COSA Report incorporates cost information updated for 2008 costs and thus, the customer/demand split is altered from the previous 1997 study.

While the minimum system is, in theory, designed to carry only a minimal amount of load, the actual facilities designated as the minimal size are capable of carrying an amount of load beyond the theoretical level, therefore overstating the level of the customer-related component. Along with the minimum system results, an offset to account for the peak load carrying capability ("PLCC") of a minimum system was incorporated into the analysis. The minimum system study is discussed in the 2009 COSA Report.

7.0 Study Results

The revenue-to-cost ratios for each customer class reflect the extent to which FortisBC is collecting revenue relative to the costs allocated to each rate class. A revenue-to-cost ratio of 100 percent indicates that the revenues exactly match the costs of providing service. A revenue-to-cost ratio below 100 percent indicates that a customer class is being subsidized by others within the system while a revenue-to-cost ratio above 100 percent indicates that a customer class is subsidizing other classes. The 2009 COSA Report revenue-to-cost results for current FortisBC rates are reproduced below.

Table 7.0 - 2009 Revenue-to-Cost Ratios

Rate Class	Ratio
Residential	98.3%
Small General Service (20)	113.4%
General Service (21)	138.9%
Large General Service Primary (30)	122.4%
Large General Service Transmission (31)	109.9%
Large General Service Transmission TOU (33)	23.5%
Lighting	81.9%
Irrigation	78.6%
Kelowna Wholesale*	89.9%
Penticton Wholesale	78.0%
Summerland Wholesale	96.6%
Grand Forks Wholesale	71.3%
BC Hydro Lardeau Wholesale	101.8%
BC Hydro Yahk Wholesale	103.5%
Nelson Wholesale	80.0%
Total	**100.0%**

* Note that in the table - Kelowna Wholesale through BC Hydro Yahk Wholesale currently belong to the same Rate class (40) and are broken out as discussed on page 13 of the EES Report.

As noted in the EES Report, “The COSA takes the revenue requirement for the utility and attempts to equitably allocate those costs to the various customer classes of service (i.e., Residential, General Service, etc.). This analysis provides a determination of the level of revenue responsibility of each class of service and the adjustments required to meet the cost of service". The principle of cost causation, and in particular the use of demand limits in recognition of contractual obligations and system planning, is a strong determinant of revenue-to-cost ratios.

FortisBC has a rate structure that has evolved over the years to meet the needs of its customers. To a large extent, the division of customer classes within the FortisBC service area reflects the type of customer, service size, and the voltage at which service is provided.

FortisBC has customer classes that fall roughly into the following groups, with several subdivisions in each, such as Time-of-Use and Green Rates.

Residential - The Residential customer class includes customers occupying residential premises such as single family homes, multi-unit residences, recreational property and domestic outbuildings.

Small General Service – This class is non-residential Customers whose electrical demand is generally not more than 40 kW and can be supplied through one meter.

General Service – This class is composed of non-residential Customers whose electrical demand is generally greater than 40 kW but less than 500 kW and can be supplied through one meter.

Large General Service – Primary – This class includes customers with a contract demand of 500 kVA or more, subject to written agreement.

Large General Service – Transmission – This class is comprised of customers with a contract demand of 5,000 kVA or more, that are served at 60,000 volts or above, subject to written agreement.

Irrigation – This rate is for irrigation and drainage season customers between April 1 and October 31 of each year.

Lighting – These customers are provided service to dusk-to-dawn and streetlights and can be individual customers, cities, towns, villages or regional districts located in the FortisBC service area.

Wholesale – Wholesale customers are provided power for resale and include the municipal utilities of Nelson, Grand Forks, Summerland, Penticton and Kelowna, as well as BC Hydro services at Lardeau and Yahk.

Currently, the utilities of the municipalities of Grand Forks, Summerland, Penticton and Kelowna, as well as BC Hydro are all provided service under Rate Schedule 40, while Nelson Hydro receives service under Rate Schedule 41.

Given the unique characteristics of each utility and the resulting range of revenue-to-costs ratios as shown in Table 7.0 above and discussed on page 13 of the EES Report, FortisBC is proposing to create distinct rate schedules for each municipality to better reflect their individual contribution to the total cost of service. During consultation, the municipal wholesale customers were advised of this proposal, but have not advised the Company as to whether or not they have considered it as a group and are supportive of the change.

8.0 Rate Rebalancing

Rate rebalancing ("rebalancing") ensures that rates reflect the actual cost of service and provides equity among rate classes. In order to accomplish this, rates for individual customer classes are adjusted either upwards or downwards towards a given revenue-to-cost ratio target. Rebalancing, though often done concurrently with Rate Design, is a separate process considered in isolation of other factors that affect rates.

The existing rates at FortisBC result in cross-subsidies, where some rate classes benefit at the expense of others. The principle of cost causation requires the reduction and elimination of these cross-subsidies in order to restore interclass equity.

The guiding Principles of this Application state that that there should be fair apportionment of costs among customers (Principle 2), that there should be rate stability (Principle 6) and that there should be no undue discrimination (Principle 8). These Principles lead to the conclusion that adjustments to current cost recovery rates are required.

Unwillingness by various customer classes to continue to subsidize other rate classes was demonstrated in the public consultation responses, as discussed in Section 4 of this Application. The purpose of rate rebalancing is to achieve a revenue-to-cost ratio for all classes equal to 100 percent. Rate rebalancing does not affect the total amount of revenue that is collected by FortisBC, but rather affects only the portion of the total revenue that is collected from each customer class.

Although FortisBC has sufficient metering data to support a goal of 100 percent revenue-to-cost ratio for the Large General Service and Wholesale classes, the Company has chosen to recommend a 95 percent to 105 percent revenue-to-cost ratio range of reasonableness for all customer groups. While it may seem ideal to attempt to bring each customer class to 100 percent, the selection of a range of reasonableness reflects the fact that, during a cost of service study, certain assumptions are necessarily made in the absence of perfect data. This has led most utilities to accept a range as an appropriate goal.

In its decision on the BC Hydro 2007 Rate Design Application Phase I (G-130-07), the Commission directed BC Hydro to adjust its rates in equal percentage amounts over the next three years so as to achieve revenue-to-cost ratios of unity for each class (2007 RDA Decision, p 71). In the same decision, the Commission directed BC Hydro to maintain the revenue-to-cost ratios within a 95-105 percent range once unity was achieved for each class and future cost of service studies are completed.

The decision to move BC Hydro to unity, as noted above, was ultimately set aside by legislation. FortisBC considers that the 95-105 percent range represents a useful and reasonable target in its own rebalancing efforts.

In addition to the rebalancing target, there are a number of other considerations in deciding on a rebalancing schedule. The Company is aware of the impact that rate increases have on customers, and works to keep such impacts to a minimum. Therefore, rate increases to individual classes should be managed such that no class experiences rate shock in any one year. This is accomplished by phasing the rebalancing in over a number of years. FortisBC recommends that no single customer group sees a total annual increase in excess of 10 percent due to a combination of a rebalancing and revenue requirement based rate increase unless the revenue requirement increase alone exceeds 10 percent. In this manner, rebalancing can be completed over five years for most customer classes. Not all classes will experience rebalancing adjustments of the same duration or magnitude. For classes that will have a rate reduction due to rebalancing (such as Small General Service and General Service), rebalancing adjustments will be applied only to the energy component of the rate in order to prevent the Basic Charges from becoming further removed from their COSA-derived amounts.

In summary, the rebalancing effort contains the following elements:

- Total increase due to rebalancing and revenue requirements not to exceed 10 percent unless the revenue requirement increase alone exceeds 10 percent;
- Increases noted above are exclusive of BC Hydro increases that the Company may apply on a flow-through basis; and
- A revenue-to-cost ratio goal of between 95 percent and 105 percent for all classes.

Annually, assuming that the revenue requirement increase is less than 10 percent, the mechanics of the rebalancing would entail:

- Each class with a revenue-to-cost ratio below 95 percent receives a combined rebalancing/revenue requirement increase up to the lesser of 10 percent or the amount required to achieve a 95 percent revenue-to-cost ratio;
- Each year, the excess revenue that results from the above increases is applied to those classes that have revenue-to-cost ratio above 105 percent. Each of these classes would receive the same percentage rate reduction unless doing so would result in a revenue-to-cost ratio below 105 percent;
- If, in any year, a customer class achieves a revenue-to-cost ratio within the range of reasonableness, no further adjustments would be made in subsequent years if the ratio again fell outside of the range;
- Where a rate class is receiving a decrease as a result of rebalancing, the decrease will be applied to the energy charges only and not to demand or Basic Charges; and

- Rate Schedule 33 will have rebalancing increases applied to the wires-based demand charge only.

8.1 Rebalancing Example

Using the assumptions above, and assuming an average annual revenue requirement rate increase of 5 percent per year, Tables 8.1a and 8.1b illustrate for informational purposes only the potential effect of the rebalancing on the revenue-to-cost ratios over a five year period.

Table 8.1a
Resulting Total Rate Increase Assuming 5% General Rate Increase and 10% Cap

	Year 1	Year 2	Year 3	Year 4	Year 5
	Total Rate % Increase	Total Rate % Increase	Total Rate % Increase	Total Rate % Increase	Total Rate % Increase
Residential	5.0	5.0	5.0	5.0	5.0
Small General Service	1.7	2.0	3.4	5.0	5.0
General Service	1.7	2.0	2.2	1.5	4.0
Large General Service Primary 30	1.7	2.0	2.2	1.5	1.8
Large General Service Transmission 31	1.7	3.6	5.0	5.0	5.0
Large General Service Transmission 33	10.0	10.0	10.0	10.0	10.0
Lighting	10.0	10.0	10.0	6.0	5.0
Irrigation	10.0	10.0	10.0	10.0	5.4
Kelowna Wholesale	10.0	5.9	5.0	5.0	5.0
Penticton Wholesale	10.0	10.0	10.0	10.0	6.2
Summerland Wholesale	5.0	5.0	5.0	5.0	5.0
Grand Forks Wholesale	10.0	10.0	10.0	10.0	10.0
BCH Lardeau Wholesale	5.0	5.0	5.0	5.0	5.0
BCH Yahk Wholesale	5.0	5.0	5.0	5.0	5.0
Nelson Wholesale	10.0	10.0	10.0	8.5	5.0

Table 8.1b Impact on Revenue-to-Cost Ratio over 5 years

	Rebalancing Increase and 5% General Rate Increase					
	Initial R/C Ratio	Year 1 R/C Ratio	Year 2 R/C Ratio	Year 3 R/C Ratio	Year 4 R/C Ratio	Year 5 R/C Ratio
	%					
Residential	98.3	98.3	98.3	98.3	98.3	98.3
Small General Service	113.4	109.8	106.7	105.0	105.0	105.0
General Service	138.9	134.6	130.7	127.2	123.0	121.8
Large General Service Primary 30	122.4	118.5	115.1	112.1	108.3	105.0
Large General Service Transmission 31	109.9	106.4	105.0	105.0	105.0	105.0
Large General Service Transmission 33	23.5	24.7	25.8	27.1	28.4	29.7
Lighting	81.9	82.3	89.8	94.1	95.0	95.0
Irrigation	78.6	82.3	86.3	90.4	94.7	95.0
Kelowna Wholesale	89.9	94.2	95.0	95.0	95.0	95.0
Penticton Wholesale	78.0	81.7	85.6	89.7	94.0	95.0
Summerland Wholesale	96.6	96.6	96.6	96.6	96.6	96.6
Grand Forks Wholesale	68.1	71.3	74.7	78.3	82.0	85.9
BCH Lardeau Wholesale	101.8	101.8	101.8	101.8	101.8	101.8
BCH Yahk Wholesale	103.5	103.5	103.5	103.5	103.5	103.5
Nelson Wholesale	80.0	83.8	87.8	92.0	95.0	95.0

The results in the table above satisfy the requirements of the rebalancing criteria mentioned previously. As shown, there are four customer groups that remain outside of the 95-105 percent range at the end of five years; however this situation cannot be remedied without introducing increases larger than 10 percent annually for those groups.

Feedback received from the Super Group consultation indicated a high degree of support for rebalancing in general, and the Company's approach was seen as reasonable.

9.0 Rate Design

9.1 Introduction

Each customer class, with the exception of time-based rates and green rates, currently has a default rate structure that has been in place since the previous rate design application was approved in 1997. With this Application, FortisBC generally considered a number of rate structure changes for all customer classes. Conceptually, all classes could have billing component rates set to recover costs in proportion to the billing component rates identified by the COSA. Practically, an across-the-board setting of billing component rates per the COSA would have prompted large changes in billed amounts for some customers and potentially dis-incent conservation (violating Principles 3 and 6). A schedule of rates has been developed that better matches revenues to costs while holding any such changes to a reasonable level and maintaining conservation objectives. Modifications to rate schedules are summarized in the table below and discussed in Sections 10.0 to 15.0.

Table 9.0: Schedule of Rate Design Changes

Rate Class	Existing Schedule	Status	Description
Residential Service	1	No Change	No change to existing rate structure.
Residential TOU	2	Deleted	5 customers on this rate that can choose between Schedule 1 or 2 A
	2 A	No Change	No change to existing rate structure.
Residential - Green	3	Deleted	Converted to common Green rate rider (Refer to Section 15)
Residential TOU - Green	4	Deleted	Converted to common Green rate rider
Small General Service	20	Modified	Changed from three-step declining block to flat. Rebalancing adjustments to be applied to energy rate only.
General Service	21	Modified	Demand charge increased. Changed from three-step declining block to two-step declining block. Rebalancing adjustments to be applied to energy rate only.

Table 9.0 Schedule of Rate Design Changes (Cont'd)

Rate Class	Existing Schedule	Status	Description
General Service - Secondary - Time of Use	22	Deleted	5 customers on this rate that can choose between Schedule 20, 21 or 22A
General Service - Secondary - Time of Use	22 A	Modified	Added metering discount for primary metering.
General Service - Primary - Time of Use	23	Deleted	No customers on this rate.
General Service - Primary - Time of Use	23 A	Added	Updating of Rate 23
Small General Service - Green Power	24	Deleted	Converted to common Green rate rider
General Service - Green Power	25	Deleted	Converted to common Green rate rider
General Service - Secondary - Time of Use - Green Power	26	Deleted	Converted to common Green rate rider
General Service - Primary - Time of Use - Green Power	27	Deleted	Converted to common Green rate rider
Large General Service - Primary	30	Modified	Demand charge increased. Rebalancing adjustments to be applied to energy charges only.
Large General Service - Transmission	31	Modified	Demand charge now split between contract demand-based wires charge and actual demand-based power supply charge.
Large General Service - Primary - Time of Use	32	Modified	Rebalancing adjustments to be applied to energy charges only.
Large General Service - Transmission - Time of Use	33	Modified	Implement contract demand-based wires charge
Large General Service - Primary - Time of Use - Green Power	34	Deleted	Converted to common Green rate rider
Large General Service - Transmission - Green Power	35	Deleted	Converted to common Green rate rider
Large General Service - Transmission - Time of Use -Green Power	36	Deleted	Converted to common Green rate rider
Wholesale Service - Primary	40	Closed	Wholesale Customers each have COSA based rate. (See Schedules 40A – 40E)
Wholesale Service – Primary	40A	New	Available to the City of Grand Forks Demand Charge Based on Demand Limit

Table 9.0 Schedule of Rate Design Changes (Cont'd)

Rate Class	Existing Schedule	Status	Description
Wholesale Service – Primary –Time of Use	40A –TOU	New	Available to the City of Grand Forks Implement Contract Demand based Wires Charge
Wholesale Service - Primary	40B	New	Available to the District of Summerland COSA Based rates Demand Charge Based on Demand Limit
Wholesale Service – Primary –Time of Use	40B - TOU	New	Available to the City of Summerland COSA Based rates Implement Contract Demand based Wires Charge
Wholesale Service - Primary	40C	New	Available to the City of Penticton Demand Charge Based on Demand Limit
Wholesale Service – Primary –Time of Use	40C - TOU	New	Available to the City of Penticton Implement Contract Demand based Wires Charge
Wholesale Service - Primary	40D	New	Available to the City of Kelowna Demand Charge Based on Demand Limit
Wholesale Service – Primary –Time of Use	40D - TOU	New	Available to the City of Kelowna Implement Contract Demand based Wires Charge
Wholesale Service - Primary	40E	New	Available to the BC Hydro services at Yahk. Demand Charge Based on Demand Limit
Wholesale Service – Primary –Time of Use	40E - TOU	New	Available to the City of BC Hydro services at Yahk. Implement Contract Demand based Wires Charge
Wholesale Service - Primary	40F	New	Available to the BC Hydro services at Lardeau Demand Charge Based on Demand Limit
Wholesale Service – Primary –Time of Use	40F - TOU	New	Available to the City of BC Hydro services at Lardeau Implement Contract Demand based Wires Charge
Wholesale Service – Transmission (Nelson)	41	Modified	Demand Charge Based on Demand Limit Updated with new COSA information
Wholesale Service - Primary - Time of Use	42	Deleted	No customers on this rate. Wholesale Customers each have modified TOU rate
Wholesale Service - Transmission - Time of Use (Nelson)	43	Modified	COSA Based Basic Charge Implement Contract Demand based Wires Charge
Wholesale Service - Primary - Green Power	44	Deleted	Converted to common Green rate rider
Wholesale Service - Primary - Time of Use - Green Power	45	Deleted	Converted to common Green rate rider

Table 9.0 Schedule of Rate Design Changes (Cont'd)

Rate Class	Existing Schedule	Status	Description
Wholesale Service - Transmission - Green Power	46	Deleted	Converted to common Green rate rider
Wholesale Service - Transmission - Time of Use - Green Power	47	Deleted	Converted to common Green rate rider
Lighting – All Areas	50	No change	No change to existing rate structure.
Lighting - Green Power	50	Deleted	Converted to common Green rate rider
Irrigation and Drainage	60	No change	No change to existing rate structure.
Irrigation and Drainage - Time of Use	61	No change	No change to existing rate structure.
Irrigation and Drainage - Green Power	62	Deleted	Converted to common Green rate rider
Irrigation and Drainage - Time of Use - Green Power	63	Deleted	Converted to common Green rate rider
Green Power Rider	85	New	Applies to specific rates

Most of the rate design changes affecting existing customers were presented to representative customer groups during the consultation process. A summary of the feedback is included in each of the following sections.

9.2 Rate Design Considerations

In selecting the appropriate default rate design option for each customer class, FortisBC considered and balanced the rate design Principles outlined in Section 5. The third Principle, which encourages FortisBC to consider rates that promote energy efficiency, received particular attention. This Principle is derived from the 2007 Energy Plan[4] and the amended UCA[5], which together encourage utilities to develop rates that:

- conserve energy or promote energy efficiency,
- reduce the energy demand a public utility must serve, or
- shift the use of energy to periods of lower demand;

[4] Policy Action #4 is "Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation."

[5] Section 1 of the Utilities Commission Act, in the definition of "demand-side measure" and in part (b) of the definition of "government's energy objectives", and Section 44.1.

In addition to the Provincial Energy Plan encouraging the exploration of conservation rates, the future conservation rate design plans of the utility as outlined in Section 3 were strongly weighted when considering rate design changes.

Changes to rate schedules can be summarized as follows:

- Default (non-TOU) rate schedules for each customer class will remain, become, or move closer to a flat rate as discussed in Section 3, Future Rate Design;
- The Basic Charge will be unchanged;
- Demand charges will be increased (as a proportion of the bill) for customers not subject to contract demand (General Service and Large General Service - Primary);
- Demand charges will be split into power supply-related demand charges using actual demand as the billing determinant and wires-based demand charges using contract demand the billing determinant for customers with a contract demand (Large General Service - Transmission and Wholesale); and
- Time-of-Use rate schedules for customers subject to contract demand (Large General Service - Transmission and Wholesale) will be modified to include a wires-based contract demand charge.

10.0 Residential Rates

10.1 Residential Rate Design Options

Although the Company believes that time-based conservation rates would be desirable for the Residential class from a demand-conservation perspective, the limitations inherent in the current Residential metering restrict changes in existing rates to adjustments in the Basic Charge and to the amount charged for total kilowatt-hour (kWh) consumption (there is no charge for peak demand in the residential rate schedules).

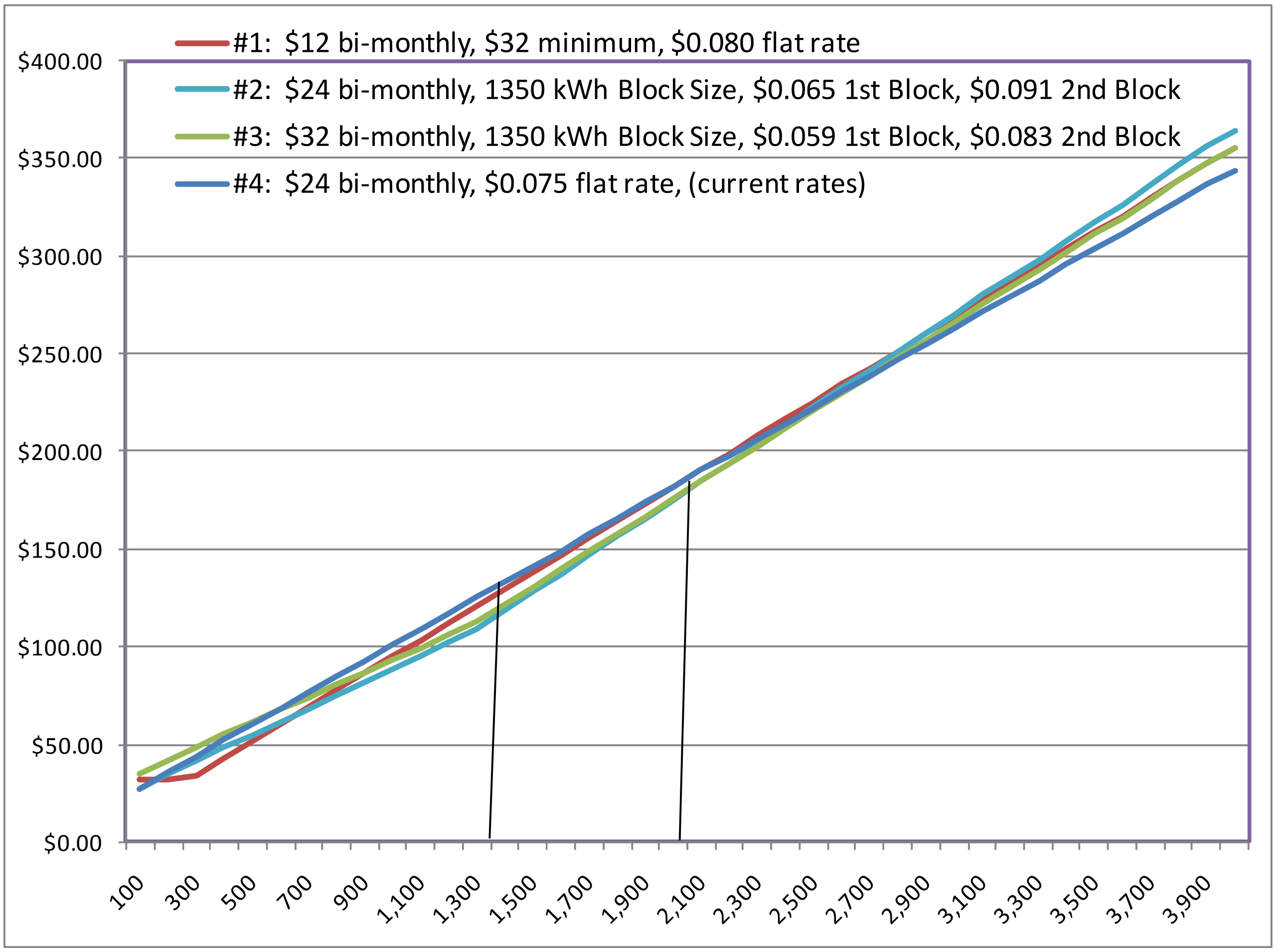
FortisBC considered and consulted on seasonal rates (where the amount charged for energy varies depending on the time of year) and urban/rural rates (in which rural customers are charged a higher rate due to the higher cost to serve). These options were rejected by the Company since it felt they were unduly discriminatory to electric heat customers (in the case of seasonal rates) or rural customers (in the case of urban/rural rates). These options were presented as “rejected options” during consultation, with no dissenting points-of-view expressed during consultation.

As such, during consultation, FortisBC presented four general options for consideration:

1. No change in the Basic Charge with an inclining-block consumption rate;
2. An increase in the Basic Charge with an inclining-block consumption rate;
3. A decrease in the Basic Charge with a flat-rate consumption rate (with the introduction of the “minimum bill” requirement; and
4. No change to existing rate structures.

Graphically, these options were presented as in Figure 10.1a below. The kWh rates included in the charts are those presented during consultation and vary slightly from the results presented herein as they were based on early data models. The bill amount is on the vertical axis with bi-monthly consumption on the horizontal axis.

Figure 10.1a - FortisBC Rate Options



Each of the alternative rate options (numbers 1 through 3) are intended to promote efficiency and conservation by charging customers with lower consumption less and those with higher consumption more as compared to the current rate structure. Since revenue neutrality within the class must be maintained, the result is a shift in the revenue burden from the lower-consumption customers to the higher-consumption customers. Two basic types of these alternative rates were presented: one that reduces the Basic Charge and the other an inclining block rate. As can be seen on the graph, customers using less than approximately 2,500 kWh bi-monthly generally paid less (although customers with very low consumption paid more in certain cases), and those that used more than 2,500 kWh bi-monthly paid more.

Basic Charge

In order to maintain revenue neutrality, any decrease in the Basic Charge requires an increase in the energy rate charged per kWh, and vice-versa. A reduction in the Basic Charge (as seen in Figure 10.1a - Option #1), maybe viewed as a conservation measure since it shifts a higher proportion of the customer's bill to the energy-related portion, and less to the fixed portion. The customer therefore has more incentive to reduce consumption since they face a higher energy-related marginal cost.

From a revenue-stability (Principle 7) and appropriate cost-recovery (Principle 2) standpoint, the Basic Charge should increase or a minimum bill be implemented in order to ensure appropriate recovery of fixed costs identified in the COSA.

During public consultation, potential changes to the Basic Charge were discussed at length at each Rate Design session. Options presented for consideration included both increasing and decreasing the amount of the Basic Charge, as well as maintaining the status quo. There was no clear preference among the consultation participants. In fact, there was an even split between those who thought the charge should be raised and those who thought it should be lowered (48 percent each with 4 percent undecided).

Table 10.1: Effect of Bimonthly Basic Charge Changes*

Basic Charge	kWh Charge
$0.00	$.08692
$12.00	$.08123
$24.26**	$.07627
$32.00	$.07177
$50.00	$.06325
$59.31***	$.05884

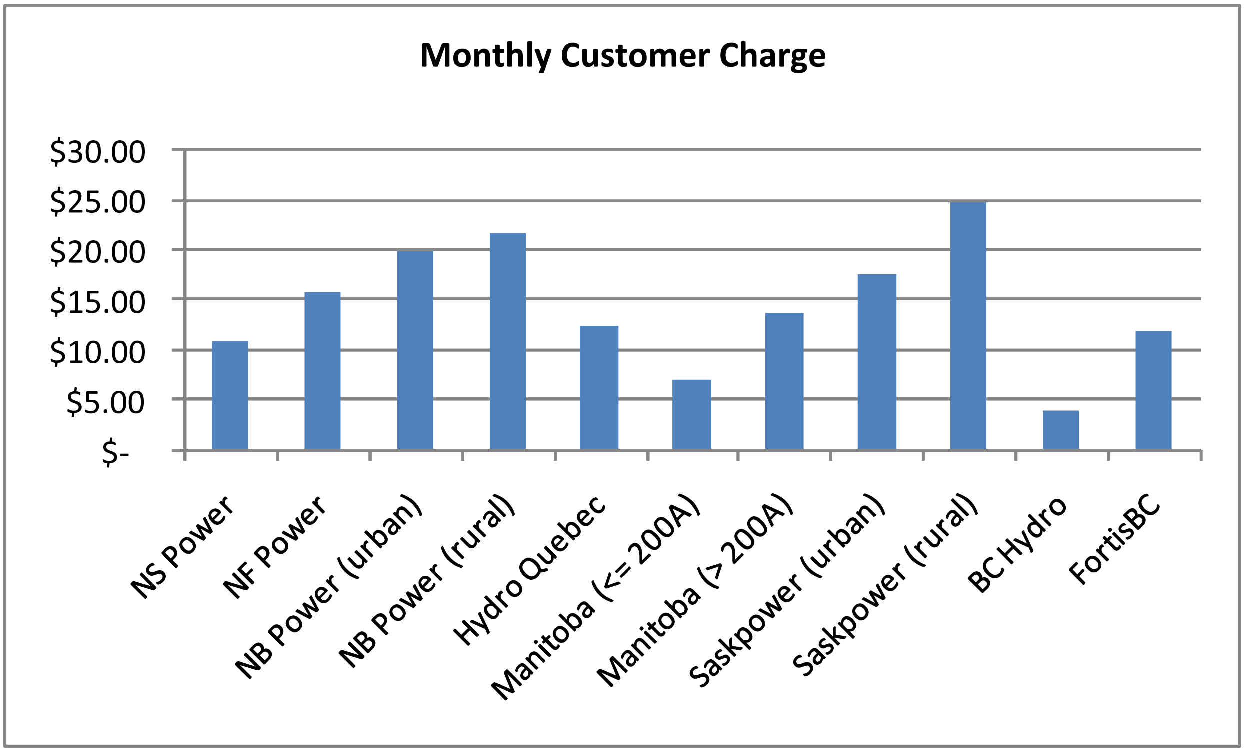
* With current flat rate structure
** Current bi-monthly Basic Charge
*** COSA Result

In order to ensure adequate recovery of non-energy related costs, the Company suggests that any reduction in the bi-monthly Basic Charge requires the implementation of a minimum bi-monthly bill. This minimum amount would apply whenever the total bi-monthly customer bill would otherwise drop below $32, which equates to approximately

250 kWh of energy use over two months. This level of energy consumption would generally result from an unoccupied building without electric heat.

A comparison of FortisBC Basic Charges to other Canadian utilities (current as of August 2009) is shown in the following chart:

Figure 10.1b: Basic Charges at select Canadian Utilities



The current FortisBC monthly Basic Charge is lower than the combined average Basic Charge of the other Canadian utilities presented in the graph.

Given the potential for a higher Basic Charge to have a detrimental effect on conservation (Principle 3) the Company does not propose to increase it at this time. This decision is consistent with the discussion of the Principles in Section 5 where it was noted that if there were a conflict between Principles, Principle 3 would be given additional weight.

Inclining Blocks

During public consultation two inclining block rate options were presented. Both of these rate options charge customers a certain amount per kilowatt hour for the first block of energy used and, if more than the first block of energy is used, the price per kilowatt hour increases in the second block. Inclining block rate structures are intended to promote conservation by increasing the marginal cost for energy in the second block in order to discourage consumption.

FortisBC used as the block threshold approximately 85 percent of the median bill amount in terms of bi-monthly kWh consumption – 1,350 kWh.

One inclining block option includes the current bi-monthly charge of approximately $24 (Option 2), while the other includes a bi-monthly charge of $32 (Option 3). The higher fixed charge in Option 3 recovers a higher proportion of the COSA-recommended non-energy costs than Option 2.

10.2 Residential Rate Recommendation

FortisBC is not proposing to change the structure of its current basic residential rate at this time. Given the considerations in Section 9.2, and the feedback received during consultation, the Company believes that it is prudent to make changes when they can best contribute to ameliorating its capacity constraints and contribute to the energy objectives of the Province. As such, a change to the Basic Charge or the implementation of inclining block rates is not seen as being in the interest of customers or FortisBC at this time. Public consultation results seem to generally support this approach. The highest ranked option, 28 percent of Super Group members, indicated that maintaining existing rates was a preferred option. In response to a later question, the highest ranked option, 46 percent of respondents, indicated that the maintaining of existing residential rates was either the first or second choice of the options presented.

Implementation of any one of the three alternative residential options would result in higher marginal energy costs for some or all customers, which in turn may result in increased energy savings and thereby support Principle 2. Nevertheless, FortisBC does not recommend any of the three options for three reasons.

First, the effective implementation of energy conservation rate structures requires that customers be provided with additional education allowing them to understand to the new pricing signals. Options 1 and 2 require an explanation of how an inclining block rate structure works, and Option 3 requires education around the minimum bill. While these changes are relatively easy to explain, the fact that time-based rates will be introduced after the implementation of an AMI means that customers would have to be re-educated in order to understand and adjust to the time-based pricing signals.

Second, certain types of energy conservation rates, inclined block in particular, require real-time energy consumption information to be available to customers for maximum effectiveness. Without this information, which will not be available until an AMI is implemented, customers will not know whether they are in the higher-priced second block of consumption or not until they receive their monthly or bi-monthly bill.

Third, energy conversation rates structure do not directly address the fundamental power supply issue at FortisBC, which is an increasing capacity constraint. This issue is discussed in more detail in Section 3. Time-based rates can be designed to directly address the capacity constraint issue, but cannot be widely implemented without an AMI.

FortisBC recommends retaining the current flat-energy charge residential rate structure at this time, but remains committed to the development of rates and programs that incorporate conservation objectives. The Company maintains its commitment with respect to Policy Action #1 of the BC Energy Plan, which sets a conservation target of offsetting 50 percent of FortisBC incremental energy growth through conservation by 2020.

11.0 General Service Rates

Standard General Service rates include Schedule 20 - Small General Service - and Schedule 21 - General Service - as well as the Time-of-Use and Green options available with each. FortisBC is not proposing any adjustments to the Green options associated with these rates other than the procedural change discussed in Section 15.

Both of the base General Service rates currently include a monthly Basic Charge of $14.61, and a three-step declining block rate structure for energy consumption following the price structure below for a one month period:

First 8,000 kW.h	8.694¢ per kW.h
Next 92,000 kW.h	6.601¢ per kW.h
Balance	4.900¢ per kW.h

In addition, Schedule 21 includes a demand component in the amount of $7.21 per kW of demand over 40 kW.

Information from the COSA indicates that a cost-based Basic Charge would be closer to $35 monthly.

11.1 General Service Rate Design Options

Mandatory time-based rates were considered for the General Service class, since they would be desirable from a demand-conservation perspective. However, the limitations inherent in the current General Service metering restricts changes to existing rates to adjustments in the Basic Charge, the amount charged for total kilowatt-hour (kWh) consumption and - for Schedule 21 customers - peak demand only.

Optional Time-of-Use rate Schedule 22 A will be retained for General Service customers as discussed later in this Application.

As presented during consultation, the Company is proposing a general flattening of Schedules 20 and 21.

Basic Charge

FortisBC considered increasing the General Service Basic Charges since, as noted above, fixed cost recovery through the current Basic Charge is not sufficient to cover the costs allocated to the General Service classes. However, in light of the need to promote energy conservation, increasing the portion of the customer bill that is not related to electricity consumption was considered undesirable and not in support of the Energy Plan, and the Basic Charge was left unchanged. General Service participants in the Super Group session also favoured leaving the Basic Charge at the same level.

Schedule 20 Energy Charges

This current three-step declining block rate structure presents Schedule 20 Small General Service customers with a declining marginal cost of energy, which is contrary to the Provincial energy objectives as set out in the Energy Plan and Utilities Commission Act.

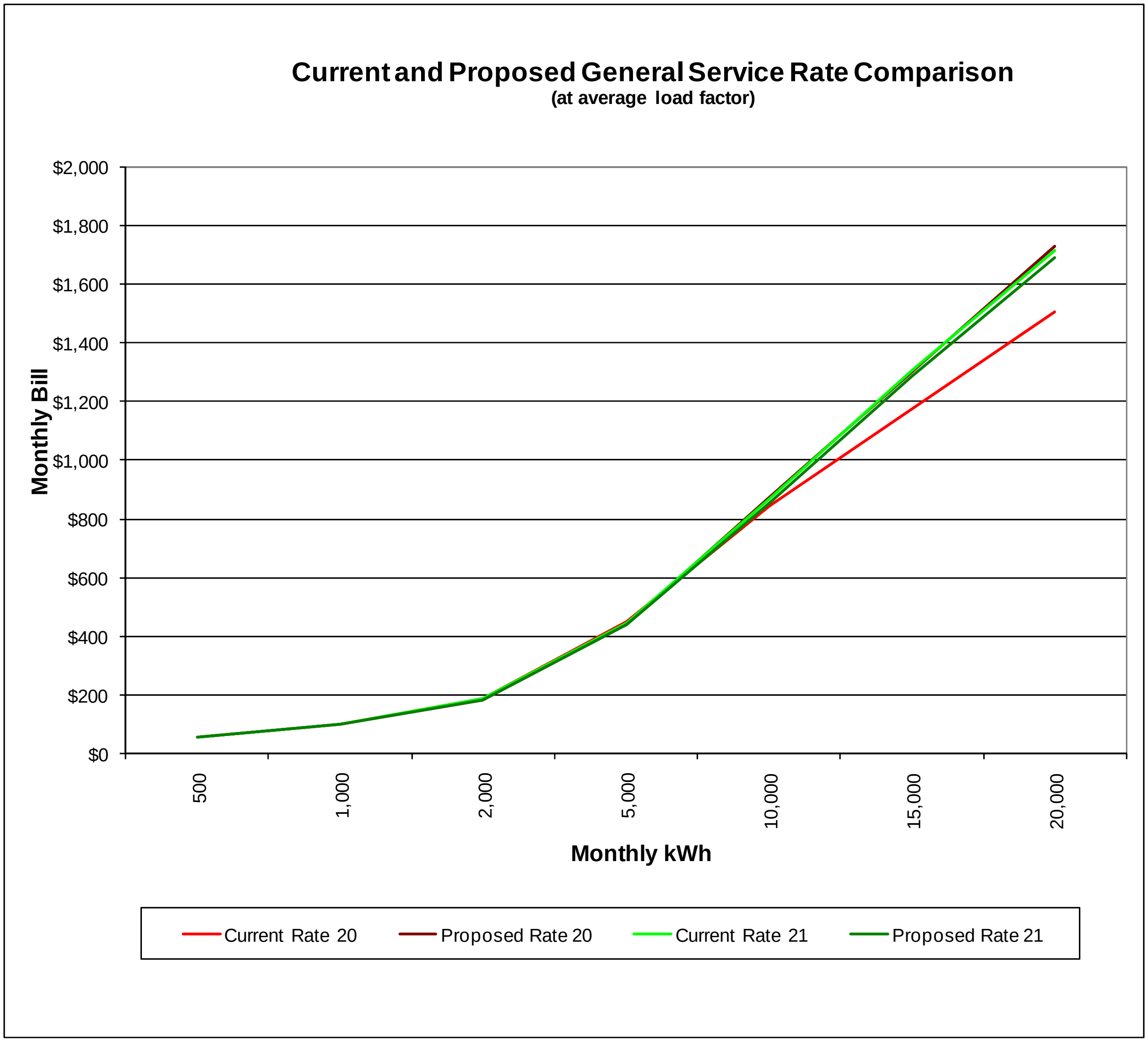
FortisBC proposes to flatten the Schedule 20 energy rate. This increases the marginal cost of energy for customers with larger bills, promoting conservation.

Almost 97 percent of Schedule 20 bills are entirely within the first energy block, thus the rate schedule in practice is already quite flat, which implies the transition to a completely flat rate would not result in excessive bill impacts or require extensive customer education for those under this rate. Schedule 20 customers with consumption below 8,500 kWh monthly would see bill reductions of 0 - 1.4 percent. Customers with monthly consumption above 8,500 kWh and below 14,000 kWh see increases of 0 - 9 percent (14,000 kWh monthly is the approximate consumption of a Schedule 20 customer at the maximum allowed demand of 40 kW and a 50 percent load factor). Based on 2008 bill frequency data over 97 percent of bills are below 8,500 kWh, representing approximately 80 percent of the energy used within the class.

Schedule 20 bills with monthly consumption over 14,000 kWh hours will see increases of up to 20 percent or more, but this only impacts less than 0.6 percent of total bills. Customers with bill increases in this range may have the option to move to Schedule 21, dependent on the frequency with which they exceed 40 kW, and with the average load factor at this consumption level of 30 percent, transitioned customers will pay approximately the same amount (see Figure 11.1).

General Service participants in the Super Groups were not generally in favour of flattening rates and increasing the Basic Charge. After consideration of customer feedback and the rate design Principles, FortisBC believes that an unchanged Basic Charge combined with a flattening of the rates is a desirable option and the effect on customer bills is manageable.

Figure 11.1



Schedule 21 Energy Charges

Customers receiving service under Schedule 21 are larger and average 16,000 kWh per month with demand generally above 4 kW than those in Schedule 20 at average usage of 3,800 kWh per month. Both rate schedules are currently billed the same Basic Charge and energy rates, but Schedule 21 customers also pay a charge for demand above 40 kW.

Completely flattening Schedule 21 energy rates was not considered practical for two reasons:

1. Schedule 21 customers currently have a significant portion of their consumption in all three declining rate blocks (approximately 20 percent in the first block, 50 percent in the second and 30 percent in the third), with the first and third block rates differing by over 75 percent. A flat rate would have a significant impact on individual customers, requiring effort for customers to understand and adjust to a flat rate.

2. FortisBC proposes to maintain the current smooth rate transition for customers near the 40 kW threshold that differentiates Schedule 20 and 21. If both Schedule 20 and 21 rates were flat, then the rates would be different and customers would experience a bill change as they moved from one rate schedule to another.

For these reasons, the Company has designed a two-step declining block rate for Schedule 21 customers in which the first block rate (up to 8,000 kWh monthly) and the flat rate of Schedule 20 are the same at approximately 8.6 cents. The second block of consumption above 100,000 kWh attracts a rate of approximately 6.3 cents per kWh. This will allow the customers who receive service under this rate to transition more smoothly to the time-based rates that FortisBC foresees will become the standard under its future plans.

As with Schedule 20, the majority of Schedule 21 customers will see a modest bill decrease as a result of the change. Those customer bills with consumption below 100,000 kWh monthly (over 98 percent of all bills and 80 percent of total energy consumed by the class) will see a reduction of between 0.8 - 1.7 percent. The small number of bills above 100,000 kWh per month will increase by up to 15 percent.

As Figure 11.1 above shows, FortisBC has achieved a smooth transition point at approximately 14,000 kWh between proposed Schedule 20 and 21 rates.

General Service participants in the Super Groups were not generally in favour of flattening rates and increasing the Basic Charge. Although the Basic Charge was left unchanged, FortisBC believes that flattening of the rates is desirable and overall the effect on customer bills is manageable.

Schedule 21 Demand Charges

The demand charge that currently applies to Schedule 21 customers is approximately 80 percent of the COSA recommended demand charge. Given the importance of demand conservation, FortisBC proposes to raise the demand charge to approximately 85 percent of COSA recommended level, or $7.70 per kW, based on current rates. While a demand charge does not necessarily result in guaranteed reductions at the system peak, the proposed increase does deliver an improved price signal for demand conservation, while still maintaining reasonable intra-class bill changes. The $7.70 per kW proposed in this Application is modestly higher than the $7.50 per kW proposed during consultation.

Table 11.1 - General Service Rate Proposal

	Current	Proposed	
		GS 20*	GS 21
Basic Charge (monthly)	$14.61	$14.61	$14.61
Block One (First 16000 kWh)	$.08694 / kWh	$.08571 / kWh	$.08571 / kWh
Block Two (Next 184000 kWh)	$.06601 / kWh	N/A	$.06.333 / kWh
Block Three (Above 200000 kWh)	$.04900 / kWh	N/A	N/A
Demand Charge	$7.21 / kW	N/A	$7.70 / kW

* Blocks are eliminated for GS20

12.0 Large General Service Rates

The Large General Service Rate classes include those customers receiving service under the basic Schedule 30 – Large General Service Primary - and Schedule 31 – Large General Service – Transmission, and the associated Time-of-Use rates, Schedules 32 and 33. Time-of-Use options are discussed for each class in a later section of the Application.

Schedule 30 and 32 customers are served at primary voltage and generally have a demand over 500 kVA. Schedule 31 and 33 customers are served at transmission voltage and generally have a demand over 5,000 kVA.

Basic Charge

As with other rate classes, fixed cost recovery for Large General Service customers through the current Basic Charge is not sufficient to cover the costs. However, in light of the need to promote energy conservation, increasing the portion of the customer bill that is not related to electricity consumption was considered undesirable, and the Basic Charge was left unchanged.

12.1 Large General Service - Primary Rate Design Options

Mandatory time-based rates were considered for Schedule 30 customers since these rates would be desirable from a demand-conservation perspective. However, the limitations inherent in the current Large General Service metering restrict changes to existing rates to adjustments in the Basic Charge, the amount charged for total kilowatt-hour (kWh) consumption and peak demand only.

Optional Time-of-Use Rate Schedule 32 will be retained for Large General Service-Primary customers as discussed later in this Application.

For the default Large General Service Primary rate, the Company proposed changes that will result in a higher demand charge and a lower energy rate. FortisBC is of the opinion that the proposed changes comply with all the rate design Principles without conflict and therefore only one option is presented for this customer group.

The demand charge that currently applies to Schedule 30 customers is approximately 75 percent of the COSA-recommended demand charge. Given the importance of demand conservation, FortisBC has raised the demand charge to approximately 80 percent of COSA-recommended level, or $7.25 per kVA, based on current rates. While a demand charge does not necessarily result in reductions at the system peak, the proposed increase does deliver an improved price signal for demand conservation, while maintaining reasonable intra-class bill changes. No change to the demand charge for Schedule 30 customers was proposed during consultation.

As discussed above, no change is proposed to the Basic Charge for Schedule 30. There is also no change to the structure of the energy rate which will continue to be flat, but due to the increase in the demand charge, the energy rate will decrease by approximately 3 percent. Customer bill impacts will be modest with decreases of up to 3.6 percent, and increases of 1 percent or less.

Table 12.1: Summary of Changes – Rate Schedule 30

Component	Current	Proposed
Basic Charge	$748.73 monthly	$748.73 monthly
Demand Charge	$6.79 per kVA	$7.25 per kVA
Energy Charge	4.539¢ per kW.h	4.383¢ per kW.h

12.2 Large General Service - Transmission Rate Design Options

Time-based rates were considered for Large General Service - Transmission customers since these rates would be desirable from a demand-conservation perspective, and current metering is capable of providing the data required for these rates. However, consistent with the treatment of the majority of customers, FortisBC proposes to leave the Large General Service Transmission Rate Schedule 33 optional TOU for Large General Service transmission customers at this time.

The primary change to the Rate Schedule 31 is in the determination of the amount of billed demand. Currently, customers on this rate are billed a single demand charge based on:

The greatest of:

a. 100 percent of the Contract Demand, or

b. The maximum demand in kVA for the current billing month; or

c. 100 percent of the maximum demand in kVA recorded during the previous eleven month period.

The proposed revision to Rate Schedule 31 will separate the demand component into a charge related to power supply and a charge related to transmission infrastructure cost, termed the "wires charge". The wires charge reflects the cost of reserving capacity on the transmission and distribution systems. Under the revised tariff, this capacity reservation, or Contract Demand, will become the billing determinant for wires-based demand. The power supply portion of the demand charges will be billed based on the actual recorded monthly peak demand as described below. Thus the provision in the tariff schedule becomes:

Wires Charge

The greatest of:

a. 100 percent of the Contract Demand, or

b. The maximum demand in kVA for the current billing month.

c. 100 percent of the maximum demand in kVA recorded during the previous eleven month period.

Power Supply Charge

The maximum demand in kVA for the current billing month.

Table 12.2 - Summary of Changes – Rate Schedule 31

Component	Current	Proposed	
		Supply	Wires
Demand Charge	$5.49 per kVA	$2.00 per kVA	$3.50 per kVA
Basic Charge	$2246.22 monthly	$2246.22 monthly	
Energy Charge	3.993¢ per kWh	3.938¢ per kWh	

As with Schedule 30, no change is proposed to the Basic Charge for Schedule 31. There is also no change to the structure of the energy rate, which will continue to be flat, but due to the increase in the demand charge revenues, the energy rate will decrease by approximately 3 percent.

13.0 Wholesale Rates

Mandatory time-based rates were considered for wholesale customers since these rates would be desirable from a demand-conservation perspective, and current metering is capable of providing the data required for these rates. However, consistent with the treatment of all customers, FortisBC proposes to leave the wholesale TOU rate schedules optional for wholesale customers at this time.

During the Cost of Service Analysis, the costs allocated to the Wholesale class were broken out by individual wholesale customer. The EES Report states:

> "*FortisBC serves seven customers at the wholesale level. These customers are quite large and have different characteristics, this COSA looks at each wholesale customer individually as a separate class of service.*"

The Company agrees that because each wholesale customer is unique in its operating characteristics, the demands that it places on the electrical system, and the costs that result (as shown by the COSA), treating them individually is appropriate and fair for each member of the class. The principles of interclass equity and cost causation can best be adhered to by this approach as R/C ratios vary even within this group from 69 percent to 103 percent.

As a result, rates were developed for each customer in this class that better reflect its unique characteristics and costs as determined by the COSA. A comparison of current and proposed rates is found in Table 13.0.

The determination of billing demand follows the same rationale and process as with the Large General Service Transmission customer class. Thus, billing demand is proposed to be composed of two elements, the Wires portion and the Power Supply portion:

<u>Wires Charge</u>

The greatest of:

a. 100 percent of the contract Demand Limit, or

b. The maximum demand in kVA for the current billing month.

c. 100 percent of the maximum demand in kVA recorded during the previous eleven month period.

Power Supply Charge

The Power Supply related demand charge is based on the monthly maximum aggregate demand in kVA, as measured by the totalized metering at the Points of Delivery for each municipality.

The rates shown in Table 13.0 below are designed to be revenue neutral with current rates, that is, they will generate the same amount of revenue per customer class. They do not include any rebalancing adjustments. They are however, a more accurate reflection of the manner in which each of these customers imposes costs on the FortisBC system.

Customer impacts from these changes are forecast to be relatively small, with a maximum decrease of 1.1 percent and an increase of 8.6 percent for one Large General Service transmission customer that is below the 5,000 kVA threshold for the rate class.

Table 13.0 - Wholesale Rate Summary

Wholesale Account	**Current Rate (as at Sept. 1, 2009)**			**Proposed Rate**			
	Basic[1]	**Demand**	**Energy**	**Basic**	**Demand**		**Energy**
					Wires Charge	Power Supply	
Kelowna[2]	$1729.08	$7.48/kVa	3.838¢ / kWh	$1729.08	$6.70/kVa	$3.54/kVa	2.290¢ /kWh
Grand Forks	$1729.08	$7.48/kVa	3.838¢ / kWh	$1729.08	$4.76/kVa	$2.85/kVa	1.728¢ /kWh
Summerland	$1729.08	$7.48/kVa	3.838¢ / kWh	$1729.08	$6.74/kVa	$3.60/kVa	2.465¢ /kWh
Penticton	$1729.08	$7.48/kVa	3.838¢ / kWh	$1729.08	$5.52/kVa	$3.17/kVa	1.990¢ /kWh
Nelson[3]	$3952.23	$4.44/kVa	3.779¢ / kWh	$1729.08	$4.59/kVa	$3.28/kVa	1.923¢ /kWh
BC Hydro - Yahk	$1729.08	$7.48/kVa	3.838¢ / kWh	$1729.08	$8.76/kVa	$3.49/kVa	2.555¢ /kWh
BC Hydro - Lardeau	$1729.08	$7.48/kVa	3.838¢ / kWh	$1729.08	$6.82/kVa	$3.01/kVa	2.707¢ /kWh

[1] Current Basic Charge is per point of delivery except for Nelson.
[2] Kelowna, Grand Forks, Summerland, Penticton, and BC Hydro are currently on Rate Schedule 40.
[3] Nelson Hydro is served under Rate Schedule 41.

14.0 Time-of-Use Schedules

14.1 General Discussion

FortisBC proposes that TOU rates will continue to be optionally available to all customer classes (except lighting), and have been adopted by approximately 150 residential, general service and Large General Service customers. The Company has not been in a position to widely promote the use of these time-based rates since the cost of maintaining current TOU metering technology is much larger than flat-rate or energy-block-based metering. Once an AMI system is deployed to all customers, however, the marginal cost of implementing time-based rates becomes negligible.

FortisBC believes it is in the interests of customers to change the current on-peak and off-peak differential ratios as little as possible in this Application, while introducing wires-based contract demand charges for Large General Service transmission and wholesale TOU rates. There are three reasons for the Company's position:

1. The scarcity of interval data makes calculations of on-peak and off-peak rates for most customer classes inaccurate.
2. The need to encourage the efficient use of electricity and reduction of demand points toward a greater on-peak off-peak differential.
3. Existing FortisBC customers are familiar with the Time-of-Use rates as they are, and in many cases they have invested in equipment and processes that allow them to recover their costs appropriately.

As stated in Section 3, FortisBC intends to study possible changes to the structure of time-based rates over the next few years in preparation for making such rates the default for most customer classes.

14.2 Schedule 2 and Schedule 22

In this Application, FortisBC proposes to remove Schedule 2 and 22, which are already closed to new customers. These relatively complex Time-of-Use rates currently have five remaining customers each. These customers will be given the option to move to the standard Time-of-Use schedules (Schedules 2 A and 22 A) or to the appropriate default rate for their customer class (Schedules 1, 20 or 21). If the customers choose to switch to the standard Time-of-Use schedules at the time Schedules 2 and 22 are removed or before, they may apply, within one year, to move to the default rate and be credited any extra cost they have incurred as compared to the default rate.

14.3 Schedule 33

Schedule 33 (Large General Service Transmission, TOU) has been modified in order to gain consistency of treatment with the other rate schedules subject to the use of Contract Demand in their billing treatment. As a TOU rate, Schedule 33 is not subject to the power supply portion of the Demand charge, only the wires-based portion is applicable.

The revenue-to-cost ratio for this rate class is only 24 percent, largely due to significant under collection of wires-related costs. Therefore, the introduction of a full-cost wires-based demand charge with a corresponding downward adjustment of TOU energy rates was not deemed to be in compliance with cost-based or energy efficiency principles. Therefore, in this extraordinary situation, FortisBC proposes to price the wires-based demand charge at $0 per kVA to begin, with all rebalancing increases for this rate schedule to be applied solely by increasing this demand charge. The current Basic Charge and TOU energy rates will be left unchanged to begin, then subject only to any annual general rate increases.

Table 14.3a - Summary of Changes – Rate Schedule 33

Component	Current	Proposed	
		Supply	Wires
Demand Charge	N/A	N/A	$0 per kVA
Basic Charge	$2065.18 monthly	$2065.18 monthly	
Energy Charge	See Below	See Below	

The current Time-of-Use schedule for this customer class effective September 1, 2009 is outlined in the table below.

Table 14.3b - Current Rate Schedule 33

		¢/kW.h
Winter (Nov. - Feb.)	On-Peak Hours: 7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	12.667
	Off-Peak Hours: 10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays	3.589
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	16.897
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	2.792
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	4.054
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	2.135

14.4 Wholesale TOU Rates

Consistent with the treatment of all Large General Service transmission and Wholesale rate schedules, FortisBC proposes to introduce a wires-based demand charge to these rate classes. As with the default Wholesale rate schedules, separate rate schedules for each Wholesale customer have been created.

Existing Time-of-Use energy rates were adjusted by an equal percentage based on the average on-peak and off-peak consumption of the four wholesale customers served under Schedule 40. The customer taking serviced under Schedule 41 was not considered representative of the wholesale class in terms of on-peak and off-peak consumption since it has its own generation capability. No customers are currently served under the wholesale TOU Schedules 42 and 43.

15.0 Green Rates

FortisBC currently has separate Green Power rates for all rate classes. These rates all offer customers the option of paying an additional 1.5 cents per kWh over the published tariff rate, or alternately, to contribute some monetary amount of their choosing toward the purchase of electricity from environmentally desirable technologies. In order to reduce the number of rate schedules in its tariff, the Company is proposing to close all of the existing Green Power schedules and instead provide the option through a Green Power rider, Schedule 85, which will result in exactly the same outcome as current Green Schedules provide. There will be no change in either the service offering or the cost of administering the program. The Company is not proposing to change the manner in which it manages the funds that are collected under the rider. Currently, the funds are collected and held in a separate account until either a physical delivery is scheduled or green credits can be acquired. The new Green Power Rider schedule can be found in Appendix B.

16.0 Schedule 50 – Lighting

Rate Schedule 50 pertains to lighting that is owned and maintained by the customer (Type I), owned by the customer and maintained by FortisBC (Type II), or owned and maintained by FortisBC (Type III). The Company is not proposing any change to the structure of the Lighting rates currently charged on a monthly basis; however maintenance costs have been examined and updated as follows. The changes proposed to Rate Schedule 50 include an update to the labour and material loading rates used to bill customers for the maintenance of Type II lights, as well as a discontinuation of the availability of 100 watt, 150 watt, and 400 watt high pressure sodium lighting fixtures for new lighting connects. FortisBC will continue to maintain currently installed high pressure sodium lighting fixtures at their existing wattages.

A clean and black-lined version of the Tariff Sheets for the Lighting Rate (Schedule 50) is included in the Application as Appendix C.

17.0 Schedule 74 - Extensions

The addition of a customer to the FortisBC system sometimes requires new facilities in addition to a drop service. A drop service is a relatively simple process that is dealt with under the Schedule 82 – New & Upgraded Service Charges.

For the more complicated service additions, FortisBC abides by its Schedule 74 – Extensions. An extension is defined in the Tariff as:

> *"an addition to, or extension of, the Company's distribution system including an addition or extension on public or private property".*

With the filing of the Rate Design Application, FortisBC is proposing a new methodology for calculating the amount that the Company contributes toward the construction of a customer extension.

The proposed method would replace one that has proven to be problematic to administer and relatively difficult for customers to understand.

A clean and black-line version of Schedule 74 – Extensions is included as Appendix D.

17.1 Proposed Schedule 74

FortisBC proposes a system extension methodology where a capital credit or allowance is provided to each new customer (as described in Section 17.2). This capital credit or allowance is predicated on the amount of investment in distribution poles, conductors, and transformers for each rate class covered in the applicable retail rate. Any investment in poles, conductors and transformers needed to provide service to a new customer in excess of this credit or allowance would be paid for upfront as a capital contribution by the new customer.

Distribution system extension charges are designed to be equitable to all customers within a rate class, and across rate classes. The charge should collect enough from a new customer to hold harmless all other customers from the incremental costs of supplying new localized distribution poles, conductors and transformers.

In order to calculate an extension charge the Company must determine how much capital for distribution poles, conductors and transformers is covered by the standard retail tariff (the capital allowance or credit), then charge a new customer the actual cost of new poles, conductors and transformers needed to provide service, less the capital allowance or credit.

For example, if a new customer requires $3,000 worth of new poles, conductors and transformers and the capital allowance or credit is $1,000, the new customer would pay $2,000 in the way of a capital contribution. This capital allowance or credit methodology is simple to calculate, can be updated with each COSA, and holds existing customers harmless from the incremental growth in pole, wire and transformer costs.

The 2009 COSA was used as the basis to calculate the line extension credit for each class of FortisBC customers. The rate-base associated with distribution accounts 364 through 370 were summed for each rate class. Accumulated depreciation and CIAC corresponding with the distribution accounts were then subtracted to provide the net distribution investment for the class. This net amount was divided by the number of customers in the class or the non-coincident kW for the class to determine the appropriate level of credit.

This method achieves the desired goals of holding existing customers harmless from the addition of new customers, while providing a stable and predictable line extension credit.

17.2 Distribution Extension Credits by Rate Class

Applying the methodology described in the preceding section yields the Company contribution amounts found in Table 17.2 below. The customer is responsible for all extension costs over and above these amounts, as well as any applicable connection charges as determined under Schedule 82.

Table 17.2 - Extension Credits

Rate Schedule	Maximum FortisBC Contribution
RS 1, 2A,	$1,765
RS 20, 21	$158 per kW
RS 50 (Type I, Type II)	$19.43 per fixture
RS 60, 61	$1,390

18.0 Schedule 80 – Standard Charges

Tariff Schedule 80 is titled CHARGES FOR CONNECTION OR RECONNECTION OF SERVICE TRANSFER OF ACCOUNT, TESTING OF METERS, AND VARIOUS CUSTOM WORK. This schedule recovers funds for various standard work procedures performed by the Company at the request of a customer.

FortisBC is proposing updates to the standard charges as specified under Schedule 80 to reflect the Company's current cost of providing these services. The derivation of the proposed updates to the standard charges is contained in Appendix E to the Application.

The proposed updates to FortisBC's standard charges are as follows:

Service	Existing Charge	Updated Charge
Meter Connection or Reconnection	$27.00	$100.00
Additional Meter Connection or Reconnection	$6.00	$25.00
Account Setup Charge	$27.00	$15.00
Meter Connection or Reconnection (Overtime Hours)	$55.00	$132.00
Meter Connection or Reconnection (Callout Hours)	$120.00	$339.00
Meter Testing	$25.00	$25.00
Install Temporary Drop Service	$200.00	As per Schedule 82
Transfer to Permanent or Salvage of Temporary Drop Service	N/A	$200.00
Disconnection and Reconnection of Meter	$50.00	$200.00
Relocation of Existing Service	$200.00	$673.00
Returned Cheque Service Charge	$20.00	$19.00
Collection Charge	$50.00	$12.00
Meter Access Charge	$170.00	$152.00 – single phase remote meter $310.00 – poly phase remote meter

Under FortisBC's current tariff, customers are only charged a fee of $6 as an Account Setup Charge when no meter reading is required. When a meter reading is required, the Account Setup Charge becomes $27. Due to the scheduled meter reading dates for particular portions of FortisBC's service territory, certain premises will generally always incur the lesser of the two current Account Setup Charges due to the fact that the premises scheduled meter reading date always corresponds approximately with the end/start of the month, which also corresponds with the period when the majority of new account setups and account transfers occur. In order to treat all customers fairly, the Company is proposing to update its Standard Charges to include one Account Setup Charge for all new account setups or account transfers.

FortisBC expects that the increase in annual revenue resulting from the proposed updates to the Standard Charges would be approximately $0.176 million.

19.0 Schedule 81 – Time-of-Use Charges

FortisBC is proposing to cancel Schedule 81, along with the corresponding elimination of the incremental meter costs charged to customers that request service under a Time-of-Use rate schedule. Similar to FortisBC's Net Metering Rate Schedule 95, the Company is proposing that customers that opt for billing under a Time–of-Use rate schedule will no longer be required to pay the incremental meter costs to support such metering. As the customer is no longer required to bear the incremental meter costs, the Company has removed the thirty-six month availability guarantee from each TOU tariff sheet. This provision was in place to ensure that the customer received full value from the expenditure. Additionally, Schedule 81 also contains charges related to a load analysis service. As the Company has seen virtually no requests from customers for use of this service, FortisBC is proposing to eliminate this charge in conjunction with the cancellation of Schedule 81. FortisBC will still provide a load analysis service to customers upon special request.

20. Schedule 82 – New & Upgraded Service Charges

22.1 Summary and Rationale for changes

FortisBC is proposing updates to the connection charges for new/upgraded services to reflect FortisBC's current costs for typical connections. The derivation for these updated costs is contained in Appendix F to the Application. The existing charges for installation of new/upgrade services as set out in Schedule 82 do not differentiate between overhead and underground installations. FortisBC is proposing to update

Schedule 82 to differentiate the charges for new/upgraded services to reflect the actual costs associated with typical single phase overhead and underground installations. The charges for new/upgraded single phase services that FortisBC is proposing are as follows:

Service Type - Size	Existing Charge	Proposed Charge
Overhead – 200 amps or less	100 Amp - $200 200 Amp - $500	$533
Overhead – 400 amps	$1100	$937
Underground – 200 amps or less	Actual costs	$565

21.0 Schedule 90 – Energy Management

21.1 Summary and Rationale for Changes

The Energy Management Tariff, Schedule 90, governs the provision of energy management service to all direct FortisBC customers and its indirect customers served directly by FortisBC wholesale customers. The Schedule has been re-written in order to:

- clarify that service is available to all FortisBC customers (not only residential) and its municipal wholesale customers;
- clarify that demand-side management applies to the efficient timing of the use of energy (demand response) in addition to efficient consumption of energy (conservation)
- remove prescriptive program measures, allowing programs to be modified more dynamically;
- ensure the Company will maintain an easily accessible list of program measures for customers;
- reflect compliance of the Schedule with applicable DSM regulations pursuant to the Utilities Commission Act;

- prudently cap monetary incentives paid for DSM measures (in compliance with DSM regulations); and
- ensure monetary incentives are disbursed prudently, with the ability to recover monetary incentives from Customers where required.

The Company will develop DSM programs on an ongoing basis in response to customer needs, regulatory and legislative requirements and Resource Plan drivers. These plans will be reviewed by the FortisBC Demand Side Management Committee, which comprised of a variety of customer and interest group stakeholders. The Company will specify the type of programs it intends to offer in Capital Expenditure Plan filings, and the program details will be available at all times on the FortisBC website, as well as in print form. The current and amended versions of Schedule 90 are attached as Appendix G. Due to the extensive changes to the schedule, they are reproduced in their entirety rather than as a black-line document.

22.0 Terms and Conditions

22.1 Summary and Rationale for Changes

The Terms and Conditions contained in the FortisBC Electric Tariff govern the Company-Customer relationship and provide the provisions under which the customer receives service from FortisBC. The Customer, by taking service, agrees to abide by the provisions within the Terms and Conditions. As part of the Rate Design Application, the Terms and Condition received an internal review which prompted a number of changes, deletions, and additions to the current sheets. In most cases, changes were attributable to the alignment of the language contained in the Terms and Conditions with current Company policy, or clarification of certain items within the Terms and Conditions that reports from the field have indicated would prove useful for customer interactions. A clean version and black-lined version of the new Tariff Sections contained in the Terms and Conditions is attached as Appendix H. All proposed changes from the current approved Terms and Conditions have been tracked in the black-lined version except for the following:

- Formatting and numbering changes;

- Capitalization of all defined terms; and
- Replacement of all gender-specific references with gender-neutral references.

FortisBC is proposing the following changes to the Terms and Conditions:

- Description of "Point of Delivery" moved from Clause 3.1 to list of Definitions;
- Addition of definition for "Premises" for clarity as it appears throughout the Terms and Conditions (Clauses 2-4);
- Addition of definitions for "Suspension" and "Termination" for clarity as they appear throughout the Terms and Conditions (Clauses 2.2(c), 2.3, 5.1, 8.1, 8.2, 8.3, and 11.5);
- Modification of the definition of "service" to include services provided by FortisBC other than the supply of electricity;
- Elimination of differentiation between Applications for Residential Service and Applications for Non-Residential Service in Clause 2.1;
- Clarification that all applicants, regardless of class of service being applied for, may be required to sign an application form for service, with a contractual relationship being established regardless of whether a signed application has been obtained, except in the case of theft of Services;
- Clarification that the Company assumes no liability for any loss, injury, or damage suffered by any Customer by reason of a refusal to provide Service;
- Clarification that Customers shall not transfer or assign a Service application or contract without the written consent of the Company;
- Clarification of Customer obligation to pay charges for the minimum required term of Service;
- Clarification of Security Deposit requirements (Clause 2.3);
- Language modification to generally incorporate payment of all required charges and receipt of all required documents prior to connection of service (Clause 2.4);
- Addition of language asserting the right of the Company to salvage facilities not used in excess of twelve consecutive months (Clause 2.6);
- Clarification that Service supplied to the same Customer at more than one Point of Delivery shall be permitted only at the discretion of the Company (Clause 3.1);

- Clarification that Customers shall only be entitled to interest on a contribution received by the Company where the delay in taking Service is not attributable to the Customer (Clause 3.3);
- Increase in threshold requiring the provision of a revenue guarantee requirement for non-residential customers from $1,000 to $5,000 for Company construction and installation cost for each customer supplied (Clause 3.4);
- Modification of 3 phase pole-mounted transformer voltages from 500 kVa to 300 kVa to reflect standard FortisBC practice (Clause 3.5);
- Clarification on Customer and Company financial responsibility for the supply of non standard voltages as well as the availability of transformer discounts for Customer owned transformation (Clause 3.5(b)(c));
- Clarification on the Company option to generally provide written consent for re-metered, sub-metered or resold electricity (Clause 3.7);
- Addition of language reserving Company right to reject applications for multiple meter residential premises, and requirement for Customers with multiple meter residential Premises to take Service under a single rate unless otherwise approved by the Company (Clause 4.3.2);
- Removal of language waiving Company's right to levy initial service costs for a separately metered commercial areas when carried on in a residential Premise (Clause 4.3.3);
- Clarification that meters for all customers will be selected at the discretion of the Company (Clause 5.4);
- Incorporation of language permitting the Company to require, at anytime, the installation of a meter for an unmetered service (Clause 5.5);
- Clarification on the Company option to generally determine the interval between consecutive meter readings (Clause 6.1);
- Modification of language from a list of specific taxes to taxes and assessments generally (Clause 6.4);
- Clarification on Company and Customer responsibilities in maintaining an acceptable power factor, as well as treatment of leading power factor (Clause 7.4);

- Removal of duplicate reference permitting the Company to suspend service to Customers that fail to take remedial steps as required by the Company to correct a disturbance (Clause 7.5);
- Clarification on the circumstances under which the Company may suspend the supply of electricity (Clause 8.2);
- Clarification on Customer obligations regarding termination of service (Clause 8.3):
- Clarification on Customer obligation to provide safe and ready access, rights of way, easements and any applicable permits (Clause 9.1);
- Clarification on the Customer financial responsibility for protection and control equipment and the installation of synchronizing equipment for parallel generation (Clause 10.1);
- Clarification on the payment of interest for deposits and other refundable payments to Customer(Clause 11.3);
- Clarification on the credit of interest due on December 31st to the Customer account (Clause 11.3);
- Modification of language to allow reconciliation of Equal Payment Plan on the anniversary date of the plan, clarification of the Customer obligation to establish satisfactory credit with the Company, as well as the addition of language permitting the Company to modify or cancel the Equal Payment Plan Service at anytime (Clause 11.5);
- Clarification on Customer financial responsibility for any expense incurred by the Company as a result of Customer owned parallel generation facilities (Clause 10.1); and
- Incorporation of various minor changes to update references to applicable legislation and/or government authorities, or to improve clarity of language.

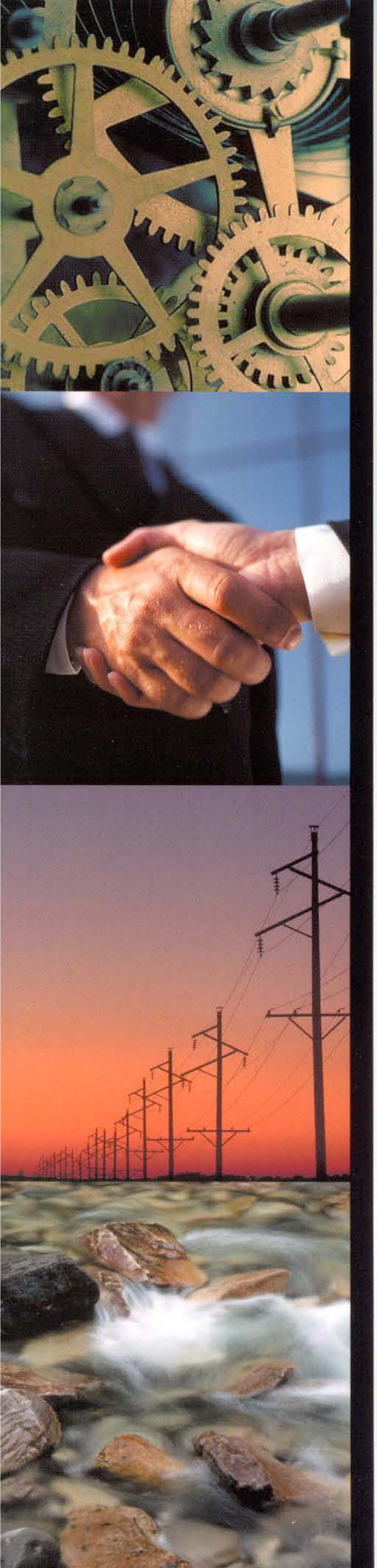
22.2 Security Deposits

FortisBC is proposing amendments to Section 2.3 of the Terms and Conditions governing security deposits to provide clarity and reflect current policy around security deposit requirements for customers. The Company is not proposing any changes to the basis for calculating the amount of the required security deposit.

FortisBC is proposing additional language to Section 2.3 to clarify that the deposit for customers with over 200 kVA will be returned once their accounts are discontinued and paid in full. Previously, the language in the Terms and Conditions only specified the conditions for refund of a security deposit for customers with less than 200 kVA of demand. The proposed clarification clearly states the conditions by which security deposit refunds are available. In addition, the Company has simplified the language governing when a security deposit is required.

Schedule of Appendices

Appendix A	EES Consulting Report – ELECTRIC COST OF SERVICE STUDY
Appendix B	Amended Rate Schedules – Electricity Supply
Appendix C	Schedule 50 - Lighting
Appendix D	Schedule 74 - Extensions
Appendix E	Schedule 80 – Charges for Connection or Reconnection of Service of Account, Testing of Meters and various Customer Work
Appendix F	Schedule 82 – Charges for Installation of New/Upgraded Services
Appendix G	Schedule 90 – Energy Management
Appendix H	Terms and Conditions
Appendix I	COSA and RDA – FortisBC Public Consultation Report



FortisBC

EES Consulting

ELECTRIC COST OF SERVICE STUDY

September 30, 2009

September 30, 2009

Mr. Dave Bennett
Mr. Dennis Swanson
FortisBC
1975 Springfield Road, Suite 100
Kelowna, BC V1Y 7V7

SUBJECT: Electric Cost of Service Study

Gentlemen:

Please find attached the Electric Cost of Service Study prepared by EES Consulting. The conclusions and recommendations contained within this report are based upon industry practice and generally accepted rate setting principles.

This study has been developed through the mutual assistance of FortisBC staff. The findings, conclusions and recommendations of this report provide the basis for the development of fair and equitable rates for FortisBC.

Thank you for the opportunity to assist FortisBC in this rate setting process. Please contact me directly if there are any questions about the subject analyses.

Very truly yours,

Gary Saleba
President

570 Kirkland Way, Suite 200
Kirkland, Washington 98033

Telephone: 425 889-2700 Facsimile: 425 889-2725

A registered professional engineering corporation with offices in
Kirkland, WA; Portland, OR; Indio, CA; and Bellingham, WA

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Executive Summary

EES Consulting, Inc. (EES Consulting) was retained by FortisBC to perform a comprehensive electric cost of service analysis (COSA). The COSA is one of the major inputs that will be used in developing proposed rates for FortisBC. Basically the COSA takes the revenue requirements established for the utility and allocates costs across the various customer classes, with the results used to ensure that proposed rates are fair, equitable and not unduly discriminatory.

FortisBC last filed a comprehensive COSA in 1997 and has been working under a Performance-Based Ratemaking approach since that time. The methodology from the 1997 COSA was considered as a starting point when performing the 2009 COSA. Changes that have occurred over the past 12 years in terms of the FortisBC system, changes in the overall electric industry, and trends in utility ratemaking were all considered when developing this COSA.

This COSA is being filed prior to a full rate application and proposed rates are not being presented at this time. It is expected that this COSA will be the starting point when FortisBC files its rate design application later this year.

Overview of the COSA

The COSA takes the revenue requirement for the utility and attempts to equitably allocate those costs to the various customer classes of service (i.e., residential, commercial, etc.). This analysis provides a determination of the level of revenue responsibility of each class of service and the adjustments required to meet the cost of service.

There are three basic steps to follow in developing a COSA, namely:

- Functionalization
- Classification
- Allocation

Functionalization separates costs into major categories that reflect the utility's plant investment and different services provided to customers. The primary functional categories are production, transmission, distribution, and general.

Classification determines the portion of the cost that is related to specific cost-causal factors, such as those that are demand-related, energy-related, or customer-related. Production costs are related to supplying power to customers on the system. Production facilities are designed and operated to meet system peak demands and total energy requirements. Transmission costs are related to the bulk transfer of power to load centres on the system. These transmission facilities are typically designed and operated to meet system peak demand requirements. The distribution system is designed to extend service to all customers attached to the system and to meet the peak load capacity requirement of each customer.

Allocation of costs to specific customer classes is based on the customer's contribution to the specific classifier selected. For instance, demand-related costs are allocated to a customer group using that customer group's contribution to the particular measurement of system demand, whether coincident peak, non-coincident peak or some variation determined to be appropriate for the particular cost item. An analysis of customer requirement, loads, and usage characteristics is completed to develop allocation factors reflecting each of the classifiers employed within the COSA. The analysis may include an evaluation of the system design and operations, its accounting and physical asset records and detailed studies of customer load data.

FortisBC Revenue Requirement and Rate Base

A revenue requirement analysis compares the overall revenues of the utility to its expenses and determines the overall adjustment to rate levels that is required. The revenue requirement is the starting point of the COSA, with all items in the revenue requirement allocated across the various customer classes. The rate base for the utility is also an important component when developing the revenue requirement. Capital spending is included in the rate base. Only approved capital expenditures are included in the rate base. The allowed return on rate base is a major component of the revenue requirement.

For purposes of this COSA, the 2009 Forecast Revenue Requirement for FortisBC was used. This revenue requirement was approved by the BCUC on December 11, 2008 under Order G-193-08. The total approved revenue requirement is $233.1 million, which includes an offset of $4.9 million in revenues from sources other than electric rates. In addition, the added costs associated with a recent increase in tariffs from BC Hydro have been incorporated. FortisBC will be passing through those added costs into rates during the latter part of 2009 consistent with Commission Order G-193-08.

The accompanying rate base associated with the 2009 revenue requirement is $908 million. This is based on a mid-year basis between 2008 and 2009. The rate base reflects gross plant of $1.2 billion, which is offset by accumulated depreciation and customer contributions. Distribution makes up 46% of gross plant, followed by 29% for transmission, 13% for power production and 12% for general plant.

FortisBC's projected customers and sales per class, as agreed upon in the negotiated settlement, are presented in Schedule 8.1 of Appendix A. FortisBC is projecting total customers of 111,913 by year-end 2009 and gross energy consumption of 3.4 million MWh. Residential customers make up 87% of the total number of customers and nearly 40% of energy sales. Wholesale customers make up another 30% of energy, with the remaining 30% related to commercial, industrial and other retail classes.

The peak is forecast to occur in the winter at a level of 701 MW. A peak of 560 MW is expected during the summer months.

Major Assumptions of the COSA

The following provides some of the major assumptions and underlying data used in conducting the COSA for FortisBC.

Customer classes of service refer to the arrangement of customers into groups that reflect common usage characteristics or facility requirements. FortisBC serves seven customers at the wholesale level. Because several of these customers are quite large and have different characteristics, this COSA looks at each wholesale customer individually as a separate class of service.

The classes of service used within this study were as follows:

- Residential
- Small General Service (Rate 20)
- General Service Secondary (Rate 21)
- Industrial Primary (Rate 30)
- Industrial Transmission (Rate 31)
- Industrial Transmission TOU (Rate 33)
- Irrigation
- Lighting
- Wholesale (7 Individual Customers)

Key assumptions include:

- Forecast year 2009 was selected as the test period for the allocation of costs.

- The 2009 forecast revenue requirement as approved for the negotiated settlement was used, with an adjustment made for the BC Hydro wholesale tariff increase.

- Monthly power supply costs were classified as demand and energy on the basis of wholesale Rate 3808 from BC Hydro and allocated on a monthly basis.

- Distribution plant was classified based on a “minimum system” approach. A peak load carrying capability (PLCC) credit was applied to correct for the inherent double-counting of demand costs with the standard minimum system study.

- Demand-related transmission costs were allocated using the 2 CP (coincident peak) method (sum of 2 winter and 2 summer peaks).

- For wholesale and Rate 31/33 customers, the contracted demand by customer was used for allocating transmission and distribution costs.

These assumptions are discussed in greater detail throughout this report.

Summary of Results

Given the above assumptions regarding the COSA, the various costs were classified and allocated to the customer classes of service. This section provides the results of the COSA in summary form. Detailed tables reflecting all of the COSA details can be found in Appendix A.

The total rate base of $908.0 million has been classified into various components and allocated to customer classes as found in 4.3 of Appendix A. The split by customer class can be summarized as follows:

	Millions
Residential	$428.3
Other Retail	$250.3
Wholesale	$229.4
Total System	$908.0

The total revenue requirement of $235.4 million has been classified into various components and allocated to customer classes as found in Schedule 3.3 of Appendix A. The results are summarized as follows:

	Millions
Residential	$108.7
Other Retail	$ 66.6
Wholesale	$ 60.2
Total System	$235.4

The allocated revenue requirement can be compared to the following projections of revenue for 2009:

	Millions
Residential	$106.0
Other Retail	$ 77.7
Wholesale	$ 49.8
Total Revenues	$233.4

A summary comparison of the revenues at present rates, allocated cost of service and resulting revenue to cost ratios can be found in Schedule 1.1 of Appendix A. The resulting revenue to cost ratios are as follows:

	Revenue to Cost Ratio	Adjusted Revenue to Cost Ratio
Residential	97.5%	98.3%
Small General Service (20)	112.4%	113.4%
General Service (21)	137.8%	138.9%
Industrial Primary (30)	121.3%	122.4%
Industrial Transmission (31)	108.9%	109.9%
Industrial Transmission TOU (33)	23.3%	23.5%
Lighting	81.2%	81.9%
Irrigation	77.9%	78.6%
Kelowna Wholesale	89.2%	89.9%
Penticton Wholesale	77.3%	78.0%
Summerland Wholesale	95.8%	96.6%
Grand Forks Wholesale	67.5%	68.1%
BC Hydro Lardeau Wholesale	100.9%	101.8%
BC Hydro Yahk Wholesale	102.7%	103.5%
Nelson Wholesale	79.3%	80.0%
Total	99.1%	100.0%

Given a number of assumptions, the results show that when using present rates FortisBC is collecting insufficient revenues to meet current costs for 2009. The amount is roughly 1% less than projected revenue requirements due to an adjustment of $2.3 million related to a change in rate 3808 from BC Hydro. While FortisBC adjusted rates September 1st to collect the shortfall associated with this wholesale rate change, the COSA was completed prior to this adjustment. Revenues for the COSA were adjusted so that revenues would match the revenue requirements. This adjustment better reflects the deviations from 100% that occur between the various customer classes. The Adjusted Revenue to Cost Ratios will be used to determine the need for interclass adjustments.

For the residential class, the revenue to cost ratio is very close to 100%. Many classes are undercollecting by a significant amount, including industrial transmission TOU, lighting and irrigation plus most of the wholesale customers. The two general service classes, industrial primary, industrial transmission and Lardeau and Yahk are all overcollecting.

The revenue to cost ratios and unit costs resulting from the COSA were used as inputs in developing the rates proposed in the Rate Design Application. The rate design for several of the classes is adjusted to better meet goals of the utility. The mechanism for rate rebalancing between classes is also described in the Rate Design Application and relies upon the revenue to cost ratios in the COSA.

Overview and Basis for the COSA

EES Consulting, Inc. (EES Consulting) was retained by FortisBC to perform a comprehensive electric cost of service analysis (COSA). The COSA is one of the major inputs that will be used in developing proposed rates for FortisBC. Basically the COSA takes the revenue requirements established for the utility and allocates costs across the various customer classes, with the results used to ensure that proposed rates are fair, equitable and not unduly discriminatory.

FortisBC last filed a comprehensive COSA in 1997, with that rate proceeding resulting in a negotiated settlement. With the exception of 2005, the utility has been working under a Performance-Based Ratemaking approach since that time. The methodology from the 1997 COSA was considered as a starting point when performing the 2009 COSA. Changes that have occurred over the past 10 years in terms of the FortisBC system, changes in the overall electric industry, and trends in utility ratemaking were all considered when developing this COSA.

This COSA is being filed prior to a full rate design application and is not directly used for designing proposed rates at this time. It is expected that this COSA will be a factor, along with updated revenue requirements for the utility, when FortisBC files its rate design application later in the year.

This report is organized such that it follows the steps taken in analyzing and developing FortisBC's COSA. Contained in this section is a generic discussion of the theory and financial principles behind setting rates. Also included in the section is a summary of the underlying financial results used as the basis for the COSA. The next section discusses the COSA and the results of that process, including the methodology used to allocate costs between customer classes. The final section provides a summary of the COSA results.

A technical appendix is attached at the end of this report that provides the details associated with the COSA for FortisBC. The schedules contained in Technical Appendix A are referenced throughout the report. Appendices B and C provide more details associated with the COSA inputs.

Overview of the COSA

The setting of electric utility rates that are "fair and equitable" is a complex process. This process is directed, however, by generally accepted methodologies that can be used as a guide in developing FortisBC's electric rates. At the same time, there are often a number of financial principles or guidelines that must be taken into consideration during this process. Therefore, the setting of electric rates that are "fair and equitable" is an integration of these generally accepted methodologies and any related financial policies or specific policy considerations from FortisBC.

The COSA analysis takes the revenue requirement for the utility and attempts to equitably allocate those costs to the various customer classes of service (i.e., residential, commercial). This analysis provides a determination of the level of revenue responsibility of each class of service and the adjustments required to meet the cost of service.

Costs are allocated to the various customer classes of service based upon a fair and equitable methodology that reflects the cost-causal relationships for the production and delivery of the services. A COSA begins by "functionalizing" a utility's revenue requirement as power supply, transmission, distribution and customer. Next, the functionalized costs are "classified" to demand-, energy-, and customer-related component costs. Demand-related costs are those that the utility incurs to meet a customer's maximum instantaneous usage requirement, and is usually measured in kilowatts (kW). Energy-related costs are those that vary directly with longer periods of consumption and are usually measured in kilowatt-hours (kWh). Customer-related costs are those that vary with the number and type of customers served.

These three component costs are then "allocated" to each class of service based upon the most equitable method for each specific cost. At that point, the revenue requirement has been allocated to each class of service and a determination of the necessary revenue adjustments between classes of service can be made. The final step is the calculation of demand, energy and customer unit costs for each class of customer or rate schedule. These unit costs provide valuable input into the rate design process.

FortisBC Revenue Requirement

A revenue requirement analysis compares the overall revenues of the utility to its expenses and determines the overall adjustment to rate levels that is required. The revenue requirement is the starting point of the COSA, with all items in the revenue requirement allocated across the various customer classes. The rate base for the utility is also an important component when developing the revenue requirement. Only approved expenditures are included in the rate base. The allowed return on rate base is a major component of the revenue requirement.

For purposes of this COSA, the 2009 Forecast Revenue Requirement for FortisBC was used. This revenue requirement was approved by the BCUC on December 11, 2008 under Order G-193-08. The total approved revenue requirement is $233.1 million, which includes an offset of $4.9 million in revenues from sources other than electric rates. The following summarizes the approved revenue requirements forecast for 2009. Consistent with Commission Order G-193-08, an adjustment of $2.3 million was added to the approved revenue requirement to reflect the wholesale tariff increase from BC Hydro.

	Millions
Purchased Power	$ 69.5
O&M Expenses	$ 49.5
Return, Depreciation & Taxes	$119.0
Other Revenue	$ - 4.9
Net Revenue Requirements	$233.1
Adjustment for BC Hydro increase	$ 2.3
Adjusted Revenue Requirements	$235.4

Just over 50% of the revenue requirement is related to return on rate base, taxes and depreciation. Another 30% is for purchased power expenses. The remaining 20% is for O&M expenses of the utility. The approved revenue requirement is the basis for the rates that are currently in place for FortisBC. Schedule 3.1 in Appendix A provides a summary of the approved revenue requirement.

Revenue requirements at the time of the 1997 COSA were $120.5 million and were broken down as 32% purchased power costs, 25% O&M costs and 43% for return, depreciation and taxes. Return, depreciation and taxes have become a larger component of costs for FortisBC, while O&M costs have become a smaller percent of the total.

This COSA is based on a forecast test year approved in 2009 and has not been updated to reflect any actual costs, sales or revenues for 2009 year-to-date other than the BC Hydro tariff increase. The use of a forecast year allows for a more standardized basis as it assumes normal weather conditions and stable economic conditions, and does not include any extraordinary costs for the year.

Rate Base

The accompanying rate base associated with the 2009 revenue requirement is $908 million. This is based on a mid-year basis between 2008 and 2009. The rate base reflects gross plant of $1.2 billion, which is offset by accumulated depreciation and customer contributions. Distribution makes up 46% of gross plant, followed by 29% for transmission, 13% for power production and 12% for general plant. The mid-year rate base is summarized as follows:

	Millions
Total Gross Plant	$1,233.0
Less Accumulated Depreciation	$ -289.7
Less Customer Contributions	$ -92.4
Working Capital, Deferred & Other	$ 57.1
Total Rate Base	$ 908.0

Schedule 4.1 of Appendix A provides the detailed rate base for FortisBC by account used for the COSA.

The 2009 rate base of $908.0 million compares to the 1997 rate base of $239.6 million. In 1997 the split was 57% distribution, 24% transmission, 9% production and 10% general plant. Distribution plant has grown the most of the various rate base functions.

Projected Load Forecast

FortisBC's projected customers and sales per class, as agreed upon in the negotiated settlement, are presented in Schedule 8.1 of Appendix A. FortisBC is projecting total customers of 111,913 by year-end 2009 and gross energy consumption of 3.4 million MWh. Residential customers make up 87% of the total number of customers and nearly 40% of energy sales. Wholesale customers make up another 30% of energy, with the remaining 30% related to commercial, industrial and other retail classes.

	GWh
Residential	1,222
Other Retail	964
Wholesale	921
Total System	3,107

The peak forecast is expected to occur in the winter at a level of 701 MW. A peak of 560 MW is expected during the summer months.

In 1997 the total system energy was 2,916.1 GWh forecast for the year. This reflects an average annual increase of 1.5% per year. Wholesale sales have increased much less than the retail classes combined.

Projected Revenues

FortisBC provided revenues by class for the 2009 Revenue Requirement. These revenues were calculated using an average rate for each class, consistent with the method used in past years. For purposes of the COSA, revenues were calculated under each tariff based on the billing determinants for each class, with the following results:

	Millions
Residential	$106.0
Other Retail	$ 77.7
Wholesale	$ 49.8
Total Revenues	$233.4

Using the revenues calculated at approved rates for the 2009 approved revenue requirement filing of $222.8 million and adding the allowed 4.6% 2009 rate increase results in projected revenues of $233.1 million. This is 0.1% lower than what is calculated for purposes of the COSA. FortisBC believes the updated calculation is appropriate for projecting revenues for the COSA and for future rate filings. Schedule 8.1 of Appendix A provides the revenues projected for each class.

Cost of Service Analysis

The objective of the COSA is to analyze costs and equitably assign those costs to customers commensurate with the cost of serving those customers. The founding principle of cost allocation is the concept of cost-causation. Cost-causation evaluates which customer or group of customers causes the utility to incur certain costs by linking system facility investments and operating costs to serve certain facilities to the services used by different customers. This section of the report will discuss the general approach used to perform the FortisBC COSA, using the FortisBC approved 2009 revenue requirement, and provide a summary of the results.

COSA Overview and General Principles

A COSA allocates the costs of providing utility service to the various customer classes served by the utility based upon the cost-causal relationship associated with specific expense items. This approach is taken to develop a fair and equitable assignment of costs to each customer class so that customers pay for the costs that they cause. Because the majority of costs are not incurred by any one type of customer, the COSA becomes an exercise in spreading joint and common costs among the various classes using factors appropriate to each type of expense. The COSA is the second step in a traditional three-step process for developing service rates. The first step is the development of the test period revenue requirement for the utility, which is the starting input for the COSA. The COSA spreads the revenue requirement across the various customer classes, creating per unit costs by class. In the third step, rates are designed for each customer class, with per unit costs being one consideration in setting the appropriate rate levels.

A COSA can be performed using embedded costs or marginal costs. Embedded costs generally reflect the actual costs incurred by the utility and closely track the costs kept in its accounting records. Marginal costs reflect the cost associated with adding a new customer, and are based on costs of facilities and services if incurred at the present time. While marginal costs can be valuable for designing rates in certain instances, marginal costs are generally higher than embedded costs. Therefore, the use of a marginal COSA usually requires that all costs be scaled back to a level equal to the embedded cost revenue requirement established using actual or projected costs from an "accounting" perspective.

This study uses an embedded COSA as its standard methodology. Therefore, FortisBC's embedded cost revenue requirement and existing rate base investment are used in developing the COSA results.

There are three basic steps to follow in developing a COSA, namely:

- Functionalization
- Classification
- Allocation

Functionalization separates costs into major categories that reflect the utility's plant investment and different services provided to customers. The primary functional categories are production, transmission, distribution, and general.

Classification determines the portion of the cost that is related to specific cost-causal factors, such as those that are demand-related, energy-related, or customer-related. Production costs are related to supplying power to customers on the system. Production facilities are designed and operated to meet system peak demands and total energy requirements. Transmission costs are related to the bulk transfer of power to load centres on the system. These transmission facilities are typically designed and operated to meet system peak demand requirement. The distribution system is designed to extend service to all customers attached to the system and to meet the peak load capacity requirement of each customer.

Allocation of costs to specific customer classes is based on the customer's contribution to the specific classifier selected. For instance, demand-related costs are allocated to a customer group using that customer group's contribution to the particular measurement of system demand, whether coincident peak, non-coincident peak or some variation determined to be appropriate for the particular cost item. An analysis of customer requirements, loads, and usage characteristics is completed to develop allocation factors reflecting each of the classifiers employed within the COSA. The analysis may include an evaluation of the system design and operations, its accounting and physical asset records, customer load data, and special studies.

While this section does not address the design of rates, it is important to note that the COSA results will be one of the considerations when the process of designing rates for various customer classes begins.

Major Assumptions of the Cost of Service Analysis

While FortisBC used the 1997 COSA as a starting point for 2009, there have been a number of changes to the Company's utility infrastructure, customers' usage patterns and shifts in government policy since the 1997 COSA. Some of these changes have an impact on the major assumptions for 2009.

FortisBC has made significant investments into its electrical infrastructure increasing its gross assets by more than 200% since 1997. Much of the investment was made to accommodate ongoing capacity constraints on the FortisBC transmission and distribution systems. In addition, customer peak electrical usage has been growing quicker in the summer than in the winter, since 1997, due in part to increased air conditioning load. Another significant change since 1997 is the extent to which FortisBC has become exposed to peak electrical demand. From a government policy perspective, changes to the Utilities Commission Act and the introduction of the 2007 BC Energy Plan have also necessitated consideration in FortisBC's 2009 COSA.

The following provides some of the major assumptions and underlying data used in conducting the 2009 COSA for FortisBC.

Customer classes of service refer to the arrangement of customers into groups that reflect common usage characteristics or facility requirement. FortisBC serves seven customers at the wholesale level. Because several of these customers are quite large and have different characteristics, this COSA looks at each wholesale customer individually as a separate class of service.

The classes of service used within this study were as follows:

- Residential
- Small General Service (Rate 20)
- General Service Secondary (Rate 21)
- Industrial Primary (Rate 30)
- Industrial Transmission (Rate 31)
- Industrial Transmission TOU (Rate 33)
- Irrigation
- Lighting
- Kelowna Wholesale
- Penticton Wholesale
- Summerland Wholesale
- Grand Forks Wholesale
- BC Hydro Lardeau Wholesale
- BC Hydro Yahk Wholesale
- Nelson Wholesale

Compared to the 1997 COSA, this COSA broke down the industrial class into those served at primary vs. transmission voltage. In addition, the wholesale customers were looked at individually.

Key assumptions include:

- Forecast year 2009 was selected as the test period for the allocation of costs.

- The 2009 forecast revenue requirement as approved for the negotiated settlement was used, with an adjustment made for the BC Hydro wholesale tariff increase.

- Monthly power supply costs were classified as demand and energy on the basis of wholesale Rate 3808 from BC Hydro and allocated on a monthly basis to in part account for the increased exposure to peak demand.

- Distribution plant was classified based on a “minimum system” approach. A peak load carrying capability (PLCC) credit was applied to correct for the inherent double-counting of demand costs with the standard minimum system study.

- Demand-related transmission costs were allocated using the 2 CP method (sum of 2 winter and 2 summer peaks) to take the significance of the growth in summer peak into consideration.

- For wholesale and Rate 31/33 customers, the contracted demand by customer was used for allocating transmission and distribution costs to take transmission capacity constraints into consideration.

These assumptions are discussed in greater detail throughout this report. Given the key assumptions, the COSA could be completed. The following sections provide the specific treatment of items within the COSA, along with the results of the COSA.

Functionalization of Costs

The first step in the COSA process is to functionalize the rate base and revenue requirement. Functionalization is the separation of cost data into the functional activities performed in the operation of a utility system (i.e., power supply, transmission, distribution and customer service). Functionalization was accomplished using FortisBC’s system of accounts for both the rate base and revenue requirement, which largely segregates costs in this manner. Revenue requirement items associated with certain types of plant were generally treated in the same manner as the corresponding plant account.

The specific functions used for FortisBC’s COSA are defined below. The functions generally follow standard cost of service approaches.

- ***Power Supply.*** The power supply function includes both rate base and expense items associated with generation owned by the utility and power purchase expenses.

- ***Transmission.*** The transmission function includes those costs for operating and maintaining the transmission lines, poles, towers, substations, etc., used to deliver power to the distribution network’s load centres. Transmission is generally those lines measured at 35,000 volts and above.

- ***Distribution.*** Distribution services include all services required to move the electricity from the point of interconnection between the transmission system and the distribution system to the end user of the power. These include substations, poles, primary and secondary poles and conductors, line transformers, services and meters as well as customer costs and any direct assignment items. Customer-related services are also included within the distribution function, even for those customers served at the transmission voltage level. These services include meter reading, billing, collections, advertising, etc. Primary distribution is at voltages of 750 to 35,000 volts while secondary distribution has voltages of 750 volts or less.

The two areas where there generally are differences in functionalization among utilities are in the treatment of general plant and administrative and general (A&G) expenses. Typically, general plant is considered a separate category in the rate base. Functionalization is performed by spreading the general plant rate base across the three other functions. On the expense side, A&G costs are treated in much the same way. Generally, they are treated as a separate expense category that can be spread across the primary functions.

Functionalization of Rate Base

FortisBC has $162.2 million in hydraulic production rate base (accounts 330 to 336). These items are related to the Kootenay River Plants owned by FortisBC. All of these accounts are functionalized to power supply.

FortisBC has $351.7 million in transmission rate base (accounts 350 to 359) which is all functionalized as transmission.

Distribution rate base is the biggest functional component of the FortisBC system and includes $571.1 million in rate base (accounts 360 to 373). These costs are all functionalized as distribution.

General plant for FortisBC is $148.0 million and includes computer and office equipment, transportation equipment and other items that are used by employees serving all three functional areas. To split general plant costs into the various functions, labour ratios were used, which is the same as for the 1997 COSA. The labour ratios reflect the number of full-time equivalents assigned to each of the three functions, with a result of 37% generation, 25% transmission and 38% distribution.

Gross plant for FortisBC is $1.23 billion. Accumulated depreciation is equal to $289.7 million, resulting in a net plant amount of $943.3 million. Accumulated depreciation was further split into production, transmission, distribution and general plant. Each of the accumulated depreciation accounts was treated in the same fashion as the corresponding gross plant accounts.

Working capital for FortisBC was set at $7.02 million, which was added to rate base along with an adjustment for capital additions of $10.9 million. Each of these items was functionalized on the same basis as all O&M costs. Working capital is set aside to cover the time lag between when costs are incurred and when revenue is received from customers. Because O&M and purchased power costs are the primary bills paid by the utility, O&M costs was considered to be a reasonable method for functionalizing and allocating working capital costs. The adjustment for capital additions is similar to working capital was therefore treated in the same manner as working capital.

The rate base was reduced by $92.4 million in customer contributions. All of these contributions were for items at the distribution level and were assigned to functions on the basis of poles, conductors and transformers.

Other rate base items totaled $39.3 million and were separated out by function. The largest item in this category is $25 million of plant acquisition adjustment and deferred costs, which were treated on the same basis of Gross Plant prior to General Plant. Also included is $6.9 million of construction work in progress (CWIP) that does not earn an allowance for funds used during construction (AFUDC). This amount was broken out by function according to total CWIP by function, and was treated in the same manner as the rate base for each of the functions. Another $7.4 million is related to demand-side management (DSM) spending. This DSM amount was functionalized and classified as 72% power supply energy, 17% power supply demand and 12% transmission and distribution. This split is consistent to that used by FortisBC in the cost/benefit analyses performed for DSM spending.

Functionalization of Revenue Requirement

FortisBC has an approved net revenue requirement from rates of $233.1 million for the 2009 forecast year. This amount, along with an added $2.3 million due to an increase in rate 3808 during 2009, is used in the COSA. The resulting revenue requirement for COSA purposes is $235.4 million. In allocating the revenue requirements, expense items often follow the treatment of the corresponding rate base item.

Total production/power supply costs are projected at $82.9 million for 2009 and are all functionalized to production. This includes accounts 535 to 556.

FortisBC has $12.2 million in transmission expenses for 2009 (accounts 560 to 567) which are all functionalized as transmission.

Total distribution expenses are projected at $7.7 million for 2009 (accounts 580-598) and are annual expenses associated with the distribution rate base accounts. All of these items are functionalized to distribution.

FortisBC has $6.7 million in customer service expenses (accounts 901 to 910). These costs are all functionalized to the Distribution Function.

A&G costs for FortisBC are forecast at $11.7 million for 2009 (accounts 920 to 933). Like general plant, these costs are related to all functions of the utility and are often associated with the number of employees of the utility. Labour ratios were used to functionalize these costs to production, transmission and distribution.

Depreciation expenses in account 403 are $37.5 million for 2009 and are split by functional areas. Generation depreciation follows generation and so on. Depreciation for general plant and deferred charges follow the gross plant before general plant. DSM amortization follows the DSM rate base account.

Return for 2009 is projected at $67.0 million, with another $4.3 million in income tax, and a $1.4 million credit for incentive adjustments. These accounts are all functionalized on the same basis as the total rate base. Property taxes of $11.6 million are related to the value of FortisBC's assets and are therefore treated in the same manner as the total system net plant.

In addition to revenues from retail and wholesale sales to customers, FortisBC receives revenues from other activities, such as pole attachment fees. Because the COSA is concerned with collecting revenues from rates by customer class, the other revenues of the utility are treated as an offset to the revenue requirement. Other revenues are therefore credited back to customer classes in a manner that fits the specific revenue item. Total other revenues for 2009 are projected at $4.9 million.

Electric apparatus rental is primarily for pole attachment and is credited on the basis on the rate base account for poles, towers and fixtures. Lease revenue is treated on the same basis as general plant rate base. Waneta and Brilliant contract revenues are credited on the same basis as generation rate base. Labour ratios are used to assign revenues from Fortis Pacific Holdings as it is related to the use of office space. Connection charge and NSF cheque revenues are credited on the basis of retail customers. Sundry revenue and investment income are assigned on the same basis as gross plant before general plant.

Classification of Costs

The second step in performing a COSA is to classify the functionalized expenses to traditional cost-causation categories. These cost-causation categories can be directly related to specific consumption behavior or system configuration measurements such as coincident peak (CP) or non-coincident peak (NCP) demand, energy, or number of customers. Each classification category will have a specific allocator that, when applied, will distribute those costs among the appropriate customer classes during the allocation phase of the analysis.

The three primary classifiers are:

- Demand
- Energy
- Customer

Functionalized power supply costs are generally split between demand and energy. Transmission system costs are generally classified as demand-related. Distribution costs are generally split between demand-related and customer-related components, or directly assigned to a specific customer class of service.

Within the three categories, there are multiple ways of defining each option as well as varying ways to split costs between two or more classifiers. For example, demand- and energy-related costs can be separated by seasonal distinctions as well as to reflect peak/off peak consumption periods. Customer categories can distinguish between actual customer and weighted customer characteristics. Other classifiers sometimes used in the process include revenue-related and direct assignment. In addition, there are many instances where costs are not specifically classified to a particular category but rather in the same manner as an individual cost account or subtotal of specific cost accounts.

Classification of Generation and Transmission Rate Base

FortisBC owns generation from four hydro units collectively referred to as the Kootenay River Plants. Output from these plants is governed by a water coordination contract with BC Hydro, and other parties on the Kootenay River which predefines the amount of power that can be used at various times. Peak capacity forecast for December 2009 for the Kootenay River Plants is 208 MW, while the average energy expected from these plants is 180 MWa. Note that the measurement of MWa is based on the total MWh generated by the plant divided by the 8,760 hours in the years. This output reflects 47% of the 2009 energy requirement and 35% of the sum of the monthly capacity requirements. The remainder of FortisBC's power supply needs is met with power supply purchases.

In the 1997 COSA, generation rate base was all considered to be energy-related. This ignores the fact that the output is available at the time of FortisBC's peak load and contributes to the capacity needed to serve loads. Because the Kootenay River Plants provide both capacity and energy to FortisBC, the 100% energy method was rejected and it was determined that the generation rate base should be split between demand and energy for purposes of the COSA.

Generation classification can be done using several different methods, most of which rely on looking at the use of various types of plants and their purpose within the system. For a utility with multiple generating plants it is common to look at the function of each plant in serving energy and demand needs, with some plants considered peaking units and others more related to providing energy. Sometimes the capital costs of a plant are considered demand-related and operating costs are considered energy-related, particularly for plants having significant fuel costs. Another approach is a peak credit method where the demand component is based on the cost of building a plant designed primarily to meet peak loads and any additional plant costs are deemed to be energy related. Other times the market based pricing of demand and energy components are used to develop the classification split.

In the case of FortisBC, the Kootenay River Plants are the only utility-owned generation, and costs associated with the plants are a small percent of total power supply costs. This makes it difficult to use many of the standard classification methodologies and the small level of costs involved do not warrant a time-consuming or expensive study of the issue. On the other hand, BC Hydro does have a great deal of utility-owned generation and has had their classification of generation costs reviewed and approved through the regulatory process.

To develop the classification split for FortisBC, the output from the Kootenay River plants was priced as if it were purchased at the 3808 tariff to determine the equivalent split in costs between demand and energy. This split was then applied to actual costs of these projects for purposes of classification. The resulting split was roughly 20% demand-related and 80% energy-related.

There were several factors considered when electing to use this proxy approach for classifying generation rate base for FortisBC. Despite some issues surrounding the derivation of Rate 3808, it does reflect the market price paid by FortisBC for a large part of its power supply. To some extent FortisBC faces the decision to generate with its own hydro plants as opposed to purchasing from BC Hydro under Rate 3808. And while Rate 3808 may not represent the best classification of costs from BC Hydro, it is what is in place today and is included in the rates of BC Hydro.

There are two issues surrounding Rate 3808. As a result of concerns from the Commission, BC Hydro has been ordered to provide a more thorough analysis of generation plant classification in its next rate application. When this is completed FortisBC will re-examine its own classification method. Also, the pricing of Rate 3808 includes a transmission component. In theory we would want to separate out just the generation component of Rate 3803 for use by FortisBC. However, in looking at the underlying classification of costs to the transmission class of BC Hydro, the generation split is equivalent to the 80% demand and 20% energy resulting from the full Rate 3808. So while Rate 3808 may not fully match the results of the BC Hydro COSA, the net result is equivalent to the approach FortisBC would like to achieve for classification.

The transmission rate base includes the utility's own transmission assets associated with providing power to FortisBC's distribution system. In addition, FortisBC purchases wheeling from the British Columbia Transmission Corporation (BCTC) 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 contribution to system peak demand that customer imposes on the system. All transmission rate base accounts are classified 100% demand-related, as was the case for the 1997 COSA.

Classification of Distribution Rate Base

Generally, there are two methodologies that can be used to classify distribution costs: 100% demand and minimum system. The 100% demand methodology assumes that the distribution system is built to meet the non-coincident peak (NCP). Therefore, distribution costs are classified as 100% demand-related. The 100% demand approach was rejected as we believe that the system is built in part to reflect the fact that the customer is hooked up to the system, regardless of load level.

Distribution costs can also be split between demand and customer according to a minimum system approach. This approach reflects the philosophy that the system is in place in part because there are customers to serve throughout the service territory expanse, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 kWh of energy per year. The concept follows that any costs associated with a system larger than this minimum size are due to the fact that customers "demand" a delivery quantity greater than the minimum unit of electricity and that therefore, those costs should be treated as demand-related. Because the residential class tends to have a higher share of the number of customers as compared to the share of non-coincident peak, the minimum system methodology tends to allocate more costs to the residential customer class and customer charges tend to be higher than with the 100% demand methodology.

The process of cost classification is the area within the COSA that can create considerable cost variability between customer classes due to differences in system configurations, demand measurements and system planning criteria. The complexity of the entire COSA process is further compounded since, in some cases, the classification category is clear but the specific allocator is not. For example, a particular cost item may clearly be peak demand-related but that demand can be measured as either a single coincident peak (1 CP) for the year, a combined winter and summer coincident peak (2 CP) approach to reflect seasonal considerations, the sum of 12 monthly coincident peaks (12 CP), or through some other approach.

Distribution services include all services required to get energy supply from the point of interconnection between the transmission system and the utility's load centres to the end user of the power. Classifying distribution costs requires a special analysis of the nature of the costs. Most distribution costs are appropriately split between demand and customer components. The demand component is the cost of facilities built to serve a particular load, such as distribution substations. The customer component is the cost of facilities that varies with the number of customers, such as meters. Different accounts within the distribution function are treated separately. For purposes of the COSA, FortisBC conducted a specialized study termed a "minimum system analysis" which is a theoretical analysis using both engineering and accounting inputs to develop a split of the distribution costs between demand and customer components.

The minimum system analysis is used to theoretically determine the lowest level of plant investment required to serve a utility's customers compared to the actual facilities in place to meet varying customer demands. FortisBC staff provided the data necessary to complete the minimum system study using current year data. Along with the minimum system results, an offset to account for the peak load carrying capability (PLCC) of a minimum system was incorporated into the analysis. The PLCC adjustment is discussed in the following section. Appendix B contains detailed descriptions of the minimum system and how the resulting splits were calculated, along with the details associated with the PLCC calculation.

The minimum system approach reflects the philosophy that the system is in place in part because there are customers to serve throughout the service territory expanse, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 kWh of energy per year. The concept follows that any costs associated with a system larger than this minimal size are due to the fact that customers use a delivery quantity greater than the minimum unit up to the level of their peak demand; therefore, that portion of the costs should be treated as demand related.

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the number of poles, conductors, and transformers in place at the utility is determined and separated by size. The cost associated with these facilities are then determined. Next, it is assumed that the actual numbers by size could be replaced by the minimum sized pole, conductor and transformer. The cost associated with the minimum size is then calculated.

The total costs of the minimum sized system is then compared to the cost of the as-built system to reflect the percent of costs attributed to the system that would be in place if all customers used a minimum amount of power. The remaining percent of costs is then attributed to the demand-related component.

Another method called the zero-intercept method was considered as well. It is very similar to the minimum system except that it creates a theoretical size of equipment which would carry zero load on the system. It is created by looking at the relationship between the cost of equipment and the size of the equipment. For example, if the formula for the price of a pole is equal to $100 plus $20 per foot, a 30-foot pole would cost $700 and a 35-foot pole would cost $800. With the zero-intercept method, a zero-foot pole would be set at $100 and would be considered the minimum size. The costs associated with that zero-foot pole would be classified as customer-related. This approach can sometimes lead to unreasonable results as the y-intercept may not always be a positive number. By using the PLCC approach in conjunction with the minimum system, the impacts are similar in theory to the zero-intercept approach.

A minimum system analysis was last conducted by FortisBC in 1993 with the resulting splits also used for the 1997 COSA. For the 2009 FortisBC COSA, the minimum system was updated using 2008 data and reflects differing splits for each distribution line item. Detailed results are found in Appendix B.

For comparison, BC Hydro is using a split of 35% customer and 65% demand for all of its distribution accounts. BC Hydro did not update its minimum system study for its recent COSA filing and the approved numbers differ from BC Hydro's request. BC Hydro was ordered to do a new minimum system study for its next COSA filing.

The following summarize the resulting classification for the distribution accounts used for the 2009 COSA.

- Substations, including land and station equipment. These costs are classified as demand-related as they are sized on the basis of the peak load for the area served.

- Poles, Towers & Fixtures. The results of the minimum system analysis are 96% customer-related and 4% demand-related. The customer-related costs are allocated on the basis of actual customers. The 1997 COSA split had a somewhat higher amount as demand-related at 76% customer-related and 24% demand-related.

- Conductors & Devices. The results of the minimum system analysis are 58% customer-related and 42% demand-related. The customer-related costs are allocated on the basis of actual customers. The 1997 COSA split ad a higher amount that was demand-related, at 48% customer-related and 52% demand-related.

- Line Transformers. The results of the minimum system analysis are 73% customer-related and 27% demand-related. The customer-related costs are allocated on the basis of actual customers. The 1997 COSA split was comparable at 72% customer-related and 28% demand-related.

- Services, Meters and Installation on Customer Premises. These costs are all related to the customer component as they are installed for each customer served.

- Street Lights & Signal Systems. These costs are all directly related to the lighting class of customers and are directly assigned to that class.

Peak Load Carrying Capability Adjustment (PLCC)

While the minimum system is, in theory, designed to carry only a minimal amount of load, the actual facilities designated as the minimal size are actually capable of carrying some amount of demand, therefore overstating the level of the customer-related component. The actual amount of demand capability within the minimum system is a function of load density, minimum required clearances, minimum equipment standards, temperature, and other engineering considerations. Under traditional cost allocation techniques, each customer/connection attracts an equal allocation of the minimum system, plus each customer class is allocated demand costs based on the total customer class' non-coincident peaks. As such, it has been argued that a customer class' non-coincident demand allocator is too large, because a portion of these peak demand-related costs are being covered through the per customer/connection minimum system allocation.

The correction of the problem of over allocating demand can be achieved by the application of a PLCC adjustment. The precise amount of a PLCC adjustment should match the definition of the minimum system adopted. In the FortisBC case, it was determined that the average PLCC for the FortisBC system is 1.0 kW per customer. The use of the PLCC credit is an enhancement over what was done for the 1997 COSA. Appendix B provides a more detailed discussion of the PLCC and how the amount was calculated.

The PLCC adjustment will determine how much demand for a customer class can be met by the minimum system (number of customers/connections x PLCC for minimum system) and will credit this amount against the classification's non-coincident peak demands used for determining demand allocators. The adjusted customer class' non-coincident peaks can then be used to allocate the distribution demand-related costs, eliminating the double-counting. The number of customers/connections used for the PLCC should match the number of customers/connections used to allocate the customer component of the distribution capital and O&M costs associated with poles, conductors and transformers.

Other Rate Base Items

General plant, after being functionalized to the three areas, was classified using the resulting classification as total rate base for each function. For example, the 37% of general plant assigned to generation was split between demand and energy in the same manner as the generation rate base. Accumulated depreciation accounts and working capital accounts were classified in the same fashion as the corresponding gross plant accounts. Customer contributions were assigned to classes on the basis of poles, conductors and transformers.

The $25 million of plant acquisition adjustment and deferred costs was classified on the same basis of Gross Plant prior to General Plant. The CWIP not earning AFUDC assigned to each function was classified in the same manner as the rate base for each function. DSM was classified as 71.6% power supply energy, 16.6% power supply demand and 11.8% transmission and distribution demand. This split is consistent to that used by FortisBC in the cost/benefit analyses performed for DSM spending.

Classification of 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. When a utility has numerous generating facilities the use of the various units to supply baseload versus peaking power should be considered. In the case of FortisBC, the power supply resources include FortisBC-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 FortisBC have both an energy and peaking component to them.

Total peak demand for the FortisBC system is expected at 701 MW in January 2009, with average energy forecast at 391 MWa for the year. Total power supply costs for 2009 include purchased power expenses of $71.8 million and direct costs associated with FortisBC-owned generation of $31.4 million.

FortisBC owns four hydroelectric generating units collectively referred to as the Kootenay River Plants. Output from these plants is governed by a water coordination contract with BC Hydro and other parties on the Kootenay River, which predefines the amount of power that can be used at various times. The O&M expenses associated with the Kootenay River Plants are all classified and allocated on the basis of the generation rate base.

The next resource is a contract for power from the Brilliant hydro plant, owned by the Columbia Power Corporation. Under the contract, FortisBC is allocated a share of the output from the project in exchange for paying a share of the costs of the project. The costs associated with the purchase from the Brilliant plants are based on the actual capital and operating costs of the plant. To reflect the fact that these projects supply both demand and energy, it was determined that the 3808 breakdown of demand and energy prices could be used as a proxy for the split between demand and energy components, as used for FortisBC's own generation. The output from this project was priced at the 3808 tariff to determine the equivalent split in costs between demand

and energy. This split was then applied to actual costs of the projects for purposes of classification. The resulting split was roughly 20% demand-related and 80% energy-related.

FortisBC purchases power from BC Hydro under a contract for up to 200 MW of power, with prices set under Rate 3808. The rate for this power, after the recent rate increase, is equal to $5.313 per kW-month plus 3.114 cents per kWh. Because there are separate demand and energy charges associated with this purchase, those respective charges are classified as demand-related and energy-related in the COSA.

The remaining power requirements for FortisBC are met using various market purchases, and in some cases there are surplus quantities sold as well to match the hourly needs of the utility. While market purchases reflect 162 MW of capacity at the time of the peak, there is only 1 MWa of market energy required to meet the forecast for the year. Net impacts of market purchases and sales are less roughly $2 million for 2009.

The following summarizes the output and costs associated with each of the power supply sources:

	Capacity (MW)	**Average Energy (MWa)**	**2009 Costs (Millions)**
Kootenay River Plants	202	180	$ 31.4
Brilliant Hydro	147	104	$ 31.1
BCH 3808 Purchases	190	106	$ 38.4
Net Market Purchases	162	1	$ 2.3
Total System	701	391	$102.1

Because power supply sources vary by month, power supply costs were classified to demand and energy for each month and then allocated to customer classes on the basis of each class' contribution to system peak and energy loads for each month. As discussed above, purchases from BC Hydro already have a demand and energy component. Market purchases and sales also are priced using demand and energy components every month and are therefore classified in that manner.

Classification of Other Expenses

The transmission function includes FortisBC's own transmission assets associated with providing power to FortisBC's distribution system. In addition, FortisBC purchases wheeling services from BCTC 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.

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.

Customer Service expenses are all classified as customer-related.

A&G was first assigned to each function on the basis of labour ratios. These amounts were then classified on the same basis as the rate base for each of the three functions. The rate base was used because the employees are more closely tied to the size of the asset value of the three functions as opposed to the O&M associated with each function.

Depreciation expenses assigned to each function follow the rate base for that function. Depreciation for general plant and deferred charges follow the gross plant before general plant. DSM amortization follows the DSM rate base account.

Return accounts are all classified on the same basis as the total rate base. Property taxes of $11.6 million are related to the value of FortisBC's assets and are therefore treated in the same manner as the total system net plant.

In addition to revenues from retail and wholesale sales to customers FortisBC also receives revenues from other activities, such as pole attachment fees. Because the COSA is concerned with collecting revenues from rates by customer class, the other revenues of the utility are treated as an offset to the revenue requirement. Other revenues are therefore credited back to customer classes in a manner that fits the specific revenue item. Total other revenues for 2009 are projected at $4.9 million.

Electric apparatus rental is primarily for pole attachment and is credited on the basis of the rate bases account for poles, towers and fixtures. Lease revenue is treated on the same basis as general plant rate base as it covers revenue from general utility assets rather than from generation assets or utility poles. Waneta and Brilliant contract revenues are credited on the same basis as generation rate base as these revenues offset the costs associated with FortisBC's power supply. Labour ratios are used to assign revenues from Fortis Pacific Holdings as it is related to the use of office space. Connection charge and NSF cheque revenues are credited on the basis of retail customers. Sundry revenue and investment income are more general in nature and are therefore assigned on the same basis as gross plant before general plant.

Allocation of Costs

The third step in performing a COSA is the allocation of the utility's total functionalized and classified revenue requirement to the customer classes of service. This is performed through the application of an appropriate allocation methodology.

For each of the primary classifiers discussed above, distinctions have been made within each category to better reflect cost-causation. The following are the specific allocation methods used in FortisBC's COSA. The specific method of cost classification and allocation for various rate base and expense items is discussed in further detail below.

Demand Allocation Factors

For purposes of this study, three types of demand allocation factors were developed.

- *Non-Coincident Peak Demand Allocation Factor (NCP).* First, a non-coincident peak demand allocation factor was developed for each customer class. Expenses classified and allocated by the non-coincident peak demand allocation factor included those predicated on maximum demands such as distribution substations, and a portion of poles and lines, transformers, meters and services. The NCP demand method allocates costs to each class of service based upon their highest non-coincident peak demand regardless of the time of occurrence. These NCP demand allocators are further separated in NCP at primary (NCPP) and secondary voltages (NCPS). The NCP allocators were used for distribution rate base items, with substations based on NCPP, transformers based on NCPS, and poles and conductors split 80% to NCPP and 20% to NCPS. This split is based on industry experience. Given the use of the PLCC adjustment as part of the minimum system treatment of distribution costs, the NCP allocation factors are calculated after subtracting the PLCC amount times the number of customers in each rate class.

- *Monthly Coincident Peaks (CP).* For each class of service, a contribution to the system coincident peak in each month was derived from the non-coincident peak and the use of a coincidence factor. Coincident peaks are used for allocating the demand-related potion of power purchases as they differ in each month based on system usage.

- *Winter/Summer Coincident Peaks (2 CP).* Coincident peaks are typically used for allocating a portion of production costs and all of transmission costs as they are generally sized for the system peak as a whole. For FortisBC, it was determined that the sum of the 2 highest summer and 2 highest winter coincident peaks were the most appropriate to reflect system use and planning for facilities, as explained further below. This is consistent with the peak allocation method used in the 1997 COSA. The 2 CP allocator was used for generation and transmission rate base accounts. Note that while 4 months of data were used to develop the 2 CP number, it is not to be confused with the 4 CP method used by BC Hydro using the 4 highest peaks of the year. The 2 CP term was used historically and represents the dual winter/summer peak of the utility.

Demand Allocation Alternatives

The issue of determining the most appropriate allocation methodology for transmission facilities has been studied by a number of regulatory bodies in North America. Precedents on rate setting matters are valuable as they come as a result of a comprehensive and transparent public proceeding. As an example, in the United States, the Federal Energy Regulatory Commission (FERC) has reviewed and opined on numerous transmission rate setting applications, and provides a good forum for aggregating information on standard industry practice in the areas of costing and pricing of transmission services. FERC also provides a convenient forum for debate of new practices within the electric industry and offers a comprehensive database of regulatory analysis, debate and precedents.

FERC was required by the *Federal Power Act* to establish transmission rates that are just and reasonable, and not unduly discriminatory or preferential. FERC also developed a transmission rate policy that stated transmission rates must "(1) allow the transmitting utility to recover all the costs incurred in connection with the transmission services and necessary associated services including, but not limited to, an appropriate share, if any, of legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any enlargement of transmission facilities; (2) promote the economically efficient transmission and generation of electricity; (3) be just and reasonable, and not unduly discriminatory or preferential; and (4) ensure, to the extent practicable, that costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services, are recovered from the applicant for service and not from a utility's existing wholesale, retail and transmission customers."[1]

In most cases, FERC has accepted one of five coincident peak (CP) methods for classifying and allocating transmission costs: 1 CP, 2 CP, 3 CP, 4 CP or 12 CP. If a utility's monthly system demands are relatively flat (i.e., there is not a large difference between the 12 monthly peaks within a given year), FERC precedent supports the use of a 12 CP allocation. If a utility experiences a "pronounced peak" during less than all 12 months, FERC precedent supports the use of other CP methods. FERC has established four tests to determine whether or not a utility has a "pronounced peak". These tests help determine if the transmission system was sized based on a peak occurring only a few times each year or if the transmission system was used more evenly during all 12 months of a year.

These tests are:

<u>FERC Test #1</u>

The first test compares the average of the system peaks during the purported peak months as a percentage of the annual peak to the average of the system peaks during the off-peak months as a percentage of the annual peak.

FERC Test #1 = (Average Monthly Peak during Peak Months ÷ Annual Peak) – (Average Monthly Peak during Off-Peak Months ÷ Annual Peak)

Given historical FERC cases, using an allocation other than 12 CP is supported if the equation above results in a value greater than 20%. A smaller value supports using 12 CP. It is not clear how many peak months should be included in the calculation. In the past, three, four or six months have been included as the peak period.

[1] Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, Notice of technical conference and request for comments, 58 Fed. Reg. 36,400 (July 7, 1993).

FERC Test #2

The second test calculates the lowest monthly peak as a percentage of the annual peak.
FERC Test #2 = Lowest Monthly Peak ÷ Annual Peak
Greater percentages support using 12 CP. Historically, FERC has supported using 12 CP when the percentage is greater than 65%.

FERC Test #3

A third FERC test looks at the extent to which peak demands in non-peak months exceed the peak demands in the alleged peak months. FERC precedents show that if the peaks in what are considered to be non-peak months frequently exceed the peaks in alleged peak months, the 12 CP methodology is adopted. If it is fairly uncommon for the peak demand in a non-peak month to exceed the peak demand in a peak month, then an allocation other than 12 CP has historically been adopted.

FERC Test #4

A fourth test calculates the average of the twelve monthly peaks as a percentage of the greatest monthly peak.

FERC Test #4 = Average of 12 Monthly Peaks ÷ Annual Peak

A greater percentage supports using the 12 CP methodology. Based on precedent, a result of 81% or greater, supports using 12 CP.

The Ontario Energy Board (OEB) has also explored the issue of an appropriate classifier and demand allocation factor for transmission facilities in the recent cost allocation review undertaken for the Ontario Local Distribution Companies (LDCs). As part of this review, two tests were developed by the OEB to determine the appropriate classification and allocation procedure for transmission facilities. These two tests are summarized below.

OEB Test #1

The first OEB test calculates the average of the twelve monthly system peaks as a percentage of the highest monthly system peak. A Test #1 result of 83% or greater indicates that 12 CP should be used. If the Test #1 result is less than 83%, then Test #2 must be conducted to determine if a 1 CP or a 4 CP is to be used.

OEB Test #2

The second OEB test calculates the average of the four highest monthly peaks as a percentage of the highest monthly system peak. Note, that contrary to the FERC tests which require that consecutive monthly peaks are used, the OEB Test #2 utilizes any four highest peaks. A Test #2 result of 83% or greater then the distributor must use 4 CP as the allocator, while a 1 CP should be used if the Test #2 result is less than 83%.

The FERC and OEB tests were developed based on comprehensive analyses of utilities in North America, and EES considers the tests to be appropriate methods of determining the appropriate allocator for FortisBC.

Selection of 2 CP Method

In selecting the appropriate peak demand allocator for production and transmission, the FERC and the OEB tests were examined along with looking at the overall shape of the peaks, and at the growth rates for winter and summer peaks. The various tests were calculated for several years as well as for the 2009 forecast used in the COSA. The results are provided in Table 1.

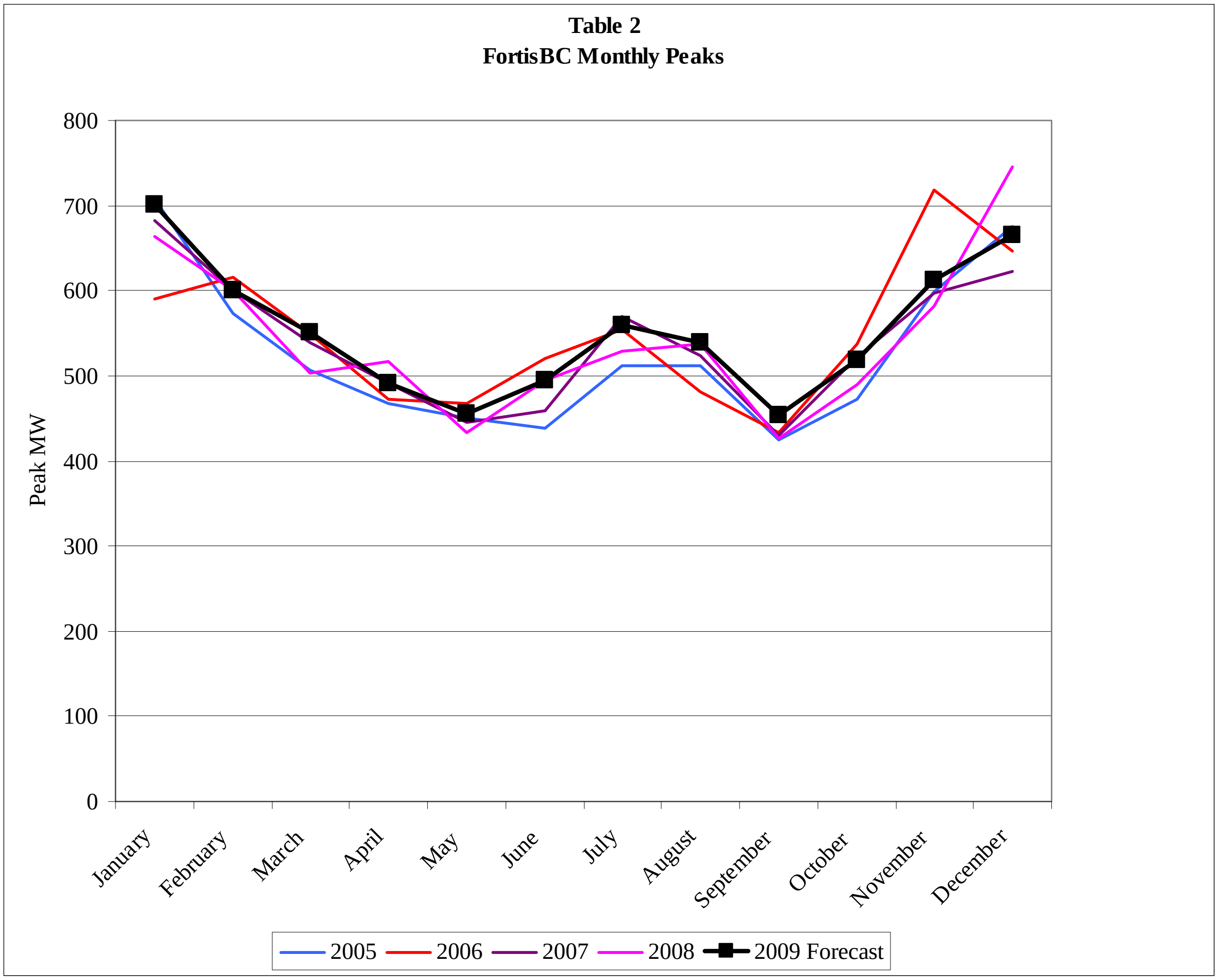
Table 1
FERC and OEB Tests for Demand Allocator

Test	C2004	C2005	C2006	C2007	C2008	C2009 Forecast
FERC Tests						
#1	1CP or 4CP	1CP or 4CP	12CP	12CP	1CP or 4CP	12CP
#2	1CP or 4CP	1CP or 4CP	1CP or 4CP	1CP or 4CP	1CP or 4CP	1CP or 4CP
#3	Does not exceed (1CP or 4CP)	Does not exceed (1CP or 4CP)	Does not exceed (1CP or 4CP)	Does not exceed (1CP or 4CP)	Does not exceed (1CP or 4CP)	Does not exceed (1CP or 4CP)
#4	1CP or 4CP	1CP or 4CP	1CP or 4CP	1CP or 4CP	1CP or 4CP	1CP or 4CP
OEB Tests						
#1	Use CP Test #2	Use CP Test #2	Use CP Test #2	Use CP Test #2	Use CP Test #2	Use CP Test #2
#2	4CP	4CP	4CP	4CP	4CP	4CP

The results generally support the use of a 1 CP or 4 CP approach, however, it is important to note that the tests only consider a 1 CP, 4 CP or 12 CP method and have left out the use of a 2 CP method. In the years 2006, 2007 and 2009 forecast the 12 CP shows up under FERC Test #1, however, the results are very borderline. None of the other tests result in a recommended 12 CP method.

As the FERC and OEB tests do not specifically contemplate a mixed winter/summer peak, the tests do not rule out the use of that approach. What is important to note from the results is that the FortisBC system is more seasonal than it is flat throughout the year, eliminating the use of the 12CP method.

The next consideration was to graphically examine the load shape for FortisBC to help in understanding the particular circumstances of the specific utility. Table 2 shows the overall shape for the 2009 test year as well as previous years. It is very clear from the table that there is a prominent peak in the summer months.



The next two tables, Tables 3 and 4, show the average monthly peaks for 2001 to 2007 for both FortisBC and BC Hydro, respectively. Table 4 was originally provided for BC Hydro in their last Rate Design Application and a comparable graph on Table 3 was prepared for FortisBC to contrast the two.

Table 3
FortisBC System Monthly Peak Demand
(2001 - 2007 Average)

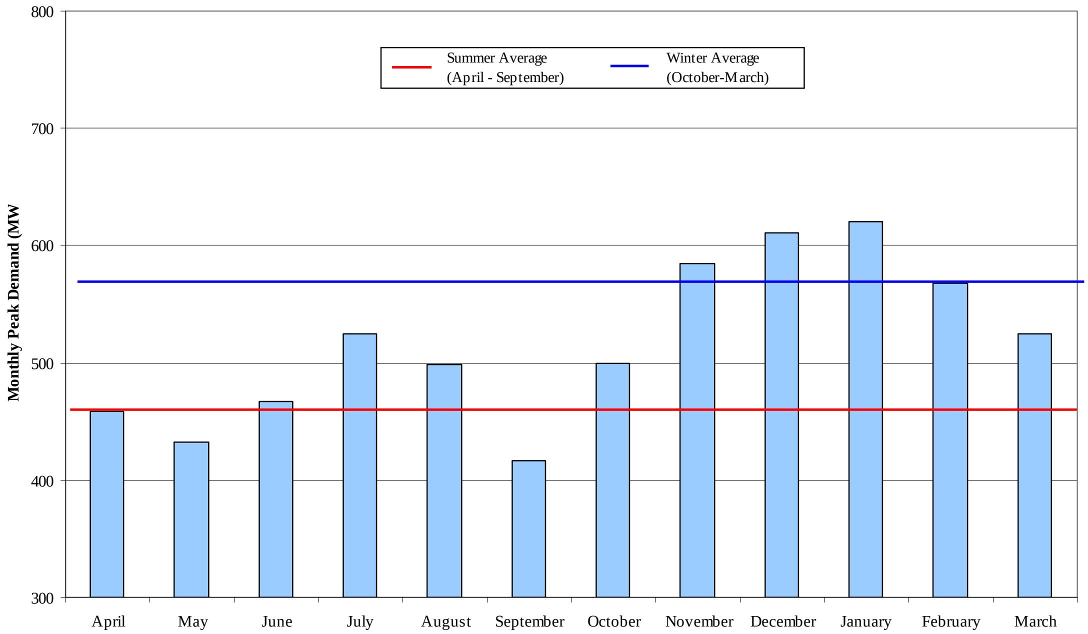
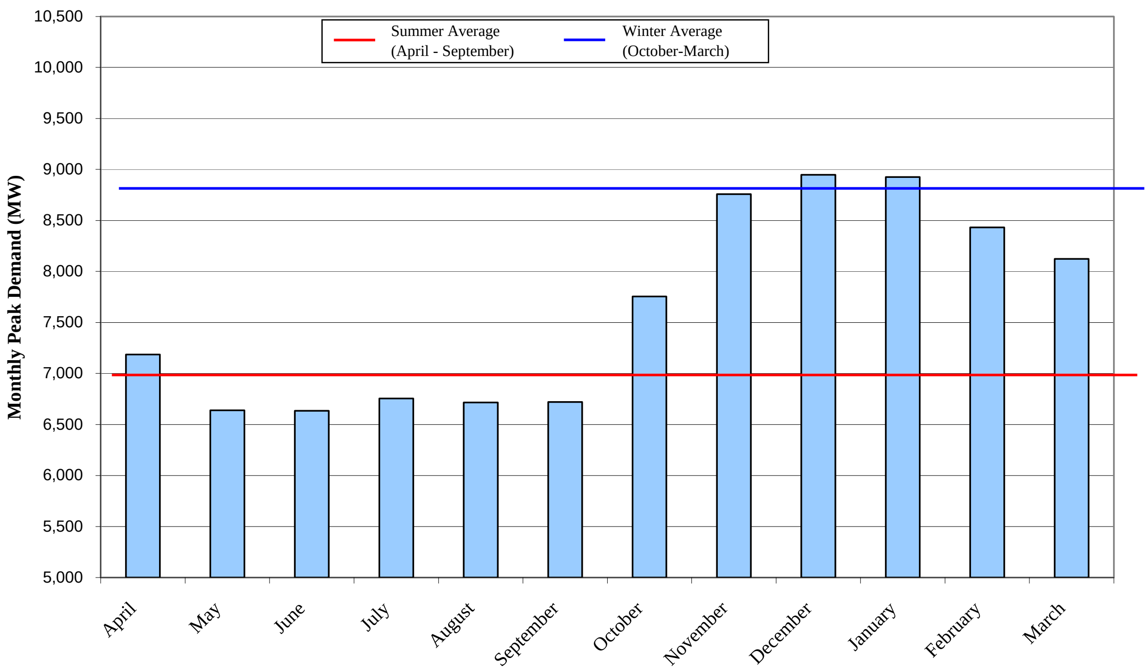


Table 4
BC Hydro Domestic System Monthly Peak Demand
(2001 - 2007 Average)



Source: BC Hydro response to JIESC IR 4.17.2 in the BC Hydro 2007 Rate Design Application

For FortisBC, the July and August peaks exceed the summer average and are approaching the winter average peak. This differs from BC Hydro, where the peaks between April and September are relatively flat. The approved method for BC Hydro is 4CP using the 4 winter peaks. This method was recently approved, despite BC Hydro requesting a 12 CP method, because 4CP better reflected the load shape specific to BC Hydro.

The final analysis was to look at the growth in the summer months relative to the growth in the winter months. When comparing the 2009 forecast peaks to 1997 actual peaks (the year of the last COSA), the summer peak is growing twice as fast as the winter peak. For that time period, the total growth was 61 MW in the winter, or about 0.8% per year. For the summer peak, the growth was 112 MW, or about 1.9% per year. This indicates that the summer peak is moving closer to the level of the winter peak, and that FortisBC system planning will continue to need to recognize the growth in the summer peak.

The demand allocation method was selected after consideration of past precedent, FERC and OEB tests, comparisons of load shapes and growth of winter and summer peaks. The 12CP approach was rejected as FortisBC does not have a flat load shape over the year. The 2 CP approach was selected rather than a 1 CP or 4CP approach because FortisBC has a significant summer peak. While the summer peak is not at the same level as the winter peak, it is growing faster than the winter peak and will increasingly have a larger impact on the system.

Use of Contractual Demand

For the wholesale and large general service / industrial customers, FortisBC has contractual arrangements with each customer to clarify FortisBC's obligation for providing electricity service. In each case, FortisBC has an obligation to provide the necessary capacity on its system to meet the contractual demand set in the contracts. FortisBC is proposing to use the contractual demands for Rate 31/33 industrial customers and for wholesale customers when developing the allocation factors within the COSA. This approach better reflects the planning criteria used for the facilities built to serve these customers and is consistent with current pricing trends for firm service.

FortisBC plans and builds facilities to meet the expected loads for its customers. In the case of residential and general service customers, the utility looks at the localized demand expected, which is accounted for in the class contribution to CP and NCP used to allocate costs. For larger customers, FortisBC is contractually obligated to have sufficient capacity to meet contractual demand levels and therefore builds facilities to reflect this demand level. In the case of the wholesale customers, FortisBC is actually required to build new facilities once actual loads reach 95% of the contractual demand. Because FortisBC has planned for and built facilities to meet the contractual obligations for these customers, it is appropriate to allocate transmission and distribution costs on the basis of the contractual demand.

The order of magnitude of the costs for facilities serving the large industrial and wholesale customers is different than those for smaller residential and general service customers. With residential and general service customers, facilities are built to serve a large number of customers in an area with diversity among the customers. If one customer leaves it does not strand a significant amount of facilities, and it is likely that surplus capacity will be used up with customer growth. For the large industrial and wholesale customers, FortisBC is spending a significant amount for facilities to serve contractual load levels, with the potential for stranding if the customer reduces its load, leaves the system or builds its own facilities.

The use of contractual demands is consistent with trends and changes that have occurred along with the opening of a market for wholesale power, the proliferation of independent power producers (IPPs), open transmission access and the unbundling of the transmission function. For wholesale transmission access available to large industrial, wholesale customers and IPPs, it is common to require a contractual purchase of transmission capacity that cannot be exceeded. This capacity is paid for whether or not it is used in a given year. In Alberta, transmission rates are set by the Alberta Electric System Operator (AESO) and the bulk system charge for transmission is set on the basis of the highest of actual demand, 90% of a 24-month ratchet or 90% of contract demand. These billing determinants are used both for billing and within the COSA. The contract demand approach is also commonly used for natural gas transportation. As a result of these trends and changes, Fortis BC has re-examined its position to include the use of contract demands within the COSA, which differs from the 1997 COSA.

For transmission and distribution cost allocation in the COSA, the NCP and 2 CP allocation factors have been adjusted to reflect the higher of the actual demand and the contractual demand for the wholesale and large general service / industrial customers. In several cases, the contractual demand has been exceeded historically. While there are some instances where FortisBC has the capability to serve customers beyond the contractual level or where customers have consistently exceeded contractual levels that added capability will not be used in the COSA allocation until such time that the contracts can be amended.

For power supply, costs have been allocated on the basis of projected actual monthly CP demand levels as the utility only pays for power supply that is actually used, and can resell any surplus amounts.

Because the transmission and distribution systems in place at the utility are built to meet the contractual obligations for wholesale and large general service / industrial customers, it is equitable for those customers to pay for that level of capacity. Because the contractual demand often exceeds actual loads, there is surplus capacity on the system. By allocating costs on the basis of contractual demand, those customers causing the surplus to be available are paying for the surplus. This avoids subsidization of the wholesale and large general service / industrial customers by all of the other classes. It also fairly assigns costs associated with the added reliability associated with redundancy at multiple points of delivery for wholesale customers. Given the directive of the BC Energy Plan for all utilities to promote efficiency and conservation, it is imperative that customers are provided price signals that reflect the true cost of the facilities used to serve them.

For those customers that have customer-owned generation on site used to serve their own load throughout the year, the contractual demand is set to cover the entire load of the customer in the event the customer-owned generation is not available to meet load. FortisBC has the obligation to serve their load in that scenario, which has occurred in the past for both Celgar and Nelson.

This standby service is currently provided under Rate 31/33 and Rate 41 without specifically charging an amount related to standby service. The use of contractual demand ensures that they pay for the equipment in place to provide standby service. It is standard utility practice to charge for standby service for customer-owned generation and is therefore appropriate for FortisBC to make this change in both the allocation of costs within the COSA and in setting rates for customers with their own generation in lieu of a specific standby charge.

Energy Allocation Factors

Energy costs vary directly with consumption. Accordingly, energy allocation factors were based upon electricity sales for each class. For purposes of monthly power supply costs, the energy in each month was used as the allocator.

Customer Allocation Factors

Two basic types of customer costs were identified—actual and weighted.

- *Actual Customers (CUST).* The allocation factor for actual customers was derived from the actual number of customers served in each class of service averaged across the 12 months of the 2009 test period. Note that for wholesale customers the number of points of delivery (POD) was included in some cases as each POD contains its own meter.

- *Customers Weighted for Meters and Services (CUSTM).* The first weighted customer allocation factor considered the relative differences among the various customer classes of meter costs. The typical cost of a new meter for each rate class was used as the weighting factor for each class.

- *Customers Weighted for Accounting/Metering (CUSTW).* The second weighted customer allocation factor considered the cost of customer accounting and meter reading by each rate class. The weighting factors for CUSTW were developed via an allocation of cost performed by FortisBC staff. Once costs were allocated to each class, they were divided by the number of customers and then scaled back so that a weighting factor of 1.0 was used for the residential class and general service customers, 1.4 for lighting and irrigation customers, 159.7 for wholesale customers and 202.5 for industrial customers.

Other Allocation Factors

Other costs are allocated based on specific rate base items, O&M function totals, revenues, labour ratios and other allocation factors.

Allocation of Rate Base

For generation, the 20% demand-related component was then allocated across classes using the 2 CP factor. The remaining 80% energy-related component was allocated on the basis of annual energy by class.

All transmission rate base accounts are allocated on the basis of the 2 CP methodology.

For the 100% demand-related components of distribution, the NCPP is used as the allocation factor. For those distribution accounts split between demand and customer components, the NCPP, NCPS and actual number of customers are used. Those distribution accounts that are 100% customer-related are allocated on the basis of customers weighted according to the average cost of meters by class. Street Lights & Signal Systems all directly related to the lighting class of customers and are directly assigned to that class.

General plant costs were allocated to classes on the same basis as was used for each of the classified components.

Each of the accumulated depreciation accounts was allocated in the same fashion as the corresponding gross plant accounts. Working capital items were allocated on the same basis as all O&M costs. Customer contributions were assigned to classes on the same basis as poles, conductors and transformers.

Allocation of Revenue Requirements

Because power supply sources vary by month, power supply costs were classified to demand and energy for each month and then allocated to customer classes on the basis of the class contribution to system peak and energy loads for each month.

All transmission expense accounts are allocated on the same basis as transmission rate base, which is based on 2 CP.

Distribution expense accounts generally correspond to a rate base account and follow allocation of the rate base item. Street lighting expenses are directly assigned to the lighting class. Account 598 – other distribution plant is allocated on the basis of total distribution rate base.

For customer service expenses, each account is considered separately for allocation. Supervision and administration expenses follow all other customer service expenses. Meter reading, customer billing and customer assistance are allocated on customers weighting for accounting/metering. Credit and collections expense are allocated to retail customer only.

A&G costs were functionalized using labour ratios and then classified and allocated on the same basis as the rate base for each of the three functions. This follows the same treatment described for general plant.

Depreciation expenses follow the allocation treatment used by the associated functional accounts. Depreciation for general plant and deferred charges follow the gross plant before general plant. DSM amortization follows the DSM rate base account.

Return accounts, (interest, earnings, and income taxes) are all allocated on the same basis as the total rate base. Property taxes of $11.6 million are related to the value of FortisBC's assets and are therefore allocated in the same manner as the total system net plant. Net plant reflects the gross plant for the utility less accumulated depreciation.

FortisBC receives revenues from retail and wholesale sales to customers, as well as for other activities, such as pole attachment fees. Because the COSA is concerned with collecting revenues from rates by customer class, the other revenues of the utility are treated as an offset to the revenue requirement. Other revenues are therefore credited back to customer classes in a manner that fits the specific revenue item. Total other revenues for 2009 are projected at $4.9 million.

Electric apparatus rental is primarily for pole attachment and is credited on the basis on the rate bases account for poles, towers and fixtures. Lease revenue is treated on the same basis as general plant rate base. Contract revenues from Brilliant and Waneta may also include Arrow Lakes revenue. As these contracts are related to FortisBC generation, they are credited on the same basis as generation rate base. Labour ratios are used to assign revenues from Fortis Pacific Holdings as it is related to contracts that use FortisBC employees to assist third parties with operations assistance. Connection charge and NSF cheque revenues are credited on the basis of retail customers. Sundry revenue and investment income are no related to any one specific function of the utility and are therefore assigned on the same basis as gross plant before general plant.

Summary and Conclusions

Given the above assumptions regarding the COSA, the various costs were classified and allocated to the customer classes of service. This section provides the results of the COSA in summary form. Detailed tables reflecting all of the COSA details can be found in Appendix A.

Rate Base

The total rate base of $908.0 million has been classified into various components and allocated to customer classes as found in Schedule 4.3 of Appendix A. The split by customer class can be summarized as follows:

	Millions
Residential	$428.3
Other Retail	$250.3
Wholesale	$229.4
Total System	$908.0

This amounts to an assignment of 47% to the residential class, 27% to other retail classes and 25% to wholesale customers.

Revenue Requirement

The total revenue requirement of $235.4 million has been classified into various components and allocated to customer classes as found in Schedule 3.3 of Appendix A. The results are summarized as follows:

	Millions
Residential	$108.7
Other Retail	$ 66.6
Wholesale	$ 60.2
Total System	$235.4

This amounts to an assignment of 46% to the residential class, 28% to other retail classes and 26% to wholesale customers. The allocated revenue requirement can be compared to the following projections of revenue for 2009:

	Millions
Residential	$106.0
Other Retail	$ 77.7
Wholesale	$ 49.8
Total Revenues	$233.4

Revenue to Cost Ratios

A summary comparison of the revenues at present rates, allocated cost of service and resulting revenue to cost ratios can be found in Schedule 1.1 of Appendix A. The resulting revenue to cost ratios are as follows:

	Revenue to Cost Ratio	Adjusted Revenue to Cost Ratio
Residential	97.5%	98.3%
Small General Service (20)	112.4%	113.4%
General Service (21)	137.8%	138.9%
Industrial Primary (30)	121.3%	122.4%
Industrial Transmission (31)	108.9%	109.9%
Industrial Transmission TOU (33)	23.3%	23.5%
Lighting	81.2%	81.9%
Irrigation	77.9%	78.6%
Kelowna Wholesale	89.2%	89.9%
Penticton Wholesale	77.3%	78.0%
Summerland Wholesale	95.8%	96.6%
Grand Forks Wholesale	67.5%	68.1%
BC Hydro Lardeau Wholesale	100.9%	101.8%
BC Hydro Yahk Wholesale	102.7%	103.5%
Nelson Wholesale	79.3%	80.0%
Total	99.1%	100.0%

Given a number of assumptions, the results show that when using present rates FortisBC is collecting insufficient revenues to meet current costs for 2009. The amount is roughly 1% less than projected revenue requirements due to an adjustment of $2.3 million related to a change in rate 3808 from BC Hydro. While FortisBC adjusted rates September 1st to collect the shortfall associated with this wholesale rate change, the COSA was completed prior to this adjustment. Revenues for the COSA were adjusted so that revenues would match the revenue requirements. This adjustment better reflects the deviations from 100% that occur between the various customer classes. The Adjusted Revenue to Cost Ratios will be used to determine the need for interclass adjustments.

For the residential class, the revenue to cost ratio is very close to 100%. Many classes are undercollecting by a significant amount, including industrial transmission, lighting and irrigation plus most of the wholesale customers. The two general service classes, industrial primary, industrial transmission and Lardeau and Yahk are all overcollecting.

Unit Costs

The unit costs per customer class resulting from the COSA are provided in Schedule 2.1 of Appendix A. These costs are useful in comparing the costs between classes as they are provided on a level basis. In summary, unit costs are as follows:

	Cents per kWh
Residential	8.90
Other Retail	6.91
Wholesale	6.53
Total System	7.58

Unit costs can also be used in setting rates that send the appropriate price signals to customers. As the wholesale customers are billed for customer charges on the basis of the number of PODs served, the unit cost for them reflects the costs on a per POD basis. For those customers that do not have demand meters, and therefore no demand charge, all of the demand-related costs have been rolled into the energy cost per unit.

Unit cost calculations were a consideration in adjusting rate design components for the accompanying rate design proposed in this application.

Comparison to 1997 COSA Methodology and Results

Over the past 10 years there have been changes in loads, rate base and expenses. Some of the methodologies were updated for this COSA to better reflect current conditions. The table provides a summary of the methods used in 1997 compared to those used for this 2009 COSA.

Table 5
1997 vs 2009 COSA Methodology

	1997 Method	2009 Method
Generation Plant	49% winter energy 51% summer energy	80% energy-related 20% demand-related at 2 CP (actual demands)
Transmission Plant	2 CP (actual demands)	2 CP (contractual demands)
Distribution Plant	Minimum System	Minimum System with PLCC
Substations	100% demand	100% demand
Poles	76% customer/24% demand	96% customer/4% demand
Conductor	48% customer/52% demand	58% customer/42% demand
Transformers	72% customer/28% demand	73% customer/27% demand
Services	100% customer	100% customer
General Plant	Labour Ratios 30% generation 16% transmission 54% distribution	Labour Ratios 37% generation 25% transmission 38% distribution
DSM	72% Generation Energy 13% Generation Demand 15% Transmission	71.6% Generation Energy 16.6% Generation Demand 11.8% Transmission & Distribution

In 1998 a settlement of the 1997 COSA/Rate Application was reached and approved by the BC Utilities Commission. Rate adjustments between classes were made as a result of the 1997 COSA. In early 1998 FortisBC was directed to increase residential rates by 1% per year for the next three years, with the additional revenue used to offset rates for other classes. The following shows the revenue to cost ratios resulting from the 1997 COSA before and after the resulting rate rebalancing occurred.

	Before Rebalancing	After Rebalancing
Residential	91.3%	94.1%
Small General Service (20/21)	114.2%	112.2%
General Service (30)	114.5%	112.5%
Industrial (31)	125.3%	112.8%
Lighting	109.1%	107.1%
Irrigation	75.8%	75.8%
Wholesale at Primary	101.2%	100.0%
Wholesale Transmission	116.7%	100.0%
Total	100.0%	100.0%

The results have changed since the 1997 COSA. The residential class went from a position of undercollecting costs by nearly 10% before rebalancing, and by 6% after rebalancing, to collecting an amount nearly equal to its costs in 2009. Small General Service customers are overcollecting by about the same amount as in 1997. General Service (Rate 21) customers are overcollecting significantly more now than when compared to the results in 1997. This is likely due to the fact that this class of customer has been separated out from Rate 20 for the 2009 COSA. Lighting customers are now undercollecting rather than overcollecting costs and irrigation customers are in a comparable position to that from 1997.

Industrial at primary (Rate 30) revenues are still more than 20% above their cost of service and the industrial customers served at transmission voltage (Rate 31) are now collecting roughly 10% above their assigned costs. The single customer on the industrial transmission TOU rate (Rate 33) is only collecting about 25% of its cost. This is due in large part because the customer does not pay a demand charge and is able to avoid all transmission costs during off-peak periods.

Wholesale rates after the 1997 rebalancing were set equal to 100%, however, they are now primarily undercollecting their costs, with the exception of BC Hydro Lardeau and BC Hydro Yahk. As a group, these customers billed under Rate Schedule 40 have a Revenue-to-Cost Ratio of 83.4%. Individually, the Revenue-to-Cost Ratios vary from 68% to 103%. Nelson in particular is only collecting about 80% of its costs due to the fact that current rates do not account for the back-up service provided and the need to build transmission facilities to meet loads in the event Nelson's generating unit is off-line.

Conclusions

The revenue to cost ratios and unit costs resulting from the COSA were used as inputs in developing the rates proposed in the Rate Design Application. The rate design for several of the classes is adjusted to better meet goals of the utility. The mechanism for rate rebalancing between classes is also described in the Rate Design Application and relies upon the revenue to cost ratios in the COSA.

Appendix A—COSA Schedules

EES Consulting, Inc.

Fortis BC 2009 COSA

Cost of Service Schedules

September 30, 2009

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Fortis BC 2009 COSA
DIRECTORY OF COST OF SERVICE
AND UNIT COST CALCULATIONS

DESCRIPTION	*Worksheet*	*Schedule / Range N*
Data Inputs		
Name of Utility	Cover	utility
Draft Version	Cover	draft
Historic kWh	Load	8.4
Forecast kWh	Load	8.1
Historic kW or kVa	Load	8.5
Forecast kW or kVa	Load	8.2
Historic, Test and Allocation Year	Load	date
Rate Class Names	Load	8.4
Historic # Of Customers	Load	8.4
Forecast # Of Customers	Load	8.1
Customer + kWh Escalation Rates	Load	8.1
Customer Weighting Factors	Load	8.1
Peak / Off Peak %	Load	8.6
Line Losses & Historic Load Reconciliation	Load	8.6
Revenue Requirement	Rev Req	3.1
Forecast Years	Rev Req	3.2
Expense / Revenue Escalation Rates	Rev Req	exgrowth
OM&A Expenses & Other Revenue	Rev Req	3.1
Capital Outlays, Debt Service and Depreciation	Rev Req	3.1
DSC and ROI	Rev Req	3.1
Rates and Revenues	Revenues	7.1
Rate Design	Rates	9.1
Rate Base & Plant Investment	Rate Base	4.1
Power Supply Rates	Power Supply	5.1
Power Supply Cost Forecast	Power Supply	5.2 - 5.6
Minimum System Analysis	C&A by Cust	minsys
Demand Allocation Method	C&A by Cust	demand
CP Allocation Method	C&A by Cust	cp
Direct Assignment Description	FA&C Factors	DA
Cost Functionalization, Allocation, & Classification Codes	FA&C Factors	
Direct Assignment Customer Allocation	C&A by Cust	6.2 & 6.5

Fortis BC 2009 COSA
DIRECTORY OF COST OF SERVICE
AND UNIT COST CALCULATIONS

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Revenue Requirement F&C	Rev Req	3.1
Rate Base F&C	Rate Base	4.1
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SUMMARY OF REVENUE REQUIREMENT COST ALLOCATION	Summary	1.4
SUMMARY OF RATE BASE COST ALLOCATIONS	Summary	1.5
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REVENUE REQUIREMENT COST ALLOCATION DIRECT ASSIGNMENT BY CUSTOMER	Rev Req	3.4
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RATE BASE FOR COST ALLOCATION FUNCTIONALIZATION AND CLASSIFICATION	Rate Base	4.2
RATE BASE COST ALLOCATION CLASSIFICATION BY CUSTOMER	Rate Base	4.3
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COST OF SERVICE SUMMARY
BY CUSTOMER CLASS
Schedule 1.1

Forecast Year: 2009	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Revenues:																
Customer Charge Revenues	$16,781,898	$13,870,451	$1,543,005	$423,237	$24,249	$290,114	$79,123		$180,478	$81,209	$101,512	$40,605	$60,907	$20,302	$20,302	$46,406
Energy Revenues	$187,277,138	$92,085,331	$16,297,213	$30,129,853	$866,025	$6,262,625	$2,605,197	$1,974,565	$2,522,827	$11,286,794	$13,336,001	$3,704,361	$1,592,612	$346,520	$105,780	$4,161,435
Demand Revenues	$29,360,043			$10,732,074		$3,175,819	$588,079			$4,922,460	$5,728,812	$1,774,748	$638,757	$325,407	$55,462	$1,418,425
Total Revenues at Existing Rates	**$233,419,080**	**$105,955,782**	**$17,840,218**	**$41,285,164**	**$890,273**	**$9,728,558**	**$3,272,400**	**$1,974,565**	**$2,703,305**	**$16,290,463**	**$19,166,325**	**$5,519,713**	**$2,292,276**	**$692,230**	**$181,544**	**$5,626,265**
Production-Related Costs	108,315,364	43,436,503	6,924,836	16,906,075	905,303	4,776,682	2,028,470	446,954	1,654,348	10,127,900	12,025,871	3,360,798	1,417,056	367,535	96,736	3,840,295
Transmission-Related Costs	56,672,801	17,707,096	2,735,359	6,772,849	2,855,048	1,841,872	790,306	84,399	722,039	6,475,657	9,952,421	1,833,425	1,481,950	206,689	36,516	3,177,178
Distribution-Related Costs	70,438,592	47,534,773	6,213,746	6,289,558	54,287	1,399,343	185,124	1,901,302	1,092,887	1,669,064	2,802,802	567,015	497,436	111,646	43,584	76,023
Total Allocated Revenue Requirements	**$235,426,757**	**$108,678,372**	**$15,873,940**	**$29,968,481**	**$3,814,638**	**$8,017,898**	**$3,003,901**	**$2,432,656**	**$3,469,274**	**$18,272,621**	**$24,781,094**	**$5,761,237**	**$3,396,442**	**$685,871**	**$176,836**	**$7,093,496**
Difference	-$2,007,677	-$2,722,590	$1,966,277	$11,316,683	-$2,924,364	$1,710,660	$268,499	-$458,091	-$765,969	-$1,982,158	-$5,614,770	-$241,524	-$1,104,166	$6,359	$4,708	-$1,467,231
% Increase to Equal Allocated Cost	0.9%	2.6%	-11.0%	-27.4%	328.5%	-17.6%	-8.2%	23.2%	28.3%	12.2%	29.3%	4.4%	48%	-1%	-3%	26%
Revenue To Cost Ratio	**99.1%**	**97.5%**	**112.4%**	**137.8%**	**23.3%**	**121.3%**	**108.9%**	**81.2%**	**77.9%**	**89.2%**	**77.3%**	**95.8%**	**67.5%**	**100.9%**	**102.7%**	**79.3%**
Adjusted Revenues at Existing Rates	$235,426,757	$106,867,126	$17,993,664	$41,640,265	$897,931	$9,812,235	$3,300,546	$1,991,549	$2,726,557	$16,430,580	$19,331,178	$5,567,189	$2,311,992	$698,184	$183,106	$5,674,658
Adjusted Revenue to Cost Ratio	**100.0%**	**98.3%**	**113.4%**	**138.9%**	**23.5%**	**122.4%**	**109.9%**	**81.9%**	**78.6%**	**89.9%**	**78.0%**	**96.6%**	**68.1%**	**101.8%**	**103.5%**	**80.0%**
Average Unit Costs:																
Customer Charge $ / Per Customer / Month	$31.91	$29.66	$35.68	$60.12	$4,737.61	$1,014.76	$5,089.41	$29.96	$37.04	$13,536.04	$19,104.77	$6,160.35	$8,449.24	$2,679.75	$2,491.12	$6,697.04
Average Energy + Demand Charge $ / kWh	$0.02617	$0.02640	$0.02628	$0.02640	$0.02848	$0.02494	$0.02413	$0.09312	$0.02596	$0.02503	$0.02505	$0.02510	$0.02494	$0.02612	$0.02496	$0.02485
Average Energy Charge $ / kWh	$0.06210	$0.06087	$0.05911	$0.05938	$0.22774	$0.05401	$0.04230	$0.12409	$0.06280	$0.06025	$0.06913	$0.05765	$0.07769	$0.07084	$0.05216	$0.06232
Demand Charge $ / kW	$13.51	$13.10	$10.51	$9.10	$24.03	$9.52	$11.65	$33.26	$12.17	$17.60	$21.72	$15.88	$26.89	$13.71	$11.89	$16.32
Combined Average Rate $ / kWh	**$0.0758**	**$0.0890**	**$0.0780**	**$0.0631**	**$0.2312**	**$0.0569**	**$0.0450**	**$0.1754**	**$0.0726**	**$0.0608**	**$0.0698**	**$0.0584**	**$0.0801**	**$0.0743**	**$0.0628**	**$0.0630**

FUNCTIONALIZATION AND CLASSIFICATION OF REVENUE REQUIREMENT SUMMARY
BY CUSTOMER CLASS
Schedule 1.2

Forecast Year: 2009	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Production																
Demand (PD)	$27,935,341	$11,185,209	$1,578,765	$4,374,208	$435,276	$1,259,293	$419,387	$97,429	$413,458	$2,604,379	$3,127,142	$884,826	$359,044	$126,521	$26,424	$1,043,979
Energy (PE)	$80,380,022	$32,251,294	$5,346,071	$12,531,866	$470,026	$3,517,389	$1,609,083	$349,525	$1,240,891	$7,523,521	$8,898,729	$2,475,972	$1,058,013	$241,015	$70,312	$2,796,316
Direct Assignment (PDA)																
Transmission																
Demand (TD)	$56,672,801	$17,707,096	$2,735,359	$6,772,849	$2,855,048	$1,841,872	$790,306	$84,399	$722,039	$6,475,657	$9,952,421	$1,833,425	$1,481,950	$206,689	$36,516	$3,177,178
Energy (TE)																
Direct Assignment (TDA)																
Distribution																
Demand (DD)	$27,026,122	$13,218,372	$2,366,171	$4,511,004	-$2,445	$997,708	$1,978	$247,638	$625,887	$1,507,124	$2,574,250	$493,243	$396,146	$79,508	$13,696	-$4,156
Energy (DE)																
Customer (DC)	$42,477,874	$34,319,963	$3,848,088	$1,779,415	$56,851	$401,845	$183,219	$711,965	$467,110	$162,432	$229,257	$73,924	$101,391	$32,157	$29,893	$80,365
Direct Assignment (DDA)	$934,596	-$3,562	-$513	-$861	-$119	-$209	-$72	$941,700	-$109	-$493	-$705	-$152	-$101	-$19	-$5	-$185
Total	**$235,426,757**	**$108,678,372**	**$15,873,940**	**$29,968,481**	**$3,814,638**	**$8,017,898**	**$3,003,901**	**$2,432,656**	**$3,469,274**	**$18,272,621**	**$24,781,094**	**$5,761,237**	**$3,396,442**	**$685,871**	**$176,836**	**$7,093,496**
Total Cost / Function																
Production	$108,315,364	$43,436,503	$6,924,836	$16,906,075	$905,303	$4,776,682	$2,028,470	$446,954	$1,654,348	$10,127,900	$12,025,871	$3,360,798	$1,417,056	$367,535	$96,736	$3,840,295
Transmission	$56,672,801	$17,707,096	$2,735,359	$6,772,849	$2,855,048	$1,841,872	$790,306	$84,399	$722,039	$6,475,657	$9,952,421	$1,833,425	$1,481,950	$206,689	$36,516	$3,177,178
Distribution	$70,438,592	$47,534,773	$6,213,746	$6,289,558	$54,287	$1,399,343	$185,124	$1,901,302	$1,092,887	$1,669,064	$2,802,802	$567,015	$497,436	$111,646	$43,584	$76,023
Total Cost / Function	**$235,426,757**	**$108,678,372**	**$15,873,940**	**$29,968,481**	**$3,814,638**	**$8,017,898**	**$3,003,901**	**$2,432,656**	**$3,469,274**	**$18,272,621**	**$24,781,094**	**$5,761,237**	**$3,396,442**	**$685,871**	**$176,836**	**$7,093,496**
Total Cost / Classifier																
Demand	$111,634,265	$42,110,677	$6,680,295	$15,658,061	$3,287,879	$4,098,873	$1,211,671	$429,466	$1,761,383	$10,587,160	$15,653,813	$3,211,493	$2,237,140	$412,718	$76,636	$4,217,001
Energy	$80,380,022	$32,251,294	$5,346,071	$12,531,866	$470,026	$3,517,389	$1,609,083	$349,525	$1,240,891	$7,523,521	$8,898,729	$2,475,972	$1,058,013	$241,015	$70,312	$2,796,316
Customer	$42,477,874	$34,319,963	$3,848,088	$1,779,415	$56,851	$401,845	$183,219	$711,965	$467,110	$162,432	$229,257	$73,924	$101,391	$32,157	$29,893	$80,365
Direct Assignment	$934,596	-$3,562	-$513	-$861	-$119	-$209	-$72	$941,700	-$109	-$493	-$705	-$152	-$101	-$19	-$5	-$185
Total Cost / Classifier	**$235,426,757**	**$108,678,372**	**$15,873,940**	**$29,968,481**	**$3,814,638**	**$8,017,898**	**$3,003,901**	**$2,432,656**	**$3,469,274**	**$18,272,621**	**$24,781,094**	**$5,761,237**	**$3,396,442**	**$685,871**	**$176,836**	**$7,093,496**

FUNCTIONALIZATION AND CLASSIFICATION OF RATE BASE SUMMARY
BY CUSTOMER CLASS
Schedule 1.3

Mid-Year	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Production																
Demand (PD)	$40,116,642	$16,126,202	$2,599,254	$6,245,880	$347,677	$1,751,649	$738,527	$157,686	$631,948	$3,732,858	$4,440,028	$1,239,609	$521,847	$137,515	$35,021	$1,410,939
Energy (PE)	$155,012,394	$62,311,669	$10,236,408	$24,125,853	$1,128,067	$6,751,577	$2,969,303	$633,701	$2,451,878	$14,438,208	$17,134,579	$4,772,682	$2,024,679	$497,619	$134,257	$5,401,914
Direct Assignment (PDA)																
Transmission																
Demand (TD)	$335,237,528	$105,126,455	$16,228,901	$40,064,111	$16,817,070	$10,888,237	$4,666,737	$523,567	$4,276,174	$38,209,223	$58,708,180	$10,821,784	$8,740,672	$1,220,406	$215,998	$18,730,012
Energy (TE)																
Direct Assignment (TDA)																
Distribution																
Demand (DD)	$171,148,062	$81,028,656	$14,826,628	$29,109,607	$113	$6,530,226	$339	$1,340,822	$4,005,557	$10,225,033	$17,442,615	$3,341,548	$2,673,307	$534,523	$88,944	$147
Energy (DE)																
Customer (DC)	$200,447,837	$163,735,850	$18,656,288	$8,446,193	$304,196	$699,068	$912,587	$3,046,791	$2,126,199	$532,005	$667,086	$265,213	$396,776	$132,100	$131,901	$395,584
Direct Assignment (DDA)	$6,016,036							$6,016,036								
Total	**$907,978,500**	**$428,328,832**	**$62,547,480**	**$107,991,645**	**$18,597,123**	**$26,620,757**	**$9,287,491**	**$11,718,603**	**$13,491,757**	**$67,137,328**	**$98,392,488**	**$20,440,836**	**$14,357,281**	**$2,522,162**	**$606,121**	**$25,938,595**
Total Cost / Function																
Production	$195,129,036	$78,437,871	$12,835,663	$30,371,734	$1,475,745	$8,503,227	$3,707,829	$791,386	$3,083,827	$18,171,066	$21,574,607	$6,012,291	$2,546,526	$635,134	$169,278	$6,812,853
Transmission	$335,237,528	$105,126,455	$16,228,901	$40,064,111	$16,817,070	$10,888,237	$4,666,737	$523,567	$4,276,174	$38,209,223	$58,708,180	$10,821,784	$8,740,672	$1,220,406	$215,998	$18,730,012
Distribution	$377,611,936	$244,764,506	$33,482,916	$37,555,800	$304,308	$7,229,294	$912,925	$10,403,650	$6,131,756	$10,757,039	$18,109,700	$3,606,761	$3,070,083	$666,622	$220,845	$395,731
Total Cost / Function	**$907,978,500**	**$428,328,832**	**$62,547,480**	**$107,991,645**	**$18,597,123**	**$26,620,757**	**$9,287,491**	**$11,718,603**	**$13,491,757**	**$67,137,328**	**$98,392,488**	**$20,440,836**	**$14,357,281**	**$2,522,162**	**$606,121**	**$25,938,595**
Total Cost / Classifier																
Demand	$546,502,233	$202,281,313	$33,654,784	$75,419,598	$17,164,860	$19,170,112	$5,405,602	$2,022,075	$8,913,679	$52,167,115	$80,590,824	$15,402,942	$11,935,826	$1,892,444	$339,963	$20,141,097
Energy	$155,012,394	$62,311,669	$10,236,408	$24,125,853	$1,128,067	$6,751,577	$2,969,303	$633,701	$2,451,878	$14,438,208	$17,134,579	$4,772,682	$2,024,679	$497,619	$134,257	$5,401,914
Customer	$200,447,837	$163,735,850	$18,656,288	$8,446,193	$304,196	$699,068	$912,587	$3,046,791	$2,126,199	$532,005	$667,086	$265,213	$396,776	$132,100	$131,901	$395,584
Direct Assignment	$6,016,036							$6,016,036								
Total Cost / Classifier	**$907,978,500**	**$428,328,832**	**$62,547,480**	**$107,991,645**	**$18,597,123**	**$26,620,757**	**$9,287,491**	**$11,718,603**	**$13,491,757**	**$67,137,328**	**$98,392,488**	**$20,440,836**	**$14,357,281**	**$2,522,162**	**$606,121**	**$25,938,595**

SUMMARY OF REVENUE REQUIREMENT COST ALLOCATION
Schedule 1.4

Forecast Year: 2009	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Hydraulic Power Generation	$9,679,000	$3,891,431	$638,470	$1,506,217	$72,420	$421,316	$184,200	$39,153	$153,485	$901,040	$1,069,753	$298,047	$126,279	$31,375	$8,372	$337,441
Purchased Power Supply/Other	$73,237,757	$29,365,453	$4,615,438	$11,434,622	$644,935	$3,244,139	$1,358,199	$308,006	$1,098,670	$6,853,738	$8,144,430	$2,277,136	$959,750	$253,435	$66,282	$2,613,525
Total Production	$82,916,757	$33,256,884	$5,253,908	$12,940,839	$717,355	$3,665,455	$1,542,399	$347,159	$1,252,155	$7,754,777	$9,214,183	$2,575,183	$1,086,029	$284,810	$74,654	$2,950,967
Total Transmission	$12,219,000	$3,831,731	$591,524	$1,460,288	$612,962	$396,863	$170,097	$19,083	$155,861	$1,392,680	$2,139,842	$394,441	$318,587	$44,482	$7,873	$682,686
Total Distribution	$7,743,000	$5,580,456	$711,452	$502,133	$12,781	$87,806	$38,344	$191,638	$95,960	$146,511	$239,842	$51,713	$49,116	$12,034	$6,614	$16,599
Total Operation & Maintenance	**$102,878,757**	**$42,669,071**	**$6,556,884**	**$14,903,260**	**$1,343,098**	**$4,150,124**	**$1,750,840**	**$557,881**	**$1,503,976**	**$9,293,969**	**$11,593,867**	**$3,021,337**	**$1,453,732**	**$341,327**	**$89,141**	**$3,650,251**
Total O&M w/o Purchased Power Supply & A&G	**$36,389,000**	**$18,770,538**	**$2,452,896**	**$3,617,260**	**$706,089**	**$1,151,879**	**$415,871**	**$390,650**	**$480,871**	**$2,469,032**	**$3,485,251**	**$757,637**	**$512,208**	**$93,886**	**$28,710**	**$1,056,221**
Total Customer Service, Accounts & Sales	$6,748,000	$5,466,920	$511,450	$148,622	$7,926	$245,895	$23,230	$140,775	$75,564	$28,801	$35,814	$13,436	$18,226	$5,994	$5,851	$19,495
Total Administrative & General	$11,721,000	$5,535,569	$818,202	$1,460,577	$182,831	$366,817	$133,486	$198,061	$177,585	$857,854	$1,194,767	$268,417	$167,260	$32,166	$8,099	$319,309
Total O&M plus A&G	**$121,347,757**	**$53,671,560**	**$7,886,536**	**$16,512,459**	**$1,533,855**	**$4,762,836**	**$1,907,556**	**$896,717**	**$1,757,125**	**$10,180,624**	**$12,824,448**	**$3,303,190**	**$1,639,218**	**$379,487**	**$103,091**	**$3,989,055**
Total Depreciation	$37,504,000	$19,490,516	$2,727,345	$4,217,210	$659,143	$979,625	$307,121	$545,957	$564,841	$2,328,165	$3,475,199	$706,567	$515,589	$89,600	$21,781	$875,341
Total Property Taxes	$11,561,000	$5,804,683	$821,139	$1,331,248	$217,546	$316,801	$105,008	$153,795	$173,154	$769,729	$1,134,460	$233,724	$166,285	$28,945	$6,931	$297,551
Total Return and Income Taxes	$69,929,000	$32,988,234	$4,817,166	$8,317,100	$1,432,279	$2,050,228	$715,287	$902,522	$1,039,083	$5,170,658	$7,577,810	$1,574,274	$1,105,742	$194,247	$46,681	$1,997,690
Revenue Requirement Before Other Revenues	**$240,341,757**	**$111,954,993**	**$16,252,185**	**$30,378,017**	**$3,842,823**	**$8,109,490**	**$3,034,972**	**$2,498,990**	**$3,534,204**	**$18,449,176**	**$25,011,917**	**$5,817,756**	**$3,426,834**	**$692,279**	**$178,484**	**$7,159,638**
Total Other Revenues	$4,915,000	$3,276,620	$378,245	$409,536	$28,185	$91,593	$31,071	$66,334	$64,930	$176,556	$230,823	$56,518	$30,393	$6,408	$1,648	$66,142
REVENUE REQUIREMENT for COST ALLOCATION	**$235,426,757**	**$108,678,372**	**$15,873,940**	**$29,968,481**	**$3,814,638**	**$8,017,898**	**$3,003,901**	**$2,432,656**	**$3,469,274**	**$18,272,621**	**$24,781,094**	**$5,761,237**	**$3,396,442**	**$685,871**	**$176,836**	**$7,093,496**

SUMMARY OF RATE BASE COST ALLOCATIONS
Schedule 1.5

Mid-Year	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Total Production Plant	$162,227,500	$65,223,391	$10,701,248	$25,245,364	$1,213,811	$7,061,573	$3,087,336	$656,231	$2,572,531	$15,102,118	$17,929,888	$4,995,505	$2,116,534	$525,871	$140,326	$5,655,774
Total Transmission Plant	$351,704,000	$110,290,142	$17,026,045	$42,032,013	$17,643,104	$11,423,054	$4,895,961	$549,284	$4,486,215	$40,086,015	$61,591,857	$11,353,338	$9,170,004	$1,280,351	$226,608	$19,650,008
Total Distribution Plant	$571,086,500	$384,794,666	$50,855,909	$55,405,952	$368,772	$10,161,473	$1,106,317	$14,345,135	$9,272,715	$13,080,106	$22,022,022	$4,385,141	$3,731,602	$809,982	$267,802	$478,905
Total Transmission & Distribution	$922,790,500	$495,084,809	$67,881,954	$97,437,965	$18,011,877	$21,584,527	$6,002,279	$14,894,420	$13,758,929	$53,166,121	$83,613,879	$15,738,479	$12,901,606	$2,090,332	$494,410	$20,128,913
Total General Plant	$147,970,500	$71,498,875	$10,409,551	$18,396,098	$2,301,672	$4,585,145	$1,665,814	$1,691,654	$2,253,037	$10,600,865	$14,697,614	$3,311,815	$2,046,217	$391,892	$97,560	$4,022,692
Total Plant Before General Plant & Intangible	**$1,085,018,000**	**$560,308,199**	**$78,583,203**	**$122,683,329**	**$19,225,688**	**$28,646,100**	**$9,089,614**	**$15,550,651**	**$16,331,460**	**$68,268,240**	**$101,543,767**	**$20,733,984**	**$15,018,139**	**$2,616,203**	**$634,736**	**$25,784,686**
Total Gross Plant in Service	**$1,232,988,500**	**$631,807,074**	**$88,992,753**	**$141,079,427**	**$21,527,360**	**$33,231,245**	**$10,755,429**	**$17,242,305**	**$18,584,497**	**$78,869,104**	**$116,241,381**	**$24,045,799**	**$17,064,357**	**$3,008,095**	**$732,296**	**$29,807,379**
Total Accumulated Depreciation	$289,697,500	$158,188,359	$21,994,034	$32,459,553	$3,777,117	$7,382,681	$2,187,627	$4,693,802	$4,456,383	$16,065,005	$23,677,910	$4,975,642	$3,496,727	$646,378	$166,810	$5,529,471
Total Net Plant	**$943,291,000**	**$473,618,714**	**$66,998,719**	**$108,619,874**	**$17,750,243**	**$25,848,564**	**$8,567,802**	**$12,548,502**	**$14,128,115**	**$62,804,099**	**$92,563,471**	**$19,070,156**	**$13,567,630**	**$2,361,717**	**$565,486**	**$24,277,908**
Total Working Capital	$17,875,000	$7,424,530	$1,131,004	$2,580,438	$232,546	$734,993	$302,472	$104,968	$262,499	$1,610,742	$2,007,814	$523,548	$251,415	$59,011	$15,368	$633,653
Total Contributions	-$92,438,500	-$72,030,188	-$8,370,479	-$7,996,418		-$1,140,173		-$1,405,197	-$1,496,045							
SUB-TOTAL RATE BASE	**$868,727,500**	**$409,013,056**	**$59,759,244**	**$103,203,894**	**$17,982,789**	**$25,443,384**	**$8,870,274**	**$11,248,274**	**$12,894,569**	**$64,414,842**	**$94,571,284**	**$19,593,704**	**$13,819,045**	**$2,420,728**	**$580,854**	**$24,911,561**
Total Other Rate Base Items	$39,251,000	$19,315,775	$2,788,236	$4,787,751	$614,334	$1,177,373	$417,217	$470,329	$597,188	$2,722,486	$3,821,204	$847,132	$538,236	$101,434	$25,268	$1,027,034
TOTAL RATE BASE	**$907,978,500**	**$428,328,832**	**$62,547,480**	**$107,991,645**	**$18,597,123**	**$26,620,757**	**$9,287,491**	**$11,718,603**	**$13,491,757**	**$67,137,328**	**$98,392,488**	**$20,440,836**	**$14,357,281**	**$2,522,162**	**$606,121**	**$25,938,595**

SUMMARY OF REVENUE REQUIREMENT UNIT COSTS
BY CUSTOMER CLASS
Schedule 2.1

Forecast Year: 2009	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Billing Determinants																
Total kVA (with ratchet)	4,391,189			1,720,080		478,286	109,512			672,467	782,625	242,452	87,262	44,455	7,577	246,474
Total Demand (kW)	8,329,272	3,213,502	635,838	1,720,080	136,800	430,457	104,036	41,225	144,719	601,397	720,794	202,239	83,197	30,106	6,443	258,440
Total kVA Contract					480,000		133,200			1,090,584	1,798,830	340,560	273,240	44,455	5,742	534,600
Total Energy (kWh)	3,107,070,981	1,221,674,870	203,446,005	474,707,344	16,500,000	141,018,352	66,680,240	13,866,327	47,802,478	300,580,396	355,153,151	98,651,430	42,413,094	9,228,226	2,817,036	112,532,033
Average Monthly Customers	110,944	96,413	8,989	2,466	1	33	3	1,980	1,051	1	1	1	1	1	1	1
Average PODs										4	5	2	3	1	1	3
Functional Cost																
Production																
Demand (PD)	$27,935,341	$11,185,209	$1,578,765	$4,374,208	$435,276	$1,259,293	$419,387	$97,429	$413,458	$2,604,379	$3,127,142	$884,826	$359,044	$126,521	$26,424	$1,043,979
$/kW	$3.35	$3.48	$2.48	$2.54	$3.18	$2.93	$4.03	$2.36	$2.86	$4.33	$4.34	$4.38	$4.32	$4.20	$4.10	$4.04
or $/kVa				$2.54		$2.63	$3.83			$3.87	$4.00	$3.65	$4.11	$2.85	$3.49	$4.24
Energy (PE)	$80,380,022	$32,251,294	$5,346,071	$12,531,866	$470,026	$3,517,389	$1,609,083	$349,525	$1,240,891	$7,523,521	$8,898,729	$2,475,972	$1,058,013	$241,015	$70,312	$2,796,316
$/kWh	$0.026	$0.026	$0.026	$0.026	$0.028	$0.025	$0.024	$0.025	$0.026	$0.025	$0.025	$0.025	$0.025	$0.026	$0.025	$0.025
Transmission																
Demand (TD)	$56,672,801	$17,707,096	$2,735,359	$6,772,849	$2,855,048	$1,841,872	$790,306	$84,399	$722,039	$6,475,657	$9,952,421	$1,833,425	$1,481,950	$206,689	$36,516	$3,177,178
$/kW	$6.80	$5.51	$4.30	$3.94	$20.87	$4.28	$7.60	$2.05	$4.99	$10.77	$13.81	$9.07	$17.81	$6.87	$5.67	$12.29
or $/kVa				$3.94		$3.85	$7.22			$9.63	$12.72	$7.56	$16.98	$4.65	$4.82	$12.89
or $/kVa Contract										$5.94	$5.53	$5.38	$5.42	$4.65	$6.36	$5.94
Distribution																
Demand (DD)	$27,026,122	$13,218,372	$2,366,171	$4,511,004	-$2,445	$997,708	$1,978	$247,638	$625,887	$1,507,124	$2,574,250	$493,243	$396,146	$79,508	$13,696	-$4,156
$/kW	$3.24	$4.11	$3.72	$2.62	-$0.02	$2.32	$0.02	$6.01	$4.32	$2.51	$3.57	$2.44	$4.76	$2.64	$2.13	-$0.02
or $/kVa				$2.62		$2.09	$0.02			$2.24	$3.29	$2.03	$4.54	$1.79	$1.81	-$0.02
Customer (DC)	$42,477,874	$34,319,963	$3,848,088	$1,779,415	$56,851	$401,845	$183,219	$711,965	$467,110	$162,432	$229,257	$73,924	$101,391	$32,157	$29,893	$80,365
$/Customer/Month	$31.91	$29.66	$35.68	$60.12	$4,737.61	$1,014.76	$5,089.41	$29.96	$37.04	$13,536.04	$19,104.77	$6,160.35	$8,449.24	$2,679.75	$2,491.12	$6,697.04
Direct Assignment (DDA)	$934,596	-$3,562	-$513	-$861	-$119	-$209	-$72	$941,700	-$109	-$493	-$705	-$152	-$101	-$19	-$5	-$185
$/kW	$0.11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.84	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$/kVa				$0.00		$0.00	$0.00			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$/kWh	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.068	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Total	**$235,426,757**	**$108,678,372**	**$15,873,940**	**$29,968,481**	**$3,814,638**	**$8,017,898**	**$3,003,901**	**$2,432,656**	**$3,469,274**	**$18,272,621**	**$24,781,094**	**$5,761,237**	**$3,396,442**	**$685,871**	**$176,836**	**$7,093,496**
Total																
$/kW	**$13.51**	**$13.10**	**$10.51**	**$9.10**	**$24.03**	**$9.52**	**$11.65**	**$33.26**	**$12.17**	**$17.60**	**$21.72**	**$15.88**	**$26.89**	**$13.71**	**$11.89**	**$16.32**
$/kVa				**$9.10**		**$8.57**	**$11.06**			**$15.74**	**$20.00**	**$13.25**	**$25.64**	**$9.28**	**$10.11**	**$17.11**
$/kWh	**$0.0262**	**$0.0264**	**$0.0263**	**$0.0264**	**$0.0285**	**$0.0249**	**$0.0241**	**$0.0931**	**$0.0260**	**$0.0250**	**$0.0251**	**$0.0251**	**$0.0249**	**$0.0261**	**$0.0250**	**$0.0248**
$/kWh (energy only)	**$0.0621**	**$0.0609**	**$0.0591**	**$0.0594**	**$0.2277**	**$0.0540**	**$0.0423**	**$0.1241**	**$0.0628**	**$0.0603**	**$0.0691**	**$0.0577**	**$0.0777**	**$0.0708**	**$0.0522**	**$0.0623**
$/Customer/Month	**$31.91**	**$29.66**	**$35.68**	**$60.12**	**$4,737.61**	**$1,014.76**	**$5,089.41**	**$29.96**	**$37.04**	**$13,536.04**	**$19,104.77**	**$6,160.35**	**$8,449.24**	**$2,679.75**	**$2,491.12**	**$6,697.04**
$/POD/Month										**$3,384.01**	**$3,820.95**	**$3,080.17**	**$2,816.41**	**$2,679.75**	**$2,491.12**	**$2,232.35**
Total Average Cost per kWh	**$0.0758**	**$0.0890**	**$0.0780**	**$0.0631**	**$0.2312**	**$0.0569**	**$0.0450**	**$0.1754**	**$0.0726**	**$0.0608**	**$0.0698**	**$0.0584**	**$0.0801**	**$0.0743**	**$0.0628**	**$0.0630**

SUMMARY OF RATE BASE UNIT COST
BY CUSTOMER CLASS
Schedule 2.2

Forecast Year: 2009	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Billing Determinants																
Total kVa	4,391,189			1,720,080		478,286	109,512			672,467	782,625	242,452	87,262	44,455	7,577	246,474
Total Demand (kW)	8,329,272	3,213,502	635,838	1,720,080	136,800	430,457	104,036	41,225	144,719	601,397	720,794	202,239	83,197	30,106	6,443	258,440
Total Energy (kWh)	3,107,070,981	1,221,674,870	203,446,005	474,707,344	16,500,000	141,018,352	66,680,240	13,866,327	47,802,478	300,580,396	355,153,151	98,651,430	42,413,094	9,228,226	2,817,036	112,532,033
Average Monthly Customers	110,944	96,413	8,989	2,466	1	33	3	1,980	1,051	1	1	1	1	1	1	1
Functional Cost																
Production																
Demand (PD)	$40,116,642	$16,126,202	$2,599,254	$6,245,880	$347,677	$1,751,649	$738,527	$157,686	$631,948	$3,732,858	$4,440,028	$1,239,609	$521,847	$137,515	$35,021	$1,410,939
$/kW		$5.02	$4.09	$3.63	$2.54	$4.07	$7.10	$3.83	$4.37	$6.21	$6.16	$6.13	$6.27	$4.57	$5.44	$5.46
or $/kVa				$3.63		$3.66	$6.74			$5.55	$5.67	$5.11	$5.98	$3.09	$4.62	$5.72
Energy (PE)	$155,012,394	$62,311,669	$10,236,408	$24,125,853	$1,128,067	$6,751,577	$2,969,303	$633,701	$2,451,878	$14,438,208	$17,134,579	$4,772,682	$2,024,679	$497,619	$134,257	$5,401,914
$/kWh	$0.050	$0.051	$0.050	$0.051	$0.068	$0.048	$0.045	$0.046	$0.051	$0.048	$0.048	$0.048	$0.048	$0.054	$0.048	$0.048
Transmission																
Demand (TD)	$335,237,528	$105,126,455	$16,228,901	$40,064,111	$16,817,070	$10,888,237	$4,666,737	$523,567	$4,276,174	$38,209,223	$58,708,180	$10,821,784	$8,740,672	$1,220,406	$215,998	$18,730,012
$/kW		$32.71	$25.52	$23.29	$122.93	$25.29	$44.86	$12.70	$29.55	$63.53	$81.45	$53.51	$105.06	$40.54	$33.52	$72.47
or $/kVa				$23.29		$22.77	$42.61			$56.82	$75.01	$44.63	$100.17	$27.45	$28.51	$75.99
Distribution																
Demand (DD)	$171,148,062	$81,028,656	$14,826,628	$29,109,607	$113	$6,530,226	$339	$1,340,822	$4,005,557	$10,225,033	$17,442,615	$3,341,548	$2,673,307	$534,523	$88,944	$147
$/kW		$25.22	$23.32	$16.92	$0.00	$15.17	$0.00	$32.52	$27.68	$17.00	$24.20	$16.52	$32.13	$17.75	$13.80	$0.00
or $/kVa				$16.92		$13.65	$0.00			$15.21	$22.29	$13.78	$30.64	$12.02	$11.74	$0.00
Customer (DC)	$200,447,837	$163,735,850	$18,656,288	$8,446,193	$304,196	$699,068	$912,587	$3,046,791	$2,126,199	$532,005	$667,086	$265,213	$396,776	$132,100	$131,901	$395,584
$/Customer/Month		$142	$173	$285	$25,350	$1,765	$25,350	$128	$169	$44,334	$55,590	$22,101	$33,065	$11,008	$10,992	$32,965
Direct Assignment (DDA)	$6,016,036							$6,016,036								
$/kW								$145.93								
$/kVa																
$/kWh								$0.434								
Total	**$907,978,500**	**$428,328,832**	**$62,547,480**	**$107,991,645**	**$18,597,123**	**$26,620,757**	**$9,287,491**	**$11,718,603**	**$13,491,757**	**$67,137,328**	**$98,392,488**	**$20,440,836**	**$14,357,281**	**$2,522,162**	**$606,121**	**$25,938,595**

INPUT REVENUE REQUIREMENT
Schedule 3.1

FERC Account	Operation & Maintenance Expense	2009 Cost, $	Function	Classification Factor	Classification Method
535.00	Op. Supervision & Engineering	-$207,000	P	RBG	On the Basis of Generation Rate Base
536.00	Water for Power	$8,286,000	P	RBG	On the Basis of Generation Rate Base
542.00	Structures	$627,000	P	RBG	On the Basis of Generation Rate Base
543.00	Dams & Waterways	$176,000	P	RBG	On the Basis of Generation Rate Base
544.00	Electric Plant	$530,000	P	RBG	On the Basis of Generation Rate Base
545.00	Other Plant	$267,000	P	RBG	On the Basis of Generation Rate Base
	Purchased Power Supply/Other				
555.00	Purchased Power - Energy Charges	$52,400,770	P	PURCHkWh	On the Basis of Energy Purchases Weighted by Month
555.00	Purchased Power - Demand Charges	$19,393,988	P	PURCHkW	On the Basis of Demand Purchases Weighted by Month
556.00	System Control	$1,443,000	P	CP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
	Total Purchased Power	$71,794,757			
	Total Production	$82,916,757			
	Transmission				
560.10	Op. Supervision & Engineering	$648,000	T	RBT	On the Basis of Transmission Rate Base
560.20	System Planning	$1,390,000	T	RBT	On the Basis of Transmission Rate Base
561.00	Load Dispatching	$1,157,000	T	RBT	On the Basis of Transmission Rate Base
562.00	Transmission Station Expense	$750,000	T	RBT	On the Basis of Transmission Rate Base
563.10	Transmission Line Maintenance	$310,000	T	RBT	On the Basis of Transmission Rate Base
563.20	Transmission TROW Maintenance	$556,000	T	RBT	On the Basis of Transmission Rate Base
565.00	Wheeling	$4,010,000	T	RBT	On the Basis of Transmission Rate Base
567.00	Rents	$3,398,000	T	RBT	On the Basis of Transmission Rate Base
	Total Transmission	$12,219,000			
	Distribution				
583.10	Distribution Line Maintenance	$3,467,000	D		On the Basis of RBD Poles, Towers & Fixtures
583.20	Distribution ROW Maintenance	$1,714,000	D		On the Basis of RBD Poles, Towers & Fixtures
586.00	Meter Expenses	$971,000	D		On the Basis of RBD Meters
592.00	Distribution Station Expense	$1,214,000	D		On the Basis of RBD Station Equipment
596.00	Street Lighting	$89,000	D	DA1	On the Basis of RBD Street Lights and Signal Systems
598.00	Other Plant	$288,000	D	RBD	On the Basis of Distribution Rate Base
	Total Distribution	$7,743,000			
	Total Operation & Maintenance	$102,878,757			
	Customer Service, Accounts, & Sales				
901.00	Supervision & Administration	$753,000	D		As All Other Customer Service Expense
902.00	Meter Reading	$1,855,000	D	CUSTW	Customers Weighted for Accounting/Metering
903.00	Customer Billing	$381,000	D	CUSTW	Customers Weighted for Accounting/Metering
904.00	Credit & Collections	$1,983,000	D	CUSTR	Retail Customers
910.00	Customer Assistance	$1,720,000	D	CUSTW	Customers Weighted for Accounting/Metering
911.00	Energy Management Promotion	$56,000	SS	DSM	Classified 72% Energy, 17% Demand & 12% T&D
	Total Customer Service, Accounts & Sales	$6,748,000			
	Total O&M w/o Purchased Power Supply & A&G	$37,832,000			

INPUT REVENUE REQUIREMENT
Schedule 3.1

		2009 Cost, $	Function	Classification Factor	Classification Method
	Administrative & General				
920.10	Executive & Senior Management	$1,768,000	SS	LABOR	On the Basis of Labor Ratios
920.20	Legal	$658,000	SS	LABOR	On the Basis of Labor Ratios
920.30	Human Resources	$1,034,000	SS	LABOR	On the Basis of Labor Ratios
920.40	Finance & Accounting	$720,000	SS	LABOR	On the Basis of Labor Ratios
920.60	Information Services	$1,792,000	SS	LABOR	On the Basis of Labor Ratios
920.70	Materials Management	$284,000	SS	LABOR	On the Basis of Labor Ratios
	Other	$705,000	SS	LABOR	On the Basis of Labor Ratios
930.20	Special Services	$1,536,000	SS	LABOR	On the Basis of Labor Ratios
931.00	Insurance	$615,000	SS	LABOR	On the Basis of Labor Ratios
932.00	Maintenance & General Plant	$1,578,000	SS	LABOR	On the Basis of Labor Ratios
933.00	Transportation Equipment Expenses	$1,031,000	SS	LABOR	On the Basis of Labor Ratios
	Total Administrative & General	$11,721,000			
	Total O&M plus A&G	$121,347,757			
	Depreciation				
403.30	Generation Plant	$3,231,000	P	RBG	On the Basis of Generation Rate Base
403.50	Transmission Plant	$9,518,000	T	RBT	On the Basis of Transmission Rate Base
403.60	Distribution Plant	$15,977,000	D	RBD	On the Basis of Distribution Rate Base
403.70	General Plant And Deferred Charges	$7,844,000	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	DSM Amortization	$934,000	SS		On the Basis of DSM-related Rate Base
	Total Depreciation	$37,504,000			
	Taxes				
408.05	Property	$11,561,000	SS	NETPLT	On the Basis of Net Plant
	Total Property Taxes	$11,561,000			
	Return and Income Taxes				
	Incentive Adjustments	-$1,443,000	SS	RBASE	On the Basis of Total Rate Base
	Income Tax	$4,354,000	SS	RBASE	On the Basis of Total Rate Base
	Return on Rate Base	$67,018,000	SS	RBASE	On the Basis of Total Rate Base
	Interest on Non Rate Base Deferral Account		SS	RBASE	On the Basis of Total Rate Base
	Total Return and Income Taxes	$69,929,000			
	Revenue Requirement Before Other Revenues	$240,341,757			
	Revenue Req. Before Taxes and Other Revenues	$228,780,757			
	Other Revenues				
	Electric Apparatus Rental	$2,133,000	SS		On the Basis of RBD Poles, Towers & Fixtures
	Lease Revenue	$171,000	SS	RBGP	On the Basis of General Plant Rate Base
	Waneta Contract Revenue	$470,000	SS	RBG	On the Basis of Generation Rate Base
	Brilliant Management Fees	$465,000	SS	RBG	On the Basis of Generation Rate Base
	Fortis Pacific Holdings	$641,000	SS	LABOR	On the Basis of Labor Ratios
	Connection Charges	$545,000	SS	CUSTR	Retail Customers
	NSF Cheque Charges	$9,000	SS	CUSTR	Retail Customers
	Sundry Revenue	$150,000	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Investment Income	$331,000	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Total Other Revenues	$4,915,000			
	REVENUE REQUIREMENT for COST ALLOCATION	$235,426,757			

Fortis BC 2009 COSA

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.2

	2009	**Production**			**Transmission**			**Distribution**			
	Total Expenses	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
Operation & Maintenance Expense											
Op. Supervision & Engineering	-$207,000	-$41,498	-$165,502								
Water for Power	$8,286,000	$1,661,123	$6,624,877								
Structures	$627,000	$125,697	$501,303								
Dams & Waterways	$176,000	$35,283	$140,717								
Electric Plant	$530,000	$106,251	$423,749								
Other Plant	$267,000	$53,526	$213,474								
Purchased Power Supply/Other											
Purchased Power - Energy Charges	$52,400,770		$52,400,770								
Purchased Power - Demand Charges	$19,393,988	$19,393,988									
System Control	$1,443,000	$1,443,000									
Total Purchased Power	$52,400,770	$19,393,988	$52,400,770								
Total Production	$82,916,757	$22,777,370	$60,139,387								
Transmission											
Op. Supervision & Engineering	$648,000				$648,000						
System Planning	$1,390,000				$1,390,000						
Load Dispatching	$1,157,000				$1,157,000						
Transmission Station Expense	$750,000				$750,000						
Transmission Line Maintenance	$310,000				$310,000						
Transmission TROW Maintenance	$556,000				$556,000						
Wheeling	$4,010,000				$4,010,000						
Rents	$3,398,000				$3,398,000						
Total Transmission	$12,219,000				$12,219,000						
Distribution											
Distribution Line Maintenance	$3,467,000							$138,680		$3,328,320	
Distribution ROW Maintenance	$1,714,000							$68,560		$1,645,440	
Meter Expenses	$971,000									$971,000	
Distribution Station Expense	$1,214,000							$1,214,000			
Street Lighting	$89,000										$89,000
Other Plant	$288,000							$120,471		$163,839	$3,690
Total Distribution	$7,743,000							$1,541,711		$6,108,599	$92,690
Total Operation & Maintenance	$102,878,757	$22,777,370	$60,139,387		$12,219,000			$1,541,711		$6,108,599	$92,690
Customer Service, Accounts, & Sales											
Supervision & Administration	$753,000	$1,168	$5,036		$316			$218		$746,262	
Meter Reading	$1,855,000									$1,855,000	
Customer Billing	$381,000									$381,000	
Credit & Collections	$1,983,000									$1,983,000	
Customer Assistance	$1,720,000									$1,720,000	
Energy Management Promotion	$56,000	$9,296	$40,096		$2,519			$1,733		$2,357	
Total Customer Service, Accounts & Sales	$6,748,000	$10,464	$45,132		$2,835			$1,950		$6,687,619	
Total O&M w/o Purchased Power Supply & A&G	$36,389,000	$1,950,846	$7,783,750		$12,221,835			$1,543,661		$12,796,217	$92,690

Fortis BC 2009 COSA

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.2

	2009	Production			Transmission			Distribution			
	Total Expenses	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
Administrative & General											
Executive & Senior Management	$1,768,000	$131,142	$523,018		$442,000			$281,032		$382,199	$8,609
Legal	$658,000	$48,807	$194,653		$164,500			$104,592		$142,244	$3,204
Human Resources	$1,034,000	$76,697	$305,883		$258,500			$164,359		$223,526	$5,035
Finance & Accounting	$720,000	$53,406	$212,994		$180,000			$114,447		$155,647	$3,506
Information Services	$1,792,000	$132,922	$530,118		$448,000			$284,847		$387,387	$8,726
Materials Management	$284,000	$21,066	$84,014		$71,000			$45,143		$61,394	$1,383
Other	$705,000	$52,294	$208,556		$176,250			$112,063		$152,404	$3,433
Special Services	$1,536,000	$113,933	$454,387		$384,000			$244,154		$332,046	$7,479
Insurance	$615,000	$45,618	$181,932		$153,750			$97,757		$132,948	$2,995
Maintenance & General Plant	$1,578,000	$117,048	$466,812		$394,500			$250,830		$341,126	$7,684
Transportation Equipment Expenses	$1,031,000	$76,475	$304,995		$257,750			$163,882		$222,877	$5,020
Total Administrative & General	$11,721,000	$869,407	$3,467,363		$2,930,250			$1,863,107		$2,533,799	$57,074
Total O&M plus A&G	$121,347,757	$23,657,241	$63,651,882		$15,152,085			$3,406,769		$15,330,016	$149,765
Depreciation											
Generation Plant	$3,231,000	$647,730	$2,583,270								
Transmission Plant	$9,518,000				$9,518,000						
Distribution Plant	$15,977,000							$6,683,206		$9,089,062	$204,732
General Plant And Deferred Charges	$7,844,000	$235,116	$937,687		$2,542,599			$1,726,999		$2,348,694	$52,905
DSM Amortization	$934,000	$155,044	$668,744		$42,005			$28,901		$39,305	
Total Depreciation	$37,504,000	$1,037,890	$4,189,701		$12,102,605			$8,439,107		$11,477,061	$257,637
Taxes											
Property	$11,561,000	$412,672	$1,645,249		$3,958,325			$2,319,376		$3,154,317	$71,061
Total Property Taxes	$11,561,000	$412,672	$1,645,249		$3,958,325			$2,319,376		$3,154,317	$71,061
Return and Income Taxes											
Incentive Adjustments	-$1,443,000	-$63,755	-$246,353		-$532,774			-$271,996		-$318,561	-$9,561
Income Tax	$4,354,000	$192,370	$743,326		$1,607,554			$820,701		$961,201	$28,849
Return on Rate Base	$67,018,000	$2,961,014	$11,441,483		$24,743,921			$12,632,459		$14,795,078	$444,044
Interest on Non Rate Base Deferral Account											
Total Return and Income Taxes	$69,929,000	$3,089,629	$11,938,456		$25,818,701			$13,181,163		$15,437,719	$463,332
Revenue Requirement Before Other Revenues	$240,341,757	$28,197,432	$81,425,289		$57,031,715			$27,346,414		$45,399,113	$941,794
Revenue Req. Before Taxes and Other Revenues	$228,780,757	$27,784,760	$79,780,040		$53,073,390			$25,027,039		$42,244,796	$870,733
Other Revenues											
Electric Apparatus Rental	$2,133,000							$85,320		$2,047,680	
Lease Revenue	$171,000	$12,684	$50,586		$42,750			$27,181		$36,966	$833
Waneta Contract Revenue	$470,000	$94,223	$375,777								
Brilliant Management Fees	$465,000	$93,220	$371,780								
Fortis Pacific Holdings	$641,000	$47,546	$189,624		$160,250			$101,890		$138,569	$3,121
Connection Charges	$545,000									$545,000	
NSF Cheque Charges	$9,000									$9,000	
Sundry Revenue	$150,000	$4,496	$17,931		$48,622			$33,025		$44,914	$1,012
Investment Income	$331,000	$9,921	$39,568		$107,292			$72,876		$99,110	$2,232
Total Other Revenues	$4,915,000	$262,090	$1,045,267		$358,914			$320,292		$2,921,239	$7,198
REVENUE REQUIREMENT for COST ALLOCATION	$235,426,757	$27,935,341	$80,380,022		$56,672,801			$27,026,122		$42,477,874	$934,596

Fortis BC 2009 COSA

REVENUE REQUIREMENT COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 3.3

	2009 **Total Expenses**	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Operation & Maintenance Expense																
Op. Supervision & Engineering	-$207,000	-$83,224	-$13,655	-$32,213	-$1,549	-$9,010	-$3,939	-$837	-$3,283	-$19,270	-$22,878	-$6,374	-$2,701	-$671	-$179	-$7,217
Water for Power	$8,286,000	$3,331,377	$546,581	$1,289,443	$61,997	$360,680	$157,690	$33,518	$131,396	$771,362	$915,794	$255,153	$108,105	$26,860	$7,167	$288,877
Structures	$627,000	$252,085	$41,360	$97,572	$4,691	$27,293	$11,932	$2,536	$9,943	$58,369	$69,298	$19,307	$8,180	$2,032	$542	$21,859
Dams & Waterways	$176,000	$70,761	$11,610	$27,389	$1,317	$7,661	$3,349	$712	$2,791	$16,384	$19,452	$5,420	$2,296	$571	$152	$6,136
Electric Plant	$530,000	$213,086	$34,961	$82,477	$3,966	$23,070	$10,086	$2,144	$8,405	$49,339	$58,577	$16,320	$6,915	$1,718	$458	$18,478
Other Plant	$267,000	$107,347	$17,613	$41,550	$1,998	$11,622	$5,081	$1,080	$4,234	$24,856	$29,510	$8,222	$3,483	$865	$231	$9,308
Purchased Power Supply/Other																
Purchased Power - Energy Charges	$52,400,770	$21,028,381	$3,500,390	$8,167,576	$267,378	$2,294,982	$1,071,602	$237,974	$797,608	$4,911,354	$5,803,050	$1,611,922	$693,012	$150,785	$46,029	$1,818,726
Purchased Power - Demand Charges	$19,393,988	$7,751,474	$1,024,646	$3,043,872	$352,943	$888,505	$267,786	$67,115	$277,242	$1,810,868	$2,182,178	$620,322	$248,821	$95,851	$19,074	$743,290
System Control	$1,443,000	$585,598	$90,402	$223,174	$24,614	$60,652	$18,810	$2,916	$23,820	$131,515	$159,202	$44,892	$17,917	$6,798	$1,179	$51,510
Total Purchased Power	$52,400,770	$21,028,381	$3,500,390	$8,167,576	$267,378	$2,294,982	$1,071,602	$237,974	$797,608	$4,911,354	$5,803,050	$1,611,922	$693,012	$150,785	$46,029	$1,818,726
Total Production	$82,916,757	$33,256,884	$5,253,908	$12,940,839	$717,355	$3,665,455	$1,542,399	$347,159	$1,252,155	$7,754,777	$9,214,183	$2,575,183	$1,086,029	$284,810	$74,654	$2,950,967
Transmission																
Op. Supervision & Engineering	$648,000	$203,205	$31,370	$77,442	$32,507	$21,047	$9,021	$1,012	$8,266	$73,857	$113,480	$20,918	$16,895	$2,359	$418	$36,204
System Planning	$1,390,000	$435,887	$67,290	$166,118	$69,729	$45,146	$19,350	$2,171	$17,730	$158,427	$243,423	$44,871	$36,242	$5,060	$896	$77,661
Load Dispatching	$1,157,000	$362,821	$56,011	$138,273	$58,040	$37,578	$16,106	$1,807	$14,758	$131,871	$202,619	$37,349	$30,167	$4,212	$745	$64,643
Transmission Station Expense	$750,000	$235,191	$36,308	$89,632	$37,623	$24,359	$10,441	$1,171	$9,567	$85,482	$131,343	$24,211	$19,555	$2,730	$483	$41,903
Transmission Line Maintenance	$310,000	$97,212	$15,007	$37,048	$15,551	$10,069	$4,315	$484	$3,954	$35,333	$54,288	$10,007	$8,083	$1,129	$200	$17,320
Transmission TROW Maintenance	$556,000	$174,355	$26,916	$66,447	$27,892	$18,058	$7,740	$868	$7,092	$63,371	$97,369	$17,948	$14,497	$2,024	$358	$31,064
Wheeling	$4,010,000	$1,257,488	$194,125	$479,234	$201,160	$130,241	$55,822	$6,263	$51,150	$457,046	$702,248	$129,447	$104,553	$14,598	$2,584	$224,042
Rents	$3,398,000	$1,065,572	$164,498	$406,094	$170,459	$110,364	$47,302	$5,307	$43,344	$387,292	$595,072	$109,691	$88,596	$12,370	$2,189	$189,849
Total Transmission	$12,219,000	$3,831,731	$591,524	$1,460,288	$612,962	$396,863	$170,097	$19,083	$155,861	$1,392,680	$2,139,842	$394,441	$318,587	$44,482	$7,873	$682,686
Distribution																
Distribution Line Maintenance	$3,467,000	$2,898,828	$292,233	$155,853		$20,498		$58,549	$41,039							
Distribution ROW Maintenance	$1,714,000	$1,433,110	$144,473	$77,050		$10,134		$28,945	$20,288							
Meter Expenses	$971,000	$575,597	$161,450	$69,137	$12,596	$4,565	$37,787		$6,275	$21,810	$27,262	$10,905	$16,357	$5,452	$5,452	$16,357
Distribution Station Expense	$1,214,000	$478,868	$87,650	$172,151		$47,484		$7,910	$23,682	$118,106	$201,474	$38,597	$30,877	$6,174	$1,027	
Street Lighting	$89,000							$89,000								
Other Plant	$288,000	$194,053	$25,647	$27,941	$186	$5,124	$558	$7,234	$4,676	$6,596	$11,106	$2,211	$1,882	$408	$135	$242
Total Distribution	$7,743,000	$5,580,456	$711,452	$502,133	$12,781	$87,806	$38,344	$191,638	$95,960	$146,511	$239,842	$51,713	$49,116	$12,034	$6,614	$16,599
Total Operation & Maintenance	$102,878,757	$42,669,071	$6,556,884	$14,903,260	$1,343,098	$4,150,124	$1,750,840	$557,881	$1,503,976	$9,293,969	$11,593,867	$3,021,337	$1,453,732	$341,327	$89,141	$3,650,251
Customer Service, Accounts, & Sales																
Supervision & Administration	$753,000	$610,046	$57,072	$16,585	$884	$27,439	$2,592	$15,709	$8,432	$3,214	$3,996	$1,499	$2,034	$669	$653	$2,175
Meter Reading	$1,855,000	$1,458,323	$135,961	$37,306	$3,063	$101,078	$9,189	$41,929	$22,256	$9,662	$12,078	$4,831	$7,247	$2,416	$2,416	$7,247
Customer Billing	$381,000	$299,526	$27,925	$7,662	$629	$20,760	$1,887	$8,612	$4,571	$1,985	$2,481	$992	$1,488	$496	$496	$1,488
Credit & Collections	$1,983,000	$1,723,398	$160,674	$44,087	$18	$590	$54	$35,393	$18,787							
Customer Assistance	$1,720,000	$1,352,191	$126,066	$34,591	$2,840	$93,722	$8,520	$38,877	$20,636	$8,959	$11,199	$4,480	$6,719	$2,240	$2,240	$6,719
Energy Management Promotion	$56,000	$23,436	$3,751	$8,390	$491	$2,307	$988	$256	$882	$4,981	$6,060	$1,634	$738	$174	$46	$1,866
Total Customer Service, Accounts & Sales	$6,748,000	$5,466,920	$511,450	$148,622	$7,926	$245,895	$23,230	$140,775	$75,564	$28,801	$35,814	$13,436	$18,226	$5,994	$5,851	$19,495
Total O&M w/o Purchased Power Supply & A&G	$36,389,000	$18,770,538	$2,452,896	$3,617,260	$706,089	$1,151,879	$415,871	$390,650	$480,871	$2,469,032	$3,485,251	$757,637	$512,208	$93,886	$28,710	$1,056,221

Fortis BC 2009 COSA

REVENUE REQUIREMENT COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 3.3

	2009 Total Expenses	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Administrative & General																
Executive & Senior Management	$1,768,000	$834,987	$123,418	$220,314	$27,578	$55,331	$20,135	$29,876	$26,787	$129,399	$180,219	$40,488	$25,230	$4,852	$1,222	$48,165
Legal	$658,000	$310,759	$45,933	$81,995	$10,264	$20,593	$7,494	$11,119	$9,969	$48,159	$67,073	$15,069	$9,390	$1,806	$455	$17,926
Human Resources	$1,034,000	$488,335	$72,180	$128,849	$16,129	$32,360	$11,776	$17,472	$15,666	$75,678	$105,400	$23,679	$14,755	$2,838	$715	$28,169
Finance & Accounting	$720,000	$340,040	$50,261	$89,721	$11,231	$22,533	$8,200	$12,167	$10,909	$52,696	$73,392	$16,488	$10,274	$1,976	$498	$19,615
Information Services	$1,792,000	$846,322	$125,093	$223,305	$27,953	$56,082	$20,408	$30,281	$27,151	$131,156	$182,666	$41,038	$25,572	$4,918	$1,238	$48,818
Materials Management	$284,000	$134,127	$19,825	$35,390	$4,430	$8,888	$3,234	$4,799	$4,303	$20,786	$28,949	$6,504	$4,053	$779	$196	$7,737
Other	$705,000	$332,956	$49,214	$87,851	$10,997	$22,063	$8,029	$11,913	$10,681	$51,599	$71,863	$16,145	$10,060	$1,935	$487	$19,206
Special Services	$1,536,000	$725,419	$107,223	$191,404	$23,959	$48,070	$17,493	$25,955	$23,272	$112,419	$156,570	$35,175	$21,919	$4,215	$1,061	$41,844
Insurance	$615,000	$290,451	$42,931	$76,636	$9,593	$19,247	$7,004	$10,392	$9,318	$45,012	$62,689	$14,084	$8,776	$1,688	$425	$16,754
Maintenance & General Plant	$1,578,000	$745,254	$110,155	$196,638	$24,615	$49,385	$17,971	$26,665	$23,908	$115,493	$160,852	$36,137	$22,518	$4,330	$1,090	$42,989
Transportation Equipment Expenses	$1,031,000	$486,918	$71,970	$128,475	$16,082	$32,266	$11,742	$17,422	$15,621	$75,458	$105,094	$23,610	$14,712	$2,829	$712	$28,087
Total Administrative & General	$11,721,000	$5,535,569	$818,202	$1,460,577	$182,831	$366,817	$133,486	$198,061	$177,585	$857,854	$1,194,767	$268,417	$167,260	$32,166	$8,099	$319,309
Total O&M plus A&G	$121,347,757	$53,671,560	$7,886,536	$16,512,459	$1,533,855	$4,762,836	$1,907,556	$896,717	$1,757,125	$10,180,624	$12,824,448	$3,303,190	$1,639,218	$379,487	$103,091	$3,989,055
Depreciation																
Generation Plant	$3,231,000	$1,299,020	$213,131	$502,799	$24,175	$140,642	$61,489	$13,070	$51,236	$300,781	$357,100	$99,493	$42,154	$10,473	$2,795	$112,643
Transmission Plant	$9,518,000	$2,984,730	$460,768	$1,137,493	$477,467	$309,137	$132,497	$14,865	$121,408	$1,084,829	$1,666,831	$307,250	$248,163	$34,650	$6,133	$531,779
Distribution Plant	$15,977,000	$10,765,207	$1,422,770	$1,550,064	$10,317	$284,282	$30,951	$401,327	$259,418	$365,936	$616,099	$122,681	$104,397	$22,660	$7,492	$13,398
General Plant And Deferred Charges	$7,844,000	$4,050,677	$568,107	$886,924	$138,990	$207,093	$65,712	$112,421	$118,066	$493,537	$734,098	$149,894	$108,572	$18,914	$4,589	$186,407
DSM Amortization	$934,000	$390,882	$62,569	$139,931	$8,194	$38,471	$16,472	$4,274	$14,713	$83,083	$101,071	$27,250	$12,302	$2,903	$773	$31,114
Total Depreciation	$37,504,000	$19,490,516	$2,727,345	$4,217,210	$659,143	$979,625	$307,121	$545,957	$564,841	$2,328,165	$3,475,199	$706,567	$515,589	$89,600	$21,781	$875,341
Taxes																
Property	$11,561,000	$5,804,683	$821,139	$1,331,248	$217,546	$316,801	$105,008	$153,795	$173,154	$769,729	$1,134,460	$233,724	$166,285	$28,945	$6,931	$297,551
Total Property Taxes	$11,561,000	$5,804,683	$821,139	$1,331,248	$217,546	$316,801	$105,008	$153,795	$173,154	$769,729	$1,134,460	$233,724	$166,285	$28,945	$6,931	$297,551
Return and Income Taxes																
Incentive Adjustments	-$1,443,000	-$680,719	-$99,403	-$171,625	-$29,555	-$42,307	-$14,760	-$18,624	-$21,442	-$106,698	-$156,370	-$32,485	-$22,817	-$4,008	-$963	-$41,223
Income Tax	$4,354,000	$2,053,951	$299,932	$517,849	$89,178	$127,654	$44,536	$56,194	$64,697	$321,941	$471,818	$98,019	$68,847	$12,094	$2,907	$124,383
Return on Rate Base	$67,018,000	$31,615,002	$4,616,637	$7,970,876	$1,372,656	$1,964,881	$685,511	$864,951	$995,828	$4,955,414	$7,262,361	$1,508,741	$1,059,713	$186,161	$44,738	$1,914,531
Interest on Non Rate Base Deferral Account																
Total Return and Income Taxes	$69,929,000	$32,988,234	$4,817,166	$8,317,100	$1,432,279	$2,050,228	$715,287	$902,522	$1,039,083	$5,170,658	$7,577,810	$1,574,274	$1,105,742	$194,247	$46,681	$1,997,690
Revenue Requirement Before Other Revenues	$240,341,757	$111,954,993	$16,252,185	$30,378,017	$3,842,823	$8,109,490	$3,034,972	$2,498,990	$3,534,204	$18,449,176	$25,011,917	$5,817,756	$3,426,834	$692,279	$178,484	$7,159,638
Revenue Req. Before Taxes and Other Revenues	$228,780,757	$106,150,310	$15,431,047	$29,046,769	$3,625,276	$7,792,689	$2,929,964	$2,345,195	$3,361,049	$17,679,447	$23,877,457	$5,584,031	$3,260,549	$663,334	$171,553	$6,862,087
Other Revenues																
Electric Apparatus Rental	$2,133,000	$1,783,444	$179,790	$95,885		$12,611		$36,021	$25,248							
Lease Revenue	$171,000	$82,627	$12,030	$21,259	$2,660	$5,299	$1,925	$1,955	$2,604	$12,251	$16,985	$3,827	$2,365	$453	$113	$4,649
Waneta Contract Revenue	$470,000	$188,963	$31,003	$73,140	$3,517	$20,459	$8,945	$1,901	$7,453	$43,753	$51,946	$14,473	$6,132	$1,524	$407	$16,386
Brilliant Management Fees	$465,000	$186,953	$30,673	$72,362	$3,479	$20,241	$8,849	$1,881	$7,374	$43,288	$51,393	$14,319	$6,067	$1,507	$402	$16,211
Fortis Pacific Holdings	$641,000	$304,770	$45,023	$80,185	$10,001	$20,119	$7,307	$7,795	$9,763	$47,000	$65,483	$14,708	$9,171	$1,764	$445	$17,466
Connection Charges	$545,000	$473,652	$44,159	$12,117	$5	$162	$15	$9,727	$5,163							
NSF Cheque Charges	$9,000	$7,822	$729	$200	$0	$3	$0	$161	$85							
Sundry Revenue	$150,000	$77,461	$10,864	$16,961	$2,658	$3,960	$1,257	$2,150	$2,258	$9,438	$14,038	$2,866	$2,076	$362	$88	$3,565
Investment Income	$331,000	$170,930	$23,973	$37,426	$5,865	$8,739	$2,773	$4,744	$4,982	$20,826	$30,977	$6,325	$4,581	$798	$194	$7,866
Total Other Revenues	$4,915,000	$3,276,620	$378,245	$409,536	$28,185	$91,593	$31,071	$66,334	$64,930	$176,556	$230,823	$56,518	$30,393	$6,408	$1,648	$66,142
REVENUE REQUIREMENT for COST ALLOCA	$235,426,757	$108,678,372	$15,873,940	$29,968,481	$3,814,638	$8,017,898	$3,003,901	$2,432,656	$3,469,274	$18,272,621	$24,781,094	$5,761,237	$3,396,442	$685,871	$176,836	$7,093,496

REVENUE REQUIREMENT COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.4

	2009 **Total Expenses**	Residential	Small General Service	General Service	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Operation & Maintenance Expense															
Op. Supervision & Engineering															
Water for Power															
Structures															
Dams & Waterways															
Electric Plant															
Other Plant															
Purchased Power Supply/Other															
Purchased Power - Energy Charges															
Purchased Power - Demand Charges															
System Control															
Total Purchased Power															
Total Production															
Transmission															
Op. Supervision & Engineering															
System Planning															
Load Dispatching															
Transmission Station Expense															
Transmission Line Maintenance															
Transmission TROW Maintenance															
Wheeling															
Rents															
Total Transmission															
Distribution															
Distribution Line Maintenance															
Distribution ROW Maintenance															
Meter Expenses															
Distribution Station Expense															
Street Lighting	$89,000						$89,000								
Other Plant	$3,690						$3,690								
Total Distribution	$92,690						$92,690								
Total Operation & Maintenance	$92,690						$92,690								
Customer Service, Accounts, & Sales															
Supervision & Administration															
Meter Reading															
Customer Billing															
Credit & Collections															
Customer Assistance															
Energy Management Promotion															
Total Customer Service, Accounts & Sales															
Total O&M w/o Purchased Power Supply & A&G	$92,690						$92,690								

REVENUE REQUIREMENT COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.4

	2009 Total Expenses	Residential	Small General Service	General Service	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Operation & Maintenance Expense															
Administrative & General															
Executive & Senior Management	$8,609						$8,609								
Legal	$3,204						$3,204								
Human Resources	$5,035						$5,035								
Finance & Accounting	$3,506						$3,506								
Information Services	$8,726						$8,726								
Materials Management	$1,383						$1,383								
Other	$3,433						$3,433								
Special Services	$7,479						$7,479								
Insurance	$2,995						$2,995								
Maintenance & General Plant	$7,684						$7,684								
Transportation Equipment Expenses	$5,020						$5,020								
Total Administrative & General	$57,074						$57,074								
Total O&M plus A&G	$149,765						$149,765								
Depreciation															
Generation Plant															
Transmission Plant															
Distribution Plant	$204,732						$204,732								
General Plant And Deferred Charges	$52,905						$52,905								
DSM Amortization															
Total Depreciation	$257,637						$257,637								
Taxes															
Property	$71,061						$71,061								
Total Property Taxes	$71,061						$71,061								
Return and Income Taxes															
Incentive Adjustments	-$9,561						-$9,561								
Income Tax	$28,849						$28,849								
Return on Rate Base	$444,044						$444,044								
Interest on Non Rate Base Deferral Account															
Total Return and Income Taxes	$463,332						$463,332								
Revenue Requirement Before Other Revenues	$941,794						$941,794								
Revenue Req. Before Taxes and Other Revenues	$870,733						$870,733								
Other Revenues															
Electric Apparatus Rental															
Lease Revenue	$833	$402	$59	$104	$26	$9	$10	$13	$60	$83	$19	$12	$2	$1	$23
Waneta Contract Revenue															
Brilliant Management Fees															
Fortis Pacific Holdings	$3,121	$1,484	$219	$390	$98	$36	$38	$48	$229	$319	$72	$45	$9	$2	$85
Connection Charges															
NSF Cheque Charges															
Sundry Revenue	$1,012	$522	$73	$114	$27	$8	$14	$15	$64	$95	$19	$14	$2	$1	$24
Investment Income	$2,232	$1,153	$162	$252	$59	$19	$32	$34	$140	$209	$43	$31	$5	$1	$53
Total Other Revenues	$7,198	$3,562	$513	$861	$209	$72	$94	$109	$493	$705	$152	$101	$19	$5	$185
REVENUE REQUIREMENT for COST ALLOCATION	$934,596	-$3,562	-$513	-$861	-$209	-$72	$941,700	-$109	-$493	-$705	-$152	-$101	-$19	-$5	-$185

INPUT RATE BASE
Schedule 4.1

FERC Account		2008 Cost, $	2009 Cost, $	Mid-Year Cost, $	Function	Classification Factor	Classification Method
	Hydraulic Production						
330.00	Land & Rights	$847,000	$847,000	$847,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
331.00	Structures & Improvements	$11,403,000	$12,138,000	$11,770,500	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
332.00	Reservoirs, Dams, & Waterways	$21,193,000	$23,099,000	$22,146,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
333.00	Water Wheels, Turbines, & Generators	$56,908,000	$69,903,000	$63,405,500	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
334.00	Accessory Electric Equipment	$23,245,000	$24,485,000	$23,865,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
335.00	Misc. Power Plant Equipment	$38,547,000	$39,734,000	$39,140,500	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
336.00	Roads, RR, & Bridges	$1,053,000	$1,053,000	$1,053,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
	Total Hydraulic Production	$153,196,000	$171,259,000	$162,227,500			
	Total Production Plant	$153,196,000	$171,259,000	$162,227,500	13%		
	Transmission Plant						
350.10	Land & Rights - R/W	$7,079,000	$7,877,000	$7,478,000	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
350.10	Land & Rights - Clearing	$4,496,000	$5,294,000	$4,895,000	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
353.00	Station Equipment	$168,913,000	$197,240,000	$183,076,500	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
355.00	Poles Towers & Fixtures	$73,975,000	$84,556,000	$79,265,500	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
356.00	Conductors & Devices	$71,198,000	$80,747,000	$75,972,500	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
359.00	Roads, Railroads & Bridges	$817,000	$1,216,000	$1,016,500	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
	Total Transmission Plant	$326,478,000	$376,930,000	$351,704,000	29%		
	Distribution Plant						
360.10	Land & Rights - R/W	$2,986,000	$3,657,000	$3,321,500	D	NCPP	Non-Coincident Peak - Primary
360.10	Land & Rights - Clearing	$7,106,000	$7,777,000	$7,441,500	D	NCPP	Non-Coincident Peak - Primary
362.00	Station Equipment	$117,123,000	$117,123,000	$117,123,000	D	NCPP	Non-Coincident Peak - Primary
364.00	Poles, Towers, & Fixtures	$114,430,000	$128,470,000	$121,450,000	D	MINSYSP	Minimum System - Poles, Towers & Fixtures (96% Customer, 4% Demand)
365.00	Conductors & Devices	$187,140,000	$198,480,000	$192,810,000	D	MINSYSC	Minimum System - Overhead and Underground Conduit (58% Customer, 42% Demand)
368.00	Line Transformers	$90,341,000	$96,046,000	$93,193,500	D	MINSYST	Minimum System - Transformers (73% Customer, 27% Demand)
369.00	Services	$7,292,000	$7,292,000	$7,292,000	D	CUSTM	Customers Weighted for Meters and Services
370.00	Meters	$13,455,000	$14,288,000	$13,871,500	D	CUSTM	Customers Weighted for Meters and Services
371.00	Installation on Customer Premises	$5,145,000	$9,386,000	$7,265,500	D	CUSTM	Customers Weighted for Meters and Services
373.00	Street Lights and Signal Systems	$7,318,000	$7,318,000	$7,318,000	D	DA1	Direct Assignment for Streetlights
	Total Distribution Plant	$552,336,000	$589,837,000	$571,086,500	46%		
	Total Transmission & Distribution	$878,814,000	$966,767,000	$922,790,500			

INPUT RATE BASE
Schedule 4.1

FERC Account		2008 Cost, $	2009 Cost, $	Mid-Year Cost, $	Function	Classification Factor	Classification Method
	General Plant						
389.00	Land & Rights	$5,800,000	$5,800,000	$5,800,000	SS	LABOR	On the Basis of Labor Ratios
390.00	Structures - Frame & Iron	$337,000	$337,000	$337,000	SS	LABOR	On the Basis of Labor Ratios
390.10	Structures - Masonry	$24,674,000	$26,680,000	$25,677,000	SS	LABOR	On the Basis of Labor Ratios
391.00	Office Furniture & Equipment	$5,767,000	$7,586,000	$6,676,500	SS	LABOR	On the Basis of Labor Ratios
391.10	Computer Equipment	$51,652,000	$57,188,000	$54,420,000	SS	LABOR	On the Basis of Labor Ratios
392.00	Transportation Equipment	$19,180,000	$21,180,000	$20,180,000	SS	LABOR	On the Basis of Labor Ratios
394.00	Tool and Work Environment	$10,664,000	$11,282,000	$10,973,000	SS	LABOR	On the Basis of Labor Ratios
397.00	Communication Structures & Equipment	$23,031,000	$24,783,000	$23,907,000	SS	LABOR	On the Basis of Labor Ratios
	Total General Plant	$141,105,000	$154,836,000	$147,970,500	12%		
	Total Plant Before General Plant & Intangible	$1,032,010,000	$1,138,026,000	$1,085,018,000			
	Total Gross Plant in Service	$1,173,115,000	$1,292,862,000	$1,232,988,500			
	Less: Accumulated Depreciation						
	Hydraulic Production Plant	$25,802,000	$27,273,000	$26,537,500	P		On the Basis of Hydraulic Production Plant
	Transmission Plant	$49,770,000	$50,897,000	$50,333,500	T	RBT	On the Basis of Transmission Rate Base
	Distribution Plant	$143,586,000	$159,226,000	$151,406,000	D	RBD	On the Basis of Distribution Rate Base
	General Plant	$52,671,000	$61,113,000	$56,892,000	SS	RBGP	On the Basis of General Plant Rate Base
	CWIP	$4,104,000	$4,953,000	$4,528,500	SS		On the Basis of CWIP
	Total Accumulated Depreciation	$275,933,000	$303,462,000	$289,697,500			
	Total Net Plant	$897,182,000	$989,400,000	$943,291,000			
	Working Capital						
	Allowance for Working Capital		$7,018,000	$7,018,000	SS	OM	On the Basis of All O&M
	Adjustment for Capital Additions		$10,857,000	$10,857,000	SS	OM	On the Basis of All O&M
	Total Working Capital		$17,875,000	$17,875,000			
	Distribution Plant CIAC	-$87,388,000	-$97,489,000	-$92,438,500	D		On the Basis of Poles, Conductors and Transformers
	Total Contributions	-$87,388,000	-$97,489,000	-$92,438,500			
	SUB-TOTAL RATE BASE	$809,794,000	$909,786,000	$868,727,500			
	Other Rate Base Items						
	Production Plant CWIP not subject to AFUDC				P	RBG	On the Basis of Generation Rate Base
	Transmission Plant CWIP not subject to AFUDC				T	RBT	On the Basis of Transmission Rate Base
	Distribution Plant CWIP not subject to AFUDC				D	RBD	On the Basis of Distribution Rate Base
	General Plant CWIP not subject to AFUDC	$6,865,000	$6,865,000	$6,865,000	D	RBGP	On the Basis of General Plant Rate Base
	Deferred DSM	$6,595,000	$8,229,000	$7,412,000	SS	DSM	Classified 72% Energy, 17% Demand & 12% T&D
	Plant Acquisition Adjustment & Deferred	$22,654,000	$27,294,000	$24,974,000	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Total Other Rate Base Items	$36,114,000	$42,388,000	$39,251,000			
	TOTAL RATE BASE	$845,908,000	$952,174,000	$907,978,500			

Fortis BC 2009 COSA

RATE BASE FOR COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 4.2

		Production			**Transmission**			**Distribution**			
Account Description	Total Rate Base	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
Hydraulic Production											
Land & Rights	$847,000	$169,801	$677,199								
Structures & Improvements	$11,770,500	$2,359,673	$9,410,827								
Reservoirs, Dams, & Waterways	$22,146,000	$4,439,685	$17,706,315								
Water Wheels, Turbines, & Generators	$63,405,500	$12,711,120	$50,694,380								
Accessory Electric Equipment	$23,865,000	$4,784,299	$19,080,701								
Misc. Power Plant Equipment	$39,140,500	$7,846,631	$31,293,869								
Roads, RR, & Bridges	$1,053,000	$211,099	$841,901								
Total Hydraulic Production	$162,227,500	$32,522,308	$129,705,192								
Total Production Plant	$162,227,500	$32,522,308	$129,705,192								
Transmission Plant											
Land & Rights - R/W	$7,478,000				$7,478,000						
Land & Rights - Clearing	$4,895,000				$4,895,000						
Station Equipment	$183,076,500				$183,076,500						
Poles Towers & Fixtures	$79,265,500				$79,265,500						
Conductors & Devices	$75,972,500				$75,972,500						
Roads, Railroads & Bridges	$1,016,500				$1,016,500						
Total Transmission Plant	$351,704,000				$351,704,000						
Distribution Plant											
Land & Rights - R/W	$3,321,500							$3,321,500			
Land & Rights - Clearing	$7,441,500							$7,441,500			
Station Equipment	$117,123,000							$117,123,000			
Poles, Towers, & Fixtures	$121,450,000							$4,858,000		$116,592,000	
Conductors & Devices	$192,810,000							$80,980,200		$111,829,800	
Line Transformers	$93,193,500							$25,162,245		$68,031,255	
Services	$7,292,000									$7,292,000	
Meters	$13,871,500									$13,871,500	
Installation on Customer Premises	$7,265,500									$7,265,500	
Street Lights and Signal Systems	$7,318,000										$7,318,000
Total Distribution Plant	$571,086,500							$238,886,445		$324,882,055	$7,318,000
Total Transmission & Distribution	$922,790,500				$351,704,000			$238,886,445		$324,882,055	$7,318,000

Fortis BC 2009 COSA

RATE BASE FOR COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 4.2

Account Description	Total Rate Base	Production Demand PD	Production Energy PE	Production Direct Assignment PDA	Transmission Demand TD	Transmission Energy TE	Transmission Direct Assignment TDA	Distribution Demand DD	Distribution Energy DE	Distribution Customer DC	Distribution Direct Assignment DDA
General Plant											
Land & Rights	$5,800,000	$430,216	$1,715,784		$1,450,000			$921,937		$1,253,821	$28,242
Structures - Frame & Iron	$337,000	$24,997	$99,693		$84,250			$53,568		$72,851	$1,641
Structures - Masonry	$25,677,000	$1,904,596	$7,595,894		$6,419,250			$4,081,478		$5,550,751	$125,031
Office Furniture & Equipment	$6,676,500	$495,231	$1,975,074		$1,669,125			$1,061,261		$1,443,299	$32,510
Computer Equipment	$54,420,000	$4,036,613	$16,098,787		$13,605,000			$8,650,312		$11,764,297	$264,992
Transportation Equipment	$20,180,000	$1,496,855	$5,969,745		$5,045,000			$3,207,705		$4,362,431	$98,264
Tool and Work Environment	$10,973,000	$813,924	$3,246,086		$2,743,250			$1,744,209		$2,372,099	$53,432
Communication Structures & Equipment	$23,907,000	$1,773,306	$7,072,284		$5,976,750			$3,800,129		$5,168,119	$116,412
Total General Plant	$147,970,500	$10,975,738	$43,773,347		$36,992,625			$23,520,598		$31,987,667	$720,525
Total Plant Before General Plant & Intangible	$1,085,018,000	$32,522,308	$129,705,192		$351,704,000			$238,886,445		$324,882,055	$7,318,000
Total Gross Plant in Service	$1,232,988,500	$43,498,046	$173,478,539		$388,696,625			$262,407,043		$356,869,722	$8,038,525
Less: Accumulated Depreciation											
Hydraulic Production Plant	$26,537,500	$5,320,064	$21,217,436								
Transmission Plant	$50,333,500				$50,333,500						
Distribution Plant	$151,406,000							$63,333,385		$86,132,473	$1,940,142
General Plant	$56,892,000	$4,219,974	$16,830,066		$14,223,000			$9,043,247		$12,298,684	$277,029
CWIP	$4,528,500	$287,068	$1,191,025		$1,170,436			$786,734		$1,069,947	$23,290
Total Accumulated Depreciation	$289,697,500	$9,827,106	$39,238,527		$65,726,936			$73,163,366		$99,501,103	$2,240,461
Total Net Plant	$943,291,000	$33,670,940	$134,240,012		$322,969,689			$189,243,676		$257,368,619	$5,798,064
Working Capital											
Allowance for Working Capital	$7,018,000	$1,553,786	$4,102,482		$833,534			$105,170		$416,706	$6,323
Adjustment for Capital Additions	$10,857,000	$2,403,741	$6,346,629		$1,289,495			$162,700		$644,653	$9,782
Total Working Capital	$17,875,000	$3,957,527	$10,449,111		$2,123,029			$267,870		$1,061,358	$16,105
Distribution Plant CIAC	-$92,438,500							-$25,182,541		-$67,255,959	
Total Contributions	-$92,438,500							-$25,182,541		-$67,255,959	
SUB-TOTAL RATE BASE	$868,727,500	$37,628,467	$144,689,123		$325,092,719			$164,329,004		$191,174,018	$5,814,169
Other Rate Base Items											
Production Plant CWIP not subject to AFUDC											
Transmission Plant CWIP not subject to AFUDC											
Distribution Plant CWIP not subject to AFUDC											
General Plant CWIP not subject to AFUDC	$6,865,000	$509,213	$2,030,837		$1,716,250			$1,091,224		$1,484,048	$33,428
Deferred DSM	$7,412,000	$1,230,392	$5,306,992		$333,343			$229,354		$311,918	
Plant Acquisition Adjustment & Deferred	$24,974,000	$748,570	$2,985,441		$8,095,217			$5,498,480		$7,477,852	$168,439
Total Other Rate Base Items	$39,251,000	$2,488,175	$10,323,271		$10,144,810			$6,819,058		$9,273,819	$201,868
TOTAL RATE BASE	$907,978,500	$40,116,642	$155,012,394		$335,237,528			$171,148,062		$200,447,837	$6,016,036

ANALYSIS OF FORECAST POWER PURCHASE EXPENSE
FOR THE YEAR ENDING DECEMBER 31
Schedule 5.1

Purchased Power Supply Summary	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	Totals
Energy Charges	$5,711,582	$4,663,080	$4,749,462	$4,166,801	$3,414,723	$3,171,778	$4,075,928	$3,582,288	$3,603,323	$4,416,048	$5,337,105	$5,508,652	$52,400,770
Total System kWh	361,624,888	319,102,862	310,114,993	270,884,123	258,896,213	244,989,642	255,898,311	254,588,796	251,457,025	265,349,496	297,889,762	335,436,486	3,426,232,597
	$0.0158	$0.0146	$0.0153	$0.0154	$0.0132	$0.0129	$0.0159	$0.0141	$0.0143	$0.0166	$0.0179	$0.0164	$0.0153
Capacity Charges	$2,867,106	$2,704,435	$2,101,202	$956,739	$1,205,871	$1,642,359	$824,263	$793,155	$902,662	$921,980	$1,617,900	$2,856,315	$19,393,988
Total System CP kW	701,345	599,525	549,651	491,965	454,587	495,572	558,002	539,724	454,353	519,211	613,583	665,540	6,643,058
	$4.09	$4.51	$3.82	$1.94	$2.65	$3.31	$1.48	$1.47	$1.99	$1.78	$2.64	$4.29	$2.92

Total Annual		Net Cost	
Combined Costs	$71,794,757	$71,794,757	
Energy %	52,400,770	$52,400,770	73%
Demand %	19,393,988	$19,393,988	27%

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
ENERGY GW.h	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
FortisBC	156	151	140	119	128	128	136	118	123	111	118	152	1581
Brilliant Base Plant	82	63	57	82	79	72	79	86	66	62	63	65	857
Brilliant Upgrade	1	-1	0	10	14	13	14	13	1	1	0	0	65
Brilliant Regulated													
Cominco													
Small Misc IPP Resource	1	0	1	1	3	2	3	1	1	1	1	1	13
Turbine Upgrades													
CPC Loss, Wheeling & PPA Adjustments													
DSM	2	2	2	2	2	2	2	2	2	2	2	2	25
City of Nelson Special Adjustment													
Market Capacity - ENERGY	1		4				3	0			0		8
Market Energy Purchase													
BCH Purchase	126	108	107	56	30	30	42	32	56	86	115	119	908
SUBTOTAL	368	324	311	270	256	247	279	251	249	263	299	340	3457
Gross Load	368	324	311	270	256	242	253	251	249	263	299	340	3426
Surplus						4	27						31
RATE (Mills/kW.h)													
Surplus Rate	58.08	53.70	48.11	25.69	20.63	17.41	33.60	39.26	41.15	57.82	61.07	73.02	
Brilliant Base Plant	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	
Brilliant Upgrade	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	
Brilliant Regulated	28.49	28.49	28.49	31.13	31.13	31.13	31.13	31.13	31.13	31.13	31.13	31.13	
Market Capacity - ENERGY	80.32	74.49	61.69	56.30	45.65	47.77	94.80	115.57	84.12	73.68	84.44	100.38	
Market Energy Purchase	58.08	53.70	48.11	25.69	20.63	17.41	33.60	39.26	41.15	57.82	61.07	73.02	
BCH : Purchase	28.49	28.49	28.49	31.13	31.13	31.13	31.13	31.13	31.13	31.13	31.13	31.13	
IPP Rate	28.49	28.49	28.49	28.49	28.49	28.49	28.49	28.49	28.49	28.49	28.49	28.49	
ENERGY EXPENSE ($000)													
Surplus Revenue						($76)	($893)						($969)
Brilliant Base Plant	$2,789	$2,146	$2,007	$2,784.85	$2,699	$2,459	$2,700	$2,931	$2,250	$2,120	$2,144	$2,215	$29,245
Brilliant Upgrade	$18	($17)	($11)	$253.61	$360	$335	$360	$330	$25	$16	$8	$9	$1,686
Brilliant Regulated													
IPP Costs	$14	$11	$20	$17.09	$71	$63	$77	$17	$20	$14	$23	$23	$370
BCH Purchase	$3,577	$3,081	$3,054	$1,750.06	$947	$921	$1,318	$1,000	$1,756	$2,685	$3,578	$3,697	$27,365
Market Capacity - ENERGY	$55		$251				$283	$1			$6		$596
Market Energy Purchase													

Fortis BC 2009 COSA

Prepared By EES Consulting, Inc.

ANALYSIS OF FORECAST POWER PURCHASE EXPENSE
FOR THE YEAR ENDING DECEMBER 31
Schedule 5.1

Purchased Power Supply Summary	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	Totals
TOTAL	$6,453	$5,222	$5,321	$4,805.61	$4,077	$3,702	$3,845	$4,279	$4,051	$4,835	$5,758	$5,944	$58,293
CAPACITY (MW)													
FortisBC	202	199	181	183	187	178	188	203	200	194	193	208	2317
Brilliant Base Plant	123	123	87	117	106	100	106	115	119	119	123	123	1359
Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	238
Brilliant Tailrace Capacity	4	3	1	3	6	6	6	4	1	1	3	5	42
Cominco													
Market Capacity	7		67				48	5			4		131
FortisBC DSM	5	4	4	4	4	3	3	3	4	4	4	5	45
Turbine Upgrades													
Cominco Market Capacity	150	75									75	125	425
CPC Market Capacity												25	25
BCH : Billing Capacity	190	176	190	165	143	188	190	190	143	182	190	168	2114
BCH : Used for Load	190	176	190	165	134	188	190	190	111	182	190	168	2074
BCH : Excess Purchases													
Gross FortisBC Monthly Peak	701	600	551	492	455	495	560	539	454	519	613	666	6644
Capacity Planning Load	701	600	551	492	455	495	560	539	454	519	613	666	6644
RATE ($/MW-month) / Expense ($000)													
BCH 3808 Rate	4861	4861	4861	5312	5312	5312	5312	5312	5312	5312	5312	5312	
BCH 3808 Capacity Charge	924	854	924	877	757	1000	1009	1009	757	966	1009	892	10978
BRD Tailrace Capacity Charge	16	11	4	10	24	24	23	14	4	4	14	19	165
Cominco Capacity Charge	1001	506									423	705	2636
CPC Capacity Charge												$183	$183
Total Capacity Expense ($000)	$1,940.471	$1,370.478	$927.192	$886.989	$780.849	$1,023.600	$1,031.969	$1,023.603	$760.531	$969.703	$1,446.064	$1,811.952	$13,973.402
TOTAL POWER PURCH EXPENSE($000)													
Surplus Revenues						($76)	($893)						($969)
Export Wheeling Costs													
Brilliant	$2,823	$2,141	$1,999	$3,048	$3,083	$2,818	$3,083	$3,276	$2,279	$2,139	$2,165	$2,243	$31,096
BCH	$4,501	$3,935	$3,978	$2,627	$1,704	$1,921	$2,327	$2,009	$2,513	$3,652	$4,587	$4,589	$38,342
BCH Excess/Unallocated Costs			$1	$4	$12	$26	$45	$7	$6	$0	$0	$0	$100
Market Spot Purchase & Com Capacity	$1,056	$506	$251				$283	$1			$429	$900	$3,427
IPP	$14	$11	$20	$17	$71	$63	$77	$17	$20	$14	$23	$23	$370
Capital Projects	($43)		($65)								($75)	($26)	($208)
Special & Accounting Adjustments													
Balancing Pool Adjustments	$228	$775	$667	($573)	($249)	$62	($22)	($934)	($311)	($467)	($174)	$635	($363)
TOTAL	$8,578.688	$7,367.515	$6,850.664	$5,123.540	$4,620.594	$4,814.137	$4,900.191	$4,375.443	$4,505.985	$5,338.028	$6,955.005	$8,364.968	$71,794.757
Ave Power Purch Cost	41.11	43.10	41.64	34.52	36.64	41.80	41.90	33.25	36.28	35.67	38.85	45.22	39.31
Ave Embedded =													
Net Cost to Customer													
Forecast Exchange Rate	1.2730	1.2730	1.2730	1.2590	1.2590	1.2590	1.2130	1.2130	1.2130	1.1660	1.1660	1.1660	-
Cummulative Balancing Pool													

ANALYSIS OF FORECAST POWER WHEELING EXPENSE
FOR THE YEAR ENDING DECEMBER 31
Schedule 5.2

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
NOMINATION (MW)													
- Okanagan	175	175	175	175	175	175	175	175	175	180	180	180	
- Creston	35	35	35	35	35	35	35	35	35	35	35	35	
RATE ($/kW/Month)													
- Okanagan	1,662	1,662	1,662	1,662	1,662	1,662	1,662	1,662	1,662	1,688	1,688	1,688	20,021
- Creston	1,083	1,083	1,083	1,083	1,083	1,083	1,083	1,083	1,083	1,100	1,100	1,100	13,048
COST ($000)													
- Okanagan	291	291	291	291	291	291	291	291	291	304	304	304	3,529
- Creston	38	38	38	38	38	38	38	38	38	39	39	39	457
EXCESS WHEELING COSTS ($000)													
Cominco Wheeling Costs	1	1	1	1	1	1	1	1	1	1	1	1	12
OATT Wheeling Costs + Emer	1	1	1	1	1	1	1	1	1	1	1	1	12
PRINCETON WTS Wheeling													
TOTAL WHEELING COSTS ($000)	331	331	331	331	331	331	331	331	331	344	344	344	4,010

Water Fee Calculation	2,009	Rates	
First 160 GW.h	1.13	mills/kW.h	
Remaining Energy	5.27	mills/kW.h	
Capacity	3.77	$/kw-year	
Payment Schedule			4,240
Upgrade Adjustment			

WKP Energy =	1,577	GW.h	
Upgrade Outage =		GW.h	
Upgrade Output =	3	GW.h	
Total Generation	1,580	GW.h	
Average Rate =	5	mills/kW.h	
			4,240

Brilliant Water Fee Calculation			
Water Fee Calculation	2,009	Rates	
First 160 GW.h	1.13	mills/kW.h	
Remaining Energy	5.27	mills/kW.h	
Capacity	3.77	$/kw-year	
Payment Schedule			2,378

Brilliant Energy =	856	GW.h	
Upgrade Outage =		GW.h	
Upgrade Output =	65	GW.h	
Total Generation	921	GW.h	
Average Rate =	6	mills/kW.h	
			2,378

POWER SUPPLY CALCULATIONS IF PURCHASED AT BC HDYRO 3808 RATES
USED FOR CLASSIFICATION OF HYDRO PLANT
Schedule 5.3

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Energy Amount (GWh)													
Brilliant Base Plant	82	63	57	82	79	72	79	86	66	62	63	65	857
Brilliant Upgrade	1	(1)	(0)	10	14	13	14	13	1	1	0	0	65
FortisBC	156	151	140	119	128	128	136	118	123	111	118	152	1,581
Demand Amount (MW)													
Brilliant Base Plant	123	123	87	117	106	100	106	115	119	119	123	123	1,359
Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	238
FortisBC	202	199	181	183	187	178	188	203	200	194	193	208	2,317
Total System Demand (MW)	539	521	479	488	452	491	509	531	450	516	530	524	6,030
System	701	600	551	492	455	495	560	539	454	519	613	666	6,644
% of Total	77%	87%	87%	99%	99%	99%	91%	99%	99%	99%	86%	79%	**90.8%**
Total System Energy (GWh)	364	322	304	267	251	242	272	249	246	261	296	337	3,411
System	368	324	311	270	256	242	253	251	249	263	299	340	3,426
% of Total	99%	99%	98%	99%	98%	100%	108%	99%	99%	99%	99%	99%	100%
Purchased Power Expense ($000)													
Brilliant Base Plant	$2,789	$2,146	$2,007	$2,785	$2,699	$2,459	$2,700	$2,931	$2,250	$2,120	$2,144	$2,215	$29,245
Brilliant Upgrade	$18	($17)	($11)	$254	$360	$335	$360	$330	$25	$16	$8	$9	$1,686
Energy Costs if Using 3808 ($000)													
Brilliant Base Plant	$2,335	$1,795	$1,626	$2,548	$2,469	$2,250	$2,470	$2,682	$2,059	$1,939	$1,961	$2,027	$26,161
Brilliant Upgrade	$20	-$18	-$13	$305	$433	$403	$433	$397	$30	$19	$9	$10	$2,028
FortisBC	$4,449	$4,303	$3,992	$3,707	$3,977	$3,976	$4,244	$3,683	$3,818	$3,470	$3,668	$4,743	$48,029
Demand Costs if Using 3808 ($000)													
Brilliant Base Plant	$596	$596	$423	$622	$562	$530	$563	$612	$631	$632	$652	$651	$7,070
Brilliant Upgrade	$96	$96	$97	$106	$105	$104	$105	$107	$104	$105	$107	$106	$1,237
FortisBC	$982	$969	$881	$974	$992	$945	$998	$1,076	$1,061	$1,031	$1,027	$1,106	$12,043
Combined Costs if Using 3808 ($000)	$5,431	$5,272	$4,873	$4,681	$4,969	$4,921	$5,242	$4,759	$4,879	$4,500	$4,695	$5,849	$60,072

Resulting Classification Factor	
Energy Component	80%
Demand Component	20%

Adjustment Factor Calculation	Combined 3808 Cost	Actual Cost vs 3808 Cost
Brilliant Base Plant	$33,231	88%
Brilliant Upgrade	$3,265	52%

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Adjusted Energy Costs if Using 3808 ($000)													
Brilliant Base Plant	$2,055	$1,580	$1,431	$2,242	$2,173	$1,980	$2,174	$2,360	$1,812	$1,707	$1,726	$1,784	$23,023
Brilliant Upgrade	$10	($9)	($7)	$157	$223	$208	$223	$205	$16	$10	$5	$5	$1,047
Adjusted Demand Costs if Using 3808 ($000)													
Brilliant Base Plant	$524	$525	$372	$548	$495	$466	$495	$538	$556	$556	$573	$573	$6,222
Brilliant Upgrade	$50	$50	$50	$55	$54	$53	$54	$55	$54	$54	$55	$55	$639

CLASSIFICATION and ALLOCATION BY FUNCTION
Schedule 6.1

Classification Factors	Production			Transmission			Distribution				Total % Allocated
	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA	
CP1	100.00%			100.00%			100.00%				100%
CP2	100.00%			100.00%			100.00%				100%
CP4	100.00%			100.00%			100.00%				100%
CP12	100.00%			100.00%			100.00%				100%
TCP1				100.00%							100%
TCP2				100.00%							100%
TCP4				100.00%							100%
TCP12				100.00%							100%
NCP	100.00%			100.00%			100.00%				100%
NCPP	100.00%			100.00%			100.00%				100%
NCPS	100.00%			100.00%			100.00%				100%
kWh		100.00%			100.00%			100.00%			100%
CUST									100.00%		100%
CUSTW									100.00%		100%
CUSTM									100.00%		100%
CUSTR									100.00%		100%
MINSYSP							4.00%		96.00%		100%
MINSYSC							42.00%		58.00%		100%
MINSYST							27.00%		73.00%		100%
20D/80E	20.05%	79.95%									100%
DA1			100.00%			100.00%				100.00%	100%
REV	12.14%	34.87%		23.20%			10.94%		18.47%	0.38%	100%
RB	4.42%	17.07%		36.92%			18.85%		22.08%	0.66%	100%
RBG	20.05%	79.95%									100%
RBT				100.00%							100%
RBD							41.83%		56.89%	1.28%	100%
RBGP	7.42%	29.58%		25.00%			15.90%		21.62%	0.49%	100%
OM	22.14%	58.46%		11.88%			1.50%		5.94%	0.09%	100%
OMAG	5.36%	21.39%		33.59%			4.24%		35.17%	0.25%	100%
GPLT	3.00%	11.95%		32.41%			22.02%		29.94%	0.67%	100%
NETPLT	3.57%	14.23%		34.24%			20.06%		27.28%	0.61%	100%
LABOR	7.42%	29.58%		25.00%			15.90%		21.62%	0.49%	100%
PURCHkWh		100.00%									100%
PURCHkW	100.00%										100%
DSM	16.60%	71.60%		4.50%			3.09%		4.21%		100%
RBASE	4.42%	17.07%		36.92%			18.85%		22.08%	0.66%	100%

CLASSIFICATION AND ALLOCATION BY CUSTOMER
Schedule 6.2

Classification Factors	Total Allocated	Residential	General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
CP1	100%	44.661%	5.255%	15.052%	1.599%	4.072%	1.149%	0.373%	0.566%	8.755%	10.249%	2.927%	1.149%	0.708%	0.083%	3.401%
CP2	100%	40.582%	6.265%	15.466%	1.706%	4.203%	1.304%	0.202%	1.651%	9.114%	11.033%	3.111%	1.242%	0.471%	0.082%	3.570%
CP4	100%	41.999%	5.039%	14.541%	1.681%	4.372%	1.270%	0.422%	1.138%	9.349%	11.192%	3.241%	1.274%	0.542%	0.096%	3.845%
CP12	100%	38.802%	5.598%	16.226%	1.854%	4.647%	1.409%	0.318%	1.747%	9.297%	11.247%	3.178%	1.281%	0.466%	0.099%	3.829%
TCP1	100%	35.140%	4.135%	11.843%	4.487%	3.204%	1.245%	0.294%	0.446%	10.196%	17.393%	3.332%	2.666%	0.557%	0.065%	4.998%
TCP2	100%	31.359%	4.841%	11.951%	5.016%	3.248%	1.392%	0.156%	1.276%	11.398%	17.512%	3.228%	2.607%	0.364%	0.064%	5.587%
TCP4	100%	32.458%	3.894%	11.238%	4.793%	3.378%	1.330%	0.326%	0.879%	10.890%	18.576%	3.559%	2.847%	0.419%	0.074%	5.338%
TCP12	100%	28.134%	4.059%	11.765%	5.239%	3.370%	1.454%	0.231%	1.267%	11.903%	19.633%	3.717%	2.982%	0.338%	0.074%	5.835%
NCP	100%	36.608%	6.701%	13.161%	3.740%	3.630%	1.038%	0.605%	1.810%	8.497%	14.496%	2.777%	2.222%	0.472%	0.078%	4.165%
NCPP	100%	39.445%	7.220%	14.181%		3.911%		0.652%	1.951%	9.729%	16.596%	3.179%	2.543%	0.509%	0.085%	
NCPS	100%	62.164%	11.378%	22.348%				1.027%	3.082%							
kWh	100%	40.110%	6.680%	15.586%	0.508%	4.390%	2.053%	0.455%	1.569%	9.358%	11.057%	3.071%	1.32%	0.29%	0.09%	3.47%
CUST	100%	86.894%	8.101%	2.223%	0.001%	0.030%	0.003%	1.784%	0.947%	0.004%	0.005%	0.002%	0.003%	0.001%	0.001%	0.003%
CUSTW	100%	78.616%	7.329%	2.011%	0.165%	5.449%	0.495%	2.260%	1.200%	0.521%	0.651%	0.260%	0.39%	0.13%	0.13%	0.39%
CUSTM	100%	59.279%	16.627%	7.120%	1.297%	0.470%	3.892%		0.646%	2.246%	2.808%	1.123%	1.68%	0.56%	0.56%	1.68%
CUSTR	100%	86.909%	8.103%	2.223%	0.001%	0.030%	0.003%	1.785%	0.947%							
MINSYSP	100%	85.178%	8.099%	2.767%	0.001%	0.154%	0.003%	1.742%	0.996%	0.315%	0.535%	0.103%	0.08%	0.02%	0.00%	0.00%
MINSYSC	100%	68.874%	8.080%	7.931%	0.001%	1.331%	0.002%	1.340%	1.464%	3.271%	5.579%	1.069%	0.86%	0.17%	0.03%	0.00%
MINSYST	100%	80.217%	8.986%	7.657%	0.001%	0.022%	0.002%	1.580%	1.524%	0.003%	0.003%	0.001%	0.00%	0.00%	0.00%	0.00%
20D/80E	100%	40.205%	6.596%	15.562%	0.748%	4.353%	1.903%	0.405%	1.586%	9.309%	11.052%	3.079%	1.305%	0.324%	0.086%	3.486%
DA1	100%							100.000%								
REV	100%	46.398%	6.745%	12.696%	1.585%	3.406%	1.281%	1.025%	1.469%	7.728%	10.437%	2.441%	1.43%	0.29%	0.07%	3.00%
RB	100%	47.174%	6.889%	11.894%	2.048%	2.932%	1.023%	1.291%	1.486%	7.394%	10.836%	2.251%	1.58%	0.28%	0.07%	2.86%
RBG	100%	40.205%	6.596%	15.562%	0.748%	4.353%	1.903%	0.405%	1.586%	9.309%	11.052%	3.079%	1.305%	0.324%	0.086%	3.486%
RBT	100%	31.359%	4.841%	11.951%	5.016%	3.248%	1.392%	0.156%	1.276%	11.398%	17.512%	3.228%	2.61%	0.36%	0.06%	5.59%
RBT-D	100%	31.359%	4.841%	11.951%	5.016%	3.248%	1.392%	0.156%	1.276%	11.398%	17.512%	3.228%	2.607%	0.364%	0.064%	5.587%
RBT-E																
RBT-DA																
RBD	100%	65.343%	8.876%	9.905%	0.077%	1.885%	0.231%	2.703%	1.625%	2.733%	4.601%	0.916%	0.780%	0.169%	0.056%	0.100%
RBGP	100%	48.320%	7.035%	12.432%	1.555%	3.099%	1.126%	1.143%	1.523%	7.164%	9.933%	2.238%	1.38%	0.26%	0.07%	2.72%
OM	100%	41.475%	6.373%	14.486%	1.306%	4.034%	1.702%	0.542%	1.462%	9.034%	11.269%	2.937%	1.41%	0.33%	0.09%	3.55%
OMAG	100%	51.583%	6.741%	9.941%	1.940%	3.165%	1.143%	1.074%	1.321%	6.785%	9.578%	2.082%	1.41%	0.26%	0.08%	2.90%
GPLT	100%	51.640%	7.243%	11.307%	1.772%	2.640%	0.838%	1.433%	1.505%	6.292%	9.359%	1.911%	1.38%	0.24%	0.06%	2.38%
NETPLT	100%	50.209%	7.103%	11.515%	1.882%	2.740%	0.908%	1.330%	1.498%	6.658%	9.813%	2.022%	1.44%	0.25%	0.06%	2.57%
LABOR	100%	47.55%	7.02%	12.51%	1.56%	3.14%	1.14%	1.22%	1.52%	7.33%	10.22%	2.29%	1.43%	0.28%	0.07%	2.72%
PURCHkWh	100%	40.13%	6.68%	15.59%	0.51%	4.38%	2.05%	0.45%	1.52%	9.37%	11.07%	3.08%	1.32%	0.29%	0.09%	3.47%
PURCHkW	100%	39.97%	5.28%	15.69%	1.82%	4.58%	1.38%	0.35%	1.43%	9.34%	11.25%	3.20%	1.28%	0.49%	0.10%	3.83%

COINCIDENT PEAK DEMAND ALLOCATION - PRODUCTION
Schedule 6.3

Calculation of 1 CP Allocation - Production

	Total Allocated	Residential	General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	701,345	313,226	36,855	105,566	11,213	28,559	8,059	2,617	3,972	61,401	71,883	20,529	8,062	4,964	584	23,855
Feb-09																
Mar-09																
Apr-09																
May-09																
Jun-09																
Jul-09																
Aug-09																
Sep-09																
Oct-09																
Nov-09																
Dec-09																
Total Annual 1CP	701,345	313,226	36,855	105,566	11,213	28,559	8,059	2,617	3,972	61,401	71,883	20,529	8,062	4,964	584	23,855
% of Total	100%	44.66%	5.25%	15.05%	1.60%	4.07%	1.15%	0.37%	0.57%	8.75%	10.25%	2.93%	1.15%	0.71%	0.08%	3.40%

Calculation of 2 CP & 4 CP Allocation - Production

	Total Allocated	Residential	General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
2 CP - Production																
Jan-09	701,345	313,226	36,855	105,566	11,213	28,559	8,059	2,617	3,972	61,401	71,883	20,529	8,062	4,964	584	23,855
Feb-09																
Mar-09																
Apr-09																
May-09																
Jun-09																
Jul-09	558,002	198,895	50,165	104,809	9,911	22,374	8,370		14,032	45,859	61,151	15,590	6,607	1,693	372	18,173
Aug-09	539,724	198,115	35,412	83,532	10,417	24,545	7,516		16,414	54,909	62,813	16,948	7,087	1,779	379	19,858
Sep-09																
Oct-09																
Nov-09																
Dec-09	665,540	289,951	31,972	87,268	10,500	28,115	8,183	2,364	6,267	62,455	76,066	23,607	8,845	3,175	679	26,092
2 Winter + 2 Summer	2,464,611	1,000,188	154,404	381,176	42,041	103,592	32,127	4,981	40,684	224,625	271,914	76,674	30,602	11,611	2,013	87,978
% of Total	100%	40.58%	6.26%	15.47%	1.71%	4.20%	1.30%	0.20%	1.65%	9.11%	11.03%	3.11%	1.24%	0.47%	0.08%	3.57%
4 CP - Production																
Jan-09	701,345	313,226	36,855	105,566	11,213	28,559	8,059	2,617	3,972	61,401	71,883	20,529	8,062	4,964	584	23,855
Feb-09	599,525	255,130	23,056	77,894	11,129	29,118	7,725	2,792	4,642	59,575	71,184	19,953	8,126	3,789	520	24,893
Mar-09																
Apr-09																
May-09																
Jun-09																
Jul-09																
Aug-09																
Sep-09																
Oct-09																
Nov-09	613,583	225,255	38,126	104,440	10,516	26,994	8,807	3,109	14,479	57,778	69,624	19,518	7,833	2,051	697	24,354
Dec-09	665,540	289,951	31,972	87,268	10,500	28,115	8,183	2,364	6,267	62,455	76,066	23,607	8,845	3,175	679	26,092
4 Winter	2,579,993	1,083,563	130,009	375,168	43,358	112,785	32,775	10,882	29,360	241,209	288,758	83,606	32,866	13,979	2,480	99,194
% of Total	100%	42.00%	5.04%	14.54%	1.68%	4.37%	1.27%	0.42%	1.14%	9.35%	11.19%	3.24%	1.27%	0.54%	0.10%	3.84%

COINCIDENT PEAK DEMAND ALLOCATION - PRODUCTION
Schedule 6.3

Calculation of 12 CP Allocation - Production

	Total Allocated	Residential	General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Power Supply																
Winter	2,579,993	1,083,563	130,009	375,168	43,358	112,785	32,775	10,882	29,360	241,209	288,758	83,606	32,866	13,979	2,480	99,194
% of Total	100%	42.00%	5.04%	14.54%	1.68%	4.37%	1.27%	0.42%	1.14%	9.35%	11.19%	3.24%	1.27%	0.54%	0.10%	3.84%
Summer	4,063,064	1,494,091	241,885	702,747	79,817	195,945	60,831	10,264	86,723	376,396	458,415	127,527	52,206	16,952	4,119	155,146
% of Total	100%	36.77%	5.95%	17.30%	1.96%	4.82%	1.50%	0.25%	2.13%	9.26%	11.28%	3.14%	1.28%	0.42%	0.10%	3.82%
Annual	6,643,058	2,577,654	371,894	1,077,915	123,174	308,730	93,606	21,146	116,084	617,606	747,173	211,133	85,072	30,931	6,599	254,340
% of Total	100%	38.80%	5.60%	16.23%	1.85%	4.65%	1.41%	0.32%	1.75%	9.30%	11.25%	3.18%	1.28%	0.47%	0.10%	3.83%
Utility Owned Transmission																
Annual	6,643,058	2,577,654	371,894	1,077,915	123,174	308,730	93,606	21,146	116,084	617,606	747,173	211,133	85,072	30,931	6,599	254,340
% of Total	100%	38.80%	5.60%	16.23%	1.85%	4.65%	1.41%	0.32%	1.75%	9.30%	11.25%	3.18%	1.28%	0.47%	0.10%	3.83%

COINCIDENT PEAK DEMAND ALLOCATION - TRANSMISSION
Schedule 6.4

Calculation of 1 CP Allocation - Transmission

	Total Allocated	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	891,369	313,226	36,855	105,566	40,000	28,559	11,100	2,617	3,972	90,882	155,034	29,700	23,760	4,964	584	44,550
Feb-09																
Mar-09																
Apr-09																
May-09																
Jun-09																
Jul-09																
Aug-09																
Sep-09																
Oct-09																
Nov-09																
Dec-09																
Total Annual 1CP	891,369	313,226	36,855	105,566	40,000	28,559	11,100	2,617	3,972	90,882	155,034	29,700	23,760	4,964	584	44,550
% of Total	100%	35.14%	4.13%	11.84%	4.49%	3.20%	1.25%	0.29%	0.45%	10.20%	17.39%	3.33%	2.67%	0.56%	0.07%	5.00%

Calculation of 2 CP & 4 CP Allocation - Transmission

	Total Allocated	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
2 CP - Transmission																
Jan-09	891,369	313,226	36,855	105,566	40,000	28,559	11,100	2,617	3,972	90,882	155,034	29,700	23,760	4,964	584	44,550
Feb-09																
Mar-09																
Apr-09																
May-09																
Jun-09																
Jul-09	742,742	198,895	50,165	104,809	40,000	22,374	11,100		14,032	90,882	124,245	21,780	17,820	1,693	396	44,550
Aug-09	710,569	198,115	35,412	83,532	40,000	24,545	11,100		16,414	90,882	124,245	21,780	17,820	1,779	396	44,550
Sep-09																
Oct-09																
Nov-09																
Dec-09	844,818	289,951	31,972	87,268	40,000	28,115	11,100	2,364	6,267	90,882	155,034	29,700	23,760	3,175	679	44,550
2 Winter + 2 Summer	3,189,498	1,000,188	154,404	381,176	160,000	103,592	44,400	4,981	40,684	363,528	558,558	102,960	83,160	11,611	2,055	178,200
% of Total	100%	31.36%	4.84%	11.95%	5.02%	3.25%	1.39%	0.16%	1.28%	11.40%	17.51%	3.23%	2.61%	0.36%	0.06%	5.59%
4 CP - Transmission																
Jan-09	891,369	313,226	36,855	105,566	40,000	28,559	11,100	2,617	3,972	90,882	155,034	29,700	23,760	4,964	584	44,550
Feb-09	791,967	255,130	23,056	77,894	40,000	29,118	11,100	2,792	4,642	90,882	155,034	29,700	23,760	3,789	520	44,550
Mar-09																
Apr-09																
May-09																
Jun-09																
Jul-09																
Aug-09																
Sep-09																
Oct-09																
Nov-09	810,178	225,255	38,126	104,440	40,000	26,994	11,100	3,109	14,479	90,882	155,034	29,700	23,760	2,051	697	44,550
Dec-09	844,818	289,951	31,972	87,268	40,000	28,115	11,100	2,364	6,267	90,882	155,034	29,700	23,760	3,175	679	44,550
4 Winter	3,338,332	1,083,563	130,009	375,168	160,000	112,785	44,400	10,882	29,360	363,528	620,136	118,800	95,040	13,979	2,480	178,200
% of Total	100%	32.46%	3.89%	11.24%	4.79%	3.38%	1.33%	0.33%	0.88%	10.89%	18.58%	3.56%	2.85%	0.42%	0.07%	5.34%

Calculation of 12 CP Allocation - Transmission

Utility Owned Transmission																
Annual	9,162,150	2,577,654	371,894	1,077,915	480,000	308,730	133,200	21,146	116,084	1,090,584	1,798,830	340,560	273,240	30,931	6,782	534,600
% of Total	100%	28.13%	4.06%	11.76%	5.24%	3.37%	1.45%	0.23%	1.27%	11.90%	19.63%	3.72%	2.98%	0.34%	0.07%	5.83%

NON-COINCIDENT PEAK DEMAND ALLOCATION
Schedule 6.5

NCP Distribution Allocation

	Total	Residential	General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Winter																
NCP at Input (NCP)	1,047,451	391,533	54,466	140,755	40,000	38,824	11,100	3,642	17,426	90,882	155,034	29,700	23,760	5,048	731	44,550
% of Total	100%	37.38%	5.20%	13.44%	3.82%	3.71%	1.06%	0.35%	1.66%	8.68%	14.80%	2.84%	2.27%	0.48%	0.07%	4.25%
NCP Primary (NCPP)	914,640	368,488	51,260	132,470		36,539		3,642	17,426	90,882	155,034	29,700	23,760	4,751	688	
% of Total	100%	40.29%	5.60%	14.48%		3.99%		0.40%	1.91%	9.94%	16.95%	3.25%	2.60%	0.52%	0.08%	
NCP Secondary (NCPS)	547,743	351,443	48,889	126,342				3,642	17,426							
% of Total	100%	64.16%	8.93%	23.07%				0.66%	3.18%							
Summer																
NCP at Input (NCP)	908,035	277,997	71,665	139,746	40,000	38,010	11,100	6,467	19,363	90,882	124,245	21,780	17,820	3,570	840	44,550
% of Total	100%	30.62%	7.89%	15.39%	4.41%	4.19%	1.22%	0.71%	2.13%	10.01%	13.68%	2.40%	1.96%	0.39%	0.09%	4.91%
NCP Primary (NCPP)	779,562	261,635	67,446	131,520		35,773		6,087	18,223	90,882	124,245	21,780	17,820	3,360	790	
% of Total	100%	33.56%	8.65%	16.87%		4.59%		0.78%	2.34%	11.66%	15.94%	2.79%	2.29%	0.43%	0.10%	
NCP Secondary (NCPS)	462,481	249,533	64,327	125,437				5,805	17,380							
% of Total	100%	53.96%	13.91%	27.12%				1.26%	3.76%							
Annual																
NCP at Input (NCP)	1,069,520	391,533	71,665	140,755	40,000	38,824	11,100	6,467	19,363	90,882	155,034	29,700	23,760	5,048	840	44,550
% of Total	100%	36.61%	6.70%	13.16%	3.74%	3.63%	1.04%	0.60%	1.81%	8.50%	14.50%	2.78%	2.22%	0.47%	0.08%	4.17%
NCP Primary (NCPP)	934,170	368,488	67,446	132,470		36,539		6,087	18,223	90,882	155,034	29,700	23,760	4,751	790	
% of Total	100%	39.45%	7.22%	14.18%		3.91%		0.65%	1.95%	9.73%	16.60%	3.18%	2.54%	0.51%	0.08%	
NCP Secondary (NCPS)	565,343	351,443	64,327	126,342				5,805	17,426							
% of Total	100%	62.16%	11.38%	22.35%				1.03%	3.08%							

POWER SUPPLY COST ALLOCATION
Schedule 6.6

		Residential	General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Monthly Power Costs-kWh																
Jan-06	$5,711,582	44.74%	6.20%	14.46%	0.48%	3.45%	1.53%	0.36%	0.17%	9.34%	11.04%	3.07%	1.32%	0.29%	0.09%	3.46%
Feb-06	$4,663,080	47.09%	5.18%	12.09%	0.53%	3.78%	1.68%	0.36%	0.21%	9.50%	11.22%	3.12%	1.34%	0.29%	0.09%	3.52%
Mar-06	$4,749,462	44.52%	6.39%	14.90%	0.43%	4.06%	1.95%	0.41%	0.13%	8.89%	10.50%	2.92%	1.25%	0.27%	0.08%	3.29%
Apr-06	$4,166,801	45.03%	5.79%	13.51%	0.56%	4.63%	2.14%	0.42%	0.26%	9.04%	10.68%	2.97%	1.28%	0.28%	0.08%	3.35%
May-06	$3,414,723	40.46%	7.18%	16.75%	0.65%	5.14%	2.35%	0.50%	1.51%	8.32%	9.83%	2.73%	1.17%	0.26%	0.08%	3.08%
Jun-06	$3,171,778	37.23%	6.73%	15.71%	0.47%	5.28%	2.61%	0.57%	2.56%	9.42%	11.13%	3.09%	1.33%	0.29%	0.09%	3.49%
Jul-06	$4,075,928	30.82%	8.70%	20.29%	0.40%	5.04%	2.54%	0.54%	4.00%	9.04%	10.68%	2.97%	1.28%	0.28%	0.08%	3.35%
Aug-06	$3,582,288	34.10%	6.97%	16.25%	0.43%	4.49%	2.18%	0.48%	4.71%	9.92%	11.73%	3.26%	1.40%	0.30%	0.09%	3.68%
Sep-06	$3,603,323	33.65%	8.13%	18.98%	0.34%	4.05%	2.02%	0.49%	3.75%	9.34%	11.03%	3.06%	1.32%	0.29%	0.09%	3.46%
Oct-06	$4,416,048	37.98%	6.86%	16.01%	0.67%	4.73%	2.09%	0.55%	2.40%	9.38%	11.08%	3.08%	1.32%	0.29%	0.09%	3.47%
Nov-06	$5,337,105	37.41%	7.44%	17.37%	0.59%	4.73%	2.17%	0.50%	0.74%	9.49%	11.21%	3.11%	1.34%	0.29%	0.09%	3.51%
Dec-06	$5,508,652	42.84%	5.52%	12.89%	0.53%	3.97%	1.79%	0.37%	0.29%	10.39%	12.27%	3.41%	1.47%	0.32%	0.10%	3.85%
Total	$52,400,770	40.11%	6.68%	15.59%	0.51%	4.39%	2.05%	0.46%	1.57%	9.36%	11.06%	3.07%	1.32%	0.29%	0.09%	3.47%
Weighted % Allocation	100.00%	40.13%	6.68%	15.59%	0.51%	4.38%	2.05%	0.45%	1.52%	9.37%	11.07%	3.08%	1.32%	0.29%	0.09%	3.47%
Monthly Power Costs-kW																
Jan-06	$2,867,106	44.7%	5.3%	15.1%	1.6%	4.1%	1.1%	0.4%	0.6%	8.8%	10.2%	2.9%	1.1%	0.7%	0.1%	3.4%
Feb-06	$2,704,435	42.6%	3.8%	13.0%	1.9%	4.9%	1.3%	0.5%	0.8%	9.9%	11.9%	3.3%	1.4%	0.6%	0.1%	4.2%
Mar-06	$2,101,202	40.5%	4.8%	17.0%	2.0%	4.5%	1.5%	0.6%	0.5%	9.0%	11.0%	3.1%	1.3%	0.5%	0.1%	3.8%
Apr-06	$956,739	39.6%	4.2%	15.0%	2.2%	4.7%	1.7%	0.7%	0.9%	9.2%	11.4%	3.8%	1.3%	0.7%	0.1%	4.4%
May-06	$1,205,871	37.1%	5.4%	19.3%	1.8%	4.9%	1.4%		1.8%	9.3%	10.6%	2.8%	1.2%	0.4%	0.2%	3.7%
Jun-06	$1,642,359	37.2%	5.7%	15.7%	2.0%	4.5%	1.7%		1.8%	10.2%	12.4%	3.2%	1.4%	0.3%	0.1%	3.8%
Jul-06	$824,263	35.6%	9.0%	18.8%	1.8%	4.0%	1.5%		2.5%	8.2%	11.0%	2.8%	1.2%	0.3%	0.1%	3.3%
Aug-06	$793,155	36.7%	6.6%	15.5%	1.9%	4.5%	1.4%		3.0%	10.2%	11.6%	3.1%	1.3%	0.3%	0.1%	3.7%
Sep-06	$902,662	30.2%	6.0%	21.2%	2.0%	6.1%	1.3%		3.2%	9.6%	11.7%	3.1%	1.4%	0.4%	0.1%	3.6%
Oct-06	$921,980	36.5%	5.6%	16.5%	2.0%	5.5%	1.4%	0.7%	3.4%	8.6%	10.7%	3.2%	1.2%	0.4%	0.1%	4.4%
Nov-06	$1,617,900	36.7%	6.2%	17.0%	1.7%	4.4%	1.4%	0.5%	2.4%	9.4%	11.3%	3.2%	1.3%	0.3%	0.1%	4.0%
Dec-06	$2,856,315	43.6%	4.8%	13.1%	1.6%	4.2%	1.2%	0.4%	0.9%	9.4%	11.4%	3.5%	1.3%	0.5%	0.1%	3.9%
Total	$19,393,988	38.80%	5.60%	16.23%	1.85%	4.65%	1.41%	0.32%	1.75%	9.30%	11.25%	3.18%	1.28%	0.47%	0.10%	3.83%
Weighted % Allocation	100.00%	39.97%	5.28%	15.69%	1.82%	4.58%	1.38%	0.35%	1.43%	9.34%	11.25%	3.20%	1.28%	0.49%	0.10%	3.83%

FORECAST OF REVENUES FROM CURRENT RATES
Schedule 7.1

	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale
Customer Charge Revenues															
Jan-09	$1,389,707	$1,148,992	$127,085	$34,863	$2,021	$24,176	$6,594		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692
Feb-09	$1,390,661	$1,149,652	$127,321	$34,921	$2,021	$24,176	$6,594		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692
Mar-09	$1,393,047	$1,151,816	$127,500	$34,964	$2,021	$24,176	$6,594		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692
Apr-09	$1,391,011	$1,149,689	$127,563	$34,992	$2,021	$24,176	$6,594		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692
May-09	$1,394,471	$1,152,708	$127,918	$35,078	$2,021	$24,176	$6,594		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692
Jun-09	$1,399,567	$1,156,865	$128,643	$35,292	$2,021	$24,176	$6,594		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692
Jul-09	$1,400,394	$1,157,208	$129,027	$35,393	$2,021	$24,176	$6,594		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692
Aug-09	$1,399,277	$1,155,912	$129,163	$35,435	$2,021	$24,176	$6,594		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692
Sep-09	$1,401,489	$1,157,873	$129,370	$35,478	$2,021	$24,176	$6,594		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692
Oct-09	$1,404,471	$1,160,502	$129,638	$35,564	$2,021	$24,176	$6,594		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692
Nov-09	$1,407,390	$1,163,274	$129,756	$35,593	$2,021	$24,176	$6,594		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692
Dec-09	$1,410,413	$1,165,960	$130,022	$35,664	$2,021	$24,176	$6,594		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692
Total	$16,781,898	$13,870,451	$1,543,005	$423,237	$24,249	$290,114	$79,123		$180,478	$81,209	$101,512	$40,605	$60,907	$20,302	$20,302
Energy Revenues															
Jan-09	$20,087,257	$10,839,896	$1,593,593	$2,961,851	$114,115	$520,117	$205,167	$166,946	$47,012	$1,189,213	$1,405,124	$390,303	$167,803	$36,510	$11,145
Feb-09	$17,666,751	$10,069,313	$1,152,033	$2,175,056	$109,969	$502,093	$198,166	$145,472	$49,629	$1,067,126	$1,260,872	$350,234	$150,576	$32,762	$10,001
Mar-09	$17,237,895	$9,251,442	$1,416,796	$2,620,003	$39,715	$524,520	$223,367	$161,308	$31,644	$970,409	$1,146,594	$318,491	$136,929	$29,793	$9,095
Apr-09	$14,997,210	$8,172,835	$1,136,291	$2,093,790	$45,964	$522,130	$214,445	$144,414	$30,909	$861,681	$1,018,126	$282,807	$121,587	$26,455	$8,076
May-09	$14,305,983	$7,019,237	$1,344,604	$2,456,275	$50,866	$554,438	$225,184	$164,180	$171,664	$758,108	$895,749	$248,814	$106,972	$23,275	$7,105
Jun-09	$13,222,541	$6,111,020	$1,206,522	$2,155,659	$35,052	$538,508	$236,358	$177,144	$276,080	$812,579	$960,109	$266,691	$114,658	$24,947	$7,615
Jul-09	$13,697,675	$5,284,078	$1,568,038	$2,871,917	$77,194	$537,427	$241,074	$176,011	$451,513	$813,960	$961,741	$267,144	$114,853	$24,990	$7,628
Aug-09	$13,492,135	$5,817,404	$1,228,415	$2,276,021	$83,134	$475,374	$205,964	$156,222	$528,151	$889,468	$1,050,958	$291,926	$125,507	$27,308	$8,336
Sep-09	$13,567,475	$5,670,487	$1,437,118	$2,722,325	$25,497	$423,560	$188,454	$155,037	$415,838	$826,621	$976,700	$271,299	$116,639	$25,378	$7,747
Oct-09	$14,388,512	$6,752,840	$1,301,276	$2,406,366	$53,341	$522,258	$205,442	$185,705	$280,371	$876,219	$1,035,303	$287,578	$123,638	$26,901	$8,212
Nov-09	$16,342,960	$7,467,793	$1,591,734	$2,944,714	$115,589	$587,093	$239,087	$186,736	$165,844	$995,010	$1,175,662	$326,565	$140,400	$30,548	$9,325
Dec-09	$18,270,745	$9,628,988	$1,320,794	$2,445,877	$115,589	$555,107	$222,489	$155,390	$74,171	$1,226,400	$1,449,063	$402,508	$173,050	$37,652	$11,494
Total	$187,277,138	$92,085,331	$16,297,213	$30,129,853	$866,025	$6,262,625	$2,605,197	$1,974,565	$2,522,827	$11,286,794	$13,336,001	$3,704,361	$1,592,612	$346,520	$105,780
Demand Revenues															
Jan-09	$2,751,257			$985,202		$293,774	$63,073			$472,314	$534,993	$168,189	$59,943	$35,126	$4,382
Feb-09	$2,560,273			$911,904		$299,531	$63,076			$423,352	$481,208	$148,510	$54,452	$26,840	$4,382
Mar-09	$2,359,708			$867,901		$257,060	$67,004			$372,883	$444,854	$141,102	$50,155	$26,344	$4,382
Apr-09	$2,287,050			$839,366		$239,206	$58,493			$372,883	$444,854	$141,102	$50,155	$26,344	$4,382
May-09	$2,311,025			$872,074		$228,707	$58,800			$372,883	$444,854	$141,102	$50,155	$26,344	$5,842
Jun-09	$2,365,458			$897,285		$230,001	$47,918			$403,577	$454,430	$141,102	$50,155	$26,344	$4,382
Jul-09	$2,447,543			$929,852		$230,156	$31,355			$431,578	$491,392	$141,102	$51,119	$26,344	$4,382
Aug-09	$2,492,699			$940,825		$252,487	$31,110			$432,198	$499,601	$141,102	$54,386	$26,344	$4,382
Sep-09	$2,370,095			$898,530		$284,762	$36,653			$372,883	$444,854	$141,102	$50,155	$26,344	$4,548
Oct-09	$2,371,942			$886,445		$293,250	$42,259			$372,883	$444,854	$141,102	$50,155	$26,344	$4,385
Nov-09	$2,344,282			$841,796		$277,679	$43,489			$397,845	$449,780	$141,102	$51,053	$26,344	$4,931
Dec-09	$2,698,710			$860,894		$289,207	$44,850			$497,178	$593,139	$188,135	$66,874	$26,344	$5,085
Total	$29,360,043			$10,732,074		$3,175,819	$588,079			$4,922,460	$5,728,812	$1,774,748	$638,757	$325,407	$55,462

FORECAST OF REVENUES FROM CURRENT RATES
Schedule 7.1

	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale
Total Revenues at Existing Rates															
Jan-09	$24,228,222	$11,988,888	$1,720,678	$3,981,916	$116,136	$838,067	$274,834	$166,946	$62,052	$1,668,295	$1,948,577	$561,876	$232,822	$73,328	$17,219
Feb-09	$21,617,685	$11,218,965	$1,279,354	$3,121,881	$111,990	$825,799	$267,835	$145,472	$64,669	$1,497,245	$1,750,539	$502,128	$210,103	$61,294	$16,075
Mar-09	$20,990,649	$10,403,258	$1,544,296	$3,522,868	$41,736	$805,757	$296,964	$161,308	$46,684	$1,350,060	$1,599,907	$462,976	$192,159	$57,829	$15,168
Apr-09	$18,675,270	$9,322,524	$1,263,853	$2,968,148	$47,984	$785,512	$279,532	$144,414	$45,949	$1,241,332	$1,471,440	$427,292	$176,817	$54,491	$14,149
May-09	$18,011,480	$8,171,945	$1,472,522	$3,363,426	$52,887	$807,321	$290,578	$164,180	$186,703	$1,137,759	$1,349,062	$393,299	$162,203	$51,311	$14,639
Jun-09	$16,987,567	$7,267,885	$1,335,165	$3,088,237	$37,073	$792,686	$290,869	$177,144	$291,120	$1,222,923	$1,422,998	$411,176	$169,889	$52,983	$13,689
Jul-09	$17,545,612	$6,441,285	$1,697,065	$3,837,161	$79,215	$791,759	$279,023	$176,011	$466,553	$1,252,306	$1,461,592	$411,630	$171,047	$53,026	$13,702
Aug-09	$17,384,111	$6,973,316	$1,357,578	$3,252,281	$85,155	$752,037	$243,668	$156,222	$543,191	$1,328,433	$1,559,018	$436,411	$184,969	$55,344	$14,410
Sep-09	$17,339,059	$6,828,360	$1,566,488	$3,656,333	$27,518	$732,498	$231,701	$155,037	$430,878	$1,206,271	$1,430,013	$415,785	$171,870	$53,414	$13,986
Oct-09	$18,164,924	$7,913,342	$1,430,913	$3,328,376	$55,362	$839,684	$254,294	$185,705	$295,411	$1,255,870	$1,488,616	$432,063	$178,869	$54,937	$14,289
Nov-09	$20,094,632	$8,631,067	$1,721,490	$3,822,103	$117,610	$888,948	$289,170	$186,736	$180,884	$1,399,622	$1,633,901	$471,051	$196,528	$58,584	$15,948
Dec-09	$22,379,868	$10,794,947	$1,450,816	$3,342,435	$117,610	$868,491	$273,932	$155,390	$89,211	$1,730,345	$2,050,660	$594,027	$244,999	$65,688	$18,270
Total	**$233,419,080**	$105,955,782	$17,840,218	$41,285,164	$890,273	$9,728,558	$3,272,400	$1,974,565	$2,703,305	$16,290,463	$19,166,325	$5,519,713	$2,292,276	$692,230	$181,544

2009 BASELINE REVENUES AT EXISTING RATES
Schedule 7.2

		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		1,156,960	95,840	95,895	96,075	95,898	96,150	96,496	96,525	96,417	96,580	96,800	97,031	97,255
Consumption	*kWh*	**1,221,674,870**	143,810,401	133,587,255	122,736,750	108,427,119	93,122,593	81,073,492	70,102,639	77,178,162	75,229,040	89,588,369	99,073,490	127,745,562
Account Fixed Charge	*Bi-monthly/2* $	11.87												
Unit Energy Charge	*$/kWh* $	0.07463												
Fixed Charge Revenue (includes 1% late fees)	*$,000*	$13,870	$1,149	$1,150	$1,152	$1,150	$1,153	$1,157	$1,157	$1,156	$1,158	$1,161	$1,163	$1,166
Energy Charge Revenue (includes 1% late fees)	*$,000*	$92,085	$10,840	$10,069	$9,251	$8,173	$7,019	$6,111	$5,284	$5,817	$5,670	$6,753	$7,468	$9,629
Total Billed Revenue (000's)	*$,000*	**$105,956**	**$11,989**	**$11,219**	**$10,403**	**$9,323**	**$8,172**	**$7,268**	**$6,441**	**$6,973**	**$6,828**	**$7,913**	**$8,631**	**$10,795**

GENERAL SERVICE		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		107,865	8,884	8,900	8,913	8,917	8,942	8,993	9,020	9,029	9,044	9,062	9,071	9,089
Consumption	*Total*	**203,446,005**	19,924,547	14,701,642	17,605,493	13,941,916	16,516,947	14,661,868	19,781,723	15,765,838	18,180,843	16,182,021	19,712,090	16,471,076
	kWh to 16000	**158,294,563**	15,124,631	10,591,347	13,780,361	11,649,417	13,695,175	12,671,489	14,695,433	10,855,016	13,237,599	13,003,254	15,915,730	13,075,112
	Next 184000 kWh	**40,029,017**	4,614,451	3,241,485	3,671,009	2,124,360	2,659,345	1,990,380	4,447,713	4,176,959	4,445,141	2,564,133	3,350,188	2,743,855
	kWh over	**5,122,424**	185,466	868,811	154,123	168,139	162,426	-	638,578	733,863	498,103	614,635	446,172	652,109
Account Fixed Charge	*Bi-monthly/2* $	14.31												
Unit Energy Charge - 0-8000	*$/kWh* $	0.08507												
Unit Energy Charge - next 92,000	*$/kWh* $	0.06459												
Unit Energy Charge - Balance of kWh	*$/kWh* $	0.04795												
Fixed Charge Revenue	*$,000*	$1,543	$127	$127	$128	$128	$128	$129	$129	$129	$129	$130	$130	$130
Energy Charge Revenue	*$,000*	$16,297	$1,594	$1,152	$1,417	$1,136	$1,345	$1,207	$1,568	$1,228	$1,437	$1,301	$1,592	$1,321
Total Billed Revenue (000's)	*$,000*	**$17,840**	$1,721	$1,279	$1,544	$1,264	$1,473	$1,335	$1,697	$1,358	$1,566	$1,431	$1,721	$1,451

GENERAL SERVICE GS21		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		29,597	2,438	2,442	2,445	2,447	2,453	2,468	2,475	2,478	2,481	2,487	2,489	2,494
Consumption	*Total*	**474,707,344**	46,490,610	34,303,832	41,079,484	32,531,137	38,539,543	34,211,026	46,157,354	36,786,955	42,421,967	37,758,050	45,994,876	38,432,510
	kWh to 8000	**92,146,278**	8,875,832	6,002,801	7,730,457	7,088,704	7,951,352	6,590,251	7,987,897	6,086,379	9,458,629	7,487,480	9,533,775	7,352,721
	kWh to 100000	**237,209,508**	24,228,065	18,471,360	21,832,171	16,273,381	18,819,073	16,262,622	21,764,475	17,197,098	20,257,650	19,106,522	23,159,041	19,838,051
	kWh over	**145,351,558**	13,386,713	9,829,671	11,516,856	9,169,052	11,769,118	11,358,154	16,404,982	13,503,479	12,705,688	11,164,048	13,302,061	11,241,737
	kW	1,522,280.0	139,745.0	129,348.1	123,106.5	119,059.0	123,698.4	127,274.5	131,893.9	133,450.4	127,451.0	125,736.9	119,403.6	122,112.6
Account Fixed Charge	*Monthly* $	14.30												
Unit Energy Charge - 0-8000	*$/kWh* $	0.08507												
Unit Energy Charge - next 92000	*$/kWh* $	0.06459												
Unit Energy Charge - Balance of kWh	*$/kWh* $	0.04795												
Unit Demand Charge	*$/KVA* $	7.05												
Fixed Charge Revenue	*$,000*	$423	$35	$35	$35	$35	$35	$35	$35	$35	$35	$36	$36	$36
Energy Charge Revenue	*$,000*	$30,130	$2,962	$2,175	$2,620	$2,094	$2,456	$2,156	$2,872	$2,276	$2,722	$2,406	$2,945	$2,446
Demand Charge Revenue	*$,001*	$10,732	$985	$912	$868	$839	$872	$897	$930	$941	$899	$886	$842	$861
Total Billed Revenue (000's)	*$,000*	**$41,285**	$3,982	$3,122	$3,523	$2,968	$3,363	$3,088	$3,837	$3,252	$3,656	$3,328	$3,822	$3,342

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INDUSTRIAL ID30		**Total**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		396	33	33	33	33	33	33	33	33	33	33	33	33
Consumption	*kWh*	**141,018,352**	11,711,699	11,305,845	11,810,860	11,757,036	12,484,524	12,125,836	12,101,478	10,704,218	9,537,494	11,759,915	13,219,843	12,499,603
	MVA	478.3	44.2	45.1	38.7	36.0	34.4	34.6	34.7	38.0	42.9	44.2	41.8	43.6
Account Fixed Charge	*Monthly* $	732.61												
Unit Energy Charge	*$/kWh* $	0.04441												
Unit Demand Charge	*$/KVA* $	6.64												
Fixed Charge Revenue	*$,000*	$290	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24
Energy Charge Revenue	*$,000*	$6,263	$520	$502	$525	$522	$554	$539	$537	$475	$424	$522	$587	$555
Demand Charge Revenue	*$,001*	$3,176	$294	$300	$257	$239	$229	$230	$230	$252	$285	$293	$278	$289
Total Billed Revenue (000's)	*$,000*	**$9,729**	$838	$826	$806	$786	$807	$793	$792	$752	$732	$840	$889	$868

INDUSTRIAL COMBINED ID31/33		**Total**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		48	4	4	4	4	4	4	4	4	4	4	4	4
Consumption	*kWh*	**83,180,240**	6,908,193	6,668,798	6,966,683	6,934,935	7,364,046	7,152,473	7,138,105	6,313,926	5,625,729	6,936,633	7,797,777	7,372,941
	MVA													
Account Fixed Charge	*Monthly* $	-												
Unit Energy Charge	*$/kWh* $	-												
Unit Demand Charge	*$/KVA* $	-												
Fixed Charge Revenue	*$,000*	$103	$9	$9	$9	$9	$9	$9	$9	$9	$9	$9	$9	$9
Energy Charge Revenue	*$,000*	$3,471	$319	$308	$263	$260	$276	$271	$318	$289	$214	$259	$355	$338
Demand Charge Revenue	*$,001*	$588	$63	$63	$67	$58	$59	$48	$31	$31	$37	$42	$43	$45
Total Billed Revenue (000's)	*$,000*	**$4,163**	**$391**	**$380**	**$339**	**$328**	**$343**	**$328**	**$358**	**$329**	**$259**	**$310**	**$407**	**$392**

INDUSTRIAL ID31		**Total**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		36	3	3	3	3	3	3	3	3	3	3	3	3
Consumption	*kWh*	**66,680,240**	5,251,269	5,072,069	5,717,098	5,488,736	5,763,604	6,049,592	6,170,322	5,271,674	4,823,496	5,258,309	6,119,453	5,694,617
	MVA	109.5	11.7	11.7	12.5	10.9	10.9	8.9	5.8	5.8	6.8	7.9	8.1	8.4
Account Fixed Charge	*Monthly* $	2,197.87												
Unit Energy Charge	*$/kWh* $	0.03907												
Unit Demand Charge	*$/KVA* $	5.37												
Fixed Charge Revenue	*$,000*	$79	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7
Energy Charge Revenue	*$,000*	$2,605	$205	$198	$223	$214	$225	$236	$241	$206	$188	$205	$239	$222
Demand Charge Revenue	*$,001*	$588	$63	$63	$67	$58	$59	$48	$31	$31	$37	$42	$43	$45
Total Billed Revenue (000's)	*$,000*	**$3,272**	$275	$268	$297	$280	$291	$291	$279	$244	$232	$254	$289	$274

INDUSTRIAL ID33		**Total**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		12	1	1	1	1	1	1	1	1	1	1	1	1
Consumption	***Total kWh***	**16,500,000**	1,656,924	1,596,729	1,249,585	1,446,198	1,600,442	1,102,881	967,783	1,042,252	802,233	1,678,324	1,678,324	1,678,324
	kWh On	**7,845,933**	629,631	606,757	724,759	838,795	928,256	639,671	367,758	396,056	465,295	973,428	637,763	637,763
	kWh Off	**8,654,067**	1,027,293	989,972	524,826	607,403	672,186	463,210	600,026	646,196	336,938	704,896	1,040,561	1,040,561
Account Fixed Charge	*Monthly* $	2,020.72												
Unit Energy Charge - Winter	*$/kWh On* $	0.12394												
Winter	*$/kWh Off* $	0.03512												
Shoulder	*$/kWh On* $	0.03967												
Shoulder	*$/kWh Off* $	0.02089												
Summer	*$/kWh On* $	0.16533												
Summer	*$/kWh Off* $	0.02732												
Fixed Charge Revenue	*$,000*	$24	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Energy Charge Revenue	*$,000*	$866	$114	$110	$40	$46	$51	$35	$77	$83	$25	$53	$116	$116
Total Billed Revenue (000's)	*$,000*	**$890**	$116	$112	$42	$48	$53	$37	$79	$85	$28	$55	$118	$118

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STREET LIGHT		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Consumption	*MWh*	13,866,327	1,172,370	1,021,572	1,132,778	1,014,144	1,152,947	1,243,991	1,236,031	1,097,065	1,088,745	1,304,110	1,311,349	1,091,224
Unit Energy Charge	*$/kWh*	$0.1424												
Energy Charge Revenue	*$,000*	$1,975	$167	$145	$161	$144	$164	$177	$176	$156	$155	$186	$187	$155
Total Billed Revenue (000's)	*$,000*	**$1,975**	$167	$145	$161	$144	$164	$177	$176	$156	$155	$186	$187	$155

IRRIGATION IR60		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		12,612	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051
Consumption	*kWh*	47,802,478	552,628	583,394	371,980	623,673	3,463,753	5,570,622	9,110,437	10,656,806	8,390,595	5,657,206	1,949,500	871,883
Account Fixed Charge	*Monthly* $	14.31												
Unit Energy Charge -Irrigation Season	*$/kWh*	$0.04956												
GS20 (0-16000 kWh)	*$/kWh*	$0.08507												
GS20 (16000 - 184000 kWh)	*$/kWh*	$0.06459												
GS20 (184000 kWh - MAX)	*$/kWh*	$0.04795												
Fixed Charge Revenue	*$,000*	$180	$ 15	$ 15	$ 15	$ 15	$ 15	$ 15	$ 15	$ 15	$ 15	$ 15	$ 15	$ 15
Energy Charge Revenue	*$,000*	$2,523	47	50	32	31	172	276	452	528	416	280	166	74
Total Billed Revenue (000's)	*$,000*	**$2,703**	$62	$65	$47	$46	$187	$291	$467	$543	$431	$295	$181	$89

WHOLESALE WH40 - Kelowna		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		48	4	4	4	4	4	4	4	4	4	4	4	4
Consumption	*KWh*	**300,580,396**	31,670,124	28,418,812	25,843,110	22,947,572	20,189,302	21,639,922	21,676,701	23,687,558	22,013,863	23,334,721	26,498,260	32,660,451
	MVA	654.7	64.5	57.8	50.6	48.2	47.1	55.1	59.0	59.0	42.3	48.8	54.4	67.9
	MVA with ratchet	672.5	64.5	57.8	50.9	50.9	50.9	55.1	59.0	59.0	50.9	50.9	54.4	67.9
Account Fixed Charge	*Monthly* $	1,691.86												
Unit Energy Charge	*$/kWh* $	0.03755												
Unit Demand Charge	*$/KVA* $	7.32000												
Fixed Charge Revenue	*$,000*	$81	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7
Energy Charge Revenue	*$,000*	$11,287	$1,189	$1,067	$970	$862	$758	$813	$814	$889	$827	$876	$995	$1,226
Demand Charge Revenue	*$,001*	$4,922	$472	$423	$373	$373	$373	$404	$432	$432	$373	$373	$398	$497
Total Billed Revenue (000's)	*$,000*	**$16,290**	$1,668	$1,497	$1,350	$1,241	$1,138	$1,223	$1,252	$1,328	$1,206	$1,256	$1,400	$1,730

WHOLESALE WH40 - Penticton		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		60	5	5	5	5	5	5	5	5	5	5	5	5
Consumption	*KWh*	**355,153,151**	37,420,086	33,578,473	30,535,132	27,113,885	23,854,830	25,568,822	25,612,278	27,988,222	26,010,654	27,571,325	31,309,230	38,590,215
	MVA	739.0	73.1	65.7	57.1	56.8	46.8	62.1	67.1	68.3	45.6	54.0	61.4	81.0
	MVA with ratchet	782.6	73.1	65.7	60.8	60.8	60.8	62.1	67.1	68.3	60.8	60.8	61.4	81.0
Account Fixed Charge	*Monthly* $	1,691.86												
Unit Energy Charge	*$/kWh* $	0.03755												
Unit Demand Charge	*$/KVA* $	7.32000												
Fixed Charge Revenue	*$,000*	$102	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8
Energy Charge Revenue	*$,000*	$13,336	$1,405	$1,261	$1,147	$1,018	$896	$960	$962	$1,051	$977	$1,035	$1,176	$1,449
Demand Charge Revenue	*$,001*	$5,729	$535	$481	$445	$445	$445	$454	$491	$500	$445	$445	$450	$593
Total Billed Revenue (000's)	*$,000*	**$19,166**	$1,949	$1,751	$1,600	$1,471	$1,349	$1,423	$1,462	$1,559	$1,430	$1,489	$1,634	$2,051

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WHOLESALE WH40 - Summerland		**Total**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		24	2	2	2	2	2	2	2	2	2	2	2	2
Consumption	*KWh*	**98,651,430**	10,394,234	9,327,143	8,481,790	7,531,465	6,626,192	7,102,290	7,114,361	7,774,331	7,225,019	7,658,529	8,696,812	10,719,263
	MVA	218.2	23.0	20.3	17.7	17.5	13.8	17.2	17.4	17.8	12.5	16.7	18.6	25.7
	MVA with ratchet	242.5	23.0	20.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	25.7
Account Fixed Charge	*Monthly* $	1,691.86												
Unit Energy Charge	*$/kWh* $	0.03755												
Unit Demand Charge	*$/KVA* $	7.32000												
Fixed Charge Revenue	*$,000*	$41	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
Energy Charge Revenue	*$,000*	$3,704	$390	$350	$318	$283	$249	$267	$267	$292	$271	$288	$327	$403
Demand Charge Revenue	*$,001*	$1,775	$168	$149	$141	$141	$141	$141	$141	$141	$141	$141	$141	$188
Total Billed Revenue (000's)	*$,000*	**$5,520**	$562	$502	$463	$427	$393	$411	$412	$436	$416	$432	$471	$594

WHOLESALE WH40 - Grand Forks		**Total**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		36	3	3	3	3	3	3	3	3	3	3	3	3
Consumption	*KWh*	**42,413,094**	4,468,781	4,010,008	3,646,566	3,237,994	2,848,791	3,053,479	3,058,669	3,342,409	3,106,244	3,292,622	3,739,010	4,608,520
	MVA	83.4	8.2	7.4	6.6	6.3	5.7	6.2	7.0	7.4	5.8	6.5	7.0	9.1
	MVA with ratchet	87.3	8.2	7.4	6.9	6.9	6.9	6.9	7.0	7.4	6.9	6.9	7.0	9.1
Account Fixed Charge	*Monthly* $	1,691.86												
Unit Energy Charge	*$/kWh* $	0.03755												
Unit Demand Charge	*$/KVA* $	7.32000												
Fixed Charge Revenue	*$,000*	$61	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
Energy Charge Revenue	*$,000*	$1,593	$168	$151	$137	$122	$107	$115	$115	$126	$117	$124	$140	$173
Demand Charge Revenue	*$,001*	$639	$60	$54	$50	$50	$50	$50	$51	$54	$50	$50	$51	$67
Total Billed Revenue (000's)	*$,000*	**$2,292**	$233	$210	$192	$177	$162	$170	$171	$185	$172	$179	$197	$245

WHOLESALE WH40 - Lardeau		**Total**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		12	1	1	1	1	1	1	1	1	1	1	1	1
Consumption	*KWh*	**9,228,226**	972,316	872,496	793,419	704,522	619,839	664,375	665,504	727,240	675,855	716,408	813,533	1,002,720
	MVA	30.4	4.8	3.7	2.5	3.4	1.8	1.6	1.7	1.7	1.9	2.1	2.0	3.2
	MVA with ratchet	44.5	4.8	3.7	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Account Fixed Charge	*Monthly* $	1,691.86												
Unit Energy Charge	*$/kWh* $	0.03755												
Unit Demand Charge	*$/KVA* $	7.32000												
Fixed Charge Revenue	*$,000*	$20	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Energy Charge Revenue	*$,000*	$347	$37	$33	$30	$26	$23	$25	$25	$27	$25	$27	$31	$38
Demand Charge Revenue	*$,001*	$325	$35	$27	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26
Total Billed Revenue (000's)	*$,000*	**$692**	$73	$61	$58	$54	$51	$53	$53	$55	$53	$55	$59	$66

WHOLESALE WH40 - Yahk		**Total**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		12	1	1	1	1	1	1	1	1	1	1	1	1
Consumption	*KWh*	**2,817,036**	296,812	266,341	242,201	215,064	189,214	202,809	203,154	222,000	206,314	218,693	248,341	306,093
	MVA	6.5	0.6	0.5	0.5	0.5	0.8	0.4	0.4	0.4	0.6	0.6	0.7	0.7
	MVA with ratchet	7.6	0.6	0.6	0.6	0.6	0.8	0.6	0.6	0.6	0.6	0.6	0.7	0.7
Account Fixed Charge	*Monthly* $	1,691.86												
Unit Energy Charge	*$/kWh* $	0.03755												
Unit Demand Charge	*$/KVA* $	7.32000												
Fixed Charge Revenue	*$,000*	$20	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Energy Charge Revenue	*$,000*	$106	$11	$10	$9	$8	$7	$8	$8	$8	$8	$8	$9	$11
Demand Charge Revenue	*$,001*	$55	$4	$4	$4	$4	$6	$4	$4	$4	$5	$4	$5	$5
Total Billed Revenue (000's)	*$,000*	**$182**	$17	$16	$15	$14	$15	$14	$14	$14	$14	$14	$16	$18

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WHOLESALE WH40 - Combined		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		192	16	16	16	16	16	16	16	16	16	16	16	16
Consumption	*kWh*	**808,843,332**	85,222,352	76,473,274	69,542,218	61,750,502	54,328,167	58,231,698	58,330,668	63,741,759	59,237,948	62,792,298	71,305,187	87,887,262
	MVA	1,732.2	174.1	155.5	134.9	132.7	116.0	142.7	152.5	154.6	108.7	128.6	144.0	187.7
	MVA with ratchet	1,836.8	174.2	155.6	142.0	142.0	142.2	147.5	156.5	158.2	142.1	142.0	146.3	188.1
Account Fixed Charge	*Monthly* $	1,691.86												
Unit Energy Charge	*$/kWh* $	0.03755												
Unit Demand Charge	*$/KVA* $	7.32												
Fixed Charge Revenue	*$,000*	$325	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27
Energy Charge Revenue	*$,000*	$30,372	$3,200	$2,872	$2,611	$2,319	$2,040	$2,187	$2,190	$2,394	$2,224	$2,358	$2,678	$3,300
Demand Charge Revenue	*$,001*	$13,446	$1,275	$1,139	$1,040	$1,040	$1,041	$1,080	$1,146	$1,158	$1,040	$1,040	$1,071	$1,377
Total Billed Revenue (000's)	*$,000*	**$44,143**	$4,502	$4,037	$3,678	$3,386	$3,108	$3,294	$3,363	$3,579	$3,291	$3,425	$3,776	$4,704

WHOLESALE WH41 - Nelson		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		12	1	1	1	1	1	1	1	1	1	1	1	1
Consumption	*kWh*	**112,532,033**	11,856,739	10,639,505	9,675,208	8,591,169	7,558,521	8,101,608	8,115,377	8,868,206	8,241,604	8,736,111	9,920,484	12,227,500
	MVA	326.8	30.9	33.9	29.5	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	29.3
Account Fixed Charge	*Monthly* $	3,867.15												
Unit Energy Charge	*$/kWh* $	0.03698												
Unit Demand Charge	*$/KVA* $	4.34												
Fixed Charge Revenue	*$,000*	$46	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4
Energy Charge Revenue	*$,000*	$4,161	$438	$393	$358	$318	$280	$300	$300	$328	$305	$323	$367	$452
Demand Charge Revenue	*$,001*	$1,418	$134	$147	$128	$110	$110	$110	$110	$110	$110	$110	$110	$127
Total Billed Revenue (000's)	*$,000*	**$5,626**	$577	$544	$490	$432	$394	$414	$414	$442	$419	$437	$481	$583

FORECAST CUSTOMERS AND ENERGY SALES
Schedule 8.1

Number of Customers / Services	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	110,237	95,840	8,884	2,438	1	33	3	1,980	1,051	1	1	1	1	1	1	1
Feb-09	110,312	95,895	8,900	2,442	1	33	3	1,980	1,051	1	1	1	1	1	1	1
Mar-09	110,508	96,075	8,913	2,445	1	33	3	1,980	1,051	1	1	1	1	1	1	1
Apr-09	110,337	95,898	8,917	2,447	1	33	3	1,980	1,051	1	1	1	1	1	1	1
May-09	110,620	96,150	8,942	2,453	1	33	3	1,980	1,051	1	1	1	1	1	1	1
Jun-09	111,032	96,496	8,993	2,468	1	33	3	1,980	1,051	1	1	1	1	1	1	1
Jul-09	111,095	96,525	9,020	2,475	1	33	3	1,980	1,051	1	1	1	1	1	1	1
Aug-09	110,999	96,417	9,029	2,478	1	33	3	1,980	1,051	1	1	1	1	1	1	1
Sep-09	111,180	96,580	9,044	2,481	1	33	3	1,980	1,051	1	1	1	1	1	1	1
Oct-09	111,424	96,800	9,062	2,487	1	33	3	1,980	1,051	1	1	1	1	1	1	1
Nov-09	111,666	97,031	9,071	2,489	1	33	3	1,980	1,051	1	1	1	1	1	1	1
Dec-09	111,913	97,255	9,089	2,494	1	33	3	1,980	1,051	1	1	1	1	1	1	1
Total Average	110,944	96,413	8,989	2,466	1	33	3	1,980	1,051	1	1	1	1	1	1	1

Historic Energy, Demand And Customer Count
Historic Year

	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Input Recorded Data																
Energy Sales (kWh)	3,107,070,981	1,221,674,870	203,446,005	474,707,344	16,500,000	141,018,352	66,680,240	13,866,327	47,802,478	300,580,396	355,153,151	98,651,430	42,413,094	9,228,226	2,817,036	112,532,033
Total Billing Capacity (kVa)	4,286,522			1,720,080		478,286	109,512			654,739	738,988	218,155	83,370	30,410	6,508	246,474
Avg. Monthly Billing Capacity (kVa)	357,210			143,340		39,857	9,126			54,562	61,582	18,180	6,948	2,534	542	20,540
Number of Customers	110,944	96,413	8,989	2,466	1	33	3	1,980	1,051	1	1	1	1	1	1	1
Ratio of NCP to Avg. Billing Capacity				88%		92%	105%			110%	117%	122%	121%	187%	146%	129%
Rate Classes NCP Demand at Meter	818,034	351,443	64,327	126,342	11,400	36,539	9,627	5,805	17,380	60,152	72,326	22,217	8,403	4,751	790	26,531
Estimated Based on Recorded Data																
Annual NCP Load Factor	43%	40%	36%	43%	17%	44%	79%	27%	31%	57%	56%	51%	58%	22%	41%	48%
Rate Classes CP Demand at Input Voltage	701,345	313,226	36,855	105,566	11,213	28,559	8,059	2,617	3,972	61,401	71,883	20,529	8,062	4,964	584	23,855
Annual CP Load Factor	51%	45%	63%	51%	17%	56%	94%	60%	137%	56%	56%	55%	60%	21%	55%	54%

Customer Information	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Weighting Factors for:																
Points of Delivery per Customer		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	4.0	5.0	2.0	3.0	1.0	1.0	3.0
Customers Meters & Services		$ 45.55	$ 137.04	$ 213.87	$ 96,100.00	$ 1,055.38	$ 96,100.00	$ -	$ 45.55	$ 41,600.00	$ 41,600.00	$ 41,600.00	$ 41,600.00	$ 41,600.00	$41,600.00	$ 41,600.00
Customer Retail		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000							
Customer Accounting/Metering		1.000	1.000	1.000	202.500	202.500	202.500	1.400	1.400	159.700	159.700	159.700	159.700	159.700	159.700	159.700
Weighted Number of Customers																
Customers (PODs)	110,956	96,413	8,989	2,466	1	33	3	1,980	1,051	4	5	2	3	1	1	3
Customers Meters & Services	7,408,437	4,391,629	1,231,815	527,493	96,100	34,828	288,300	-	47,873	166,400	208,000	83,200	124,800	41,600	41,600	124,800
Customer Retail	110,937	96,413	8,989	2,466	1	33	3	1,980	1,051	-	-	-	-	-	-	-
Customer Accounting/Metering	122,639	96,413	8,989	2,466	203	6,683	608	2,772	1,471	639	799	319	479	160	160	479
Provided Services																
Power Purchased from Utility*		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Reg & Shaping from Utility*		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Uses Utility Transmission*		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Uses Primary Distribution*		1	1	1		1		1	1	1	1	1	1	1	1	
Uses Secondary Distribution*		1	1	1				1	1							

* (yes=1,no=0)

FORECAST CUSTOMERS AND ENERGY SALES
Schedule 8.1

Load Data And Customer Sales by Rate Class

kWh Sales at the Meter		Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
	Jan-09	327,649,540	143,810,401	19,924,547	46,490,610	1,656,924	11,711,699	5,251,269	1,172,370	552,628	31,670,124	37,420,086	10,394,234	4,468,781	972,316	296,812	11,856,739
	Feb-09	289,285,119	133,587,255	14,701,642	34,303,832	1,596,729	11,305,845	5,072,069	1,021,572	583,394	28,418,812	33,578,473	9,327,143	4,010,008	872,496	266,341	10,639,505
	Mar-09	280,921,453	122,736,750	17,605,493	41,079,484	1,249,585	11,810,860	5,717,098	1,132,778	371,980	25,843,110	30,535,132	8,481,790	3,646,566	793,419	242,201	9,675,208
	Apr-09	245,571,631	108,427,119	13,941,916	32,531,137	1,446,198	11,757,036	5,488,736	1,014,144	623,673	22,947,572	27,113,885	7,531,465	3,237,994	704,522	215,064	8,591,169
	May-09	234,531,042	93,122,593	16,516,947	38,539,543	1,600,442	12,484,524	5,763,604	1,152,947	3,463,753	20,189,302	23,854,830	6,626,192	2,848,791	619,839	189,214	7,558,521
	Jun-09	222,372,614	81,073,492	14,661,868	34,211,026	1,102,881	12,125,836	6,049,592	1,243,991	5,570,622	21,639,922	25,568,822	7,102,290	3,053,479	664,375	202,809	8,101,608
	Jul-09	232,073,813	70,102,639	19,781,723	46,157,354	967,783	12,101,478	6,170,322	1,236,031	9,110,437	21,676,701	25,612,278	7,114,361	3,058,669	665,504	203,154	8,115,377
	Aug-09	231,112,936	77,178,162	15,765,838	36,786,955	1,042,252	10,704,218	5,271,674	1,097,065	10,656,806	23,687,558	27,988,222	7,774,331	3,342,409	727,240	222,000	8,868,206
	Sep-09	227,953,964	75,229,040	18,180,843	42,421,967	802,233	9,537,494	4,823,496	1,088,745	8,390,595	22,013,863	26,010,654	7,225,019	3,106,244	675,855	206,314	8,241,604
	Oct-09	240,714,712	89,588,369	16,182,021	37,758,050	1,678,324	11,759,915	5,258,309	1,304,110	5,657,206	23,334,721	27,571,325	7,658,529	3,292,622	716,408	218,693	8,736,111
	Nov-09	270,284,596	99,073,490	19,712,090	45,994,876	1,678,324	13,219,843	6,119,453	1,311,349	1,949,500	26,498,260	31,309,230	8,696,812	3,739,010	813,533	248,341	9,920,484
	Dec-09	304,599,561	127,745,562	16,471,076	38,432,510	1,678,324	12,499,603	5,694,617	1,091,224	871,883	32,660,451	38,590,215	10,719,263	4,608,520	1,002,720	306,093	12,227,500
Total Sales		3,107,070,981	1,221,674,870	203,446,005	474,707,344	16,500,000	141,018,352	66,680,240	13,866,327	47,802,478	300,580,396	355,153,151	98,651,430	42,413,094	9,228,226	2,817,036	112,532,033

FORECAST CUSTOMER DEMAND
Schedule 8.2

Billing Demand - kVa	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
				All kVA						kVA	kVA	kVA	kVA	kVA	kVA	kVA
Jan-09	432,004			168,457	12,000	44,243	8,624			64,524	73,087	22,977	8,189	4,799	564	24,541
Feb-09	367,693			124,298	12,000	45,110	8,330			57,835	65,739	20,288	7,439	3,667	503	22,484
Mar-09	362,584			148,850	12,000	38,714	9,389			50,568	57,073	17,690	6,644	2,496	467	18,691
Apr-09	324,904			117,875	12,000	36,025	9,014			48,185	56,818	17,494	6,325	3,394	464	17,310
May-09	325,121			139,646	12,000	34,444	9,466			47,083	46,817	13,808	5,733	1,794	798	13,533
Jun-09	341,628			123,962	12,000	34,639	9,936			55,133	62,081	17,233	6,229	1,625	384	18,406
Jul-09	393,457			167,249	12,000	34,662	10,134			58,959	67,130	17,424	6,983	1,669	366	16,881
Aug-09	360,837			133,296	12,000	38,025	8,658			59,043	68,252	17,778	7,430	1,749	372	14,234
Sep-09	343,628			153,714	12,000	42,886	7,922			42,344	45,560	12,482	5,787	1,906	621	18,406
Oct-09	355,318			136,815	12,000	44,164	8,636			48,793	53,958	16,710	6,501	2,083	599	25,059
Nov-09	401,034			166,660	12,000	41,819	10,050			54,350	61,445	18,568	6,974	1,981	674	26,512
Dec-09	422,313			139,258	12,000	43,555	9,353			67,920	81,030	25,702	9,136	3,247	695	30,417
Total	4,430,522			1,720,080		478,286	109,512			654,739	738,988	218,155	83,370	30,410	6,508	246,474

Individual Load Factor		Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	-0.05%	49.5%	42.5%	37.1%		39.5%	86.1%	67.1%	15.0%	73.0%	73.4%	72.3%	75.6%	73.6%	73.6%	67.5%
Feb-09	0.06%	62.5%	55.5%	41.1%		41.4%	95.4%	60.7%	15.0%	73.5%	73.9%	73.3%	76.0%	74.2%	74.2%	65.9%
Mar-09	0.15%	59.5%	52.5%	37.1%		45.6%	86.1%	52.3%	15.0%	74.4%	70.9%	68.9%	73.8%	72.0%	72.0%	64.3%
Apr-09	0.03%	62.0%	55.0%	38.3%		50.4%	89.0%	43.1%	15.0%	71.5%	69.4%	58.2%	71.6%	67.7%	67.7%	57.5%
May-09	0.18%	59.5%	52.5%	37.1%		54.1%	86.1%	34.5%	45.0%	66.7%	67.7%	69.7%	68.4%	68.1%	68.1%	60.0%
Jun-09	-0.18%	49.0%	42.0%	38.3%		54.0%	89.0%	29.8%	70.0%	61.8%	58.1%	62.5%	64.0%	61.6%	61.6%	60.0%
Jul-09	0.32%	38.0%	31.0%	37.1%		52.1%	86.1%	32.2%	70.0%	60.8%	59.6%	64.2%	64.5%	62.3%	62.3%	60.0%
Aug-09	-0.12%	42.0%	35.0%	37.1%		42.0%	86.1%	39.9%	70.0%	60.3%	61.5%	63.7%	63.9%	62.4%	62.4%	60.0%
Sep-09	-0.12%	61.0%	54.0%	38.3%		34.3%	89.0%	49.0%	65.0%	69.9%	70.3%	74.9%	67.0%	70.5%	70.5%	60.0%
Oct-09	0.00%	51.0%	44.0%	37.1%		39.8%	86.1%	57.8%	35.0%	70.6%	67.3%	66.3%	68.2%	68.1%	68.1%	44.3%
Nov-09	-0.18%	49.0%	42.0%	38.3%		48.8%	89.0%	65.3%	15.0%	65.9%	65.5%	65.5%	69.0%	66.5%	66.5%	57.3%
Dec-09	0.02%	47.5%	40.5%	37.1%		42.9%	86.1%	69.1%	15.0%	73.0%	71.7%	64.8%	73.7%	70.8%	70.8%	62.0%
	0.01%	52.5%	46%	38%		45%	88%	50%								

Individual NCP (kW)	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
	Power Factor:		100%	100%	95%	90%	95%	100%	100%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
Jan-09		390,492	63,012	168,457	11,400	39,819	8,193	2,349	4,952	58,329	68,490	19,321	7,945	4,751	559	23,596
Feb-09		318,065	39,419	124,298	11,400	40,599	7,914	2,506	5,788	57,549	67,651	18,943	7,851	3,630	498	24,009
Mar-09		277,258	45,073	148,850	11,400	34,843	8,920	2,910	3,333	46,709	57,874	16,546	6,642	2,471	463	20,214
Apr-09		242,892	35,207	117,875	11,400	32,423	8,564	3,269	5,775	44,591	54,263	17,983	6,283	3,360	459	20,760
May-09		210,361	42,286	139,646	11,400	30,999	8,993	4,488	10,346	40,705	47,336	12,784	5,595	1,776	790	16,932
Jun-09		229,800	48,485	123,962	11,400	31,175	9,439	5,805	11,053	48,632	61,116	15,789	6,628	1,609	380	18,754
Jul-09		247,958	85,769	167,249	11,400	31,196	9,627	5,166	17,493	47,919	57,724	14,894	6,370	1,652	363	18,180
Aug-09		246,986	60,545	133,296	11,400	34,223	8,225	3,696	20,462	52,789	61,159	16,394	7,028	1,731	369	19,866
Sep-09		171,287	46,761	153,714	11,400	38,597	7,526	3,088	17,929	43,733	51,403	13,402	6,435	1,887	615	19,078
Oct-09		236,107	49,432	136,815	11,400	39,748	8,204	3,033	21,725	44,435	55,066	15,534	6,487	2,062	593	26,531
Nov-09		280,821	65,185	166,660	11,400	37,637	9,548	2,791	18,051	55,854	66,387	18,431	7,529	1,961	667	24,034
Dec-09		361,476	54,663	139,258	11,400	39,200	8,885	2,122	7,813	60,152	72,326	22,217	8,403	3,215	688	26,487
Maximum		390,492	85,769	168,457	11,400	40,599	9,627	5,805	21,725	60,152	72,326	22,217	8,403	4,751	790	26,531
										601,397	720,794	202,239	83,197	30,106	6,443	258,440

Group Coincidence Factor		Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09		90.00%	75.00%	75.00%	100.0%	90.0%	100.0%	100.0%	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Feb-09		90.00%	75.00%	75.00%	100.0%	90.0%	100.0%	100.0%	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Mar-09		90.00%	75.00%	75.00%	100.0%	90.0%	100.0%	100.0%	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Apr-09		90.00%	75.00%	75.00%	100.0%	90.0%	100.0%	100.0%	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
May-09		90.00%	75.00%	75.00%	100.0%	90.0%	100.0%	100.0%	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Jun-09		90.00%	75.00%	75.00%	100.0%	90.0%	100.0%	100.0%	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Jul-09		90.00%	75.00%	75.00%	100.0%	90.0%	100.0%	100.0%	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Aug-09		90.00%	75.00%	75.00%	100.0%	90.0%	100.0%	100.0%	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Sep-09		90.00%	75.00%	75.00%	100.0%	90.0%	100.0%	100.0%	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Oct-09		90.00%	75.00%	75.00%	100.0%	90.0%	100.0%	100.0%	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Nov-09		90.00%	75.00%	75.00%	100.0%	90.0%	100.0%	100.0%	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Dec-09		90.00%	75.00%	75.00%	100.0%	90.0%	100.0%	100.0%	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

FORECAST CUSTOMER DEMAND
Schedule 8.2

Rate Class NCP @ Meter (kW)	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	351,443	47,259	126,342	11,400	35,837	8,193	2,349	3,961	58,329	68,490	19,321	7,945	4,751	559	23,596
Feb-09	286,258	29,564	93,224	11,400	36,539	7,914	2,506	4,630	57,549	67,651	18,943	7,851	3,630	498	24,009
Mar-09	249,533	33,805	111,637	11,400	31,358	8,920	2,910	2,667	46,709	57,874	16,546	6,642	2,471	463	20,214
Apr-09	218,603	26,405	88,406	11,400	29,180	8,564	3,269	4,620	44,591	54,263	17,983	6,283	3,360	459	20,760
May-09	189,325	31,715	104,735	11,400	27,899	8,993	4,488	8,277	40,705	47,336	12,784	5,595	1,776	790	16,932
Jun-09	206,820	36,364	92,972	11,400	28,057	9,439	5,805	8,842	48,632	61,116	15,789	6,628	1,609	380	18,754
Jul-09	223,162	64,327	125,437	11,400	28,076	9,627	5,166	13,995	47,919	57,724	14,894	6,370	1,652	363	18,180
Aug-09	222,287	45,409	99,972	11,400	30,800	8,225	3,696	16,370	52,789	61,159	16,394	7,028	1,731	369	19,866
Sep-09	154,158	35,071	115,286	11,400	34,738	7,526	3,088	14,343	43,733	51,403	13,402	6,435	1,887	615	19,078
Oct-09	212,496	37,074	102,611	11,400	35,773	8,204	3,033	17,380	44,435	55,066	15,534	6,487	2,062	593	26,531
Nov-09	252,738	48,889	124,995	11,400	33,873	9,548	2,791	14,441	55,854	66,387	18,431	7,529	1,961	667	24,034
Dec-09	325,328	40,997	104,444	11,400	35,280	8,885	2,122	6,250	60,152	72,326	22,217	8,403	3,215	688	26,487
Maximum	351,443	64,327	126,342	11,400	36,539	9,627	5,805	17,380	60,152	72,326	22,217	8,403	4,751	790	26,531
Winter Peak Month	351,443	48,889	126,342	11,400	36,539	9,548	2,791	14,441	60,152	72,326	22,217	8,403	4,751	688	26,487
Summer Peak Month	249,533	64,327	125,437	11,400	35,773	9,627	5,805	17,380	52,789	61,159	17,983	7,028	3,360	790	26,531

Rate Class NCP @ Primary Voltage (kW)	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Line Losses:	4.85%	4.85%	4.85%				4.85%	4.85%							
Jan-09	368,488	49,551	132,470	11,400	35,837	8,193	2,463	4,154	58,329	68,490	19,321	7,945	4,751	559	23,596
Feb-09	300,142	30,998	97,745	11,400	36,539	7,914	2,627	4,855	57,549	67,651	18,943	7,851	3,630	498	24,009
Mar-09	261,635	35,444	117,052	11,400	31,358	8,920	3,052	2,796	46,709	57,874	16,546	6,642	2,471	463	20,214
Apr-09	229,205	27,686	92,694	11,400	29,180	8,564	3,428	4,844	44,591	54,263	17,983	6,283	3,360	459	20,760
May-09	198,507	33,253	109,814	11,400	27,899	8,993	4,705	8,678	40,705	47,336	12,784	5,595	1,776	790	16,932
Jun-09	216,851	38,127	97,481	11,400	28,057	9,439	6,087	9,271	48,632	61,116	15,789	6,628	1,609	380	18,754
Jul-09	233,985	67,446	131,520	11,400	28,076	9,627	5,417	14,673	47,919	57,724	14,894	6,370	1,652	363	18,180
Aug-09	233,068	47,611	104,821	11,400	30,800	8,225	3,876	17,164	52,789	61,159	16,394	7,028	1,731	369	19,866
Sep-09	161,635	36,772	120,877	11,400	34,738	7,526	3,238	15,039	43,733	51,403	13,402	6,435	1,887	615	19,078
Oct-09	222,802	38,872	107,588	11,400	35,773	8,204	3,181	18,223	44,435	55,066	15,534	6,487	2,062	593	26,531
Nov-09	264,996	51,260	131,057	11,400	33,873	9,548	2,926	15,141	55,854	66,387	18,431	7,529	1,961	667	24,034
Dec-09	341,107	42,986	109,509	11,400	35,280	8,885	2,225	6,553	60,152	72,326	22,217	8,403	3,215	688	26,487
Maximum	368,488	67,446	132,470	11,400	36,539	9,627	6,087	18,223	60,152	72,326	22,217	8,403	4,751	790	26,531
Winter Peak Month	368,488	51,260	132,470	11,400	36,539	9,548	2,926	15,141	60,152	72,326	22,217	8,403	4,751	688	26,487
Summer Peak Month	261,635	67,446	131,520	11,400	35,773	9,627	6,087	18,223	52,789	61,159	17,983	7,028	3,360	790	26,531

Rate Class NCP @ Input Voltage (kW)		Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
	Line Losses:	6.25%	6.25%	6.25%	5.22%	6.25%	5.22%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	5.22%
Jan-09	844,854	391,533	52,650	140,755	11,995	38,078	8,621	2,617	4,413	61,977	72,774	20,529	8,442	5,048	594	24,828
Feb-09	713,952	318,913	32,937	103,858	11,995	38,824	8,327	2,792	5,158	61,148	71,881	20,128	8,342	3,857	529	25,263
Mar-09	661,092	277,997	37,661	124,372	11,995	33,319	9,386	3,242	2,971	49,630	61,493	17,581	7,057	2,626	492	21,270
Apr-09	588,971	243,540	29,417	98,491	11,995	31,005	9,011	3,642	5,147	47,380	57,657	19,107	6,676	3,570	488	21,844
May-09	561,877	210,922	35,332	116,682	11,995	29,644	9,462	5,000	9,221	43,250	50,296	13,584	5,945	1,887	840	17,817
Jun-09	604,837	230,413	40,512	103,577	11,995	29,812	9,932	6,467	9,851	51,673	64,938	16,777	7,043	1,710	404	19,733
Jul-09	689,446	248,619	71,665	139,746	11,995	29,832	10,130	5,755	15,591	50,916	61,334	15,826	6,769	1,755	385	19,129
Aug-09	654,437	247,644	50,588	111,376	11,995	32,727	8,655	4,118	18,237	56,091	64,984	17,419	7,468	1,840	392	20,904
Sep-09	560,392	171,743	39,072	128,436	11,995	36,910	7,919	3,440	15,979	46,468	54,618	14,240	6,838	2,005	653	20,074
Oct-09	633,596	236,736	41,303	114,316	11,995	38,010	8,633	3,379	19,363	47,214	58,510	16,506	6,893	2,191	630	27,917
Nov-09	738,070	281,569	54,466	139,254	11,995	35,992	10,046	3,109	16,088	59,347	70,539	19,584	7,999	2,084	709	25,289
Dec-09	797,944	362,439	45,674	116,358	11,995	37,486	9,349	2,364	6,963	63,914	76,849	23,607	8,928	3,416	731	27,870
Maximum	844,854	391,533	71,665	140,755	11,995	38,824	10,130	6,467	19,363	63,914	76,849	23,607	8,928	5,048	840	27,917
Winter Peak Month	8,049,469	391,533	54,466	140,755	11,995	38,824	10,046	3,109	16,088	63,914	76,849	23,607	8,928	5,048	731	27,870
Summer Peak Month		277,997	71,665	139,746	11,995	38,010	10,130	6,467	19,363	56,091	64,984	19,107	7,468	3,570	840	27,917

System Coincidence Factor	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	80.00%	70.00%	75.00%	93.48%	75.00%	93.48%	100.00%	90.00%	99.07%	98.78%	100.00%	95.49%	98.34%	98.34%	96.08%
Feb-09	80.00%	70.00%	75.00%	92.78%	75.00%	92.78%	100.00%	90.00%	97.43%	99.03%	99.13%	97.41%	98.25%	98.25%	98.54%
Mar-09	80.00%	70.00%	75.00%	89.53%	75.00%	89.53%	100.00%	90.00%	99.55%	98.02%	97.70%	97.68%	98.24%	98.24%	97.56%
Apr-09	80.00%	70.00%	75.00%	90.88%	75.00%	90.88%	100.00%	90.00%	95.52%	97.31%	98.37%	95.55%	96.69%	96.69%	98.84%
May-09	80.00%	70.00%	75.00%	68.22%	75.00%	68.22%		90.00%	98.07%	96.03%	92.60%	94.50%	95.30%	95.30%	95.00%
Jun-09	80.00%	70.00%	75.00%	84.45%	75.00%	84.45%		90.00%	97.73%	94.34%	95.66%	97.48%	96.30%	96.30%	95.00%
Jul-09	80.00%	70.00%	75.00%	82.62%	75.00%	82.62%		90.00%	90.07%	99.70%	98.51%	97.62%	96.48%	96.48%	95.00%
Aug-09	80.00%	70.00%	75.00%	86.84%	75.00%	86.84%		90.00%	97.89%	96.66%	97.29%	94.91%	96.69%	96.69%	95.00%
Sep-09	80.00%	70.00%	75.00%	76.69%	75.00%	76.69%		90.00%	93.67%	96.97%	98.19%	94.01%	95.71%	95.71%	82.19%
Oct-09	80.00%	70.00%	75.00%	86.16%	75.00%	86.16%	100.00%	90.00%	94.30%	94.93%	99.40%	91.80%	95.11%	95.11%	80.96%
Nov-09	80.00%	70.00%	75.00%	87.67%	75.00%	87.67%	100.00%	90.00%	97.36%	98.70%	99.66%	97.92%	98.41%	98.41%	96.30%
Dec-09	80.00%	70.00%	75.00%	87.53%	75.00%	87.53%	100.00%	90.00%	97.72%	98.98%	100.00%	99.07%	92.96%	92.96%	93.62%

FORECAST CUSTOMER DEMAND
Schedule 8.2

Coincident Peak (CP) @ Input (kW)	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	701,345	313,226	36,855	105,566	11,213	28,559	8,059	2,617	3,972	61,401	71,883	20,529	8,062	4,964	584	23,855
Feb-09	599,525	255,130	23,056	77,894	11,129	29,118	7,725	2,792	4,642	59,575	71,184	19,953	8,126	3,789	520	24,893
Mar-09	549,651	222,398	26,363	93,279	10,739	24,990	8,403	3,242	2,674	49,408	60,272	17,176	6,893	2,580	483	20,751
Apr-09	491,965	194,832	20,592	73,868	10,902	23,254	8,189	3,642	4,632	45,257	56,106	18,796	6,379	3,452	472	21,592
May-09	454,587	168,737	24,733	87,512	8,183	22,233	6,455		8,299	42,415	48,300	12,579	5,618	1,798	800	16,926
Jun-09	495,572	184,330	28,358	77,683	10,130	22,359	8,387		8,866	50,500	61,262	16,049	6,866	1,646	389	18,747
Jul-09	558,002	198,895	50,165	104,809	9,911	22,374	8,370		14,032	45,859	61,151	15,590	6,607	1,693	372	18,173
Aug-09	539,724	198,115	35,412	83,532	10,417	24,545	7,516		16,414	54,909	62,813	16,948	7,087	1,779	379	19,858
Sep-09	454,353	137,394	27,350	96,327	9,199	27,682	6,073		14,381	43,527	52,965	13,982	6,428	1,919	625	16,498
Oct-09	519,211	189,389	28,912	85,737	10,335	28,508	7,438	3,379	17,426	44,520	55,546	16,407	6,328	2,084	599	22,601
Nov-09	613,583	225,255	38,126	104,440	10,516	26,994	8,807	3,109	14,479	57,778	69,624	19,518	7,833	2,051	697	24,354
Dec-09	665,540	289,951	31,972	87,268	10,500	28,115	8,183	2,364	6,267	62,455	76,066	23,607	8,845	3,175	679	26,092
Total	6,643,058	2,577,654	371,894	1,077,915	123,174	308,730	93,606	21,146	116,084	617,606	747,173	211,133	85,072	30,931	6,599	254,340
Peak Month	701,345	313,226	36,855	105,566	11,213	28,559	8,059	2,617	3,972	61,401	71,883	20,529	8,062	4,964	584	23,855
Winter Peak Month		313,226	38,126	105,566	11,213	29,118	8,807	3,242	14,479	62,455	76,066	23,607	8,845	4,964	697	26,092
Summer Peak Month		198,895	50,165	104,809	10,902	28,508	8,387	3,642	17,426	54,909	62,813	18,796	7,087	3,452	800	22,601

Contract Demand Limit (kW)	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Feb-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Mar-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Apr-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
May-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Jun-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Jul-09					40,000		11,100			90,882	124,245	21,780	17,820		396	44,550
Aug-09					40,000		11,100			90,882	124,245	21,780	17,820		396	44,550
Sep-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Oct-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Nov-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Dec-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Total					480,000		133,200			1,090,584	1,798,830	340,560	273,240		5,742	534,600

Max Demand @ Input (kW)	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	891,369	313,226	36,855	105,566	40,000	28,559	11,100	2,617	3,972	90,882	155,034	29,700	23,760	4,964	584	44,550
Feb-09	791,967	255,130	23,056	77,894	40,000	29,118	11,100	2,792	4,642	90,882	155,034	29,700	23,760	3,789	520	44,550
Mar-09	771,046	222,398	26,363	93,279	40,000	24,990	11,100	3,242	2,674	90,882	155,034	29,700	23,760	2,580	495	44,550
Apr-09	719,794	194,832	20,592	73,868	40,000	23,254	11,100	3,642	4,632	90,882	155,034	29,700	23,760	3,452	495	44,550
May-09	709,138	168,737	24,733	87,512	40,000	22,233	11,100		8,299	90,882	155,034	29,700	23,760	1,798	800	44,550
Jun-09	718,763	184,330	28,358	77,683	40,000	22,359	11,100		8,866	90,882	155,034	29,700	23,760	1,646	495	44,550
Jul-09	742,742	198,895	50,165	104,809	40,000	22,374	11,100		14,032	90,882	124,245	21,780	17,820	1,693	396	44,550
Aug-09	710,569	198,115	35,412	83,532	40,000	24,545	11,100		16,414	90,882	124,245	21,780	17,820	1,779	396	44,550
Sep-09	700,706	137,394	27,350	96,327	40,000	27,682	11,100		14,381	90,882	155,034	29,700	23,760	1,919	625	44,550
Oct-09	751,061	189,389	28,912	85,737	40,000	28,508	11,100	3,379	17,426	90,882	155,034	29,700	23,760	2,084	599	44,550
Nov-09	810,178	225,255	38,126	104,440	40,000	26,994	11,100	3,109	14,479	90,882	155,034	29,700	23,760	2,051	697	44,550
Dec-09	844,818	289,951	31,972	87,268	40,000	28,115	11,100	2,364	6,267	90,882	155,034	29,700	23,760	3,175	679	44,550
Total	9,162,150	2,577,654	371,894	1,077,915	480,000	308,730	133,200	21,146	116,084	1,090,584	1,798,830	340,560	273,240	30,931	6,782	534,600
Peak Month	891,369	313,226	50,165	105,566	40,000	29,118	11,100	3,642	17,426	90,882	155,034	29,700	23,760	4,964	800	44,550
Winter Peak Month	891,369	313,226	38,126	105,566	40,000	29,118	11,100	3,642	17,426	90,882	155,034	29,700	23,760	4,964	697	44,550
Summer Peak Month	742,742	198,895	50,165	104,809	40,000	27,682	11,100		16,414	90,882	155,034	29,700	23,760	1,919	800	44,550

FORECAST CUSTOMER DEMAND
Schedule 8.2

Coincident Peak (CP) @ Input (kW)	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	701,345	313,226	36,855	105,566	11,213	28,559	8,059	2,617	3,972	61,401	71,883	20,529	8,062	4,964	584	23,855
Feb-09	599,525	255,130	23,056	77,894	11,129	29,118	7,725	2,792	4,642	59,575	71,184	19,953	8,126	3,789	520	24,893
Mar-09	549,651	222,398	26,363	93,279	10,739	24,990	8,403	3,242	2,674	49,408	60,272	17,176	6,893	2,580	483	20,751
Apr-09	491,965	194,832	20,592	73,868	10,902	23,254	8,189	3,642	4,632	45,257	56,106	18,796	6,379	3,452	472	21,592
May-09	454,587	168,737	24,733	87,512	8,183	22,233	6,455		8,299	42,415	48,300	12,579	5,618	1,798	800	16,926
Jun-09	495,572	184,330	28,358	77,683	10,130	22,359	8,387		8,866	50,500	61,262	16,049	6,866	1,646	389	18,747
Jul-09	558,002	198,895	50,165	104,809	9,911	22,374	8,370		14,032	45,859	61,151	15,590	6,607	1,693	372	18,173
Aug-09	539,724	198,115	35,412	83,532	10,417	24,545	7,516		16,414	54,909	62,813	16,948	7,087	1,779	379	19,858
Sep-09	454,353	137,394	27,350	96,327	9,199	27,682	6,073		14,381	43,527	52,965	13,982	6,428	1,919	625	16,498
Oct-09	519,211	189,389	28,912	85,737	10,335	28,508	7,438	3,379	17,426	44,520	55,546	16,407	6,328	2,084	599	22,601
Nov-09	613,583	225,255	38,126	104,440	10,516	26,994	8,807	3,109	14,479	57,778	69,624	19,518	7,833	2,051	697	24,354
Dec-09	665,540	289,951	31,972	87,268	10,500	28,115	8,183	2,364	6,267	62,455	76,066	23,607	8,845	3,175	679	26,092
Total	6,643,058	2,577,654	371,894	1,077,915	123,174	308,730	93,606	21,146	116,084	617,606	747,173	211,133	85,072	30,931	6,599	254,340
Peak Month	701,345	313,226	36,855	105,566	11,213	28,559	8,059	2,617	3,972	61,401	71,883	20,529	8,062	4,964	584	23,855
Winter Peak Month		313,226	38,126	105,566	11,213	29,118	8,807	3,242	14,479	62,455	76,066	23,607	8,845	4,964	697	26,092
Summer Peak Month		198,895	50,165	104,809	10,902	28,508	8,387	3,642	17,426	54,909	62,813	18,796	7,087	3,452	800	22,601

Contract Demand Limit (kW)	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Feb-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Mar-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Apr-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
May-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Jun-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Jul-09					40,000		11,100			90,882	124,245	21,780	17,820		396	44,550
Aug-09					40,000		11,100			90,882	124,245	21,780	17,820		396	44,550
Sep-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Oct-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Nov-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Dec-09					40,000		11,100			90,882	155,034	29,700	23,760		495	44,550
Total					480,000		133,200			1,090,584	1,798,830	340,560	273,240		5,742	534,600

Max Demand @ Input (kW)	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	891,369	313,226	36,855	105,566	40,000	28,559	11,100	2,617	3,972	90,882	155,034	29,700	23,760	4,964	584	44,550
Feb-09	791,967	255,130	23,056	77,894	40,000	29,118	11,100	2,792	4,642	90,882	155,034	29,700	23,760	3,789	520	44,550
Mar-09	771,046	222,398	26,363	93,279	40,000	24,990	11,100	3,242	2,674	90,882	155,034	29,700	23,760	2,580	495	44,550
Apr-09	719,794	194,832	20,592	73,868	40,000	23,254	11,100	3,642	4,632	90,882	155,034	29,700	23,760	3,452	495	44,550
May-09	709,138	168,737	24,733	87,512	40,000	22,233	11,100		8,299	90,882	155,034	29,700	23,760	1,798	800	44,550
Jun-09	718,763	184,330	28,358	77,683	40,000	22,359	11,100		8,866	90,882	155,034	29,700	23,760	1,646	495	44,550
Jul-09	742,742	198,895	50,165	104,809	40,000	22,374	11,100		14,032	90,882	124,245	21,780	17,820	1,693	396	44,550
Aug-09	710,569	198,115	35,412	83,532	40,000	24,545	11,100		16,414	90,882	124,245	21,780	17,820	1,779	396	44,550
Sep-09	700,706	137,394	27,350	96,327	40,000	27,682	11,100		14,381	90,882	155,034	29,700	23,760	1,919	625	44,550
Oct-09	751,061	189,389	28,912	85,737	40,000	28,508	11,100	3,379	17,426	90,882	155,034	29,700	23,760	2,084	599	44,550
Nov-09	810,178	225,255	38,126	104,440	40,000	26,994	11,100	3,109	14,479	90,882	155,034	29,700	23,760	2,051	697	44,550
Dec-09	844,818	289,951	31,972	87,268	40,000	28,115	11,100	2,364	6,267	90,882	155,034	29,700	23,760	3,175	679	44,550
Total	9,162,150	2,577,654	371,894	1,077,915	480,000	308,730	133,200	21,146	116,084	1,090,584	1,798,830	340,560	273,240	30,931	6,782	534,600
Peak Month	891,369	313,226	50,165	105,566	40,000	29,118	11,100	3,642	17,426	90,882	155,034	29,700	23,760	4,964	800	44,550
Winter Peak Month	891,369	313,226	38,126	105,566	40,000	29,118	11,100	3,642	17,426	90,882	155,034	29,700	23,760	4,964	697	44,550
Summer Peak Month	742,742	198,895	50,165	104,809	40,000	27,682	11,100		16,414	90,882	155,034	29,700	23,760	1,919	800	44,550

FORECAST kWh AT INPUT
Schedule 8.3

kWh @ Input Voltage		Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
	Jan-09	361,624,888	161,773,663	22,413,309	52,297,722	1,748,236	12,493,005	5,540,662	1,318,810	621,657	33,782,888	39,916,439	11,087,650	4,766,900	1,037,180	316,613	12,510,154
	Feb-09	319,102,862	150,273,551	16,538,015	38,588,702	1,684,723	12,060,076	5,351,587	1,149,176	656,265	30,314,676	35,818,546	9,949,372	4,277,522	930,702	284,109	11,225,840
	Mar-09	310,114,993	138,067,717	19,804,584	46,210,695	1,318,449	12,598,781	6,032,162	1,274,273	418,444	27,567,145	32,572,179	9,047,624	3,889,834	846,349	258,359	10,208,400
	Apr-09	270,884,123	121,970,679	15,683,391	36,594,580	1,525,897	12,541,367	5,791,216	1,140,821	701,576	24,478,441	28,922,696	8,033,901	3,454,006	751,521	229,412	9,064,621
	May-09	258,896,213	104,754,475	18,580,068	43,353,492	1,688,641	13,317,386	6,081,232	1,296,961	3,896,409	21,536,162	25,446,223	7,068,236	3,038,838	661,189	201,837	7,975,064
	Jun-09	244,989,642	91,200,328	16,493,273	38,484,303	1,163,660	12,934,769	6,382,980	1,399,377	6,266,445	23,083,556	27,274,558	7,576,095	3,257,182	708,696	216,339	8,548,081
	Jul-09	255,898,311	78,859,113	22,252,645	51,922,839	1,021,117	12,908,787	6,510,363	1,390,423	10,248,416	23,122,788	27,320,914	7,588,972	3,262,718	709,901	216,707	8,562,609
	Aug-09	254,588,796	86,818,435	17,735,138	41,381,990	1,099,689	11,418,314	5,562,192	1,234,099	11,987,941	25,267,792	29,855,360	8,292,969	3,565,386	775,756	236,809	9,356,926
	Sep-09	251,457,025	84,625,849	20,451,800	47,720,867	846,443	10,173,755	5,089,315	1,224,739	9,438,658	23,482,442	27,745,866	7,707,011	3,313,466	720,943	220,077	8,695,792
	Oct-09	265,349,496	100,778,793	18,203,307	42,474,383	1,770,815	12,544,438	5,548,090	1,467,006	6,363,844	24,891,417	29,410,652	8,169,441	3,512,278	764,200	233,282	9,217,550
	Nov-09	297,889,762	111,448,694	22,174,314	51,740,066	1,770,815	14,101,760	6,456,691	1,475,148	2,193,010	28,266,001	33,397,918	9,276,990	3,988,446	867,805	264,909	10,467,194
	Dec-09	335,436,486	143,702,176	18,528,467	43,233,089	1,770,815	13,333,472	6,008,442	1,227,528	980,789	34,839,281	41,164,629	11,434,361	4,915,962	1,069,613	326,513	12,901,348
Total Purchases - Bottom Up		3,426,232,597	1,374,273,473	228,858,311	534,002,726	17,409,301	150,425,909	70,354,932	15,598,361	53,773,454	320,632,590	378,845,979	105,232,622	45,242,539	9,843,856	3,004,965	118,733,579

Historic Load Reconciliation	Total	Residential	Small General Service	General Service	Rate 33 Industrial	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Secondary Line Losses		4.85%	4.85%	4.85%				4.85%	4.85%							
Primary Line Losses		6.25%	6.25%	6.25%	5.22%	6.25%	5.22%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	5.22%

Appendix B—Minimum System Analysis

The minimum system analysis is used to determine the lowest level of plant investment required to serve a utility's customers compared to the actual facilities in place to meet varying customer demands. FortisBC staff provided the data necessary to complete the minimum system study using 2008 data. Along with the minimum system results, an offset to account for the peak load carrying capability (PLCC) of a minimum system was incorporated into the analysis.

The minimum system approach reflects the philosophy that the system is in place in part because there are customers to serve throughout the service territory expanse, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 kWh of energy per year. The concept follows that any costs associated with a system larger than this minimal size are due to the fact that customers use a delivery quantity greater than the minimum unit up to the level of their peak demand, therefore, that portion of the costs should be treated as demand related.

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the number of poles, conductors, and transformers in place at the utility separating them according to size. The cost associated with these facilities are then determined. Next, it is assumed that the actual numbers by size could be replaced by the minimum sized pole, conductor and transformer. The cost associated with the minimum size is then calculated.

The total costs of the minimum sized system is then compared to the cost of the as-built system to reflect the percent of costs attributed to the system that would be in place if all customers used a minimum amount of power. The remaining percent of costs is then attributed to the demand-related component.

The following summarize the resulting classification and allocation for the distribution accounts.

- Substations, including land and station equipment. These costs are classified as demand-related as they are sized on the basis of the peak load for the area served. The non-coicident peak at primary (NCPP) is used as the allocation factor.

- Poles, Towers & Fixtures. The results of the minimum system analysis are 96% customer-related and 4% demand-related. The customer-related costs are allocated on the basis of actual customers. The demand-related component is allocated on the basis of the non-coincident peak (NCP) split between primary and secondary.

- Conductors & Devices. The results of the minimum system analysis are 58% customer-related and 42% demand-related. The customer-related costs are allocated on the basis of actual customers. The demand-related component is allocated on the basis of the NCP split between primary and secondary.

- Line Transformers. The results of the minimum system analysis are 73% customer-related and 27% demand-related. The customer-related costs are allocated on the basis of actual customers. The demand-related component is allocated on the basis of the NCPS.

- Services, Meters and Installation on Customer Premises. These costs are all related to the customer component as they are installed for each customer served. They are allocated on the basis of customers weighted according to the average cost of meters by class.

- Street Lights & Signal Systems. These costs are all directly related to the lighting class of customers and are directly assigned to that class.

To develop the minimum system percentage splits, FortisBC provided analysis for the poles, conductors and transformer categories. The following provides the technical information provided by staff to calculate the percentage splits for the minimum system analysis.

A count of each size of equipment was provided along with the cost of a new unit of a comparable size. The cost reflects equipment cost plus the labour and truck use required to install the equipment. To that amount, a capital overhead loading of 7.7% was added plus a direct overhead loading of 7.3%

Poles

FortisBC has a total of 58,760 poles ranging from 35 feet to 50 feet, with both single and three phase configuration. The installed cost per pole, before overheads, range from $1,154 to $1,622 per pole based on the current purchase price. In the case of poles, it was determined that the size of the poles is a function of the location of the pole rather than the peak load on the system. Because of the diverse topography in the region, the pole size is determined based primarily on the physical requirements at each location rather than the voltage of the line. The minimum pole therefore varies in size but reflects the slightly lower costs associated with a single phase configuration. The cost of the cross arms, anchor plates and insulators were included in the installed cost of the poles. The difference between the cost of installed poles at single-phase versus the cost for three-phase was determined to be the demand-related portion of pole costs.

When the minimum size was applied across all poles, the results showed a minimum system cost of $92.8 million compared to an installed cost of $96.3 million. This means that 96% of the costs were related to the minimum size pole, and were therefore classified as customer-related costs. The remaining 4% was classified as demand-related. This compares to a 76% customer/24% demand split resulting from the last minimum system study, which was conducted in 1992. This same split was used in the 1997 COSA.

The following information provides the details associated with the pole analysis.

FortisBC Minimum System Analysis Power Poles – As built						
Pole Size	**Cost**	**# Installed**	**Sub-Total**	**Capital Overhead** **7.7%**	**Direct Overhead** **7.3%**	**Total Loaded Cost**
35' Single	$1,154	1,579	$1,822,489	$140,332	$133,042	$2,095,863
40' Single	$1,349	8,009	$10,803,700	$831,885	$788,670	$12,424,254
40' Three	$1,476	4,843	$7,145,848	$550,230	$521,647	$8,217,725
45' Single	$1,376	23,597	$32,462,272	$2,499,595	$2,369,746	$37,331,613
45' Three	$1,502	16,340	$24,546,770	$1,890,101	$1,791,914	$28,228,785
50' Single	$1,496	1,465	$2,190,959	$168,704	$159,940	$2,519,602
50' Three	$1,622	2,927	$4,747,858	$365,585	$346,594	$5,460,037
Total		58,760	$83,719,896	$6,446,432	$6,111,552	$96,277,880

FortisBC
Minimum System Analysis
Power Poles – Minimum

Pole Size	**Loaded Cost**	**# Installed**	**Sub-Total**
35' Single	$1,327.34	1,579	$2,095,863
40' Single	$1,551.29	8,009	$12,424,254
40' Three	$1,551.29	4,843	$7,512,881
45' Single	$1,582.05	23,597	$37,331,613
45' Three	$1,582.05	16,340	$25,850,682
50' Single	$1,719.87	1,465	$2,519,602
50' Three	$1,719.87	2,927	$5,034,045
Total		58,760	$92,768,941

Customer-Related	81%
Demand-Related	19%

Assumptions 2008

Cost reflects 2007 year-end or current data. Cost should be for newly installed pole, including installation cost.
Pole costs include anchor plate, rod and material O/H as priced in SAP material master.
Actual pole cost derived from FortisBC purchase price contract.

Power Pole Costs (from 2007 Study)

	Labour Base Rate	Fringe Benefit Loading 72.5%	Cost/Hr	Hours/pole	Total/pole	
Total Truck Costs	$42.53	n/a	$42.53	3.00	$127.59	
Labour cost with cross-arm	$32.95	0.00	$32.95	8.72	$287.32	(1.5 hrs travel + 7.22 hrs on-site)
Labour cost without cross-arm	$32.95	0.00	$32.95	8.42	$277.44	(1.5 hrs travel + 6.92 hrs on-site)
Total Installation Costs with crossarm					$414.91	
Total Installation Costs without crossarm					$405.03	

Cost per pole calculations (from 2007 Study)

	Pole	Other Material	Material Loading 7%	Truck & Labour	Total Cost
35' Single	$433.00	$79.18	$21,783	$405.03	$22,700.22
40' Single	$615.00	$79.18	$29,523	$405.03	$30,622.68
40' Three	$615.00	$181.52	$33,876	$414.91	$35,087.43
45' Single	$640.00	$79.18	$30,587	$405.03	$31,710.93
45' Three	$640.00	$181.52	$34,939	$414.91	$36,175.68
50' Single	$752.00	$79.18	$35,350	$405.03	$36,586.29
50' Three	$752.00	$181.52	$39,703	$414.91	$41,051.04
Minimum	$433.00	$79.18	$21,783.02	$405.03	$22,700.22

Other Material:

Crossarm	$89.30
Anchor plate (every 3rd pole)	$36.54
Anchor rod (every 3rd pole)	$36.12
Insulators	$6.52
insulators three phase	$19.56
insulator single phase	$6.52

Conductors

FortisBC has a total of 14,369 kilometers of overhead conductor of various size and configuration. The installed cost, before overheads, ranges from $3,055 to $5,683 per kilometer based on the current purchase price. The minimum sized conductor was determined to be two lines of 2 ACSR, with a loaded cost of $3,514 per kilometer. When this minimum size was applied across all conductors, with an adjustment to comparable single phase km, the results showed a minimum system cost of $33.6 million compared to an installed cost of $58.3 million. This means that 58% of the costs were related to the minimum size conductor, and were therefore classified as customer-related costs. The remaining 42% was classified as demand-related.

This compares to a 48% customer/52% demand split resulting from the last minimum system study, which was conducted in 1992. This same split was used in the 1997 COSA. In the 1992 study the minimum sized conductor was set at 2 lines of 4 ACSR, which at the time was less costly than 2 ACSR. Current costs for conductor are less variable than in 1992, reflecting the increasing labour component associated with installing conductor.

The following information provides the details associated with the conductor analysis.

FortisBC Minimum System Analysis TOTAL CONDUCTOR						
Conductor Type OH	Cost/km	Line in km	sub-total	Capital Overhead 7.7%	Direct Overhead 7.3%	Total Loaded Cost
927 AL	$5,662	63.03	$356,889	$27,480	$26,053	$410,422
477 AL	$5,683	1,606.62	$9,130,757	$703,068	$666,545	$10,500,370
4/0 Al	$3,757	79.42	$298,382	$22,975	$21,782	$343,140
336 AL	$5,683	41.44	$235,494	$18,133	$17,191	$270,818
397 Al	$5,683	53.08	$301,642	$23,226	$22,020	$346,888
3/0 ACSR	$3,757	57.71	$216,814	$16,695	$15,827	$249,336
266 ACSR	$3,757	243.96	$916,612	$70,579	$66,913	$1,054,104
2/0 ACSR	$3,757	2,346.03	$8,814,531	$678,719	$643,461	$10,136,710
1/0 ASCR	$3,055	24.07	$73,542	$5,663	$5,369	$84,573
2 ACSR	$3,055	7,470.36	$22,824,132	$1,757,458	$1,666,162	$26,247,752
4 ACSR	$3,055	204.77	$625,622	$48,173	$45,670	$719,466
90 MCM Cu	$3,757	201.70	$757,821	$58,352	$55,321	$871,494
2 CU	$3,055	114.61	$350,162	$26,962	$25,562	$402,686
3 CU	$3,055	61.21	$187,006	$14,399	$13,651	$215,057
4 CU	$3,055	440.09	$1,344,613	$103,535	$98,157	$1,546,304
6 CU	$3,055	932.41	$2,848,769	$219,355	$207,960	$3,276,085
8 CU	$3,055	282.43	$862,921	$66,445	$62,993	$992,359
1/0 CU	$3,055	15.53	$47,440	$3,653	$3,463	$54,556
3/0 CU	$3,757	3.97	$14,910	$1,148	$1,088	$17,147
4/0 CU	$3,757	108.93	$409,272	$31,514	$29,877	$470,663
300 CU	$3,757	17.78	$66,820	$5,145	$4,878	$76,843
Total		14,369	$50,684,150	$3,902,680	$3,699,943	$58,286,772

Minimum System Loaded Cost per km				$3,514
Minimum System Cost (2 ACSR)	$33,641,312	$3,887,512	$3,685,564	$58,060,249
Actual System Cost	$58,286,772			
Customer-Related	58%			
Demand-Related	42%			

Assumptions in 2007 Study

The length of single and three phase included the neutral conductor as the same size as the phase conductor
The line in km includes the length of 1 neutral and three conductors
Actual conductor cost derived from FortisBC purchase price contract.
The minimum system used for this analysis was two lines of 2 ACSR.
Underground conductor is NOT included and represents 12% of total
The prices for Cu conductor were assume as follows based on ampacity and similar, in the case they were going to be replace by ASCR conductors:
#2, 3, 4, 6, 8 Cu assumed as the minimum #2 ASCR
90 MCM Cu = #2 ASCR; 1/0 Cu = #2 ASCR; #2/0 Cu = 3/0 ASCR; 300 MCM Cu = 3/0 ASCR

Conductor Costs per Kilometer (from 2007 Study)

	Labour Base Rate	Fringe Benefit Loading	Cost/Hr	Hours/km	Total/km
		72.5%			
1 Line Truck	$42.53	n/a	$42.53	2.30	$97.82
1 Wire Truck	$42.53	n/a	$42.53	2.30	$97.82
Total Truck Costs					$195.64
10 Man Crew					
4 Journeyman Lineman	32.95	23.89	$56.84	3.80	$863.95
6 Groundman	32.95	23.89	$56.84	3.80	$1,295.92
Total Labour Costs					$2,159.87
Total Labour & Truck					$2,355.51

* Includes 2.3 hours per km for installation plus 1.5 hours of travel time

Cost per km calculations for 1 conductor (from 2007 Study)

	Material	Material Loading	Truck & Labour	Total Cost
		7%		
2 ACSR (4 CU)	$654.0	$46	$2,355.51	$3,055.29
3/0 ACSR	$1,310.0	$92	$2,355.51	$3,757.21
477 AL	$3,110.0	$218	$2,355.51	$5,683.21

Transformers

FortisBC has a total of 28,479 transformers ranging from 10 kVA to 750 kVA. The installed cost per transformer, before overheads, ranges from $1,645 to $17,725 per transformer based on the current purchase price. The minimum sized transformer was determined to be a 15 kVA transformer, with a loaded cost of $1,946. While there are a number of transformers within the system at 10 kVA, this size is no longer readily available or routinely installed by FortisBC. When this minimum size was applied across all transformers, the results showed a minimum system cost of $48.2 million compared to an installed cost of $75.4 million. This means that 73% of the costs were related to the minimum size transformer, and were therefore classified as customer-related costs. The remaining 27% was classified as demand-related. This compares to a 73% customer/27% demand split resulting from the last minimum system study, which was conducted in 1992. This same split was used in the 1997 COSA.

The following information provides the details associated with the transformer analysis.

FortisBC Minimum System Analysis Transformers						
Size	**Cost**	**# Installed**	**sub-total**	**Capital Overhead 7.7%**	**Direct Overhead 7.3%**	**Total Loaded Cost**
10 kVA	$1,645	2,361	$3,884,253	$299,087	$283,550	**$4,466,891**
15 kVA	$1,692	6,806	$11,517,472	$886,845	$840,775	**$13,245,093**
25 kVA	$2,148	11,203	$24,064,859	$1,852,994	$1,756,735	**$27,674,588**
37 kVA	$2,287	518	$1,184,755	$91,226	$86,487	**$1,362,469**
50 kVA	$2,963	6,215	$18,417,610	$1,418,156	$1,344,486	**$21,180,252**
75 kVA	$4,283	936	$4,008,628	$308,664	$292,630	**$4,609,923**
100 kVA	$4,887	304	$1,485,731	$114,401	$108,458	**$1,708,591**
167 kVA	$5,640	107	$603,501	$46,470	$44,056	**$694,026**
250 kVA	$13,788	12	$165,459	$12,740	$12,079	**$190,278**
333 kVA	$13,788	8	$110,306	$8,494	$8,052	**$126,852**
500 kVA	$15,725	6	$94,350	$7,265	$6,888	**$108,502**
750 kVA	$15,725	3	$47,175	$3,632	$3,444	**$54,251**
Total		28,479	$65,584,099	$5,049,976	$4,787,639	$75,421,714

Loaded Cost per transformer	$1,946			
Minimum System Cost (15 kVA)	$48,193,666	$3,710,912	$3,518,138	**$55,422,716**
Actual System Cost	$75,421,714			
Customer-Related	73%			
Demand-Related	27%			

Assumptions 2008

Actual transformer cost derived from FortisBC purchase price contract.

Any transformers that weren't available were replaced by the next larger size.

A 15 kVA transformer is assumed to be the minimum size used for this analysis.

Transformer Costs (from 2007 Study)

	Labour Base Rate	Fringe Benefit Loading	Cost/Hr	Hours	Total	
Total Truck Costs		**72.5%**				
<= 150 kVA	42.53	n/a	$42.53	3.00	$127.59	
> 150 kVA	42.53	n/a	$42.53	4.50	$191.39	
Total Labour Costs						
<= 150 kVA	32.95	23.89	$56.84	5.00	$284.19	(1.5 hrs travel + 3.5 hrs on-site)
> 150 kVA	32.95	23.89	$56.84	9.50	$539.97	(1.5 hrs travel + 8 hrs on-site)
Total Installation Costs						
<= 150 kVA			$411.78			
> 150 kVA			$731.35			

Cost per transformer calculations (from 2007 Study)

	Transformer	Other Material	Material Loading 7%	Truck & Labour	Total Cost
15 kVA	$994.00	$202.70	$84	$411.78	$1,692.25
25 kVA	$1,420.00	$202.70	$114	$411.78	$2,148.07
37 kVA	$1,550.00	$202.70	$123	$411.78	$2,287.17
50 kVA	$2,182.00	$202.70	$167	$411.78	$2,963.41
75 kVA	$3,415.00	$202.70	$253	$411.78	$4,282.72
100 kVA	$3,980.00	$202.70	$293	$411.78	$4,887.27
167 kVA	$4,385.00	$202.70	$321	$731.35	$5,640.19
300 kVA	$12,000.00	$202.70	$854	$731.35	$13,788.24
500 kVA	$13,810.00	$202.70	$981	$731.35	$15,724.94

Other Material includes cut out @ $142.70 plus mounting bracket @ $60.00

Peak Load Carrying Capability Adjustment (PLCC)

While the minimum system is, in theory, designed to carry only a minimal amount of load, the actual facilities designated as the minimal size are actually capable of carrying some amount of demand, therefore overstating the level of the customer-related component. The actual amount of demand capability within the minimum system is a function of load density, minimum required clearances, minimum equipment standards, temperature, and other engineering considerations. Under traditional cost allocation techniques, each customer/connection attracts an equal allocation of the minimum system, plus each classification is allocated demand costs based on the total classification’s non-coincident peaks. As such, it has been argued that a classification’s non-coincident demand allocator is too large, because a portion of these peak demand-related costs are being covered through the per customer/connection minimum system allocation.

The correction of the problem of over allocating demand can be achieved by the application of a PLCC adjustment. The precise amount of a PLCC adjustment should match the definition of the minimum system adopted. In the FortisBC case, the engineers that provided the data associated with the minimum system method determined that the average PLCC for the FortisBC system is 1.0 kW per customer.

The PLCC adjustment determines how much demand for a rate classification can be met by the minimum system (number of customers/connections x PLCC for minimum system) and will credit this amount against the classification’s non-coincident peak demands used for determining demand allocators. The adjusted classification’s non-coincident peaks can then be used to allocate the distributor’s demand-related costs, eliminating the double-counting. The number of customers/connections used for the PLCC should match the number of customers/connections used to allocate the customer component of the distributor’s capital and O&M costs associated with poles, conductors and transformers.

FortisBC staff provided information for feeders under the current configuration and assuming a minimum sized system. The capacity of the system with the minimum size was then determined and compared to the number of customers served by the feeder. The resulting kVA per customer was calculated for each feeder and represents the PLCC for that feeder. The resulting average of 1.0 kW per customer was used as the PLCC for purposes of the COSA.

The following tables provide the details associated with the PLCC calculations.

Feeder Number	Voltage	Running Distance (KM)	Conductor Length (KM)	Conductor and Neutral Length (KM)	Estimated Customers	Feeder Classification	Max KVA
W110S-CRA1	13	27.24	46.06	73.30	314.00	Rural	93.89
W110S-CRA2	13	52.69	119.27	171.96	479.00	Rural	93.89
W110S-CRA3	13	14.49	20.60	35.10	141.00	Rural	93.89
W110S-CRA4	13	29.27	51.27	80.55	245.00	Rural	93.89
W121S-CRE1	13	90.13	163.01	253.14	870.00	Rural	93.89
W121S-CRE2	13	86.01	174.77	260.78	1366.00	Rural	93.89
W121S-CRE3	13	20.43	44.16	64.59	1365.00	Urban	1576.17
W121S-CRE4	13	77.74	140.36	218.10	797.00	Rural	93.89
W124S-AAL1	13	88.15	184.92	273.07	634.00	Rural	93.89
W124S-AAL2	13	120.31	237.82	358.13	502.00	Rural	93.89
W124S-AAL3	13	23.08	44.65	67.74	419.00	Rural	93.89
W129S-VAL1	13	75.52	103.51	179.03	705.00	Rural	93.89
W130S-PAS1	13	51.66	90.25	141.91	238.00	Rural	93.89
W130S-PAS2	13	47.24	68.44	115.68	404.00	Rural	93.89
W131S-PLA1	13	55.88	86.36	142.24	855.00	Urban	1576.17
W131S-PLA2	13	89.18	137.97	227.15	1003.00	Urban	1576.17
W131S-PLA3	13	45.46	67.85	113.31	425.00	Rural	93.89
W200S-WHI1	13	13.13	34.13	47.26	17.00	Rural	93.89
W202S-SAL1	13	53.53	87.36	140.89	767.00	Urban	1576.17
W202S-SAL2	13	23.31	49.02	72.33	140.00	Rural	93.89
W204S-HER1	13	46.69	90.19	136.89	271.00	Rural	93.89
W205S-FRU1	13	52.11	86.89	139.00	1273.00	Urban	1576.17
W205S-FRU2	13	3.87	9.13	13.00	132.00	Urban	1576.17
W206S-YMR1	13	24.55	30.99	55.54	5.00	Rural	93.89
W221S-CAS1	13	23.17	47.62	70.79	743.00	Urban	1576.17
W221S-CAS2	13	41.45	88.35	129.80	1431.00	Urban	1576.17
W221S-CAS3	13	104.15	192.39	296.54	1504.00	Urban/Rural	234.72
W222S-BLU1	13	15.05	32.73	47.77	747.00	Rural	93.89
W222S-BLU2	13	43.02	87.89	130.91	1311.00	Rural	93.89
W246S-BEP1	13	21.74	45.51	67.25	662.00	Urban	1576.17
W246S-BEP2	13	50.85	84.53	135.37	630.00	Rural	93.89
W247S-GLM1	13	9.55	13.90	23.45	45.00	Rural	93.89
W247S-GLM2	13	21.21	48.23	69.45	1731.00	Urban	1576.17
W247S-GLM3	13	10.46	23.12	33.59	983.00	Urban	1576.17
W248S-STC1	13	29.55	56.78	86.32	1368.00	Urban	1576.17
W248S-STC2	13	28.69	60.02	88.70	644.00	Rural	93.89
W256S-PAT1	13	0.10	0.29	0.39		Rural	93.89
W270S-CHR1	13	99.88	155.19	255.06	1173.00	Urban	1576.17
W271S-RUC5	13	51.08	104.85	155.93	319.00	Urban	1576.17
W275S-GFT1	13	167.75	299.06	466.81	1218.00	Urban	1576.17
W291S-MID1	13	80.32	190.17	270.49	534.00	Rural	93.89
W296S-GRE1	13	52.39	96.88	149.27	340.00	Rural	93.89
W296S-GRE2	13	40.67	87.19	127.86	188.00	Rural	93.89
W302S-GLE1	13	10.84	30.09	40.93	768.00	Urban	1576.17

Feeder Number	Voltage	Running Distance (KM)	Conductor Length (KM)	Conductor and Neutral Length (KM)	Estimated Customers	Feeder Classification	Max KVA
W302S-GLE2	13	9.44	26.89	36.34	451.00	Urban	1576.17
W302S-GLE5	13	37.64	69.00	106.64	1642.00	Urban	1576.17
W302S-GLE7	13	38.18	86.22	124.40	903.00	Urban	1576.17
W304S-HOL1	13	87.76	144.65	232.42	1843.00	Urban/Rural	234.72
W304S-HOL2	13	25.22	50.12	75.34	1673.00	Urban	1576.17
W304S-HOL3	13	22.51	45.14	67.65	1974.00	Urban	1576.17
W304S-HOL4	13	22.11	45.48	67.59	2165.00	Urban	1576.17
W304S-HOL5	13	53.25	85.36	138.61	2158.00	Urban	1576.17
W304S-HOL7	13	10.53	26.45	36.98	859.00	Urban	1576.17
W305S-COKOKM1	13	9.99	20.95	30.94	464.00	Urban	1576.17
W305S-OKM1	13	50.12	93.86	143.98	2617.00	Urban	1576.17
W305S-OKM2	13	11.47	26.18	37.64	1017.00	Urban	1576.17
W305S-OKM3	13	27.27	55.63	82.90	1089.00	Urban	1576.17
W305S-OKM4	13	32.15	61.99	94.14	3245.00	Urban	1576.17
W308S-SEX1	13	77.20	173.03	250.23	1395.00	Urban	1576.17
W308S-SEX2	13	47.01	85.20	132.21	2114.00	Urban	1576.17
W308S-SEX3	13	53.27	90.73	144.00	971.00	Urban	1576.17
W308S-SEX4	13	5.34	15.49	20.83	121.00	Urban	1576.17
W316S-DUC1	13	72.03	133.72	205.75	983.00	Urban/Rural	234.72
W316S-DUC2	13	22.43	41.97	64.40	439.00	Urban/Rural	234.72
W321S-KAL1	13	136.29	229.77	366.06	775.00	Urban/Rural	234.72
W322S-NAR1	13	34.05	53.50	87.55	515.00	Urban/Rural	234.72
W322S-NAR2	13	46.33	74.16	120.49	325.00	Urban/Rural	234.72
W323S-OKF1	13	33.22	67.16	100.38	729.00	Urban	1576.17
W323S-OKF2	13	10.92	19.97	30.89	183.00	Rural	93.89
W323S-OKF3	13	44.58	84.04	128.63	932.00	Rural	93.89
W333S-PIN1	13	32.77	64.14	96.91	1040.00	Urban	1576.17
W333S-PIN2	13	126.23	222.86	349.09	905.00	Rural	93.89
W333S-PIN3	13	32.23	63.08	95.32	1282.00	Urban	1576.17
W338S-OSO1	13	24.64	57.13	81.77	1314.00	Urban	1576.17
W338S-OSO2	13	68.05	114.78	182.83	1075.00	Urban	1576.17
W338S-OSO3	13	94.43	196.54	290.96	1464.00	Urban	1576.17
W345S-KER1	13	99.41	210.12	309.53	739.00	Rural	93.89
W345S-KER2	13	137.53	317.53	455.06	1466.00	Rural	93.89
W347S-HED2	13	51.30	124.58	175.88	409.00	Rural	93.89
W347S-HED3	13	11.19	30.56	41.75	23.00	Rural	93.89
W371S-DGB1	13	31.37	50.11	81.47	1333.00	Urban	1576.17
W371S-DGB2	13	92.43	151.95	244.38	1416.00	Urban	1576.17
W371S-DGB3	13	50.79	83.44	134.23	717.00	Urban	1576.17
W372S-LEE1	13	72.09	125.88	197.97	2998.00	Urban	1576.17
W372S-LEE2	13	79.02	137.96	216.98	896.00	Urban/Rural	234.72
W386S-OLI1	13	80.24	135.63	215.87	611.00	Rural	93.89
W386S-OLI2	13	46.99	98.04	145.04	742.00	Rural	93.89
W390S-BUR1	13	14.28	33.56	47.83	372.00	Urban	1576.17

Feeder Number	Voltage	Running Distance (KM)	Conductor Length (KM)	Conductor and Neutral Length (KM)	Estimated Customers	Feeder Classification	Max KVA
W390S-EAS1	13	50.07	125.26	175.33	363.00	Urban	1576.17
W390S-LIM1	13	27.32	55.44	82.76	1125.00	Urban	1576.17
W390S-NOR1	13	197.56	406.64	604.20	951.00	Rural	93.89
W102S-KAS1	25	16.36	27.24	43.60	398.00	Rural	347.22
W102S-KAS2	25	36.71	60.59	97.30	428.00	Rural	347.22
W103S-COF1	25	40.88	88.43	129.30	200.00	Rural	347.22
W258S-CSC1	25	21.61	51.86	73.47	79.00	Rural	347.22
W258S-CSC2	25	19.30	35.65	54.95	1161.00	Urban	3031.09
W258S-CSC3	25	51.18	91.64	142.81	558.00	Urban	3031.09
W292S-ROC1	25	182.30	349.28	531.57	374.00	Rural	347.22
W292S-ROC2	25	116.48	174.63	291.11	311.00	Rural	347.22
W315S-JOR1	25	74.31	158.80	233.10	1102.00	Rural	347.22
W315S-JOR2	25	77.84	182.00	259.84	537.00	Rural	347.22
W320S-HUT2	8.66	0.04	0.12	0.16		Urban	1049.97
W326S-WEB1	8.66	34.72	73.12	107.85	912.00	Urban	1049.97
W326S-WEB2	8.66	31.62	62.68	94.30	502.00	Urban	1049.97
W327S-SPL	5	7.09	7.09	14.19	16.00	Rural	13.89
W329S-TRC1	8.66	3.77	11.30	15.07		Rural	41.66
W347S-HED4	25	23.90	64.60	88.49	434.00	Urban	3031.09
W380S-RGA1	8.66	19.52	26.49	46.01	75.00	Rural	41.66

	Total Customers	Total Peak Load
	89,616	92,973
PLCC = (Peak/Customers)		1.0

Zero-Intercept Approach

An alternative to the minimum system approach used for classifying distribution costs is a zero-intercept approach. This is basically like the minimum system but takes the minimum sized system back to a theoretical minimum rather than the minimum size that is actually available for purchase. It calculates the cost of a pole, conductor or transformer as if it had zero capacity. That zero capacity system would theoretically reflect the customer-related component as it would be in place only to serve customers as it would have no ability to serve any amount of load.

The zero capacity system cost is calculated using a regression analysis that compares the cost of poles, conductor and transformers to their relative sizes. A regression generally yields a formula of cost = *a* + *b* x size. The intercept is reflected by *a* and would reflect the cost if the size equals zero.

While the zero-intercept is theoretically valuable, in practice it is often not practical. The *a* component can result in a negative number, the relationship between cost and size may not be linear and often there are not sufficient data points to get a reliable result. While the zero-intercept approach did not yield negative results in this case, it was not used in the COSA for 2009. The minimum system approach was used as it is the more common approach and is consistent with the 1997 COSA methodology.

The use of the PLCC with the minimum system approach reflects the same theory as the zero-intercept approach. The impact of the PLCC is to adjust for a large customer-related percentage resulting from a minimum system approach that incorporates equipment that is capable of carrying some amount of load. In both cases, the resulting allocation to classes with a large number of customers (like residential) is reduced. In the case of FortisBC, the results were similar when the zero-intercept approach was used rather than the minimum system method with the PLCC adjustment.

Using the data from the minimum system analysis, a zero-intercept split was also calculated for FortisBC for poles, conductors and transformers. In each case a regression analysis was used to determine the zero cost per item and the results all contained a positive intercept. The following table summarizes the results in comparison to the minimum system.

	Poles	**Conductors**	**Transformers**
Minimum System			
Minimum Cost	various	$3,514	$1,946
Percent Customer	96%	87%	73%
Percent Demand	4%	13%	27%
Zero Intercept			
Minimum Cost	$513	$2,520	$1,743
Percent Customer	31%	62%	66%
Percent Demand	69%	38%	34%

Because the PLCC was used in conjunction with the minimum system study, the results associated with the zero-intercept approach were not significantly different for FortisBC.

The following tables provide the details associated with the zero-intercept analysis for poles, conductors and transformers.

Zero-Intercept Poles

Size (Feet)	Total Loaded Cost
0	$513
35	$1,551
40	$1,551
40	$1,697
45	$1,582
45	$1,728
50	$1,720
50	$1,865

Zero-Intercept Results

Number Poles	58,760
Zero-Intercept Cost	$512.79
Zero-Intercept Total	$30,131,261
Actual Cost Total	$96,277,880
Percent Customer	31%
Percent Demand	69%

Minimum System Results

Percent Customer	81%
Percent Demand	19%

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.836827225
R Square	0.700279805
Adjusted R Square	0.640335766
Standard Error	103.0228245
Observations	7

ANOVA

	df	*SS*	*MS*	*F*
Regression	1	123991.67	123991.67	11.682226
Residual	5	53068.512	10613.702	
Total	6	177060.18		

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	512.7852377	331.68525	1.5459995	0.1827703
X Variable 1	25.83887474	7.5598085	3.4179271	0.0188805

Zero-Intercept Conductor

Size (kVA)	**Total Loaded Cost**	Ampacity (A)
	$2,520	
6 CU	$3,514	160
4 CU	$3,514	180
4 ACSR	$3,514	193
2 CU	$3,514	240
2 ACSR	$3,514	404
2/0 ACSR	$4,321	404
266 ACSR	$4,321	500
4/0 CU	$4,321	520
4/0 Al	$4,321	543
477 AL	$6,536	660
927 AL	$6,511	
3 CU	$3,514	
1/0 CU	$3,514	
8 CU	$3,514	
1/0 ASCR	$4,321	
90 MCM Cu	$4,321	

Zero-Intercept Results	
Conductor KM	14,369
Zero-Intercept Cost	$2,520.12
Zero-Intercept Total	$36,211,886
Actual Cost Total	$58,286,772
Percent Customer	62%
Percent Demand	38%
Minimum System Results	
Percent Customer	87%
Percent Demand	13%

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.808932514
R Square	0.654371812
Adjusted R Square	0.611168288
Standard Error	581.6976764
Observations	10

ANOVA

	df	*SS*	*MS*	*F*
Regression	1	5125073.2	5125073.2	15.14626
Residual	8	2706977.5	338372.19	
Total	9	7832050.7		

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	2520.11545	454.75309	5.5417225	0.0005463

X Variable 1	4.254896492	1.0932923	3.8918197	0.0045974

Zero-Intercept Transformers

Size (kVA)	Total Loaded Cost
0	$1,743
10	$1,946
15	$1,946
25	$2,470
37	$2,630
50	$3,408
75	$4,925
100	$5,620
167	$6,486
250	$15,856
333	$15,856
500	$18,084
750	$18,084

Zero-Intercept Results	
Number Transformers	28,479
Zero-Intercept Cost	$1,743.20
Zero-Intercept Total	$49,644,688
Actual Cost Total	$75,421,714
Percent Customer	66%
Percent Demand	34%
Minimum System Results	
Percent Customer	73%
Percent Demand	27%

SUMMARY OUTPUT (First 8 Data Points)

Regression Statistics	
Multiple R	0.962236644
R Square	0.925899358
Adjusted R Square	0.913549251
Standard Error	521.638557
Observations	8

ANOVA

	df	*SS*	*MS*	*F*
Regression	1	20400106	20400106	74.970959
Residual	6	1632640.7	272106.78	
Total	7	22032747		

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	1743.203355	289.22346	6.0271851	0.0009419
X Variable 1	32.2183408	3.720974	8.6585772	0.0001308

Appendix C—Load Analysis

To allocate costs within the COSA, a combination of customer, demand and energy factors are used. The customer and energy allocations are straightforward as both the number of customers and energy per class are easy to track and forecast. Demand per customer class is more difficult. Demand is not metered for all classes plus there are several different types of demand that are considered. Developing the necessary demand allocators requires piecing together information from various sources. The following defines the different types of loads necessary to develop all of the allocators by class.

Energy

Energy per class is provided for each customer class based on metered kWh sales and is the starting point for the analysis. The annual energy forecast is broken out by month based on the 200 actual shape. Losses for the total system are projected and are added to each class on the basis of the voltage level for the class. Projected losses are 5.2% for transmission voltage classes, 6.2% for primary voltage classes, and 11% for secondary voltage classes. The kWh at input includes losses and reflects the energy amounts needed to be generated or purchased.

Billing Demand

For those customers with demand meters, the billing demand reflects the maximum demand during the month for each customer, summed together. For FortisBC, the General Service (Rate 21), Industrial and Wholesale Customers are demand-metered and billed on the basis of kVA. These demands are converted from kVA to kW using the power factor by class. Because FortisBC had detailed metering data for its large customers, we had individual power factors for the wholesale and industrial customers. The Wholesale power factor was set at 99% . The power factor for Rate 30 was 90% and the power factor for Rates 31 and 33 was 95%. The general service customers were assumed to have a power factor of 100%. The resulting sum of the individual peaks on a per kW basis is called the individual non-coincident peak (NCP).

Individual Load Factor

The relationship between the energy and the billing demand kW is the individual load factor. For the demand-metered customers the individual load factor was calculated. For the residential, Rate 20, lighting and irrigation customers, the individual load factor was estimated and applied to the energy forecast to develop the sum of the individual customer peaks. Load data from BC Hydro for the Southern Interior was used to assist in developing load data for those classes without demand meters. This data was balanced against what was known for other FortisBC classes and what the total projected peak demand was for the system.

Group Coincident Factor

To get from the individual NCP to the NCP for the entire group a group coincident peak was used. This reflects the difference between the individual peak load and the load at the time the class has its peak. The class NCP is not necessarily at the same time as the system peak. The group coincidence factors were developed based on standard industry data and the BC Hydro Southern Interior load data. For the individual wholesale customers, their group coincidence factor is 100% since they are the only customer in their class. The lighting class also has a 100% group coincidence factor as all street lights are assumed to be on at the same time. Industrial class group coincidence factors are 90% to 100%. General Service group coincidence factors are set at 75% and Residential group coincidence factors are set at 90%. The residential class has a higher group coincidence factor as they are more homogeneous than the general service customers.

Rate Class Non-Coincident Peak (NCP)

The NCP for the rate class is developed by multiplying the sum of the individual non-coincident peaks by the group coincident factor. The class NCP is used to allocate distribution assets as the distribution system is generally sized to serve localized peaks. For the wholesale customers where they are individualized for the COSA, and for industrial and lighting customers that are assumed to all peak at the same time, the NCP is the same as the individual NCP. The residential and general service customers have some diversity in the timing of their peaks, leading to a lower group NCP for the class when compared to the individual NCP.

System Coincident Factor

The final factor used in developing load data is the system coincident factor. This factor reflects the percent of load that is on at the time of the system peak. For example, the system peak may be at 6 pm but the general service class peaks at 4 pm. The system coincidence factor represents the relationship between the highest peak for the class (NCP) and the contribution of that class to the system coincident peak (CP). Generation and power purchases are designed to serve the system load, as is the bulk transmission system.

For the wholesale and industrial customers, FortisBC has hourly meters allowing for the collection of data on a detailed basis. System coincident factors for these classes were based on actual hourly load data. Wholesale customers generally have system coincident factors in the range of 90% to 100%. Industrial transmission customers have factors in the 68% to 93% range. Assumptions were made for the other classes, including 75% for industrial primary and large general service customers, 70% for small general service and 80% for residential customers.

Rate Class Coincident Peak (CP)

Multiplying the group NCP by the system coincident factor results in the CP for the rate class. This is an important measure for the COSA as it is used for the allocation of generation/power supply costs and for transmission costs. The total CP is a measured variable for the utility and it is also forecast on a monthly basis. The system forecast for the CP can be compared to the CP calculated by all of the steps leading from energy to CP. By reconciling these two different approaches to developing the same monthly peak forecast, the various assumptions made throughout the process can be adjusted to make sure that the two numbers balance against each other.

Appendix B

Amended Rate Schedules

- including rate schedules modified by this Application and not the subject of a separate Appendix.

Introduction

Appendix B, the Amended Tariff Sheets, contain two changes to those currently filed with the Commission and not discussed elsewhere in the Application. These are:

1. Renaming of select Rate Classes: FortisBC is proposing to change the names of a number of rate classes to better align with the way these classes are referred to in other regulatory processes and general internal and external communication. The changes are contained in the table below:

Schedule Number	**Current Rate Class Name**	**Proposed Rate Class Name**
20	Small General Service	Small Commercial
21	General Service	Commercial
22A	General Service - Secondary - Time-of-Use	Commercial - Secondary - Time-of-Use
23	General Service - Primary - Time-of-Use	Commercial - Primary - Time-of-Use
30	Large General Service - Primary	Industrial - Primary
31	Large General Service - Transmission	Industrial - Transmission
32	Large General Service - Primary - Time-of-Use	Industrial - Primary - Time-of-Use
33	Large General Service - Transmission - Time-of-Use	Industrial - Transmission - Time-of-Use

2. General Clean-Up - FortisBC is filing a new set of Rate Schedules that include general clean up edits. The new tariff sheets have been cleared of previous revision, date, Commission Order, and signature information. This set of the schedules is effectively the starting point for future revisions.

FORTISBC INC.

ELECTRIC TARIFF B.C.U.C. NO. 2

FOR SERVICE IN THE WEST KOOTENAY AND OKANAGAN AREAS

TERMS AND CONDITIONS

AND

RATE SCHEDULES

EXPLANATION OF SYMBOLS
APPEARING ON TARIFF PAGES

A - signifies Increase

C - signifies Change

D - signifies Decrease

N - signifies New

O - signifies Omission

R - signifies Reduction

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The Company will furnish electric Service in accordance with the Rate Schedules and these Terms and Conditions filed with and approved by the British Columbia Utilities Commission. Copies are available on the Company's web site or upon request.

The Customer, by taking Service, agrees to abide by the provisions of these Terms and Conditions.

1. DEFINITIONS:

Company	FortisBC Inc.
Customer	A person, partnership, corporation, organization, governmental agency, municipality or other legal entity who accepts, uses or otherwise is the recipient of Service at any one Premises or location, or whose application for Service is accepted by the Company. The Company shall determine whether any entity as defined above receives Service at one or more Premises or locations.
Billing Demand	The Demand used in establishing the Demand portion of billing for Service during a specific billing period.
Contract Demand	The Demand reserved for the Customer by the Company and contracted for by the Customer.
Demand	The rate of delivery of Electricity measured in kilowatts (kW), kilovolt-amperes (kVA), or horsepower (hp) over a given period of time.
Drop Service	The portion of a overhead Service connection extending not more than 30 metres onto the Customer's property and not requiring any intermediate support on the Customer's property.
Electricity	The term used to mean both electric Demand and electric energy unless the context requires otherwise.
Load Factor	The percentage determined by dividing the Customer's average Demand over a specific time period by the Customer's maximum Demand during that period.
Power Factor	The percentage determined by dividing the Customer's Demand measured in kilowatts by the same Demand measured in kilovolt-amperes.

1. DEFINITIONS: (Cont'd)

Point of Delivery	The first point of connection of the Company's facilities to the Customer's conductors or equipment at a location designated by or satisfactory to the Company, without regard to the location of the Company's metering equipment.
Premises	A dwelling, a building or machinery together with the surrounding land.
Suspension	the physical interruption of the supply of Electricity to the Premises independent of whether or not the Service is terminated.
Transmission Voltage	a nominal potential greater than 35,000 volts measured phase to phase.
Termination	the cessation of the Company's ongoing responsibility with respect to the supply of Service to the Premises independent of whether or not the Service is suspended.
Primary Voltage	a nominal potential of 750 to 35,000 volts measured phase to phase.
Secondary Voltage	a nominal potential of 750 volts or less measured phase to phase.
Service	any Service(s) provided by the Company pursuant to these Terms and Conditions and rate schedules

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2. APPLICATION FOR SERVICE

2.1 Application for Service

Applications for Service shall be made via the Company's contact center, online at www.fortisbc.com, or by other means acceptable to the Company. Applicants for Service shall pay the connection or other charges required pursuant to these Terms and Conditions and rate schedules, and shall supply all information relating to load, supply requirements and such other matters relating to the Service as the Company may require.

Applicants shall be required to provide information and identification acceptable to the Company.

Applicants may be required to sign an application form for Service. A contractual relationship shall be established by the taking of Service in the absence of an application for Service or a signed application, except where a theft of Service has occurred.

The Company will assist in selecting the rate schedule applicable to the Customer's requirements, but will not be responsible if the most favourable rate is not selected. Changing of rate schedules will be allowed only if a change is deemed to be more appropriate to the Customer's circumstances. One request to change rate schedules will be permitted in any 12-month period. At the Company's option, where the Customer's load characteristics warrant, Customers served under Rate Schedule 20 may be transferred to Rate Schedule 21 or vice versa.

The Company retains the right to reject applications for Service if, in the opinion of the Company:

(a) conditions other than standard conditions are required by the applicant;
(b) facilities are not available to provide adequate Service;
(c) the Customer's facilities are not satisfactory to the Company;
(d) the applicant or owner or occupant of the Premises has an unpaid account for Service;
(e) the applicant has provided false or misleading information;
(f) the applicant is not the owner or occupant of the Premises;
(g) the Service requested is already supplied to the Premises for another Customer who does not consent to having the Service terminated;
(h) or if the applicant cannot provide satisfactory security for payment as required by the Company;
(i) the applicant is in receivership or bankruptcy, or operating under the protection of insolvency legislation and has failed to pay any outstanding bills to the Company;
(j) the applicant has breached any agreement or terms with the Company; or

2. APPLICATION FOR SERVICE (Cont'd)

2.1 Application for Service (Cont'd)

If occupancy of a rental Premises is of a transient nature, or if the rental Premises has an unacceptable billing history, the Company may require the Service to be in the name of the owner of the Premises on a continuous basis.

The Company shall not be liable for any loss, injury or damage suffered by any Customer by reason of a refusal to provide Service.

A Customer shall not transfer or assign a Service application or contract without the written consent of the Company.

Applications for Residential Service involving a standard connection of Service should be made via telephone or internet at least ten working days before Service is required.

Applications involving the installation of facilities should be discussed with the local Company representative well in advance of the date that Service is required.

2.2 Term of Service

Unless otherwise specifically provided in these Terms and Conditions, the rate schedules, or in any contract between the Customer and the Company, the term of Service and obligation to pay the charges under the applicable rate schedule for the minimum required term of Service shall commence on the day when the Company's Service is connected to the Customer's installation for the purpose of supplying Electricity, and

(a) shall be for one year where the connection does not require more than a Drop Service, unless a shorter period is agreed to by the Company; or

(b) shall be for five years where additional facilities other than those for a Drop Service are required; and

(c) shall continue thereafter until canceled by written notice of Termination by either party, except that in the case of Customers whose Contract Demand exceeds 200 kVA, 12 months' prior written notice of Termination shall be required and shall be given in such manner that the contact terminates with the last day of a billing period.

2. APPLICATION FOR SERVICE (Cont'd)

2.3 Security Deposit

If a Customer or applicant cannot establish or maintain credit to the satisfaction of the Company, the Customer or applicant may be required to make a security deposit in the form of cash or an equivalent form of security acceptable to the Company.

Security deposits shall be in the form of cash or equivalent form of security in an amount equal to the Customer's bill for 3 months as estimated by the Company and shall be in addition to any other deposits required.

For Customers with a Demand in excess of 200 kVA the security deposit is mandatory and shall be increased by an amount equivalent to the estimated minimum charge under the applicable rate schedule for six months.

Failure to pay a security deposit or to provide an equivalent form of security acceptable to the Company may, in the Company's discretion, result in Termination or refusal of Service. FortisBC reserves the right to review and adjust the security deposit required from a Customer at anytime.

The Company shall have the right to apply the security deposit to the Customer's billing account at any time the Customer fails to pay any amounts owed by the Customer. If a Customer's security deposit or equivalent form of security is called upon by the Company towards paying an unpaid account, the Customer must re-establish the security deposit or equivalent form of security before the Company will reconnect or continue Service to the Customer.

Interest shall be paid on all cash security deposits from the date of receipt if held for more than one month in accordance with Clause 11.3. No interest is payable on any unclaimed deposit left with FortisBC after the account for which it is security is closed or on a deposit held by FortisBC in a form other than cash.

Upon application by the Customer after 2 years of continuous Service, a security deposit may be returned if the Customer has, by the payment of each and every account by the due date, established credit to the satisfaction of the Company.

Customers with Demand in excess of 200 kVA will only be eligible for return of a security deposit upon discontinuation of Service, and only when the final account, together with all arrears, is paid in full. When the Customer pays the final bill, the Company will refund any remaining security deposit plus any accrued interest or cancel the equivalent form of security.

2. APPLICATION FOR SERVICE (Cont'd)

2.3 Security Deposit (Cont'd)

If the Company is unable to locate the Customer to whom a security deposit is payable, FortisBC will take reasonable steps to trace the Customer; but if the security deposit remains unclaimed 7 years after the date on which it first became refundable, the deposit, together with any interest accrued thereon, will be forfeited.

If, in the Company's sole discretion, the deposit is likely to cause undue financial hardship, then bi-monthly account Customers may be permitted to pay the deposit in two equal installments.

2.4 Connection of Service

The Company will connect a Drop Service to the Customer's Premises after receipt of an application; payment of any applicable charges and deposits; Electrical Inspection Department permit to connect Service; and other permits as may be required by others or by the Company.

For extensions requiring more than a Drop Service, connection will be made under the provisions of the applicable Extension Schedule.

If space for a Drop Service to the Customer's Premises most convenient to the Company is obstructed, the Company will charge the Customer for the additional cost of providing Service.

2.5 Delay in Taking Service

If, with respect to an application to extend its facilities to any Point of Delivery, the Company has reason to believe that Service through that Point of Delivery will not be taken within 30 days after such Service is available, then the Company, in addition to any other payment required, may require payment equivalent to the Company's investment, subject to prior written notification to the affected Customer by the Company. The payment shall be comprised of a monthly charge based on the Company's investment multiplied by 2% to provide for a return on investment, depreciation, taxes and other fixed costs.

2.6 Termination of Service

Customers requesting a Termination of Service shall provide the Company with a minimum of 24 hours notice. If the Customer fails to provide the required notice, the Customer will be held responsible for all applicable charges until 24 hours after the Company has received the required notice.

2. APPLICATION FOR SERVICE (Cont'd)

2.6 Termination of Service (cont'd)

Customers having a notice of Termination period in their contracts shall provide the Company with a request for Termination of Service in accordance with the notice provision in the contract.

2.7 Reconnection of Service

If a Service is terminated at the Customer's request and the same Customer or spouse, servant or agent of that Customer requests reconnection of that Service within 12 months, the applicant shall pay the reconnection charge plus the total of the minimum charges the Customer would have incurred during the period of the disconnection, if they had not been disconnected. If a Service has been disconnected for over 90 days, or the electrical use within the building has changed substantially, an Electrical Inspection Department permit may be required before reconnection.

3. CONDITIONS OF SERVICE

3.1 Point of Delivery

Unless otherwise specifically agreed to, the Point of Delivery is the first point of connection of the Company's facilities to the Customer's conductors or equipment at a location designated by or satisfactory to the Company, without regard to the location of the Company's metering equipment.

The Company, at its option, may supply Commercial Service through one Point of Delivery to two or more adjacent buildings owned and used as a single business function.

The rate schedule for each class of Service named in this tariff is based upon the supply of Service for each Customer through a single Point of Delivery. Additional Service supplied to the same Customer at more than one Point of Delivery shall be permitted only at the discretion of the Company, and shall not be combined but shall be metered and billed separately unless specifically approved by the Company.

3.2 Ownership of Facilities

Subject to any contractual arrangement and, notwithstanding the payment of any Customer contribution toward the cost of facilities, the Company shall retain full title to all equipment and facilities installed and maintained by the Company.

3. CONDITIONS OF SERVICE (Cont'd)

3.3 Customer Contributions

The Customer may be required to make a contribution toward the cost of facilities in excess of the charges for installation of new/upgraded Services provided for under Schedule 82 when:

(a) as provided in the Company's Extension Schedule, Extension of Service is in excess of a Drop Service;
(b) Service is underground;
(c) the nature of the Service is such that the revenue derived from the minimum billing would be insufficient to cover the cost of Service. A contribution would be required for such Services as fire pumps, sirens or emergency supply where the level of consumption is below that necessary to cover the annual costs;
(d) space for a Drop Service to the Customer's Premise, most convenient to the Company is obstructed by the Customer's property;
(e) facilities must be upgraded significantly to meet an increase in the Customer's load.

If a Customer contribution is required and if the Customer does not receive Service within three months of the contribution being received by the Company, and where the delay in taking Service is not attributable to the Customer, the Customer shall receive interest as calculated in Clause 11.3 on such payment.

3.4 Revenue Guarantee Deposit

If the provision of Service by the Company to a non-residential Customer will require construction and installation costs by the Company of more than $5,000 per Customer supplied, each such Customer shall provide a revenue guarantee deposit, as assurance that the Company will receive sufficient revenue to recover the installation costs of the facilities.

The Company will repay 20 per cent of the revenue guarantee to the Customer at the end of each year of Service, for a period of five years, provided that the Customer's bills are paid in full at the time the refund is due. Interest will be paid on refunds as calculated in Clause 11.3.

If the contract for Service is terminated prior to five years from the date of installation, any balance of the revenue guarantee remaining shall belong to the Company absolutely as part of the consideration for the Company installing Service.

3. CONDITIONS OF SERVICE (Cont'd)

3.5 Voltages Supplied

The Company will supply nominal 60 cycle alternating electric current to the Point of Delivery at the available phase and voltage.

Before wiring Premises or purchasing any electrical equipment, the Customer should consult with the Company to ascertain what type of Service may be available at the requested location. The Customer should present a description of the load to be connected so that the Company can furnish information regarding voltage and phase characteristics available at the Point of Delivery.

The Company will not supply transformation from one Secondary Voltage to another Secondary Voltage.

The Company reserves the right to determine the voltage of the Service connection.

Nominal Standard Secondary Voltage from Pole-Mounted Transformers

Single phase:	(i)	120/240 volts, 3 wire, maximum 600 amperes.
Three phase:	(i)	120/208 volts, 4 wire, 300 kVA maximum transformation capacity.
	(ii)	347/600 volts, 4 wire, maximum 300 kVA transformation capacity.

Nominal Standard Secondary Voltage from Pad-Mounted Transformers

Single phase:	(i)	120/240 volts, 3 wire, maximum 600 amperes.
Three phase:	(i)	120/208 volts, 4 wire, maximum 500 kVA transformation capacity.
	(ii)	347/600 volts, 4 wire, maximum 2,500 kVA transformation capacity.

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3. CONDITIONS OF SERVICE (Cont'd)

3.5 Voltages Supplied (Cont'd)

Special Conditions

Special arrangements may be required under the following conditions:

(a) For Customer loads or supply voltages different from those listed above with pole-mounted and pad-mounted transformer installations, the Customer will be required to supply its own transformers and take Service at the available Primary Voltage.

(b) Customers initiating an upgrade of existing facilities using non standard Secondary Voltages may be required to upgrade to standard voltages at their own expense.

(c) Where a Customer has been required to supply its own transformation, transformation discounts will only be applicable if available under the existing rate schedule to which Service is provided to the Customer.

3.6 Customer's Equipment

All Customer owned transformers and equipment used to connect them to the Company's electrical system shall be approved by and installed in a manner satisfactory to the Company.

3.7 Limitation of Use

Service supplied to a Customer shall be for the use of that Customer only and for the purpose applied for, and shall not be remetered, submetered or resold to others except with the written consent of the Company or as provided in the applicable rate schedule.

Single phase motors rated larger than two hp and other equipment with rated capacity greater than 1,650 watts shall not be used on 120 volt circuits, unless otherwise authorized by the Company. Motors of 20 hp or larger shall be equipped with reduced voltage starters or other devices approved by the Company to reduce starting current, unless otherwise authorized by the Company.

3. CONDITIONS OF SERVICE (Cont'd)

3.7 Limitation of Use (Cont'd)

Space Heating Specifications

(a) Residential

The maximum capacity of residential heating units to be controlled by one switch or thermostat shall be 6,000 watts. Where applicable, time delay equipment must be installed so that each of the heating units, as required, is energized sequentially at minimum intervals of ten seconds. Heating units shall be connected so as to balance as nearly as possible the current drawn from the circuits at the Point of Delivery.

(b) Industrial Use

The maximum capacity of industrial heating units to be controlled by one switch or thermostat shall be ten kW for single phase and 25 kW for three-phase units.

Water Heating Specifications

The heating units shall be of non-inductive design for a nominal voltage of 240 volts unless otherwise agreed to by the Company, but units of less than 1,650 watts may have a nominal voltage of 120 volts.

Installations may consist of either one or two-unit heaters. In the single unit heater tank, the unit shall be placed to heat the entire tank. In the two-unit heater tank, a "base" unit heater shall be placed to heat the entire tank and a "booster" unit heater placed to heat not more than the top third of the tank.
Each unit heater shall be controlled by a separate thermostat and shall not exceed 6,000 watts, except heating units installed in tanks of 350 litres and larger may, at the Company's option, exceed 6,000 watts but shall not exceed 17 watts per litre for either "base" or "booster" unit heater.

Thermostats must be permanently connected so that both heating units cannot operate at the same time except on tanks where the installed capacity does not exceed 6,000 watts.

The Company, may at its expense, install a time switch, carrier current control, or other device to limit the hours of Service to the water heater. The period or periods each day during which Service may be so limited shall not exceed a total of two hours.

4. TYPE OF SERVICE

4.1 Temporary Service

Where the Company has facilities available, temporary Service may be supplied under any rate schedule applicable to the class of Service required. The basic charge or minimum set forth in that rate schedule shall be applicable to the temporary Service, but in no case shall it be less than one full month. The Customer shall also pay for the cost of the installation and removal of the equipment used to supply the temporary Service as prescribed in Schedule 82.

4.2 Underground Facilities

The Company's Tariff is designed to recover the cost of providing electrical Service from overhead poles and conductors. The Customer applying for underground Service under any Rate Schedule shall be responsible for any added cost and agrees as follows:

(a) The Company shall own, install and maintain the underground Service line to the Point of Delivery. The Customer shall own, install and maintain the underground Service line beyond the Point of Delivery.

(b) The underground installation must comply with the Company's underground distribution standards.

(c) The Company shall not be responsible for any loss or damage beyond the reasonable control of the Company due to the installation, operation or maintenance of the underground circuit.

4.3 Residential Service

Residential Service is intended strictly for residential use. Some minor exceptions as indicated in the following are accepted under this Tariff for reasons of administration and practicality. Where partial commercial use or other use is made of Electricity supplied, refer to Section 4.3.3 or 4.3.4.

Residential Service is normally single phase 120/240 volt, maximum 200 amperes. Three phase residential Service or single phase Service in excess of 200 amperes may be provided under special contract terms requiring the Customer to pay all the additional costs of a larger Service.

4. TYPE OF SERVICE (Cont'd)

4.3 Residential Service (Cont'd)

Residential rates are available for Service as follows:

4.3.1 Single meter residential Premises - exclusive residential use

(a) individually metered single family residences used exclusively for normal residential and housekeeping requirements;

(b) any outbuilding located on residential property and supplied through the residential meter;

(c) residential property where less than three rooms are rented and supply is through the same meter as the residence, (three or more rented rooms will be billed on the Commercial Service rate);

(d) At the Company's option, multiple family dwellings used exclusively for living quarters and served through one meter. For billing purposes, the kilowatt-hour blocks, basic charge and minimum charge will be increased in proportion to the number of single family living quarters served.

4.3.2 Multiple meter residential Premises - exclusive residential use

(a) multiple family dwellings such as apartments, condos, duplex, quadruplex, etc., where each separate living quarter is separately metered;

(b) common use areas in multiple residential dwellings where each single family residence is separately metered;

(c) individually metered motel units where the owner contracts with the Company for the Service to each unit;

(d) where a Customer requests and the Company permits a separate Service to an outbuilding related to the Customer's residential occupancy as in 4.3.1 (a) above. The Company may provide the separately metered residential Service if the Customer pays the full cost of the separate Service less any contribution by FortisBC as specified in Schedule 74 towards the separate Service.

Customers with multiple meter residential Premises shall take Service under a single rate, unless otherwise approved by the Company.

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Accepted for filing ______________________ BRITISH COLUMBIA UTILITIES COMMISSION

By: ______________________

By: ______________________ Commission Secretary

EFFECTIVE (applicable to consumption on and after) ______________________

4. TYPE OF SERVICE (Cont'd)

4.3.3 Partial commercial use

Where a partial commercial use is carried on in a single metered residential Premises (with or without outbuildings), and if the total connected load of the commercial enterprise is less than 5,000 watts, excluding space heating, the Customer shall be billed under Residential Service rates.

If the total connected load of the commercial enterprise is greater than 5,000 watts, excluding space heating, the account shall be billed at Commercial Service rates.

Where commercial use is carried on in a residential Premises or in an outbuilding to that Premises and the commercial area is separately metered, the commercial area only shall be on a Commercial Service rate. If new buildings are erected or major alterations are made to Premises receiving combined Service, the Customer shall be required to arrange the wiring to provide for separate metering.

4.3.4 Other Use

Where water pumps supply single family residences, the water pumps shall be on the Residential Service rate provided they can be supplied single phase and total 5 HP or less.

4.3.5 Farms

Farm residences and their outbuildings shall qualify for the Residential Service rate provided the farm is assessed for property tax purposes as agricultural land and the Service is used primarily for the production of food or industrial crops on that land. Other use for commercial or non farm purposes shall be billed on the Commercial Service rate.

5. METERING

5.1 Installation

The Company shall provide all meters necessary for measuring the Customer's use of the electric Service provided by the Company. The meters shall remain the property of the Company and shall be maintained in accurate operating condition in accordance with the regulations of Measurement Canada.

The Customer may furnish, install and maintain at its expense a meter system to verify the accuracy of the Company's meter system. The Customer's meter system and the manner of its installation shall be approved by the Company.

5. METERING (Cont'd)

5.1 Installation (Cont'd)

Should an accurate meter reading be unavailable due to meter failure, temporary inaccessibility, or any other reason, Electricity delivered to the Customer shall be estimated by the Company from the best available sources and evidence.

The Customer shall exercise all reasonable diligence to protect the Company's meter from damage or defacement and shall be held responsible for any costs of repair or cleaning resulting from defacement or damage.

All connections and disconnections of electric Service and installation and repair of the Company's meter system shall be made only by the Company. All meters shall be sealed by the Company. Breaking the seals or tampering with the meter or meter wiring is unlawful and may be cause for Termination of Service by the Company, and may result in criminal charges for theft of Electricity.

5.2 Location

The Customer shall provide a Service entrance and meter socket location in accordance with Company requirements, and where required a metering equipment enclosure.

The meter socket shall be located on an outside wall and be within 1 m. of the corner nearest the point of supply except, in the case of metering over 300 volts, the meter socket shall be installed on the load side of the Service box and shall be accessible to Company personnel. All sockets must be installed between 1.4 m. and 1.7 m. above final grade to the centre of the meter. Meters shall not be installed in carports, breezeways or similar areas. Any exceptions must be approved by the Company.

Meters shall be installed in places providing safe and reasonable access. Meters shall not be exposed to live steam, corrosive vapours or falling debris. Where the meter is recessed in the wall of a building, sufficient clearance must be provided to permit removal and testing of Company equipment. The full cost of relocating an inaccessible meter shall be borne by the Customer.

5.3 Meter Tests or Adjustments

A Customer may request in writing a test of the accuracy of a meter. The Customer shall deposit an amount as provided in Schedule 80 and the Company shall remove the meter within 10 days and apply 7to the authorized authority to have the meter tested. If the meter fails to meet any of the applicable laws and regulations, the deposit shall be refunded to the Customer. If the meter is found to satisfy the applicable laws and regulations, the Customer shall forfeit the deposit.

5. METERING (Cont'd)

5.3 Meter Tests or Adjustments (Cont'd)

If after testing the meter is found not to be registering within the limits allowed by Measurement Canada, bills will be adjusted as prescribed in the applicable laws and regulations. If a refund is necessary, it shall be calculated in accordance with Clause 11.6.

5.4 Metering Selection

Meters will be selected at the Company's discretion and shall be compliant with the regulations of Measurement Canada. The Company at its discretion may change the type of metering equipment.

5.5 Unmetered Service

The Company may permit unmetered Service if it can estimate to its satisfaction the energy used based on the connected load and hours of use. Customers served under this provision must notify the Company immediately of any proposed or actual changes in load or hours of use. The Company, at its discretion, may at any time require the installation of a meter or meters and thereafter bill the Customer on the consumption registered.

6. METER READING AND BILLING

6.1 Meter Reading

Meters shall be read at the end of each billing period in accordance with the applicable rate schedule. The interval between consecutive meter readings shall be determined by the Company. An accurate record of all meter readings shall be kept by the Company and shall be the basis for determination of all bills rendered for Service.

For billing purposes, the Company may estimate the Customer's meter reading if, for any reason, the Company does not obtain a meter reading. Where the Customer requests Termination of Service pursuant to Section 2.6, the Company may estimate the final meter reading for final billing.

The term "one month" (unless a calendar month is specified) as used herein and in the rate schedules, normally means the time elapsed between the meter reading date of one calendar month and that of the next. The term "two-month period" as used herein and in the rate schedules, normally means the time elapsed between the meter reading date of one calendar month and the second following calendar month.

6. METER READING AND BILLING (Cont'd)

6.2 Proration of Billing

Bills will be prorated as appropriate under the following conditions:

(1) For meters normally read every one month where the billing period is less than 21 days or greater than 39 days.
(2) For meters normally read every two months where the billing period is less than 51 days or greater than 69 days.

6.3 Rates for Electricity

The Customer shall pay for Electricity in accordance with these Terms and Conditions and the Customer's applicable rate schedule, as amended from time to time and accepted for filing by the British Columbia Utilities Commission. If it is found that the Customer has been overcharged, the appropriate refund shall be with interest as calculated in Clause 11.3.

6.4 Sales Tax and Assessments

In addition to payments for Services provided, the Customer shall pay to the Company the amount of any taxes or assessments imposed by any competent taxing authority on any Services provided to the Customer.

6.5 Payment of Accounts

Bills for electric Service are due and payable when rendered. Payments may be made to the Company's collection office, electronically or to authorized collectors.

Customers' accounts not paid by the due date printed on the bill shall be in arrears. Late payment charges may be applied to overdue accounts at the rate specified on the bill and as set out on the applicable rate schedule.

Customers will be advised that their account is in arrears by way of notification on the next billing. If payment is not received, a letter will be mailed to the Customer advising that if payment is not received within ten days of the date of mailing, Service may be suspended without further notice. The Company will make every reasonable effort to contact the Customer by telephone or in person to advise the Customer of the consequences of non-payment, but the account may be disconnected if payment is not received.

7. LOAD CHANGES AND OPERATION

7.1 Notice by Customer

A Customer shall give to the Company reasonable written notice of any change in its load requirements to permit the Company to determine whether or not it can meet the requirements without changes to its equipment or system.

Notwithstanding any other provision of these Terms and Conditions, the Company shall not be required to supply to any Customer Electricity in excess of that previously agreed to by the Company.

Customers with a Demand component in the rate schedule who wish to change the Contract Demand or the Demand limit, shall submit to the Company a written request subject to the following provisions.

(a) an increase requested of less than 1,000 kVA shall be submitted not less than three months in advance of the date the increase is intended to become effective; and

(b) an increase requested in excess of 1,000 kVA but less than 5,000 kVA shall be submitted not less than one year in advance of the date the increase is intended to become effective; and

(c) an increase requested in excess of 5,000 kVA shall be submitted not less than three years in advance of the date the increase is intended to become effective.

(d) a decrease requested of up to 10 per cent per year of the existing Contract Demand or Demand limit shall be submitted not less than three months in advance of the date the decrease is intended to become effective. Customers with a Contract Demand in excess of 500 kVA shall provide the Company by January 31 of each year their best estimate of their annual Electricity requirements to allow the Company to forecast future load on its facilities.

If the Company approves the request in writing, the Contract Demand or the Demand limit may be changed either by amendment to the Customer's contract or by the parties executing a new contract. The Company shall not be required to approve any requested change in the Contract Demand or the Demand limit.

7.2 Changes to Facilities

The Customer may be required to pay for the cost of any alterations to the Company's facilities necessary to provide the Customer's increased load. If any increase in load, Contract Demand or Demand limit, approved by the Company, requires it to add to its existing facilities for the purpose of complying with the Customer's request, the approved increase shall be subject to payment of a Customer

7. LOAD CHANGES AND OPERATION (Cont'd)

7.2 Changes to Facilities (Cont'd)

contribution under clause 3.3. The Customer may also be required to provide a revenue guarantee deposit as set out in clause 3.4.

7.3 Responsibility for Damage

A Customer shall be responsible for and pay for all damage caused to the Company's facilities as a result of that Customer increasing its load without the consent of the Company.

The Customer shall indemnify the Company for all costs, damages, or losses arising from the Customer exceeding its Demand limit, including without limiting generality, direct or consequential costs, damages or losses arising from any penalty incurred by the Company for exceeding its Demand limit with its suppliers of Electricity.

7.4 Power Factor

Customers shall regulate their loads to maintain a Power Factor of not less than 90 percent lagging or as otherwise provided for in the applicable rate schedule. If the Power Factor of the Customer's load is less than the minimum required, the Customer's bill may be increased by an adjustment for low Power Factor. The Company may also require the Customer, at its expense, to install Power Factor corrective equipment to maintain the minimum required Power Factor.

The Company may refuse Service for neon, mercury vapour, fluorescent or other types of outdoor lighting or display device which has a Power Factor of less than 90 percent or other detrimental characteristics.

No credit will be given for leading Power Factor.

7.5 Load Fluctuations

The Customer shall operate its motors, apparatus and other electrical equipment in a manner that will not cause sudden fluctuation to the Company's line voltage, or introduce any element into the Company's system which in the Company's opinion disturbs or threatens to disturb its electrical system or the property or Service of any other Customer. Under no circumstances shall the imbalance in current between any two phases be greater than five percent. The Customer shall indemnify the Company against any liability, loss, cost and expense occasioned by the Customer's failure to operate its electrical equipment in compliance with this section.

8. CONTINUITY OF SERVICE

8.1 Interruptions and Defects in Service

The Company will endeavour to provide a regular and uninterrupted supply of Electricity but it does not guarantee a constant supply of Electricity or the maintenance of unvaried frequency or voltage and shall not be responsible or liable for any loss, injury, damage or expense caused by or resulting from any interruption, Suspension, Termination, failure or defect in the supply of Electricity, whether caused by the negligence of the Company, its servants or agents, or otherwise unless the loss, injury, damage or expense is directly resulting from the willful misconduct of the Company, its servants or agents provided, however, that the Company, its servants and agents are not responsible for any loss of profit, loss of revenues or other economic loss even if the loss is directly resulting from the willful misconduct of the Company, its servants or agents.

All responsibility of the Company for Electricity delivered to the Customer shall cease at the Point of Delivery, and the Customer shall indemnify the Company and save it harmless from all liability, loss and expense caused by or arising out of the taking of Electricity by the Customer.

The expense of any interruption of Service to others, loss of or damage to the property of the Company through misuse or negligence of the Customer, or the cost of necessary repairs or replacement shall be paid to the Company by the Customer.

8.2 Suspension of Service

The Company and the Customer may demand the Suspension of Service whenever necessary to safeguard life or property, or for the purpose of making repairs on or improvements to any of its apparatus, equipment or work. Such reasonable notice of the Suspension as the circumstances permit shall be given.

The Company may suspend Service to the Customer for the failure by the Customer to take remedial action acceptable to the Company, within 15 days of receiving notice from the Company, to correct the breach of any provision of these Terms and Conditions to be observed or performed by the Customer. The Company shall be under no obligation to resume Service until the Customer gives assurances satisfactory to the Company that the breach which resulted in the Suspension shall not recur.

The Company shall have the right to suspend Service to make repairs or improvements to its electrical system and will, whenever practicable, give reasonable notice to the Customer.

The Company shall have the right to suspend or terminate Service at any time without notice whenever the Customer has breached any agreement with the Company, or failed to pay arrears within

8. CONTINUITY OF SERVICE (Cont'd)

8.2 Suspension of Service (Cont'd)

the specified time, fraudulently used the Service, tampered with the Company's equipment, committed similar actions, compromised the Company's Service to other Customers or if ordered by an authorized authority to suspend or terminate such Service. The cause of any Suspension must be corrected, and all applicable charges paid before Service will be resumed. Suspension of Service by the Company shall not operate as a cancellation of any contract with the Company, and shall not relieve any Customer of its obligations under these Terms and Conditions or the applicable rate schedule.

8.3 Termination by Customer

Whenever a Customer wishes to terminate Service from the Company, it shall give the Company timely notice so that arrangements can be made for final meter reading and billing. Until notice of Termination is given, the Customer shall continue to be responsible for all Service supplied unless the Company receives an application for Service from a new Customer for the Premises concerned.

Notice of Termination requirements for contract Customers shall be in accordance with the terms of the contract. If a contract Customer terminates its contract but fails to give the required notice of Termination, the minimum charges for the notice period, as well as any amounts due for Service supplied, shall immediately become due and payable.

9. RIGHTS-OF-WAY AND ACCESS TO FACILITIES

9.1 Rights-of-Way

By applying for electric Service, the Customer agrees to grant to the Company such rights-of-way, easements and any applicable permits on, over and under the property of the Customer as may be necessary for the construction, installation, maintenance or removal of facilities.

On request, the Customer at their own expense shall deliver to the Company documents satisfactory to the Company in registrable form granting the rights-of-way, easements and executed permits. The Customer shall at their own expense be responsible for obtaining rights-of-way, easements and any applicable permits on other properties necessary for the Company to provide Service to the Customer.

9. RIGHTS-OF-WAY AND ACCESS TO FACILITIES (Cont'd)

9.1 Rights-of-Way (Cont'd)

Notwithstanding payment by the Customer towards the cost of electrical facilities installed by the Company or that electrical facilities may be affixed to the Customer's property, all electrical facilities installed by the Company up to the Point of Delivery shall remain the property of the Company, and the Company shall have the right to safe and ready access to upgrade, renew, replace or remove any facilities on the Customer's property at any time.

9.2 Access

The Company, through its authorized employees and agents, shall have safe and ready access to its electrical facilities at all reasonable times for the purpose of reading meters and testing, installing, removing, repairing or replacing any equipment which is the property of the Company. If access is restricted, the Company shall be supplied with keys to such locks if requested or, at the Company's option, a key holder box, where such locations are unattended during reasonable times.
In no case will the Company accept keys to private residential properties.

If safe and ready access to the Company's electrical facilities is denied or obstructed in any manner, including the presence of animals, and the Customer takes no action to remedy the problem upon being so advised, Service shall be suspended and not reconnected until the problem is corrected.

In cases where the Customer does not provide the Company with safe and ready access to the meter, the Company, may install a remote meter. The Customer will be responsible for the cost (as specified in the Standard Charges) of the remote meter and its installation.

9.3 Exception

Notwithstanding the provisions of Section 9.1 and 9.2, approval of the B.C. Utilities Commission will be required prior to any removal of plant constructed to serve industrial Customers supplied at 60 kV and above

10. CUSTOMER-OWNED GENERATION

10.1 Parallel Generation Facilities

The Customer may, at its expense, install, connect and operate its own electrical generating facilities to its electrical circuit in parallel with the Company's electrical system provided that the manner of installation and operation of the facilities is satisfactory to the Company, and the facilities have the capacity to be immediately isolated from the Company's system in the event of disruption of Service from the Company.

Prior to the commencement of installation of any generating facilities, the Customer shall provide to the Company full particulars of the facilities, and the proposed installation, and shall permit the Company to inspect the installation. The Customer at its own expense shall provide approved synchronizing equipment before connecting parallel generating facilities to the Company electrical system.

The Customer's generating facilities shall not be operated in parallel with the Company's electrical system until written approval has been received from the Company. The Customer shall not modify its parallel facilities or the installation in any manner without first obtaining the written approval of the Company.

If at any time the Company's electrical system is adversely affected due to difficulties caused by the Customer's generating facilities, upon oral or written notice being given by the Company to a responsible employee of the Customer, the Customer shall immediately discontinue parallel operation, and the Company may suspend Service until such time as the difficulties have been remedied to the satisfaction of the Company.

The Customer shall be responsible for the proper installation, operation and maintenance of all protective and control equipment necessary to isolate the Customer's generating facilities from the Company's electrical system upon the occurrence of a fault on the Customer's generating facilities or the Company's electrical system. The Customer's protective equipment shall not be modified in any manner and the settings thereto shall not be changed without first obtaining written approval of the Company.

The Customer shall notify the Company in advance each and every time that the Customer's generating facilities are to be connected to or intentionally disconnected from the Company's electrical system.

10. CUSTOMER-OWNED GENERATION (Cont'd)

10.1 Parallel Generation Facilities (Cont'd)

During parallel operation of its generating facilities, the Customer shall cooperate with the Company so as to maintain the voltage and the Power Factor of Electricity at the Point of Delivery within limits agreeable to the Company, and shall take and use Electricity in a manner that does not adversely affect the Company's electrical system.

Notwithstanding any approval given by the Company, parallel operation of the Customer's generating facilities with the Company's electrical system shall be entirely at the risk of the Customer, and the Customer shall indemnify the Company and save it harmless from all injury, damage and loss and all actions, suits, claims, demands and expenses caused by or in any manner arising out of the operation of the Customer's generating facilities.

10.2 Standby Generation

The Customer may, at its expense, install standby generation facilities to provide electrical Service in the event of a disruption of Service from the Company. Standby generation facilities shall be installed so that they remain at all times electrically isolated from the Company's electrical system either directly or indirectly, and shall be installed in such a way that it is not possible for the facilities to operate in parallel with the Company's electrical system.

The Customer's standby electrical generating facilities shall not be operated without the prior inspection and written approval of the Company, and the facilities shall not be modified thereafter without the written approval of the Company.

10.3 Electrical Inspection Authority

The Customer must obtain the approval of the appropriate electrical inspection authority before installation.

11. GENERAL PROVISIONS

11.1 Notices

Any notice, direction or other instrument shall be deemed to have been received on the following dates:

(a) if sent by electronic transmission, on the business day next following the date of transmission;

(b) if delivered, on the business day next following the date of delivery;

(c) if sent by registered mail, on the fifth business day following its mailing, provided that if there is at the time of mailing or within two days thereafter a mail strike, slowdown, lockout or other labour dispute which might affect delivery, then any notice, direction or other instrument shall only be deemed to be effective if delivered or sent by electronic transmission.

11.2 Conflicts

In case of conflict between these Terms and Conditions and the rate schedules, the provisions of the rate schedules shall prevail. Where there is a conflict between a contract and these Terms and Conditions, the provisions of the contract shall apply.

11.3 Payment of Interest

When interest is to be applied to certain Customer payments as provided in these Terms and Conditions, it shall be calculated as follows:

The Company will pay simple interest at the average prime rate of the principle bank with which the Company conducts its business, commencing with the date the subject funds were received by the Company.

The interest will be remitted to the Customers at the time the deposit or other payments are refunded, or in the case when a deposit or other refundable payment is to be held beyond one year, the interest will be calculated once every 12 months and shall be applied to the Customer's account.

11. GENERAL PROVISIONS (Cont'd)

11.4 Force Majeure

If any Large Commercial Service rate schedule Customer is prevented from taking Electricity, except for emergency purposes, for a period in excess of five calendar days by damage to its works from fire, explosion, the elements, sabotage, act of God or the Queen's enemies, or from insurrection, strike, or difficulties with workmen and invokes force majeure, the Company shall not be bound to make Electricity available during the period of the interruption except for emergency purposes, and commencing on the sixth calendar day of the interruption but for not more than 25 calendar days, the Customer shall, in lieu of the Demand Charge stipulated in the applicable Large Commercial Service rate schedule, pay a reduced Demand Charge for the period of the interruption, commencing on the sixth calendar day of the interruption to a maximum of 25 calendar days, derived from the Demand Charge rate multiplied by the maximum Demand recorded during that period of the interruption. The Customer shall not be entitled to any adjustment in the monthly Demand Charge under this clause unless the Customer informs the Company in writing it is invoking this clause, and the Company will read the meters used for billing purposes at the end of the fifth day of interruption and at the end of the period of interruption. The Customer shall be prompt and diligent in removing the cause of the interruption (by restoring its works or such other action as may be necessary and as soon as the cause of the interruption is removed or ceases to exist the Company shall without delay make Electricity available and the Customer shall take and pay for the same in accordance with this Tariff.

The force majeure provisions of this Clause 11.4 shall not apply in any month in which the Company purchases Electricity from British Columbia Hydro and Power Authority, unless the Company and British Columbia Hydro and Power Authority agree to a force majeure provision, in which case the Customer shall be given relief from the Demand Charge in accordance with that agreement.

11.5 Equal Payment Plan

Upon application, the Company may permit qualifying residential Customers to pay their accounts in equal monthly payments. The payments will be calculated to yield, over a twelve month period, the total estimated amount that would be payable by the Customer calculated by applying the applicable Residential Service rate to the Customer's estimated consumption during the same twelve month period. Customers may make application at any time of the year. All accounts will be reconciled annually or the earlier Termination date, at which time the amounts payable by the Customer to the Company for Electricity actually consumed during the equal payment period will be compared to the sum of equal payments made during the period. Any resulting amount owing by the Customer will be paid to the Company.

11. GENERAL PROVISIONS (Cont'd)

11.5 Equal Payment Plan (Cont'd)

A residential Customer may qualify for the plan provided their account is not in arrears, they have established credit to the satisfaction of the Company and the Customer expects to be on the plan for at least one year.

The Company may at any time revise the equal monthly installments to reflect changes in estimated consumption or the applicable rate schedule.

The equal payment plan may be terminated by the Customer upon reasonable notice, or the Company if the Customer has not maintained their credit to the satisfaction of the Company. The Company reserves the right to cancel or modify the Equal Payment Plan Service at any time.

11.6 Back-billing

(a) Back-billing means the rebilling for Services rendered to a Customer because the original billings are discovered to be either too high (over-billed) or too low (under-billed). The discovery may be made by either the Customer or the Company, and may result from the conduct of an inspection under provisions of the federal statute, the Electricity and Gas Inspection Act ("EGI Act"). The cause of the billing error may include any of the following non-exhaustive reasons or combination thereof:

(i) Stopped meter.
(ii) Metering equipment failure.
(iii) Missing meter now found.
(iv) Switched meters.
(v) Double metering.
(vi) Incorrect meter connections.
(vii) Incorrect use of any prescribed apparatus respecting the registration of a meter.
(viii) Incorrect meter multiplier.
(ix) The application of an incorrect rate.
(x) Incorrect reading of meters or data processing.
(xi) Tampering, fraud, theft or any other criminal act.

(b) Whenever the dispute procedure of the EGI Act is invoked, the provisions of that Act apply, except those which purport to determine the nature and extent of legal liability flowing from metering or billing errors.

Issued ______________________ Accepted for filing ______________________
FORTISBC INC. BRITISH COLUMBIA UTILITIES COMMISSION

By: ______________________ By: ______________________
Commission Secretary

EFFECTIVE (applicable to consumption on and after) ______________________

11. GENERAL PROVISIONS (Cont'd)

11.6 Back-Billing (Cont'd)

(c) Where metering or billing errors occur and the dispute procedure under the EGI Act is not invoked, the consumption and Demand will be based upon the records of the Company for the Customer, or the Customer's own records to the extent they are available and accurate, or if not available, reasonable and fair estimates may be made by the Company. Such estimates will be on a consistent basis within each Customer class or according to a contract with the Customer, if applicable.

(d) If there are reasonable grounds to believe that the Customer has tampered with or otherwise used the Company's Service in an unauthorized way, or evidence of fraud, theft or other criminal act exists, then the extent of back-billing will be for the duration of unauthorized use, subject to the applicable limitation period provided by law and the provisions of items 11.6(g), 11.6(h), 11.6(i) and 11.6(j) below do not apply.

In addition, the Customer is liable for the administrative costs incurred by the Company in the investigation of any incident of tampering, including the direct costs of repair, or replacement of equipment.

Under-billing resulting from circumstances described above will bear interest at the rate normally charged by the Company on unpaid accounts from the date of the original under-billed invoice until the amount underbilled is paid in full.

(e) In every case of under-billing or over-billing, the cause of the error will be remedied without delay, and the Customer will be promptly notified of the error and of the effect upon the Customer's ongoing bill.

(f) In every case of over-billing, the Company will refund to the Customer all money incorrectly collected for the duration of the error, subject to the applicable limitation period provided by law. Interest will be paid in accordance with Clause 11.3.

(g) Subject to item 11.6(d) above, in every case of under-billing, the Company will back-bill the Customer for the shorter of:

(i) the duration of the error; or

11. GENERAL PROVISIONS (Cont'd)

11.6 Back-Billing (Cont'd)

(ii) six months for Residential, Commercial Service, Lighting and Irrigation; and
(iii) one year for all other Customers or as set out in a special or individually negotiated contract with the Company.

(h) Subject to item 11.6(d) above, in all cases of under-billing, the Company will offer the Customer reasonable terms of repayment. If requested by the Customer, the repayment term will be equivalent in length to the back-billing period. The repayment will be interest free and in equal installments corresponding to the normal billing cycle. However, delinquency in payment of such installments will be subject to the usual late payment charges.

(i) Subject to item 11.6(d) above, if a Customer disputes a portion of a back-billing due to under-billing based upon either consumption, Demand or duration of the error, the Company will not threaten or cause the discontinuance of Service for the Customer's failure to pay that portion of the back-billing, unless there are no reasonable grounds for the Customer to dispute that portion of the back-billing. The undisputed portion of the bill shall be paid by the Customer and the Company may threaten or cause the discontinuance of Service if such undisputed portion of the bill is not paid.

(j) Subject to item 11.6(d) above, back-billing in all instances where changes of occupancy have occurred, the Company will make a reasonable attempt to locate the former Customer. If, after a period of one year, such Customer cannot be located, the over or under billing applicable to them will be canceled.

12. REPAYMENT OF ENERGY MANAGEMENT INCENTIVES

For those Customers supplied under Large Commercial Service or Wholesale rate schedules or Customers with a Contract Demand of 300 kVA or more, the unamortized balance of financial incentives paid to the Customer under Rate Schedule 90 shall be remitted to the Company within 30 days of billing, if:

(a) the operations at the Customer site are reduced by more than 50% for a continuous period of three months or longer; or

12. REPAYMENT OF ENERGY MANAGEMENT INCENTIVES (Cont'd)

(b) over 50% of the Electricity previously provided by the Company is replaced by another source including self-generation or another supplier.

In both cases the repayment shall be prorated based on the amount of energy replaced compared to the amount of energy supplied by the Company in the year immediately preceding the Electricity replacement.

SCHEDULE 1 - RESIDENTIAL SERVICE

APPLICABLE:

To residential use including Service to incidental motors of 5 HP or less.

BIMONTHLY RATE:	For a two month period
	All kW.h @ 7.627¢ per kW.h
	plus:
BASIC CHARGE:	$ 24.26 per two month period
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.

SCHEDULE 2 A - RESIDENTIAL SERVICE - TIME OF USE

APPLICABLE: To residential use including Service to incidental motors of 5 HP or less. This rate is applicable to Customers with satisfactory, as determined by the Company, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive months after commencement of Service.

RATES BY PRICING PERIOD:

		¢/kW.h
Summer (July, August)	On-Peak Hours: 9:00 am - 11:00 am Monday-Friday 3:00 pm - 11:00 pm Monday-Friday	12.796
	Off-Peak Hours: 11:00 pm - 9:00 am Monday-Friday 11:00 am - 3:00pm Monday-Friday All hours on Saturday and Sunday	4.145
All other months	On-Peak Hours: 8:00 am - 1:00 pm Monday-Friday 5:00 pm - 10:00 pm Monday-Friday	12.796
	Off-Peak Hours: 10:00 pm to 8:00 am Monday-Friday 1:00 pm - 5:00 pm Monday-Friday All hours on Saturday and Sunday	4.145

plus:

BASIC CHARGE: $24.26 per two month period

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

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SCHEDULE 20 - SMALL COMMERCIAL SERVICE

APPLICABLE: To non-residential Customers whose electrical Demand is generally not more than 40 kW and can be supplied through one meter. Where there is more than one Service to the same location and they are of the same voltage and phase classification and they were connected prior to January 5, 1977, the electrical energy and Demands registered for such Services will be combined and billed at this rate.

BIMONTHLY RATE: For a two month period

All kW.h @ 8.571¢ per kW.h

plus:

BASIC CHARGE: $29.24 per two month period

DELIVERY AND METERING VOLTAGE DISCOUNTS: The above rate applies to power Service when taken at the Company's standard Secondary Voltage. A discount of 1 1/2% shall be applied to the above rate if the electric Service is metered at a 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.

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SCHEDULE 21 - COMMERCIAL SERVICE

APPLICABLE: To non-residential Customers whose electrical Demand is generally greater than 40 kW but less than 500 kW and can be supplied through one meter. Where there is more than one Service to the same location and they are of the same voltage and phase classification and they were connected prior to January 5, 1977, the electrical energy and Demands registered for such Services will be combined and billed at this rate.

MONTHLY
RATE: A Demand Charge of:

$7.70 per kW of "Billing Demand" above 40 kW

plus:

An Energy Charge of:

First	8000 kW.h	8.571¢ per kW.h
Balance		6.333¢ per kW.h

plus:

BASIC
CHARGE: $14.61 per month

"Billing Demand"

The greatest of:

(a) Twenty five per cent (25%) of the Contract Demand, or
(b) The maximum Demand in kW for the current billing month, or
(c) Seventy-five per cent (75%) of the maximum Demand in kW registered during the months previous eleven month period.

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SCHEDULE 21 - COMMERCIAL SERVICE (Cont'd)

DELIVERY AND METERING VOLTAGE DISCOUNTS: The above rate applies to power Service when taken at the Company's standard Secondary Voltage.

(a) A discount of 1 1/2% shall be applied to the above rate if the electric Service is metered at a primary distribution voltage.

(b) A discount of 45.0¢ per kW of Billing Demand shall 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 the Company's option, the Demand is measured in kVA instead of kW then;

40 kW shall become 45 kVA
45.0¢ per kW shall become 40.5¢ per kVA
$7.70 per kW shall become $6.93 per kVA
where used in this schedule.

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

"A" - Demand measured in kW, Company owned transformation from primary to secondary distribution voltage, metering at secondary distribution voltage
"B" - Demand measured in kVA, Company 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.

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

APPLICABLE: To non-residential 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 the Company, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive months after commencement of Service.

RATES BY PRICING PERIOD:

		¢/kW.h
Summer (July, August)	On-Peak Hours: 9:00 am - 11:00 am Monday-Friday 3:00 pm - 11:00 pm Monday-Friday	13.406
	Off-Peak Hours: 11:00 pm - 9:00 am Monday-Friday 11:00 am - 3:00pm Monday-Friday All hours on Saturday and Sunday	4.344
All other months	On-Peak Hours: 8:00 am - 1:00 pm Monday-Friday 5:00 pm - 10:00 pm Monday-Friday	13.406
	Off-Peak Hours: 10:00 pm to 8:00 am Monday-Friday 1:00 pm - 5:00 pm Monday-Friday All hours on Saturday and Sunday	4.344

plus:

BASIC CHARGE: $14.61 per month

BILLING: The Company may, at its option, bill this rate bimonthly in which case the Basic Charge shall 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.

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SCHEDULE 23 A - COMMERCIAL SERVICE - PRIMARY - TIME OF USE

APPLICABLE: To non-residential Customers whose electrical Demand is less than 500 kW and is supplied at a primary distribution voltage through one meter. This rate is applicable to Customers with satisfactory, as determined by the Company, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive months after commencement of Service.

RATES BY PRICING PERIOD:

		¢/kW.h
Summer (July, August)	On-Peak Hours: 9:00 am - 11:00 am Monday-Friday 3:00 pm - 11:00 pm Monday-Friday	12.406
	Off-Peak Hours: 11:00 pm - 9:00 am Monday-Friday 11:00 am - 3:00pm Monday-Friday All hours on Saturday and Sunday	3.344
All other months	On-Peak Hours: 8:00 am - 1:00 pm Monday-Friday 5:00 pm - 10:00 pm Monday-Friday	12.406
	Off-Peak Hours: 10:00 pm to 8:00 am Monday-Friday 1:00 pm - 5:00 pm Monday-Friday All hours on Saturday and Sunday	3.344

plus:

BASIC CHARGE: $14.61 per month

BILLING: The Company may, at its option, bill this rate bimonthly in which case the Basic Charge shall 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.

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SCHEDULE 30 - LARGE COMMERCIAL SERVICE - PRIMARY

APPLICABLE: To power Service to Customers for a Contract Demand of 500 kVA or more, subject to written agreement.

MONTHLY RATE: A Basic Charge of $748.73

plus: A Demand Charge of $7.25 per kVA of Billing Demand

plus: An Energy Charge of 4.383¢ per kW.h

"Billing Demand"

The greatest of:

(a) twenty-five percent (25%) of the Contract Demand, or

(b) the maximum Demand in kVA for the current billing month, or

(c) seventy-five percent (75%) of the maximum Demand in kVA registered during the previous eleven month period.

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SCHEDULE 30 - LARGE COMMERCIAL SERVICE - PRIMARY (Cont'd)

DELIVERY AND METERING VOLTAGE DISCOUNTS: The above rate applies to power Service when taken at the Company's standard primary distribution voltage available in the area.

(a) A discount of 1 1/2% shall be applied to the above rate if the electric Service is metered at a transmission line voltage.

(b) A discount of $2.15 per kVA of Billing Demand shall be applied to the above rate if the Customer supplies the transformation from the transmission line voltage to the primary distribution voltage.

(c) If a Customer is entitled to both of the above discounts, the discount applicable to the metering at a transmission line voltage is to be applied first.

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.

SCHEDULE 31 - LARGE COMMERCIAL SERVICE - TRANSMISSION

AVAILABLE: In all areas served by the Company for supply at 60 hertz, three phase with a nominal potential of 60,000 volts or higher as available.

APPLICABLE: Applicable to industrial Customers with loads of 5,000 kVA or more, subject to written agreement.

MONTHLY RATE: A Basic Charge of $2,246.22

plus: A Demand Charge composed of:

(a) Wires Charge

$3.50 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
ii. The maximum Demand in kVA for the current billing month.
iii. 100% of the maximum Demand in kVA recorded during the previous eleven month period.

(b) Power Supply Charge

$2.00 per kVA determined by:

the monthly maximum Demand in kVA for the current billing month, as measured by the metering at the Point of Delivery.

plus: An Energy Charge of 3.938¢ per kW.h

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.

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SCHEDULE 32 - LARGE COMMERCIAL SERVICE - PRIMARY - TIME OF USE

APPLICABLE: To power Service to Customers for a Contract Demand of 500 kVA or more, taking Service at a standard primary distribution voltage, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by the Company, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive months after commencement of Service.

RATES BY PRICING PERIOD:

		¢/kW.h
Winter (Nov. - Feb.)	On-Peak Hours: 7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	17.966
	Off-Peak Hours: 10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays	3.663
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	17.247
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	2.850
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	4.138
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	2.180

plus:

BASIC CHARGE: $1,769.27 per month

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.

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SCHEDULE 33 - LARGE COMMERCIAL SERVICE - TRANSMISSION - TIME OF USE

APPLICABLE: In all areas served by the Company for supply at 60 hertz, three phase with a nominal potential of 60,000 volts or higher as available. Applicable to industrial Customers with loads of 5,000 kVA or more, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by the Company, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive months after commencement of Service.

RATES BY PRICING PERIOD:

		¢/kW.h
Winter (Nov. - Feb.)	On-Peak Hours: 7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	12.667
	Off-Peak Hours: 10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays	3.589
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	16.897
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	2.792
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	4.054
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	2.135

plus:

BASIC CHARGE: $2,065.18 per month

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SCHEDULE 33 - LARGE COMMERCIAL SERVICE - TRANSMISSION - TIME OF USE (Cont'd)

plus: A Demand Charge composed of:

Wires Charge

$0.00 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
i. The maximum Demand in kVA for the current billing month.
ii. 100% of the maximum Demand in kVA recorded during the previous eleven month period.

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

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SCHEDULE 40 A - WHOLESALE SERVICE - PRIMARY - GRAND FORKS

AVAILABLE: In Grand Forks

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

MONTHLY RATE: A Basic Charge of $1,729.08 per Point of Delivery

plus: A Demand Charge composed of:

(a) Wires Charge

$4.76 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
ii. The sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery as measured for the current billing month.
iii. 100% of the sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery during the previous eleven month period.

(b) Power Supply Charge

$2.85 per kVA determined by:

the monthly maximum Demand in kVA, as measured by the totalized metering at the Points of Delivery.

plus: An Energy Charge of 1.728¢ per kW.h

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.

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SCHEDULE 40 A - WHOLESALE SERVICE - PRIMARY - TIME OF USE - GRAND FORKS

AVAILABLE: In Grand Forks

APPLICABLE: To power Service to Grand Forks at a Primary Voltage for resale, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by the Company, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive months after commencement of Service.

RATES BY PRICING PERIOD:

		¢/kW.h
Winter (Nov. - Feb.)	On-Peak Hours: 7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	11.338
	Off-Peak Hours: 10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays	2.312
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	10.885
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	1.799
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	2.611
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	1.375

plus:

BASIC CHARGE: $1,729.08 per month per Point of Delivery

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SCHEDULE 40 A - WHOLESALE SERVICE - PRIMARY - TIME OF USE - GRAND FORKS
(Cont'd)

plus: A Demand Charge composed of:

Wires Charge

$4.76 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
ii. The sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery as measured for the current billing month.
iii. 100% of the sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery during the previous eleven month period.

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.

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SCHEDULE 40 B - WHOLESALE SERVICE - PRIMARY - SUMMERLAND

AVAILABLE: In Summerland.

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

MONTHLY RATE: A Basic Charge of $1,729.08 per Point of Delivery

plus: A Demand Charge composed of:

(a) Wires Charge

$6.74 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
ii. The sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery as measured for the current billing month.
iii. 100% of the sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery during the previous eleven month period.

(b) Power Supply Charge

$3.60 per kVA determined by:

the monthly maximum aggregate Demand in kVA, as measured by the totalized metering at the Points of Delivery.

plus: An Energy Charge of 2.465¢ per kW.h

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.

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SCHEDULE 40 B - TOU - WHOLESALE SERVICE - PRIMARY - TIME OF USE - SUMMERLAND

AVAILABLE: In Summerland.

APPLICABLE: To power Service to Summerland at a Primary Voltage for resale, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by the Company, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive months after commencement of Service.

RATES BY PRICING PERIOD:

		¢/kW.h
Winter (Nov. - Feb.)	On-Peak Hours: 7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	9.741
	Off-Peak Hours: 10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays	1.986
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	9.352
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	1.546
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	2.244
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	1.181

plus:

BASIC CHARGE: $1,729.08 per month per Point of Delivery

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SCHEDULE 40 B - TOU - WHOLESALE SERVICE - PRIMARY - TIME OF USE - SUMMERLAND
(Cont'd)

plus: A Demand Charge composed of:

Wires Charge

$6.74 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
ii. The sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery as measured for the current billing month.
iii. 100% of the sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery during the previous eleven month period.

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.

SCHEDULE 40 C - WHOLESALE SERVICE - PRIMARY - PENTICTON

AVAILABLE: In Penticton.

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

MONTHLY RATE: A Basic Charge of $1,729.08 per Point of Delivery

plus: A Demand Charge composed of:

(a) Wires Charge

$5.52 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
ii. The sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery as measured for the current billing month.
iii. 100% of the sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery during the previous eleven month period.

(b) Power Supply Charge

$3.17 per kVA determined by:

the monthly maximum aggregate Demand in kVA, as measured by the totalized metering at the Points of Delivery.

plus: An Energy Charge of 1.990¢ per kW.h

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.

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SCHEDULE 40 C - TOU - WHOLESALE SERVICE - PRIMARY - TIME OF USE - PENTICTON

AVAILABLE: In Penticton.

APPLICABLE: To power Service to Penticton at a Primary Voltage for resale, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by the Company, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive months after commencement of Service.

RATES BY PRICING PERIOD:

		¢/kW.h
Winter (Nov. - Feb.)	On-Peak Hours: 7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	6.932
	Off-Peak Hours: 10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays	1.141
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	6.655
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	1.100
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	1.597
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	0.841

plus:

BASIC CHARGE: $1,729.08 per month per Point of Delivery

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SCHEDULE 40 C - TOU - WHOLESALE SERVICE - PRIMARY - TIME OF USE - PENTICTON
(Cont'd)

plus: A Demand Charge composed of:

Wires Charge

$5.52 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
ii. The sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery as measured for the current billing month.
iii. 100% of the sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery during the previous eleven month period.

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.

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SCHEDULE 40 D - WHOLESALE SERVICE - PRIMARY - KELOWNA

AVAILABLE: In Kelowna

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

MONTHLY RATE: A Basic Charge of $1,729.08 per Point of Delivery

plus: A Demand Charge composed of:

(a) Wires Charge

$6.70 per kVA determined by:

The greatest of:
i. 100% of the contract Demand Limit, or
ii. The sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery as measured for the current billing month.
iii. 100% of the sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery during the previous eleven month period.

(b) Power Supply Charge

$3.54 per kVA determined by:

the monthly maximum aggregate Demand in kVA, as measured by the totalized metering at the Points of Delivery.

plus: An Energy Charge of 2.290¢ per kW.h

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.

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SCHEDULE 40 D - TOU - WHOLESALE SERVICE - PRIMARY - TIME OF USE - KELOWNA

AVAILABLE: In Kelowna.

APPLICABLE: To power Service to Kelowna at a Primary Voltage for resale, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by the Company, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive months after commencement of Service.

RATES BY PRICING PERIOD:

		¢/kW.h
Winter (Nov. - Feb.)	On-Peak Hours: 7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	8.449
	Off-Peak Hours: 10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays	1.723
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	8.112
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	1.341
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	1.946
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	1.024

plus:

BASIC CHARGE: $1,729.08 per month per Point of Delivery

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SCHEDULE 40 D - TOU - WHOLESALE SERVICE - PRIMARY - TIME OF USE - Kelowna
(Cont'd)

plus: A Demand Charge composed of:

Wires Charge

$6.70 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
ii. The sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery as measured for the current billing month.
iii. 100% of the sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery during the previous eleven month period.

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.

SCHEDULE 40 E - WHOLESALE SERVICE - PRIMARY -BC HYDRO YAHK

AVAILABLE: To BC Hydro Service at Yahk

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

MONTHLY RATE: A Basic Charge of $1,729.08 per Point of Delivery

plus: A Demand Charge composed of:

(a) Wires Charge

$8.76 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
ii. The sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery as measured for the current billing month.
iii. 100% of the sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery during the previous eleven month period.

(b) Power Supply Charge

$3.49 per kVA determined by:

the monthly maximum aggregate Demand in kVA, as measured by the totalized metering at the Points of Delivery.

plus: An Energy Charge of 2.555¢ per kW.h

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.

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SCHEDULE 40 E - TOU - WHOLESALE SERVICE - PRIMARY - TIME OF USE - BC HYDRO YAHK

AVAILABLE: To BC Hydro Service at Yahk.

APPLICABLE: To power Service to BC Hydro at Yahk at a Primary Voltage for resale, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by the Company, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive months after commencement of Service.

RATES BY PRICING PERIOD:

		¢/kW.h
Winter (Nov. - Feb.)	On-Peak Hours: 7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	11.529
	Off-Peak Hours: 10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays	2.351
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	11.068
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	1.830
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	2.656
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	1.398

plus:

BASIC CHARGE: $1,729.08 per month per Point of Delivery

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SCHEDULE 40 E - TOU - WHOLESALE SERVICE - PRIMARY - TIME OF USE - BC HYDRO YAHK (Cont'd)

plus: A Demand Charge composed of:

Wires Charge

$8.76 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
ii. The sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery as measured for the current billing month.
iii. 100% of the sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery during the previous eleven month period.

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.

SCHEDULE 40 F - WHOLESALE SERVICE - PRIMARY - BC HYDRO LARDEAU

AVAILABLE: To BC Hydro Service at Lardeau

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

MONTHLY RATE: A Basic Charge of $1,729.08 per Point of Delivery

plus: A Demand Charge composed of:

(a) Wires Charge

$6.82 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
ii. The sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery as measured for the current billing month.
iii. 100% of the sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery during the previous eleven month period.

(b) Power Supply Charge

$3.01 per kVA determined by:

the monthly maximum aggregate Demand in kVA, as measured by the totalized metering at the Points of Delivery.

plus: An Energy Charge of 2.707¢ per kW.h

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.

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SCHEDULE 40 F - TOU - WHOLESALE SERVICE - PRIMARY - TIME OF USE- BC HYDRO LARDEAU

AVAILABLE: To BC Hydro Service at Lardeau.

APPLICABLE: To power Service to BC Hydro at Lardeau at a Primary Voltage for resale, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by the Company, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive months after commencement of Service.

RATES BY PRICING PERIOD:

		¢/kW.h
Winter (Nov. - Feb.)	On-Peak Hours: 7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	10.833
	Off-Peak Hours: 10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays	2.209
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	10.400
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	1.719
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	2.495
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	1.313

plus:

BASIC CHARGE: $1,729.08 per month per Point of Delivery

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SCHEDULE 40 F - TOU - WHOLESALE SERVICE - PRIMARY - TIME OF USE - BC HYDRO LARDEAU (Cont'd)

plus: A Demand Charge composed of:

Wires Charge

$6.82 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
ii. The sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery as measured for the current billing month.
iii. 100% of the sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery during the previous eleven month period.

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.

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SCHEDULE 41 - WHOLESALE SERVICE - TRANSMISSION

APPLICABLE: To supplementary power Service to the City of Nelson, subject to written agreement.

AVAILABLE: At suitable City of Nelson interconnections with the Company's 66 kV system.

MONTHLY RATE: A Basic Charge of $1,729.08 per Point of Delivery

plus: A Demand Charge composed of:

(a) Wires Charge

$4.59 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
ii. The sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery as measured for the current billing month.
iii. 100% of the sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery during the previous eleven month period.

(b) Power Supply Charge

$3.28 per kVA determined by:

the monthly maximum aggregate Demand in kVA, as measured by the totalized metering at the Points of Delivery.

plus: An Energy Charge of 1.923¢ per kW.h

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SCHEDULE 41 - WHOLESALE SERVICE - TRANSMISSION (Cont'd)

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.

RATE FOR EMERGENCY PURPOSES: The additional Demand resulting from emergency or shutdown Service (Emergency Demand) will be excluded in determining the application of Item (c) in the calculation of the Billing Demand, provided the City of Nelson requests that the Demand meter be read by the Company immediately before and after the emergency or as soon as practical at the commencement of the emergency period. The amount of Emergency Demand will be determined from the meter readings and the best information available. The City of Nelson will compensate the Company for any higher Demand charges resulting from the Emergency Demand.

SCHEDULE 43 - WHOLESALE SERVICE - TRANSMISSION - TIME OF USE

APPLICABLE: To supplementary power Service to the City of Nelson, subject to written agreement. At suitable City of Nelson interconnections with the Company's 63kV system. This rate is applicable to Customers with satisfactory, as determined by the Company, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive months after commencement of Service.

RATES BY PRICING PERIOD:

		¢/kW.h
Winter (Nov. - Feb.)	On-Peak Hours: 7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	6.313
	Off-Peak Hours: 10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays	1.789
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	8.421
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	1.390
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	2.020
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	1.064

plus:

BASIC CHARGE: $1,729.08 per month per Point of Delivery

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SCHEDULE 43 - WHOLESALE SERVICE - TRANSMISSION - TIME OF USE (Cont'd)

plus: A Demand Charge composed of:

Wires Charge

$4.59 per kVA determined by:

The greatest of:

i. 100% of the contract Demand Limit, or
ii. The sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery as measured for the current billing month.
iii. 100% of the sum of maximum non-totalized Demand in kVA recorded at each Point of Delivery during the previous eleven month period.

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.

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SCHEDULE 50 - LIGHTING - ALL AREAS

APPLICABLE: To lighting applications where the Customer will contract for Service for a term of one year. The Company will supply Service for lighting from dusk to dawn daily.

All lighting equipment installed on and after the effective date of this Schedule will be Company approved and conform to all relevant Company design and installation standards and requirements, and be suitable to accept electrical Service at the Company's available Secondary Voltage. Other requirements may be supplied under special contract.

This Schedule is not available for equipment other than Company approved lighting fixtures.

TYPES OF SERVICE:

1. Customer-Owned and Customer-Maintained

Type I - For a Customer-owned street lighting fixture or lighting system where the Customer owns and maintains at its own expense the light standards if any, lighting fixtures and all auxiliary equipment.

Electricity at 120/240 volts single phase is supplied by the Company at a single Point of Delivery for each separate Customer system. Multiple light systems shall be provided Service at a single Point of Delivery wherever practical. The Customer shall supply transformers for other than 120/240 volt single phase supply.

Type I shall apply only if the Customer system can be operated and maintained, beyond the point of supply of Electricity, independently of the Company's system. The installed cost of devices necessary for independent operation shall be paid by the Customer. Where Customer owned lighting fixtures are on Company owned poles maintenance work shall only be performed by parties qualified to do the work, and authorised by the Company. Type One Service may be refused for safety reasons.

2. Customer-Owned and Company-Maintained

Type II - Customer-owned street lighting fixtures installed on existing Company poles at the Customer's expense with all maintenance to be performed by the Company at costs described below.

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SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

TYPES OF SERVICE:(Cont'd)

3. Company-Owned, Company-Installed and Maintained

Type III - For Company-owned street lighting fixtures on existing Company-owned poles where the Company performs all maintenance. Facilities provided by the Company, including fixtures, lamp, control relay, support bracket, and conductor and energy for operation thereof are owned by the Company.

TERMS AND CONDITIONS:

Installation

Type II lighting fixtures of design and specifications approved by the Company for installation on Company-owned poles will be installed by the Company at the Customer's expense. There will be no charge to the Customer for the use of existing Company-owned poles as standards for mounting of fixtures other than as provided for in this Section.

The Company will provide to the Customer on request, lighting fixtures and standards, where required, of Company approved design and specifications at its cost plus overheads and handling costs as described in the Cost Recovery section below. For Type III fixtures the Company will provide one span of duplex of not more than 30 metres.

Extension of Service

Extensions of Service will be provided under the terms of the Company's Extension Policy.

Relocation

At the Customer's request, the location of a light may be changed provided the Customer pays for the cost of removal and reinstallation, including cost of extension of Service if applicable, with costs recovered as described below.

Other Equipment

Equipment other than lighting fixtures is not permitted on Company-owned poles except with the Company's written consent.

SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

TERMS AND CONDITIONS:

Maintenance of Type III Lights

Maintenance of Type III lighting fixtures shall be performed by the Company, the cost of which is provided for in the "Monthly Rate" of this Schedule. Such work will be undertaken by the Company during regular working hours and the Company will be allowed ten working days subsequent to notification by the Customer for performance of such maintenance. Cleaning of the glassware will be carried out only when the lamp is replaced.

The Customer shall be responsible for any wilful damage to the Company's equipment.

Maintenance of Type II Lights

The Customer will pay maintenance and capital costs, including the cost of installation, maintenance of underground supply, and relocation, on an as spent basis. Customers will inform the Company in writing of the location of any lighting fixture requiring maintenance and the time in which the maintenance must be performed. The Company will bill the Customer for all costs incurred including the following overheads:

Cost Recovery

Labour Loading

On labour costs excluding overtime	72.5% of labour rate

Material Loading

Inventory - Material Handling	7% of cost

Loading rates may be adjusted from time to time as required to ensure appropriate recovery of costs.

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SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

MONTHLY RATE FOR EACH
TYPE OF SERVICE:

				Rate ($ per month)		
		Monthly	Nominal	Customer-Owned		Company-Owned
Type of Light	Watts	Use (kW.h)	Lumens	Type I	Type II	Type III
Fluorescent	* 383	140	21,800	16.92		
Mercury Vapour	* 125	55	5,000	6.77	6.77	15.00
	* 175	78	7,000	9.58	9.58	17.83
	* 250	107	10,000	13.14	13.14	21.39
	* 400	166	21,000	20.38	20.38	28.63
Sodium Vapour	70	33	6,000	4.09	4.09	12.29
	*100	47	9,000	5.76	5.76	14.01
	*150	70	14,000	8.58	8.58	16.84
	200	91	20,000	11.17	11.17	19.42
	250	111	23,000	13.65	13.65	21.87
	*400	173	45,000	21.26	21.26	29.51

* No longer available at new locations or as replacement fixtures where existing fixtures are being replaced except at the sole discretion of the Company.

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

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SCHEDULE 60 - IRRIGATION AND DRAINAGE

AVAILABLE: For an irrigation or drainage season commencing with the Customer's meter reading taken within 5 business days of April 1st each year and terminating with the Customer's meter reading taken within 5 business days of October 31st each year. During the non-irrigation season Customers will be automatically transferred to the applicable commercial Service rate and billings prorated for a partial first or final Service month when read dates are outside of the 5 day band.

APPLICABLE: To motors at one Point of Delivery, which are to be used primarily for irrigation and drainage purposes. This schedule applies to electric Service when taken at the Company's standard Secondary Voltage. Incidental lighting essential to the pumping operation will be allowed on this schedule provided that the Customer supplies and installs his own transformers and other necessary equipment as required. Service to motors of 5 HP or less will be single phase, unless the Company specifically agrees to supply three phase.

BILLING: Bills will be rendered monthly or bimonthly but may be estimated in periods of low consumption or when access is restricted.

MONTHLY RATE:

During the Irrigation Season

Basic Charge:	$14.62
All Energy:	5.065¢ per kW.h

During the Non-Irrigation Season

Customers will be transferred to the applicable Commercial Service rate.

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.

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SCHEDULE 61 - IRRIGATION AND DRAINAGE - TIME OF USE

APPLICABLE: For Customers normally supplied under Rate Schedule 60. Service to motors of 5 HP or less will be single phase, unless the Company specifically agrees to supply three phase. This rate is applicable to Customers with satisfactory, as determined by the Company, 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.

RATES BY PRICING PERIOD:

		¢/kW.h
Winter (Nov. - Feb.)	On-Peak Hours: 7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	13.423
	Off-Peak Hours: 10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays	3.365
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	12.917
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	2.791
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	3.696
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	2.319

plus:

BASIC CHARGE: $35.99 per month

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.

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SCHEDULE 73 - EXTENSIONS - ALL AREAS - CLOSED

APPLICABLE:

To Extensions constructed after the filing date of this Schedule, which are operated and maintained by the Company.

DEFINITIONS:

In this schedule,

1. "Extension Cost" means the cost of constructing an Extension including all labour, material, construction equipment costs, surveying, easements and clearing, but excluding the necessary transformers and metering equipment.

2. "Gazetted Roadway" means any road gazetted according to the provisions of the Highway Act and includes:
   (a) Section 4 Roads under the Highway Act which are maintained by public funds. If required by the Company, easements are provided by the Customer at no cost to the Company.

   (b) Extensions over private property which are constructed on easements as an alternative to building on gazetted roadways.

3. "Extension" means the total length of line rated 25 kV or less from a point on an existing distribution line to an applicant's service entrance.

4. "Monthly Extension Charge" is a charge under this Schedule calculated on a monthly basis which is additional to all other applicable charges or levies for electric service under the Company's tariff.

5. "Permanent Principal Residence" means a residence which is constructed in a permanent manner and is presently occupied or will be occupied in the near future by the owner or a tenant for the major portion of the year.

6. "Private Property" includes lands held by the Crown in the right of the Province of British Columbia and lands held in fee simple, but does not include Indian Reserve land where Extensions are constructed along main public roads within Reserve land and the purpose of the extension is to supply electric service to the residents on the Indian Reserve.

7. "Drop Service" includes that portion of an overhead service connection extending not more than 30 metres onto the Customer's property and not requiring any intermediate support on the Customer's property.

SCHEDULE 73 - EXTENSIONS - ALL AREAS - CLOSED (Cont'd)

GENERAL:

1. Notwithstanding payments by the Customer to the Company toward the cost of a portion or all of an Extension, ownership of the Extension shall remain with the Company.

2. Rate Schedules 71 and 72 will continue to apply to Extensions constructed prior to the filing date of this Schedule, and to additional Customers served from those Extensions where only a Drop Service is required and where the line facility charge as determined under Schedule 72 applies.

3. Applicants shall provide at no cost to the Company a cleared right of way and easement acceptable to the Company. This shall include tree trimming and tree removal rights and right of access to Company lines and equipment for supplying or terminating service.

4. Service will be provided by overhead Extensions unless an underground Extension is requested in which case the Customer shall pay the difference in cost between overhead and underground.

SPECIAL CONTRACTS:

Notwithstanding the other provisions of this Schedule, special contract arrangements may be required:

1. where additional investment is required in order to upgrade or reinforce existing facilities or install new facilities to provide service at a phase and voltage not presently available,

2. where an Extension is required to provide service to a Customer and the permanency of continuing use or an increase in the number of Customers served from such Extension is uncertain,

3. where Extensions are made for seasonal use or the supply of service to recreational areas,

4. where temporary or standby service is required,

5. for large General Service and Industrial Customers, where installation and upgrading of substation and transmission facilities may be required, or

6. where the ongoing operating cost of the line exceed those provided for in the Monthly Extension Charges.

SCHEDULE 73 - EXTENSIONS - ALL AREAS - CLOSED (Cont'd)

SPECIAL CONTRACTS (Cont'd)

The Special Contracts may require the applicant to pay for such Extensions and additions to facilities, to pay for any renewals or replacements of the extension which may be required, and to pay Monthly Extension Charges as required to reflect the ongoing costs of operating the line. In the case of temporary or standby service, the Customer may also be required to pay the cost of removal of the facilities.

REQUIREMENTS PRIOR TO CONSTRUCTION:

The Company will not commence construction of an Extension under this Schedule until:

1. the applicant has completed the required service contract and other required documentation;

2. the applicant has paid the required connection charge and revenue guarantee deposit described in this Schedule;

3. the applicant has agreed to be responsible for the cost of obtaining necessary easements, permits, survey costs, or licenses of occupation;

4. the applicant has paid the required cash contribution, if applicable, towards the Extension Cost or other facilities as calculated by the Company, and

5. where applicable, construction of the new home has advanced to the point where completion seems assured, or the applicant has provided adequate security for the amount of the Company contribution.

Extensions will be made as material and labour are available and the Company reserves the right to postpone the extension of lines and services where climatic conditions would cause abnormally high construction costs.

TERM AND BILLING:

1. Applicants will be required to contract for service for a five-year period where the Extension Cost exceeds $2,000.00, otherwise the contract shall be for one year.

2. Billings for service will commence on the date that service was requested to be supplied as set out in the contract for service or the date on which the Extension is energized, whichever occurs later.

SCHEDULE 73 - EXTENSIONS - ALL AREAS - CLOSED (Cont'd)

TERM AND BILLING (Cont'd)

3. When a Customer terminates service before the contract period has elapsed, he shall continue to be responsible for the levies as provided for in this and other applicable Schedules until expiry of the contract period or until permanent service at the same location is contracted for by another party, whichever occurs first.

4. For those Customers to which this Schedule applies who are billed monthly, the Monthly Extension Charges applicable shall be as set out in the Schedule of Charges. For those Customers to which this Schedule applies who are billed every two months, the Monthly Extension Charges applicable shall be double the amounts set out in the Schedule of Charges.

SHARING OF EXTENSION COST:

1. Calculation of Extension Cost:

The Company shall determine the Extension Cost based upon standard costs shown on the Schedule of Charges set out on Sheet 49 except that actual costs may be used when special circumstances exist such that the standard would be unusually high or low.

2. Extensions over Private Property:

The applicant shall provide a cleared space satisfactory to the Company for the Extension over Private Property. This space shall be cleared and maintained clear of obstructions at no cost to the Company.

The Company shall provide a Drop Service to the point of delivery. The cost of any additional facilities shall be borne by the applicant in accordance with the Schedule of Charges.

If within ten years others take service from such an Extension, then a refund may be made to the previous applicant in proportion to that part of the Extension used by other applicants.

If an Extension over Private Property serves several Customers, the Company may consider it as being along a Gazetted Roadway. An acceptable right of way easement shall be supplied at no cost to the Company and the terms for an Extension along a Gazetted Roadway will apply.

SCHEDULE 73 - EXTENSIONS - ALL AREAS - CLOSED (Cont'd)

SHARING OF EXTENSION COST (Cont'd)

3. Extensions Along Gazetted Roadways:

The cost of Extensions along Gazetted Roadways, required upgrading of existing facilities and installation of other facilities to provide service, will be paid for as follows:

(a) General Service and Industrial Customers
The Customer will contribute the full Extension Cost in excess of $2,000. The Company may contribute toward the cost of upgrading of existing facilities which would be required in the near future, or result in a betterment to the system.

Revenue Guarantee Deposit
General Service and Industrial Customers may be required to provide a revenue guarantee deposit equivalent to the Company's contribution to the Extension which amount may be refunded in equal installments in the next five year period provided the Customer's account is paid in full by the due date.

(b) Irrigation and Drainage Service
The Customer will contribute the full Extension Cost of providing service to permanent irrigation and drainage services.

(c) Subdivisions
The Company will extend service to a subdivision upon application for service and execution of a contract by the developer, subject to the terms and conditions contained in this Schedule.

The Developer will contribute the full Extension Cost of providing service to subdivisions.

(d) Residential Service
The Company will contribute a basic $2,000 for each Permanent Principal Residence. The balance of the Extension Cost will be shared equally by the Company and Customer except that the maximum Company contribution will be $3,000 in addition to the basic contribution.

No Customer contribution will be required on Extensions along Gazetted Roadway where the amount of the contribution is less than $200 per Customer.

SCHEDULE 73 - EXTENSIONS - ALL AREAS - CLOSED (Cont'd)

REFUND OF CUSTOMER CONTRIBUTIONS:

1. The Company shall have the right to connect subsequent Customers to all line extensions along Gazetted Roadway.

2. If an additional permanent Customer takes service from the Extension, he shall be required to share the Extension Cost, and refunds will be made to existing Customers in relation to the new contributions received, provided that no further contributions and refunds are required:

   (i) if the refund would be less than $200 per Customer, or
   (ii) if more than five years have passed since the Extension was completed and the refund would be less than $500 per Customer, or
   (iii) if more than ten years have passed since the Extension was completed.

3. Applicants for service involving an addition to an existing Extension will be considered as applicants for a new Extension except where the capital contribution per applicant for the new Extension is less than the capital contribution for the existing Extension, in which case the existing Extension and the new Extension will be considered as a joint Extension for determining the capital contribution, subject to 2 above.

MONTHLY EXTENSION CHARGE:

In addition to all other charges applicable under the Company's tariff, the Customer may be required to pay a Monthly Extension Charge based on the length of the Extension.

Applicants for service involving an addition to an existing Extension will be considered as applicants for a new Extension except where the Monthly Extension Charge per applicant for the new Extension is less than the Monthly Extension Charge for the existing Extension in which case the existing Extension and the new Extension will be considered as a joint Extension for determining the charge.

The Monthly Extension Charge applicable to each applicant contracting for service from an Extension shall be determined by dividing the total Monthly Extension Charge applicable to an Extension by the number of applicants contracting for service, subtracting $10.00, and increasing or decreasing the result to the nearest dollar. (see Schedule of Charges for monthly rate per metre)

A Monthly Extension Charge of less than $10.00 per applicant will not be billed.

SCHEDULE 73 - EXTENSIONS - ALL AREAS - CLOSED (Cont'd)

MONTHLY EXTENSION CHARGE: (Cont'd)

TERMS AND CONDITIONS: Service under this Schedule is subject to the Terms and Conditions contained in this tariff.

Schedule of Charges Applicable to Distribution Line Extensions

A. Standard Costs used to calculate Extension Cost

1.	Pole in place cost	30 foot	$ 830.00
		35 foot	$ 900.00
		40 foot	$1,045.00
		45 foot	$1,130.00
		50 foot	$1,175.00
2.	Primary conductor	Single Phase	$ 1.15 per meter
		Three Phase	$ 4.00 per meter
3.	Secondary conductor	Single Phase	$ 2.85 per metre
		Three Phase	$ 5.70 per metre
4.	Anchors		$ 175.00

Note: Standard Costs above are applicable to services up to 200 amps. For services in excess of 200 amps, actual cost of secondary conductor will be determined.

B. Summary of Customer Contributions to Extension Cost

(a) Private Property Portion
All costs other than the Drop Service.

SCHEDULE 73 - EXTENSIONS - ALL AREAS - CLOSED (Cont'd)

Schedule of Charges Applicable to Distribution Line Extensions (Cont'd)

(b) Gazetted Roadway Portion

i.	Residential	- No contribution on first $2,000 of Extension Cost - 50% of that portion of Extension Cost between $2,000 and $8,000, plus - 100% of that portion of Extension Cost in excess of $8,000
ii.	General Service	- Extension Cost in excess of $2,000
iii.	Irrigation	- full Extension Cost
iv.	Subdivision	- full Extension Cost

(c) Underground
The Customer will be required to pay the excess of the cost of underground compared to overhead services, in addition to other contributions which may be required by the above.

C. Monthly Extension Charge

(a)	single phase	6.4¢ per metre
(b)	three phase	8.0¢ per metre
(c)	underbuild	3.2¢ per metre

SCHEDULE 74 - EXTENSIONS

APPLICABLE:

To the construction of an addition to, or extension of, the Company's distribution system.

Rate Schedule 73 will continue to apply to all Extensions for which payment of the Customer Portion of Costs has been made prior to October 1, 1997.

CUSTOMER PORTION OF COSTS:

1. An Applicant will apply for Service pursuant to Section 2 of the Terms and Conditions.

2. The Company shall contribute towards an Extension as follows, multiplied by the number of Customers served to be served from the Extension:

Rate Schedule	**Maximum FortisBC Contribution**
RS 1, 2A,	$1,765
RS 20, 21	$158 per kW
RS 50 (Type I, Type II)	$19.43 per fixture
RS 60, 61	$1,390

The Applicant will pay the Customer Portion of Costs ("CPC"). The CPC is the estimated cost of construction of the Extension less the Company Contribution towards the Extension, and does not include any applicable connection charges as specified in Schedule 82. The CPC will be paid either in cash or, with the Company's agreement, wholly or partly in kind.

Where Customer actions cause construction to be delayed by a period of 6 months or greater after receipt of the CPC, the Company reserves the right to re-quote the CPC using current pricing, excluding any material(s) already purchased. Any additional costs must be paid by the Customer to the Company prior to the commencement of construction. Any resulting credit will be promptly refunded by the Company to the Customer.

REFUND OF CUSTOMER PORTION OF COSTS:

1. The Company shall have the right to connect additional Applicants to an Extension. Additional Customers that take Service from an Extension within five years of the connection of the Extension to the Company's distribution system shall pay a share of the Extension Cost (less the

SCHEDULE 74 - EXTENSIONS (Cont'd)

REFUND OF CUSTOMER PORTION OF COSTS: (Cont'd)

Company Contribution towards the Extension), without interest, in proportion to that part of the Extension that is used to provide Service and in proportion to the number of original Applicants taking Service from the Extension.

2. No share of the Extension Cost will be paid where:

   (i) the contribution would be less than $200.00 per Applicant, or

   (ii) more than five years have passed from the date the Extension was connected to the Company's distribution system to the date of the connection of the additional Applicant to the Extension.

3. A refund of the Extension Cost that has been received from an additional Applicant shall be made to existing Applicants.

FINANCING:

Company financing is available on approval of credit. The CPC will be financed based on the Company's weighted average cost of capital as approved by the British Columbia Utilities Commission. A downpayment of 20% of the CPC is required from each Applicant. Financing is available for one to five year terms for extensions costing over $2,000. The Company will finance a maximum of $10,000 per Applicant.

SPECIAL CONTRACTS:

The Applicant may be required to make a contribution in addition to the CPC in the following circumstances:

1. where additional investment is required in order to upgrade or reinforce existing facilities or install new facilities to provide Service at a phase and voltage not presently available,

2. for Large Commercial Service and Industrial Applicants, where installation and upgrading of substation and transmission facilities may be required; or

SCHEDULE 74 - EXTENSIONS (Cont'd)

SPECIAL CONTRACTS: (Cont'd)

3. for temporary or standby Service, where the Applicant may also be required to pay the cost of removal of the facilities.

In any of the the above circumstances, the Company may request the Applicant to enter into a special contract arrangement. The special contract may require the Applicant to pay for Extension Costs and upgrades or reinforcements of existing facilities, and to pay for any replacements of the Extension which may be required.

OWNERSHIP AND MAINTENANCE OF EXTENSIONS:

The Company will assume ownership and maintenance of an Extension on public or private property, upon connection of the Extension to the Company's distribution system.

EASEMENTS AND RIGHT OF WAY CLEARING:

1. The Applicant shall provide an easement for the Extension, including an easement for vehicle access to the Extension, that is acceptable to the Company. For Extensions to be constructed by the Company, such easement will be provided prior to the construction of the Extension. For all other Extensions, such easement will be provided prior to the connection of the Extension to the Company's distribution system.

2. The Applicant shall be responsible for all right of way clearing costs required for the construction of an Extension.

3. The Applicant shall ensure that all right of way clearing is performed in accordance with the Company's distribution construction standards.

DESIGN AND CONSTRUCTION REQUIREMENTS:

1. Extensions will normally be constructed overhead, but may be constructed underground where such construction is in accordance with the Company's distribution system plans.

2. Upon receipt of a request for Service requiring an Extension, the Company shall engineer and design the Extension ("Design Package"), and provide a quote of the Extension cost ("Estimate

SCHEDULE 74 - EXTENSIONS (Cont'd)

DESIGN AND CONSTRUCTION REQUIREMENTS: (Cont'd)

2. Package"). The cost of preparing the Design Package, including the cost of any revisions to the Design Package that are requested by the Applicant, shall be borne by the Applicant and shall be paid upon receipt of the Design Package. Prior to the release of the Design Package and the Estimate Package, the Applicant may be required to sign a contract that includes terms and conditions relating to the construction of the Extension.

3. The Applicant may select the Company or a contractor authorized by the Company to construct the Extension.

4. Where the Applicant selects the Company to construct the Extension, the Company will construct the Extension at the cost quoted in the Estimate Package.

5. Where the Applicant selects an authorized contractor to construct the Extension, prior to the connection of the Extension to the Company's distribution system, the Applicant will pay to the Company all additional costs, which will be estimated in advance by the Company, incurred for designing, engineering, surveying, obtaining permits, connecting to the Company's distribution system, and inspecting the Extension.

6. Extensions shall be constructed in accordance with the Design Package and in accordance with the Company's distribution construction standards and material specifications.

7. For Extensions constructed by an authorized contractor, the Company, in its sole discretion, may survey, at the cost of the Applicant, such Extensions prior to connecting the Extension to the Company's distribution system.

8. An authorized contractor may not work on any of the Company's electrical facilities, and the Company shall make all connections to or disconnections from the Company's distribution system.

The Company will not commence construction of an Extension or authorize a connection or disconnection of an Extension constructed by an authorized contractor until:

1. the Applicant has completed a contract for Service as required by Section 2.1 of the Terms and Conditions and any other required documentation;

SCHEDULE 74 - EXTENSIONS (Cont'd)

DESIGN AND CONSTRUCTION REQUIREMENTS: (Cont'd)

2. all necessary easements, permits, or licences of occupation have been obtained;

3. where applicable, construction of the new building has advanced to the point where completion seems assured, or the Applicant has provided adequate security for the amount of the Company's investment; and

3. the Applicant has paid to the Company the full estimated CPC less any amount financed by the Company and less any amount agreed to by the Company pursuant to the "Customer Portion of Costs" section found on Sheet 50 of this Schedule.

DEFINITIONS:

In this Schedule,

1. "Applicant" includes a corporation, partnership, or person that has applied to the Company for a Service connection that requires the construction of an Extension.

2. "Customer Portion of Costs" (CPC) means Extension Cost less the Company Contribution towards the Extension.

3. "Company Contribution" means the Company's financial contribution towards the Extension Cost for Service as specified on Sheet 50.

4. "Extension Cost" means the Company's estimated cost of constructing an Extension including the cost of labour, material and construction equipment. Extension Cost includes the cost of connecting the Extension to the Company's distribution system, inspection costs, survey costs, permit costs. If in the Company's opinion, upgrades to the Company's distribution system would be beneficial for Service to other Customers, the extra cost of this reinforcement is excluded from the Extension Cost.

5. "Extension" means an addition to, or extension of, the Company's distribution system including an addition or extension on public or private property.

6. "Transformer" includes transformers, cutouts, lightning arrestors and associated equipment, and labour to install.

SCHEDULE 80 - CHARGES FOR CONNECTION OR RECONNECTION OF SERVICE TRANSFER OF ACCOUNT, TESTING OF METERS, AND VARIOUS CUSTOM WORK

CHARGE FOR SERVICE: Performed During Normal Working Hours

The charge for a meter connection, transfer of an account involving either a meter connection or reconnection of a meter after disconnection for violation of the Terms and Conditions contained in this tariff will be $100.00

Where two or more meter connections are to be made for one Customer at the same time at one location, the charge shall be $100.00 for one connection or transfer and $25.00 for each additional. The $100.00 fee will not be incurred when the Customer is required to pay the charge for Connection New/Upgraded Services.

There will be a $15.00 charge for the setup or transfer of an account.

Performed During Overtime Hours

If the Customer requests the Company to perform the above functions during overtime hours, being a continuation of the normal work day for the personnel concerned, the $100.00 charge becomes $132.00

Performed During Callout Hours

If the Customer requests the Company to call out personnel to perform the above functions, the $100.00 charge becomes $339.00.

METER TESTING: The deposit for removing and replacing a meter in Service for testing at the request of the Customer shall be $25.00 except where increased to defray expenses incurred.

TEMPORARY DROP SERVICE: The charge for installing a temporary Drop Service of less than 30 meters over private property shall be as prescribed in Schedule 82 plus $200.00 provided the temporary Service can be converted to the permanent Service at little additional cost.

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SCHEDULE 80 - CHARGES FOR CONNECTION OR RECONNECTION OF SERVICE, TRANSFER OF ACCOUNT, TESTING OF METERS, AND VARIOUS CUSTOM WORK (Cont'd)

TEMPORARY DROP SERVICE: (Cont'd)

If this temporary drop Service cannot be used to form the permanent Service, and must be removed, the charge for installing and removing a temporary drop Service of less than 30 meters shall be as prescribed in Schedule 82 plus $200 for the cost of the removal of the equipment used to supply the temporary Service. The charge for the permanent connection shall be as prescribed in Schedule 82, in addition to the charge for installation and removal of a temporary drop Service of less than 30 meters.

DISCONNECTION AND RECONNECTION OF METER: The standard charge for a disconnection and subsequent reconnection of a meter at the meter location shall be $200.00 provided such work can be performed during normal working hours.

RELOCATION OF EXISTING SERVICE: The charge for the relocating of a Service requiring a Service drop change on the same building shall be $673.00 provided such work can be performed during normal working hours. The Service entrance and meter box shall be in a location satisfactory to the Company.

CUSTOM WORK: The Company may recover the full cost of the following custom work:

1. At the Customer's request, when a special trip is necessary to inspect a Service due to an outage and the fault is found to be beyond the Point of Delivery, the Company shall be reimbursed for the full cost.

2. Installation of facilities beyond those considered necessary by the Company in order to provide Service and not provided for elsewhere in the Company's tariff.

3. Replacement or repair of facilities damaged by other than reasonable wear and tear.

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SCHEDULE 80 - CHARGES FOR CONNECTION OR RECONNECTION OF SERVICE, TRANSFER OF ACCOUNT, TESTING OF METERS, AND VARIOUS CUSTOM WORK (Cont'd)

CUSTOM WORK: (Cont'd)

4. At the Customer's request, relocation of the Service to permit tree trimming, construction, etc., where recovery of the costs are not provided for in the standard charges above.

RETURNED CHEQUE SERVICE CHARGE: If a cheque received from a Customer for the payment of an electric Service account or other billing is returned by the Bank for the reason of Not Sufficient Funds (N.S.F.) or reasons other than clerical error, the Customer will be charged a Service charge of $19.00.

COLLECTION CHARGE: A collection charge of $12.00 per occurrence may be levied if it is necessary for a Company representative to attend a Customer's Premises more than twice in one calendar year for the purposes of affixing a disconnect notice to the Customer's Premises.

METER ACCESS CHARGE: If it is necessary for the Company to install a remote metering device, a charge of $152.00 for a single phase remote meter, or $310.00 for a poly phase remote meter, shall be levied.

FALSE SITE VISIT CHARGE: A charge of $182.00 per occurrence may be levied if a FortisBC representative attends a Customer's Premises at the request of a Customer but, on attending, is unable to perform the requested work because the facilities required to be provided by the Customer, for this purpose, are found to be deficient.

SCHEDULE 82 - CHARGES FOR INSTALLATION OF NEW/UPGRADED SERVICES

APPLICABLE:

To all new Service installations or increases in Service size of existing Services.

CHARGE FOR SERVICE:

Residential Service, Commercial Service, Lighting Type III and Irrigation
Customers are required to provide their Electrical Inspection Permit for verification of the Service size.

Where Customers supply their own transformation from the primary distribution voltage, the rate for Large Commercial Service and Industrial Service will apply.

The charge for the installation of a new or upgrading of an existing Service is:

Overhead - Single Phase	200 Amps or less	$533.00
	400 Amps	$937.00
Underground - Single Phaase	200 Amps or less	$565.00

For Service connections only requiring the installation of a meter, the Customer shall pay the charge for a meter connection as specified in Schedule 80.

For all other Service connections and a meter, the applicant shall pay the Customer Portion of Costs of the Service connection as determined under Schedule 74, which shall include the installation cost of the meter.

SCHEDULE 85 - GREEN POWER RIDER

APPLICABLE: To any current rate Schedules and on the same terms applicable to rate Schedule under which Service is taken, for the purchase of Electricity from environmentally desirable technologies.

RATE: OPTION A - In addition to all charges on the applicable rate Schedule, an additional charge, of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

OPTION B - In addition to all charges on applicable rate Schedule, the Customer may select a dollar amount of their choosing to be added to their periodic billing, but in no case shall the amount be less than $2.50 per month.

SCHEDULE 90 - DEMAND-SIDE MANAGEMENT SERVICES

APPLICABLE: To all Customers in all areas served by the Company and its municipal wholesale Customers.

OBJECTIVE: The purpose of the Company's Demand-Side Management (DSM) Services is to promote the efficient use of Electricity, in terms of consumption (Conservation) and/or timing (Demand Response).

PROGRAMS: DSM programs, compliant with applicable regulations, address electrical end-uses, through approved Measure(s), which may consist of an energy-efficient product, device, piece of equipment, system, building or process design and/or operational practice which exceeds applicable codes and/or current practice.

The Company will maintain an updated DSM program listing on its website, available in print format, detailing current program offerings and rules.

FINANCIAL DETAILS: DSM programs will consist of monetary incentives provided by the Company in the form of custom option or product option offerings to promote the purchase and installation of approved Measures. Incentives are targeted to Customers but may also be provided to trade allies who provide or install the Measures.

Monetary incentives are based on the annual kWh savings, or the on-peak kW reduction, attained through the Measure as determined on a prescriptive or custom calculation basis.

Monetary incentives are capped to the lesser of:

i. the Company's long-term avoided power purchase costs,
ii. 50% of installed Measure cost for existing construction,
iii. 100% of incremental cost for new construction, or
iv. The amount sufficient for the Customer to achieve a two-year payback.

Monetary incentives may alternately consist of low-cost financing O.A.C. for residential Customers only.

DSM Services may also consist of non-monetary offerings in the form of: public information, educational programs, or training; audits of Customer Premises or processes or Measures and reports thereof; product samples; pilot projects to test new Measures; and market transformation activities undertaken in conjunction with other utilities and/or governments.

SCHEDULE 90 – DEMAND-SIDE MANAGEMENT SERVICES (Cont'd)

TERMS AND CONDITIONS

The following terms and conditions are an integral part of the Demand-Side Management Services listed under Schedule 90:

FINANCIAL INCENTIVES

1. In order to be eligible for financial incentives, a Customer must receive the Company's approval prior to initiation of work on the approved Measure.

2. Only those audit or upgrade costs which are pertinent to DSM considerations will be eligible for financial incentives. An estimate of costs related to such issues as obsolescence, depreciation, maintenance, plant betterment and environmental concerns will be made to isolate that portion of the cost strictly related to energy.

3. Where incentives are in excess of $10,000, payment of one half of the rebate will be deferred for up to one year. Upon confirmation of project savings, the remaining portion of the rebate will be paid pro rata to the energy savings. No interest will be paid on the withheld portion. Irrespective of actual savings, the final rebate will not exceed the original estimated rebate.

4. For those Customers in receipt of an incentive in excess of $20,000, the unamortized balance of financial incentives paid to or on behalf of the Customer, under Rate Schedule 90 shall be remitted to the Company within 30 days of billing, if:

   (a) the incented equipment or facilities are disabled or removed;

   (b) the Customer's electrical load is reduced by more than 50% for a continuous period of twelve months or longer; or

   (c) over 50% of the Electricity previously provided by the Company is replaced by another source including self-generation or another supplier.

   In regards to (c) above, the repayment shall be prorated based on the amount of energy replaced compared to the amount of energy supplied by the Company in the year immediately preceding the Electricity replacement.

5. Any consulting or study subsidy offered under the Demand-Side Management tariff is contingent upon available budget and resources. When the Company pays more than $1,500 for these Services on behalf of a Customer, any incentive amount that is eventually payable to that Customer will be reduced by the amount of the consulting or study contribution.

SCHEDULE 95 - NET METERING

DEFINITION:

Customer-Generator - An electric Service Customer of the Company that also utilizes the output of a Net Metered System.

Net Consumption - Net Consumption occurs at any point in time where the Electricity required to serve the Customer-Generator's load exceeds that being generated by the Customer-Generator's Net Metered System.

Net Generation - Net Generation occurs at any point in time where Electricity supplied by FortisBC to the Customer-Generator is less than that being generated by the Customer-Generator's Net Metering System.

Net Excess Generation - Net Excess Generation results when over a billing period, Net Generation exceeds Net Consumption.

Net Metering - Net Metering is a metering and billing practice that allows for the flow of Electricity both to and from the Customer through a single, bi-directional meter. With Net Metering, consumers with small, privately-owned generators can efficiently offset part or all of their own electrical requirements by utilizing their own generation.

Net Metered System - A facility for the production of electric energy that:

(a) uses as its fuel, a source defined as a clean and renewable resource in the BC Energy Plan;

(b) has a design capacity of not more than 50 kW;

(c) is located on the Customer-Generator's Premises;

(d) operates in parallel with the Company's transmission or distribution facilities; and

(e) is intended to offset part or all of the Customer-Generator's requirements for Electricity.

APPLICABLE: To FortisBC Customers receiving Service under Rate Schedules 1, 2A, 20, 21, 22, 22 A, 23 A, 60, 61.

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SCHEDULE 95 - NET METERING (Cont'd)

ELIGIBILITY: To be eligible to participate in the Net Metering Program, Customers must generate a portion or all of their own retail Electricity requirements using a renewable energy source. The generation equipment must be located on the Customer's Premises, Service only the Customer's Premises and must be intended to offset a portion or all of the Customer's requirements for Electricity.

Clean or renewable resources include sources of energy that are constantly renewed by natural processes, such as water power, solar energy, wind energy, geothermal energy, wood residue energy, and energy from organic municipal waste, and shall have a maximum installed generating capacity of no greater than 50 kW.

RATE: A Customer enrolled in the Net Metering Program will be billed as set forth in the rate schedule under which the Customer receives electric Service from the Company and as specified in the Net Metering Billing Calculation section in this schedule.

BILLING CALCULATION:

1. Net metering shall be, for billing purposes, the net consumption at FortisBC's Service meter(s).
2. If the eligible Customer-Generator is a net consumer of energy in any billing period, the eligible Customer generator will be billed in accordance with the Customer-Generator's applicable rate schedule.
3. If in any billing period, the eligible Customer-Generator is a net generator of energy, the Net Excess Generation shall be valued at the rates specified in the applicable Rate Schedule and credited to the Customers account.
4. For eligible Customers receiving Service under a Time-of-Use (TOU) rate schedule, consumption and generation during On-Peak Hours shall be recorded and netted separately from consumption and generation during Off-Peak Hours such that any charges or credits applied to the account reflect the appropriate time-dependent value for the energy.
5. In the event that the operation of a renewable energy generating system results in a credit balance on the Customer-Generator's account at the end of a calendar year, the credit will be purchased by the Company. If such amounts are not large, they will be carried forward and included in the billing calculation for the next period at the discretion of the Company.

SCHEDULE 95 - NET METERING (Cont'd)

SPECIAL CONDITIONS:

1. Prior to the interconnection of a Net Metering System the Customer-Generator must submit a Net Metering Application for review and execute a written Net Metering Interconnection Agreement with the Company.
2. The Net Metered System and all wiring, equipment and devices forming part of it, shall conform to FortisBC's, "GUIDELINES FOR OPERATING, METERING And PROTECTIVE RELAYING FOR NET METERING SYSTEMS UP TO 50 kW And VOLTAGE BELOW 750 VOLTS" and shall be installed, maintained and operated in accordance with those Requirements.
3. Unless otherwise approved by the Company, the Customer-generator's Service shall be metered with a single, bi-directional meter.
4. The Contract Period for Service under this schedule shall be one (1) year and thereafter shall be renewed for successive one-year periods. After the initial period, the Customer may terminate Service under this Rider by giving at least sixty (60) days previous notice of such Termination in writing to FortisBC.
5. If the Customer-Generator voluntarily terminates the net-metering Service, the Service may not be renewed for a period of 12 months from the date of Termination.
6. The Company maintains the right to inspect the facilities with reasonable prior notice and at a reasonable time of day.
7. The Company maintains the right to disconnect, without liability, the Customer-Generator for issues relating to safety and reliability.
8. Inflows of Electricity from the FortisBC system to the Customer-Generator, and outflows of Electricity from the Customer-Generators Net Metering System to the FortisBC system, will normally be determined by means of a single meter capable of measuring flows of Electricity in both directions.
9. Alternatively, if FortisBC determines that flows of Electricity in both directions cannot be reliably determined by a single meter, or that dual metering will be more cost-effective, FortisBC may require that, at the Customers cost, separate meter bases be installed to measure inflows and outflows of Electricity.
10. Except as specifically set forth herein, Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Electric Tariff on file with the British Columbia Utilities Commission.

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SCHEDULE 95 - NET METERING (Cont'd)

SPECIAL CONDITIONS: (Cont'd)

11. A Net Metered System used by a Customer-Generator shall meet all applicable safety and performance standards established as set forth in the Company's Rules and Regulations.
12. A Customer-Generator shall, at its expense, provide lockable switching equipment capable of isolating the Net Metered System from the Company's system. Such equipment shall be approved by the Company and shall be accessible by the Company at all times.
13. The Customer-Generator is responsible for all costs associated with the Net Metered System and is also responsible for all costs related to any modifications to the Net Metered System that may be required by the Company including but not limited to safety and reliability.
14. The Customer shall indemnify and hold FortisBC or its agents harmless for any damages resulting to FortisBC or its agents as a result of the Customer's use, ownership, or operation of the Customer's facilities other than damages resulting to FortisBC or its agents directly as a result of FortisBC or its agents own negligence or willful misconduct, including, but not limited to, any consequential damages suffered by FortisBC or its agents. The Customer is solely responsible for ensuring that the Customer's facilities operate and function properly in parallel with FortisBC's system and shall release FortisBC or its agents from any liability resulting to the Customer from the parallel operation of the Customer's facilities with FortisBC's system other than damages resulting to the Customer from the parallel operation of the Customer's facilities with FortisBC's system directly as a result of FortisBC or its agents own negligence or willful misconduct.

SCHEDULE 100 - NETWORK INTEGRATION TRANSMISSION SERVICE

AVAILABILITY: For Network Integration Transmission Service.

RATE: Monthly Network Transmission Revenue Requirement:

Customers will be charged the applicable Load Ratio Share of one twelfth ($1/12^{th}$) of the Network Transmission Revenue Requirement per month. The Network Transmission Revenue Requirement is as set forth in Attachment H to Electric Tariff Supplement No. 7.

NOTE: The terms and conditions under which Network Integration Transmission Service is supplied are contained in Electric Tariff Supplement No. 7 and capitalized terms appearing in this Rate Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

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SCHEDULE 101 - LONG-TERM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

AVAILABILITY: For transmission of Electricity on a firm basis from one or more Point(s) of Receipt (POR) to one or more Point(s) of Delivery (POD).

ANNUAL RATE FOR LONG-TERM FIRM SERVICE:

The Monthly Rate is billed on the sum of the Reserved Capacity at each POD. The Monthly Rate will be zero ($0.00) where the POD is a point of interconnection between the Transmission System and the transmission system of the B.C. Hydro and Power Authority.

MONTHLY RATE:

Wholesale Service-Transmission
A Basic Charge of $326 per POD to a maximum of $326 in any calendar month,
plus
$3.55 per kVA of Reserved Capacity Billing Demand.

Wholesale Service-Primary
A Basic Charge of $1,771 per POD to a maximum of $1,771 in any calendar month,
plus
$6.90 per kVA of Reserved Capacity Billing Demand.

Large Commercial Service-Transmission
A Basic Charge of $2,224 per POD to a maximum of $2,224 in any calendar month,
plus
$3.76 per kVA of Reserved Capacity Billing Demand.

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SCHEDULE 101 - LONG-TERM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE (Cont'd)

RATES FOR SHORT-TERM FIRM SERVICE

The posted prices will be above a minimum price and below a maximum price as set out below; except that the Monthly, Weekly, Daily or Hourly Rate, as applicable, will be zero ($0.00) where the POD is a point of interconnection between the Transmission System and the transmission system of the B.C. Hydro and Power Authority.

MINIMUM PRICE: $0.002 per kW per hour plus the applicable Basic Charge.

MAXIMUM PRICE:

The Transmission Customer shall pay each month for Reserved Capacity designated at the POD at rates not to exceed the applicable charges set forth below:

Delivery	Large Commercial Service - Transmission	Wholesale - Primary	Wholesale - Transmission
	(Per KVA of Reserved Capacity Billing Demand)		
Monthly	$5.07	$9.27	$4.78
Weekly	$1.31	$2.47	$1.24
Daily	$0.225	$0.388	$0.215
Hourly	$0.0112	$0.0204	$0.1042
plus: a Basic Charge of			
Per Calendar Month per POD	$2,224	$1,771	$326

SCHEDULE 101 - LONG-TERM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE (Cont'd)

SPECIAL CONDITION:

Discounts: Three principal requirements apply to discounts for Transmission Service as follows:

1. any offer of a discount made must be announced to all Transmission Customers on OASIS in a timely manner;

2. any Customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must be provided to other Transmission Customers on OASIS; and

3. once a discount is negotiated, details must be immediately posted on OASIS. For any discount agreed upon for Service on a path, from POR to POD, an offer of the same discounted transmission Service rate for the same time period must be made for all unconstrained transmission paths that go to the same POD on the Transmission System.

NOTE: The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement 7. Capitalized terms appearing in this Rate Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

PENALTY CHARGE:

A penalty charge will be applied at the rate of 125 per cent of the applicable rate for all usage in excess of the Reserved Capacity.

RESERVED CAPACITY BILLING DEMAND:

The sum of the Reserved Capacity designated at each POD for the applicable period.

SCHEDULE 102 - NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

AVAILABILITY: For transmission of Electricity on a Non-firm basis from one or more Point(s) of Receipt (POR) to one or more Point(s) of Delivery (POD).

RATES FOR SHORT-TERM NON-FIRM SERVICE

The Transmission Customer shall pay each month for Reserved Capacity designated at the POR at the posted prices which will be above a minimum price and below a maximum price as set out below.

MINIMUM PRICE: $0.001 per kW per hour

MAXIMUM PRICE:
The Transmission Customer shall pay for Non-Firm Point-to-Point Transmission Service at rates not to exceed the applicable charges set forth below; except that the Monthly, Weekly, Daily or Hourly Rate, as applicable, will be zero ($0.00) where the POD is a point of interconnection between the Transmission System and the transmission system of the B.C. Hydro and Power Authority.

Delivery	Large Commercial Service - Transmission	Wholesale - Primary	Wholesale - Transmission
	(Per KVA of Reserved Capacity Billing Demand)		
Monthly	$5.07	$9.27	$4.78
Weekly	$1.31	$2.47	$1.24
Daily	$0.225	$0.388	$0.215
Hourly	$0.0112	$0.0204	$0.1042
plus: a Basic Charge of			
Per Calendar Month per POD	$2,224	$1,771	$326

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SCHEDULE 102 - NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE (Cont'd)

SPECIAL CONDITIONS:

Discounts - Three principal requirements apply to discounts for Transmission Service as follows.

1. any offer of a discount made must be announced to all Transmission Customers on OASIS in a timely manner;

2. any Customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must be provided to other Transmission Customers on OASIS; and

3. once a discount is negotiated, details must be immediately posted on OASIS. For any discount agreed upon for Service on a path, from POR to POD, an offer of the same discounted transmission Service rate for the same time period must be made for all unconstrained transmission paths that go to the same POD on the Transmission System.

NOTE: The terms and conditions under which Non-Firm Transmission Service is supplied are contained in Electric Tariff Supplement 7. Capitalized terms appearing in this Rate Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

PENALTY CHARGE:

A penalty charge will be applied at a rate of 125 percent of the applicable rate for all usage in excess of the Reserved Capacity.

RESERVED CAPACITY BILLING DEMAND:

The sum of the Reserved Capacity designated at each POD for the applicable period.

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SCHEDULE 103 - SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

PREAMBLE: This Service is required to schedule the movement of power through, out of, or within the Service territory.

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

RATE:

Wholesale Service-Transmission:	$0.00088 per kW.h
Wholesale Service-Primary:	$0.00091 per kW.h
Large Commercial Service-Transmission:	$0.00088 per kW.h

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.

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:

Wholesale Service-Transmission:	$0.00098 per kW.h
Wholesale Service-Primary:	$0.00091 per kW.h
Large Commercial Service-Transmission:	$0.00091 per kW.h

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.

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SCHEDULE 105 - REGULATION AND FREQUENCY RESPONSE SERVICE

PREAMBLE: Regulation and Frequency Response (RFR) Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The Transmission Customer must either purchase this Service from the Company or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below.

AVAILABILITY: In support of the transmission of Electricity under Rate Schedules 100, 101, and 102.

RATE: $9.51 per mega-watt per hour of generating capacity requested for RFR.

The required amount of RFR Service is a minimum of 2% of the Customer's load located in the Company's Service territory.

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.

SCHEDULE 106 - ENERGY IMBALANCE SERVICE

PREAMBLE: Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a the Company's Service territory over a single hour. The Company must offer this Service when the transmission Service is used to serve load within its Service area. The Transmission Customer must either purchase this Service from the Company or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. The Company shall establish a deviation band of +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). Parties should attempt to eliminate energy imbalances within the limits of the deviation band within thirty (30) days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by the Company. If an energy imbalance is not corrected within thirty (30) days or a reasonable period of time that is generally accepted in the region and consistently adhered to by the Company, the Transmission Customer will compensate the Company for such Service. Energy imbalances outside the deviation band will be subject to charges to be specified by the Company. The charges for Energy Imbalance Service are set forth below.

AVAILABILITY: In support of the transmission of Electricity under Rate Schedules 100, 101, and 102.

ENERGY IMBALANCE: Customers are allowed to maintain a ±1.5% balance between generation (minus losses) and load within the hour. The ±1.5% hourly balance limit is based on the capacity reserved. Positive hourly imbalances within the ±1.5% band not eliminated within 30 days, will attract a credit that is equal to the Company's minimum monthly cost of purchasing energy. If the Company does not purchase energy during the month, the previous minimum price will be used. Positive hourly imbalances outside the ±1.5% band will be forfeit.

For negative energy imbalances (when generation minus losses is less than load) that fall within the ±1.5% band and are not eliminated within 30 days, the energy imbalance charge will be:

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SCHEDULE 106 - ENERGY IMBALANCE SERVICE (Cont'd)

RATE	Wholesale Service-Transmission:	$0.03520 per kW.h
	Wholesale Service-Primary:	$0.03350 per kW.h
	Large Commercial Service-Transmission:	$0.03348 per kW.h

For any negative energy imbalances (when generation minus losses is less than load) that fall outside the ±1.5% band the energy imbalance charge will be the actual cost the Company incurs in supplying that imbalance, plus 10%.

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.

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SCHEDULE 107 - OPERATING RESERVE (OR) - SPINNING RESERVE SERVICE

PREAMBLE: Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Company must offer this Service when the transmission Service is used to serve load within its Service area. The Transmission Customer must either purchase this Service from the Company or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below.

AVAILABILITY: In support of the transmission of Electricity under Rate Schedules 100, 101, and 102.

RATE: $9.51 per mega-watt per hour of generating Capacity requested for OR - Spinning.

The required amount of Spinning Reserve Service, for a Customer's load located in the Company's Service area, depends upon the type of generation serving the load. When the load is served by hydro generation, the required amount of Spinning Reserve Service is a minimum of 2.5% of the Customer's load. When the load is served by thermal generation, the required amount of Spinning Reserve Service is a minimum of 3.5% of the Customer's load.

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.

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SCHEDULE 108 - OPERATING RESERVE (OR) - SUPPLEMENTAL RESERVE SERVICE

PREAMBLE: Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Company must offer this Service when the transmission Service is used to serve load within its Service Area. The Transmission Customer must either purchase this Service from the Company or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below.

AVAILABILITY: In support of the transmission of Electricity under Rate Schedule 100, 101, and 102.

RATE: $9.51 per mega-watt per hour of generating Capacity requested for OR-Supplemental.

The required amount of Supplemental Reserve Service, for a Customer’s load located in the Company Service area, depends upon the type of generation serving the load. When the load is served by hydro generation, the required amount of Supplemental Reserve Service is a minimum of 2.5% of the Customer’s load. When the load is served by thermal generation, the required amount of Supplemental Reserve Service is a minimum of 3.5% of the Customer’s load.

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.

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SCHEDULE 109 - TRANSMISSION LOSSES

APPLICABLE: All transactions under rate Schedules 100, 101, and 102 will incur real power losses as follows:

Wholesale Service - Transmission	6.08%
Wholesale Service - Primary	11.53%
Large Commercial Service - Transmission	6.08%

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Appendix C

SCHEDULE 50 - LIGHTING

Clean Version

SCHEDULE 50 - LIGHTING - ALL AREAS

APPLICABLE: To lighting applications where the Customer will contract for Service for a term of one year. The Company will supply Service for lighting from dusk to dawn daily.

All lighting equipment installed on and after the effective date of this Schedule will be Company approved and conform to all relevant Company design and installation standards and requirements, and be suitable to accept electrical Service at the Company's available Secondary Voltage. Other requirements may be supplied under special contract.

This Schedule is not available for equipment other than Company approved lighting fixtures.

TYPES OF SERVICE:

1. Customer-Owned and Customer-Maintained

Type I - For a Customer-owned street lighting fixture or lighting system where the Customer owns and maintains at its own expense the light standards if any, lighting fixtures and all auxiliary equipment.

Electricity at 120/240 volts single phase is supplied by the Company at a single Point of Delivery for each separate Customer system. Multiple light systems shall be provided Service at a single Point of Delivery wherever practical. The Customer shall supply transformers for other than 120/240 volt single phase supply.

Type I shall apply only if the Customer system can be operated and maintained, beyond the point of supply of Electricity, independently of the Company's system. The installed cost of devices necessary for independent operation shall be paid by the Customer. Where Customer owned lighting fixtures are on Company owned poles maintenance work shall only be performed by parties qualified to do the work, and authorised by the Company. Type One Service may be refused for safety reasons.

2. Customer-Owned and Company-Maintained

Type II - Customer-owned street lighting fixtures installed on existing Company poles at the Customer's expense with all maintenance to be performed by the Company at costs described below.

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SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

TYPES OF SERVICE:(Cont'd)

3. Company-Owned, Company-Installed and Maintained

Type III - For Company-owned street lighting fixtures on existing Company-owned poles where the Company performs all maintenance. Facilities provided by the Company, including fixtures, lamp, control relay, support bracket, and conductor and energy for operation thereof are owned by the Company.

TERMS AND CONDITIONS:

Installation

Type II lighting fixtures of design and specifications approved by the Company for installation on Company-owned poles will be installed by the Company at the Customer's expense. There will be no charge to the Customer for the use of existing Company-owned poles as standards for mounting of fixtures other than as provided for in this Section.

The Company will provide to the Customer on request, lighting fixtures and standards, where required, of Company approved design and specifications at its cost plus overheads and handling costs as described in the Cost Recovery section below. For Type III fixtures the Company will provide one span of duplex of not more than 30 metres.

Extension of Service

Extensions of Service will be provided under the terms of the Company's Extension Policy.

Relocation

At the Customer's request, the location of a light may be changed provided the Customer pays for the cost of removal and reinstallation, including cost of extension of Service if applicable, with costs recovered as described below.

Other Equipment

Equipment other than lighting fixtures is not permitted on Company-owned poles except with the Company's written consent.

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SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

TERMS AND CONDITIONS:

Maintenance of Type III Lights

Maintenance of Type III lighting fixtures shall be performed by the Company, the cost of which is provided for in the "Monthly Rate" of this Schedule. Such work will be undertaken by the Company during regular working hours and the Company will be allowed ten working days subsequent to notification by the Customer for performance of such maintenance. Cleaning of the glassware will be carried out only when the lamp is replaced.

The Customer shall be responsible for any wilful damage to the Company's equipment.

Maintenance of Type II Lights

The Customer will pay maintenance and capital costs, including the cost of installation, maintenance of underground supply, and relocation, on an as spent basis. Customers will inform the Company in writing of the location of any lighting fixture requiring maintenance and the time in which the maintenance must be performed. The Company will bill the Customer for all costs incurred including the following overheads:

Cost Recovery

Labour Loading

On labour costs excluding overtime	72.5% of labour rate

Material Loading

Inventory – Material Handling	7% of cost

SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

MONTHLY RATE FOR EACH
TYPE OF SERVICE:

				Rate ($ per month)		
		Monthly	Nominal	Customer-Owned		Company-Owned
Type of Light	Watts	Use (kW.h)	Lumens	Type I	Type II	Type III
Fluorescent	* 383	140	21,800	16.92		
Mercury Vapour	* 125	55	5,000	6.77	6.77	15.00
	* 175	78	7,000	9.58	9.58	17.83
	* 250	107	10,000	13.14	13.14	21.39
	* 400	166	21,000	20.38	20.38	28.63
Sodium Vapour	70	33	6,000	4.09	4.09	12.29
	*100	47	9,000	5.76	5.76	14.01
	*150	70	14,000	8.58	8.58	16.84
	200	91	20,000	11.17	11.17	19.42
	250	111	23,000	13.65	13.65	21.87
	*400	173	45,000	21.26	21.26	29.51

* No longer available at new locations or as replacement fixtures where existing fixtures are being replaced except at the sole discretion of the Company.

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

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Appendix C

SCHEDULE 50 - LIGHTING

Black-Line Version

SCHEDULE 50 - LIGHTING - ALL AREAS

APPLICABLE: To lighting applications where the Customer will contract for Service for a term of one year. The Company will supply Service for lighting from dusk to dawn daily.

All lighting equipment installed on and after the effective date of this Schedule will be Company approved and conform to all relevant Company design and installation standards and requirements, and be suitable to accept electrical Service at the Company's available Secondary Voltage. Other requirements may be supplied under special contract.

This Schedule is not available for equipment other than Company approved lighting fixtures.

TYPES OF SERVICE:

1. Customer-Owned and Customer-Maintained

Type I - For a Customer-owned street lighting fixture or lighting system where the Customer owns and maintains at its own expense the light standards if any, lighting fixtures and all auxiliary equipment.

Electricity at 120/240 volts single phase is supplied by the Company at a single Point of Delivery for each separate Customer system. Multiple light systems shall be provided Service at a single Point of Delivery wherever practical. The Customer shall supply transformers for other than 120/240 volt single phase supply.

Type I shall apply only if the Customer system can be operated and maintained, beyond the point of supply of Electricity, independently of the Company's system. The installed cost of devices necessary for independent operation shall be paid by the Customer. Where Customer owned lighting fixtures are on Company owned poles maintenance work shall only be performed by parties qualified to do the work, and authorised by the Company. Type One Service may be refused for safety reasons.

2. Customer-Owned and Company-Maintained

Type II - Customer-owned street lighting fixtures installed on existing Company poles at the Customer's expense with all maintenance to be performed by the Company at costs described below.

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SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

TYPES OF SERVICE:(Cont'd)

3. Company-Owned, Company-Installed and Maintained

Type III - For Company-owned street lighting fixtures on existing Company-owned poles where the Company performs all maintenance. Facilities provided by the Company, including fixtures, lamp, control relay, support bracket, and conductor and energy for operation thereof are owned by the Company.

TERMS AND CONDITIONS:

Installation

Type II lighting fixtures of design and specifications approved by the Company for installation on Company-owned poles will be installed by the Company at the Customer's expense. There will be no charge to the Customer for the use of existing Company-owned poles as standards for mounting of fixtures other than as provided for in this Section.

The Company will provide to the Customer on request, lighting fixtures and standards, where required, of Company approved design and specifications at its cost plus overheads and handling costs as described in the Cost Recovery section below. For Type III fixtures the Company will provide one span of duplex of not more than 30 metres.

Extension of Service

Extensions of Service will be provided under the terms of the Company's Extension Policy.

Relocation

At the Customer's request, the location of a light may be changed provided the Customer pays for the cost of removal and reinstallation, including cost of extension of Service if applicable, with costs recovered as described below.

Other Equipment

Equipment other than lighting fixtures is not permitted on Company-owned poles except with the Company's written consent.

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SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

TERMS AND CONDITIONS:

Maintenance of Type III Lights
Maintenance of Type III lighting fixtures shall be performed by the Company, the cost of which is provided for in the "Monthly Rate" of this Schedule. Such work will be undertaken by the Company during regular working hours and the Company will be allowed ten working days subsequent to notification by the Customer for performance of such maintenance. Cleaning of the glassware will be carried out only when the lamp is replaced.

The Customer shall be responsible for any wilful damage to the Company's equipment.

Maintenance of Type II Lights
The Customer will pay maintenance and capital costs, including the cost of installation, maintenance of underground supply, and relocation, on an as spent basis. Customers will inform the Company in writing of the location of any lighting fixture requiring maintenance and the time in which the maintenance must be performed. The Company will bill the Customer for all costs incurred including the following overheads:

Cost Recovery
Labour Loading
On labour costs excluding overtime 72.5% of labour rate

Material Loading
Inventory – Material Handling 7% of cost

Deleted: Overhead Absorption Loading $13.00 per hour
Exempt Staff 68% of labour rate
OPEIU Staff 55% of labour rate
IBEW Staff 54% of labour rate

Deleted: 5

Deleted: Freight and tax 10% of cost
General and Administrative Overhead 20% on first $1,000
on total invoice price 12% on next $9,000
11% on amounts > $10,000

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SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

MONTHLY RATE FOR EACH
TYPE OF SERVICE:

Type of Light	Watts	Monthly Use (kW.h)	Nominal Lumens	Rate ($ per month) Customer-Owned Type I	Customer-Owned Type II	Company-Owned Type III
Fluorescent	* 383	140	21,800	16.92		
Mercury Vapour	* 125	55	5,000	6.77	6.77	15.00
	* 175	78	7,000	9.58	9.58	17.83
	* 250	107	10,000	13.14	13.14	21.39
	* 400	166	21,000	20.38	20.38	28.63
Sodium Vapour	70	33	6,000	4.09	4.09	12.29
	*100	47	9,000	5.76	5.76	14.01
	*150	70	14,000	8.58	8.58	16.84
	200	91	20,000	11.17	11.17	19.42
	250	111	23,000	13.65	13.65	21.87
	*400	173	45,000	21.26	21.26	29.51

* No longer available at new locations or as replacement fixtures where existing fixtures are being replaced except at the sole discretion of the Company.

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

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Appendix D

SCHEDULE 74 - EXTENSIONS

Clean Version

SCHEDULE 74 - EXTENSIONS

APPLICABLE:

To the construction of an addition to, or extension of, the Company's distribution system.

Rate Schedule 73 will continue to apply to all Extensions for which payment of the Customer Portion of Costs has been made prior to October 1, 1997.

CUSTOMER PORTION OF COSTS:

1. An Applicant will apply for Service pursuant to Section 2 of the Terms and Conditions.

2. The Company shall contribute towards an Extension as follows, multiplied by the number of Customers to be served from the Extension:

Rate Schedule	**Maximum FortisBC Contribution**
RS 1, 2A,	$1,765
RS 20, 21	$158 per kW
RS 50 (Type I, Type II)	$19.43 per fixture
RS 60, 61	$1,390

The Applicant will pay the Customer Portion of Costs ("CPC"). The CPC is the estimated cost of construction of the Extension less the Company Contribution towards the Extension, and does not include any applicable connection charges as specified in Schedule 82. The CPC will be paid either in cash or, with the Company's agreement, wholly or partly in kind.

Where Customer actions cause construction to be delayed by a period of 6 months or greater after receipt of the CPC, the Company reserves the right to re-quote the CPC using current pricing, excluding any material(s) already purchased. Any additional costs must be paid by the Customer to the Company prior to the commencement of construction. Any resulting credit will be promptly refunded by the Company to the Customer.

REFUND OF CUSTOMER PORTION OF COSTS:

1. The Company shall have the right to connect additional Applicants to an Extension. Additional Customers that take Service from an Extension within five years of the connection of the Extension to the Company's distribution system shall pay a share of the Extension Cost (less the

SCHEDULE 74 - EXTENSIONS (Cont'd)

REFUND OF CUSTOMER PORTION OF COSTS: (Cont'd)

Company Contribution towards the Extension), without interest, in proportion to that part of the Extension that is used to provide Service and in proportion to the number of original Applicants taking Service from the Extension.

2. No share of the Extension Cost will be paid where:

   (i) the contribution would be less than $200.00 per Applicant, or

   (ii) more than five years have passed from the date the Extension was connected to the Company's distribution system to the date of the connection of the additional Applicant to the Extension.

3. A refund of the Extension Cost that has been received from an additional Applicant shall be made to existing Applicants.

FINANCING:

Company financing is available on approval of credit. The CPC will be financed based on the Company's weighted average cost of capital as approved by the British Columbia Utilities Commission. A downpayment of 20% of the CPC is required from each Applicant. Financing is available for one to five year terms for extensions costing over $2,000. The Company will finance a maximum of $10,000 per Applicant.

SPECIAL CONTRACTS:

The Applicant may be required to make a contribution in addition to the CPC in the following circumstances:

1. where additional investment is required in order to upgrade or reinforce existing facilities or install new facilities to provide Service at a phase and voltage not presently available,

2. for Large General Service and Industrial Applicants, where installation and upgrading of substation and transmission facilities may be required; or

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SCHEDULE 74 - EXTENSIONS (Cont'd)

SPECIAL CONTRACTS: (Cont'd)

3. for temporary or standby Service, where the Applicant may also be required to pay the cost of removal of the facilities.

In any of the the above circumstances, the Company may request the Applicant to enter into a special contract arrangement. The special contract may require the Applicant to pay for Extension Costs and upgrades or reinforcements of existing facilities, and to pay for any replacements of the Extension which may be required.

OWNERSHIP AND MAINTENANCE OF EXTENSIONS:

The Company will assume ownership and maintenance of an Extension on public or private property, upon connection of the Extension to the Company's distribution system.

EASEMENTS AND RIGHT OF WAY CLEARING:

1. The Applicant shall provide an easement for the Extension, including an easement for vehicle access to the Extension, that is acceptable to the Company. For Extensions to be constructed by the Company, such easement will be provided prior to the construction of the Extension. For all other Extensions, such easement will be provided prior to the connection of the Extension to the Company's distribution system.

2. The Applicant shall be responsible for all right of way clearing costs required for the construction of an Extension.

3. The Applicant shall ensure that all right of way clearing is performed in accordance with the Company's distribution construction standards.

DESIGN AND CONSTRUCTION REQUIREMENTS:

1. Extensions will normally be constructed overhead, but may be constructed underground where such construction is in accordance with the Company's distribution system plans.

2. Upon receipt of a request for Service requiring an Extension, the Company shall engineer and design the Extension ("Design Package"), and provide a quote of the Extension cost ("Estimate

SCHEDULE 74 - EXTENSIONS (Cont'd)

DESIGN AND CONSTRUCTION REQUIREMENTS: (Cont'd)

2. Package"). The cost of preparing the Design Package, including the cost of any revisions to the Design Package that are requested by the Applicant, shall be borne by the Applicant and shall be paid upon receipt of the Design Package. Prior to the release of the Design Package and the Estimate Package, the Applicant may be required to sign a contract that includes terms and conditions relating to the construction of the Extension.

3. The Applicant may select the Company or a contractor authorized by the Company to construct the Extension.

4. Where the Applicant selects the Company to construct the Extension, the Company will construct the Extension at the cost quoted in the Estimate Package.

5. Where the Applicant selects an authorized contractor to construct the Extension, prior to the connection of the Extension to the Company's distribution system, the Applicant will pay to the Company all additional costs, which will be estimated in advance by the Company, incurred for designing, engineering, surveying, obtaining permits, connecting to the Company's distribution system, and inspecting the Extension.

6. Extensions shall be constructed in accordance with the Design Package and in accordance with the Company's distribution construction standards and material specifications.

7. For Extensions constructed by an authorized contractor, the Company, in its sole discretion, may survey, at the cost of the Applicant, such Extensions prior to connecting the Extension to the Company's distribution system.

8. An authorized contractor may not work on any of the Company's electrical facilities, and the Company shall make all connections to or disconnections from the Company's distribution system.

The Company will not commence construction of an Extension or authorize a connection or disconnection of an Extension constructed by an authorized contractor until:

1. the Applicant has completed a contract for Service as required by Section 2.1 of the Terms and Conditions and any other required documentation;

SCHEDULE 74 - EXTENSIONS (Cont'd)

DESIGN AND CONSTRUCTION REQUIREMENTS: (Cont'd)

2. all necessary easements, permits, or licences of occupation have been obtained;

3. where applicable, construction of the new building has advanced to the point where completion seems assured, or the Applicant has provided adequate security for the amount of the Company's investment; and

4. the Applicant has paid to the Company the full estimated CPC less any amount financed by the Company and less any amount agreed to by the Company pursuant to the "Customer Portion of Costs" section found on Sheet 50 of this Schedule.

DEFINITIONS:

In this Schedule,

1. "Applicant" includes a corporation, partnership, or person that has applied to the Company for a Service connection that requires the construction of an Extension.

2. "Customer Portion of Costs" (CPC) means Extension Cost less the Company Contribution towards the Extension.

3. "Company Contribution" means the Company's financial contribution towards the Extension Cost for Service as specified on Sheet 50.

4. "Extension Cost" means the Company's estimated cost of constructing an Extension including the cost of labour, material and construction equipment. Extension Cost includes the cost of connecting the Extension to the Company's distribution system, inspection costs, survey costs, permit costs. If in the Company's opinion, upgrades to the Company's distribution system would be beneficial for Service to other Customers, the extra cost of this reinforcement is excluded from the Extension Cost.

5. "Extension" means an addition to, or extension of, the Company's distribution system including an addition or extension on public or private property.

6. "Transformer" includes transformers, cutouts, lightning arrestors and associated equipment, and labour to install.

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Appendix D

SCHEDULE 74 - EXTENSIONS

Black-Line Version

SCHEDULE 74 - EXTENSIONS

APPLICABLE:

To the construction of an addition to, or extension of, the Company's distribution system.

Rate Schedule 73 will continue to apply to all Extensions for which payment of the Customer Portion of Costs has been made prior to October 1, 1997.

CUSTOMER PORTION OF COSTS:

1. An Applicant will apply for Service pursuant to Section 2 of the Terms and Conditions.

2. The Company shall contribute towards an Extension as follows, multiplied by the number of Customers to be served from the Extension:

Rate Schedule	Maximum FortisBC Contribution
RS 1, 2A,	$1,765
RS 20, 21	$158 per kW
RS 50 (Type I, Type II)	$19.43 per fixture
RS 60, 61	$1,390

The Applicant will pay the Customer Portion of Costs ("CPC"). The CPC is the estimated cost of construction of the Extension less the Company Contribution towards the Extension, and does not include any applicable connection charges as specified in Schedule 82. The CPC will be paid either in cash or, with the Company's agreement, wholly or partly in kind.

Where Customer actions cause construction to be delayed by a period of 6 months or greater after receipt of the CPC, the Company reserves the right to re-quote the CPC using current pricing, excluding any material(s) already purchased. Any additional costs must be paid by the Customer to the Company prior to the commencement of construction. Any resulting credit will be promptly refunded by the Company to the Customer.

REFUND OF CUSTOMER PORTION OF COSTS:

1. The Company shall have the right to connect additional Applicants to an Extension. Additional Customers that take Service from an Extension within five years of the connection of the Extension to the Company's distribution system shall pay a share of the Extension Cost (less the

Deleted: <#>A Drop Service and an Extension may be required to provide a new service to an Applicant. ¶
¶

Deleted: <#>The Company will contribute the Transformer, Drop Service and metering equipment toward new services operating at distribution voltage (35 kV or less). When the Applicant requests an underground service, the Company's contribution will be limited to an amount for an equivalent overhead Transformer, Drop Service, and metering equipment. ¶

Deleted: OPERATION AND MAINTENANCE SURCHARGE:¶
¶
The Operation and Maintenance Surcharge is calculated as follows:¶
¶
First $2000 of Extension Costs Free¶
Extension Cost Above $2000 20%¶
¶
The $2,000 referenced above will be multiplied by the number of Customers to be served from the Extension. ¶
¶

Deleted: and the Operation and Maintenance Surcharge

SCHEDULE 74 - EXTENSIONS (Cont'd)

REFUND OF CUSTOMER PORTION OF COSTS: (Cont'd)

Company Contribution towards the Extension), without interest, in proportion to that part of the Extension that is used to provide Service and in proportion to the number of original Applicants taking Service from the Extension.

2. No share of the Extension Cost will be paid where:

(i) the contribution would be less than $200.00 per Applicant, or

(ii) more than five years have passed from the date the Extension was connected to the Company's distribution system to the date of the connection of the additional Applicant to the Extension.

3. A refund of the Extension Cost that has been received from an additional Applicant shall be made to existing Applicants.

Deleted: and the Operation and Maintenance Surcharge

Deleted: No further contributions or refunds will be paid where:
<#>
<#>the refund would be less than $200.00 per Applicant, or
<#>
<#> (ii) more than five years have passed from the date the Extension was connected to the Company's distribution system to the date of the connection of the additional Applicant to the Extension.

FINANCING:

Company financing is available on approval of credit. The CPC will be financed based on the Company's weighted average cost of capital as approved by the British Columbia Utilities Commission. A downpayment of 20% of the CPC is required from each Applicant. Financing is available for one to five year terms for extensions costing over $2,000. The Company will finance a maximum of $10,000 per Applicant.

SPECIAL CONTRACTS:

The Applicant may be required to make a contribution in addition to the CPC in the following circumstances:

1. where additional investment is required in order to upgrade or reinforce existing facilities or install new facilities to provide Service at a phase and voltage not presently available,

2. for Large General Service and Industrial Applicants, where installation and upgrading of substation and transmission facilities may be required; or

SCHEDULE 74 - EXTENSIONS (Cont'd)

SPECIAL CONTRACTS: (Cont'd)

3. for temporary or standby Service, where the Applicant may also be required to pay the cost of removal of the facilities.

Deleted: 3. where the ongoing operating cost of the Extension exceed those provided for in the Operation and Maintenance Surcharge, or¶
¶
4

In any of the the above circumstances, the Company may request the Applicant to enter into a special contract arrangement. The special contract may require the Applicant to pay for Extension Costs and upgrades or reinforcements of existing facilities, and to pay for any replacements of the Extension which may be required.

OWNERSHIP AND MAINTENANCE OF EXTENSIONS:

The Company will assume ownership and maintenance of an Extension on public or private property, upon connection of the Extension to the Company's distribution system.

EASEMENTS AND RIGHT OF WAY CLEARING:

1. The Applicant shall provide an easement for the Extension, including an easement for vehicle access to the Extension, that is acceptable to the Company. For Extensions to be constructed by the Company, such easement will be provided prior to the construction of the Extension. For all other Extensions, such easement will be provided prior to the connection of the Extension to the Company's distribution system.

2. The Applicant shall be responsible for all right of way clearing costs required for the construction of an Extension.

3. The Applicant shall ensure that all right of way clearing is performed in accordance with the Company's distribution construction standards.

DESIGN AND CONSTRUCTION REQUIREMENTS:

1. Extensions will normally be constructed overhead, but may be constructed underground where such construction is in accordance with the Company's distribution system plans.

2. Upon receipt of a request for Service requiring an Extension, the Company shall engineer and design the Extension ("Design Package"), and provide a quote of the Extension cost ("Estimate

SCHEDULE 74 - EXTENSIONS (Cont'd)

DESIGN AND CONSTRUCTION REQUIREMENTS: (Cont'd)

2. Package"). The cost of preparing the Design Package, including the cost of any revisions to the Design Package that are requested by the Applicant, shall be borne by the Applicant and shall be paid upon receipt of the Design Package. Prior to the release of the Design Package and the Estimate Package, the Applicant may be required to sign a contract that includes terms and conditions relating to the construction of the Extension.

3. The Applicant may select the Company or a contractor authorized by the Company to construct the Extension.

4. Where the Applicant selects the Company to construct the Extension, the Company will construct the Extension at the cost quoted in the Estimate Package.

5. Where the Applicant selects an authorized contractor to construct the Extension, prior to the connection of the Extension to the Company's distribution system, the Applicant will pay to the Company all additional costs, which will be estimated in advance by the Company, incurred for designing, engineering, surveying, obtaining permits, connecting to the Company's distribution system, and inspecting the Extension.

6. Extensions shall be constructed in accordance with the Design Package and in accordance with the Company's distribution construction standards and material specifications.

7. For Extensions constructed by an authorized contractor, the Company, in its sole discretion, may survey, at the cost of the Applicant, such Extensions prior to connecting the Extension to the Company's distribution system.

8. An authorized contractor may not work on any of the Company's electrical facilities, and the Company shall make all connections to or disconnections from the Company's distribution system.

The Company will not commence construction of an Extension or authorize a connection or disconnection of an Extension constructed by an authorized contractor until:

1. the Applicant has completed a contract for Service as required by Section 2.1 of the Terms and Conditions and any other required documentation;

SCHEDULE 74 - EXTENSIONS (Cont'd)

DESIGN AND CONSTRUCTION REQUIREMENTS: (Cont'd)

2. all necessary easements, permits, or licences of occupation have been obtained;

3. where applicable, construction of the new building has advanced to the point where completion seems assured, or the Applicant has provided adequate security for the amount of the Company's investment; and

4. the Applicant has paid to the Company the full estimated CPC less any amount financed by the Company and less any amount agreed to by the Company pursuant to the "Customer Portion of Costs" section found on Sheet 50 of this Schedule.

Deleted: Section 3 of

Deleted: 49.1

DEFINITIONS:

In this Schedule,

1. "Applicant" includes a corporation, partnership, or person that has applied to the Company for a Service connection that requires the construction of an Extension.

2. "Customer Portion of Costs" (CPC) means Extension Cost less the Company Contribution towards the Extension.

Deleted: plus

Deleted: the Operation and Maintenance Surcharge

3. "Company Contribution" means the Company's financial contribution towards the Extension Cost for Service as specified on Sheet 50.

4. "Extension Cost" means the Company's estimated cost of constructing an Extension including the cost of labour, material and construction equipment. Extension Cost includes the cost of connecting the Extension to the Company's distribution system, inspection costs, survey costs, permit costs. If in the Company's opinion, upgrades to the Company's distribution system would be beneficial for Service to other Customers, the extra cost of this reinforcement is excluded from the Extension Cost.

Deleted: "Drop Service" includes that portion of an overhead service connection extending not more than 30 meters onto the Applicant's property and not requiring any intermediate support on the Applicant's property. ¶
¶

Deleted: and does not include the cost of the Transformer, Drop Service and metering equipment

5. "Extension" means an addition to, or extension of, the Company's distribution system including an addition or extension on public or private property.

Deleted: , but not including the Drop Service

6. "Transformer" includes transformers, cutouts, lightning arrestors and associated equipment, and labour to install.

Deleted: "Operation and Maintenance Surcharge" is a charge for incremental operation and maintenance costs related to the Extension Cost calculated on a one-time basis.¶

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Appendix E

SCHEDULE 80 - CHARGES FOR CONNECTION OR RECONNECTION OF SERVICE TRANSFER OF ACCOUNT, TESTING OF METERS, AND VARIOUS CUSTOM WORK

Clean Version

SCHEDULE 80 - CHARGES FOR CONNECTION OR RECONNECTION OF SERVICE TRANSFER OF ACCOUNT, TESTING OF METERS, AND VARIOUS CUSTOM WORK

CHARGE FOR SERVICE: Performed During Normal Working Hours

The charge for a meter connection, transfer of an account involving either a meter connection or reconnection of a meter after disconnection for violation of the Terms and Conditions contained in this tariff will be $100.00

Where two or more meter connections are to be made for one Customer at the same time at one location, the charge shall be $100.00 for one connection or transfer and $25.00 for each additional. The $100.00 fee will not be incurred when the Customer is required to pay the charge for Connection New/Upgraded Services.

There will be a $15.00 charge for the setup or transfer of an account.

Performed During Overtime Hours

If the Customer requests the Company to perform the above functions during overtime hours, being a continuation of the normal work day for the personnel concerned, the $100.00 charge becomes $132.00

Performed During Callout Hours

If the Customer requests the Company to call out personnel to perform the above functions, the $100.00 charge becomes $339.00.

METER TESTING: The deposit for removing and replacing a meter in service for testing at the request of the Customer shall be $25.00 except where increased to defray expenses incurred.

TEMPORARY DROP SERVICE: The charge for installing a temporary Drop Service of less than 30 meters over private property shall be as prescribed in Schedule 82 plus $200.00 provided the temporary Service can be converted to the permanent Service at little additional cost.

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SCHEDULE 80 - CHARGES FOR CONNECTION OR RECONNECTION OF SERVICE, TRANSFER OF ACCOUNT, TESTING OF METERS, AND VARIOUS CUSTOM WORK (Cont'd)

TEMPORARY DROP SERVICE: (Cont'd)

If this temporary Drop Service cannot be used to form the permanent Service, and must be removed, the charge for installing and removing a temporary Drop Service of less than 30 meters shall be as prescribed in Schedule 82 plus $200 for the cost of the removal of the equipment used to supply the temporary Service. The charge for the permanent connection shall be as prescribed in Schedule 82, in addition to the charge for installation and removal of a temporary Drop Service of less than 30 meters.

DISCONNECTION AND RECONNECTION OF METER: The standard charge for a disconnection and subsequent reconnection of a meter at the meter location shall be $200.00 provided such work can be performed during normal working hours.

RELOCATION OF EXISTING SERVICE: The charge for the relocating of a Service requiring a Drop Service change on the same building shall be $673.00 provided such work can be performed during normal working hours. The Service entrance and meter box shall be in a location satisfactory to the Company.

CUSTOM WORK: The Company may recover the full cost of the following custom work:

1. At the Customer's request, when a special trip is necessary to inspect a Service due to an outage and the fault is found to be beyond the point of delivery, the Company shall be reimbursed for the full cost.

2. Installation of facilities beyond those considered necessary by the Company in order to provide Service and not provided for elsewhere in the Company's tariff.

3. Replacement or repair of facilities damaged by other than reasonable wear and tear.

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SCHEDULE 80 - CHARGES FOR CONNECTION OR RECONNECTION OF SERVICE, TRANSFER OF ACCOUNT, TESTING OF METERS, AND VARIOUS CUSTOM WORK (Cont'd)

CUSTOM WORK: (Cont'd)

4. At the Customer's request, relocation of the Service to permit tree trimming, construction, etc., where recovery of the costs are not provided for in the standard charges above.

RETURNED CHEQUE SERVICE CHARGE: If a cheque received from a Customer for the payment of an electric Service account or other billing is returned by the Bank for the reason of Not Sufficient Funds (N.S.F.) or reasons other than clerical error, the Customer will be charged a service charge of $19.00.

COLLECTION CHARGE: A collection charge of $12.00 per occurrence may be levied if it is necessary for a Company representative to attend a Customer's Premises more than twice in one calendar year for the purposes of affixing a disconnect notice to the Customer's Premises.

METER ACCESS CHARGE: If it is necessary for the Company to install a remote metering device, a charge of $152.00 for a single phase remote meter, or $310.00 for a poly phase remote meter, shall be levied.

FALSE SITE VISIT CHARGE: A charge of $182.00 per occurrence may be levied if a FortisBC representative attends a Customer's Premises at the request of a Customer but, on attending, is unable to perform the requested work because the facilities required to be provided by the Customer, for this purpose, are found to be deficient.

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Appendix E

SCHEDULE 80 - CHARGES FOR CONNECTION OR RECONNECTION OF SERVICE TRANSFER OF ACCOUNT, TESTING OF METERS, AND VARIOUS CUSTOM WORK

Black-Line Version

RATE SCHEDULES

Electric Tariff
B.C.U.C. No. 2
Sheet 55

SCHEDULE 80 - CHARGES FOR CONNECTION OR RECONNECTION OF SERVICE TRANSFER OF ACCOUNT, TESTING OF METERS, AND VARIOUS CUSTOM WORK

CHARGE FOR SERVICE: Performed During Normal Working Hours

The charge for a meter connection, transfer of an account involving either a meter connection or reconnection of a meter after disconnection for violation of the Terms and Conditions contained in this tariff will be $100.00

Where two or more meter connections are to be made for one Customer at the same time at one location, the charge shall be $100.00 for one connection or transfer and $25.00 for each additional. The $100.00 fee will not be incurred when the Customer is required to pay the charge for Connection New/Upgraded Services.

There will be a $15.00 charge for the setup or transfer of an account.

Performed During Overtime Hours

If the Customer requests the Company to perform the above functions during overtime hours, being a continuation of the normal work day for the personnel concerned, the $100.00 charge becomes $132.00

Performed During Callout Hours

If the Customer requests the Company to call out personnel to perform the above functions, the $100.00 charge becomes $339.00.

METER TESTING: The deposit for removing and replacing a meter in service for testing at the request of the Customer shall be $25.00 except where increased to defray expenses incurred.

TEMPORARY DROP SERVICE: The charge for installing a temporary Drop Service of less than 30 meters over private property shall be as prescribed in Schedule 82 plus $200.00 provided the temporary Service can be converted to the permanent Service at little additional cost.

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RATE SCHEDULES

Electric Tariff
B.C.U.C. No. 2
Sheet 56

SCHEDULE 80 - CHARGES FOR CONNECTION OR RECONNECTION OF SERVICE, TRANSFER OF ACCOUNT, TESTING OF METERS, AND VARIOUS CUSTOM WORK (Cont'd)

TEMPORARY DROP SERVICE: (Cont'd)

If this temporary Drop Service cannot be used to form the permanent Service, and must be removed, the charge for installing and removing a temporary Drop Service of less than 30 meters shall be as prescribed in Schedule 82 plus $200 for the cost of the removal of the equipment used to supply the temporary Service. The charge for the permanent connection shall be as prescribed in Schedule 82, in addition to the charge for installation and removal of a temporary Drop Service of less than 30 meters.

DISCONNECTION AND RECONNECTION OF METER: The standard charge for a disconnection and subsequent reconnection of a meter at the meter location shall be $200.00 provided such work can be performed during normal working hours.

RELOCATION OF EXISTING SERVICE: The charge for the relocating of a Service requiring a Drop Service change on the same building shall be $673.00 provided such work can be performed during normal working hours. The Service entrance and meter box shall be in a location satisfactory to the Company.

CUSTOM WORK: The Company may recover the full cost of the following custom work:

1. At the Customer's request, when a special trip is necessary to inspect a Service due to an outage and the fault is found to be beyond the point of delivery, the Company shall be reimbursed for the full cost.

2. Installation of facilities beyond those considered necessary by the Company in order to provide Service and not provided for elsewhere in the Company's tariff.

3. Replacement or repair of facilities damaged by other than reasonable wear and tear.

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SCHEDULE 80 - CHARGES FOR CONNECTION OR RECONNECTION OF SERVICE, TRANSFER OF ACCOUNT, TESTING OF METERS, AND VARIOUS CUSTOM WORK (Cont'd)

CUSTOM WORK: (Cont'd)

4. At the Customer's request, relocation of the Service to permit tree trimming, construction, etc., where recovery of the costs are not provided for in the standard charges above.

RETURNED CHEQUE SERVICE CHARGE: If a cheque received from a Customer for the payment of an electric Service account or other billing is returned by the Bank for the reason of Not Sufficient Funds (N.S.F.) or reasons other than clerical error, the Customer will be charged a service charge of $19.00.

COLLECTION CHARGE: A collection charge of $12.00 per occurrence may be levied if it is necessary for a Company representative to attend a Customer's Premises more than twice in one calendar year for the purposes of affixing a disconnect notice to the Customer's Premises.

METER ACCESS CHARGE: If it is necessary for the Company to install a remote metering device, a charge of $152.00 for a single phase remote meter, or $310.00 for a poly phase remote meter, shall be levied.

FALSE SITE VISIT CHARGE: A charge of $182.00 per occurrence may be levied if a FortisBC representative attends a Customer's Premises at the request of a Customer but, on attending, is unable to perform the requested work because the facilities required to be provided by the Customer, for this purpose, are found to be deficient.

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Derivation of Updated Standard Charges

Basis for Calculation of Rate Schedule 80 Standard Charges

Meter Connection or Reconnection

Based on system weighted average times and costs for FortisBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 1 Power Line Technician	
Labour	- 0.25 hours site time + 0.60 hours travel time	
	= 0.85 hours	
Crew Labour (including loadings)		
	= 0.85 hours x $66.10 (standard labour rate)	= $56.19
Admin	- 1 admin staff	
Labour	- 0.25 hours	
Admin labour (including loadings)		
	= 0.25 hours x $ 46.56 (standard labour rate)	= $11.64
Total Labour		**= $67.83**
Vehicle Cost		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 0.85 hours x $22.29 (vehicle rate)	= $18.95
Subtotal		**= $86.78**
Overhead loadings = 15% x $86.78		= $13.02
TOTAL FOR SERVICE		**= $99.80**
Rounded		**= $100**

Additional Meter Connection or Reconnection

Based on system weighted average times and costs for FortisBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 1 Power Line Technician	
Labour	- 0.25 hours site time	
	= 0.25 hours	
Crew Labour (including loadings)		
	= 0.25 hours x $66.10 (standard labour rate)	= $16.53
Total Labour		**= $16.53**

Vehicle Cost

Vehicle Use	- 1 Service truck	
Vehicle Use	- 0.25 hours x $22.29 (vehicle rate)	= $5.57

Subtotal	**= $22.10**
Overhead loadings = 15% x $22.10	= $3.31
TOTAL FOR SERVICE	**= $25.41**
Rounded	**= $25**

<u>Account Setup Charge</u>

Based on system weighted average times and costs for FortisBC's service area:

<u>Total labour (standard labour rates including loadings)</u>

Crew	- 1 Meter Reader	
Labour	- 0.13 hours site time	
	= 0.13 hours	
Crew Labour (including loadings)		
	= 0.13 hours x $43.42 (standard labour rate)	= $5.64
Admin	- 1 admin staff	
Labour	- 5 minutes TCC x $46.56 (standard labour rate)	= $3.89
	- 5 minutes account maint. x $43.24 (std. labour rate)	= $3.60
Total Labour		**= $13.13**
Subtotal		**= $13.13**
Overhead loadings = 15% x $13.13		= $1.96
TOTAL FOR SERVICE		**= $15.10**
Rounded		**= $15**

Meter Connection or Reconnection Performed During Overtime Hours

Based on system weighted average times and costs for FortisBC's service area:

Total labour (overtime labour rates including loadings)

Crew	- 1 Power Line Technician	
Labour	- 0.25 hours site time + 0.60 travel time	
	= 0.85 hours	
Crew Labour (including loadings)		
	= 0.85 hours x $104.42 (overtime labour rate)	= $88.76
Admin	- 1 admin staff	
Labour	- 0.25 hours	
Admin labour (including loadings)		
	= 0.25 hours x $ 46.56 (standard labour rate)	= $11.64
Total Labour		**= $100.40**
Vehicle Cost		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 0.85 hours x $22.29 (vehicle rate)	= $18.95
Subtotal		**= $119.35**
Overhead loadings (excluding overtime labour)		
	= 15% x $86.78	= $13.02
TOTAL FOR SERVICE		**= $132.37**
Rounded		**= $132**

Meter Connection or Reconnection Performed During Callout Hours

Based on system weighted average times and costs for FortisBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 1 Power Line Technician	
Labour	- 4 hours site time & travel time (minimum 4 hour)	
	= 4 hours	
Crew Labour (including loadings)		
	= 4 hours x $66.10 (standard labour rate)	= $264.40
Admin	- 1 admin staff	
Labour	- 0.25 hours	
Admin labour (including loadings)		
	= 0.25 hours x $ 46.56 (standard labour rate)	= $11.64
Total Labour		**= $276.04**
Vehicle Cost		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 0.85 hours x $22.29 (vehicle rate)	= $18.95
Subtotal		**= $294.99**
Overhead loadings = 15% x $294.99		= $44.25
TOTAL FOR SERVICE		**= $339.24**
Rounded		**= $339**

Transfer of Overhead Temporary Service to Permanent OR Salvage

Based on system weighted average times and costs for FortisBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 1 Power Line Technician	
Labour	- 0.5 hours site time + 1 hours travel time	
	= 1.5 hours	
Crew Labour (including loadings)		
	= 1.5 hours x $66.10 (standard labour rate)	= $99.15
Admin	- 1 admin staff	
Labour	- 0.33 hours	
Admin labour (including loadings)		
	= 0.33 hours x $ 46.56 (standard labour rate)	= $15.36
Total Labour		**= $114.51**
Vehicle and Material Cost		
Vehicle Use	- 1 Bucket Service truck	
Vehicle Use	- 1.5 hours x $39.76 (vehicle rate)	= $59.64
Subtotal		**= $174.15**
Overhead loadings = 15% x $174.15		= $26.12
TOTAL FOR SERVICE		**= $200.27**
Rounded		**= $200.00**

Disconnection and Reconnection of Meter

Based on system weighted average times and costs for FortisBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 1 Power Line Technician	
Labour	- 0.5 hours site time + 1.2 hours travel time	
	= 1.7 hours	
Crew Labour (including loadings)		
	= 1.7 hours x $66.10 (standard labour rate)	= $112.37
Admin	- 1 admin staff	
Labour	- 0.5 hours	
Admin labour (including loadings)		
	= 0.5 hours x $ 46.56 (standard labour rate)	= $23.28
Total Labour		**= $135.65**
Vehicle Cost		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 1.7 hours x $22.29 (vehicle rate)	= $37.89
Subtotal		**= $173.54**
Overhead loadings = 15% x $173.54		= $26.03
TOTAL FOR SERVICE		**= $199.57**
Rounded		**= $200**

Relocation of Existing Service

Based on system weighted average times and costs for FortisBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 1 Power Line Technician	
Labour	- 3 hours site time + 2 hours travel time	
	= 5 hours	
Crew Labour (including loadings)		
	= 5 hours x $66.10 (standard labour rate)	= $330.51
Admin	- 1 admin staff	
Labour	- 0.75 hours	
Admin labour (including loadings)		
	= 0.75 hours x $ 46.56 (standard labour rate)	= $34.92
Total Labour		**= $365.43**
Vehicle and Material Cost		
Vehicle Use	- 1 Bucket Service truck	
Vehicle Use	- 5 hours x $39.76 (vehicle rate)	= $198.80
Material	- Connectors	
	= $20.00 + 7% loadings	= $21.40
Subtotal		**= $585.63**
Overhead loadings = 15% x $585.63		= $87.84
TOTAL FOR SERVICE		**= $673.47**
Rounded		**= $673.00**

Returned Cheque Service Charge

Based on system weighted average times and costs for FortisBC's service area:

Total labour (standard labour rates including loadings)

Customer Service - 1 Customer Service Staff

Labour - 0.33 hours

Labour (including loadings)

	= 0.33 hours x $46.56 (standard labour rate)	= $15.36
Total Labour		**= $15.36**
Subtotal		**= $15.36**
Overhead loadings = 15% x $15.36		= $2.30
Returned Cheque Bank Fees		= $1.50
TOTAL FOR SERVICE		**= $19.16**
Rounded		**= $19.00**

Collection Charge

Based on system weighted average times and costs for FortisBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 1 Meter Reader Staff	
Labour	- 0.13 hours	
Labour (including loadings)		
	= 0.13 hours x $43.42 (standard labour rate)	= $5.64
Admin	- 1 admin staff	
Labour	- 0.083 hours	
Admin labour (including loadings)		
	= 0.083 hours x $ 46.56 (standard labour rate)	= $3.86
Total Labour		**= $9.50**
Material Cost		
Material	- Tags	
	= $1.00 + 7% loadings	= $1.07
Subtotal		**= $10.57**
Overhead loadings = 15% x $10.57		= $1.59
TOTAL FOR SERVICE		**= $12.16**
Rounded		**= $12.00**

Meter Access Charge (Remote meter – Single Phase)

Based on system weighted average times and costs for FortisBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 1 Power Line Technician	
Labour	- 0.25 hours site time + 0.60 hours travel time	
Labour (including loadings)		
	= 0.85 hours x $66.10 (standard labour rate)	= $56.19
Admin	- 1 admin staff	
Labour	- 0.25 hours	
Admin labour (including loadings)		
	= 0.25 hours x $ 46.56 (standard labour rate)	= $11.64
Total Labour		**= $67.83**
Vehicle and Material Cost		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 0.85 hours x $22.29 (vehicle rate)	= $18.95
Material	- Incremental single phase meter	
	= $42.82 + 7% loadings	= $45.82
Subtotal		**= $132.60**
Overhead loadings = 15% x $132.60		= $19.89
TOTAL FOR SERVICE		**= $152.49**
Rounded		**= $152**

Meter Access Charge (Remote meter – Poly Phase)

Based on system weighted average times and costs for FortisBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 1 Power Line Technician	
Labour	- 0.25 hours site time + 0.60 hours travel time	
Labour (including loadings)		
	= 0.85 hours x $66.10 (standard labour rate)	= $56.19
Admin	- 1 admin staff	
Labour	- 0.25 hours	
Admin labour (including loadings)		
	= 0.25 hours x $ 46.56 (standard labour rate)	= $11.64
Total Labour		**= $67.83**
Vehicle and Material Cost		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 0.85 hours x $22.29 (vehicle rate)	= $18.95
Material	- Incremental single phase meter	
	= $171.14 + 7% loadings	= $183.12
Subtotal		**= $269.90**
Overhead loadings = 15% x $269.90		= $40.48
TOTAL FOR SERVICE		**= $310.38**
Rounded		**= $310**

False Site Visit Charge

Based on system weighted average times and costs for FortisBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 1.5 Power Line Technicians	
Labour	- 0.3 hours site time + 1 hours travel time	
	= 1.95 hours	
Crew Labour (including loadings)		
	= 1.95 hours x $66.10 (standard labour rate)	= $128.90
Total Labour		**= $128.90**

Vehicle and Material Cost

Vehicle Use	- 1 Service truck	
Vehicle Use	- 1.30 hours x $22.29 (vehicle rate)	= $28.98
Subtotal		**= $157.88**
Overhead loadings = 15% x $157.88		= $23.68
TOTAL FOR SERVICE		**= $181.56**
Rounded		**= $182**

Estimated Revenue Impact

Service	Existing Charge	Updated Charge	Approx 2008 Count	Approx 2008 Revenue	Approx Updated Annual Revenue	Increase / (Decrease)
Meter connection or reconnection	$27.00	$100.00	3609	$ 97,000	$ 361,000	**$ 264,000**
Additional meter connection	$6.00	$25.00	0	$ -	$ -	**$ -**
Account Setup Charge	$27.00	$15.00	10986	$ 297,000	$ 165,000	**$ (132,000)**
Account Setup Charge - no reading	$6.00	$15.00	2308	$ 14,000	$ 35,000	**$ 21,000**
Meter connection or reconnection (overtime hours)	$55.00	$132.00	159	$ 9,000	$ 21,000	**$ 12,000**
Meter connection or reconnection (callout hours)	$120.00	$339.00	35	$ 4,000	$ 12,000	**$ 8,000**
Meter Testing	$25.00	$25.00	0	$ -	$ -	**$ -**
Temporary Drop Service (to be used for permanent service or salvaged)	$200.00	$200.00	197	$ 39,000	$ 39,000	**$ -**
Meter disconnection and reconnection	$50.00	$200.00	0	$ -	$ -	**$ -**
Relocation of existing service	$200.00	$673.00	8	$ 2,000	$ 5,000	**$ 3,000**
Returned cheque service charge	$20.00	$19.00	434	$ 9,000	$ 8,000	**$ (1,000)**
		$152.00 (single phase remote meter)	0	$ -	$ -	**$ -**
Meter Access Charge	$170.00	$310.00 (poly phase remote meter)	0	$ -	$ -	**$ -**
				$ 471,000	**$ 646,000**	**$ 175,000**

Appendix F

SCHEDULE 82 - CHARGES FOR INSTALLATION OF NEW / UPGRADED SERVICES

Clean Version

SCHEDULE 82 - CHARGES FOR INSTALLATION OF NEW/UPGRADED SERVICES

APPLICABLE:

To all new service installations or increases in service size of existing services.

CHARGE FOR SERVICE:

Residential Service, Commercial Service, Lighting Type III and Irrigation
Customers are required to provide their Electrical Inspection Permit for verification of the service size.

Where customers supply their own transformation from the primary distribution voltage, the rate for Large Commercial Service and Industrial Service will apply.

The charge for the installation of a new or upgrading of an existing service is:

Overhead – Single Phase	200 Amps or less	$533.00
	400 Amps	$937.00
Underground – Single Phaase	200 Amps or less	$565.00

For service connections only requiring the installation of a meter, the Customer shall pay the charge for a meter connection as specified in Schedule 80.

For all other service connections and a meter, the applicant shall pay the Customer Portion of Costs of the service connection as determined under Schedule 74, which shall include the installation cost of the meter.

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FORTISBC INC. BRITISH COLUMBIA UTILITIES COMMISSION

By: ______________________ By: ______________________
Commission Secretary

EFFECTIVE (applicable to consumption on and after) ______________________

Appendix F

SCHEDULE 82 - CHARGES FOR INSTALLATION OF NEW / UPGRADED SERVICES

Black-Line Version

SCHEDULE 82 - CHARGES FOR INSTALLATION OF NEW/UPGRADED SERVICES

APPLICABLE:

To all new service installations or increases in service size of existing services.

CHARGE FOR SERVICE:

Residential Service, Commercial Service, Lighting Type III and Irrigation
Customers are required to provide their Electrical Inspection Permit for verification of the service size.

Where customers supply their own transformation from the primary distribution voltage, the rate for Large Commercial Service and Industrial Service will apply.

The charge for the installation of a new or upgrading of an existing service is:

Overhead – Single Phase	200 Amps or less	$533.00
	400 Amps	$937.00
Underground – Single Phaase	200 Amps or less	$565.00

For service connections only requiring the installation of a meter, the Customer shall pay the charge for a meter connection as specified in Schedule 80.

For all other service connections and a meter, the applicant shall pay the Customer Portion of Costs of the service connection as determined under Schedule 74, which shall include the installation cost of the meter.

Deleted: SINGLE PHASE:

Deleted: $200.00

PLUS

$3.00 per ampere above 100 amperes for single phase

The service size of multi-unit buildings will be determined by the size of the main service.

THREE PHASE: $200.00

PLUS

$3.00 x 1.7 x Supply Voltage x Service Amperage
240

(b) Large General Service and Industrial

$200.00. Where the Company is required to add additional facilities, a customer contribution may be required.

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Derivation of Updated Standard Charges

Basis for Calculation of Rate Schedule 82 Charges

Overhead Single Phase – New Connection or Upgrade 200 Amps or Less

Based on system weighted average times and costs for FortisBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 2 Power Line Technician	
Labour	- 1.5 hours site time + 1.0 hours travel time	
	= 2.5 hours	
Crew Labour (including loadings)		
	= 4 hours x $66.10 (standard labour rate)	= $264.40
Admin	- 1 admin staff	
Labour	- 0.75 hours	
Admin labour (including loadings)		
	= 0.75 hours x $ 46.56 (standard labour rate)	= $34.92
Total Labour		**= $299.32**
Vehicle Cost		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 2.5 hours x $22.29 (vehicle rate)	= $55.73
Material Cost – 30m #2 triplex & related items		
	= $101.00 + 7% loadings	= $108.07
Subtotal		**= $463.12**
Overhead loadings = 15% x $463.12		= $69.47
TOTAL FOR SERVICE		**= $532.59**
Rounded		**= $533**

Overhead Single Phase – New Connection or Upgrade 400 Amps

Based on system weighted average times and costs for FortisBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 2 Power Line Technician	
	- 1 Meter Technician	
Labour	- 1.75 hours PLT site time + 1.0 hours travel time	
	- 2.0 hours Meter Tech site time + 1.0 hours travel time	
	= 5.75 hours	
Crew Labour (including loadings)		
	= 7.5 hours x $66.10 (standard labour rate)	= $495.75
Admin	- 1 admin staff	
Labour	- 0.75 hours	
Admin labour (including loadings)		
	= 0.75 hours x $ 46.56 (standard labour rate)	= $34.92
Total Labour		**= $530.67**

Vehicle Cost

Vehicle Use	- 1 Service truck (Meter Tech)	
Vehicle Use	- 3.0 hours x $22.29 (vehicle rate)	
Vehicle Use	- 1 Bucket Service truck (PLT)	
Vehicle Use	- 2.75 hours x $39.76 (vehicle rate)	= $176.21

Material Cost – 30m #2 triplex & related items

	= $101.00 + 7% loadings	= $108.07

Subtotal	**= $814.95**
Overhead loadings = 15% x $814.95	= $122.24
TOTAL FOR SERVICE	**= $937.19**
Rounded	**= $937**

Underground Single Phase – New Connection or Upgrade 200 Amps or Less

Based on system weighted average times and costs for FortisBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 2 Power Line Technician	
Labour	- 1.5 hours site time + 1.0 hours travel time	
	= 2.5 hours	
Crew Labour (including loadings)		
	= 4 hours x $66.10 (standard labour rate)	= $264.40
Admin	- 1 admin staff	
Labour	- 0.75 hours	
Admin labour (including loadings)		
	= 0.75 hours x $ 46.56 (standard labour rate)	= $34.92
Total Labour		**= $299.32**
Vehicle Cost		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 2.5 hours x $22.29 (vehicle rate)	= $55.73
Material Cost – 30m 1/0 cable & related items		
	= $127.00 + 7% loadings	= $135.89
Subtotal		**= $490.94**
Overhead loadings = 15% x $490.94		= $73.64
TOTAL FOR SERVICE		**= $564.58**
Rounded		**= $565**

Appendix G

SCHEDULE 90 - DEMAND-SIDE MANAGEMENT SERVICES

Amended Tariff Schedule

SCHEDULE 90 DEMAND-SIDE MANAGEMENT SERVICES

APPLICABLE: To all Customers in all areas served by the Company and its municipal wholesale Customers.

OBJECTIVE: The purpose of the Company's Demand-Side Management (DSM) Services is to promote the efficient use of electricity, in terms of consumption (Conservation) and/or timing (Demand Response).

PROGRAMS: DSM programs, compliant with applicable regulations, address electrical end-uses, through approved Measure(s), which may consist of an energy-efficient product, device, piece of equipment, system, building or process design and/or operational practice which exceeds applicable codes and/or current practice.

The Company will maintain an updated DSM program listing on its website, available in print format, detailing current program offerings and rules.

FINANCIAL DETAILS: DSM programs will consist of monetary incentives provided by the Company in the form of custom option or product option offerings to promote the purchase and installation of approved Measures. Incentives are targeted to Customers but may also be provided to trade allies who provide or install the Measures.

Monetary incentives are based on the annual kWh savings, or the on-peak kW reduction, attained through the Measure as determined on a prescriptive or custom calculation basis.

Monetary incentives are capped to the lesser of:

i. the Company's long-term avoided power purchase costs,
ii. 50% of installed Measure cost for existing construction,
iii. 100% of incremental cost for new construction, or
iv. The amount sufficient for the Customer to achieve a two-year payback.

Monetary incentives may alternately consist of low-cost financing O.A.C. for residential Customers only.

DSM Services may also consist of non-monetary offerings in the form of: public information, educational programs, or training; audits of Customer Premises or processes or Measures and reports thereof; product samples; pilot projects to test new Measures; and market transformation activities undertaken in conjunction with other utilities and/or governments.

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By: ______________________ By: ______________________
Commission Secretary

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SCHEDULE 90 DEMAND-SIDE MANAGEMENT SERVICES (Cont'd)

TERMS AND CONDITIONS

The following terms and conditions are an integral part of the Demand-Side Management Services listed under Schedule 90:

Financial Incentives

1. In order to be eligible for financial incentives, a Customer must receive the Company's approval prior to initiation of work on the approved Measure.

2. Only those audit or upgrade costs which are pertinent to DSM considerations will be eligible for financial incentives. An estimate of costs related to such issues as obsolescence, depreciation, maintenance, plant betterment and environmental concerns will be made to isolate that portion of the cost strictly related to energy.

3. Where incentives are in excess of $10,000, payment of one half of the rebate will be deferred for up to one year. Upon confirmation of project savings, the remaining portion of the rebate will be paid pro rata to the energy savings. No interest will be paid on the withheld portion. Irrespective of actual savings, the final rebate will not exceed the original estimated rebate.

4. For those Customers in receipt of an incentive in excess of $20,000, the unamortized balance of financial incentives paid to or on behalf of the Customer, under Rate Schedule 90 shall be remitted to the Company within 30 days of billing, if:

   (a) the incented equipment or facilities are disabled or removed;

   (b) the Customer's electrical load is reduced by more than 50% for a continuous period of twelve months or longer; or

   (c) over 50% of the electricity previously provided by the Company is replaced by another source including self-generation or another supplier.

   In regards to (c) above, the repayment shall be prorated based on the amount of energy replaced compared to the amount of energy supplied by the Company in the year immediately preceding the electricity replacement.

5. Any consulting or study subsidy offered under the Demand-Side Management tariff is contingent upon available budget and resources. When the Company pays more than $1,500 for these Services on behalf of a Customer, any incentive amount that is eventually payable to that Customer will be reduced by the amount of the consulting or study contribution.

Appendix G

SCHEDULE 90 - DEMAND-SIDE MANAGEMENT SERVICES

Current Tariff Schedule

SCHEDULE 90 - ENERGY MANAGEMENT SERVICE

APPLICABLE: To all residential Customers in all areas served by the Company and its municipal wholesale customers.

RESIDENTIAL PROGRAMS

1. New Home Construction

OBJECTIVE: To develop and promote energy efficient construction standards and optional high efficiency heating and cooling technologies for new residential dwellings.

DESCRIPTION: This program is targeted at multi-unit developers and single family housing customers who heat electrically.

The program provides incentives for high efficiency lighting and energy efficient windows. Incentives related to high efficiency heating and air conditioning technologies are described under the heat pump program.

FINANCIAL DETAILS:

Upon implementing specified energy efficiency measures, the participant will be eligible for:

- Incentives on lighting and window upgrades, which reduce the participant's payback to a maximum 3-year period.
- To meet this payback criterion, developers will be eligible for up to $2.50 per square foot (SF) of energy efficient window and single-family housing customers will be eligible for $1.50 per SF.
- All customers will be eligible for 10 compact fluorescent light bulbs per residential unit.
- Recognition including a PowerSense certificate, site signs and advertising as may be appropriate.

2. Home Improvements Program

OBJECTIVE: To develop and promote energy efficient retrofits for electrically heated residences.

Issued July 7, 2004
FORTISBC INC.

By: Robert Meyers
Vice President Finance and CFO

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EFFECTIVE (applicable to consumption on and after) June 1, 2004

SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

RESIDENTIAL PROGRAMS: (Cont'd)

2. Home Improvements Program (Cont'd)

DESCRIPTION: Under this program, any customer with an electrically heated residence is eligible for a free energy audit. Recommendations to improve energy efficiency will be made. A combination of loans and grants will be available to customers for qualified projects. In addition, customers using electricity for hot water heating will have a free energy saving hot water kit installed.

Typical recommendations include upgrading of insulation in ceilings to R48, walls to R24, heated basements to R20 and floors to R28. Measures to reduce air infiltration such as weather stripping doors and windows and caulking cracks and the installation of vapour barriers are covered. Energy rated windows, thermal doors and digital thermostats are examples of products that are also eligible for financial assistance.

FINANCIAL DETAILS: Financial assistance is available for all owners of electrically heated residential dwellings.

The company will calculate a grant for energy saving measures based on 5 cents per kW.h saved. For the period September 1 to December 31, 2003, the company will pay $75 for each qualifying high efficiency fan motor furnace.

Customers are eligible for loans on approved credit (OAC) through TD Canada Trust for energy efficiency measures. Loans will be available up to $25,000 at 5-year fixed rates with an amortization period of 10 years.

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By: Robert Meyers
Vice President Finance and CFO

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Commission Secretary

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SCHEDULE 90 – ENERGY MANAGEMENT SERVICE (Cont'd)

RESIDENTIAL PROGRAMS: (Cont'd)

3. Residential Lighting

OBJECTIVE: To encourage the installation or replacement of incandescent lighting with compact fluorescent lamps and other energy efficient fixtures where projected annual use is greater than 1800 hours, in single or multi-unit residential dwellings.

DESCRIPTION: The promotion will provide financial incentives and consumer information on the benefits of compact fluorescents and energy efficient lighting.

FINANCIAL DETAILS: Financial incentives and rebates are the same as those outlined in General Servie lighting programs.

4. Heat Pumps

OBJECTIVE: To create customer awareness and to promote the installation of energy efficient heat pumps in residential dwellings.

DESCRIPTION: Qualifying residential Customers will be eligible for a grant or low interest loan towards the installed cost of a ground source or air source heat pump provided the following conditions are met:

1. The system equipment design and installation must meet the requirements of CSA Standards.
2. The seasonal energy efficiency ratio (SEER) and Heating Seasonal Performance Factor (HSPF) must meet PowerSense efficiency standards and must be greater or equal to 12.0

FINANCIAL DETAILS: At the customer's option, the following incentives are available for the purchase of a heat pump:

- A cash grant of 5¢/kW.h saved or,
- A $5,000 loan (OAC) fixed at 4.9% with a term and amortization of 10 years, or
- A cash grant of 5¢/kW.h saved plus a preferred interest and a loan of up to $25,000 from TD Canada Trust at a preferred interest rate.

5. Load Shifting Program

OBJECTIVE: To encourage the adoption of load shifting technologies, such as Electrical Thermal Storage (ETS) devices and domestic hot water (DHW) controls, through a demonstration initiative ending December 21, 2001.

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Vice President Finance and CFO

By: ____________
Commission Secretary

EFFECTIVE (applicable to consumption on and after) June 1, 2004

SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

RESIDENTIAL PROGRAMS: (Cont'd)

5. Load Shifting Program (Cont'd)

QUALIFYING CUSTOMERS: Qualifying customers include those electric heat customers in apartments and seasonal lodges with baseboard heat, or any electric heat customers at Big White Ski Resort, subject to funding availability.

DESCRIPTION: Qualifying customers will be eligible for the installed cost of ETS units, controls, a larger DHW tank (if necessary) and a Time of Use (TOU) meter.

The Company will provide periodic information and feedback data to participants in order to encourage lifestyle changes that will augment the load shifting opportunities and associated savings.

FINANCIAL DETAILS: The Company will pay the incremental cost of installing the necessary ETS units and DHW controls for qualifying customers. Those customers will enter into an initial eight (8) year contract that provides for an equal sharing of the positive difference between the standard rate and the Time of Use (TOU) rate. After the initial 8 year term, if the customer chooses to continue to participate in the program, the Company will pay the customer 85% of the difference described above.

The Company will install a TOU meter on the site to determine the overall TOU savings and calculate each participant's share thereof. The minimum payment to a participating customer will be $24 per annum.

6. Refrigerator Recovery Program

OBJECTIVE: To improve energy efficiency in households by eliminating under-utilised second refrigerators through a pick-up and recycling service.

Issued July 7, 2004
FORTISBC INC.

By: Robert Meyers
Vice President Finance and CFO

Accepted for filing ____________
BRITISH COLUMBIA UTILITIES COMMISSION

By: ____________
Commission Secretary

EFFECTIVE (applicable to consumption on and after) June 1, 2004

SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

RESIDENTIAL PROGRAMS: (Cont'd)

6. Refrigeration Recovery Program: (Cont'd)

DESCRIPTION: This program is a co-operative effort involving the Company and regional districts and municipal operators of solid waste disposal sites in the service area. It is aimed at integrating services related to collecting and recycling the scrap metal from appliances and freon from unwanted or under-utilised refrigerators.

It is delivered by a qualified contractor who will arrange for the appliance pick-up and is licensed to extract and recover freon from refrigerators. The contractor has a toll-free number through which customers can schedule the pick-up and confirm the cost for the units being collected.

The Company provides an administration allowance for the contractor and pays for advertising costs to encourage customer participation.

FINANCIAL DETAILS: The refrigerator recovery initiative is a user pay program. The Customer pays the contractor directly for the service being provided.

The Company will negotiate refrigerator recovery rates with the program contractor to ensure good value for participating customers.

GENERAL SERVICE PROGRAMS

AVAILABLE: To all General Service Customers in all areas served by the Company and its Municipal Wholesale Customers.

1. New Building and Process Design

OBJECTIVE: To promote energy efficient technologies, design and construction in new commercial, institutional and small industrial buildings.

DESCRIPTION: The program aims to introduce higher standards of energy efficiency in new commercial, institutional and small industrial buildings through technical and financial assistance.

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SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

GENERAL SERVICE PROGRAMS (Cont'd)

1. New Building and Process Design: (Cont'd)

The Company will perform a preliminary review of the building plans. Based on the results of this review, we may assist in providing a more comprehensive energy study of the Customer's plans, to identify major uses of electricity and propose opportunities for electrical energy conservation measures.

FINANCIAL DETAILS: The Company will provide a free initial assessment of energy efficiency in the building design. At the Company's option, the services of a consultant may be used to determine the best combination of energy saving measures. Under this option, the Company will pay for 50% of the approved review costs, to a maximum of $5000.

For energy conservation measures not covered under existing programs, financial incentives will be based on 1 cent per estimated annual kW.h saved times the lesser of 5 years or product life. The maximum rebate is the lesser of 100% of the incremental cost of energy conservation measures or that amount required to bring the Customer's payback to two years. The energy conservation measure must exceed standard levels of construction as identified by Power Sense.

The Company will install a free energy saving hot water kit where appropriate.

OBJECTIVE: To upgrade equipment, technologies and building envelope to more energy efficient levels in existing commercial, institutional and small industrial buildings.

DESCRIPTION: This program combines all applicable technologies to help Customers make existing buildings more energy efficient.

We will provide a "walk through" inspection to identify any energy saving measures.

Based on the results of the "walk through" audit, we may assist in providing a more comprehensive energy study of the Customer's building to identify major uses of electricity and propose electrical energy conservation measures.

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Vice President Finance and CFO

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SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

GENERAL SERVICE PROGRAMS (Cont'd)

2. Building and Process Improvements

FINANCIAL DETAILS: The "walk through" inspection is free.

For Customers requiring a more comprehensive study, we will pay 50% of the energy study costs paid for an approved consultant to a maximum of $5,000.

Financial incentives to encourage the implementation of identified energy conservation measures include existing product rebates and custom options. The building improvement program will provide rebates of 1 cent per estimated annual kW.h saved times the lesser of 5 years or product life. The maximum rebate is the lesser of 50% of the project's total incremental cost or that amount required to bring the Customer's payback to two years.

The Company will install a free energy saving hot water kit for applications where an electric hot water tank is used.

3. (i) Lighting

OBJECTIVE: To encourage commercial, institutional and small industrial Customers to adopt energy-efficient lighting technologies.

DESCRIPTION: This program of information and rebates will promote the use of efficient lighting equipment such as:

- energy-saving fluorescent lamps and ballasts
- energy-efficient alternatives to standard incandescent lamps
- reflectors for fluorescent lighting fixtures
- lighting controls
- metal halide and high-pressure and low-pressure sodium high-intensity discharge lighting systems

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SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

GENERAL SERVICE PROGRAMS (Cont'd)

3. (i) Lighting (Cont'd)

FINANCIAL DETAILS:

PRODUCT REBATE OPTION

Incandescent bulb	Compact fluorescent	$7.50 (Adapter) $ up to $7 (self contained bulb) $1.00 (replaceable bulb)
Incandescent bulb	Compact fluorescent fixture (hardwire type)	Custom Option Rebate
Standard ballast	Electronic ballast **	Custom Option rebate
No reflector	Reflector ***	Custom Option rebate
Exit sign using incandescent bulb	Energy efficient exit lamp. (Power reduction of at least 10W. per sign. 15000 hr. min. lamp life)	$2.00 per lamp. Compact fluorescent hardwired exit sign qualifies for Custom Option rebate.
No switching or manual switching	Occupancy sensors, with no manual over-ride feature	$75/kW. of lighting load or $50/sensor (whichever is less)
Incandescent, Mercury vapour	Metal halide, high pressure sodium, low pressure sodium	Custom Option rebate (in existing installations)
Old lighting system	New energy efficient system	Custom Option rebate

* Product option rebates may not exceed 50% of product cost.
** Only ballasts on approved list qualify for rebates.
*** Installations must meet current Electrical Safety Branch requirements.
**** H.I.D. rebates for new installations will not be paid.

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By: Robert Meyers
Vice President Finance and CFO

By:
Commission Secretary

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SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

GENERAL SERVICE PROGRAMS (Cont'd)

3. (i) Lighting (Cont'd)

FINANCIAL DETAILS: (Cont'd)

CUSTOM OPTION REBATE

(a) The financial rebate under this program is the product of 1cent per kW.h and the lesser of 5 years or the product life.

(b) For new installations, the maximum rebate calculated in (a) will be the lesser of the incremental cost of the energy efficient equipment over its standard equivalent or that amount required to bring the Customer's payback to two years.

(c) For retrofits, the maximum rebate calculated in (a) will be 50% of the total incremental installed equipment cost or the amount required to bring the Customer's payback to two years

3. (ii)Light Emitting Diode (LED) Demonstration Projects

OBJECTIVE: To improve the efficiency of Christmas lights.

DESCRIPTION: The Company will establish a number of display projects for the LED Christmas lighting technology. Project sites will include municipal facilities.

FINANCIAL DETAILS: The Company will supply free LED Christmas Lights for high profile municipal facilities and fire halls. To promote this technology, the company will provide advertising and promotion to inform customers about LED technology advantages.

4. Efficient Pumps and Fans

OBJECTIVE: To improve the efficiency of commercial and irrigation pumping systems.

DESCRIPTION: This program assists commercial and irrigation Customers in examining their pumping use to improve efficiency. Solutions explored may include variable speed drives, two speed motors, or adding a smaller motor to achieve operational efficiency in matching water demand. The Company will provide assistance in determining energy savings and simple paybacks for investment decisions

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By: Robert Meyers
Vice President Finance and CFO

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SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

GENERAL SERVICE PROGRAMS (Cont'd)

4. Efficient Pumps and Fans (Cont'd) C

FINANCIAL DETAILS:

The Company will provide a free initial assessment of energy savings potential. Based on the results, a more comprehensive study may be undertaken and the Company will pay up to 50% of approved study costs, to a maximum of $5,000.

Financial incentives will be based on 1 cent per estimated annual kW.h saved times the lesser of 5 years or product life for the energy conservation measure with the maximum rebate calculated to provide a simple two year payback.

For new installations the maximum rebate will be equal to 100% of the total incremental cost of the energy conservation measures.

For retrofits, the maximum rebate will be 50% of the total incremental cost.

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FORTISBC INC.

By: Don Debienne
Vice President Generation and Regulatory Affairs

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By:
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SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

INDUSTRIAL PROGRAMS

AVAILABLE: To all industrial Customers in all areas served by the Company and its Municipal Wholesale Customers whose demand is greater than 500 kVA.

1. New Process Design

OBJECTIVE: To assist industrial Customers with improving the electrical efficiency of new facilities and processes.

DESCRIPTION: This program helps Customers to build efficiency into the design of new plants. Information will be provided to assess energy efficiency options which exceed approved industry standards. Financial assistance will be available to implement approved energy efficiency measures.

FINANCIAL DETAILS: The Company will provide a free initial assessment of energy efficiency potential. Based on these results, a more comprehensive study may be undertaken and the Company will pay up to 50% of approved study costs.

Financial incentives will consist of those offered in existing programs. Where proposed energy efficiency measures are outside the scope of existing programs, we will provide financial rebates based on 1 cent per estimated annual kW.h saved times the lesser of 5 years or product life for the energy conservation measure.

The maximum rebate is the lesser of 100% of the incremental costs of the energy conservation measure or that amount required to bring the Customer's payback to two years.

2. Industrial Efficiency

OBJECTIVE: To assist industrial Customers with improving electrical efficiency in existing facilities and processes.

DESCRIPTION: This program helps Customers to improve energy efficiency in existing plants. Information will be provided to assess energy options and financial assistance will be available to implement energy efficiencies.

SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

INDUSTRIAL PROGRAMS (Cont'd)

2. Industrial Efficiency (Cont'd)

FINANCIAL DETAILS: The Company will provide a free initial assessment of energy efficiency potential. Based on these results, a more comprehensive study may be undertaken and the Company will pay up to 50% of approved study costs.

Financial incentives will consist of those offered in existing programs. Where proposed energy efficient measures are outside the scope of existing programs, we will provide financial rebates based on 1 cent per estimated annual kW.h saved times the lesser of 5 years or product life for the energy conservation measure.

The maximum rebate is the lessor of 50% of the total incremental cost of the energy conservation measure or that amount required to bring the Customer's payback to two years.

3. Lighting

OBJECTIVE: To encourage industrial Customers to adopt energy-efficient lighting technologies.

DESCRIPTION: This program of information and rebates will promote the use of efficient lighting equipment.

FINANCIAL DETAILS: Rebates and financial incentives are those listed in the General Service Lighting program.

4. Efficient Motors

OBJECTIVE: To encourage Customers to use high efficiency three phase electric motors.

DESCRIPTION: This program promotes, through rebates, the use of high efficiency motors in all new installations and for replacing failed motors.

SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

INDUSTRIAL PROGRAMS (Cont'd)

4. Efficient Motors (Cont'd)

FINANCIAL DETAILS: To help offset the difference in price between a standard motor and a high efficiency one, we offer rebates on new motors of $400 per kW saved. In no case will the rebate exceed the difference in cost between a high efficiency motor and standard motor of the same type.

Rebates for motors over 500 HP will be determined on an individual basis.

5. Efficient Pumps and Fans

OBJECTIVE: To promote energy efficiency in the use of electric fans and pumping systems.

DESCRIPTION: This program assists industrial Customers in examining their fan or pumping use to improve efficiency. Solutions explored may include adjustable speed drives, two speed motors, adding a smaller motor for process control, or operational and maintenance improvements.

The Company will provide assistance in determining energy savings and simple paybacks for investment decisions.

FINANCIAL DETAILS: The Company will provide a free initial assessment of energy savings potential. Based on the results, a more comprehensive study will be undertaken and the Company will pay up to 50% of approved study costs.

Financial incentives will be based on 1 cent per estimated annual kW.h saved times the lesser of 5 years or product life for the energy conservation measure. The maximum rebate will be equal to 100% of the incremental cost of the energy conservation measures for new installation and 50% of the total incremental cost for retrofits, with the maximum rebate calculated to provide a simple two year payback.

6. Efficient Compressors

OBJECTIVE: To reduce the amount of energy used in industrial air compressor systems exceeding 50 hp.

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By: Robert Meyers
Vice President Finance and CFO

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SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

INDUSTRIAL PROGRAMS (Cont'd)

6. Efficient Compressors (Cont'd)

DESCRIPTION: This program offers information, system evaluation and incentives to improve the performance of compressed air systems.

FINANCIAL DETAILS:

1. The Company will arrange for a free air leak test and provide compressed air information to maintenance personnel. After the leaks have been repaired, the system will again be tested for air leaks.

2. The Company may agree to study the potential for improved operational efficiencies. Methods for improvement may include the installation of new equipment such as high efficiency compressors, sequencers, controllers and timers.

   The incentive for the purchase of an approved high efficiency compressor is $400 per kW saved. Only those compressors between 50 hp and 350 hp that have high efficiency motors qualify.

   The high efficiency motor incentive will also apply.

   The incentive for the purchase of other equipment such as an automatic sequencer will be based on 5 cents per estimated annual kW.h saved up to the lesser of 50% of the total incremental cost, or that amount required to bring the Customer's payback to two years.

OTHER PROGRAMS

1. Efficient Outdoor Lighting

OBJECTIVE: The Company will convert off-street Dusk to Dawn lights to energy efficient lighting.

DESCRIPTION: HPS are the most commonly used energy efficient lights for outdoor lighting. They give the same light output while using 50% less electricity than mercury vapour lighting.

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SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

OTHER PROGRAMS

1. Efficient Outdoor Lighting (Cont'd)

FINANCIAL DETAILS: Off-street Dusk to Dawn lights owned by the Company will be changed over to HPS at no cost to the Customer leasing the system.

2. Energy Information

A Power Sense display panel is available for use at trade and home shows.

There are a number of booklets available that describe the various Power Sense programs in all district Customer Service offices.

Power Sense representatives are available to speak to service clubs, public access TV programs and schools. Sponsorship of Destination Conservation is covered under this Section.

SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

TERMS AND CONDITIONS

The following terms and conditions are an integral part of Energy Management services listed under Schedule 90:

Total Resource Cost

1. In order that energy management services are cost effective, only individual projects with a Total Resource Cost Test greater than 1.0 will be eligible for financial incentives. The total resource cost test is defined as the life cycle value of energy, capacity and deferred capital expenditures divided by the cost of the energy management measure.

Financial Incentives

1. In order to be eligible for financial incentives, all projects must receive the Company approval prior to initiation of work on the project.

2. Only those study or upgrade costs which are incremental to energy considerations will be eligible for financial incentives. An estimate of costs related to such issues as obsolescence, depreciation, maintenance, plant betterment and environmental concerns will be made to isolate that portion of the cost strictly related to energy.

3. Where rebates are in excess of $5,000, payment of one half of the rebate will be deferred for one year. Upon confirmation of project savings, the remaining portion of the rebate will be paid. If actual savings are less than projected savings, the customer will be paid the pro rata rebate and allowed another year to achieve the balance of savings. If all projected savings are not achieved, the rebate remaining to be paid will be recalculated on actual achieved savings at the end of the second year. No interest will be paid on the withheld portion. Irrespective of actual savings, the final rebate will not exceed the original estimated rebate.

4. Where a rebate is in excess of $10,000, the customer is to commit in writing to retain the Company subsidized equipment or facilities or the customer shall repay the unamortized balance of the original rebate.

SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

TERMS AND CONDITIONS (Cont'd)

Financial Incentives: (Cont'd)

5. For those customers supplied under Large General Service or Wholesale rate schedules or customers with a contract demand of 300 kVA or more, the unamortized balance of financial incentives paid to or on behalf of the customer, under Rate Schedule 90 shall be remitted to the Company within 30 days of billing, if:

    (a) the operations at the customer site are reduced by more than 50% for a continuous period of three months or longer; or
    (b) over 50% of the electricity previously provided by the Company is replaced by another source including self-generation or another supplier.

    In both cases, the repayment shall be prorated based on the amount of energy replaced compared to the amount of energy supplied by the Company in the year immediately preceding the electricity replacement.

6. The Company will assist customers in locating attractively priced financing with a 10 year term for energy management (including Time of Use technology) installation costs not covered under our tariff. The Company would assist the customer with:

    a) applying for the financing with a financial institution.
    b) billing the customer for payments on the financial obligations.
    c) guaranteeing the financial obligations.

    For these services, the Company would levy a 1% premium on the interest rate of the financing.

7. Any consulting or study incentive offered in the Energy Management tariffs is dependent upon available budget and resources. When the company pays more than $1000 for these services on behalf of a customer, any rebate amount that is eventually payable to that customer will be reduced by the amount of the consulting or study contribution

.Quality Assurance

1. Only approved contractors can participate in energy management services. This will ensure adherence to program guidelines, due care and diligence, appropriate experience and technical knowledge.

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By: Robert Meyers
Vice President Finance and CFO

By: ______________________
Commission Secretary

EFFECTIVE (applicable to consumption on and after) June 1, 2004

SCHEDULE 90 - ENERGY MANAGEMENT SERVICE (Cont'd)

TERMS AND CONDITIONS (Cont'd)

Quality Assurance (Cont'd)

2. To ensure the quality of energy efficient products for general service and industrial installations, the Company will promote those products labelled as Power Smart.

3. Quality assurance inspections will be performed for all projects having rebates greater than $10,000 and sample inspections may be carried out for those projects under that amount.

4. To introduce customers to TOU technologies, the Company may establish special arrangements with manufacturers of TOU technologies to provide an initial distribution channel, arrange for training and trades accreditation and integrate TOU measures with our current energy management programs.

5. Optional Energy Efficiency Services will be provided by the Company in conjunction with qualified Energy Service Providers (ESP) to better meet the energy efficiency needs of customers. Under this arrangement, the ESP will work with the Company to identify and implement energy efficiency measures. To actively promote and provide quality assurance for energy efficiency projects in our service area, the Company will perform the following optional energy efficiency services in cooperation with an ESP:

   a) perform or coordinate a detailed energy audit;
   a) review design and product specifications;
   b) prepare an energy efficiency proposal and review with customer;
   c) develop tender documents for installation and assist in bid selection;
   d) ensure quality control through project management;
   e) coordinate future service requirements;
   f) provide short-term project financing; and
   g) guaranty performance for municipal, university, school and hospital sector lighting projects.

A fee for service in the range of 2-15% of the project cost will be incorporated into the ESP contract for the customer. Any fees that are earned from these optional services will be offset against DSM costs.

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By: Robert Meyers
Vice President Finance and CFO

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Appendix H

FortisBC Inc. Terms & Conditions

Clean Version

FORTISBC INC.

ELECTRIC TARIFF B.C.U.C. NO. 2

FOR SERVICE IN THE WEST KOOTENAY AND OKANAGAN AREAS

TERMS AND CONDITIONS

AND

RATE SCHEDULES

EXPLANATION OF SYMBOLS
APPEARING ON TARIFF PAGES

A - signifies Increase

C - signifies Change

D - signifies Decrease

N - signifies New

O - signifies Omission

R - signifies Reduction

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By: ______________________ By: ______________________
Commission Secretary

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FORTISBC INC. BRITISH COLUMBIA UTILITIES COMMISSION

By: ____________________ By: ____________________
Commission Secretary

EFFECTIVE (applicable to consumption on and after) ____________________

The Company will furnish electric Service in accordance with the Rate Schedules and these Terms and Conditions filed with and approved by the British Columbia Utilities Commission. Copies are available on the Company's web site or upon request.

The Customer, by taking Service, agrees to abide by the provisions of these Terms and Conditions.

1. DEFINITIONS:

Company	FortisBC Inc.
Customer	A person, partnership, corporation, organization, governmental agency, municipality or other legal entity who accepts, uses or otherwise is the recipient of Service at any one Premises or location, or whose application for Service is accepted by the Company. The Company shall determine whether any entity as defined above receives Service at one or more Premises or locations.
Billing Demand	The Demand used in establishing the Demand portion of billing for Service during a specific billing period.
Contract Demand	The Demand reserved for the Customer by the Company and contracted for by the Customer.
Demand	The rate of delivery of Electricity measured in kilowatts (kW), kilovolt-amperes (kVA), or horsepower (hp) over a given period of time.
Drop Service	The portion of a overhead Service connection extending not more than 30 metres onto the Customer's property and not requiring any intermediate support on the Customer's property.
Electricity	The term used to mean both electric Demand and electric energy unless the context requires otherwise.
Load Factor	The percentage determined by dividing the Customer's average Demand over a specific time period by the Customer's maximum Demand during that period.
Power Factor	The percentage determined by dividing the Customer's Demand measured in kilowatts by the same Demand measured in kilovolt-amperes.

Issued ______________________ Accepted for filing ______________________
FORTISBC INC. BRITISH COLUMBIA UTILITIES COMMISSION

By: ______________________ By: ______________________
Commission Secretary

EFFECTIVE (applicable to consumption on and after) ______________________

1. DEFINITIONS: (Cont'd)

Point of Delivery	The first point of connection of the Company's facilities to the Customer's conductors or equipment at a location designated by or satisfactory to the Company, without regard to the location of the Company's metering equipment.
Premises	A dwelling, a building or machinery together with the surrounding land.
Suspension	the physical interruption of the supply of Electricity to the Premises independent of whether or not the Service is terminated.
Transmission Voltage	a nominal potential greater than 35,000 volts measured phase to phase.
Termination	the cessation of the Company's ongoing responsibility with respect to the supply of Service to the Premises independent of whether or not the Service is suspended.
Primary Voltage	a nominal potential of 750 to 35,000 volts measured phase to phase.
Secondary Voltage	a nominal potential of 750 volts or less measured phase to phase.
Service	any Service(s) provided by the Company pursuant to these Terms and Conditions and rate schedules

2. APPLICATION FOR SERVICE

2.1 Application for Service

Applications for Service shall be made via the Company's contact center, online at www.fortisbc.com, or by other means acceptable to the Company. Applicants for Service shall pay the connection or other charges required pursuant to these Terms and Conditions and rate schedules, and shall supply all information relating to load, supply requirements and such other matters relating to the Service as the Company may require.

Applicants shall be required to provide information and identification acceptable to the Company.

Applicants may be required to sign an application form for Service. A contractual relationship shall be established by the taking of Service in the absence of an application for Service or a signed application, except where a theft of Service has occurred.

The Company will assist in selecting the rate schedule applicable to the Customer's requirements, but will not be responsible if the most favourable rate is not selected. Changing of rate schedules will be allowed only if a change is deemed to be more appropriate to the Customer's circumstances. One request to change rate schedules will be permitted in any 12-month period. At the Company's option, where the Customer's load characteristics warrant, Customers served under Rate Schedule 20 may be transferred to Rate Schedule 21 or vice versa.

The Company retains the right to reject applications for Service if, in the opinion of the Company:

(a) conditions other than standard conditions are required by the applicant;
(b) facilities are not available to provide adequate Service;
(c) the Customer's facilities are not satisfactory to the Company;
(d) the applicant or owner or occupant of the Premises has an unpaid account for Service;
(e) the applicant has provided false or misleading information;
(f) the applicant is not the owner or occupant of the Premises;
(g) the Service requested is already supplied to the Premises for another Customer who does not consent to having the Service terminated;
(h) or if the applicant cannot provide satisfactory security for payment as required by the Company;
(i) the applicant is in receivership or bankruptcy, or operating under the protection of insolvency legislation and has failed to pay any outstanding bills to the Company;
(j) the applicant has breached any agreement or terms with the Company; or

2. APPLICATION FOR SERVICE (Cont'd)

2.1 Application for Service (Cont'd)

If occupancy of a rental Premises is of a transient nature, or if the rental Premises has an unacceptable billing history, the Company may require the Service to be in the name of the owner of the Premises on a continuous basis.

The Company shall not be liable for any loss, injury or damage suffered by any Customer by reason of a refusal to provide Service.

A Customer shall not transfer or assign a Service application or contract without the written consent of the Company.

Applications for Residential Service involving a standard connection of Service should be made via telephone or internet at least ten working days before Service is required.

Applications involving the installation of facilities should be discussed with the local Company representative well in advance of the date that Service is required.

2.2 Term of Service

Unless otherwise specifically provided in these Terms and Conditions, the rate schedules, or in any contract between the Customer and the Company, the term of Service and obligation to pay the charges under the applicable rate schedule for the minimum required term of Service shall commence on the day when the Company's Service is connected to the Customer's installation for the purpose of supplying Electricity, and

(a) shall be for one year where the connection does not require more than a Drop Service, unless a shorter period is agreed to by the Company; or
(b) shall be for five years where additional facilities other than those for a Drop Service are required; and
(c) shall continue thereafter until canceled by written notice of Termination by either party, except that in the case of Customers whose Contract Demand exceeds 200 kVA, 12 months' prior written notice of Termination shall be required and shall be given in such manner that the contact terminates with the last day of a billing period.

2. APPLICATION FOR SERVICE (Cont'd)

2.3 Security Deposit

If a Customer or applicant cannot establish or maintain credit to the satisfaction of the Company, the Customer or applicant may be required to make a security deposit in the form of cash or an equivalent form of security acceptable to the Company.

Security deposits shall be in the form of cash or equivalent form of security in an amount equal to the Customer's bill for 3 months as estimated by the Company and shall be in addition to any other deposits required.

For Customers with a Demand in excess of 200 kVA the security deposit is mandatory and shall be increased by an amount equivalent to the estimated minimum charge under the applicable rate schedule for six months.

Failure to pay a security deposit or to provide an equivalent form of security acceptable to the Company may, in the Company's discretion, result in Termination or refusal of Service. FortisBC reserves the right to review and adjust the security deposit required from a Customer at anytime.

The Company shall have the right to apply the security deposit to the Customer's billing account at any time the Customer fails to pay any amounts owed by the Customer. If a Customer's security deposit or equivalent form of security is called upon by the Company towards paying an unpaid account, the Customer must re-establish the security deposit or equivalent form of security before the Company will reconnect or continue Service to the Customer.

Interest shall be paid on all cash security deposits from the date of receipt if held for more than one month in accordance with Clause 11.3. No interest is payable on any unclaimed deposit left with FortisBC after the account for which it is security is closed or on a deposit held by FortisBC in a form other than cash.

Upon application by the Customer after 2 years of continuous Service, a security deposit may be returned if the Customer has, by the payment of each and every account by the due date, established credit to the satisfaction of the Company.

Customers with Demand in excess of 200 kVA will only be eligible for return of a security deposit upon discontinuation of Service, and only when the final account, together with all arrears, is paid in full. When the Customer pays the final bill, the Company will refund any remaining security deposit plus any accrued interest or cancel the equivalent form of security.

2. APPLICATION FOR SERVICE (Cont'd)

2.3 Security Deposit (Cont'd)

If the Company is unable to locate the Customer to whom a security deposit is payable, FortisBC will take reasonable steps to trace the Customer; but if the security deposit remains unclaimed 7 years after the date on which it first became refundable, the deposit, together with any interest accrued thereon, will be forfeited.

If, in the Company's sole discretion, the deposit is likely to cause undue financial hardship, then bi-monthly account Customers may be permitted to pay the deposit in two equal installments.

2.4 Connection of Service

The Company will connect a Drop Service to the Customer's Premises after receipt of an application; payment of any applicable charges and deposits; Electrical Inspection Department permit to connect Service; and other permits as may be required by others or by the Company.

For extensions requiring more than a Drop Service, connection will be made under the provisions of the applicable Extension Schedule.

If space for a Drop Service to the Customer's Premises most convenient to the Company is obstructed, the Company will charge the Customer for the additional cost of providing Service.

2.5 Delay in Taking Service

If, with respect to an application to extend its facilities to any Point of Delivery, the Company has reason to believe that Service through that Point of Delivery will not be taken within 30 days after such Service is available, then the Company, in addition to any other payment required, may require payment equivalent to the Company's investment, subject to prior written notification to the affected Customer by the Company. The payment shall be comprised of a monthly charge based on the Company's investment multiplied by 2% to provide for a return on investment, depreciation, taxes and other fixed costs.

2.6 Termination of Service

Customers requesting a Termination of Service shall provide the Company with a minimum of 24 hours notice. If the Customer fails to provide the required notice, the Customer will be held responsible for all applicable charges until 24 hours after the Company has received the required notice.

2. APPLICATION FOR SERVICE (Cont'd)

2.6 Termination of Service (Cont'd)

Customers having a notice of Termination period in their contracts shall provide the Company with a request for Termination of Service in accordance with the notice provision in the contract.

2.7 Reconnection of Service

If a Service is terminated at the Customer's request and the same Customer or spouse, servant or agent of that Customer requests reconnection of that Service within 12 months, the applicant shall pay the reconnection charge plus the total of the minimum charges the Customer would have incurred during the period of the disconnection, if they had not been disconnected. If a Service has been disconnected for over 90 days, or the electrical use within the building has changed substantially, an Electrical Inspection Department permit may be required before reconnection.

3. CONDITIONS OF SERVICE

3.1 Point of Delivery

Unless otherwise specifically agreed to, the Point of Delivery is the first point of connection of the Company's facilities to the Customer's conductors or equipment at a location designated by or satisfactory to the Company, without regard to the location of the Company's metering equipment.

The Company, at its option, may supply Commercial Service through one Point of Delivery to two or more adjacent buildings owned and used as a single business function.

The rate schedule for each class of Service named in this tariff is based upon the supply of Service for each Customer through a single Point of Delivery. Additional Service supplied to the same Customer at more than one Point of Delivery shall be permitted only at the discretion of the Company, and shall not be combined but shall be metered and billed separately unless specifically approved by the Company.

3.2 Ownership of Facilities

Subject to any contractual arrangement and, notwithstanding the payment of any Customer contribution toward the cost of facilities, the Company shall retain full title to all equipment and facilities installed and maintained by the Company.

3. CONDITIONS OF SERVICE (Cont'd)

3.3 Customer Contributions

The Customer may be required to make a contribution toward the cost of facilities in excess of the charges for installation of new/upgraded Services provided for under Schedule 82 when:

(a) as provided in the Company's Extension Schedule, Extension of Service is in excess of a Drop Service;
(b) Service is underground;
(c) the nature of the Service is such that the revenue derived from the minimum billing would be insufficient to cover the cost of Service. A contribution would be required for such Services as fire pumps, sirens or emergency supply where the level of consumption is below that necessary to cover the annual costs;
(d) space for a Drop Service to the Customer's Premise, most convenient to the Company is obstructed by the Customer's property;
(e) facilities must be upgraded significantly to meet an increase in the Customer's load.

If a Customer contribution is required and if the Customer does not receive Service within three months of the contribution being received by the Company, and where the delay in taking Service is not attributable to the Customer, the Customer shall receive interest as calculated in Clause 11.3 on such payment.

3.4 Revenue Guarantee Deposit

If the provision of Service by the Company to a non-residential Customer will require construction and installation costs by the Company of more than $5,000 per Customer supplied, each such Customer shall provide a revenue guarantee deposit, as assurance that the Company will receive sufficient revenue to recover the installation costs of the facilities.

The Company will repay 20 per cent of the revenue guarantee to the Customer at the end of each year of Service, for a period of five years, provided that the Customer's bills are paid in full at the time the refund is due. Interest will be paid on refunds as calculated in Clause 11.3.

If the contract for Service is terminated prior to five years from the date of installation, any balance of the revenue guarantee remaining shall belong to the Company absolutely as part of the consideration for the Company installing Service.

3. CONDITIONS OF SERVICE (Cont'd)

3.5 Voltages Supplied

The Company will supply nominal 60 cycle alternating electric current to the Point of Delivery at the available phase and voltage.

Before wiring Premises or purchasing any electrical equipment, the Customer should consult with the Company to ascertain what type of Service may be available at the requested location. The Customer should present a description of the load to be connected so that the Company can furnish information regarding voltage and phase characteristics available at the Point of Delivery.

The Company will not supply transformation from one Secondary Voltage to another Secondary Voltage.

The Company reserves the right to determine the voltage of the Service connection.

Nominal Standard Secondary Voltage from Pole-Mounted Transformers

Single phase:	(i)	120/240 volts, 3 wire, maximum 600 amperes.
Three phase:	(i)	120/208 volts, 4 wire, 300 kVA maximum transformation capacity.
	(ii)	347/600 volts, 4 wire, maximum 300 kVA transformation capacity.

Nominal Standard Secondary Voltage from Pad-Mounted Transformers

Single phase:	(i)	120/240 volts, 3 wire, maximum 600 amperes.
Three phase:	(i)	120/208 volts, 4 wire, maximum 500 kVA transformation capacity.
	(ii)	347/600 volts, 4 wire, maximum 2,500 kVA transformation capacity.

3. CONDITIONS OF SERVICE (Cont'd)

3.5 Voltages Supplied (Cont'd)

Special Conditions

Special arrangements may be required under the following conditions:

(a) For Customer loads or supply voltages different from those listed above with pole-mounted and pad-mounted transformer installations, the Customer will be required to supply its own transformers and take Service at the available Primary Voltage.

(b) Customers initiating an upgrade of existing facilities using non standard Secondary Voltages may be required to upgrade to standard voltages at their own expense.

(c) Where a Customer has been required to supply its own transformation, transformation discounts will only be applicable if available under the existing rate schedule to which Service is provided to the Customer.

3.6 Customer's Equipment

All Customer owned transformers and equipment used to connect them to the Company's electrical system shall be approved by and installed in a manner satisfactory to the Company.

3.7 Limitation of Use

Service supplied to a Customer shall be for the use of that Customer only and for the purpose applied for, and shall not be remetered, submetered or resold to others except with the written consent of the Company or as provided in the applicable rate schedule.

Single phase motors rated larger than two hp and other equipment with rated capacity greater than 1,650 watts shall not be used on 120 volt circuits, unless otherwise authorized by the Company. Motors of 20 hp or larger shall be equipped with reduced voltage starters or other devices approved by the Company to reduce starting current, unless otherwise authorized by the Company.

3. CONDITIONS OF SERVICE (Cont'd)

3.7 Limitation of Use (Cont'd)

Space Heating Specifications

(a) Residential

The maximum capacity of residential heating units to be controlled by one switch or thermostat shall be 6,000 watts. Where applicable, time delay equipment must be installed so that each of the heating units, as required, is energized sequentially at minimum intervals of ten seconds. Heating units shall be connected so as to balance as nearly as possible the current drawn from the circuits at the Point of Delivery.

(b) Industrial Use

The maximum capacity of industrial heating units to be controlled by one switch or thermostat shall be ten kW for single phase and 25 kW for three-phase units.

Water Heating Specifications

The heating units shall be of non-inductive design for a nominal voltage of 240 volts unless otherwise agreed to by the Company, but units of less than 1,650 watts may have a nominal voltage of 120 volts.

Installations may consist of either one or two-unit heaters. In the single unit heater tank, the unit shall be placed to heat the entire tank. In the two-unit heater tank, a "base" unit heater shall be placed to heat the entire tank and a "booster" unit heater placed to heat not more than the top third of the tank.
Each unit heater shall be controlled by a separate thermostat and shall not exceed 6,000 watts, except heating units installed in tanks of 350 litres and larger may, at the Company's option, exceed 6,000 watts but shall not exceed 17 watts per litre for either "base" or "booster" unit heater.

Thermostats must be permanently connected so that both heating units cannot operate at the same time except on tanks where the installed capacity does not exceed 6,000 watts.

The Company, may at its expense, install a time switch, carrier current control, or other device to limit the hours of Service to the water heater. The period or periods each day during which Service may be so limited shall not exceed a total of two hours.

4. TYPE OF SERVICE

4.1 Temporary Service

Where the Company has facilities available, temporary Service may be supplied under any rate schedule applicable to the class of Service required. The basic charge or minimum set forth in that rate schedule shall be applicable to the temporary Service, but in no case shall it be less than one full month. The Customer shall also pay for the cost of the installation and removal of the equipment used to supply the temporary Service as prescribed in Schedule 82.

4.2 Underground Facilities

The Company's Tariff is designed to recover the cost of providing electrical Service from overhead poles and conductors. The Customer applying for underground Service under any Rate Schedule shall be responsible for any added cost and agrees as follows:

(a) The Company shall own, install and maintain the underground Service line to the Point of Delivery. The Customer shall own, install and maintain the underground Service line beyond the Point of Delivery.

(b) The underground installation must comply with the Company's underground distribution standards.

(c) The Company shall not be responsible for any loss or damage beyond the reasonable control of the Company due to the installation, operation or maintenance of the underground circuit.

4.3 Residential Service

Residential Service is intended strictly for residential use. Some minor exceptions as indicated in the following are accepted under this Tariff for reasons of administration and practicality. Where partial commercial use or other use is made of Electricity supplied, refer to Section 4.3.3 or 4.3.4.

Residential Service is normally single phase 120/240 volt, maximum 200 amperes. Three phase residential Service or single phase Service in excess of 200 amperes may be provided under special contract terms requiring the Customer to pay all the additional costs of a larger Service.

4. TYPE OF SERVICE (Cont'd)

4.3 Residential Service (Cont'd)

Residential rates are available for Service as follows:

4.3.1 Single meter residential Premises - exclusive residential use

(a) individually metered single family residences used exclusively for normal residential and housekeeping requirements;

(b) any outbuilding located on residential property and supplied through the residential meter;

(c) residential property where less than three rooms are rented and supply is through the same meter as the residence, (three or more rented rooms will be billed on the Commercial Service rate);

(d) At the Company's option, multiple family dwellings used exclusively for living quarters and served through one meter. For billing purposes, the kilowatt-hour blocks, basic charge and minimum charge will be increased in proportion to the number of single family living quarters served.

4.3.2 Multiple meter residential Premises - exclusive residential use

(a) multiple family dwellings such as apartments, condos, duplex, quadruplex, etc., where each separate living quarter is separately metered;

(b) common use areas in multiple residential dwellings where each single family residence is separately metered;

(c) individually metered motel units where the owner contracts with the Company for the Service to each unit;

(d) where a Customer requests and the Company permits a separate Service to an outbuilding related to the Customer's residential occupancy as in 4.3.1 (a) above. The Company may provide the separately metered residential Service if the Customer pays the full cost of the separate Service less any contribution by FortisBC as specified in Schedule 74 towards the separate Service.

Customers with multiple meter residential Premises shall take Service under a single rate, unless otherwise approved by the Company.

4. TYPE OF SERVICE (Cont'd)

4.3.3 Partial commercial use

Where a partial commercial use is carried on in a single metered residential Premises (with or without outbuildings), and if the total connected load of the commercial enterprise is less than 5,000 watts, excluding space heating, the Customer shall be billed under Residential Service rates.

If the total connected load of the commercial enterprise is greater than 5,000 watts, excluding space heating, the account shall be billed at Commercial Service rates.

Where commercial use is carried on in a residential Premises or in an outbuilding to that Premises and the commercial area is separately metered, the commercial area only shall be on a Commercial Service rate. If new buildings are erected or major alterations are made to Premises receiving combined Service, the Customer shall be required to arrange the wiring to provide for separate metering.

4.3.4 Other Use

Where water pumps supply single family residences, the water pumps shall be on the Residential Service rate provided they can be supplied single phase and total 5 HP or less.

4.3.5 Farms

Farm residences and their outbuildings shall qualify for the Residential Service rate provided the farm is assessed for property tax purposes as agricultural land and the Service is used primarily for the production of food or industrial crops on that land. Other use for commercial or non farm purposes shall be billed on the Commercial Service rate.

5. METERING

5.1 Installation

The Company shall provide all meters necessary for measuring the Customer's use of the electric Service provided by the Company. The meters shall remain the property of the Company and shall be maintained in accurate operating condition in accordance with the regulations of Measurement Canada.

The Customer may furnish, install and maintain at its expense a meter system to verify the accuracy of the Company's meter system. The Customer's meter system and the manner of its installation shall be approved by the Company.

5. METERING (Cont'd)

5.1 Installation (Cont'd)

Should an accurate meter reading be unavailable due to meter failure, temporary inaccessibility, or any other reason, Electricity delivered to the Customer shall be estimated by the Company from the best available sources and evidence.

The Customer shall exercise all reasonable diligence to protect the Company's meter from damage or defacement and shall be held responsible for any costs of repair or cleaning resulting from defacement or damage.

All connections and disconnections of electric Service and installation and repair of the Company's meter system shall be made only by the Company. All meters shall be sealed by the Company. Breaking the seals or tampering with the meter or meter wiring is unlawful and may be cause for Termination of Service by the Company, and may result in criminal charges for theft of Electricity.

5.2 Location

The Customer shall provide a Service entrance and meter socket location in accordance with Company requirements, and where required a metering equipment enclosure.

The meter socket shall be located on an outside wall and be within 1 m. of the corner nearest the point of supply except, in the case of metering over 300 volts, the meter socket shall be installed on the load side of the Service box and shall be accessible to Company personnel. All sockets must be installed between 1.4 m. and 1.7 m. above final grade to the centre of the meter. Meters shall not be installed in carports, breezeways or similar areas. Any exceptions must be approved by the Company.

Meters shall be installed in places providing safe and reasonable access. Meters shall not be exposed to live steam, corrosive vapours or falling debris. Where the meter is recessed in the wall of a building, sufficient clearance must be provided to permit removal and testing of Company equipment. The full cost of relocating an inaccessible meter shall be borne by the Customer.

5.3 Meter Tests or Adjustments

A Customer may request in writing a test of the accuracy of a meter. The Customer shall deposit an amount as provided in Schedule 80 and the Company shall remove the meter within 10 days and apply to the authorized authority to have the meter tested. If the meter fails to meet any of the applicable laws and regulations, the deposit shall be refunded to the Customer. If the meter is found to satisfy the applicable laws and regulations, the Customer shall forfeit the deposit.

5. METERING (Cont'd)

5.3 Meter Tests or Adjustments (Cont'd)

If after testing the meter is found not to be registering within the limits allowed by Measurement Canada, bills will be adjusted as prescribed in the applicable laws and regulations. If a refund is necessary, it shall be calculated in accordance with Clause 11.6.

5.4 Metering Selection

Meters will be selected at the Company's discretion and shall be compliant with the regulations of Measurement Canada. The Company at its discretion may change the type of metering equipment.

5.5 Unmetered Service

The Company may permit unmetered Service if it can estimate to its satisfaction the energy used based on the connected load and hours of use. Customers served under this provision must notify the Company immediately of any proposed or actual changes in load or hours of use. The Company, at its discretion, may at any time require the installation of a meter or meters and thereafter bill the Customer on the consumption registered.

6. METER READING AND BILLING

6.1 Meter Reading

Meters shall be read at the end of each billing period in accordance with the applicable rate schedule. The interval between consecutive meter readings shall be determined by the Company. An accurate record of all meter readings shall be kept by the Company and shall be the basis for determination of all bills rendered for Service.

For billing purposes, the Company may estimate the Customer's meter reading if, for any reason, the Company does not obtain a meter reading. Where the Customer requests Termination of Service pursuant to Section 2.6, the Company may estimate the final meter reading for final billing.

The term "one month" (unless a calendar month is specified) as used herein and in the rate schedules, normally means the time elapsed between the meter reading date of one calendar month and that of the next. The term "two-month period" as used herein and in the rate schedules, normally means the time elapsed between the meter reading date of one calendar month and the second following calendar month.

6. METER READING AND BILLING (Cont'd)

6.2 Proration of Billing

Bills will be prorated as appropriate under the following conditions:

(1) For meters normally read every one month where the billing period is less than 21 days or greater than 39 days.
(2) For meters normally read every two months where the billing period is less than 51 days or greater than 69 days.

6.3 Rates for Electricity

The Customer shall pay for Electricity in accordance with these Terms and Conditions and the Customer's applicable rate schedule, as amended from time to time and accepted for filing by the British Columbia Utilities Commission. If it is found that the Customer has been overcharged, the appropriate refund shall be with interest as calculated in Clause 11.3.

6.4 Sales Tax and Assessments

In addition to payments for Services provided, the Customer shall pay to the Company the amount of any taxes or assessments imposed by any competent taxing authority on any Services provided to the Customer.

6.5 Payment of Accounts

Bills for electric Service are due and payable when rendered. Payments may be made to the Company's collection office, electronically or to authorized collectors.

Customers' accounts not paid by the due date printed on the bill shall be in arrears. Late payment charges may be applied to overdue accounts at the rate specified on the bill and as set out on the applicable rate schedule.

Customers will be advised that their account is in arrears by way of notification on the next billing. If payment is not received, a letter will be mailed to the Customer advising that if payment is not received within ten days of the date of mailing, Service may be suspended without further notice. The Company will make every reasonable effort to contact the Customer by telephone or in person to advise the Customer of the consequences of non-payment, but the account may be disconnected if payment is not received.

7. LOAD CHANGES AND OPERATION

7.1 Notice by Customer

A Customer shall give to the Company reasonable written notice of any change in its load requirements to permit the Company to determine whether or not it can meet the requirements without changes to its equipment or system.

Notwithstanding any other provision of these Terms and Conditions, the Company shall not be required to supply to any Customer Electricity in excess of that previously agreed to by the Company.

Customers with a Demand component in the rate schedule who wish to change the Contract Demand or the Demand limit, shall submit to the Company a written request subject to the following provisions.

(a) an increase requested of less than 1,000 kVA shall be submitted not less than three months in advance of the date the increase is intended to become effective; and

(b) an increase requested in excess of 1,000 kVA but less than 5,000 kVA shall be submitted not less than one year in advance of the date the increase is intended to become effective; and

(c) an increase requested in excess of 5,000 kVA shall be submitted not less than three years in advance of the date the increase is intended to become effective.

(d) a decrease requested of up to 10 per cent per year of the existing Contract Demand or Demand limit shall be submitted not less than three months in advance of the date the decrease is intended to become effective. Customers with a Contract Demand in excess of 500 kVA shall provide the Company by January 31 of each year their best estimate of their annual Electricity requirements to allow the Company to forecast future load on its facilities.

If the Company approves the request in writing, the Contract Demand or the Demand limit may be changed either by amendment to the Customer's contract or by the parties executing a new contract. The Company shall not be required to approve any requested change in the Contract Demand or the Demand limit.

7.2 Changes to Facilities

The Customer may be required to pay for the cost of any alterations to the Company's facilities necessary to provide the Customer's increased load. If any increase in load, Contract Demand or Demand limit, approved by the Company, requires it to add to its existing facilities for the purpose of complying with the Customer's request, the approved increase shall be subject to payment of a Customer

7. LOAD CHANGES AND OPERATION (Cont'd)

7.2 Changes to Facilities (Cont'd)

contribution under clause 3.3. The Customer may also be required to provide a revenue guarantee deposit as set out in clause 3.4.

7.3 Responsibility for Damage

A Customer shall be responsible for and pay for all damage caused to the Company's facilities as a result of that Customer increasing its load without the consent of the Company.

The Customer shall indemnify the Company for all costs, damages, or losses arising from the Customer exceeding its Demand limit, including without limiting generality, direct or consequential costs, damages or losses arising from any penalty incurred by the Company for exceeding its Demand limit with its suppliers of Electricity.

7.4 Power Factor

Customers shall regulate their loads to maintain a Power Factor of not less than 90 percent lagging or as otherwise provided for in the applicable rate schedule. If the Power Factor of the Customer's load is less than the minimum required, the Customer's bill may be increased by an adjustment for low Power Factor. The Company may also require the Customer, at its expense, to install Power Factor corrective equipment to maintain the minimum required Power Factor.

The Company may refuse Service for neon, mercury vapour, fluorescent or other types of outdoor lighting or display device which has a Power Factor of less than 90 percent or other detrimental characteristics.

No credit will be given for leading Power Factor.

7.5 Load Fluctuations

The Customer shall operate its motors, apparatus and other electrical equipment in a manner that will not cause sudden fluctuation to the Company's line voltage, or introduce any element into the Company's system which in the Company's opinion disturbs or threatens to disturb its electrical system or the property or Service of any other Customer. Under no circumstances shall the imbalance in current between any two phases be greater than five percent. The Customer shall indemnify the Company against any liability, loss, cost and expense occasioned by the Customer's failure to operate its electrical equipment in compliance with this section.

8. CONTINUITY OF SERVICE

8.1 Interruptions and Defects in Service

The Company will endeavour to provide a regular and uninterrupted supply of Electricity but it does not guarantee a constant supply of Electricity or the maintenance of unvaried frequency or voltage and shall not be responsible or liable for any loss, injury, damage or expense caused by or resulting from any interruption, Suspension, Termination, failure or defect in the supply of Electricity, whether caused by the negligence of the Company, its servants or agents, or otherwise unless the loss, injury, damage or expense is directly resulting from the willful misconduct of the Company, its servants or agents provided, however, that the Company, its servants and agents are not responsible for any loss of profit, loss of revenues or other economic loss even if the loss is directly resulting from the willful misconduct of the Company, its servants or agents.

All responsibility of the Company for Electricity delivered to the Customer shall cease at the Point of Delivery, and the Customer shall indemnify the Company and save it harmless from all liability, loss and expense caused by or arising out of the taking of Electricity by the Customer.

The expense of any interruption of Service to others, loss of or damage to the property of the Company through misuse or negligence of the Customer, or the cost of necessary repairs or replacement shall be paid to the Company by the Customer.

8.2 Suspension of Service

The Company and the Customer may demand the Suspension of Service whenever necessary to safeguard life or property, or for the purpose of making repairs on or improvements to any of its apparatus, equipment or work. Such reasonable notice of the Suspension as the circumstances permit shall be given.

The Company may suspend Service to the Customer for the failure by the Customer to take remedial action acceptable to the Company, within 15 days of receiving notice from the Company, to correct the breach of any provision of these Terms and Conditions to be observed or performed by the Customer. The Company shall be under no obligation to resume Service until the Customer gives assurances satisfactory to the Company that the breach which resulted in the Suspension shall not recur.

The Company shall have the right to suspend Service to make repairs or improvements to its electrical system and will, whenever practicable, give reasonable notice to the Customer.

The Company shall have the right to suspend or terminate Service at any time without notice whenever the Customer has breached any agreement with the Company, or failed to pay arrears within

8. CONTINUITY OF SERVICE (Cont'd)

8.2 Suspension of Service (Cont'd)

the specified time, fraudulently used the Service, tampered with the Company's equipment, committed similar actions, compromised the Company's Service to other Customers or if ordered by an authorized authority to suspend or terminate such Service. The cause of any Suspension must be corrected, and all applicable charges paid before Service will be resumed. Suspension of Service by the Company shall not operate as a cancellation of any contract with the Company, and shall not relieve any Customer of its obligations under these Terms and Conditions or the applicable rate schedule.

8.3 Termination by Customer

Whenever a Customer wishes to terminate Service from the Company, it shall give the Company timely notice so that arrangements can be made for final meter reading and billing. Until notice of Termination is given, the Customer shall continue to be responsible for all Service supplied unless the Company receives an application for Service from a new Customer for the Premises concerned.

Notice of Termination requirements for contract Customers shall be in accordance with the terms of the contract. If a contract Customer terminates its contract but fails to give the required notice of Termination, the minimum charges for the notice period, as well as any amounts due for Service supplied, shall immediately become due and payable.

9. RIGHTS-OF-WAY AND ACCESS TO FACILITIES

9.1 Rights-of-Way

By applying for electric Service, the Customer agrees to grant to the Company such rights-of-way, easements and any applicable permits on, over and under the property of the Customer as may be necessary for the construction, installation, maintenance or removal of facilities.

On request, the Customer at their own expense shall deliver to the Company documents satisfactory to the Company in registrable form granting the rights-of-way, easements and executed permits. The Customer shall at their own expense be responsible for obtaining rights-of-way, easements and any applicable permits on other properties necessary for the Company to provide Service to the Customer.

9. RIGHTS-OF-WAY AND ACCESS TO FACILITIES (Cont'd)

9.1 Rights-of-Way (Cont'd)

Notwithstanding payment by the Customer towards the cost of electrical facilities installed by the Company or that electrical facilities may be affixed to the Customer's property, all electrical facilities installed by the Company up to the Point of Delivery shall remain the property of the Company, and the Company shall have the right to safe and ready access to upgrade, renew, replace or remove any facilities on the Customer's property at any time.

9.2 Access

The Company, through its authorized employees and agents, shall have safe and ready access to its electrical facilities at all reasonable times for the purpose of reading meters and testing, installing, removing, repairing or replacing any equipment which is the property of the Company. If access is restricted, the Company shall be supplied with keys to such locks if requested or, at the Company's option, a key holder box, where such locations are unattended during reasonable times.
In no case will the Company accept keys to private residential properties.

If safe and ready access to the Company's electrical facilities is denied or obstructed in any manner, including the presence of animals, and the Customer takes no action to remedy the problem upon being so advised, Service shall be suspended and not reconnected until the problem is corrected.

In cases where the Customer does not provide the Company with safe and ready access to the meter, the Company, may install a remote meter. The Customer will be responsible for the cost (as specified in the Standard Charges) of the remote meter and its installation.

9.3 Exception

Notwithstanding the provisions of Section 9.1 and 9.2, approval of the B.C. Utilities Commission will be required prior to any removal of plant constructed to serve industrial Customers supplied at 60 kV and above

Sheet TC23

10. CUSTOMER-OWNED GENERATION

10.1 Parallel Generation Facilities

The Customer may, at its expense, install, connect and operate its own electrical generating facilities to its electrical circuit in parallel with the Company's electrical system provided that the manner of installation and operation of the facilities is satisfactory to the Company, and the facilities have the capacity to be immediately isolated from the Company's system in the event of disruption of Service from the Company.

Prior to the commencement of installation of any generating facilities, the Customer shall provide to the Company full particulars of the facilities, and the proposed installation, and shall permit the Company to inspect the installation. The Customer at its own expense shall provide approved synchronizing equipment before connecting parallel generating facilities to the Company electrical system.

The Customer's generating facilities shall not be operated in parallel with the Company's electrical system until written approval has been received from the Company. The Customer shall not modify its parallel facilities or the installation in any manner without first obtaining the written approval of the Company.

If at any time the Company's electrical system is adversely affected due to difficulties caused by the Customer's generating facilities, upon oral or written notice being given by the Company to a responsible employee of the Customer, the Customer shall immediately discontinue parallel operation, and the Company may suspend Service until such time as the difficulties have been remedied to the satisfaction of the Company.

The Customer shall be responsible for the proper installation, operation and maintenance of all protective and control equipment necessary to isolate the Customer's generating facilities from the Company's electrical system upon the occurrence of a fault on the Customer's generating facilities or the Company's electrical system. The Customer's protective equipment shall not be modified in any manner and the settings thereto shall not be changed without first obtaining written approval of the Company.

The Customer shall notify the Company in advance each and every time that the Customer's generating facilities are to be connected to or intentionally disconnected from the Company's electrical system.

10. CUSTOMER-OWNED GENERATION (Cont'd)

10.1 Parallel Generation Facilities (Cont'd)

During parallel operation of its generating facilities, the Customer shall cooperate with the Company so as to maintain the voltage and the Power Factor of Electricity at the Point of Delivery within limits agreeable to the Company, and shall take and use Electricity in a manner that does not adversely affect the Company's electrical system.

Notwithstanding any approval given by the Company, parallel operation of the Customer's generating facilities with the Company's electrical system shall be entirely at the risk of the Customer, and the Customer shall indemnify the Company and save it harmless from all injury, damage and loss and all actions, suits, claims, demands and expenses caused by or in any manner arising out of the operation of the Customer's generating facilities.

10.2 Standby Generation

The Customer may, at its expense, install standby generation facilities to provide electrical Service in the event of a disruption of Service from the Company. Standby generation facilities shall be installed so that they remain at all times electrically isolated from the Company's electrical system either directly or indirectly, and shall be installed in such a way that it is not possible for the facilities to operate in parallel with the Company's electrical system.

The Customer's standby electrical generating facilities shall not be operated without the prior inspection and written approval of the Company, and the facilities shall not be modified thereafter without the written approval of the Company.

10.3 Electrical Inspection Authority

The Customer must obtain the approval of the appropriate electrical inspection authority before installation.

11. GENERAL PROVISIONS

11.1 Notices

Any notice, direction or other instrument shall be deemed to have been received on the following dates:

(a) if sent by electronic transmission, on the business day next following the date of transmission;

(b) if delivered, on the business day next following the date of delivery;

(c) if sent by registered mail, on the fifth business day following its mailing, provided that if there is at the time of mailing or within two days thereafter a mail strike, slowdown, lockout or other labour dispute which might affect delivery, then any notice, direction or other instrument shall only be deemed to be effective if delivered or sent by electronic transmission.

11.2 Conflicts

In case of conflict between these Terms and Conditions and the rate schedules, the provisions of the rate schedules shall prevail. Where there is a conflict between a contract and these Terms and Conditions, the provisions of the contract shall apply.

11.3 Payment of Interest

When interest is to be applied to certain Customer payments as provided in these Terms and Conditions, it shall be calculated as follows:

The Company will pay simple interest at the average prime rate of the principle bank with which the Company conducts its business, commencing with the date the subject funds were received by the Company.

The interest will be remitted to the Customers at the time the deposit or other payments are refunded, or in the case when a deposit or other refundable payment is to be held beyond one year, the interest will be calculated once every 12 months and shall be applied to the Customer's account.

11. GENERAL PROVISIONS (Cont'd)

11.4 Force Majeure

If any Large Commercial Service rate schedule Customer is prevented from taking Electricity, except for emergency purposes, for a period in excess of five calendar days by damage to its works from fire, explosion, the elements, sabotage, act of God or the Queen's enemies, or from insurrection, strike, or difficulties with workmen and invokes force majeure, the Company shall not be bound to make Electricity available during the period of the interruption except for emergency purposes, and commencing on the sixth calendar day of the interruption but for not more than 25 calendar days, the Customer shall, in lieu of the Demand Charge stipulated in the applicable Large Commercial Service rate schedule, pay a reduced Demand Charge for the period of the interruption, commencing on the sixth calendar day of the interruption to a maximum of 25 calendar days, derived from the Demand Charge rate multiplied by the maximum Demand recorded during that period of the interruption. The Customer shall not be entitled to any adjustment in the monthly Demand Charge under this clause unless the Customer informs the Company in writing it is invoking this clause, and the Company will read the meters used for billing purposes at the end of the fifth day of interruption and at the end of the period of interruption. The Customer shall be prompt and diligent in removing the cause of the interruption (by restoring its works or such other action as may be necessary and as soon as the cause of the interruption is removed or ceases to exist the Company shall without delay make Electricity available and the Customer shall take and pay for the same in accordance with this Tariff.

The force majeure provisions of this Clause 11.4 shall not apply in any month in which the Company purchases Electricity from British Columbia Hydro and Power Authority, unless the Company and British Columbia Hydro and Power Authority agree to a force majeure provision, in which case the Customer shall be given relief from the Demand Charge in accordance with that agreement.

11.5 Equal Payment Plan

Upon application, the Company may permit qualifying residential Customers to pay their accounts in equal monthly payments. The payments will be calculated to yield, over a twelve month period, the total estimated amount that would be payable by the Customer calculated by applying the applicable Residential Service rate to the Customer's estimated consumption during the same twelve month period. Customers may make application at any time of the year. All accounts will be reconciled annually or the earlier Termination date, at which time the amounts payable by the Customer to the Company for Electricity actually consumed during the equal payment period will be compared to the sum of equal payments made during the period. Any resulting amount owing by the Customer will be paid to the Company.

11. GENERAL PROVISIONS (Cont'd)

11.5 Equal Payment Plan (Cont'd)

A residential Customer may qualify for the plan provided their account is not in arrears, they have established credit to the satisfaction of the Company and the Customer expects to be on the plan for at least one year.

The Company may at any time revise the equal monthly installments to reflect changes in estimated consumption or the applicable rate schedule.

The equal payment plan may be terminated by the Customer upon reasonable notice, or the Company if the Customer has not maintained their credit to the satisfaction of the Company. The Company reserves the right to cancel or modify the Equal Payment Plan Service at any time.

11.6 Back-billing

(a) Back-billing means the rebilling for Services rendered to a Customer because the original billings are discovered to be either too high (over-billed) or too low (under-billed). The discovery may be made by either the Customer or the Company, and may result from the conduct of an inspection under provisions of the federal statute, the Electricity and Gas Inspection Act ("EGI Act"). The cause of the billing error may include any of the following non-exhaustive reasons or combination thereof:

(i) Stopped meter.
(ii) Metering equipment failure.
(iii) Missing meter now found.
(iv) Switched meters.
(v) Double metering.
(vi) Incorrect meter connections.
(vii) Incorrect use of any prescribed apparatus respecting the registration of a meter.
(viii) Incorrect meter multiplier.
(ix) The application of an incorrect rate.
(x) Incorrect reading of meters or data processing.
(xi) Tampering, fraud, theft or any other criminal act.

(b) Whenever the dispute procedure of the EGI Act is invoked, the provisions of that Act apply, except those which purport to determine the nature and extent of legal liability flowing from metering or billing errors.

11. GENERAL PROVISIONS (Cont'd)

11.6 Back-Billing (Cont'd)

(c) Where metering or billing errors occur and the dispute procedure under the EGI Act is not invoked, the consumption and Demand will be based upon the records of the Company for the Customer, or the Customer's own records to the extent they are available and accurate, or if not available, reasonable and fair estimates may be made by the Company. Such estimates will be on a consistent basis within each Customer class or according to a contract with the Customer, if applicable.

(d) If there are reasonable grounds to believe that the Customer has tampered with or otherwise used the Company's Service in an unauthorized way, or evidence of fraud, theft or other criminal act exists, then the extent of back-billing will be for the duration of unauthorized use, subject to the applicable limitation period provided by law and the provisions of items 11.6(g), 11.6(h), 11.6(i) and 11.6(j) below do not apply.

In addition, the Customer is liable for the administrative costs incurred by the Company in the investigation of any incident of tampering, including the direct costs of repair, or replacement of equipment.

Under-billing resulting from circumstances described above will bear interest at the rate normally charged by the Company on unpaid accounts from the date of the original under-billed invoice until the amount underbilled is paid in full.

(e) In every case of under-billing or over-billing, the cause of the error will be remedied without delay, and the Customer will be promptly notified of the error and of the effect upon the Customer's ongoing bill.

(f) In every case of over-billing, the Company will refund to the Customer all money incorrectly collected for the duration of the error, subject to the applicable limitation period provided by law. Interest will be paid in accordance with Clause 11.3.

(g) Subject to item 11.6(d) above, in every case of under-billing, the Company will back-bill the Customer for the shorter of:

(i) the duration of the error; or

11. GENERAL PROVISIONS (Cont'd)

11.6 Back-Billing (Cont'd)

(ii) six months for Residential, Commercial Service, Lighting and Irrigation; and
(iii) one year for all other Customers or as set out in a special or individually negotiated contract with the Company.

(h) Subject to item 11.6(d) above, in all cases of under-billing, the Company will offer the Customer reasonable terms of repayment. If requested by the Customer, the repayment term will be equivalent in length to the back-billing period. The repayment will be interest free and in equal installments corresponding to the normal billing cycle. However, delinquency in payment of such installments will be subject to the usual late payment charges.

(i) Subject to item 11.6(d) above, if a Customer disputes a portion of a back-billing due to under-billing based upon either consumption, Demand or duration of the error, the Company will not threaten or cause the discontinuance of Service for the Customer's failure to pay that portion of the back-billing, unless there are no reasonable grounds for the Customer to dispute that portion of the back-billing. The undisputed portion of the bill shall be paid by the Customer and the Company may threaten or cause the discontinuance of Service if such undisputed portion of the bill is not paid.

(j) Subject to item 11.6(d) above, back-billing in all instances where changes of occupancy have occurred, the Company will make a reasonable attempt to locate the former Customer. If, after a period of one year, such Customer cannot be located, the over or under billing applicable to them will be canceled.

12. REPAYMENT OF ENERGY MANAGEMENT INCENTIVES

For those Customers supplied under Large Commercial Service or Wholesale rate schedules or Customers with a Contract Demand of 300 kVA or more, the unamortized balance of financial incentives paid to the Customer under Rate Schedule 90 shall be remitted to the Company within 30 days of billing, if:

(a) the operations at the Customer site are reduced by more than 50% for a continuous period of three months or longer; or

12. REPAYMENT OF ENERGY MANAGEMENT INCENTIVES (Cont'd)

(b) over 50% of the Electricity previously provided by the Company is replaced by another source including self-generation or another supplier.

In both cases the repayment shall be prorated based on the amount of energy replaced compared to the amount of energy supplied by the Company in the year immediately preceding the Electricity replacement.

FORTISBC INC.

ELECTRIC TARIFF B.C.U.C. NO. 2

FOR SERVICE IN THE WEST KOOTENAY AND OKANAGAN AREAS

TERMS AND CONDITIONS

AND

RATE SCHEDULES

EXPLANATION OF SYMBOLS
APPEARING ON TARIFF PAGES

A - signifies Increase

C - signifies Change

D - signifies Decrease

N - signifies New

O - signifies Omission

R - signifies Reduction

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The Company will furnish electric Service in accordance with the Rate Schedules and these Terms and Conditions filed with and approved by the British Columbia Utilities Commission. Copies are available on the Company's web site or upon request.

The Customer, by taking Service, agrees to abide by the provisions of these Terms and Conditions.

1. DEFINITIONS:

Company	FortisBC Inc.
Customer	A person, partnership, corporation, organization, governmental agency, municipality or other legal entity who accepts, uses or otherwise is the recipient of Service at any one Premises or location, or whose application for Service is accepted by the Company. The Company shall determine whether any entity as defined above receives Service at one or more Premises or locations.
Billing Demand	The Demand used in establishing the Demand portion of billing for Service during a specific billing period.
Contract Demand	The Demand reserved for the Customer by the Company and contracted for by the Customer.
Demand	The rate of delivery of Electricity measured in kilowatts (kW), kilovolt-amperes (kVA), or horsepower (hp) over a given period of time.
Drop Service	The portion of a overhead Service connection extending not more than 30 metres onto the Customer's property and not requiring any intermediate support on the Customer's property.
Electricity	The term used to mean both electric Demand and electric energy unless the context requires otherwise.
Load Factor	The percentage determined by dividing the Customer's average Demand over a specific time period by the Customer's maximum Demand during that period.
Power Factor	The percentage determined by dividing the Customer's Demand measured in kilowatts by the same Demand measured in kilovolt-amperes.

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EFFECTIVE (applicable to consumption on and after)

TERMS AND CONDITIONS

Electric Tariff
B.C.U.C. No. 2
Sheet TC2

1. DEFINITIONS: (Cont'd)

Point of Delivery	The first point of connection of the Company's facilities to the Customer's conductors or equipment at a location designated by or satisfactory to the Company, without regard to the location of the Company's metering equipment.
Premises	A dwelling, a building or machinery together with the surrounding land.
Suspension	the physical interruption of the supply of Electricity to the Premises independent of whether or not the Service is terminated.
Transmission Voltage	a nominal potential greater than 35,000 volts measured phase to phase.
Termination	the cessation of the Company's ongoing responsibility with respect to the supply of Service to the Premises independent of whether or not the Service is suspended.
Primary Voltage	a nominal potential of 750 to 35,000 volts measured phase to phase.
Secondary Voltage	a nominal potential of 750 volts or less measured phase to phase.
Service	any Service(s) provided by the Company pursuant to these Terms and Conditions and rate schedules.

Deleted: the availability and/or delivery of electricity to the Customer at the point of delivery, irrespective of whether electricity is actually taken.

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EFFECTIVE (applicable to consumption on and after)

2. APPLICATION FOR SERVICE

2.1 Application for Service

Applications for Service shall be made via the Company's contact center, online at www.fortisbc.com, or by other means acceptable to the Company. Applicants for Service shall pay the connection or other charges required pursuant to these Terms and Conditions and rate schedules, and shall supply all information relating to load, supply requirements and such other matters relating to the Service as the Company may require.

Applicants shall be required to provide information and identification acceptable to the Company.

Applicants may be required to sign an application form for Service. A contractual relationship shall be established by the taking of Service in the absence of an application for Service or a signed application, except where a theft of Service has occurred.

The Company will assist in selecting the rate schedule applicable to the Customer's requirements, but will not be responsible if the most favourable rate is not selected. Changing of rate schedules will be allowed only if a change is deemed to be more appropriate to the Customer's circumstances. One request to change rate schedules will be permitted in any 12-month period. At the Company's option, where the Customer's load characteristics warrant, Customers served under Rate Schedule 20 may be transferred to Rate Schedule 21 or vice versa.

The Company retains the right to reject applications for Service if, in the opinion of the Company:

(a) conditions other than standard conditions are required by the applicant;
(b) facilities are not available to provide adequate Service;
(c) the Customer's facilities are not satisfactory to the Company;
(d) the applicant or owner or occupant of the Premises has an unpaid account for Service;
(e) the applicant has provided false or misleading information;
(f) the applicant is not the owner or occupant of the Premises;
(g) the Service requested is already supplied to the Premises for another Customer who does not consent to having the Service terminated;
(h) or if the applicant cannot provide satisfactory security for payment as required by the Company;
(i) the applicant is in receivership or bankruptcy, or operating under the protection of insolvency legislation and has failed to pay any outstanding bills to the Company;
(j) the applicant has breached any agreement or terms with the Company; or

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an application form shall become a Customer upon provision of service.

2. APPLICATION FOR SERVICE (Cont'd)

2.1 Application for Service (Cont'd)

Deleted: Residential

If occupancy of a rental Premises is of a transient nature, or if the rental Premises has an unacceptable billing history, the Company may require the Service to be in the name of the owner of the Premises on a continuous basis.

The Company shall not be liable for any loss, injury or damage suffered by any Customer by reason of a refusal to provide Service.

A Customer shall not transfer or assign a Service application or contract without the written consent of the Company.

Applications for Residential Service involving a standard connection of Service should be made via telephone or internet at least ten working days before Service is required.

Applications involving the installation of facilities should be discussed with the local Company representative well in advance of the date that Service is required.

Deleted: ¶
Application for Non-Residential Service¶
¶
Non-residential service applicants shall be required to sign a contract for service. No contract or any modification thereof shall be binding upon the Company until executed by the Customer and by the Company by its duly authorized representatives.¶

2.2 Term of Service

Unless otherwise specifically provided in these Terms and Conditions, the rate schedules, or in any contract between the Customer and the Company, the term of Service and obligation to pay the charges under the applicable rate schedule for the minimum required term of Service shall commence on the day when the Company's Service is connected to the Customer's installation for the purpose of supplying Electricity, and

(a) shall be for one year where the connection does not require more than a Drop Service, unless a shorter period is agreed to by the Company; or

(b) shall be for five years where additional facilities other than those for a Drop Service are required; and

(c) shall continue thereafter until canceled by written notice of Termination by either party, except that in the case of Customers whose Contract Demand exceeds 200 kVA, 12 months' prior written notice of Termination shall be required and shall be given in such manner that the contact terminates with the last day of a billing period.

TERMS AND CONDITIONS

Electric Tariff
B.C.U.C. No. 2
Sheet TC5

2. APPLICATION FOR SERVICE (Cont'd)

2.3 Security Deposit

If a Customer or applicant cannot establish or maintain credit to the satisfaction of the Company, the Customer or applicant may be required to make a security deposit in the form of cash or an equivalent form of security acceptable to the Company.

Deleted: As a condition of connecting service a security deposit will be required except where the Customer can provide to the Company a satisfactory credit history.

Security deposits shall be in the form of cash or equivalent form of security in an amount equal to the Customer's bill for 3 months as estimated by the Company and shall be in addition to any other deposits required.

Deleted: ¶
A security deposit may be required as a condition of continuing service under the following circumstances:¶
¶
(a) the applicant has an unpaid overdue bill with any utility within the last four years; or¶
(b) service is temporary (for less than one year); or¶
(c) Customer's service has been disconnected for inadequate payment of billings for electric service; or¶
(d) the applicant or Customer is bankrupt or a receiver or receiver manager has been appointed; or¶
(e) the Customer's account is in arrears for more than two consecutive billing periods; or¶
(f) the Customer's demand exceeds 200 kVA.¶

For Customers with a Demand in excess of 200 kVA the security deposit is mandatory and shall be increased by an amount equivalent to the estimated minimum charge under the applicable rate schedule for six months.

Deleted: The security deposit to be paid by these Customers may be in the form of cash, surety bond or other form of security satisfactory to the Company.

Failure to pay a security deposit or to provide an equivalent form of security acceptable to the Company may, in the Company's discretion, result in Termination or refusal of Service. FortisBC reserves the right to review and adjust the security deposit required from a Customer at anytime.

The Company shall have the right to apply the security deposit to the Customer's billing account at any time the Customer fails to pay any amounts owed by the Customer. If a Customer's security deposit or equivalent form of security is called upon by the Company towards paying an unpaid account, the Customer must re-establish the security deposit or equivalent form of security before the Company will reconnect or continue Service to the Customer.

Interest shall be paid on all cash security deposits from the date of receipt if held for more than one month in accordance with Clause 11.3. No interest is payable on any unclaimed deposit left with FortisBC after the account for which it is security is closed or on a deposit held by FortisBC in a form other than cash.

Upon application by the Customer after 2 years of continuous Service, a security deposit may be returned if the Customer has, by the payment of each and every account by the due date, established credit to the satisfaction of the Company.

Customers with Demand in excess of 200 kVA will only be eligible for return of a security deposit upon discontinuation of Service, and only when the final account, together with all arrears, is paid in full. When the Customer pays the final bill, the Company will refund any remaining security deposit plus any accrued interest or cancel the equivalent form of security.

Deleted: A deposit shall be refunded for Customers with less than 200 kVA demand:¶
¶
(a) upon discontinuation of service only when the final account, together with all arrears, is paid in full; or¶
(b) upon receipt from the Customer of a credit history from another utility suitable to the Company; or¶
(c) upon application by the Customer after 2 years continuous service if the customer, has by prompt payment of his account, established credit to the satisfaction of the Company.

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2. APPLICATION FOR SERVICE (Cont'd)

2.3 Security Deposit (Cont'd)

If the Company is unable to locate the Customer to whom a security deposit is payable, FortisBC will take reasonable steps to trace the Customer; but if the security deposit remains unclaimed 7 years after the date on which it first became refundable, the deposit, together with any interest accrued thereon, will be forfeited.

If, in the Company's sole discretion, the deposit is likely to cause undue financial hardship, then bi-monthly account Customers may be permitted to pay the deposit in two equal installments.

2.4 Connection of Service

The Company will connect a Drop Service to the Customer's Premises after receipt of an application; payment of any applicable charges and deposits; Electrical Inspection Department permit to connect Service; and other permits as may be required by others or by the Company.

Deleted: connection and installation

Deleted: charges; security

Deleted: when required

For extensions requiring more than a Drop Service, connection will be made under the provisions of the applicable Extension Schedule.

If space for a Drop Service to the Customer's Premises most convenient to the Company is obstructed, the Company will charge the Customer for the additional cost of providing Service.

Deleted: service line

2.5 Delay in Taking Service

If, with respect to an application to extend its facilities to any Point of Delivery, the Company has reason to believe that Service through that Point of Delivery will not be taken within 30 days after such Service is available, then the Company, in addition to any other payment required, may require payment equivalent to the Company's investment, subject to prior written notification to the affected Customer by the Company. The payment shall be comprised of a monthly charge based on the Company's investment multiplied by 2% to provide for a return on investment, depreciation, taxes and other fixed costs.

2.6 Termination of Service

Deleted: Disconnection

Customers requesting a Termination of Service shall provide the Company with a minimum of 24 hours notice. If the Customer fails to provide the required notice, the Customer will be held responsible for all applicable charges until 24 hours after the Company has received the required notice.

Deleted: disconnection

Deleted: t least ten working days' notice

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2. APPLICATION FOR SERVICE (Cont'd)

2.6 Termination of Service (Cont'd)

Deleted: Disconnection

Customers having a notice of Termination period in their contracts shall provide the Company with a request for Termination of Service in accordance with the notice provision in the contract.

Deleted: disconnection

2.7 Reconnection of Service

If a Service is terminated at the Customer's request and the same Customer or spouse, servant or agent of that Customer requests reconnection of that Service within 12 months, the applicant shall pay the reconnection charge plus the total of the minimum charges the Customer would have incurred during the period of the disconnection, if they had not been disconnected. If a Service has been disconnected for over 90 days, or the electrical use within the building has changed substantially, an Electrical Inspection Department permit may be required before reconnection.

Deleted: Customer

3. CONDITIONS OF SERVICE

3.1 Point of Delivery

Unless otherwise specifically agreed to, the Point of Delivery is the first point of connection of the Company's facilities to the Customer's conductors or equipment at a location designated by or satisfactory to the Company, without regard to the location of the Company's metering equipment.

The Company, at its option, may supply Commercial Service through one Point of Delivery to two or more adjacent buildings owned and used as a single business function.

The rate schedule for each class of Service named in this tariff is based upon the supply of Service for each Customer through a single Point of Delivery. Additional Service supplied to the same Customer at more than one Point of Delivery shall be permitted only at the discretion of the Company, and shall not be combined but shall be metered and billed separately unless specifically approved by the Company.

Deleted: single metering point

Deleted: at a different voltage or phase, or at more than one point of delivery

3.2 Ownership of Facilities

Subject to any contractual arrangement and, notwithstanding the payment of any Customer contribution toward the cost of facilities, the Company shall retain full title to all equipment and facilities installed and maintained by the Company.

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3. CONDITIONS OF SERVICE (Cont'd)

3.3 Customer Contributions

The Customer may be required to make a contribution toward the cost of facilities in excess of the charges for installation of new/upgraded Services provided for under Schedule 82 when:

(a) as provided in the Company's Extension Schedule, Extension of Service is in excess of a Drop Service;
(b) Service is underground;
(c) the nature of the Service is such that the revenue derived from the minimum billing would be insufficient to cover the cost of Service. A contribution would be required for such Services as fire pumps, sirens or emergency supply where the level of consumption is below that necessary to cover the annual costs;
(d) space for a Drop Service to the Customer's Premise, most convenient to the Company is obstructed by the Customer's property;
(e) facilities must be upgraded significantly to meet an increase in the Customer's load.

If a Customer contribution is required and if the Customer does not receive Service within three months of the contribution being received by the Company, and where the delay in taking Service is not attributable to the Customer, the Customer shall receive interest as calculated in Clause 11.3 on such payment.

Deleted: power

3.4 Revenue Guarantee Deposit

If the provision of Service by the Company to a non-residential Customer will require construction and installation costs by the Company of more than $5,000 per Customer supplied, each such Customer shall provide a revenue guarantee deposit, as assurance that the Company will receive sufficient revenue to recover the installation costs of the facilities.

Deleted: supply of electricity

Deleted: 1

The Company will repay 20 per cent of the revenue guarantee to the Customer at the end of each year of Service, for a period of five years, provided that the Customer's bills are paid in full at the time the refund is due. Interest will be paid on refunds as calculated in Clause 11.3.

If the contract for Service is terminated prior to five years from the date of installation, any balance of the revenue guarantee remaining shall belong to the Company absolutely as part of the consideration for the Company installing Service.

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3. CONDITIONS OF SERVICE (Cont'd)

3.5 Voltages Supplied

The Company will supply nominal 60 cycle alternating electric current to the Point of Delivery at the available phase and voltage.

Before wiring Premises or purchasing any electrical equipment, the Customer should consult with the Company to ascertain what type of Service may be available at the requested location. The Customer should present a description of the load to be connected so that the Company can furnish information regarding voltage and phase characteristics available at the Point of Delivery.

The Company will not supply transformation from one Secondary Voltage to another Secondary Voltage.

The Company reserves the right to determine the voltage of the Service connection.

Nominal Standard Secondary Voltage from Pole-Mounted Transformers

Single phase:	(i)	120/240 volts, 3 wire, maximum 600 amperes.
Three phase:	(i)	120/208 volts, 4 wire, 300 kVA maximum transformation capacity. **Deleted:** 5
	(ii)	347/600 volts, 4 wire, maximum 300 kVA transformation capacity. **Deleted:** 5

Nominal Standard Secondary Voltage from Pad-Mounted Transformers

Single phase:	(i)	120/240 volts, 3 wire, maximum 600 amperes.
Three phase:	(i)	120/208 volts, 4 wire, maximum 500 kVA transformation capacity.
	(ii)	347/600 volts, 4 wire, maximum 2,500 kVA transformation capacity.

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3. CONDITIONS OF SERVICE (Cont'd)

3.5 Voltages Supplied (Cont'd)

Special Conditions

Special arrangements may be required under the following conditions:

(a) For Customer loads or supply voltages different from those listed above with pole-mounted and pad-mounted transformer installations, the Customer will be required to supply its own transformers and take Service at the available Primary Voltage.

(b) Customers initiating an upgrade of existing facilities using non standard Secondary Voltages may be required to upgrade to standard voltages at their own expense.

(c) Where a Customer has been required to supply its own transformation, transformation discounts will only be applicable if available under the existing rate schedule to which Service is provided to the Customer.

3.6 Customer's Equipment

All Customer owned transformers and equipment used to connect them to the Company's electrical system shall be approved by and installed in a manner satisfactory to the Company.

3.7 Limitation of Use

Service supplied to a Customer shall be for the use of that Customer only and for the purpose applied for, and shall not be remetered, submetered or resold to others except with the written consent of the Company or as provided in the applicable rate schedule.

Single phase motors rated larger than two hp and other equipment with rated capacity greater than 1,650 watts shall not be used on 120 volt circuits, unless otherwise authorized by the Company. Motors of 20 hp or larger shall be equipped with reduced voltage starters or other devices approved by the Company to reduce starting current, unless otherwise authorized by the Company.

Deleted: may

Deleted: The Company may supply a non-standard secondary voltage and phase for a Customer from what is already available, providing the size of the Customer's load justifies a separate transformer installation or the Company has suitable transformers available.

Deleted: main supply

Deleted: The Company shall not unreasonably withhold consent where the Customer requests approval to resell electricity to contractors who are engaged by the Customer in activities directly related to its business operation.

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3. CONDITIONS OF SERVICE (Cont'd)

3.7 Limitation of Use (Cont'd)

Space Heating Specifications

(a) Residential

The maximum capacity of residential heating units to be controlled by one switch or thermostat shall be 6,000 watts. Where applicable, time delay equipment must be installed so that each of the heating units, as required, is energized sequentially at minimum intervals of ten seconds. Heating units shall be connected so as to balance as nearly as possible the current drawn from the circuits at the Point of Delivery.

(b) Industrial Use

The maximum capacity of industrial heating units to be controlled by one switch or thermostat shall be ten kW for single phase and 25 kW for three-phase units.

Water Heating Specifications

The heating units shall be of non-inductive design for a nominal voltage of 240 volts unless otherwise agreed to by the Company, but units of less than 1,650 watts may have a nominal voltage of 120 volts.

Installations may consist of either one or two-unit heaters. In the single unit heater tank, the unit shall be placed to heat the entire tank. In the two-unit heater tank, a "base" unit heater shall be placed to heat the entire tank and a "booster" unit heater placed to heat not more than the top third of the tank.
Each unit heater shall be controlled by a separate thermostat and shall not exceed 6,000 watts, except heating units installed in tanks of 350 litres and larger may, at the Company's option, exceed 6,000 watts but shall not exceed 17 watts per litre for either "base" or "booster" unit heater.

Thermostats must be permanently connected so that both heating units cannot operate at the same time except on tanks where the installed capacity does not exceed 6,000 watts.

The Company, may at its expense, install a time switch, carrier current control, or other device to limit the hours of Service to the water heater. The period or periods each day during which Service may be so limited shall not exceed a total of two hours.

4. TYPE OF SERVICE

4.1 Temporary Service

Where the Company has facilities available, temporary Service may be supplied under any rate schedule applicable to the class of Service required. The basic charge or minimum set forth in that rate schedule shall be applicable to the temporary Service, but in no case shall it be less than one full month. The Customer shall also pay for the cost of the installation and removal of the equipment used to supply the temporary Service as prescribed in Schedule 82.

Deleted: , except where the temporary Service is utilized for all or a major part of the permanent service where the Standard Charge will apply.

4.2 Underground Facilities

The Company's Tariff is designed to recover the cost of providing electrical Service from overhead poles and conductors. The Customer applying for underground Service under any Rate Schedule shall be responsible for any added cost and agrees as follows:

(a) The Company shall own, install and maintain the underground Service line to the Point of Delivery. The Customer shall own, install and maintain the underground Service line beyond the Point of Delivery.

(b) The underground installation must comply with the Company's underground distribution standards.

(c) The Company shall not be responsible for any loss or damage beyond the reasonable control of the Company due to the installation, operation or maintenance of the underground circuit.

4.3 Residential Service

Residential Service is intended strictly for residential use. Some minor exceptions as indicated in the following are accepted under this Tariff for reasons of administration and practicality. Where partial commercial use or other use is made of Electricity supplied, refer to Section 4.3.3 or 4.3.4.

Residential Service is normally single phase 120/240 volt, maximum 200 amperes. Three phase residential Service or single phase Service in excess of 200 amperes may be provided under special contract terms requiring the Customer to pay all the additional costs of a larger Service.

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4. TYPE OF SERVICE (Cont'd)

4.3 Residential Service (Cont'd)

Residential rates are available for Service as follows:

4.3.1 Single meter residential Premises - exclusive residential use

(a) individually metered single family residences used exclusively for normal residential and housekeeping requirements;

(b) any outbuilding located on residential property and supplied through the residential meter;

(c) residential property where less than three rooms are rented and supply is through the same meter as the residence, (three or more rented rooms will be billed on the Commercial Service rate);

(d) At the Company's option, multiple family dwellings used exclusively for living quarters and served through one meter. For billing purposes, the kilowatt-hour blocks, basic charge and minimum charge will be increased in proportion to the number of single family living quarters served.

4.3.2 Multiple meter residential Premises - exclusive residential use

(a) multiple family dwellings such as apartments, condos, duplex, quadruplex, etc., where each separate living quarter is separately metered;

(b) common use areas in multiple residential dwellings where each single family residence is separately metered;

(c) individually metered motel units where the owner contracts with the Company for the Service to each unit;

(d) where a Customer requests and the Company permits a separate Service to an outbuilding related to the Customer's residential occupancy as in 4.3.1 (a) above. The Company may provide the separately metered residential Service if the Customer pays the full cost of the separate Service less any contribution by FortisBC as specified in Schedule 74 towards the separate Service.

Customers with multiple meter residential Premises shall take Service under a single rate, unless otherwise approved by the Company.

Deleted: excluding the costs of meters and transformers

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4. TYPE OF SERVICE (Cont'd)

4.3.3 Partial commercial use

Where a partial commercial use is carried on in a single metered residential Premises (with or without outbuildings), and if the total connected load of the commercial enterprise is less than 5,000 watts, excluding space heating, the Customer shall be billed under Residential Service rates.

If the total connected load of the commercial enterprise is greater than 5,000 watts, excluding space heating, the account shall be billed at Commercial Service rates.

Where commercial use is carried on in a residential Premises or in an outbuilding to that Premises and the commercial area is separately metered, the commercial area only shall be on a Commercial Service rate. If new buildings are erected or major alterations are made to Premises receiving combined Service, the Customer shall be required to arrange the wiring to provide for separate metering.

Deleted: No additional initial service costs shall be levied against the Customer for the second service.¶

4.3.4 Other Use

Where water pumps supply single family residences, the water pumps shall be on the Residential Service rate provided they can be supplied single phase and total 5 HP or less.

Deleted: will

4.3.5 Farms

Farm residences and their outbuildings shall qualify for the Residential Service rate provided the farm is assessed for property tax purposes as agricultural land and the Service is used primarily for the production of food or industrial crops on that land. Other use for commercial or non farm purposes shall be billed on the Commercial Service rate.

5. METERING

5.1 Installation

The Company shall provide all meters necessary for measuring the Customer's use of the electric Service provided by the Company. The meters shall remain the property of the Company and shall be maintained in accurate operating condition in accordance with the regulations of Measurement Canada.

Deleted: (the "Department")

The Customer may furnish, install and maintain at its expense a meter system to verify the accuracy of the Company's meter system. The Customer's meter system and the manner of its installation shall be approved by the Company.

5. METERING (Cont'd)

5.1 Installation (Cont'd)

Should an accurate meter reading be unavailable due to meter failure, temporary inaccessibility, or any other reason, Electricity delivered to the Customer shall be estimated by the Company from the best available sources and evidence.

The Customer shall exercise all reasonable diligence to protect the Company's meter from damage or defacement and shall be held responsible for any costs of repair or cleaning resulting from defacement or damage.

All connections and disconnections of electric Service and installation and repair of the Company's meter system shall be made only by the Company. All meters shall be sealed by the Company. Breaking the seals or tampering with the meter or meter wiring is unlawful and may be cause for Termination of Service by the Company, and may result in criminal charges for theft of Electricity.

5.2 Location

The Customer shall provide a Service entrance and meter socket location in accordance with Company requirements, and where required a metering equipment enclosure.

The meter socket shall be located on an outside wall and be within 1 m. of the corner nearest the point of supply except, in the case of metering over 300 volts, the meter socket shall be installed on the load side of the Service box and shall be accessible to Company personnel. All sockets must be installed between 1.4 m. and 1.7 m. above final grade to the centre of the meter. Meters shall not be installed in carports, breezeways or similar areas. Any exceptions must be approved by the Company.

Meters shall be installed in places providing safe and reasonable access. Meters shall not be exposed to live steam, corrosive vapours or falling debris. Where the meter is recessed in the wall of a building, sufficient clearance must be provided to permit removal and testing of Company equipment. The full cost of relocating an inaccessible meter shall be borne by the Customer.

5.3 Meter Tests or Adjustments

A Customer may request in writing a test of the accuracy of a meter. The Customer shall deposit an amount as provided in Schedule 80 and the Company shall remove the meter within 10 days and apply to the authorized authority to have the meter tested. If the meter fails to meet any of the applicable laws and regulations, the deposit shall be refunded to the Customer. If the meter is found to satisfy the applicable laws and regulations, the Customer shall forfeit the deposit.

Deleted: employees

Deleted: an

Deleted: meter inspector

Deleted: required tests

Deleted: prescribed

Deleted: tests

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5. METERING (Cont'd)

5.3 Meter Tests or Adjustments (Cont'd)

If after testing the meter is found not to be registering within the limits allowed by Measurement Canada, bills will be adjusted as prescribed in the applicable laws and regulations. If a refund is necessary, it shall be calculated in accordance with Clause 11.6.

Deleted: the Department

Deleted: federal Electricity and Gas Inspection Act

5.4 Metering Selection

Deleted: Demand

Meters will be selected at the Company's discretion and shall be compliant with the regulations of Measurement Canada. The Company at its discretion may change the type of metering equipment.

Deleted: Demand m

Deleted: approved by the Department will normally be either:¶
(a) thermal demand metering equipment; or¶
(b) 15 minute sliding window demand metering equipment.¶
¶

5.5 Unmetered Service

The Company may permit unmetered Service if it can estimate to its satisfaction the energy used based on the connected load and hours of use. Customers served under this provision must notify the Company immediately of any proposed or actual changes in load or hours of use. The Company, at its discretion, may at any time require the installation of a meter or meters and thereafter bill the Customer on the consumption registered.

6. METER READING AND BILLING

6.1 Meter Reading

Meters shall be read at the end of each billing period in accordance with the applicable rate schedule. The interval between consecutive meter readings shall be determined by the Company. An accurate record of all meter readings shall be kept by the Company and shall be the basis for determination of all bills rendered for Service.

Deleted: The Company will, as nearly as possible, read meters on the same date of the month, but a variation in meter reading dates may occur.

For billing purposes, the Company may estimate the Customer's meter reading if, for any reason, the Company does not obtain a meter reading. Where the Customer requests Termination of Service pursuant to Section 2.6, the Company may estimate the final meter reading for final billing.

Deleted: If the Company estimates the Customer's meter reading, the Customer may read the meter and supply the reading to the Company for billing purposes.

The term "one month" (unless a calendar month is specified) as used herein and in the rate schedules, normally means the time elapsed between the meter reading date of one calendar month and that of the next. The term "two-month period" as used herein and in the rate schedules, normally means the time elapsed between the meter reading date of one calendar month and the second following calendar month.

6. METER READING AND BILLING (Cont'd)

6.2 Proration of Billing

Bills will be prorated as appropriate under the following conditions:

(1) For meters normally read every one month where the billing period is less than 21 days or greater than 39 days.
(2) For meters normally read every two months where the billing period is less than 51 days or greater than 69 days.

6.3 Rates for Electricity

The Customer shall pay for Electricity in accordance with these Terms and Conditions and the Customer's applicable rate schedule, as amended from time to time and accepted for filing by the British Columbia Utilities Commission. If it is found that the Customer has been overcharged, the appropriate refund shall be with interest as calculated in Clause 11.3.

6.4 Sales Tax and Assessments

In addition to payments for Services provided, the Customer shall pay to the Company the amount of any taxes or assessments imposed by any competent taxing authority on any Services provided to the Customer.

Deleted: electricity

Deleted: sales tax, consumption tax, or any other tax or assessment levied

Deleted: electricity

Deleted: delivered

6.5 Payment of Accounts

Bills for electric Service are due and payable when rendered. Payments may be made to the Company's collection office, electronically or to authorized collectors.

Customers' accounts not paid by the due date printed on the bill shall be in arrears. Late payment charges may be applied to overdue accounts at the rate specified on the bill and as set out on the applicable rate schedule.

Customers will be advised that their account is in arrears by way of notification on the next billing. If payment is not received, a letter will be mailed to the Customer advising that if payment is not received within ten days of the date of mailing, Service may be suspended without further notice. The Company will make every reasonable effort to contact the Customer by telephone or in person to advise the Customer of the consequences of non-payment, but the account may be disconnected if payment is not received.

Deleted: special

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7. LOAD CHANGES AND OPERATION

7.1 Notice by Customer

A Customer shall give to the Company reasonable written notice of any change in its load requirements to permit the Company to determine whether or not it can meet the requirements without changes to its equipment or system.

Notwithstanding any other provision of these Terms and Conditions, the Company shall not be required to supply to any Customer Electricity in excess of that previously agreed to by the Company.

Customers with a Demand component in the rate schedule who wish to change the Contract Demand or the Demand limit, shall submit to the Company a written request subject to the following provisions.

(a) an increase requested of less than 1,000 kVA shall be submitted not less than three months in advance of the date the increase is intended to become effective; and

(b) an increase requested in excess of 1,000 kVA but less than 5,000 kVA shall be submitted not less than one year in advance of the date the increase is intended to become effective; and

(c) an increase requested in excess of 5,000 kVA shall be submitted not less than three years in advance of the date the increase is intended to become effective.

(d) a decrease requested of up to 10 per cent per year of the existing Contract Demand or Demand limit shall be submitted not less than three months in advance of the date the decrease is intended to become effective. Customers with a Contract Demand in excess of 500 kVA shall provide the Company by January 31 of each year their best estimate of their annual Electricity requirements to allow the Company to forecast future load on its facilities.

If the Company approves the request in writing, the Contract Demand or the Demand limit may be changed either by amendment to the Customer's contract or by the parties executing a new contract. The Company shall not be required to approve any requested change in the Contract Demand or the Demand limit.

7.2 Changes to Facilities

The Customer may be required to pay for the cost of any alterations to the Company's facilities necessary to provide the Customer's increased load. If any increase in load, Contract Demand or Demand limit, approved by the Company, requires it to add to its existing facilities for the purpose of complying with the Customer's request, the approved increase shall be subject to payment of a Customer

7. LOAD CHANGES AND OPERATION (Cont'd)

7.2 Changes to Facilities (Cont'd)

contribution under clause 3.3. The Customer may also be required to provide a revenue guarantee deposit as set out in clause 3.4.

7.3 Responsibility for Damage

A Customer shall be responsible for and pay for all damage caused to the Company's facilities as a result of that Customer increasing its load without the consent of the Company.

The Customer shall indemnify the Company for all costs, damages, or losses arising from the Customer exceeding its Demand limit, including without limiting generality, direct or consequential costs, damages or losses arising from any penalty incurred by the Company for exceeding its Demand limit with its suppliers of Electricity.

7.4 Power Factor

Customers shall regulate their loads to maintain a Power Factor of not less than 90 percent lagging or as otherwise provided for in the applicable rate schedule. If the Power Factor of the Customer's load is less than the minimum required, the Customer's bill may be increased by an adjustment for low Power Factor. The Company may also require the Customer, at its expense, to install Power Factor corrective equipment to maintain the minimum required Power Factor.

Deleted: 90 percent lagging

Deleted: ensure that a lagging power factor of not less than 90 percent is maintained

The Company may refuse Service for neon, mercury vapour, fluorescent or other types of outdoor lighting or display device which has a Power Factor of less than 90 percent or other detrimental characteristics.

No credit will be given for leading Power Factor.

7.5 Load Fluctuations

The Customer shall operate its motors, apparatus and other electrical equipment in a manner that will not cause sudden fluctuation to the Company's line voltage, or introduce any element into the Company's system which in the Company's opinion disturbs or threatens to disturb its electrical system or the property or Service of any other Customer. Under no circumstances shall the imbalance in current between any two phases be greater than five percent. The Customer shall indemnify the Company against any liability, loss, cost and expense occasioned by the Customer's failure to operate its electrical equipment in compliance with this section.

Deleted: The Company may suspend supply of electricity if the Customer fails to take remedial steps required by the Company to correct a disturbance.

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8. CONTINUITY OF SERVICE

Deleted: SUPPLY

8.1 Interruptions and Defects in Service

The Company will endeavour to provide a regular and uninterrupted supply of Electricity but it does not guarantee a constant supply of Electricity or the maintenance of unvaried frequency or voltage and shall not be responsible or liable for any loss, injury, damage or expense caused by or resulting from any interruption, Suspension, Termination, failure or defect in the supply of Electricity, whether caused by the negligence of the Company, its servants or agents, or otherwise unless the loss, injury, damage or expense is directly resulting from the willful misconduct of the Company, its servants or agents provided, however, that the Company, its servants and agents are not responsible for any loss of profit, loss of revenues or other economic loss even if the loss is directly resulting from the willful misconduct of the Company, its servants or agents.

All responsibility of the Company for Electricity delivered to the Customer shall cease at the Point of Delivery, and the Customer shall indemnify the Company and save it harmless from all liability, loss and expense caused by or arising out of the taking of Electricity by the Customer.

The expense of any interruption of Service to others, loss of or damage to the property of the Company through misuse or negligence of the Customer, or the cost of necessary repairs or replacement shall be paid to the Company by the Customer.

8.2 Suspension of Service

Deleted: Supply

The Company and the Customer may demand the Suspension of Service whenever necessary to safeguard life or property, or for the purpose of making repairs on or improvements to any of its apparatus, equipment or work. Such reasonable notice of the Suspension as the circumstances permit shall be given.

The Company may suspend Service to the Customer for the failure by the Customer to take remedial action acceptable to the Company, within 15 days of receiving notice from the Company, to correct the breach of any provision of these Terms and Conditions to be observed or performed by the Customer. The Company shall be under no obligation to resume Service until the Customer gives assurances satisfactory to the Company that the breach which resulted in the Suspension shall not recur.

Deleted: discontinue the supply of electricity

Deleted: discontinuance

The Company shall have the right to suspend Service to make repairs or improvements to its electrical system and will, whenever practicable, give reasonable notice to the Customer.

Deleted: temporarily the supply of electricity

The Company shall have the right to suspend or terminate Service at any time without notice whenever the Customer has breached any agreement with the Company, or failed to pay arrears within

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8. CONTINUITY OF SERVICE (Cont'd)

8.2 Suspension of Service (Cont'd)

the specified time, fraudulently used the Service, tampered with the Company's equipment, committed similar actions, compromised the Company's Service to other Customers or if ordered by an authorized authority to suspend or terminate such Service. The cause of any Suspension must be corrected, and all applicable charges paid before Service will be resumed. Suspension of Service by the Company shall not operate as a cancellation of any contract with the Company, and shall not relieve any Customer of its obligations under these Terms and Conditions or the applicable rate schedule.

8.3 Termination by Customer

Whenever a Customer wishes to terminate Service from the Company, it shall give the Company timely notice so that arrangements can be made for final meter reading and billing. Until notice of Termination is given, the Customer shall continue to be responsible for all Service supplied unless the Company receives an application for Service from a new Customer for the Premises concerned.

Notice of Termination requirements for contract Customers shall be in accordance with the terms of the contract. If a contract Customer terminates its contract but fails to give the required notice of Termination, the minimum charges for the notice period, as well as any amounts due for Service supplied, shall immediately become due and payable.

9. RIGHTS-OF-WAY AND ACCESS TO FACILITIES

9.1 Rights-of-Way

By applying for electric Service, the Customer agrees to grant to the Company such rights-of-way, easements and any applicable permits on, over and under the property of the Customer as may be necessary for the construction, installation, maintenance or removal of facilities.

On request, the Customer at their own expense shall deliver to the Company documents satisfactory to the Company in registrable form granting the rights-of-way, easements and executed permits. The Customer shall at their own expense be responsible for obtaining rights-of-way, easements and any applicable permits on other properties necessary for the Company to provide Service to the Customer.

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9. RIGHTS-OF-WAY AND ACCESS TO FACILITIES (Cont'd)

9.1 Rights-of-Way (Cont'd)

Notwithstanding payment by the Customer towards the cost of electrical facilities installed by the Company or that electrical facilities may be affixed to the Customer's property, all electrical facilities installed by the Company up to the Point of Delivery shall remain the property of the Company, and the Company shall have the right to safe and ready access to upgrade, renew, replace or remove any facilities on the Customer's property at any time.

9.2 Access

The Company, through its authorized employees and agents, shall have safe and ready access to its electrical facilities at all reasonable times for the purpose of reading meters and testing, installing, removing, repairing or replacing any equipment which is the property of the Company. If access is restricted, the Company shall be supplied with keys to such locks if requested or, at the Company's option, a key holder box, where such locations are unattended during reasonable times.
In no case will the Company accept keys to private residential properties.

If safe and ready access to the Company's electrical facilities is denied or obstructed in any manner, including the presence of animals, and the Customer takes no action to remedy the problem upon being so advised, Service shall be suspended and not reconnected until the problem is corrected.

In cases where the Customer does not provide the Company with safe and ready access to the meter, the Company, may install a remote meter. The Customer will be responsible for the cost (as specified in the Standard Charges) of the remote meter and its installation.

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9.3 Exception

Notwithstanding the provisions of Section 9.1 and 9.2, approval of the B.C. Utilities Commission will be required prior to any removal of plant constructed to serve industrial Customers supplied at 60 kV and above

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10. CUSTOMER-OWNED GENERATION

10.1 Parallel Generation Facilities

The Customer may, at its expense, install, connect and operate its own electrical generating facilities to its electrical circuit in parallel with the Company's electrical system provided that the manner of installation and operation of the facilities is satisfactory to the Company, and the facilities have the capacity to be immediately isolated from the Company's system in the event of disruption of Service from the Company.

Prior to the commencement of installation of any generating facilities, the Customer shall provide to the Company full particulars of the facilities, and the proposed installation, and shall permit the Company to inspect the installation. The Customer at its own expense shall provide approved synchronizing equipment before connecting parallel generating facilities to the Company electrical system.

The Customer's generating facilities shall not be operated in parallel with the Company's electrical system until written approval has been received from the Company. The Customer shall not modify its parallel facilities or the installation in any manner without first obtaining the written approval of the Company.

If at any time the Company's electrical system is adversely affected due to difficulties caused by the Customer's generating facilities, upon oral or written notice being given by the Company to a responsible employee of the Customer, the Customer shall immediately discontinue parallel operation, and the Company may suspend Service until such time as the difficulties have been remedied to the satisfaction of the Company.

The Customer shall be responsible for the proper installation, operation and maintenance of all protective and control equipment necessary to isolate the Customer's generating facilities from the Company's electrical system upon the occurrence of a fault on the Customer's generating facilities or the Company's electrical system. The Customer's protective equipment shall not be modified in any manner and the settings thereto shall not be changed without first obtaining written approval of the Company.

The Customer shall notify the Company in advance each and every time that the Customer's generating facilities are to be connected to or intentionally disconnected from the Company's electrical system.

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10. CUSTOMER-OWNED GENERATION (Cont'd)

10.1 Parallel Generation Facilities (Cont'd)

During parallel operation of its generating facilities, the Customer shall cooperate with the Company so as to maintain the voltage and the Power Factor of Electricity at the Point of Delivery within limits agreeable to the Company, and shall take and use Electricity in a manner that does not adversely affect the Company's electrical system.

Notwithstanding any approval given by the Company, parallel operation of the Customer's generating facilities with the Company's electrical system shall be entirely at the risk of the Customer, and the Customer shall indemnify the Company and save it harmless from all injury, damage and loss and all actions, suits, claims, demands and expenses caused by or in any manner arising out of the operation of the Customer's generating facilities.

10.2 Standby Generation

The Customer may, at its expense, install standby generation facilities to provide electrical Service in the event of a disruption of Service from the Company. Standby generation facilities shall be installed so that they remain at all times electrically isolated from the Company's electrical system either directly or indirectly, and shall be installed in such a way that it is not possible for the facilities to operate in parallel with the Company's electrical system.

The Customer's standby electrical generating facilities shall not be operated without the prior inspection and written approval of the Company, and the facilities shall not be modified thereafter without the written approval of the Company.

10.3 Electrical Inspection Authority

The Customer must obtain the approval of the appropriate electrical inspection authority before installation.

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11. GENERAL PROVISIONS

11.1 Notices

Any notice, direction or other instrument shall be deemed to have been received on the following dates:

(a) if sent by electronic transmission, on the business day next following the date of transmission;

(b) if delivered, on the business day next following the date of delivery;

(c) if sent by registered mail, on the fifth business day following its mailing, provided that if there is at the time of mailing or within two days thereafter a mail strike, slowdown, lockout or other labour dispute which might affect delivery, then any notice, direction or other instrument shall only be deemed to be effective if delivered or sent by electronic transmission.

11.2 Conflicts

In case of conflict between these Terms and Conditions and the rate schedules, the provisions of the rate schedules shall prevail. Where there is a conflict between a contract and these Terms and Conditions, the provisions of the contract shall apply.

11.3 Payment of Interest

When interest is to be applied to certain Customer payments as provided in these Terms and Conditions, it shall be calculated as follows:

The Company will pay simple interest at the average prime rate of the principle bank with which the Company conducts its business, commencing with the date the subject funds were received by the Company.

The interest will be remitted to the Customers at the time the deposit or other payments are refunded, or in the case when a deposit or other refundable payment is to be held beyond one year, the interest will be calculated once every 12 months and shall be applied to the Customer's account.

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Deleted: December 31 of any
Deleted: as of December 31 of each year
Deleted: in January of the following year
Deleted: or if the amount of interest is in excess of $100 and the Customer's account is not in arrears, the interest will be paid to the Customer.

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11. GENERAL PROVISIONS (Cont'd)

11.4 Force Majeure

If any Large Commercial Service rate schedule Customer is prevented from taking Electricity, except for emergency purposes, for a period in excess of five calendar days by damage to its works from fire, explosion, the elements, sabotage, act of God or the Queen's enemies, or from insurrection, strike, or difficulties with workmen and invokes force majeure, the Company shall not be bound to make Electricity available during the period of the interruption except for emergency purposes, and commencing on the sixth calendar day of the interruption but for not more than 25 calendar days, the Customer shall, in lieu of the Demand Charge stipulated in the applicable Large Commercial Service rate schedule, pay a reduced Demand Charge for the period of the interruption, commencing on the sixth calendar day of the interruption to a maximum of 25 calendar days, derived from the Demand Charge rate multiplied by the maximum Demand recorded during that period of the interruption. The Customer shall not be entitled to any adjustment in the monthly Demand Charge under this clause unless the Customer informs the Company in writing it is invoking this clause, and the Company will read the meters used for billing purposes at the end of the fifth day of interruption and at the end of the period of interruption. The Customer shall be prompt and diligent in removing the cause of the interruption (by restoring its works or such other action as may be necessary and as soon as the cause of the interruption is removed or ceases to exist the Company shall without delay make Electricity available and the Customer shall take and pay for the same in accordance with this Tariff.

The force majeure provisions of this Clause 11.4 shall not apply in any month in which the Company purchases Electricity from British Columbia Hydro and Power Authority, unless the Company and British Columbia Hydro and Power Authority agree to a force majeure provision, in which case the Customer shall be given relief from the Demand Charge in accordance with that agreement.

11.5 Equal Payment Plan

Upon application, the Company may permit qualifying residential Customers to pay their accounts in equal monthly payments. The payments will be calculated to yield, over a twelve month period, the total estimated amount that would be payable by the Customer calculated by applying the applicable Residential Service rate to the Customer's estimated consumption during the same twelve month period. Customers may make application at any time of the year. All accounts will be reconciled annually or the earlier Termination date, at which time the amounts payable by the Customer to the Company for Electricity actually consumed during the equal payment period will be compared to the sum of equal payments made during the period. Any resulting amount owing by the Customer will be paid to the Company.

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11. GENERAL PROVISIONS (Cont'd)

11.5 Equal Payment Plan (Cont'd)

A residential Customer may qualify for the plan provided their account is not in arrears, they have established credit to the satisfaction of the Company and the Customer expects to be on the plan for at least one year.

The Company may at any time revise the equal monthly installments to reflect changes in estimated consumption or the applicable rate schedule.

The equal payment plan may be terminated by the Customer upon reasonable notice, or the Company if the Customer has not maintained their credit to the satisfaction of the Company. The Company reserves the right to cancel or modify the Equal Payment Plan Service at any time.

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Deleted: On the reconciliation date or termination, the amounts payable by the Customer to the Company for electricity actually consumed during the equal payment period will be compared to the sum of equal payments made during the period. Any resulting amount owing by the Customer will be paid to the Company

Deleted: Any excess of payments over charges will be paid or credited by the Company to the Customer. If such amounts are not large, they will be carried forward and included in the calculation of the equal payments for the next period.

11.6 Back-billing

(a) Back-billing means the rebilling for Services rendered to a Customer because the original billings are discovered to be either too high (over-billed) or too low (under-billed). The discovery may be made by either the Customer or the Company, and may result from the conduct of an inspection under provisions of the federal statute, the Electricity and Gas Inspection Act ("EGI Act"). The cause of the billing error may include any of the following non-exhaustive reasons or combination thereof:

(i) Stopped meter.
(ii) Metering equipment failure.
(iii) Missing meter now found.
(iv) Switched meters.
(v) Double metering.
(vi) Incorrect meter connections.
(vii) Incorrect use of any prescribed apparatus respecting the registration of a meter.
(viii) Incorrect meter multiplier.
(ix) The application of an incorrect rate.
(x) Incorrect reading of meters or data processing.
(xi) Tampering, fraud, theft or any other criminal act.

(b) Whenever the dispute procedure of the EGI Act is invoked, the provisions of that Act apply, except those which purport to determine the nature and extent of legal liability flowing from metering or billing errors.

11. GENERAL PROVISIONS (Cont'd)

11.6 Back-Billing (Cont'd)

(c) Where metering or billing errors occur and the dispute procedure under the EGI Act is not invoked, the consumption and Demand will be based upon the records of the Company for the Customer, or the Customer's own records to the extent they are available and accurate, or if not available, reasonable and fair estimates may be made by the Company. Such estimates will be on a consistent basis within each Customer class or according to a contract with the Customer, if applicable.

(d) If there are reasonable grounds to believe that the Customer has tampered with or otherwise used the Company's Service in an unauthorized way, or evidence of fraud, theft or other criminal act exists, then the extent of back-billing will be for the duration of unauthorized use, subject to the applicable limitation period provided by law and the provisions of items 11.6(g), 11.6(h), 11.6(i) and 11.6(j) below do not apply.

In addition, the Customer is liable for the administrative costs incurred by the Company in the investigation of any incident of tampering, including the direct costs of repair, or replacement of equipment.

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Under-billing resulting from circumstances described above will bear interest at the rate normally charged by the Company on unpaid accounts from the date of the original under-billed invoice until the amount underbilled is paid in full.

(e) In every case of under-billing or over-billing, the cause of the error will be remedied without delay, and the Customer will be promptly notified of the error and of the effect upon the Customer's ongoing bill.

(f) In every case of over-billing, the Company will refund to the Customer all money incorrectly collected for the duration of the error, subject to the applicable limitation period provided by law. Interest will be paid in accordance with Clause 11.3.

(g) Subject to item 11.6(d) above, in every case of under-billing, the Company will back-bill the Customer for the shorter of:

(i) the duration of the error; or

11. GENERAL PROVISIONS (Cont'd)

11.6 Back-Billing (Cont'd)

(ii) six months for Residential, Commercial Service, Lighting and Irrigation; and
(iii) one year for all other Customers or as set out in a special or individually negotiated contract with the Company.

(h) Subject to item 11.6(d) above, in all cases of under-billing, the Company will offer the Customer reasonable terms of repayment. If requested by the Customer, the repayment term will be equivalent in length to the back-billing period. The repayment will be interest free and in equal installments corresponding to the normal billing cycle. However, delinquency in payment of such installments will be subject to the usual late payment charges.

(i) Subject to item 11.6(d) above, if a Customer disputes a portion of a back-billing due to under-billing based upon either consumption, Demand or duration of the error, the Company will not threaten or cause the discontinuance of Service for the Customer's failure to pay that portion of the back-billing, unless there are no reasonable grounds for the Customer to dispute that portion of the back-billing. The undisputed portion of the bill shall be paid by the Customer and the Company may threaten or cause the discontinuance of Service if such undisputed portion of the bill is not paid.

(j) Subject to item 11.6(d) above, back-billing in all instances where changes of occupancy have occurred, the Company will make a reasonable attempt to locate the former Customer. If, after a period of one year, such Customer cannot be located, the over or under billing applicable to them will be canceled.

12. REPAYMENT OF ENERGY MANAGEMENT INCENTIVES

For those Customers supplied under Large Commercial Service or Wholesale rate schedules or Customers with a Contract Demand of 300 kVA or more, the unamortized balance of financial incentives paid to the Customer under Rate Schedule 90 shall be remitted to the Company within 30 days of billing, if:

(a) the operations at the Customer site are reduced by more than 50% for a continuous period of three months or longer; or

12. REPAYMENT OF ENERGY MANAGEMENT INCENTIVES (Cont'd)

(b) over 50% of the Electricity previously provided by the Company is replaced by another source including self-generation or another supplier.

In both cases the repayment shall be prorated based on the amount of energy replaced compared to the amount of energy supplied by the Company in the year immediately preceding the Electricity replacement.

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Cost of Service Analysis and Rate Design

Public Consultation Report

Appendix I

COST OF SERVICE ANALYSIS AND RATE DESIGN – PUBLIC CONSULTATION REPORT

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Public Consultation Program

FortisBC engaged in public consultation for the Cost of Service Analysis (COSA) study and Rate Design Application (RDA) to ensure that interested residents, government and business stakeholders, as well as First Nations were provided with an opportunity to learn about and provide input into the final COSA study and RDA. Activities included face to face meetings, seven public open houses, one stakeholder technical workshop, one First Nations workshop, and two facilitated Super Groups (focus groups).

The consultation process was advertised in local news media across the service territory and on the FortisBC website. Stakeholders and First Nations were also notified through direct mail, email and phone calls.

These activities encouraged customer groups including residential, general service (commercial), industrial, lighting, irrigation and wholesale to learn more about the COSA study and RDA, and to ask questions and provide meaningful input.

FortisBC recognizes the need to file a COSA and RDA that balance the interests of all customer groups and to make sure that rates charged to its customers are fair and equitable. An overview of, and the materials used for, the public consultation activities for the COSA and RDA are provided below.

Consultation Notification and Open Houses

FortisBC's consultation program and notification strategies sought feedback through e-mail and mail, by telephone, through recorded comments during face to face meetings and at the technical workshop, and through questionnaires at seven open houses and two Super Groups (focus groups).

Open House Notification and Invitation

First Nations and stakeholders were notified of the COSA study, the RDA and all public sessions through direct mail, email and by telephone. The stakeholder list developed for these notifications endeavoured to represent all customer groups and included:

- First Nations (bands and nations)
- Mayor and Council of service area municipalities
- Members of Parliament and Members of the Legislative Assembly
- Past regular FortisBC intervenors
- The interior members of the BC Municipal Electrical Utilities
- Wholesale Customers
- Area Chambers of Commerce and Economic Development Commissions

- Representative customer organizations such as the BC Cattleman's Association, and the Water Supply Association of BC
- FortisBC large customers
- Participants from public open houses

In addition, a news release was issued and newspaper advertisements were placed in print media throughout the service area. Notification and all consultation documents were also included on the FortisBC website.

Open Houses

COSA

Three open houses were held in May 2009 with a focus on the COSA study. They ran from 7:00 p.m. to 8:00 p.m., with scheduled time for a PowerPoint presentation and an opportunity for open house participants to ask questions. The first open house was at the Sandman Hotel in Castlegar on May 26, 2009 and the second was at the Ramada Hotel in Kelowna on May 27, 2009 and the third was at the Best Western Sunrise Inn in Osoyoos on May 28, 2009.

Open House Materials

Participants were provided with copies of the PowerPoint slides to follow during the presentation. Attendees were asked to fill out an exit questionnaire prior to their departure. Copies of the draft COSA study were also made available.

RDA

Four open houses were held in July 2009 with a focus on rate rebalancing and rate design options. They ran from 6:00 p.m. to 8:00 p.m., with scheduled time for a PowerPoint presentation and an opportunity for participants to ask questions. The first open house was held at the RotoCrest Hall in Creston on July 27, 2009, the second was in at the Sandman Hotel in Castlegar, the third was held at Manteo Resort in Kelowna on July 29, 2009 and the last was held at the Sonora Community Centre in Osoyoos on July 30, 2009.

Open House Materials

A discussion guide was developed for the open houses and the participants were also provided with copies of the PowerPoint slides to follow during the presentation. Attendees were asked to fill out an exit questionnaire to prior to their departure. Copies of the draft COSA study were available.

Feedback received

FortisBC received 20 questionnaires and four written responses as a result of these open houses.

Follow-up Mechanisms

To ensure each attendee's input was included in the final COSA and RDA, the final slide of each open house presentation included a number of feedback mechanisms. These were communicated verbally during the presentation and were also included in the open house notifications, PowerPoint presentation handouts, discussion guide, and on the FortisBC website.

All open house participants that left contact information and those who provided comments in writing were notified when the final COSA and RDA was submitted to the BC Utilities Commission.

Application Team - Subject Matter Experts for Open Houses

Attendees had an opportunity to ask questions and discuss the COSA and RDA with the team identified below:

Dennis Swanson – Regulatory Affairs Director
Corey Sinclair – Regulatory Affairs Manager
Mark Warren – Customer Services Director
Gary Saleba – EES Consulting President
Gail Tabone – EES Consulting
Jodie Foster Sexsmith – Corporate Communications

Super Groups

In order to gather additional feedback and ensure input from a representative sample of FortisBC customer groups about the COSA and RDA, FortisBC hired Environics Research Group to conduct two Super Groups. The first was in Castlegar on August 17, and the second in Kelowna on August 18, 2009.

In each case a representative sample of customer groups (residential, general service, industrial, irrigation and lighting) was randomly selected. 70 participants were confirmed to attend, and told only that they would be participating in a focus group, but if they asked they were told that the subject matter was electricity rates for FortisBC. Participants were paid either $75 or $100 which was determined by their distance from the meeting location.

In Castlegar 58 people participated and in Kelowna 56 people participated. Each participant was asked to fill out a short entrance survey. A PowerPoint presentation was provided by FortisBC staff and then participants completed a detailed exit survey.

Feedback received

FortisBC received 114 complete surveys with in-depth feedback, which have been provided in Appendix I together with a summary of findings.

Government Consultation

FortisBC sent invitations for each of the open houses and the technical workshop to each Mayor and CAO / CEO, MP and MLA within the FortisBC service area. FortisBC followed up these invitations with a phone call to the CAO / CEO at each area municipality and attended face to face meetings with many of the municipalities.

Business Consultation

Invitations to the open houses and the technical workshop were sent to wholesale and industrial customers as well as chambers of commerce, economic development commissions and customer organizations. Additional businesses and organizations such as the Okanagan Environmental Industry Association and BC Sustainable Energy Association were also included in this list.

The wholesale customers were additionally offered individual meetings since their electrical needs are significantly different from the needs of other customer classes. FortisBC staff spoke to all wholesale customers during May and June 2009.

First Nations Consultation

In addition to the public open houses, invitations were sent to the Bands and Nations within the FortisBC service area for a First Nations open house scheduled for July 21, 2009. No Bands or Nations attended and no written feedback was received on either the COSA or RDA.

Consultation Material Samples

Samples of the following materials have been included:

Stakeholder contact list used for COSA and RDA

COSA

- Ad for open houses
- Mailed / emailed invite to open houses

- News release
- Survey from open houses
- PowerPoint presentation

RDA

- Ad for open house
- News release
- Survey from open houses
- PowerPoint presentation
- COSA and RDA discussion guide
- Backgrounder for Super Groups
- Environics Super Group summary report

Method of Contact	First Name	Last Name	Organization	Position
BCUC				
Ministry of Energy, Mines and Petroleum Resources				
FortisBC Board of Directors				
Intervenors				
Invite / Letter and email	Harold	Lunner	Nova Independent Resources Ltd.	President
Invite / Letter and email + DSM	David	Mayes	Okanagan Environmental Industry Alliance	Executive Director
Invite / Letter and email	Mark	McKenny	MGM Management	
Invite / Letter and email	Richard	Billingsley		
Invite / Letter and email	Ludo	Bertsch	Horizon Technologies Inc.	
Invite / Letter and email	Thomas	Hackney	BC Sustainable Energy Association	
Invite / Letter and email	Norman	Gabana		
Invite / Letter and email + DSM	Sarah Y.	Khan	BC Public Interest Advocacy Centre	
Invite / Letter and email	Bill	Harper	Econalysis Consulting Service Inc.	
Invite / Letter and email	Andy	Shadrack		
Invite / Letter + DSM	Buryl	Goodman		
Invite / Letter and email + DSM	Richard	Tarnoff	Natural Resource Industries	
Invite / Letter and email + DSM	Alan	Wait		
Letter only	Don	Scarlett		
Email only	Chris	Weafer	Owen Bird Barristers and Solicitors	Commercial Energy Consumers of BC
Invite / Letter and DSM	Robert	Macrae		
Invite / Letter and DSM	Andrew	Pape-Salmon	BC Ministry of Energy, Mines and Petroleum Resources	Director - Energy Efficiency
Call	Tom	Loski	Terasen Gas	
IMEU Wholesale				
Email invite and call with offer of meeting	Sasha	Bird	City of Grand Forks	Interior Municipal Electrical Utilities
Email invite and call with offer of meeting	Terry	Andreychuk	City of Penticton	Interior Municipal Electrical Utilities
Email invite and call with offer of meeting	Cindy	McNeely	City of Kelowna	Interior Municipal Electrical Utilities
Email invite and call with offer of meeting	Ken	Ostraat	District of Summerland	Interior Municipal Electrical Utilities
Email invite and call with offer of meeting	Alexander	Love	Nelson Hydro	Interior Municipal Electrical Utilities
Other Wholesale Customers				

Method of Contact	First Name	Last Name	Organization	Position
Call for meeting			Zellstoff/Celgar	
Call for meeting			BC Hydro Yahk & Lardeau	
Call for meeting			Corona	
Call for meeting			Interfor	
Call for meeting			Roxul	
Chambers of Commerce				
Invite / letter and email with request to circulate to members and phone call	Pam	McLeod	Castlegar and District Chamber of Commerce	Executive Director
Invite / letter and email with request to circulate to members and phone call	Minika	Coleman	Creston and District Chamber of Commerce	Executive Director
Invite with **no** request to circulate			Grand Forks Chamber of Commerce	Executive Director
Invite / letter and email with request to circulate to members and phone call	Jerry	Henke	Greenwood Board of Trade	Executive Director
Invite / letter and email with request to circulate to members and phone call			Kaslo and Area Chamber of Commerce	Executive Director
Invite with **no** request to circulate	Linda	Wilson	Lake Country Chamber of Commerce	Executive Director
Invite / letter and email with request to circulate to members and phone call	Tom	Thompson	Nelson and District Chamber of Commerce	Executive Director
Invite with **no** request to circulate	Lorraine	Renyard	Penticton & Wine Country Chamber of Commerce	Executive Director
Invite / letter and email with request to circulate to members and phone call			Rossland Chamber of Commerce	Executive Director
Invite / letter and email with request to circulate to members and phone call			Salmo and District Chamber of Commerce	Executive Director
Invite with **no** request to circulate	Lisa	Jaagar	Summerland Chamber of Commerce	Executive Director
Invite / letter and email with request to circulate to members and phone call	Christine	Slagel	Trail and District Chamber of Commerce	Executive Director
Invite / letter and email with request to circulate to members and phone call	Joe	Sloga	Christina Lake Chamber of Commerce	VP

Method of Contact	First Name	Last Name	Organization	Position
Invite / letter and email with request to circulate to members and phone call	Bonny	Dancey	South Okanagan Chamber of Commerce	Executive Director
Invite / letter and email with request to circulate to members and phone call	Weldon	Leblanc	Kelowna Chamber of Commerce	Executive Director
Invite / letter and email with request to circulate to members and phone call	Colleen	Christensen	Similkameen Country	Executive Director
Invite / letter and email with request to circulate to members and phone call			Slocan District Chamber of Commerce	Executive Director
Economic Development Commissions				
Invite Letter and email			District of Summerland	Director of Economic Development
Invite Letter and email	Robert	Louie	Westbank First Nation	Chief
Invite Letter and email	Robert	Fine	Central Okanagan Economic Development Commission	
Invite Letter			Oliver and District Community Economic Development Society	Economic Development Officer
Invite Letter			Destination Osoyoos	Economic Development Officer
Invite Letter and email	Wendy	McCulloch	Regional District of Kootenay Boundary	Community Economic Development Coordinator
Invite Letter and email	Paul	Weist	Nelson Economic Development Partnership	General Manager of Community Futures
Invite Letter and email	Chris	Scott	Osoyoos Indian Band	Osoyoos Indian Band
Other Customer Groups				
Email	Dominique	Ramirez	Commercial Energy Consumers	Executive
Invite Letter	Archie	MacDonald	Council of Forest Industries	General Manager South Office
Invite Letter and email	Bob	France	BC Cattlemen's Association	Executive
Invite Letter and email	Len	Lucas	BC Fruit Growers Association	Executive
Invite Letter and email			Association of BC Winegrowers	
Invite Letter			BC Grapegrowers Association	

Method of Contact	First Name	Last Name	Organization	Position
Invite Letter	James	Chase	BC Hotel Association	Chief Executive Officer
Invite letter and email	Toby	Pike	Water Supply Association of BC	Chairman
Local Government				
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Lawrence	Chernoff	City of Castlegar	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Ron	Toyota	Town of Creston	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Libby	Nelson	Village of Fruitvale	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Brian	Taylor	City of Grand Forks	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Colleen	Lang	City of Greenwood	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Greg	Lay	Kaslo	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Sharon	Shepherd	City of Kelowna	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Walter	Despot	Village of Keremeos	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor James	Baker	District of Lake Country	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Randy	Kappes	Village of Midway	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Griff	Welsh	Village of Montrose	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor John	Dooley	City of Nelson	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Pat	Hampson	Town of Oliver	Mayor

Method of Contact	First Name	Last Name	Organization	Position
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Stu	Wells	Town of Osoyoos	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Dan	Ashton	City of Penticton	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Randy	McLean	Town of Princeton	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Greg	Granstrom	City of Rossland	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Ann	Henderson	Village of Salmo	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Madeleine	Perriere	Village of Slocan	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Janice	Perrino	District of Summerland	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Dieter	Bogs	City of Trail	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Mayor Jim	Nelson	Village of Warfield	Mayor
Letter for information and invite with cc: to CAO / Call to CAO follow up	Chair Gary	Wright	Regional District of Central Kootenay	Chair
Letter for information and invite with cc: to CAO / Call to CAO follow up	Chair Robert	Hobson	Regional District of Central Okanagan	Chair
Letter for information and invite with cc: to CAO / Call to CAO follow up	Chair Marguerite	Rotvold	Regional District of Kootenay-Boundary	Chair
Letter for information and invite with cc: to CAO / Call to CAO follow up	Chair Dan	Ashton	Regional District of Okanagan-Similkameen	Chair
Government (MLA and MP)				
Email for information with follow up call	Bill	Barisoff	MLA	Penticton

Method of Contact	First Name	Last Name	Organization	Position
Email for information with follow up call	John	Slater	MLA	Boundary-Similkameen
Email for information with follow up call	Katrine	Conroy	MLA	Kootenay West
Email for information with follow up call	Michelle	Mungall	MLA	Nelson-Creston
Email for information with follow up call	Ben	Stewart	MLA	Westside-Kelowna
Email for information with follow up call	Norm	Letnick	MLA	Kelowna-Lake Country
Email for information with follow up call	Steve	Thomson	MLA	Kelowna-Mission
Email for information with follow up call	Harry	Lali	MLA	Fraser Nicola
Email for information with follow up call	Stockwell	Day	MP	Okanagan-Coquihalla
Email for information with follow up call	Ron	Cannan	MP	Kelowna-Lake Country
Email for information with follow up call	Alex	Atamanenko	MP	British Columbia Southern Interior
Email for information with follow up call	Jim	Abbott	MP	Kootenay Columbia
First Nations				
Letters and call to CFO or band manager with offer to meet	Chief Johnathan	Kruger		Penticton Indian Band
Letters and call to CFO or band manager with offer to meet	Chief Fabian	Alexis		Okanagan Indian Band
Letters and call to CFO or band manager with offer to meet	Chief Clarence	Louie		Osoyoos Indian Band
Letters and call to CFO or band manager with offer to meet	Chief Chris	Luke Sr		Lower Kootenay Indian Band
Letters and call to CFO or band manager with offer to meet	Chief Richard	Holmes		Upper Similkameen Indian Band
Letters and call to CFO or band manager with offer to meet	Chief Joseph	Dennis		Lower Similkameen Indian Band
Business Associations				
Email invite with request to redistribute			Uptown Rutland Business Association	
Large Customers				
Call with invite to open houses	Jackie	Podger	UBC O	AVP
Call with invite to open houses	Doug	Owram	UBC O	Deputy Vice Chancellor
Call with invite to open houses	Al	Smilie	Crown Packaging	General Manager
Call with invite to open houses	Michael	Mercer	District of Lake Country	Director of Engineering
Call with invite to open houses	Al	Stober	Al Stober Construction	Owner

Method of Contact	First Name	Last Name	Organization	Position
Call with invite to open houses	Mark	Stober	Al Stober Construction	
Call with invite to open houses	Ted	Spearin	Interior Health	Energy Manager
Call with invite to open houses	Al	Cumbers	School District # 23	Director of Operations
Call with invite to open houses	Jeremy	Hopkinson	Big White Ski Resort	VP Operations
Call with invite to open houses	Paul	Plocktis	Big White Ski Resort	VP Real Estae and Development
Call with invite to open houses	Pat	Gable	Rona	Manager
Call with invite to open houses	Wayne	Meger	Overwaitea Food Group	Energy Manager
Call with invite to open houses	Norbert	Gelowitz	Orchard Park Shopping Centre	General Manager
Call with invite to open houses	Ron	Stevenson	Orchard Park Shopping Centre	Operations Manager
Call with invite to open houses	John	Younger	Sysco	VP
Call with invite to open houses	Kara	Baybutt	Sysco	CFO
Call with invite to open houses	Stan	Walt	Bingo Kelowna	Owner
Call with invite to open houses	Brad	Bennett	McIntosh Properties	
Call with invite to open houses	Greg	Saloum	Best Western Hotel	Owner
Call with invite to open houses	Ted	Callahan	Callahan Construction	Owner
Call with invite to open houses	Tod	Sanderson	Uptown Rutland Business Association	President
Call with invite to open houses	Deb	Gutherie	Uptown Rutland Business Association	Executive Director
Call with invite to open houses	Ralph	Tomlin	Springer creek	
Call with invite to open houses	David	Mcanerney	Columbia Brewery	Director
Call with invite to open houses	Gwen	Telling	Hushcroft Mill	
Call with invite to open houses	Craig	Upper	Porcupine Wood Products	
Call with invite to open houses	Scott	Weatherford	ATCO Wood Products	
Call with invite to open houses	Michael	Wigen	Wyndel Box and Lumber	
Call with invite to open houses	Steve	Podovinikoff	Selkirk College	
Call with invite to open houses	Steve	Moresette	SD 20	
Call with invite to open houses	Larry	Brown	SD8	
Call with invite to open houses	Michael	Strukoff	SD51	
Call with invite to open houses	Ted	Spearin	IHA	
Call with invite to open houses	John	MacLean	RDKB	

Method of Contact	First Name	Last Name	Organization	Position
Call with invite to open houses			Canadian Tire	
Call with invite to open houses	Wayne	Meager	Overwaite	
Call with invite to open houses			Safeway	
Call with invite to open houses	Don	Thompson	Red Mountain Resorts	
Call with invite to open houses	Elaine	Kalesnikoff	Kootenay Innovative Wood	
Call with invite to open houses			Toxco	
Call with invite to open houses	Thor		Pine Profiles	
Call with invite to open houses			Terasen	
Call with invite to open houses			Westfair foods (extra foods)	
Call with invite to open houses	Mitch	Van Aller	School District 53	Manager of Operations
Call with invite to open houses	Jeff	Larsen	Weyerhaeuser Princeton	Mill Manager
Call with invite to open houses	Wade	Walker	Greenwood Forest Products	Manager
Call with invite to open houses	Elizabeth	Everitt	Princeton Wood Preserves	President
Call with invite to open houses			Princeton Co-Gen	
Call with invite to open houses	Barry	Grace	Agriculture Canada	Science Director
Call with invite to open houses			Sterile Insect Release Program	
Call with invite to open houses	Alan	Tyabji	Okanagan Similkameen Cooperative Growers	General Manager
Call with invite to open houses	Michael	Daley	Vincor	Manager

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Public Open House

Cost of Service Analysis (COSA)

This project links the revenue requirement for the utility to equitable allocation of those costs to the various customer classes.

FortisBC invites all customers including residential, commercial, irrigation, industrial and wholesale to attend a public open house to learn more about a Cost of Service Analysis (COSA) that will be filed with the BC Utilities Commission as a draft in June 2009.

The COSA will help FortisBC fairly and equitably allocate the cost of providing electrical service amongst the various customer classes.

Open houses will be hosted:

Castlegar Tuesday, May 26, 2009 from 7– 8 pm
Sandman Hotel, 1944 Columbia Ave

Kelowna Wednesday, May 27, 2009 from 7 - 8 pm
Ramada Hotel, 2170 Harvey Ave

Osoyoos Thursday, May 28, 2009 from 7 - 8 pm
Best Western Sunrise Inn, 5506 Main Street

These open houses focus on COSA and are the first step in examining both cost of service and rate design. More open houses will be held this summer.

For more information call 1-866-4FORTIS (1-866-436-7847) or visit www.fortisbc.com

FortisBC is a Canadian owned electric utility operating in the southern interior of British Columbia.

www.fortisbc.com

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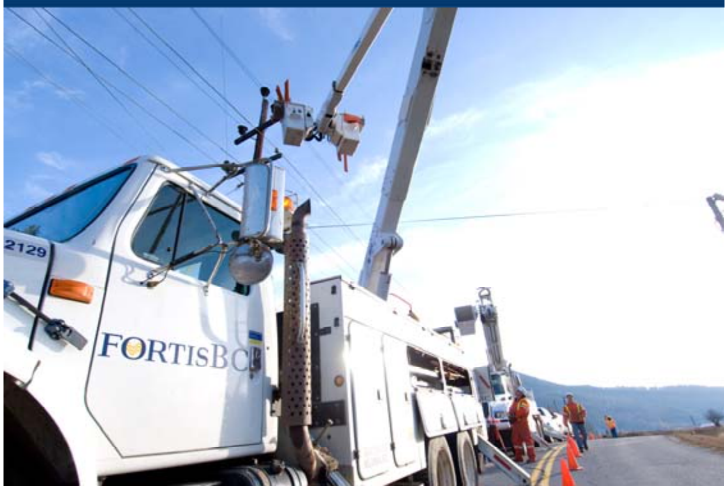

Public Open House Invitation

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FortisBC is a Canadian owned electric utility operating in the southern interior of British Columbia.

www.fortisbc.com

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News Release

FOR IMMEDIATE RELEASE:

FortisBC hosts a series of open houses

Kelowna, BC, May 26, 2009 – FortisBC Inc. is hosting a series of open houses this week to provide information and receive feedback from stakeholders on a 2009 Cost of Service Analysis (COSA) currently underway.

The open houses have been scheduled to provide the public and interested parties with an opportunity to review and comment on the principles and preliminary results of FortisBC's 2009 COSA. As a utility, FortisBC is required to complete a Cost of Service study to review and update its cost of service allocations and methodologies.

"All utilities undertake a COSA periodically. The COSA is the basis to ensure that current rates reflect the fair and equitable allocation of costs to each customer class," said Michael Mulcahy, FortisBC's Vice President of Customer and Corporate Services. "As part of our consultation, we want to provide customers, stakeholders and First Nations with an opportunity to participate in this process, ask questions and understand how the COSA and the future rate design process may or may not affect them."

This week's open houses are the first step in a public process examining both cost of service and rate design. The open houses, which include a presentation with a question and answer period, are being held in Castlegar, Kelowna and Osoyoos.

FortisBC has made significant investments in the electrical system since the last COSA and rate design application process was completed. The 2009 COSA will reflect these changes and will update cost of service allocations and methodologies accordingly.

Once public input from the open houses has been gathered, a final draft of the COSA report will be prepared and posted on the Company's website to invite additional feedback and comment on the document.

Public, First Nations and stakeholder feedback is an important part of the consultation process and will be considered in FortisBC's Cost of Service Analysis filing, and a subsequent rate design review scheduled to start in July 2009. A draft 2009 Cost of Service Analysis report will be filed with the British Columbia Utilities Commission (BCUC) on June 30, 2009. Additional open houses will be held over the summer to further review the draft 2009 COSA report and explore future rate design options. A final 2009 COSA report and a 2009 Rate Design application will be filed with the BCUC by September 30, 2009.

For more information, contact FortisBC on the toll free number at 1-866-4FORTIS (1-866-436-7847) or visit the Company's website at www.fortisbc.com.

About FortisBC Inc.

FortisBC Inc. is an integrated regulated electric utility based in Kelowna, British Columbia. Focused on the safe delivery of reliable and cost-effective electricity, FortisBC serves approximately 158,000 customers directly and indirectly through wholesale utilities in the southern interior of B.C. FortisBC owns and operates four regulated hydroelectric generating plants and approximately 7,000 kilometres of transmission and distribution power lines. FortisBC employs over 500 people in British Columbia and is an indirect wholly owned subsidiary of Fortis Inc., the largest investor-owned distribution utility in Canada. Fortis Inc. shares are listed on the Toronto Stock Exchange and trade under the symbol FTS. Additional information can be accessed at www.fortisinc.com or www.sedar.com .

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For further information contact:
Jodie Foster Sexsmith
Communications and Media Relations Advisor
FortisBC Inc.
Tel: (250) 469-8007, Media Tel: (250) 718-1718
www.fortisbc.com

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Cost of Service Analysis
Open House Questionnaire

Please take a few minutes of time to complete this feedback form.

1. Now that you've attended an Open House and have had the opportunity to learn about Cost of Service Analysis, please provide us with feedback by rating the following statements:

a) The 2009 Cost of Service Analysis information was presented in a balanced manner.

1 Strongly Agree	2	3	4	5 Strongly Disagree

b) As a result of the Open House and presentation, I have a better understanding of the Cost of Service Analysis process.

1 Strongly Agree	2	3	4	5 Strongly Disagree

c) Based on the information I received this evening, I believe I will have reasonable opportunity to stay informed and be involved as the Cost of Service Analysis review and the consultation on future rate design continues.

1 Strongly Agree	2	3	4	5 Strongly Disagree

d) The methodology and principles as presented and used for the 2009 Cost of Service Analysis allocations appear reasonable.

1 Strongly Agree	2	3	4	5 Strongly Disagree

Please explain your choice(s).

2. Do you feel your questions were answered at this Open House? (Please circle your choice)

   Yes No

   Please explain your choice.

   ____

   ____

   ____

   ____

3. Are there any areas where you feel you may still need more information in order to fully understand and comment on the 2009 COSA? Please explain.

   ____

   ____

   ____

   ____

4. Would you attend another Open House in the summer to learn more about the 2009 COSA results and to participate in rate design consultation? (Please circle your choice)

   Yes No

   Please explain your choice.

   ____

   ____

   ____

   ____

5. How did you first hear about this Open House? (Check one)

   Newspaper Ad? (which) ______________________ Personal Invitation letter?__________________

   Other? (please specify) ____

6. If you are interested in receiving updates on Cost of Service Analysis and rate design, please provide us your contact information below. (Please print)

   Name: ______________________________ Phone: ____________________

   Title and Organization (if applicable) ______________________________

   Mailing Address: ______________________________

   E-mail address: ________________________ Fax: ____________________

7. To give us a better idea of who attended this Open House, we would appreciate it if you would answer the following questions. (Please circle your choice)

   a) Are you…

   Male Female

   b) A residential, commercial, industrial, irrigation, transmission or wholesale customer? (Please circle your choice)

   Residential General Service (Commercial) Industrial Irrigation Transmission Wholesale

8. Additional comments:

____

____

____

____

8. Would you like to be contacted when FortisBC schedules the next series of open houses on COSA and rate design? (Please circle your choice)

   Yes No

Thank you for your comments.
Please return this questionnaire to the front table.

FortisBC Inc.
100- 1975 Springfield Road,
Kelowna, BC
V1W 5C9

Email: regulatory@fortisbc.com

FortisBC Cost of Service Analysis

Public Open House
May 2009

FortisBC

Goals of COSA Public Consultation

- Explain Cost of Service
- Gather Input
- Answer Questions
- Encourage Ongoing Participation

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The Public Consultation Process – "Who"

- Residential customers
- Industrial Customers
- Commercial Customers
- Municipal Utilities (Wholesale customers)
- Customer Group Organizations
- Government
- First Nations
- British Columbia Utilities Commission

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The Public Consultation Process – "How"

- General Communications
- One-on-one communications
- Meetings with wholesale and industrial customers
- Open Houses and Information Sessions

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FortisBC Profile

- Oldest electric utility in British Columbia
- 110,000 direct customers across BC's southern interior
- Provide power to 5 Municipal utilities (resellers)
- Four hydroelectric generating stations
- 7000 km of power lines, 65+ substations,
- Kelowna-based head office, with over 14 field offices
- Over 500 employees
- Many different types of customers

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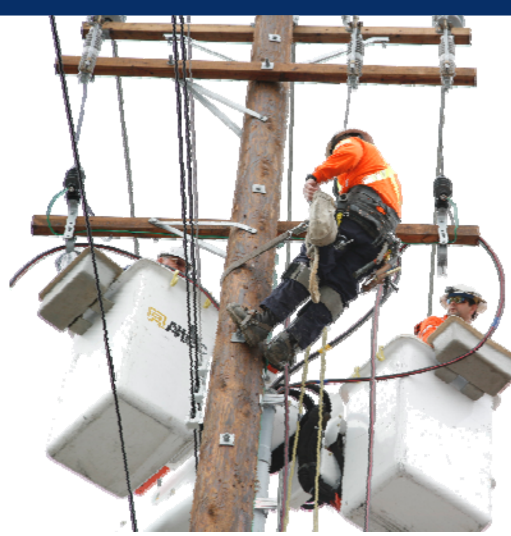
FortisBC Cost of Service Analysis



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Key Concept - Revenue Requirement

Revenue Requirement

=

Power Supply
Operations & Maintenance
Depreciation & Taxes
Interest and Return

•Determines the revenue required to operate the utility

•Approved Annually by the Utilities Commission

•Basis for Annual Rate Adjustment

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What is "Cost of Service Analysis" ?

- The purpose of a Cost of Service Study is to break down the total Revenue Requirement to the Customer Classes.
- The result of the Cost of Service Study shows the Cost to Serve each Customer Class.

Why now?

- Last done in 1997
- Many changes to the system and the industry.

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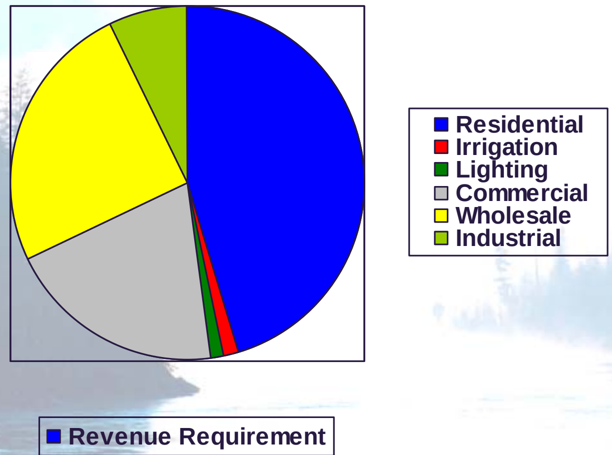
Slicing the Revenue Pie

Revenue Requirement – The "Size" of the Pie



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Overview – The COSA Process

Revenue Requirement	•The total dollars to collect.
Cost of Service Analysis	•Determine the costs that each customer class is causing and how much revenue the utility is collecting from each.
Rate Design	•How does the utility collect the costs?

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Brief Overview of COSA

	Determine the revenue requirement of the utility	Revenue Requirement Determination
Step 1	**Functionalize costs and services**	**Cost of Service Analysis**
Step 2	**Classify costs**	
Step 3	**Allocate costs among customer classes**	
	Design rates	Rate Design

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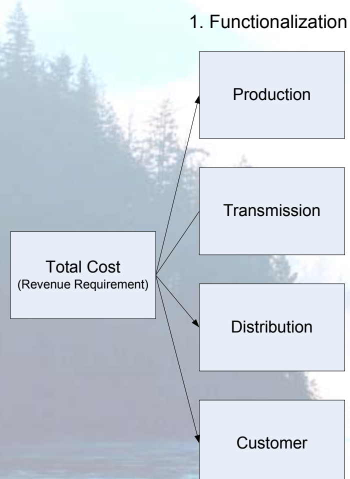
Step 1 - Functionalization



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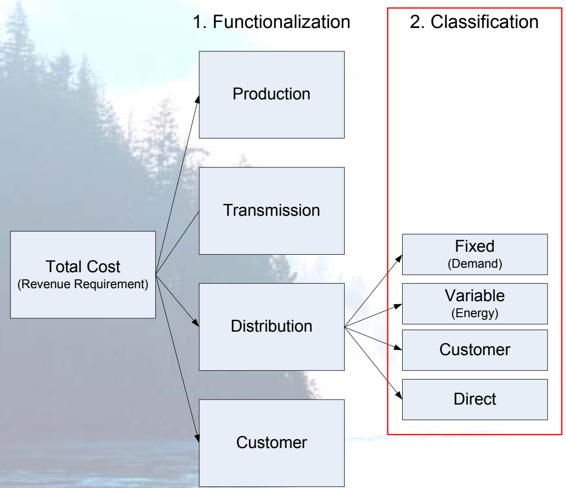
Steps in COSA



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Step 3 – Allocation of Costs

- **Cost allocation** – the process of matching the different types of classified costs to different groups of customers
- allocation factors proportion the costs on an equitable basis.
- Example
  - Meter costs can be allocated based upon the number of customers in each class of service

Class of Service	Number of Customers	%
Residential	4,000	93.9%
Commercial	250	5.9
Industrial	10	0.2%
Total	4,260	100.0%

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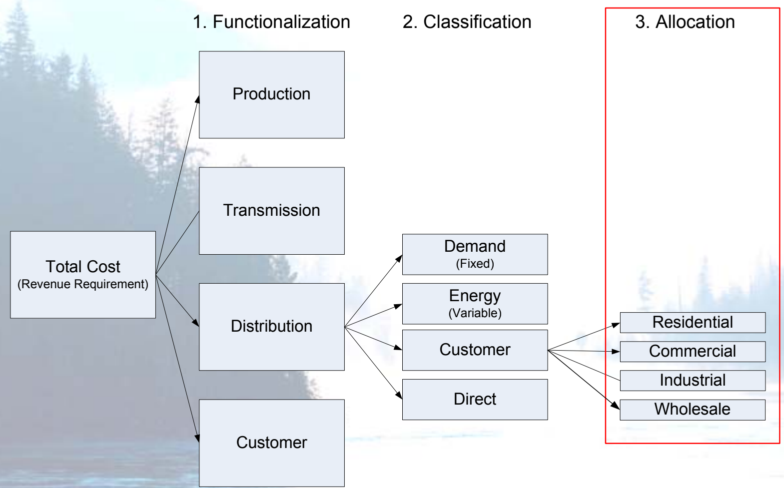
Steps in COSA



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Then & Now

Since 1997 the FortisBC system has changed in a number of ways:

- Significant investment in infrastructure
- Customer load characteristics are different
- Capacity Constrained

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Interpreting the COSA Results

- The COSA results show the allocated cost that should be collected from rates for each customer class.
- The revenue to cost ratios for each class show FortisBC is collecting the appropriate amount of revenue from each class.
- COSA can be used to help design rates
- Revenue neutral to the Utility

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Results of FBC COSA

- **Revenue to Cost Ratios are used to show how much customers are paying relative to their allocated costs.**

	2009 Revenue To Cost Ratio
Residential	97.1%
Small GS (20)	111.9%
General Service (21)	143.1%
Industrial Primary (30)	125.9%
Industrial Transmission	54.4%
Lighting	84.8%
Irrigation	81.3%
Kelowna Wholesale	90.1%
Penticton Wholesale	80.4%
Summerland Wholesale	96.4%
Grand Forks Wholesale	85.4%
BCH Lardeau Wholesale	103.3%
BCH Yahk Wholesale	104.9%
Nelson Wholesale	82.3%

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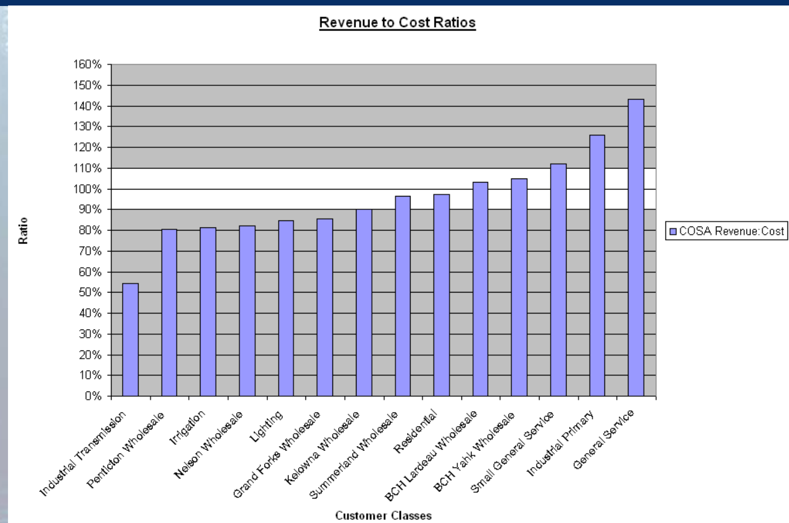
Results of FBC COSA



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What is "Cost of Service Analysis" ?

Determines,

- How costs are divided among the customer groups.
- Whether FortisBC is collecting the appropriate amount of revenue from each class.

Now you know!

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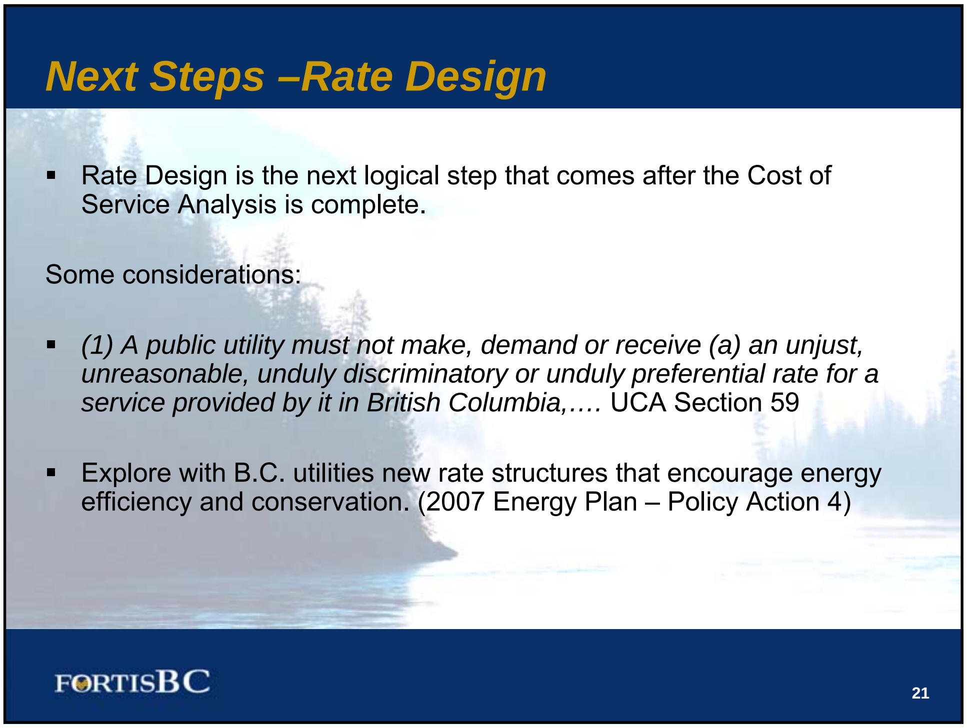
Next Steps –Rate Design
Rate Design is the next logical step that comes after the Cost of Service Analysis is complete.
Some considerations:
(1) A public utility must not make, demand or receive (a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia,…. UCA Section 59
Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation. (2007 Energy Plan – Policy Action 4)
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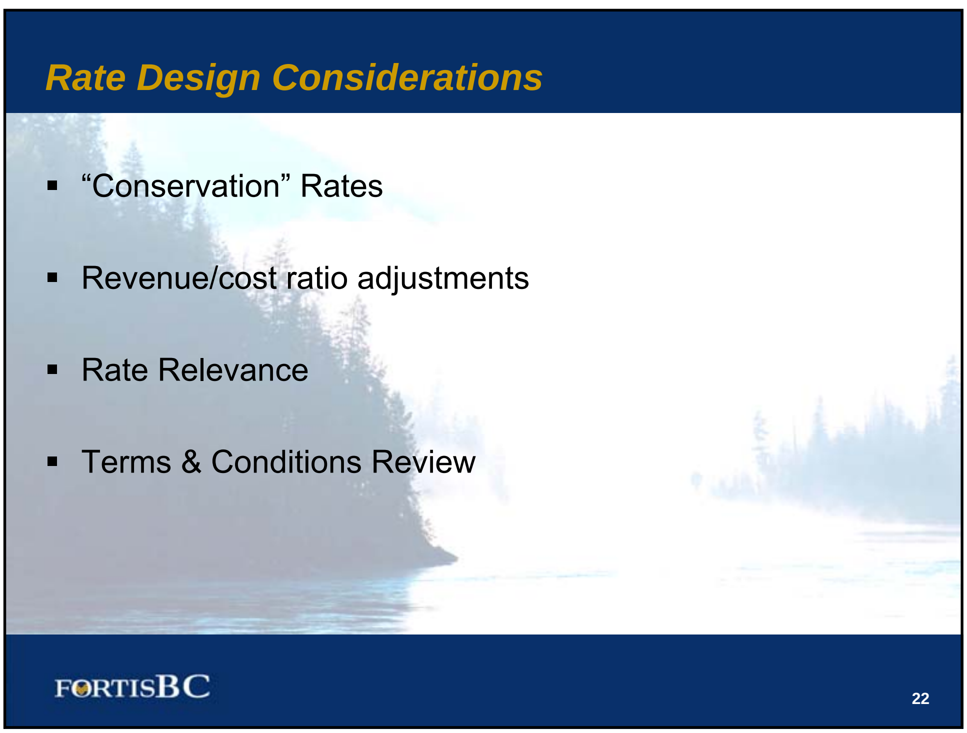
Rate Design Considerations
“Conservation” Rates
Revenue/cost ratio adjustments
Rate Relevance
Terms & Conditions Review
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Rate Design Options

Options to Consider

- Flat Pricing
- Inclining Block Rates
- Time-of- Use Rates
- Critical Peak Pricing
- Customer Charge adjustments
- Others

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Regulatory Process

1. Cost of Service
   - Public Consultation
     - Open Houses – Castlegar, Osoyoos, Kelowna
     - Feedback received by June 12
   - COSA Submission to BCUC – June 30, 2009
2. Final COSA & Rate Design
   - More Public Consultation
   - Rate Design Application to BCUC – September 30, 2009

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Feedback

- Sign-in sheets
- Surveys
- Website
- Hand-out
- E-mail: regulatory@fortisbc.com

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Q & A

- Questions / Comments ?

FortisBC

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Public open house

Rate design

Your views are important to us.

FortisBC is seeking public input as we review how existing electricity rates are structured for all customers—residential, commercial, industrial, wholesale and irrigation—and determine what updates to rate structures are needed.

Over the next few months, FortisBC will be completing a review of cost of service and rate design to make sure rates charged to customers are fair and equitable. We invite you to learn more about rate design options and share your thoughts on this topic with us. Some examples of rate design options include conservation-based rates such as critical peak pricing, inclining rates, and time of use rates.

Feedback received from customers and stakeholders will be considered, along with technical and financial information, as FortisBC prepares a rate design application for submission with the BC Utilities Commission in September 2009.

Please drop by any of the following open houses. Each open house will begin with a presentation at 6 p.m. :

Creston: Monday, July 27, 2009 | 6-8 p.m.
Rotocrest Hall, 230B 19th Avenue

Castlegar: Tuesday, July 28, 2009 | 6-8 p.m.
Sandman Hotel, 1944 Columbia Avenue

Kelowna: Wednesday July 29, 2009 | 6-8 p.m.
Manteo Resort, 3762 Lakeshore Road

Osoyoos: Thursday, July 30, 2009 | 6-8 p.m.
Sonora Community Centre, 8505 68th Avenue

For more information, call 1-866-4FORTIS (1-866-436-7847) or visit www.fortisbc.com.

Energizing your community.

www.fortisbc.com

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News Release

FOR IMMEDIATE RELEASE:

Public input invited as FortisBC begins electricity rate design review

KELOWNA, BC – July 24, 2009: FortisBC Inc. is hosting a series of open houses next week to provide information and gather public feedback as the utility completes a review of its cost of service and rate design to make sure rates charged to customers are fair and equitable.

“We are completing a review of how existing electricity rates are structured for all customers—residential, commercial, industrial, wholesale, lighting and irrigation—which will help determine what updates to rate structures are needed,“ said Michael Mulcahy, FortisBC’s Vice President of Customer and Corporate Services. “Public input into this review is an important part of the process and will provide us with valuable information on what factors are important to our customers.”

All utilities review cost of service and rate design periodically to make sure that rates reflect the fair and equitable allocation of costs. A cost of service analysis determines the cost of providing electrical service by customer class. In May, open houses and customer meetings were held throughout the region to invite public input into the Company’s 2009 cost of service analysis (COSA). Following these open houses, FortisBC filed a draft COSA report with the British Columba Utilities Commission (BCUC).

The next step for the Company is the rate design review currently underway to evaluate various rate structures, and determine if changes are needed to the Company’s basic customer charge and/or its energy charges. Essentially, rate structures determine how customers are billed for their electricity use.

Some examples of possible conservation based rate design options for residential customers include inclining block rates and time of use rates, among others.

Overall, changes resulting from a COSA and rate design review do not generate more revenue for a utility. Any changes proposed as a result of FortisBC’s 2009 COSA and rate design review would be aimed at rebalancing and restructuring rates paid by customers, making sure rates paid by a given customer reflect the cost of providing service to that customer, and that classes of customers are not unduly subsidizing each other.

The upcoming open houses will be held in the following communities and will start with presentations at 6 pm:

Creston	Monday, July 27 | 6-8 p.m; Rotocrest Hall, 230B 19th Avenue
Castlegar	Tuesday, July 28 | 6-8 p.m. Sandman Hotel, 1944 Columbia Avenue
Kelowna	Wednesday, July 29 | 6-8 p.m. Manteo Resort, 3762 Lakeshore Road
Osoyoos	Thursday, July 30 | 6-8 pm Sonora Community Centre, 8505 68th Avenue.

All feedback received will be considered, along with technical and financial information, as FortisBC prepares a rate design application for submission to the BCUC by September 30, 2009. Once the COSA and rate design applications have been filed, the BCUC manages the regulatory process and will make the final decision regarding cost of service analysis and rate design(s) to be implemented.

Individuals interested in more information about rate design and these open houses are encouraged to visit www.fortisbc.com or call 1-866-4FORTIS (1-866-436-7847).

About FortisBC Inc.

FortisBC Inc. is an integrated regulated electric utility based in Kelowna, British Columbia. Focused on the safe delivery of reliable and cost-effective electricity, FortisBC serves approximately 158,000 customers directly and indirectly through wholesale utilities in the southern interior of B.C. FortisBC owns and operates four regulated hydroelectric generating plants and approximately 7,000 kilometres of transmission and distribution power lines. FortisBC employs over 500 people in British Columbia and is an indirect wholly owned subsidiary of Fortis Inc., the largest investor-owned distribution utility in Canada. Fortis Inc. shares are listed on the Toronto Stock Exchange and trade under the symbol FTS. Additional information can be accessed at www.fortisinc.com or www.sedar.com .

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For further information contact:
Jodie Foster Sexsmith
Communications and Media Relations Advisor
FortisBC Inc.
Tel: (250) 469-8007, Media Tel: (250) 718-1718
www.fortisbc.com

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Rate rebalancing and rate design feedback form

Now that you've had the opportunity to learn about cost of service analysis, rate rebalancing and rate design, please provide us with feedback by rating the following statements and sharing your comments below.

Rate rebalancing

In my opinion, rate rebalancing is needed.

1	2	3	4	5
Strongly Agree				Strongly Disagree

Five years seems like an appropriate phase-in period for rate rebalancing.

1	2	3	4	5
Strongly Agree				Strongly Disagree

For customers whose revenue to cost ratios are below 100 per cent, capping their increases at 5% per year seems reasonable.

1	2	3	4	5
Strongly Agree				Strongly Disagree

It is important that FortisBC understands your level of agreement. Please provide any additional comments on rate rebalancing below:

____

____

____

Residential rate design

Please rank residential rate structure options proposed by FortisBC in your order of preference from 1—5:

_____ Option 1 Reduce basic charge with higher energy rates and minimum bill

_____ Option 2 Inclining block rate with lower basic charge and higher energy rates

_____ Option 3 Inclining block rate with higher basic charge and lower energy rates

_____ Option 4 Maintain existing rates

_____ Option 5 Other ______________________________

It is important that FortisBC understands your level of agreement. Please provide any additional comments on residential rate design below:

____

____

____

Residential rate design cont.

I am currently billed every two months, but I would prefer to have my meter read and be billed monthly, even if there is a one-time, one per cent rate increase.

1	2	3	4	5
Strongly Agree				Strongly Disagree

It is important that FortisBC understands your level of agreement. Please provide any additional comments on monthly billing below:

General service rate design

It is appropriate to flatten the rate structure for commercial customers, moving them from three tiers to two.

1	2	3	4	5
Strongly Agree				Strongly Disagree

It is important that FortisBC understands your level of agreement. Please provide any additional comments on general service rate design below:

I agree that wholesale, industrial, irrigation, and lighting customers should continue with a flat rate structure because of the rebalancing required for those customer classes.

1	2	3	4	5
Strongly Agree				Strongly Disagree

It is important that FortisBC understands your level of agreement. Please provide any additional comments below:

General questions

Introducing rate structures that encourage energy efficiency and conservation is important.

1	2	3	4	5
Strongly Agree				Strongly Disagree

It is important that FortisBC understands your level of agreement. Please provide any additional comments below:

The materials in the presentation and discussion guide were presented objectively.

1	2	3	4	5
Strongly Agree				Strongly Disagree

It is important that FortisBC understands your level of agreement. Please provide any additional comments below:

The presentation and discussion guide helped me understand cost of service, and rate design including rate Rebalancing.

1	2	3	4	5
Strongly Agree				Strongly Disagree

It is important that FortisBC understands your level of agreement. Please provide any additional comments below:

Overall, the information provided in the presentation and discussion guide met my expectations.

1	2	3	4	5
Strongly Agree				Strongly Disagree

It is important that FortisBC understands your level of agreement. Please provide any additional comments below:

Going forward

FortisBC is committed to assisting customers transition to the new rate structures. Please indicate how helpful you would find the following methods to support your transition:

	Very helpful				Not very helpful
Information on how to read your meter so you can monitor usage	1	2	3	4	5
Spreadsheet to track electricity usage and costs	1	2	3	4	5
Website to view and forecast electricity usage and costs	1	2	3	4	5
Assistance via telephone to identify savings opportunities	1	2	3	4	5
Other ______________________	1	2	3	4	5

Based on the information I have received, I believe I will have reasonable opportunity to stay informed and be involved in the cost of service analysis and rate design application public consultation and British Columbia Utilities Commission regulatory processes .

1	2	3	4	5
Strongly Agree				Strongly Disagree

About you

Your feedback will be considered along with technical and financial input as FortisBC prepares our rate design application and final cost of service analysis filing. Feedback collected at open houses, through feedback forms and via written comments will be recorded and summarized in the rate design application consultation report which will be provided to the British Columbia Utilities Commission during the regulatory review process.

Please indicate if your account (or majority of accounts) is:

_____ Residential _____ Industrial _____ Wholesale
_____ General Service _____ Irrigation _____ Lighting

Did you attend an open house? _____ Yes _____ No

_____Castlegar _____ Creston _____ Kelowna _____ Osoyoos

Please provide your contact information (optional):

Name ____
Address ____
Email ______________________ Phone ______________________

Deadline for feedback forms or written comment is **Friday, August 28, 2009**.
You can return written feedback forms or comments by:


Rate
Rebalancing
and
Rate Design
FORTISBC
1


Corey Sinclair – Regulatory Affairs
FortisBC
FORTISBC
2

Cost of Service Analysis

FORTISBC

3

Overview – The COSA Process

Cost of Service Analysis	➔ *Determine costs each customer class is causing and how much revenue the utility is collecting from each.*
Rate Design	➔ *How the utility collects the costs?*

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Preliminary 2009 COSA Results

- Revenue to cost ratios are used to show how much customers are paying relative to their allocated costs

Customer Class	2009 Revenue to Cost Ratio
Residential	99%
General Service	110% - 140%
Industrial Primary (30)	124%
Industrial Transmission (31)	62%
Lighting	84%
Irrigation	80%
Municipal Wholesale	68% - 96%
BC Hydro Wholesale	101% - 103%

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Rate Rebalancing

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Rate Rebalancing

- **Rebalancing – moving rates closer to their costs**
- **Some rebalancing between classes is necessary**
- **Goal:**
  - Move classes as close to 100 per cent as possible
  - Rebalancing increases capped at 5 per cent per year
  - Revenue from rebalancing used to manage increases to over-collecting classes

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Revenue to Cost Ratios

Customer Class	Revenue to Cost Ratio
Customer Class #1	**140%**
Customer Class #2	**100%**
Customer Class #3	**70%**

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Questions
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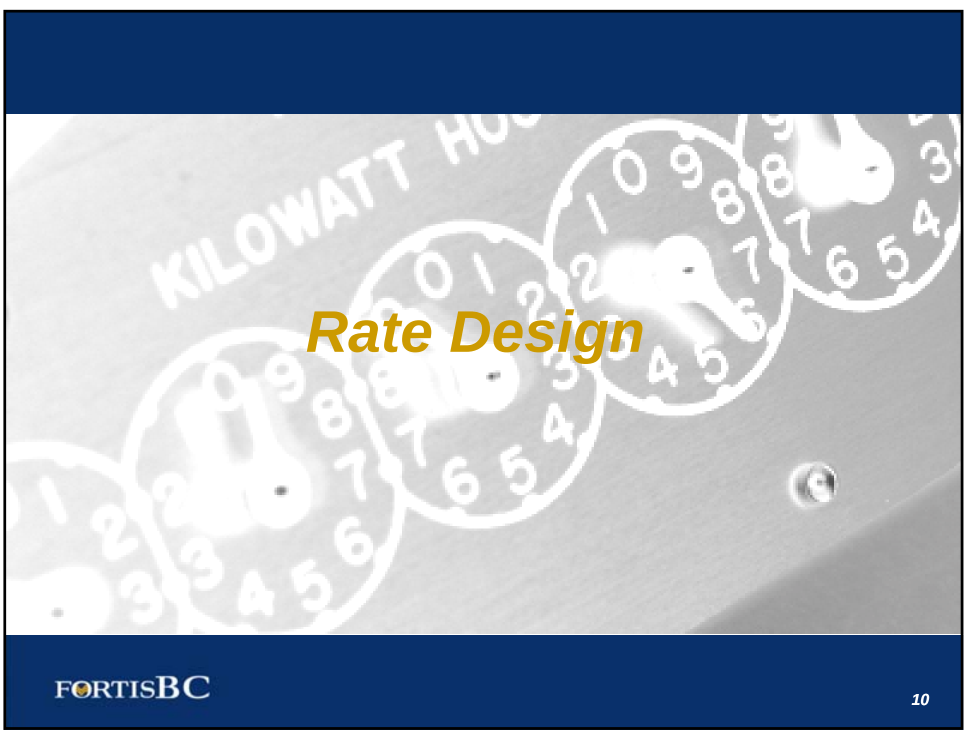
Rate Design
FORTISBC
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Agenda

- Provincial Policy and Legislation
- Rate Design Principles
- Rate Design Options

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Provincial Policy and Legislation

BC Energy Plan

Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.

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FortisBC Rate Design Principles

- Customer feedback critical
- Fixed cost recovery must improve
- Rates should be simple
- Rate impact should be managed for large majority of customers
- New rate structures should only be introduced if they address long-term needs

- Conventional meters are not suitable for wide-scale time-based rates

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Rate Design Options

	Residential	Commercial
Net Metering	X	X
Basic Customer Charge	X	X
Inclining Block Rate	X	
Flattening Declining Block Rates		X
Monthly Meter Reading & Billing	X	X
Urban/Rural Rates	X	
Seasonal Rates	X	

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Residential Rate Structures

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Residential Rate Options

- **Two components that can be adjusted:**
  - Basic customer charge
  - Energy charge

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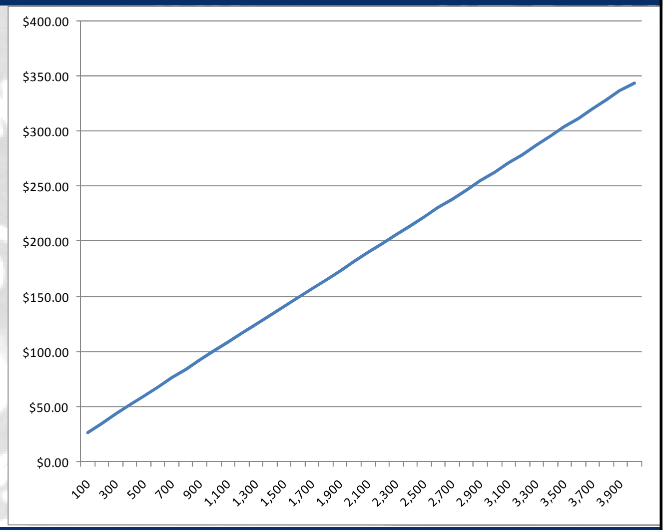
Residential Flat Rate Billing (today)

Fixed basic bi-monthly charge

Flat rate per kWh



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Residential Monthly Charges

- **Reduce basic bi-monthly charges, increase energy rates**
- **Requires minimum bill to recover appropriate fixed costs**
  - Residential: 50% reduction in basic bi-monthly charge = 7% increase in energy charge

Pros

- **Encourages conservation since higher proportion of bill directly relates to energy use**

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Residential Inclining Block Rates

- First block of energy used is priced at a base rate
- Second block of energy is priced higher than the first block

Pros:

- Customers using energy in second block have higher incentive to save energy
- Lower costs for customers below a consumption threshold

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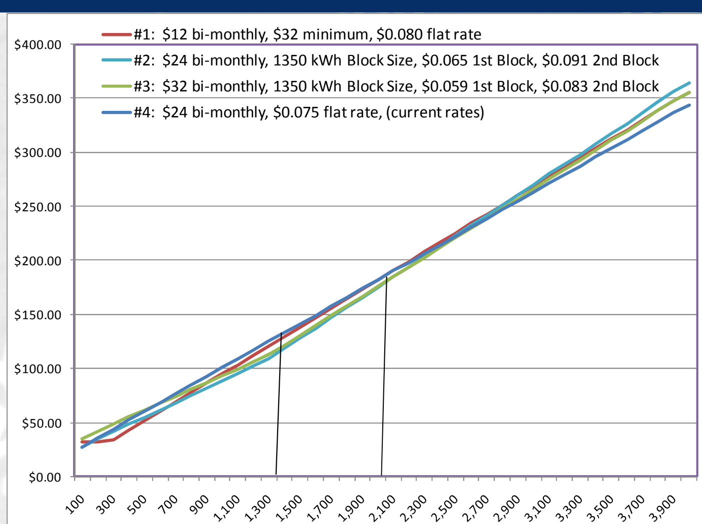
Residential Rate Choices



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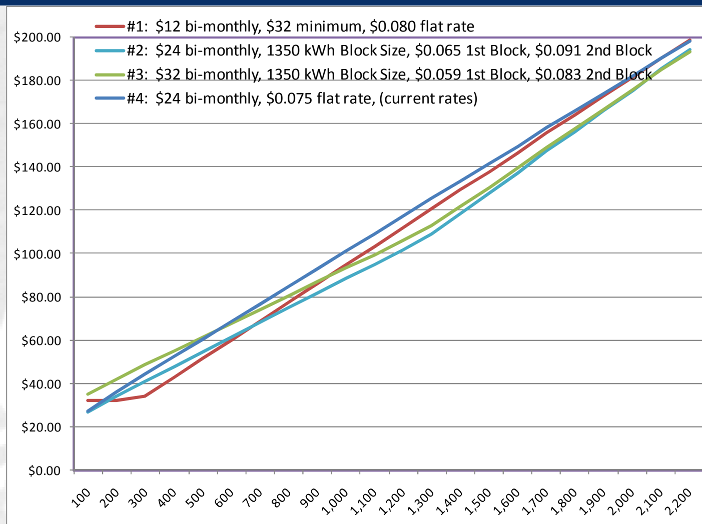
Residential Energy Bill < $200 bi-monthly



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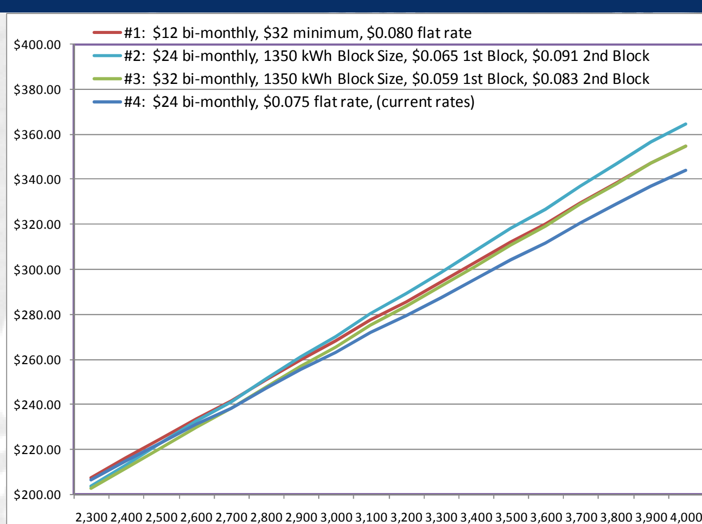
Residential Energy Bill > $200 bi-monthly



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Other Rate Strategy Considerations

- Within the next five years, FortisBC hopes to implement Advanced Metering Infrastructure (AMI)
- AMI will allow a wider variety of rates, including time-varying rates
- Time-varying rates are more suitable for addressing the FortisBC capacity deficit

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Residential Rate Feedback

Which conservation rate option do you think FortisBC should implement?

1. Implement lower bi-monthly charge and minimum bill
2. Implement residential inclining block rates – existing bi-monthly basic charge + higher rates than #3
3. Implement residential inclining block rates – higher bi-monthly basic charge + lower rates than #2
4. Maintain existing rate structure
5. Other - please explain

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General Service Rate Proposal
KILOWATT HO
FORTISBC
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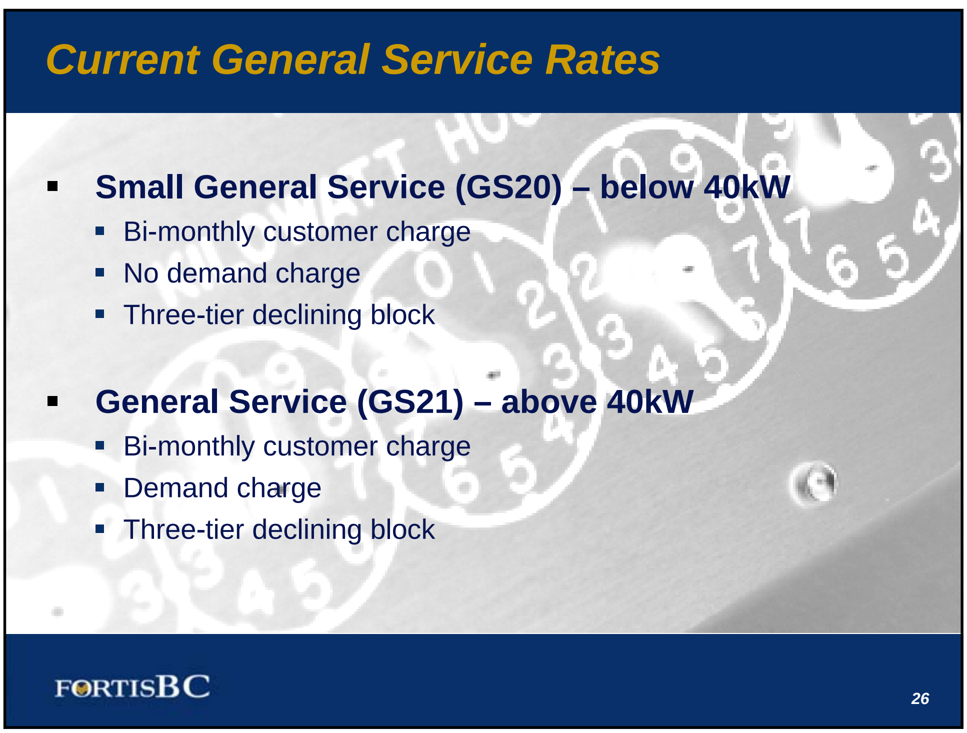
Current General Service Rates
Small General Service (GS20) – below 40kW
Bi-monthly customer charge
No demand charge
Three-tier declining block
General Service (GS21) – above 40kW
Bi-monthly customer charge
Demand charge
Three-tier declining block
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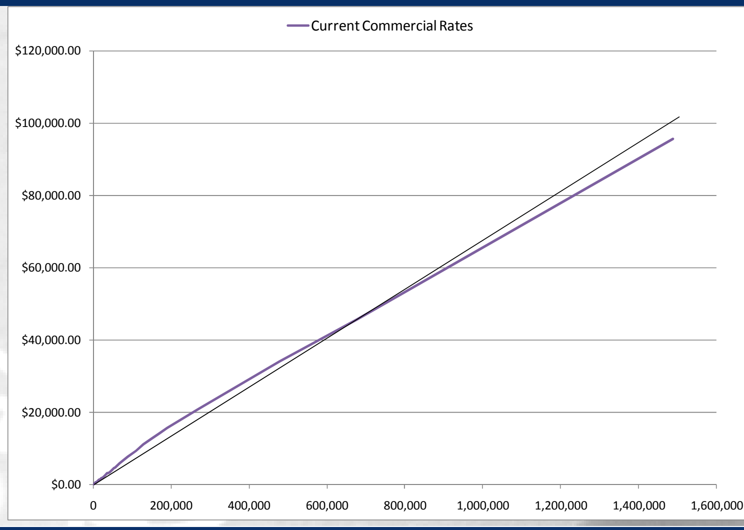
Current Declining Block Commercial Rates



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General Service Rate Proposal

- **Increase bi-monthly basic charges**
- **Increase demand component of GS21**
- **Reduce energy rate**
- **Convert GS20 to flat rate**
- **Convert GS21 rate to two-step rate, from existing three-tier declining block**

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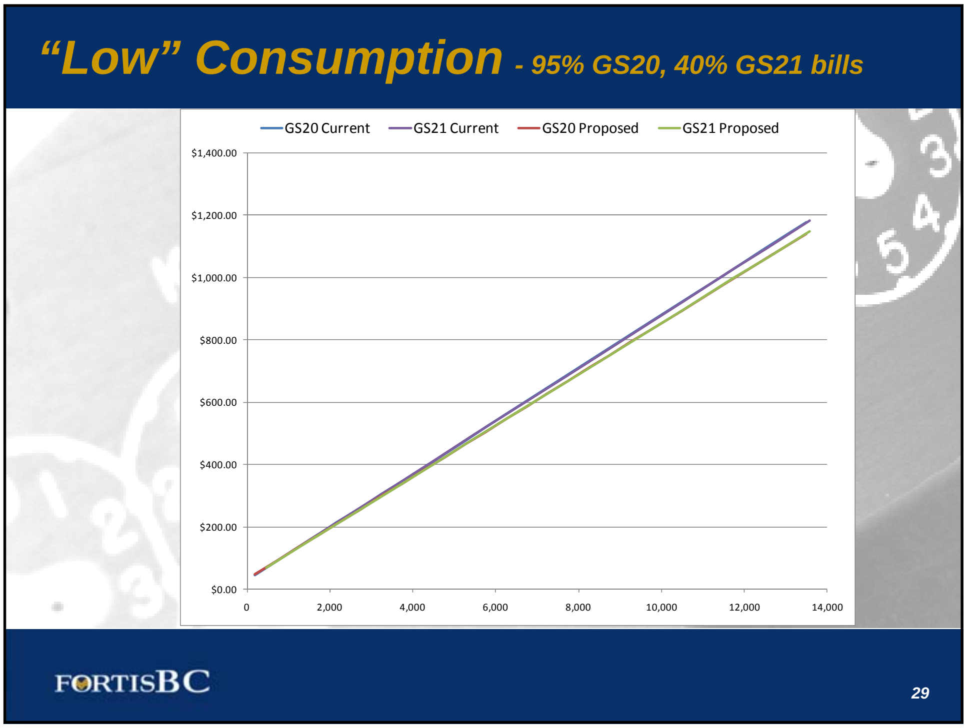
"Low" Consumption - 95% GS20, 40% GS21 bills
GS20 Current
GS21 Current
GS20 Proposed
GS21 Proposed
$1,400.00
$1,200.00
$1,000.00
$800.00
$600.00
$400.00
$200.00
$0.00
0
2,000
4,000
6,000
8,000
10,000
12,000
14,000
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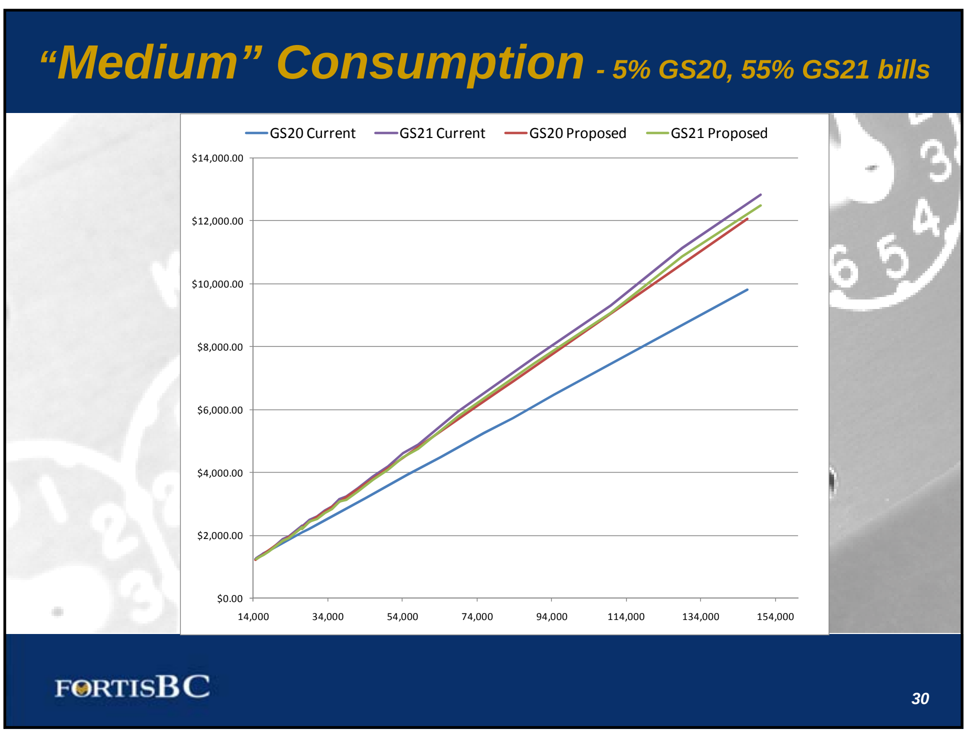
"Medium" Consumption - 5% GS20, 55% GS21 bills
GS20 Current
GS21 Current
GS20 Proposed
GS21 Proposed
$14,000.00
$12,000.00
$10,000.00
$8,000.00
$6,000.00
$4,000.00
$2,000.00
$0.00
14,000
34,000
54,000
74,000
94,000
114,000
134,000
154,000
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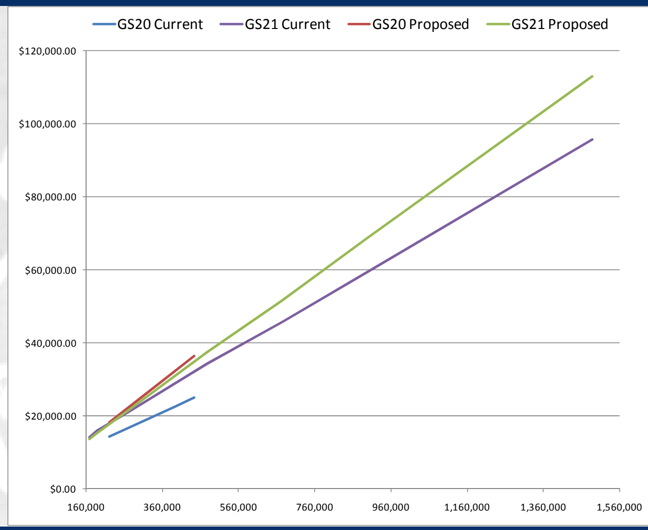
"High" Consumption - 0.01% GS20, 5% GS21 bills



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General Service Summary

GS20

- **33% of bills will be an average of 4% higher in the 0-700 kWh range**
- **62% of bills will be an average of 2% lower in the 700-14000 kWh range**
- **5% of GS20 bills will be an average of 4% higher in the 14000-160000 kWh range**

GS21

- **40% of GS21 bills will be an average of 3% lower in the 0-14000 kWh range**
- **55% of GS21 bills will be an average of 3% lower in the 14000-160000 kWh range**
- **5% of GS21 bills will be an average of 6% higher above 160000 kWh**
- **1% of GS21 bills will be more than 10% higher**

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Next Steps

- Deadline for additional written feedback, August 28, 2009
- File final COSA and Rate Design application to BCUC – September 30, 2009
- Further regulatory process – www.bcuc.com

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Provide Your Feedback

- Website: www.fortisbc.com
- E-mail: regulatory@fortisbc.com
- Mail: 1290 Esplanade, PO Box 130, Trail, BC V1R 4L4

We encourage and welcome your ongoing participation!

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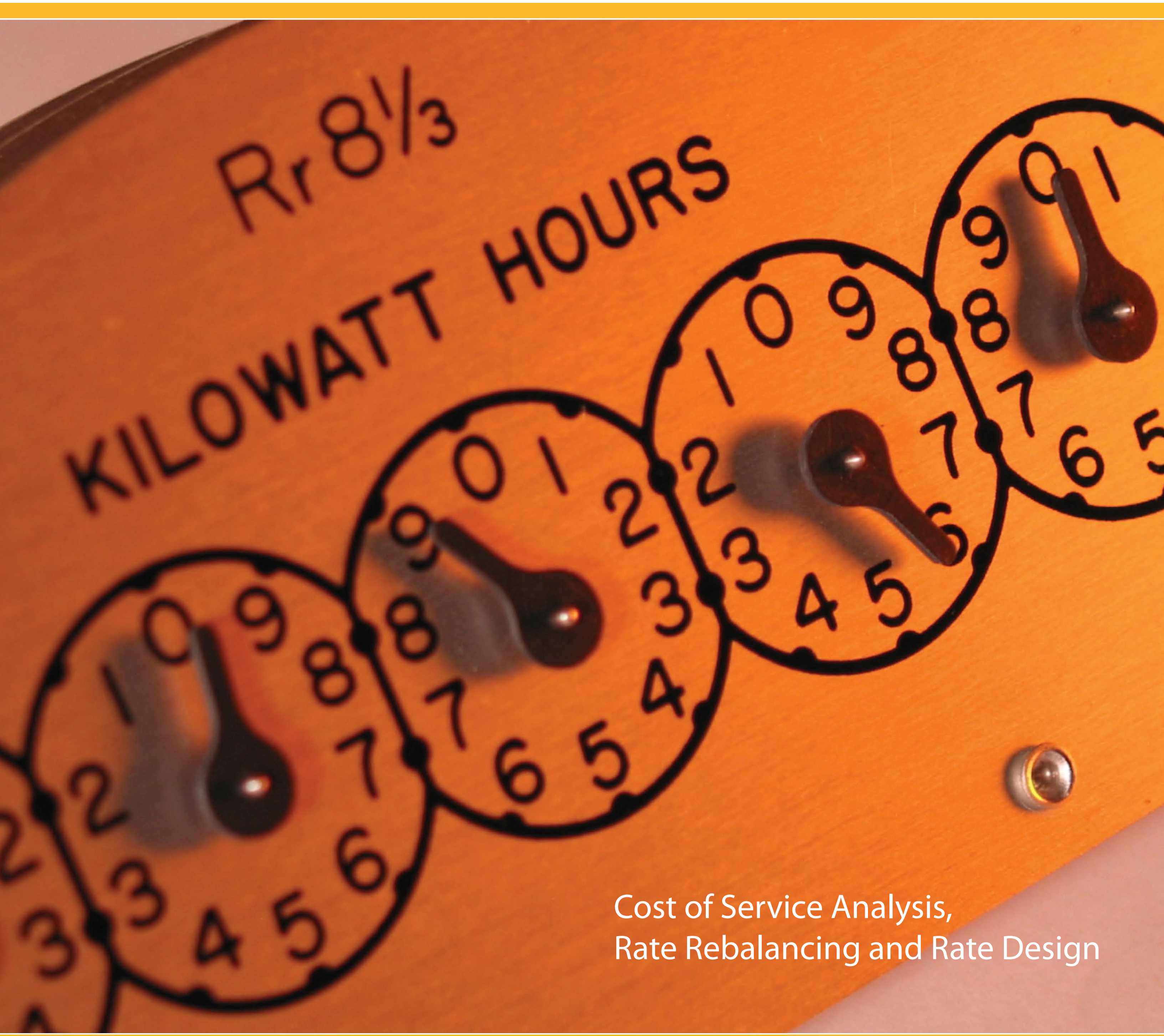
Discussion Guide



Cost of Service Analysis,
Rate Rebalancing and Rate Design

Rate design

Your views are important to us

FortisBC is seeking public and First Nations input as we complete a review of cost of service and rate design to make sure rates charged to customers are fair and equitable.

All utilities review cost of service and rate design periodically to make sure rates reflect the fair and equitable allocation of costs. A cost of service analysis (COSA) determines the cost of providing electrical service by customer class and rate design evaluates various rate structures. Rate structures direct how customers are billed for their electricity use.

Overall, changes resulting from COSA and rate design do not generate more revenue for a utility. Any changes proposed will be aimed at rebalancing and restructuring rates paid by customers, and making sure rates paid by a given customer reflect the cost of providing service to that customer, and that classes of customers are not unduly subsidizing each other.

FortisBC is committed to open dialogue with customers, stakeholders and First Nations. We believe your feedback is an important part of the process as FortisBC completes a 2009 cost of service analysis (COSA) and rate design review. Please share your thoughts on these topics with us.

Input gathered from our consultation activities will be compiled and included in FortisBC's final cost of service analysis filing and rate design application to the British Columbia Utilities Commission (BCUC).

Public consultation and regulatory process

FortisBC is committed to consultation, information sharing and building long-term cooperative relationships.

In the process of developing a 2009 cost of service analysis, FortisBC hosted public open houses and met with First Nations, customers and municipalities within our service territory in May and June of this year. The draft 2009 COSA was filed with the British Columbia Utilities Commission (BCUC) on June 30, 2009. Additional feedback from the public and First Nations on this draft COSA will be accepted until August 28, 2009. This input will be considered as FortisBC prepares the final 2009 COSA report to be filed with the BCUC on September 30, 2009.

FortisBC is also seeking public and First Nations input as we review how existing electricity rates are structured for all customers — residential, commercial, industrial, wholesale, lighting and irrigation — and determine what updates to rate structures are needed.

A series of open houses is being held across FortisBC's service area to invite public input. For those unable to attend an open house, FortisBC is providing opportunities for input through an online feedback form available on our website at *http://www.fortisbc.com/about_fortisbc/rates/other_applications.html*. Submissions can also be sent to our regulatory affairs department by:

Email: regulatory@fortisbc.com
Fax: 250 364-1270
Mail: Corey Sinclair
1290 Esplanade, PO Box 130
Trail, BC
V1R 4L4

All input must be received by August 28, 2009 in order to be considered for the final 2009 COSA filing and rate design application (RDA).

Feedback received from this consultation will be considered, along with technical and financial information, as FortisBC prepares its rate design application for submission to the BCUC by September 30, 2009. Once the COSA and RDA have been filed, the BCUC manages the regulatory process and will make the final decision regarding cost of service analysis and rate design(s) to be implemented.

The BCUC will set a schedule for a regulatory review process of both the COSA and RDA by the BCUC and interested parties.

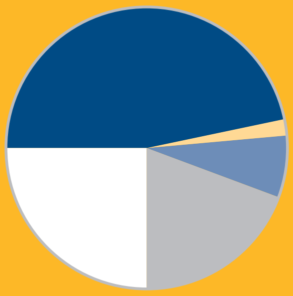
For more information on the BCUC, visit www.bcuc.com.

Customer classes

Customer classes or customer groups, as they are also known in the utility sector, include residential, general service (commercial), industrial, wholesale, lighting and irrigation. Each group has different characteristics and different requirements from the utility.

For example, a residential customer requires generation, transmission and distribution of electricity. A wholesale customer requires only generation and transmission of bulk electricity, but not distribution. Both customer groups need customer service such as billing and meter reading. Each customer group should pay its "fair share" of the total cost to operate the utility.

2008 Customer class revenues ($1000s)



Residential	102,600
Commercial	53,820
Wholesale	45,614
Industrial	14,470
Lighting & Irrigation	4,405

Cost of service analysis and rate design

Rate setting involves three steps. The first step is to establish revenue requirements, a review that is done annually to determine the total cost of operating the utility each year.

Steps two and three are the focus of the 2009 COSA and rate design consultation.

- Cost of service analysis – completed periodically to determine the costs each customer class is causing and how much revenue the utility is collecting from each group. COSA is a critical step in setting fair and equitable rates for customer groups, making sure one customer group is not subsidizing another.

- Rate design – reviewed periodically to determine how the utility recovers costs from customers. Rate design evaluates rate structures, including the basic customer charge. Both cost of service analysis and rate design are revenue neutral to FortisBC, they merely distribute the cost and revenue amongst the customer groups.

Cost of service analysis (COSA)

COSA is an important component in setting fair and equitable rates. Prior to 2009, the most recent cost of service analysis was completed for FortisBC in 1997. The FortisBC system has changed significantly since then with considerable investment in electrical infrastructure such as new transmission lines, substations and upgrades to generation facilities in order to meet our customers' electricity needs. The nature of customer electrical loads has also changed. FortisBC now experiences two seasonal peaks, summer and winter, rather than just the traditional winter peak for electricity demand. The utility is becoming capacity constrained, meaning that existing generation resources are becoming insufficient to meet customer demand during peak periods.

COSA principles

In order to reflect the changes in the electrical system, FortisBC used the principles below in the cost of service analysis study. With the exception of the use of contract demand as an allocation factor, these revisions to the 1997 methodology have a small impact on the study results.

- Contract demand – updated to better reflect the fact that FortisBC is contractually obligated to provide a firm reservation of line capacity for certain wholesale and industrial transmission customers to the limits specified in their demand contracts.

- Two coincident peak method – reflects the trend within the FortisBC system to a dual-peak system demand resulting in the convergence of the summer and winter peaks.

- Minimum system - along with the minimum system results, an offset to account for the peak load carrying capability (PLCC) of a minimum system was incorporated into the analysis. The PLCC adjustment recognizes that the minimum system would allow for some ability to carry additional capacity.

- Demand component of generation - in consideration of the capacity constrained nature of the FortisBC system and the fact that FortisBC's generation provides both energy and capacity, the allocation of generation rate base was changed from an assumption that 100 per cent of the cost amount was energy related, as was done in the 1997 study, to an 80 per cent energy, 20 per cent demand split in the 2009 version.

Rate design

A rate design application proposes rate structures including the basic monthly customer charge. Rate structures determine how customers are billed for their electricity use. Some examples include conservation-based rates such as inclining block rates, and time of use rates. Overall, changes resulting from rate design will not generate more revenue for FortisBC.

Rate rebalancing

The COSA is used to make sure that all customer groups are paying their fair share of the cost of electrical service. The draft 2009 COSA determined that there are currently some inequities. The table below shows revenue to cost ratios. Ideally, each customer group would show 100 per cent, meaning that they would be paying $1 for every $1 of their cost to the electrical system. Based on this analysis, customer classes over 100 per cent are paying more than their "fair share", and customers below 100 per cent are not paying their "fair share".

In order to move customer groups closer to a 100 percent revenue to cost ratio, rates must be rebalanced.

FortisBC is proposing to achieve equity over time by moving customer classes as close to 100 per cent as possible over a five year period. This could be accomplished by increasing rates for those classes under 100 per cent by a maximum rebalancing increase of five per cent per year. The additional revenues generated would then be applied to those customers whose rates are currently over 100 per cent.

Please take a moment to provide us with your thoughts on this topic by filling out the rate rebalancing section of the feedback form.

Customer Class	2009 Revenue to Cost Ratio
Residential	98.5%
Small GS (20)	113.4%
General Service (21)	139.8%
Industrial Primary (30)	123.6%
Industrial Transmission	61.9%
Lighting	84.2%
Irrigation	79.6%
Kelowna Wholesale	87.9%
Penticton Wholesale	77.1%
Summerland Wholesale	95.6%
Grand Forks Wholesale	68.1%
BCH Lardeau Wholesale	101.2%
BCH Yahk Wholesale	103.1%
Nelson Wholesale	80.2%

Rate design considerations

In the rate design process FortisBC will be taking into consideration that:

- Customer feedback is critical
- Rates should be simple and easy to understand
- Rates should reflect costs to the utility – both fixed and variable
- Rate impact should be managed for the majority of customers
- Rates should consider the 2007 BC Energy Plan which encourages conservation
- Existing meters do not support wide-scale, time-based rates
- Within five years the company expects to implement advanced metering infrastructure (AMI) or "smart meters"
- New rate structures should only be introduced if they meet long-term needs

Conservation based rates

FortisBC supports the BC Energy Plan objectives. Rate structures that encourage energy efficiency and conservation can play a role in helping to meet these goals.

Residential rate structure options

The residential customer class includes approximately 96,000 customers who live in communities across FortisBC's service area in the southern interior of BC.

The current residential customer rate structures have two components:

- Basic charge of $ 23.74/bi-monthly
- Energy charge of $0.0764 cents/ kilowatt hour (kwh)

In our review, FortisBC investigated many rate structure options.

Some conservation based rate structures offered by other utilities, such as time varying rates, are not feasible on a wide scale basis without automated metering infrastructure or "smart meters" installed for all residential customers. Pending future regulatory approval, FortisBC expects to introduce AMI technology within the next five years. This would enable the introduction of a wider variety of rates, including time varying rate structures, that encourage conservation and could also help address FortisBC's capacity deficit.

For FortisBC's 2009 rate design review, we have evaluated four feasible options in-depth. The impact of each of the rate structure options currently being considered is shown in the table below.

FortisBC bills its residential customers bi-monthly (every second month). The amounts shown in this table are for a two month period. These examples assume no change in customer consumption.

Recognizing the need to meet BC Energy Plan conservation goals, FortisBC sees option 3 as viable. The inclining block rate achieves conservation goals and the increased basic monthly charge meets the COSA principle of working toward appropriate cost recovery for fixed energy costs.

Option 4 is also viable. By maintaining the existing rate structure, FortisBC can work toward appropriate technology including meters, which will support alternate conservation rates.

Please take a moment to provide us with your thoughts on rate structures by filling out the residential rate design section of the feedback form.

Customer	KWh used for two months	Current bill amount for two months	Option 1 Reduce basic charge with an increase energy rate and minimum bill	Option 2 Inclining block rate with lower basic charge and higher energy rates	Option 3 Inclining block rate with higher basic charge and lower energy rates	Option 4 Maintain existing rate structure
Average customer	1900	$166	$164	$156	$158	$166
Median customer (50 % of bills are higher, and 50% are lower)	1350	$125	$121	$109	$113	$125
High end consumption customer	3850	$312	$320	$327	$319	$312
Low end consumption customer	385	$52	$43	$48	$55	$52

General service rate structure options

The general service customer classes (GS20 / GS21) include close to 11,000 diverse customer accounts representing numerous commercial ventures from corner stores to shopping malls, and from construction companies to hair salons. These customer classes are currently billed using a declining block rate structure.

In order to encourage energy conservation as directed by the BC Energy Plan and the Utilities Commission Act, FortisBC proposes a flattened rate structure, moving from three declining blocks to two. In addition, FortisBC proposes an increased monthly basic charge and lower energy rates.

See the table below for sample customers.

Rate design for other customer classes

FortisBC is not proposing new rate structures for wholesale, industrial, irrigation or lighting customers at this time since these customer groups are already billed under a flat rate structure. In addition, these customer groups will see rate rebalancing over the next several years.

Please take a moment to provide us with your thoughts on this topic by filling out the general service (commercial) rate design section of the feedback form.

Customer	KWh	KVA (demand)	Current bill	Preferred Option Flattened blocks, increase basic monthly charge and lower energy rate
GS20 average	3750		$348	$340
GS20 low consumption	743		$92	$93
GS20 high consumption	13,500		$1,176	$1,140
GS21 average	42,000	76	$3,504	$3,393
GS21 low consumption	11,700	40	$1,026	$995
GS21 high consumption	150,000	243	$12,800	$12,500

Industrial, lighting and irrigation customers

- The industrial primary customer class includes approximately 40 customer accounts.
- The industrial transmission customer class includes four customer accounts.
- The lighting customer class includes approximately 1900 customer accounts.
- The irrigation customer class includes approximately 1100 customer accounts.

Wholesale customers

FortisBC's wholesale customers include the municipal electric utilities of Kelowna, Penticton, Summerland, Grand Forks and Nelson Hydro as well as BC Hydro facilities at Yahk and Lardeau.

These customers are listed individually rather than as a customer class, since each has a separate demand contract and uses specific components of FortisBC infrastructure such as transmission lines and substations.

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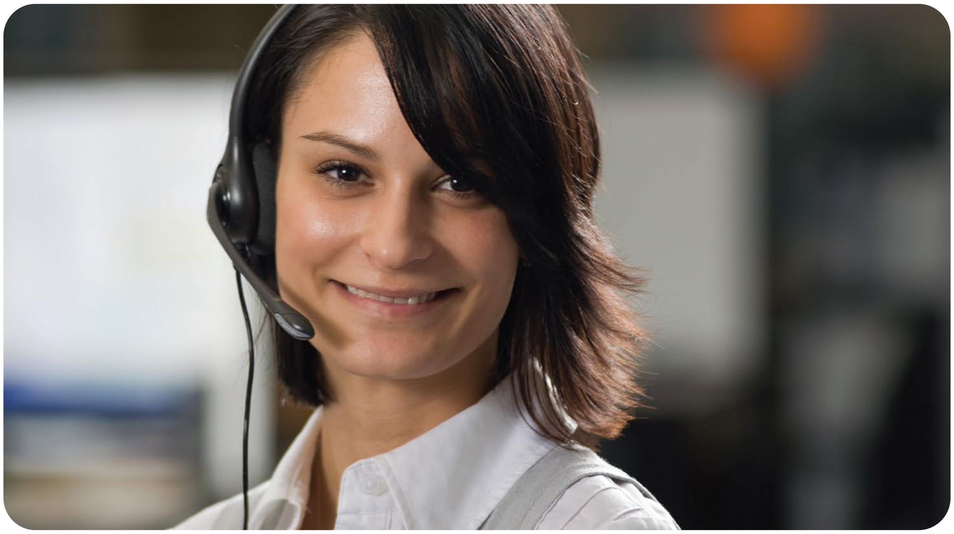
Next steps

All feedback received will be considered, along with technical and financial information, as FortisBC prepares its rate design application for submission to the BCUC by September 30, 2009. Once the COSA and RDA have been filed, the BCUC manages the regulatory process and will make the final decision regarding cost of service analysis and rate design(s) to be implemented.

The BCUC will set a schedule for a regulatory review process of both the COSA and RDA, by the BCUC and interested parties. For more information on the BCUC, visit www.bcuc.com.



FortisBC Inc.

FortisBC Inc. is an integrated regulated electric utility based in Kelowna, British Columbia. Focused on the safe delivery of reliable and cost-effective electricity, FortisBC serves more than 158,000 customers directly and indirectly through wholesale utilities in the southern interior of B.C. FortisBC owns and operates four regulated hydroelectric generating plants and approximately 7,000 kilometres of transmission and distribution power lines. FortisBC employs over 500 people in British Columbia and is an indirect wholly owned subsidiary of Fortis Inc., the largest investor-owned distribution utility in Canada. Fortis Inc. shares are listed on the Toronto Stock Exchange and trade under the symbol FTS. Additional information can be accessed at www.fortisinc.com or www.sedar.com

For more information about the Cost of Service Analysis and Rate Design Applications:
Call 1-866-4FORTIS (1-866-436-7847)
Email regulatory@fortisbc.com
Or visit www.fortisbc.com

FortisBC Inc. is a Canadian owned electric utilty
operating in the southren interior of Britsh Columbia

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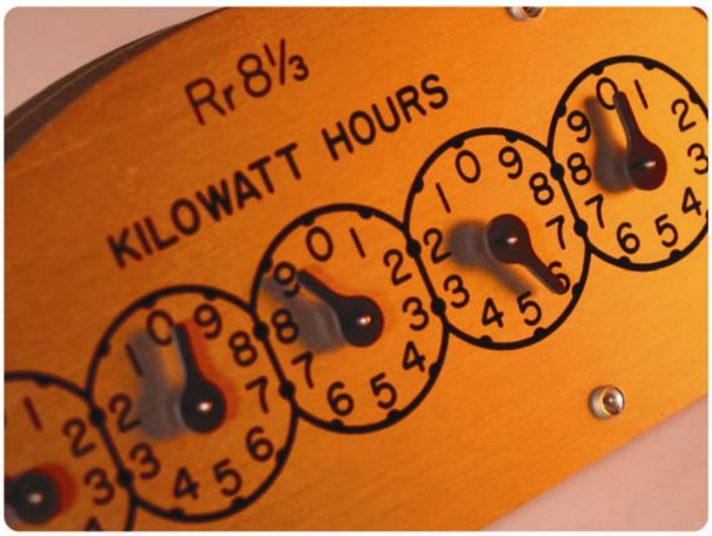
Backgrounder

Rate Design and Rebalancing



Definitions

Rate rebalancing
Rate rebalancing moves customer classes closer to a 100 per cent cost ratio, where customer classes pay $1 for every $1 of cost they cause on the electrical system. Rebalancing ensures each customer class pays its fair share of the total cost of operating the electric utility without one class unduly subsidizing another.

Basic customer charge
The basic customer charge is applied to each customer's bill to recover FortisBC's fixed costs. Fixed costs stay the same no matter how much or how little energy customers use and include costs for reading meters and maintaining poles and wires.

The basic customer charge for residential customers is approximately $24 bi-monthly, or every two months. Some commercial customers are billed monthly and some bi-monthly and the basic customer charge is approximately $29 bi-monthly.

Inclining block rate structure
Customers pay a certain amount per kilowatt hour (kWh) for the first block of energy they use. If customers use more than the first block of energy, the price per kWh goes up in the second block.

Declining block rate structure
Customers pay a certain amount per kilowatt hour (kWh) for the first block of energy they use. If customers use more than the first block of energy, the price per kWh goes down in the second block and down again in the third block.

Energy charge
The energy charge is the amount a customer is charged for each kilowatt hour (kWh) of energy they use. For residential customers it is a flat rate of approximately 7.5 cents per kWh.

For general service classes (GS20 and GS21), the energy charge is approximately 8.5 cents for the first block, 6.5 cents for the second and 4.8 cents per kWh for the third block of energy.

Proposed residential option descriptions

Option 1 - Lower basic bi-monthly charge with higher energy rates and a minimum bill
This option lowers the bi-monthly charge to $12, implements a $32 minimum bill and increases energy rates to a flat rate of approximately 8.0 cents per kWh.

Option 2 - Inclining block rate with existing bi-monthly basic charge and higher energy rates
In this option the bi-monthly basic customer charge remains at approximately $24. The energy rate in the first block of 1350 kWh is approximately 6.5 cents and 9.1 cents per kWh after the first block. These energy rates are higher than Option 3.

Option 3 - Inclining block rate with higher basic bi-monthly charge and lower energy rates
This option increases the basic bi-monthly charge to $32. The energy rate in the first block of 1350 kWh is approximately 5.9 cents and 8.3 cents per kWh after the first block. These energy rates are lower than Option 2.

Option 4 – Maintain existing rates
In this option the basic bi-monthly customer change remains at approximately $24 and the energy charge remains at approximately 7.5 cents per kWh regardless of how much energy you use.

FORTIS BC

An Assessment of Public Reactions to the Rate Rebalancing and Rate Design Options

September 4, 2009

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PN 6755

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Summary and Insights

Support for the Principles of Rate Rebalancing

85% of Super Group participants agreed that rate rebalancing is needed. They strongly supported the notion of fairness across the customer classes.

"Making things fair for all." (General Service)

"To make it fair and equitable for everyone." (Residential)

"Those paying less than 100% should be paying equal to those paying more." (General Service)

"To make it fair for those who have been paying for other people's power." (Residential)

Issues to Communicate:

Changing from a Declining Block Rate to a Flatter Rate for Commercial Customers is Fair and Encourages More Conservation

"Commercial customers should not get a lower rate for using more." (Irrigation)

"Some customers pay less, use more. In general it should be the opposite." (General Service)

Large Industry and Small Business Deserve Equal Treatment

"Small business should not subsidize larger industry." (General Service)

"Why should any people be subsidized by other groups?" (Residential)

Residential Customers Are Already Paying Their Own Way

Emphasize the principles of fairness and equity in the rate rebalancing communications.

Community Support for Conservation Measures

Energy conservation has strong community support, but there are concerns about the effectiveness of higher electricity rates to encourage conservation.

70% **of workshop participants strongly agreed that rate structures that encourage energy efficiency are important….**

35% **… but only 35% of workshop participants strongly agreed that a conservation rate that charges customers with higher energy usage more will reduce energy consumption.**

Barriers to Greater Energy Conservation:

I'm Already Doing It

"I don't know of anyone who deliberately uses more energy than they need." (Castlegar)

I Can't Change My House/Appliances

"[It's] expensive to rebuild an existing home." (Kelowna)

I Don't Know How

"We don't know what uses the most power in our homes." (Kelowna)

Lifestyle/Comfort Is More Important

"Can't control usage all the time, you tell a teenager showers are 5 mins." (Castlegar)

Facilitating energy conservation through education, grants/upgrading support, and financial 'rewards' for conservation provide incentives and support – but customers have to see how changes in behaviour affect electricity usage. Advanced metering (AMI) may provide greater visibility and control over electricity usage.

Preferred Residential Options

	Definitely/ Probably Should Consider	Most Frequently Cited Reasons Why Should Consider	Most Frequently Cited Reasons Why Should Not Consider
Option 1 – Lower basic bi-monthly charge with higher energy rates and a minimum bill	**44%**	Promotes conservation (43%)	Low income need more help (33%)
Option 2 – Inclining block rate with existing bi-monthly basic charge and higher energy rates	**56%**	Promotes conservation (50%)	Low income need more help (42%)
Option 3 – Inclining block rate with higher basic bimonthly charge and lower energy rates	**61%**	Promotes conservation (44%)	Low income need more help (14%)
Option 4 – Maintain existing rates	**61%**	This is fair/makes sense (21%) Wait for new AMI meters to adjust rates (18%)	Want the AMI meters (16%)

Participants were split on implementing inclining block rates to promote energy conservation and maintaining the status quo until advanced metering (AMI) is implemented. The final preferred option may depend how long it will take for AMI to be implemented.

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General Service Option

General Service participants were not generally in favour of the proposal to flatten the blocks and increase the basic charge. Many thought their electricity bills would increase with this change to electricity billing.

Residential Customers believe that the current declining block structure is unfair and does not do enough to encourage conservation.

"Companies should not get a declining rate." (Residential)

"More companies would not leave lights on all night… if it hit them in the pocket book they would learn to conserve more." (Residential)

General Service are as supportive of conservation rates as Residential Customers, and do not feel they should be subsidizing other customer classes. However, many are concerned that the proposed changes will have a negative effect on their business costs.

"Small business should not subsidize larger industry." (General Service)

"Encouraging efficiency and conservation is important but there may be better ways to achieve this than just rate structure." (General Service)

"It's easy to get used to a basic charge. The energy rates could throw your monthly budget out the window." (General Service)

The benefits of the new rate structure for General Service customers need to be clearly communicated.

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Background and Methodology

Project Overview

Background

FortisBC Inc. is an integrated regulated electric utility based in Kelowna, British Columbia. Focused on the safe delivery of reliable and cost-effective electricity, FortisBC serves approximately 158,000 customers directly and indirectly through wholesale utilities in the southern interior of B.C. FortisBC owns and operates four regulated hydroelectric generating plants and approximately 7,000 kilometres of transmission and distribution power lines. FortisBC employs over 500 people in British Columbia and is an indirect wholly owned subsidiary of Fortis Inc., the largest investor-owned distribution utility in Canada.

Customer classes include residential, commercial (general service), industrial, lighting, irrigation and wholesale electricity customers.

Purpose for Research

FortisBC is currently reviewing the rates that different customer classes pay for electricity. As part of its Cost of Service Analysis and Rate Design Application for the BC Utilities Commission, FortisBC is undertaking consultation in the communities it services through open houses and direct dialogue with key stakeholders as well as general communications and one-on-one discussions.

FortisBC has asked Environics Research Group to utilise a market research process that will enable FortisBC to gain detailed customer feedback on the proposed rebalancing and rate design. This process will enable FortisBC to better understand the impacts that changes in rates will have on the different customer classes. The Super Group process also allowed a balanced representation of all customer classes, providing feedback from some customer classes which had been under-represented during previous public open houses.

Research Objectives

- Engage customers, stakeholders and First Nations in meaningful dialogue and consultation on rate rebalancing and rate design.
- Gain input from each customer class so that all types of customers have the opportunity to have a say in the rate rebalancing and rate design process.
- Understand the impacts that changes in electricity rates will have on different customer classes (residential, general service [commercial], industrial, irrigation and lighting).
- Gain customer feedback on proposed rate options to identify which options will be most acceptable to members of the target audience.
- Provide useful information to help refine communications messages so that subsequent communications are able to explain the changes in rates in a way that resonates with each customer class.

Methodology

- Individuals were randomly selected by Research House, an Environics company, from FortisBC's customer database. These individuals were invited by telephone to attend a 'focus group'.
- The customer classes represented were: residential, general service (commercial), industrial, irrigation and lighting. A quota system was used to ensure that a minimum number of members of each of these customer classes was registered to attend the session.
- One Super Group was held in Castlegar on August 17, 2009 and second one was held in Kelowna on August 18, 2009. Participants were not advised in advance what the workshop would be about or who was sponsoring the session.
- In each Super Group, FortisBC gave a 90-minute presentation on the cost of service analysis and rate design options. Questions from participants were answered during the presentation.
- The Part A survey was completed prior to the presentation upon entry to the meeting, and the Part B survey was completed following the presentation.
- Local participants received a $75 cash honorarium for attending. Individuals driving in excess of 1.5 hours were given a larger incentive of $100.

	Castlegar **Monday, August 17, 2009**	**Kelowna** **Tuesday, August 18, 2009**
Total Number of Participants	58	56
Participants by Customer Class: - Residential - General Service - Industrial - Irrigation/Lighting	 Residential – 42 General Service – 11 Industrial – 0 Irrigation/Lighting - 5	 Residential – 40 General Service – 12 Industrial – 1 Irrigation/Lighting - 3

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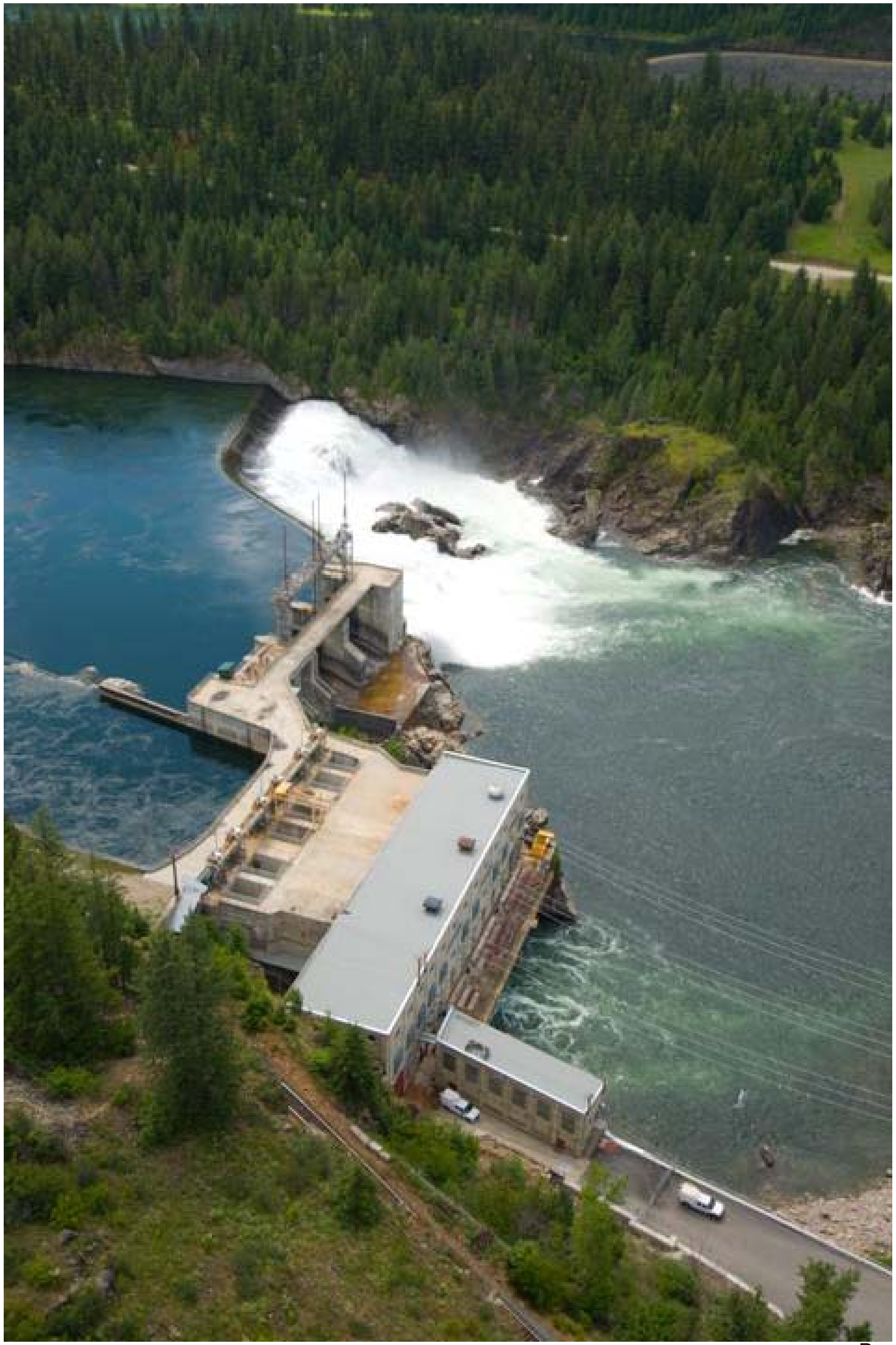

Who We Talked To

Super Group Participants - Profiles

The demographic profile for Castlegar and Kelowna participants were similar.

	Total n=114	Castlegar n=58	Kelowna n=56
Age			
18 to 34	15%	10%	20%
35 to 54	39%	41%	36%
55 and more	46%	48%	43%
Refused	1%	0%	2%
Gender			
Male	52%	52%	52%
Female	48%	48%	48%
Employment Status			
Working full-time	54%	45%	63%
Working part-time	12%	14%	11%
Unemployed or looking for a job	4%	5%	2%
Stay at home full-time	6%	10%	2%
Student	2%	0%	4%
Retired	22%	26%	18%
Don't Know/Refused	1%	0%	2%
Number of People in Household			
1	20%	24%	16%
2	44%	41%	46%
3	17%	12%	21%
4 or more	18%	22%	14%
Don't Know/Refused	1%	0%	2%

	Total n=114	Castlegar n=58	Kelowna n=56
Account Type			
Residential	100%	100%	100%
General Service	29%	31%	27%
Industrial	3%	0%	5%
Irrigation	8%	9%	7%
Wholesale	1%	0%	2%
Lighting	7%	7%	7%
Home Ownership			
Own	84%	86%	82%
Rent	16%	14%	18%
Dwelling Type			
Single detached house	79%	83%	75%
Townhouse or duplex	9%	3%	14%
Apartment building	4%	2%	7%
Mobile home	4%	9%	0%
Basement Suite/Suite	1%	2%	0%
Other	2%	2%	2%
Don't Know/Refused	1%	0%	2%
Square Footage			
Less than 800 sq. ft.	7%	9%	5%
800 to less than 1200 sq. ft.	26%	31%	21%
1200 to less than 1600 sq. ft.	21%	22%	20%
1600 to less than 2000 sq. ft.	11%	17%	5%
2000 to less than 2500 sq. ft.	16%	9%	23%
More than 2500 sq. ft.	18%	12%	23%
Don't Know/Refused	1%	0%	2%

Kelowna participants were more likely to have larger homes than those from Castlegar.

Indicates significant differences

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Super Group Participants - Profiles

	Total n=114	Castlegar n=58	Kelowna n=56
Fuel Used to Heat House (Multiple Responses)			
Natural Gas	63%	59%	68%
Oil	2%	3%	0%
Propane	3%	3%	2%
Electricity	47%	48%	46%
Wood	21%	33%	9%
Other	1%	2%	0%
Main Heating System			
Central air	56%	52%	61%
Electric baseboards	18%	19%	16%
Hot water baseboards / radiator	3%	3%	2%
Heat pump (air or ground)	4%	2%	5%
Wood, gas or electric fireplace	13%	16%	11%
Other (please describe):	5%	7%	4%
Don’t Know/Refused	2%	2%	2%
Air Conditioning in Home			
Yes, central air	35%	21%	50%
Yes, a window unit	29%	22%	36%
No	36%	57%	14%
Opinion on Current Pricing			
Too low	0%	0%	0%
About right	54%	47%	61%
Too high	46%	53%	38%
Impact of Electricity Bill on Household Finances			
Noticeably	39%	48%	29%
Small impact	52%	45%	59%
No impact	6%	7%	5%
Don't Know/Refused	4%	0%	7%

Indicates significant differences

Castlegar participants were more likely to use wood to heat their homes while Kelowna participants were more likely to have central air.

Participants in Castlegar had a greater propensity to report that their electricity bill has a noticeable impact on their household finances.

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Rate Rebalancing and Rate Design Overall Opinions

Rate Rebalancing: Summary of Findings

- Over 85% of participants were in agreement that rate rebalancing is needed. (Page 18)
- The most critically important consideration in developing the rate structure is to encourage energy savings and conservation. (Page 19)
- Participants were mixed about the idea of recovering fixed costs by raising the basic customer charge. (Page 20)
- Most participants agreed that it is important to flatten the rate structure for commercial customers. (Page 21)
- Most participants agreed that capping increases at 5% per year is reasonable when customers' revenue-to-cost ratio is below 100%. (Page 22)
- Participants strongly disagreed with the rate design option which included a meter read and a monthly bill because it would increase costs without any major customer benefit. (Page 23)
- There was overwhelming agreement (86%) that it is important to introduce rate structures that encourage energy efficiency and conservation. (Page 24)
- There was general agreement that a conservation rate design where cost is relative to usage would result in lower energy consumption. (Page 25)
- Participants were mixed as to whether or not charging higher rates to higher users would result in lower energy usage. (Page 26)
- Participants perceived the cost of service analysis and rate design changes as revenue-neutral to FortisBC. They understood the goals of Rate Rebalancing and Rate Design as improving customer class equity. (Page 27)

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Rate Rebalancing

Cost of Service Analysis (COSA) is an important component in setting fair and equitable rates. Prior to 2009, the most recent cost of service analysis was completed for FortisBC in 1997. Since then, FortisBC has invested in the electrical infrastructure and the nature of customer demand has changed, with seasonal peaks in both summer and winter. These changes in supply capability and demand characteristics mean that the Cost of Service Analysis conducted in 1997 is not a true reflection of today's costs.

The Cost of Service Analysis (COSA) is used to make sure that all customer groups are paying their fair share of the cost of electrical service. The draft 2009 COSA determined that there are currently some inequities.

The table at right shows revenue to cost ratios. Ideally, each customer group would show 100 per cent, meaning that they would be paying $1 for every $1 of their cost to the electrical system. Based on this analysis, customer classes over 100 per cent are paying more than their "fair share", and customers below 100 per cent are not paying their "fair share".

In order to move customer groups closer to a 100 percent revenue to cost ratio, rates must be rebalanced. FortisBC is proposing to achieve equity over time by moving customer classes as close to 100 per cent as possible over a five year period. This could be accomplished by increasing rates for those classes under 100 per cent by a maximum rebalancing increase of five per cent per year. The additional revenues generated would then be applied to those customers whose rates are currently over 100 per cent.

Customer Class	2009 Revenue to Cost Ratio
Residential	98.5%
Small GS (20)	113.4%
General Service (21)	139.8%
Industrial Primary (30)	123.6%
Industrial Transmission	61.9%
Lighting	84.2%
Irrigation	79.6%
Kelowna Wholesale	87.9%
Penticton Wholesale	77.1%
Summerland Wholesale	95.6%
Grand Forks Wholesale	68.1%
BCH Lardeau Wholesale	101.2%
BCH Yahk Wholesale	103.1%
Nelson Wholesale	80.2%

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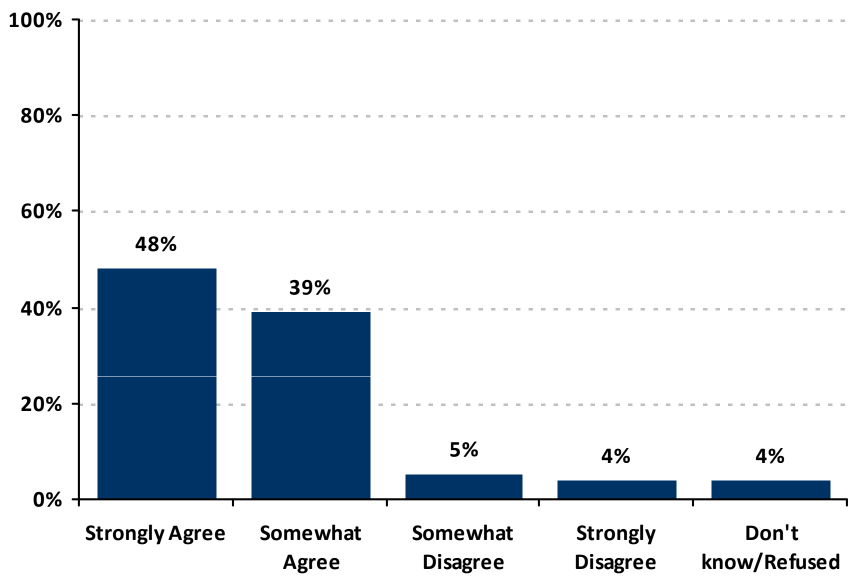
Overall Opinions about Rate Rebalancing

Over 85% of participants were in agreement that rate rebalancing is needed.

% of Agreement – In my opinion, rate rebalancing is needed.
(Total Respondents, n=114)



These results were similar across both Castlegar and Kelowna participants.

"Small business should not subsidize larger industry." (Kelowna)

"Encourages conservation, rewards 'better' users." (Kelowna)

"Why should any people be subsidized by other groups?" (Kelowna)

"Those paying less than 100% should be paying equal to those paying more." (Kelowna)

"Rate rebalancing is needed but it would be better to wait for AMI meters to implement." (Castlegar)

"To make it fair for those who have been paying for other people's power, it seems like that is fair." (Castlegar)

"It seems it should be more fair to balance actual costs." (Castlegar)

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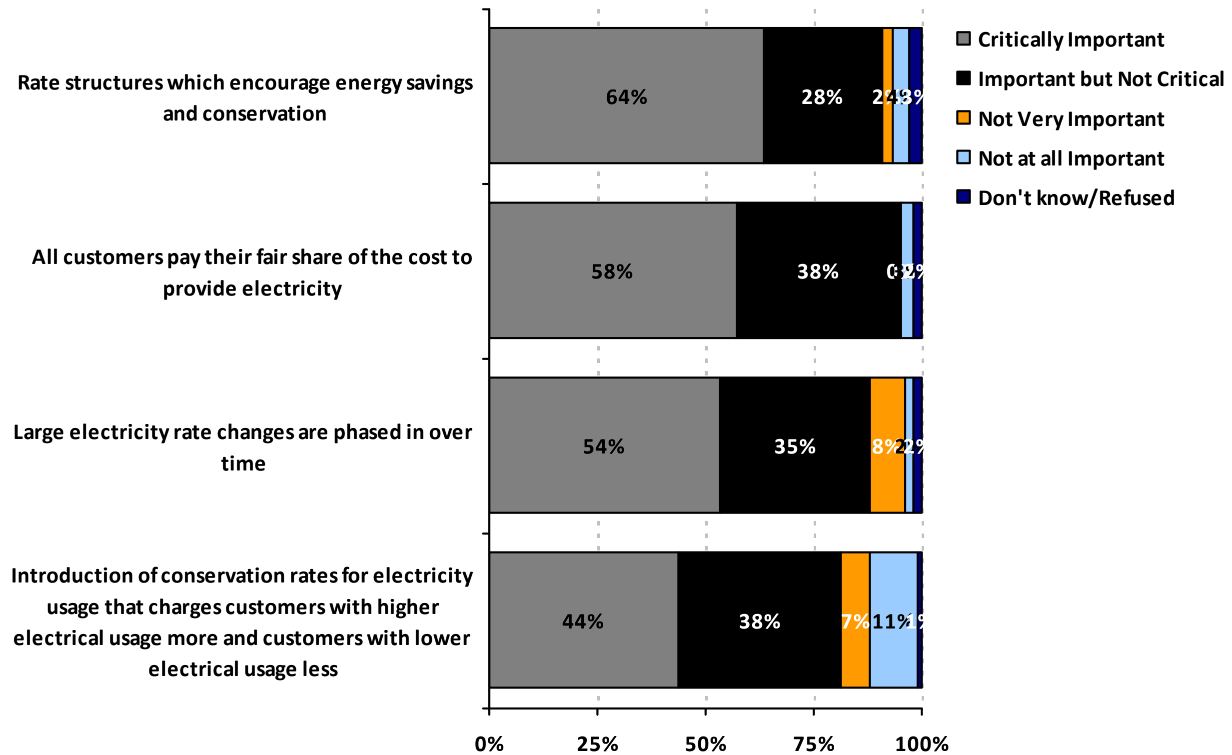
Considerations for Rate Rebalancing and Rate Design

The most critically important consideration in developing the rate structure is to encourage energy savings and conservation.

Considerations in Identifying the Best Rate Structure
(Total Respondents, n=114)



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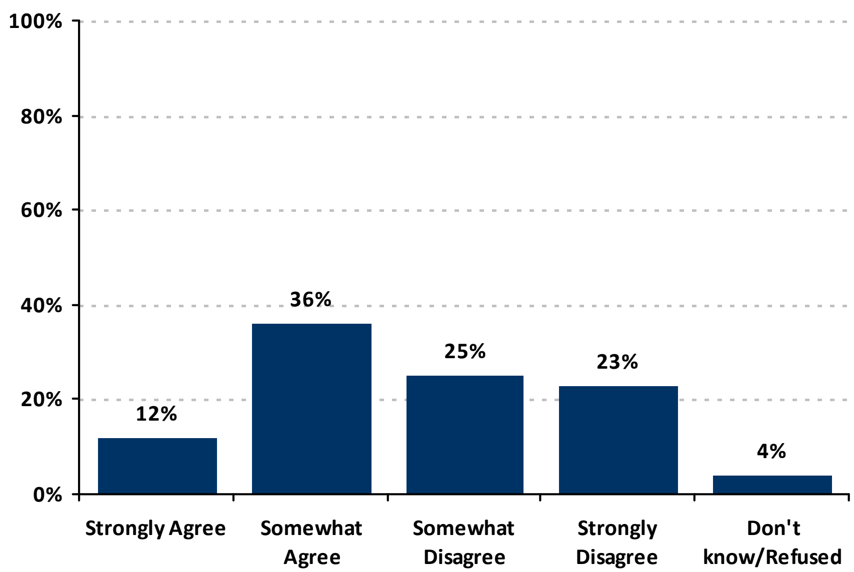
Overall Opinions about Rate Rebalancing

Participants were mixed about the idea of recovering fixed costs by raising the basic customer charge.

% of Agreement – It seems reasonable to recover more of the fixed costs by raising the basic customer charge.
(Total Respondents, n=114)



"Raising fixed costs does nothing to promote energy conservation = less power usage." (Kelowna)

"I'm lukewarm on this issue. I basically think the user should pay in relation to consumption." (Kelowna)

"This would not allow customers the control to regulate their cost." (Kelowna)

"Fixed costs need fixed revenue but in this case attempts to conserve energy needs to be rewarded." (Castlegar)

"Charging more should come from usage of power." (Castlegar)

"[The] basic customer charge does not encourage conservation." (Castlegar)

"The fixed cost should remain the same and … lower usage should be rewarded." (Castlegar)

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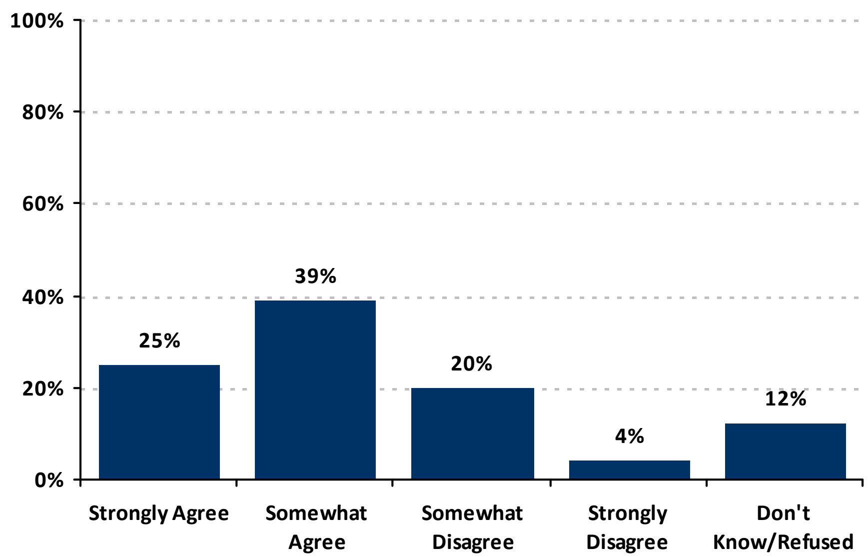
Overall Opinions Towards Rate Design

Most participants agreed that it is important to flatten the rate structure for commercial customers.

% Agreement: It is important to flatten the rate structure for commercial customers.
(Total Respondents, n=114)



(Strongly Agree) "Everyone should pay the same rates regardless of why." (Castlegar)

(Strongly Agree) "Commercial customers need to start conserving energy also." (Kelowna)

(Strongly Agree) "Small business should not be paying more than large companies." (Kelowna)

(Somewhat Agree) "Ensure all users pay an equal amount to cover costs." (Castlegar)

(Somewhat Agree) "Smaller commercial customers need some help." (Castlegar)

(Somewhat Agree) "Declining rates do not help promote conservation." (Kelowna)

(Somewhat Disagree) "The gap between rates needs to be reduced but flatter rates probably would not be best." (Castlegar)

(Somewhat Disagree) "It's not consistent with your cost of doing business." (Kelowna)

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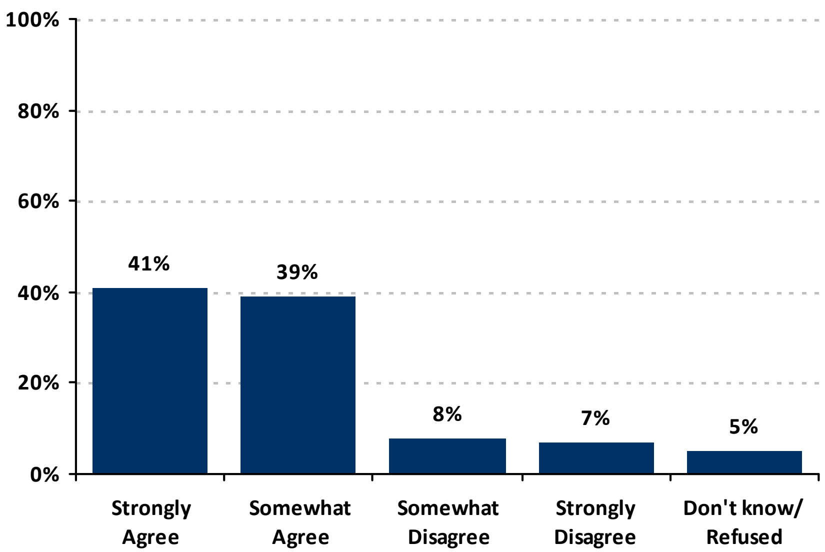
Overall Opinions about Rate Rebalancing

Most participants agreed that capping increases at 5% per year is reasonable when customers' revenue to cost ratio is below 100%.

% of Agreement – For customers whose revenue to cost ratios are below 100%, capping their increases at 5% per year seems reasonable.
(Total Respondents, n=114)



Kelowna participants were more likely to strongly agree that capping increases is reasonable for those with revenue to cost ratios below 100%.

"Reasonable cost increase allows time to meet new expenses." (Kelowna)

"They need time to adjust their new costs." (Kelowna)

"5% could be a big increase that could make or break someone." (Kelowna)

"There should not be a shock to cost of doing business." (Kelowna)

"Cost should reflect usage." (Castlegar)

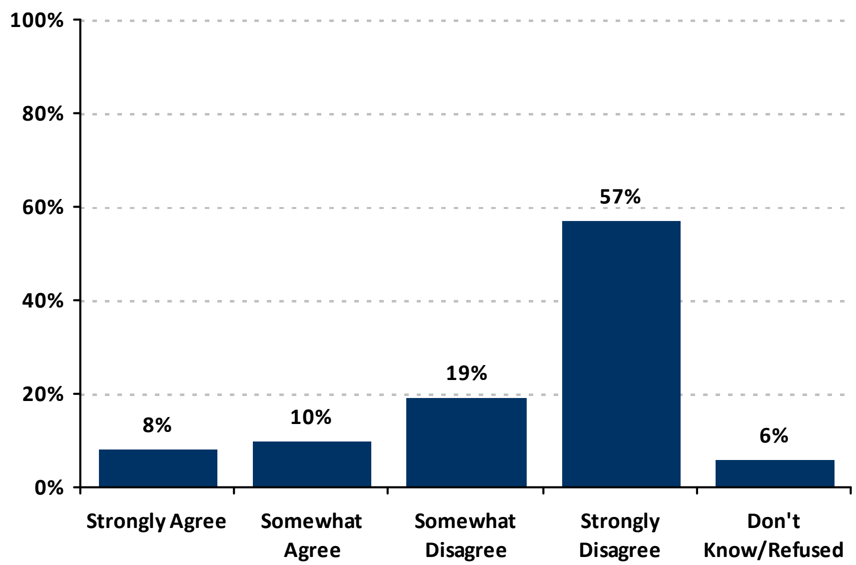
"Too much increase for some customers could be too difficult to manage." (Castlegar)

"Given the economy businesses may need more mercy, maybe 2% until economy gets moving again." (Castlegar)

Overall Opinions Towards Rate Design

Participants strongly disagreed with the rate design option which included a meter read and a monthly bill because it would increase costs without any major customer benefit.

% Agreement: Residential customers are billed every two months, but I would prefer to have my meter read and be billed monthly, even if there is a one-time one percent rate increase.
(Total Respondents, n=114)



(Strongly Agree) "I would like to see where I stand on a monthly basis." (Castlegar)

(Somewhat Disagree) "Don't think it would make any real difference." (Kelowna)

(Strongly Disagree) "Reading meters more often would increase costs with no benefit to the customer." (Castlegar)

(Strongly Disagree) "2 months is fine, what difference does it make?" (Castlegar)

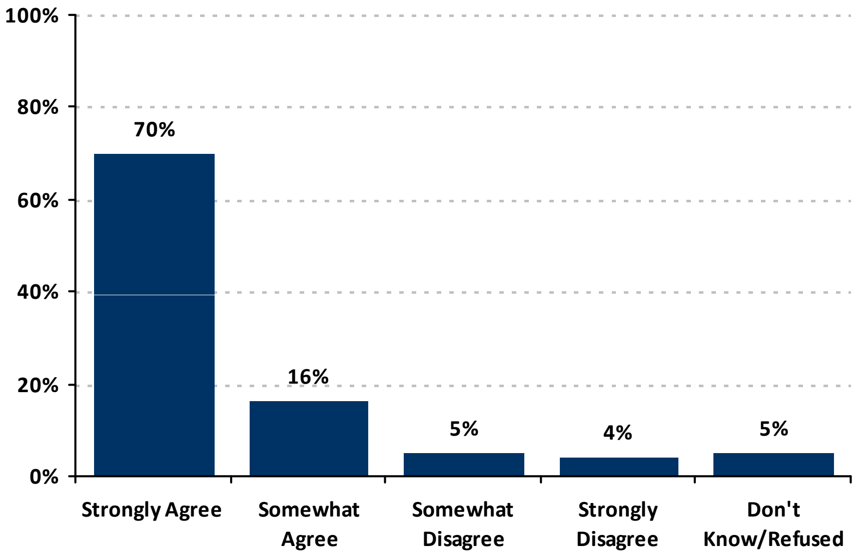
(Strongly Disagree) "I don't see any benefit to me, only an increase in cost." (Kelowna)

(Strongly Disagree) "Until AMI is established leave it at 2 month periods." (Kelowna)

Overall Opinions Towards Rate Design

There was overwhelming agreement (86%) that it is important to introduce rate structures that encourage energy efficiency and conservation.

% Agreement: Introducing rate structures that encourage energy efficiency and conservation is important.
(Total Respondents, n=114)



When giving reasons for selecting their answer, Castlegar participants were more likely to report that 'we need education on conservation' while Kelowna participants reported that 'we need to do all we can for the earth by reducing consumption.'

(Strongly Agree) "Rate should reflect how a person applies efficiency and conservation." (Castlegar)

(Strongly Agree) "A lot of changes need to be forced for some people/businesses to make a difference." (Castlegar)

(Strongly Agree) "It will help keep fixed costs lower by reducing needs for new generation." (Kelowna)

(Somewhat Disagree) "Expensive to rebuild an existing home." (Kelowna)

(Strongly Disagree) "People are already conserving an inclining rate for residential would be devastating for families." (Castlegar)

(Strongly Disagree) "Price to cost, not to control behaviour. pricing to cost will achieve that anyway." (Kelowna)

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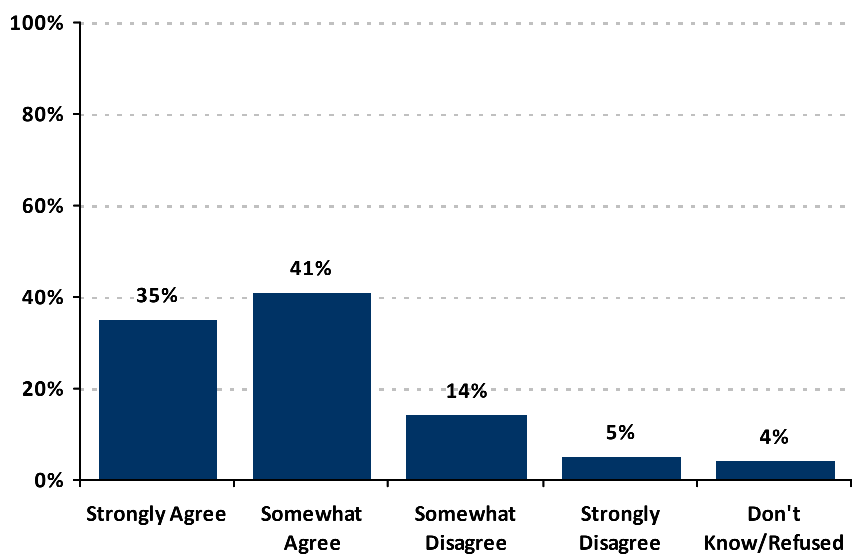
Overall Opinions Towards Rate Design

There was general agreement that a conservation rate design where cost is relative to usage would result in lower energy consumption.

% Agreement: A conservation rate for electricity usage that charges customers with higher electrical usage more and customers with lower electrical usage less will result in lower energy consumption.
(Total Respondents, n=114)



(Strongly Agree) "Education and mindset is a step towards more awareness and invitation to further improve efficiency." (Kelowna)

(Somewhat Agree) "A big house, energy efficient, need not pay the same as a house that is not cared for or energy efficient." (Castlegar)

(Somewhat Agree) "It is a good idea but individual circumstances need to be considered." (Castlegar)

(Somewhat Agree) "[This] will encourage lower consumption to those who are able to reduce consumption. Businesses are less able to reduce." (Kelowna)

(Somewhat Agree) "It's a complicated subject. We don't know what uses the most power in our homes. Education process to reduce consumption." (Kelowna)

(Somewhat Disagree) "Not necessarily, some companies may not be able to reduce their consumption any more than they already have." (Kelowna)

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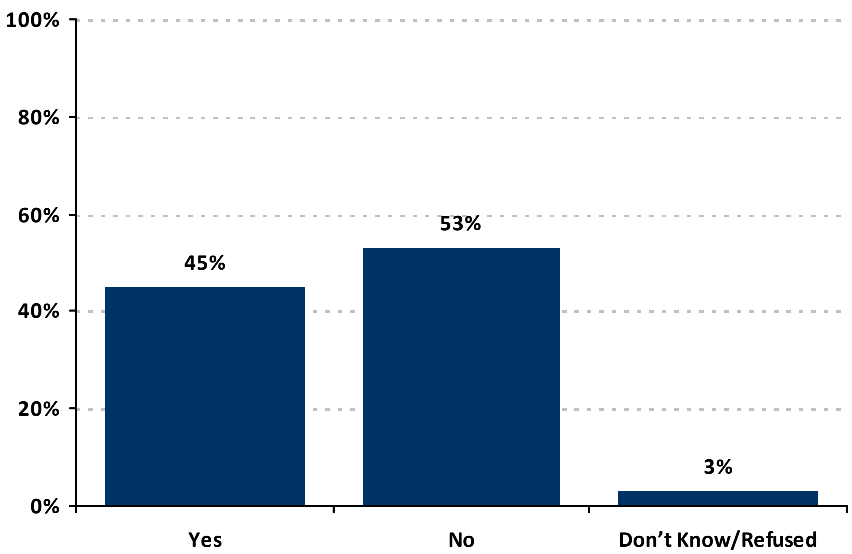
Impact on Energy Usage

Participants were mixed as to whether or not charging higher rates to higher users would result in lower energy usage.

Do you think that charging higher-usage customers a 20% higher rate for electricity will result in lower energy usage?
(Total Respondents, n=114)



(Yes) "Anything that encourages someone to save money will make more people consider making changes . People care when their money is at stake." (Castlegar)

(Yes) "Most customers are not reducing consumption at all or enough, while most are price conscious. If savings are the incentive, more efforts will be made to reduce consumption." (Castlegar)

(Yes) "Yes, but minimally. People accustomed to a standard of living will pay more thus use more to maintain it. The less usage of energy will come from more efficient and conservative technology, as opposed to any significant reduction of usage." (Kelowna)

(No) "Because higher usage customers often have a high enough income that by raising the rate won't make them aware of their electricity usage. Some people just don't care." (Castlegar)

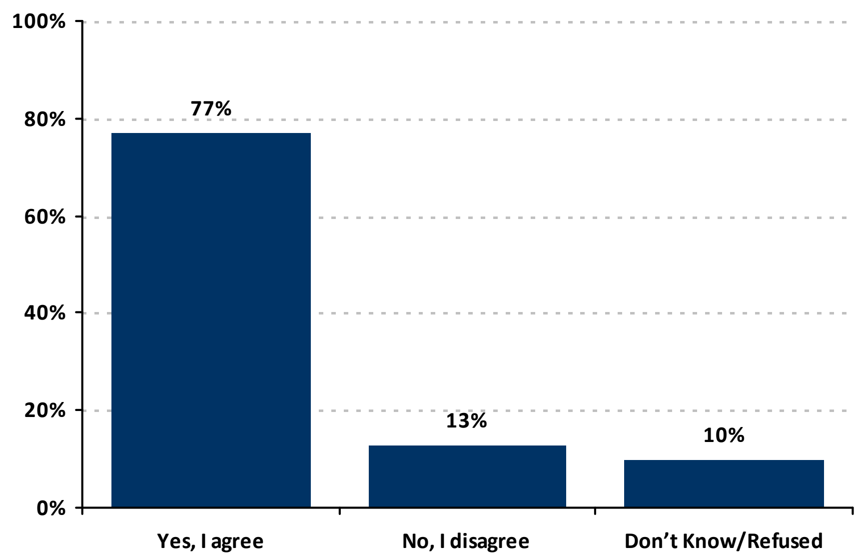
(No) "If applied to commercial users it will simply be passed on to their customers. If applied to residential users the high use consumers will pay whatever it takes to maintain their comfort with air conditioners." (Kelowna)

(No) "Because people will use the resources they need in spite of the cost (within reason)." (Castlegar)

Perceptions of Revenue Neutrality

Participants perceived the cost of service analysis and rate design changes as revenue-neutral to FortisBC. They understood the goals of Rate Rebalancing and Rate Design as improving customer class equity.

% Agreement: The cost of service analysis and rate design changes are revenue neutral to FortisBC and merely distribute the costs and revenue more equitably among customer groups.
(Total Respondents, n=114)



Residential
Rate Design Options

Residential Rate Design: Summary of Findings

- **Energy conservation was the primary reason for supporting Options 1, 2 or 3, while supporters for Option 4 often cited the implementation of AMI or a lack of reason to change as the rationale for preferring that option. (Page 32)**
- **Participants cited concerns with the impact on low-income households as the main concern with Option 2. (Page 33)**
- **Participants were mixed about Option 1, which was seen as more strongly promoting conservation through higher energy rates. (Page 34)**
- **Option 3 was one of the most preferred options but some participants did not like the concept of inclining block rates. (Page 38)**
- **Most participants who preferred Option 4 cited a lack of reason to change or the implementation of AMI as their reason for their preference. (Page 40)**

Rate Design Options

FortisBC presented detailed information on each of the following four Rate Design options as part of the presentation. In addition, FortisBC invited participants to outline other options that they considered worth considering in the space provided for additional comments.

Information on each of the four options was provided to participants with their survey, so they could recall the differences between each option as they completed the Part B survey.

Option 1 - Lower basic bi-monthly charge with higher energy rates and a minimum bill

This option lowers the bi-monthly charge to $12, implements a $32 minimum bill and increases energy rates to a flat rate of 8 cents per kilowatt hour.

Option 2 - Inclining block rate with existing bi-monthly basic charge and higher energy rates

In this option the bi-monthly basic customer charge remains at approximately $24. The energy rate in the first block of 1350 kWh is 6.5 cents and 9.1 cents per kilowatt hour after the first block. These energy rates are higher than Option 3.

Option 3 - Inclining block rate with higher basic bimonthly charge and lower energy rates

This option increases the basic bi-monthly charge to $32. The energy rate in the first block of 1350 kWh is 5.9 cents and 8.3 cents per kilowatt hour after the first block. These energy rates are lower than Option 2.

Option 4 – Maintain existing rates

In this option the basic bi-monthly customer change remains at approximately $24 and the energy charge remains at approximately 7.5 cents per kilowatt hour regardless of how much energy you use.

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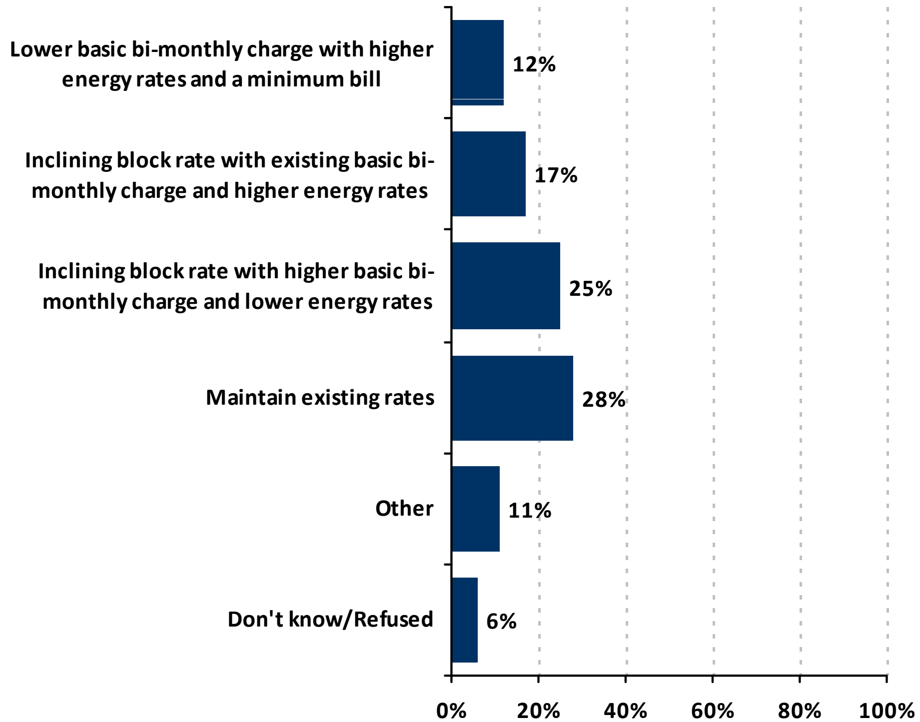
Preferred Rate Options

Participants preferred to maintain existing rates or implement the inclining block rate with higher bi-monthly charges and lower energy rates.

Of All the Options Presented Tonight, Which ONE is Your Preferred Option?
(Total Respondents, n=114)



Castlegar and Kelowna had similar levels of preference for each rate option. There were no significant differences between these groups.

(Option 1) "This benefits consumers with lower consumption." (Kelowna)

(Option 2) "I do not think my billing would change very much, if any. I also believe this option would promote the most conservation." (Kelowna)

(Option 3) "Because it encourages conservation and helps to cover fixed costs for all customers." (Castlegar)

(Option 3) "[It] will lead to conservation of power and possible lower cost to each household." (Castlegar)

(Option 4) "It would make more sense to wait for new AMI meters to adjust rates as there would be more options available." (Castlegar)

(Option 4) "Leave it the way it is, I know what is happening." (Kelowna)

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Reasons for Preferred Option

Energy conservation was the primary reason for supporting Options 1, 2 or 3, while supporters for Option 4 often cited the implementation of AMI or a lack of reason to change as the rationale for preferring that option.

Preferred Option #1:
Lower basic bi-monthly charge with higher energy rates and a minimum bill

Why: Prefer Option 1 Total Mentions	Total n=14
Promotes conservation	43%
Use more should pay more	29%
Should save money	21%
Low energy rate based on usage	7%
I conserve as much as I can	7%
Small business will benefit	7%
I am a low energy user	7%

Preferred Option #2:
Inclining block rate with existing basic bi-monthly charge and higher energy rates

Why: Prefer Option 2 Total Mentions	Total n=18
Promotes conservation	50%
Should save money	33%
Use more should pay more	22%
Low energy rate based on usage	6%
This is fair/makes sense	6%
Not properly informed about options - too much information	6%

Preferred Option #3:
Inclining block rate with higher basic bi-monthly charge and lower energy rates

Why: Prefer Option 3 Total Mentions	Total n=27
Promotes conservation	44%
Should save money	41%
Low energy rate based on usage	11%
Helps to cover fixed costs	11%
This is fair/makes sense	7%
I conserve as much as I can	7%
I use a lot of power	4%
Use more should pay more	4%
Bill will stay the same	4%
Easier to get used to basic charge	4%
Would like lower basic charge	4%

Preferred Option #4:
Maintain Existing Rates

Why: Prefer Option 4 Total Mentions	Total n=28
This is fair/makes sense	21%
Wait for new AMI meters to adjust rates	18%
Change is not needed	18%
Should save money	7%
Bill will stay the same	7%
Low energy rate based on usage	4%
I conserve as much as I can	4%
Use more should pay more	4%
Not properly informed about options - too much information	4%
I have no control over usage	4%
Change should be over time	4%
Cost of change will go to the consumer	4%
Other option will hurt low income users	4%
Would like decreased block with an equal energy rate	4%

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Problems or Concerns with Preferred Option

Participants cited concerns with the impact on low-income households as the main concern with Option 2.

Preferred Option #1:
Lower basic bi-monthly charge with higher energy rates and a minimum bill

Why: Prefer Option 1 Total Mentions	Total n=9
No problems	44%
Low income need more help	33%
People already try to conserve and save money	11%
Need better options	11%
Need to know usage	11%
Need to save our resources	11%

Preferred Option #2:
Inclining block rate with existing basic bi-monthly charge and higher energy rates

Why: Prefer Option 2 Total Mentions	Total n=12
Low income need more help	42%
No problems	8%
People already try to conserve and save money	8%
Need to know usage	8%
All the time it takes for Fortis to research and actually change	8%
Excess profits being made	8%
Those with electric heat will suffer	8%
Overload of important information for making an unformed decision	8%
Education on ways to conserve	8%
Will it make a difference	8%

Preferred Option #3:
Inclining block rate with higher basic bi-monthly charge and lower energy rates

Why: Prefer Option 3 Total Mentions	Total n=22
Low income need more help	14%
No problems	14%
People already try to conserve and save money	9%
Rates would again raise in the near future	9%
Don't want bill to go up	9%
Not green enough	9%
Need to penalize choice not need of energy	9%
Need to know usage	5%
Those with electric heat will suffer	5%
Education on ways to conserve	5%
Need better options	5%
People need time to adjust	5%
All groups should be at 100%	5%
Don't know where the block rate will start	5%
I do not use Fortis	5%

Preferred Option #4:
Maintain Existing Rates

Why: Prefer Option 4 Total Mentions	Total n=19
No problems	42%
Want the AMI meters	16%
People already try to conserve and save money	11%
Will change anyways, doesn't matter what I say	11%
People need time to adjust	5%
All the time it takes for Fortis to research and actually change	5%
Need to read the meters once a month	5%
Renters need incentive to save power	5%
Studies should be regulated every five years, ten years is too long	5%

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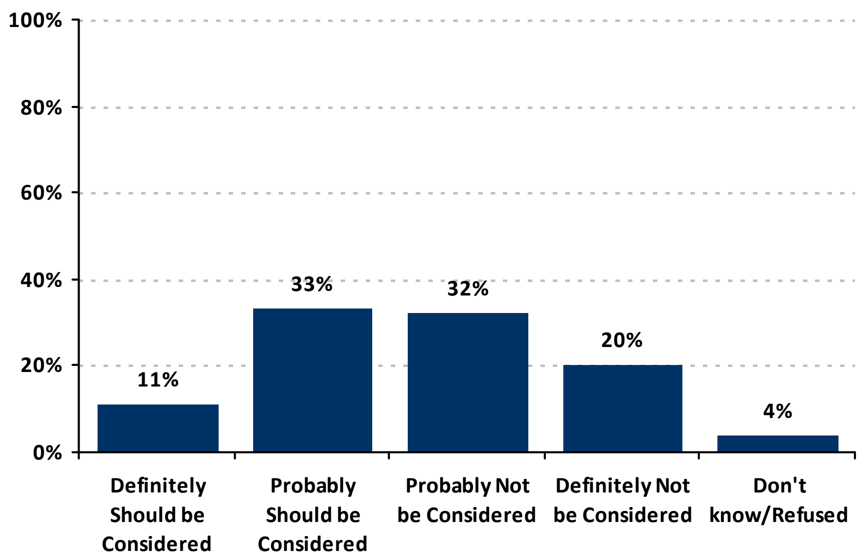
Opinions towards Residential Option 1

Participants were mixed about Option 1, which was seen as more strongly promoting conservation through higher energy rates.

Preference towards Option 1: Lower basic bi-monthly charge with higher energy rates and a minimum bill
(Total Respondents, n=114)



(Definitely Should be Considered) "Promotes conservation by tying costs to usage." (Kelowna)

(Definitely Should be Considered) "This is a direct means of encouraging conservation." (Kelowna)

(Definitely Should be Considered) "Reward those who try to conserve." (Castlegar)

(Probably Should Not be Considered) "Not enough incentive to conserve." (Castlegar)

(Definitely Not be Considered) "Does not allow equalization of monthly bills when all conservation efforts have been exhausted." (Kelowna)

(Definitely Not be Considered) "Simply charge everyone a basic rate to cover Fortis fixed costs and then charge everyone the same energy rate." (Castlegar)

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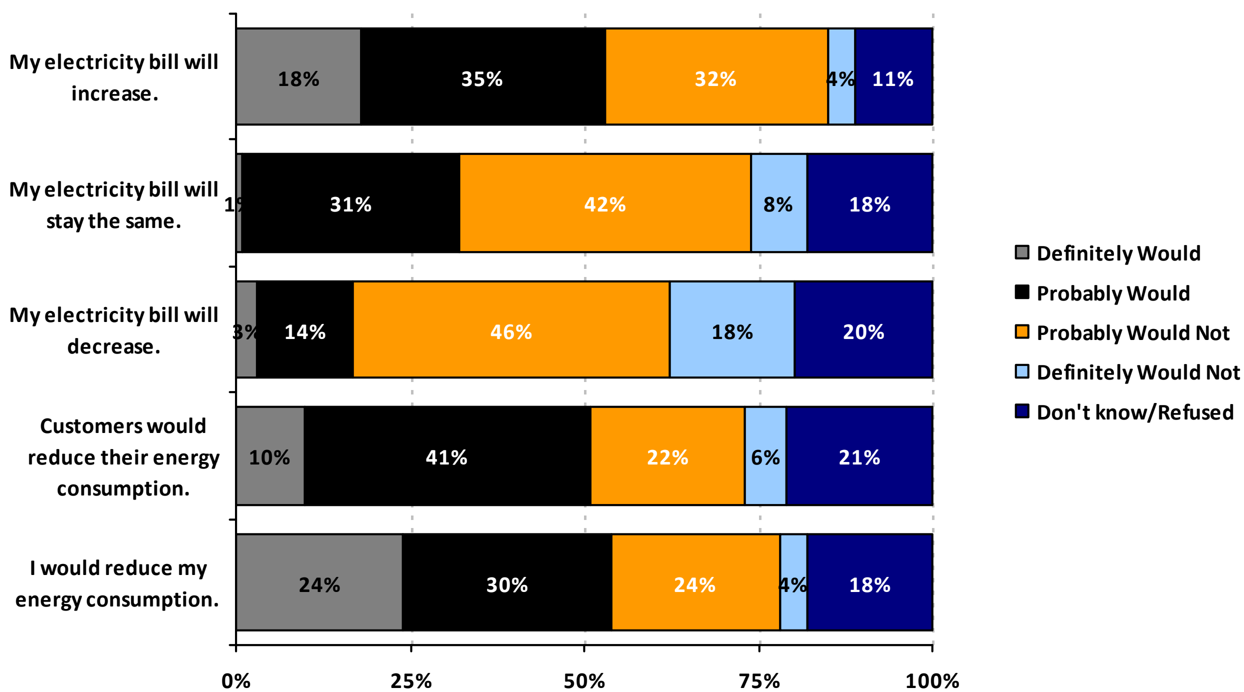
Perceived Outcomes of Implementation: Option 1

At least half of participants expected that Option 1 would reduce personal energy consumption, increase electricity bills and reduce energy consumption by customers overall.

Perceived Outcomes Due to Implementation of Option 1
(Total Respondents, n=114)



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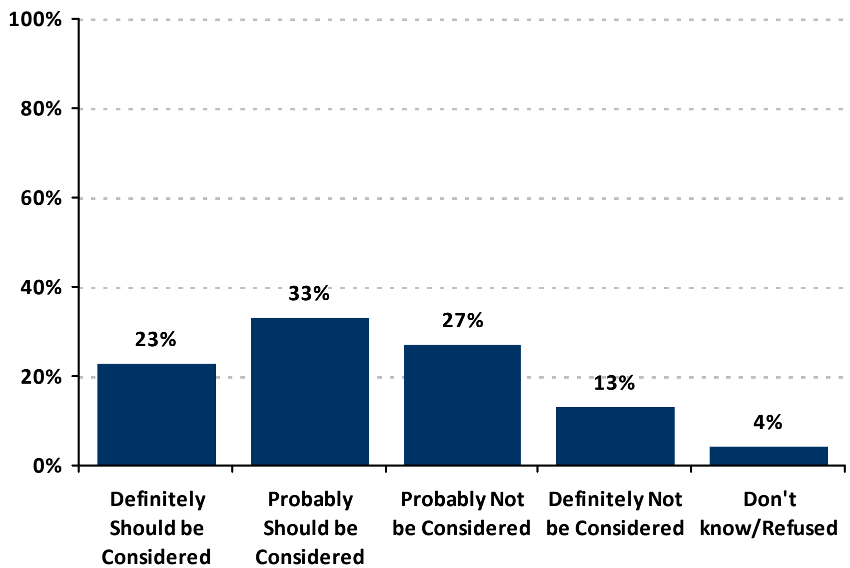
Opinions towards Residential Option 2

More than half thought Option 2 should be considered.

Preference towards Option 2: Inclining block rate with existing basic bi-monthly charge and higher energy rates
(Total Respondents, n=114)



(Definitely Should be Considered) "The change to low users is less drastic. The incentive to use less power is higher, i.e., bigger gap between block prices." (Castlegar)

(Definitely Should be Considered) "Hopefully people would try to use less energy." (Kelowna)

(Probably Not be Considered) "Reduce consumption should be voluntary, plus I have renters downstairs and no control." (Kelowna)

(Probably Not be Considered) "Energy rate should be consistent with higher usage not higher rate." (Castlegar)

(Definitely Not be Considered) "Users will not be equal, lower income households will pay more." (Castlegar)

(Definitely Not be Considered) "Residential rates should definitely not be put on an inclining rate. Too many struggling families." (Castlegar)

(Definitely Not be Considered) "Because I feel I already am trying to save and our bill is high, so how am I going to save more?" (Kelowna)

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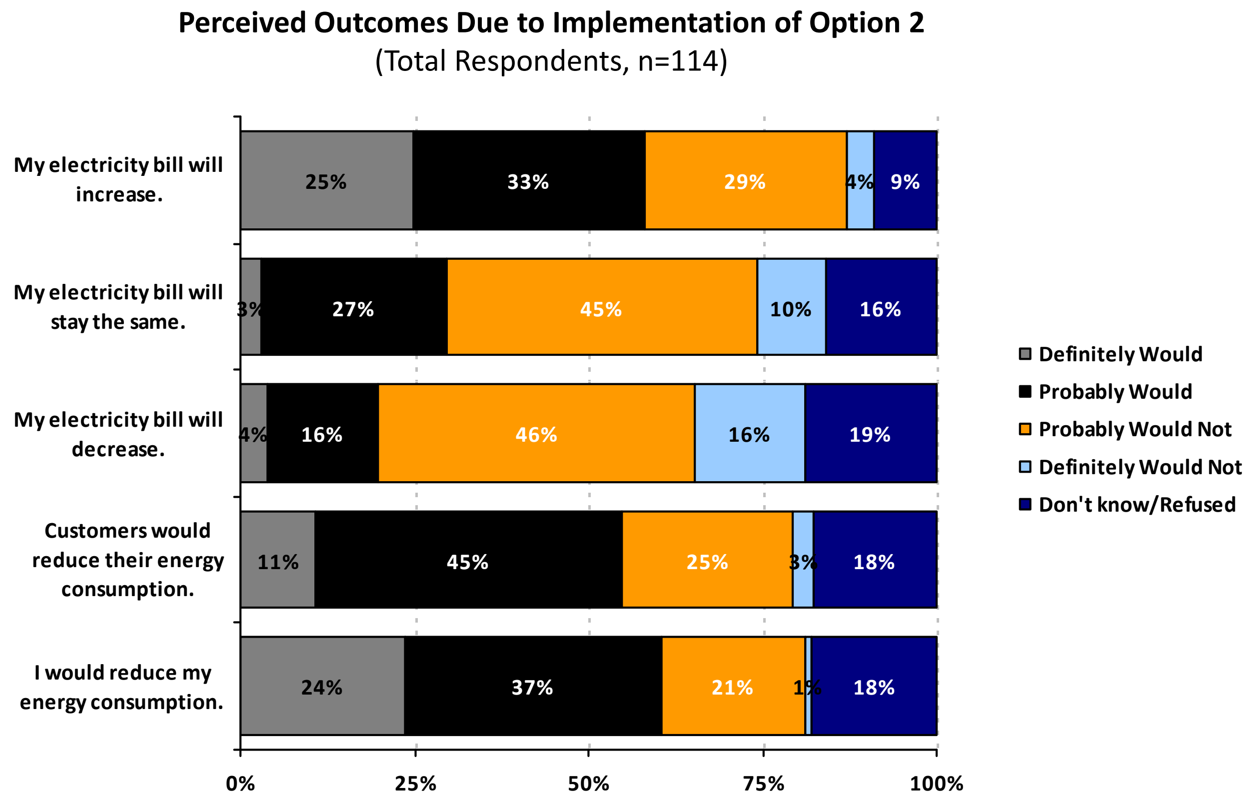
Perceived Outcomes of Implementation: Option 2

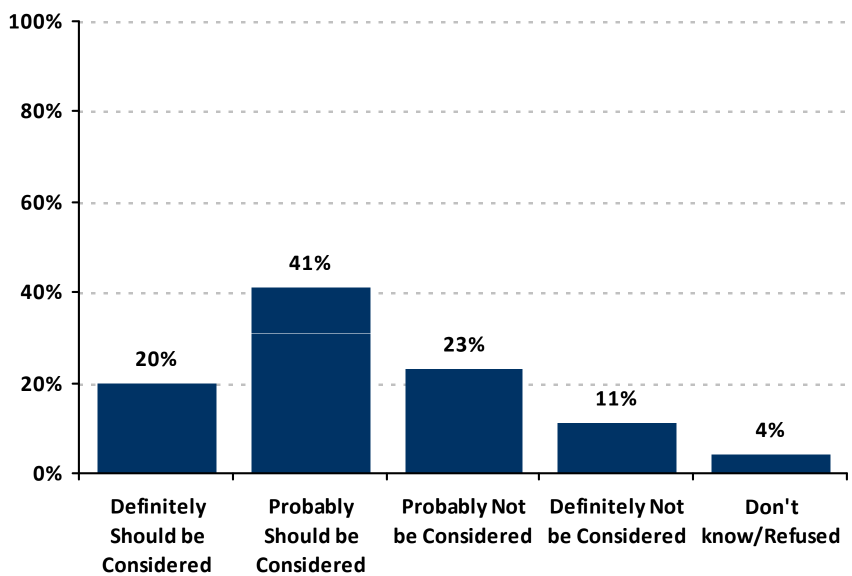
Participants felt the same outcomes would occur from implementing Option 2 as Option 1—reduced personal consumption and customer consumption overall and increased bills.



Opinions towards Residential Option 3

Option 3 was one of the most preferred options but some participants did not like the concept of inclining block rates.

Preference towards Option 3: Inclining block rate with higher basic bi-monthly charge and lower energy rates
(Total Respondents, n=114)



(Definitely Should be Considered) "Seems to encourage better 'smart' usage whilst still covering fixed costs." (Kelowna)

(Definitely Should be Considered) "1-Fixed costs should be reflected in basic charge; 2-Conservation goals supported." (Castlegar)

(Probably Should be Considered) "It's fair to people to control their consumption. It kinda penalizes for more consumption." (Kelowna)

(Probably Should be Considered) "Could reduce monthly costs depending on how much the bimonthly charge increased." (Kelowna)

(Definitely Not be Considered) "No to the inclining block rate for residential." (Castlegar)

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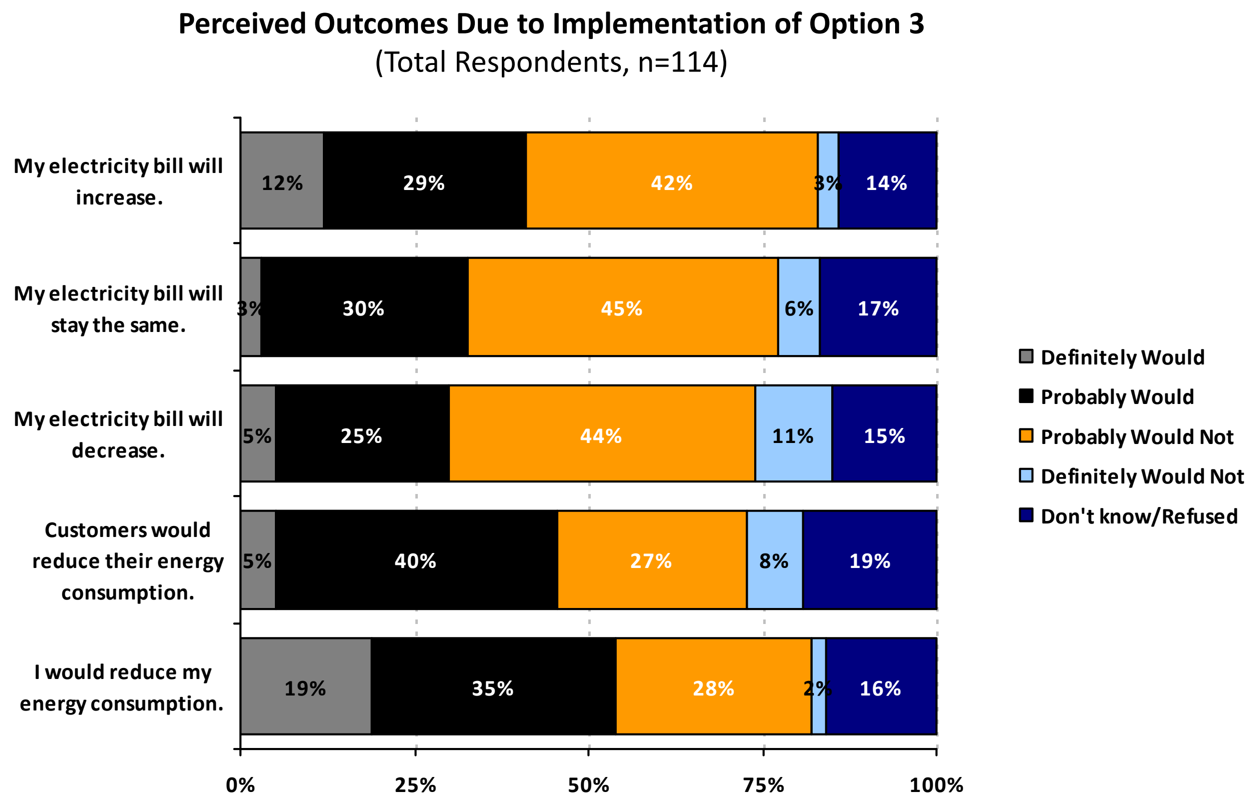
Perceived Outcomes of Implementation: Option 3

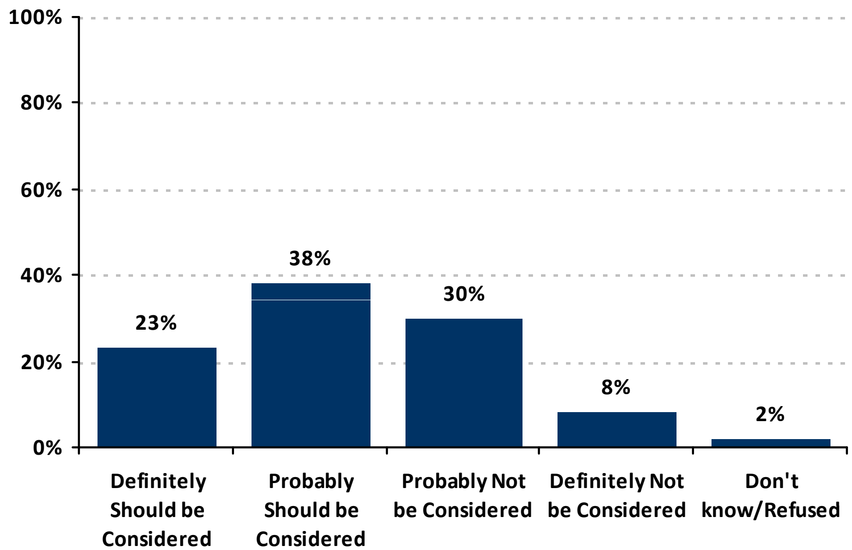
The majority of participants thought Option 3 would encourage them to reduce their own electricity consumption.



Opinions towards Residential Option 4

Most participants who preferred Option 4 cited a lack of reason to change or the implementation of AMI as their reason for their preference.

Preference towards Option 4: Maintain existing rates
(Total Respondents, n=114)



(Definitely Should be Considered) "It makes more sense to wait for new meters and the new options they will allow before making changes." (Castlegar)

(Definitely Should be Considered) "As you are at 99% there is a consideration rates should stay the same." (Kelowna)

(Probably Should be Considered) "Wait until the smart meters come in and introduce a rebalanced rate then." (Castlegar)

(Probably Should be Considered) "There is no substantial evidence to show that there will be a cost saving or a reduction in energy used to consider the choice." (Kelowna)

(Probably Not be Considered) "There is no incentive to reduce consumption." (Castlegar)

(Probably Not be Considered) "Doesn't encourage reduction of consumption." (Kelowna)

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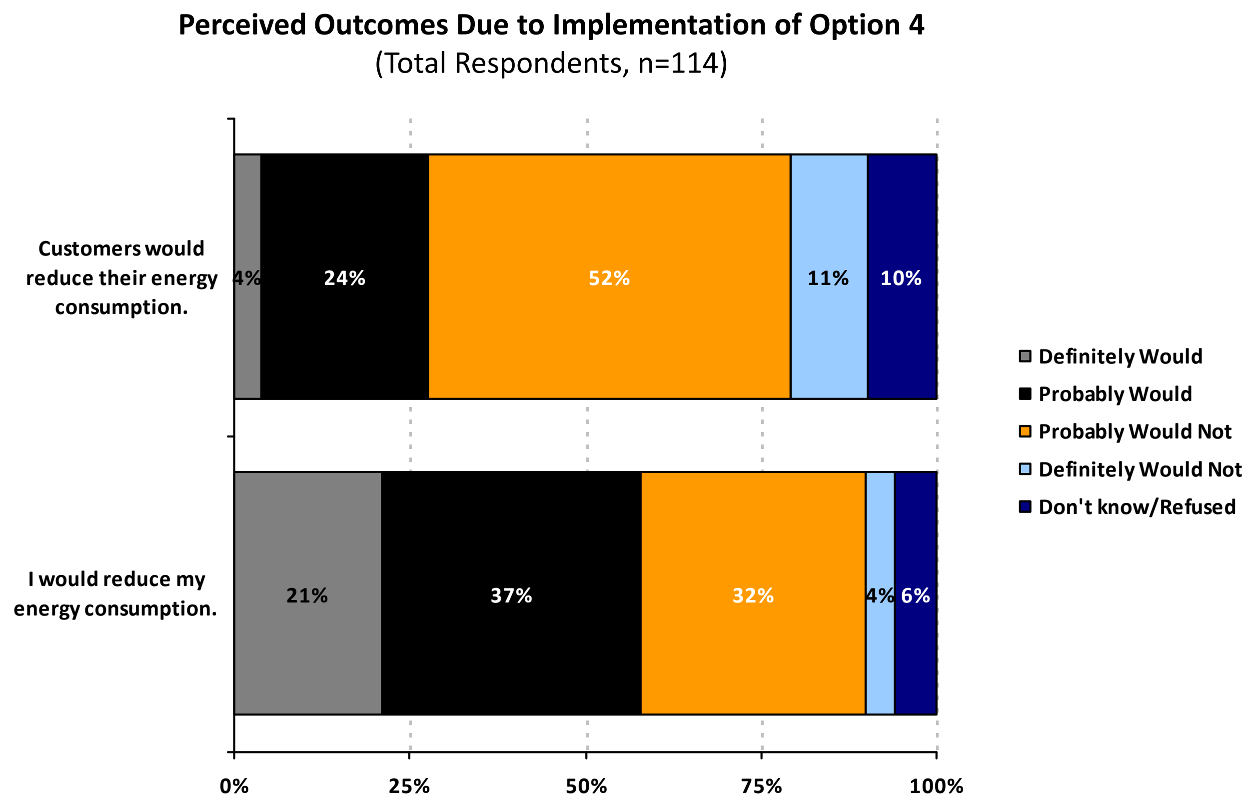
Perceived Outcomes of Implementation: Option 4

Many participants felt that maintaining existing rates would reduce their personal energy consumption but would not reduce overall consumption.



General Service
Rate Design Options

General Service Rate Design Options: Summary of Findings

- **The majority of participants (55%) felt the general service option should be considered, however, there were also many against it. (Page 44)**
- **The General Service participants were also divided in their opinions on the general service option. Most felt it should not be considered, but many others disagreed. (Page 46)**
- **Nearly half of the General Service customers surveyed thought their electricity bill would increase with this option. (Page 47)**

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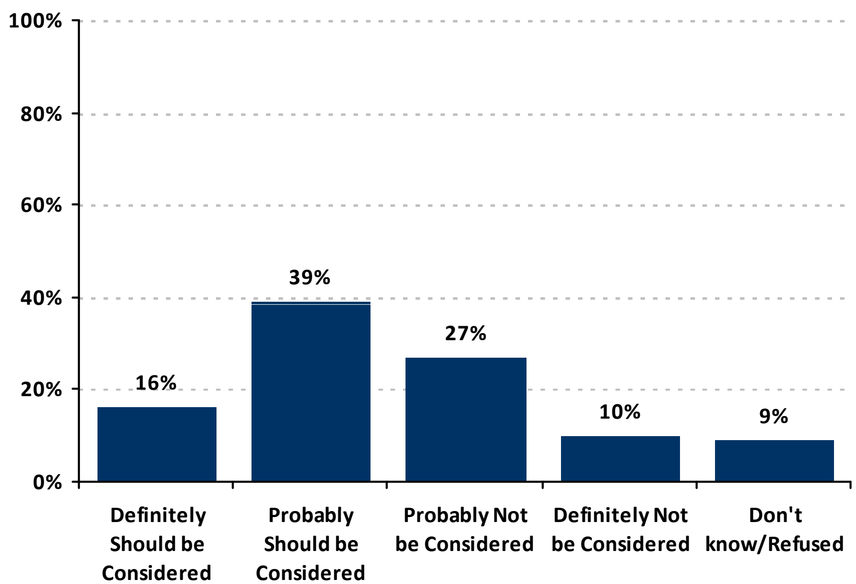
Opinions towards General Service (Commercial) Option

The majority of participants (55%) felt the general service option should be considered, however, there were also many against it.

Preference towards General Service Option: Flattened blocks with higher basic customer charge and lower energy rates
(Total Respondents, n=114)



(Definitely Should be Considered) "Business could lower their bills by reducing consumption." (Kelowna)

(Definitely Should be Considered) "1-Declining block rates are in opposition to conservation goals. 2-Basic charge should reflect fixed costs." (Castlegar)

(Probably Should be Considered) "These are high usage customers who need regular fixed costs." (Castlegar)

(Probably Should be Considered) "Flatten block would be fair, the more they use the more they pay." (Castlegar)

(Probably Should be Considered) "To bring cost and returns into better balance." (Kelowna)

(Probably Not be Considered) "No incentive to use less power." (Kelowna)

When looking at the answers from a Residential perspective versus a General Service perspective we find that the General Service segment is more likely to suggest that this option "probably should not be considered."

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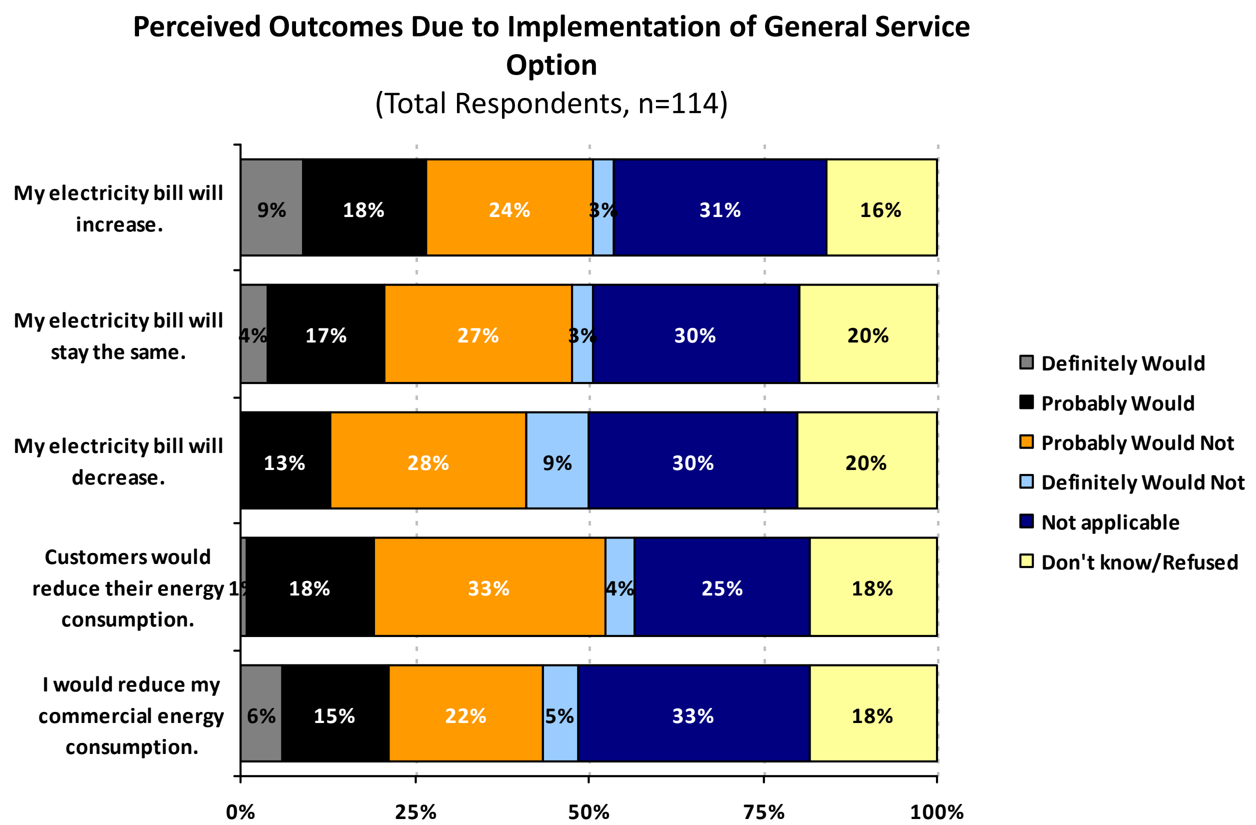
Perceived Outcomes of Implementation: General Service

Many participants were not really sure what the outcome of implementing the General Service option would be. However, the General Service segment were more likely than Residential to claim they definitely would reduce consumption.



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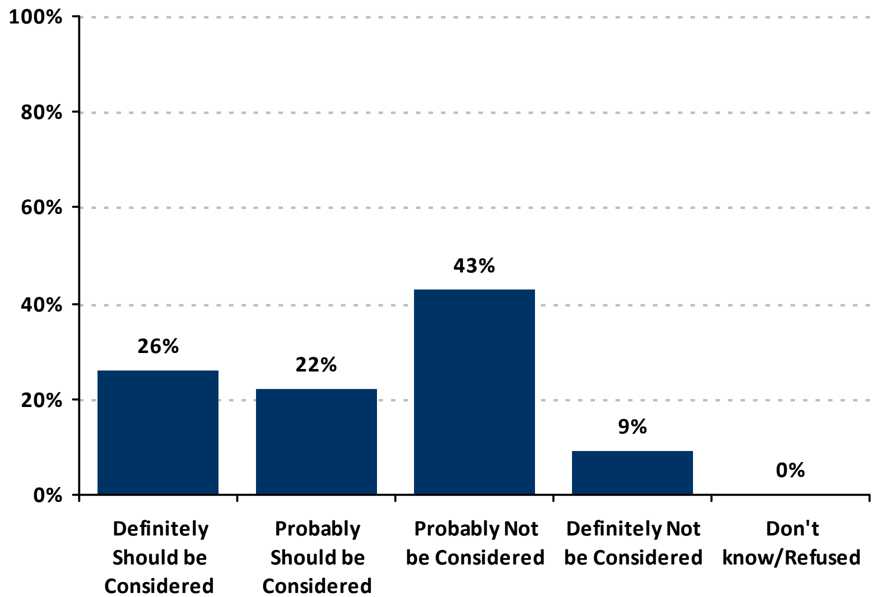
General Service Opinions Towards General Service (Commercial) Option

The General Service participants were also divided in their opinions on the general service option. Most felt it should not be considered, but many others disagreed.

Preference Towards General Service Option: Flattened blocks with higher basic customer charge and lower energy rates
(General Service Respondents, n=23)



CAUTION: Small sample base (n=23)

(Definitely Should be Considered) "Needs to be flattened for fairness." (General Service)

(Definitely Should be Considered) "They should not be encouraged to use more." (General Service)

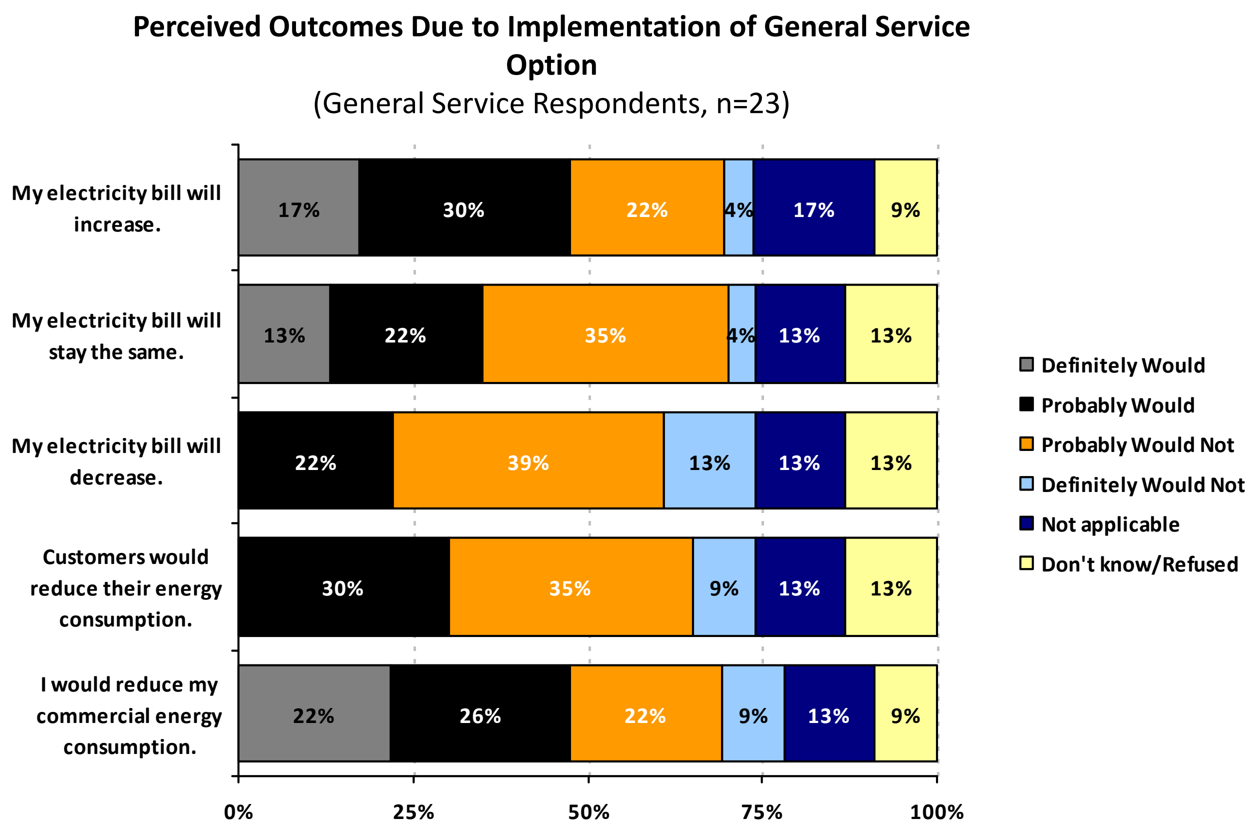
(Probably Should be Considered) "Flatten block would be fair, the more they use the more they pay." (General Service)

(Probably Should be Considered) "I don't know, but according to the first half of the presentation Fortis should do everything possible to bring these rates down." (General Service)

(Definitely Not be Considered) "One rate for all." (General Service)

Perceived Outcomes of Implementation: General Service

Nearly half of the General Service customers surveyed thought their electricity bill would increase with this option.



CAUTION: Small sample base (n=23)

Communications and Consultation

Communications and Consultation: Summary of Findings

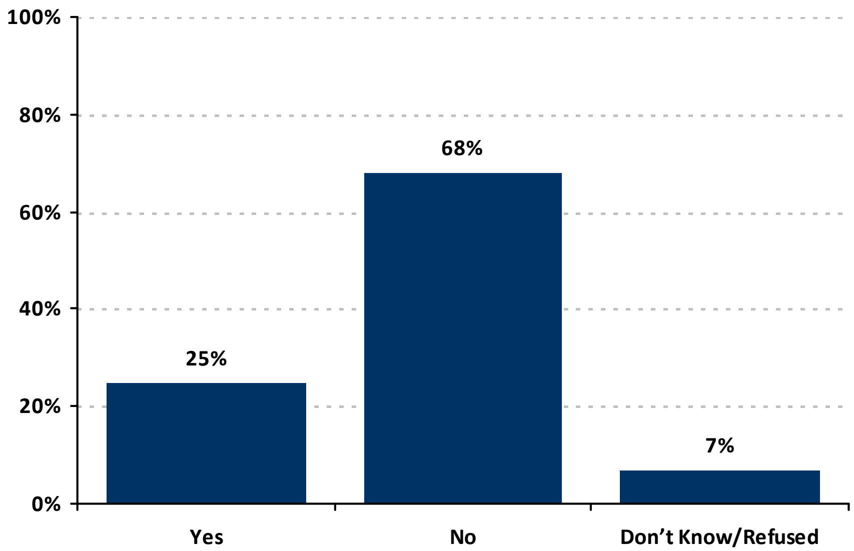
- **Most Super Group participants felt that the presentation was easy to understand. (Page 50)**
- **Super Group participants agreed that the materials in the presentation were presented objectively. However, 38% indicated only being somewhat in agreement. (Page 51)**
- **The presentation was successful in helping participants understand cost of service and rate design, including rate rebalancing. (Page 52)**
- **Participants identified a wide range of materials that would be helpful. Information on how to read the meter was rated as most helpful. (Page 53)**

ENVIRONICS
RESEARCH GROUP

Opinions Towards the FortisBC Presentation

Most Super Group participants felt that the presentation was easy to understand.

Was there anything in the presentation that was confusing or difficult for you to understand?
(Total Respondents, n=114)



(Yes) "Hard to really comprehend how much my bill would be impacted." (Castlegar)

(Yes) "Difficult to consider all the options because of variety of billing situations for different customers. Would not be possible to break down every one." (Kelowna)

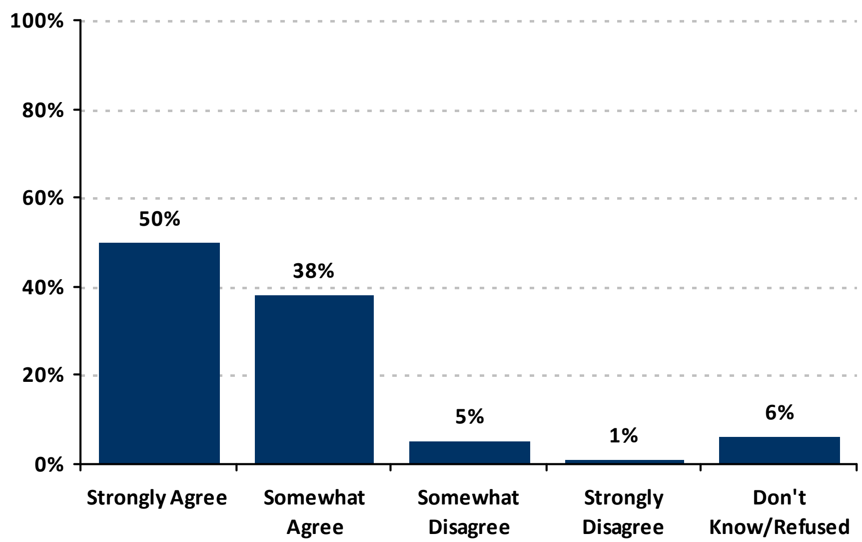
(Yes) "Why the commercial and light industrial users have been allowed to get so far out of balance with residential users." (Kelowna)

(No) "Nothing- plain to see power is going to cost more." (Castlegar)

Opinions Towards the FortisBC Presentation

Super Group participants agreed that the materials in the presentation were presented objectively. However, 38% indicated only being somewhat in agreement.

% Agreement: The materials in the presentation were presented objectively.
(Total Respondents, n=114)



Kelowna participants were more likely to strongly agree that materials were presented objectively.

(Strongly Agree) "Corey gave a very good presentation and kept the discussion on track for the most part." (Castlegar)

(Strongly Agree) "Enjoy [ed] very much and learned a lot about power." (Kelowna)

(Somewhat Agree) "Presentation a bit confusing for some people." (Castlegar)

(Somewhat Agree) "Can't really be totally objective if presented by a rep of the company." (Kelowna)

(Somewhat Disagree) "Being objective is unlikely when you are management presenting mgmt view." (Castlegar)

(Somewhat Disagree) "Presented confusingly, and giving us Fortis preferred method." (Kelowna)

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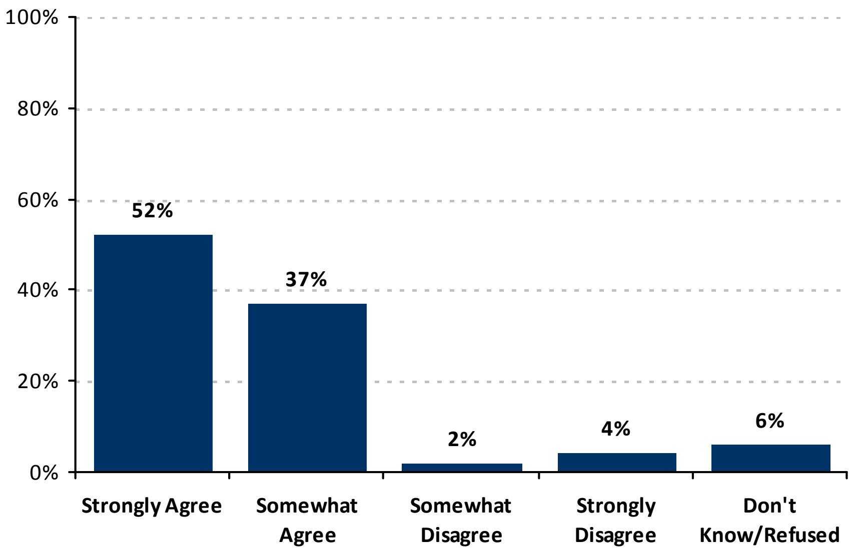
Opinions Towards the FortisBC Presentation

The presentation was successful in helping participants understand cost of service and rate design, including rate rebalancing.

% Agreement: The presentation helped me understand cost of service and rate design, including rate rebalancing.
(Total Respondents, n=114)



(Strongly Agree) "Some people just have beefs that blocked their ability to understand the purpose of this exercise." (Castlegar)

(Strongly Agree) "Makes me angry to see big business on a declining rate." (Castlegar)

(Strongly Agree) "Great way to show what and how the design works." (Kelowna)

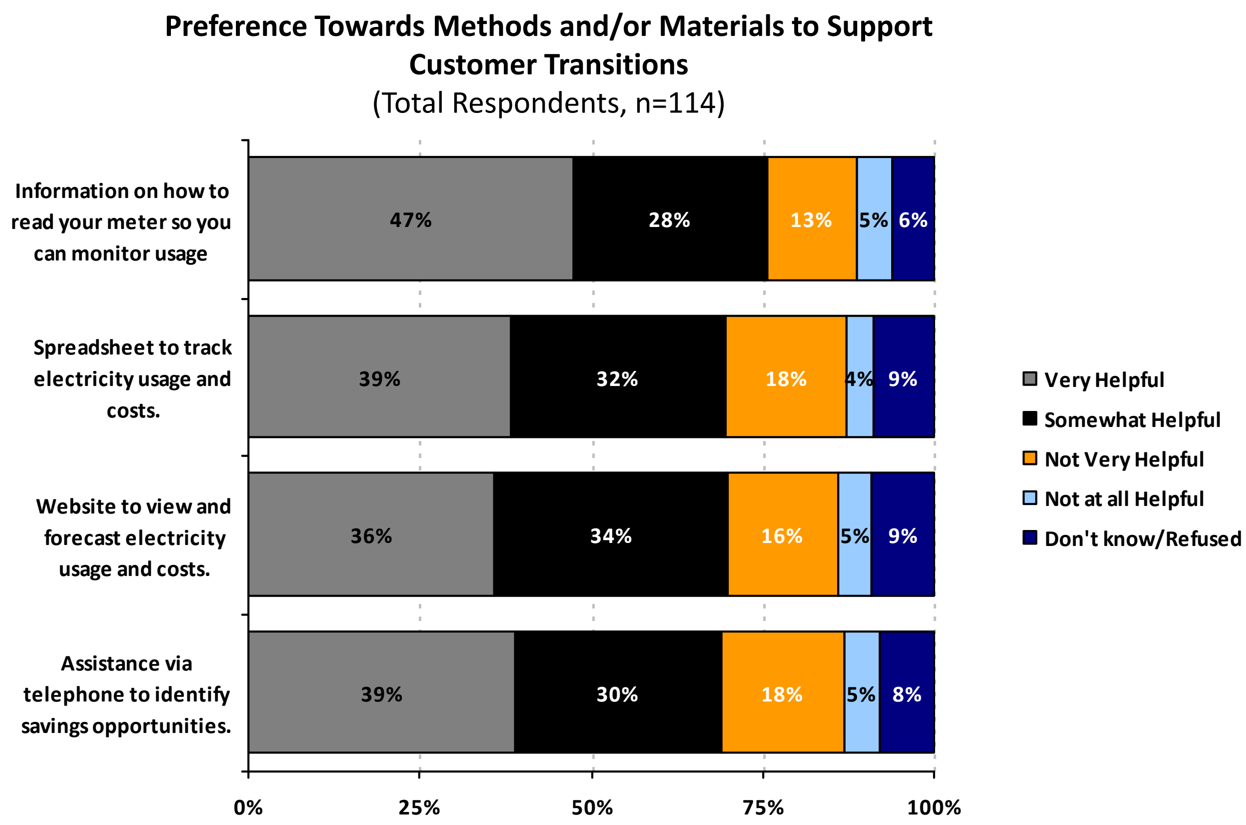
(Somewhat Agree) "Some information presented [was] more convoluted than necessary." (Castlegar)

(Strongly Disagree) "I was given absolutely NO sound and logical reason for any changes to be implemented." (Castlegar)

(Strongly Disagree) "This is too much for people to absorb." (Castlegar)

Preferred Methods and/or Materials to Support Transitions

Participants identified a wide range of materials that would be helpful. Information on how to read the meter was rated as most helpful.



Appendix 1: Questionnaires

Questionnaire

Questionnaire: Part 1

Castlegar: August 17, 2009
Kelowna: August 18, 2009

Respondent: _______________

PN: 6755

PART 1:

BACKGROUND INFORMATION

Instructions

- You have 15 minutes to complete this section
- When you are done this section, please put your pencil down
- When everyone is ready, the facilitator will provide further instructions
- Please don't disturb your neighbours (Thank you!)

Questionnaire

Part 1: Background Information

About You

1. Which of the following describes your account (or accounts) with FortisBC? Is it…

   [CHECK ALL BOXES THAT APPLY]

   - ☐ 1 Residential
   - ☐ 2 General Service
   - ☐ 3 Industrial
   - ☐ 4 Irrigation
   - ☐ 5 Wholesale
   - ☐ 6 Lighting

2. Please write in your age.

   ________AGE

3. Please indicate your gender.

   [CHECK BOX]

   - ☐ 1 Male
   - ☐ 2 Female

Part 1: Background Information Page 2

4. Please record your postal code

   ___ ___ ___ ___ ___ ___

5. Which of the following best describes your own present employment status? Are you... **[CHECK ONE BOX ONLY]**

   - ☐ 1 Working full-time
   - ☐ 2 Working part-time
   - ☐ 3 Unemployed or looking for a job
   - ☐ 4 Stay at home full-time
   - ☐ 5 Student
   - ☐ 6 Retired

6. Do you currently own or rent your home? **[CHECK ONE BOX ONLY]**

   - ☐ 1 Own
   - ☐ 2 Rent

7. Which of the following best describes your home? **[CHECK ONE BOX ONLY]**

   - ☐ 1 Single detached house
   - ☐ 2 Townhome or duplex
   - ☐ 3 Apartment building
   - ☐ 4 Mobile home
   - ☐ 5 Basement Suite / Suite
   - ☐ 6 Other

Part 1: Background Information Page 3

Questionnaire

8. What is the square footage of your home?
   - ☐ 1 Less than 800 sq. ft.
   - ☐ 2 800 to less than 1200 sq. ft.
   - ☐ 3 1200 to less than 1600 sq. ft.
   - ☐ 4 1600 to less than 2000 sq. ft.
   - ☐ 5 2000 to less than 2500 sq. ft.
   - ☐ 6 More than 2500 sq. ft.

9. What fuel do you use to heat your home?

   [CHECK ALL BOXES THAT APPLY]
   - ☐ 1 Natural Gas
   - ☐ 2 Oil
   - ☐ 3 Propane
   - ☐ 4 Electricity
   - ☐ 5 Wood
   - ☐ 6 Other (please describe): ______________________

10. Please indicate the **main** heating system you use in your home

    [CHECK ONE BOX ONLY]
    - ☐ 1 Central air
    - ☐ 2 Electric baseboards
    - ☐ 3 Hot water baseboards / radiator
    - ☐ 4 Heat pump (air or ground)
    - ☐ 5 Wood, gas or electric fireplace
    - ☐ 6 Other (please describe): ______________________

11. Do you have air conditioning in your home?
    - ☐ 1 Yes, central air
    - ☐ 2 Yes, a window unit
    - ☐ 3 No

12. How many people, including yourself, currently live in your household?

    ____

13. Do you feel the price you currently pay for your household electricity service is:

    [CHECK ONE BOX ONLY]
    - ☐ 1 Too low
    - ☐ 2 About right
    - ☐ 3 Too high

14. Does the current size of your household electricity bill make a noticeable, small or no impact on your household finances each month?

    [CHECK ONE BOX ONLY]
    - ☐ 1 Noticeable impact
    - ☐ 2 Small impact
    - ☐ 3 No impact

Questionnaire

15. FortisBC, your electricity supplier, is completing a review of electricity rates for all customer classes: residential, commercial, industrial, wholesale, lighting and irrigation. This review will help to ensure the electricity rates paid by each customer class reflects the cost of providing service to that customer class, and that classes of customers are not unduly subsidizing each other. It will also help to determine what, if any, updates to the rate structures are needed.

There are number of considerations in identifying the best rate structure going forward. Do you think each of the following considerations in Column A is critically important, important but not critical, or not very important in deciding updates to the current rate structures for electricity usage?

[CIRCLE ONE NUMBER IN EACH ROW FOR EACH ITEM IN COLUMN A]

	COLUMN A	Critically Important	Important but Not Critical	Not Very Important	Not at all Important
A	All customers pay their fair share of the cost to provide electricity	1	2	3	4
B	Introduction of conservation rates for electricity usage that charges customers with higher electrical usage more and customers with lower electrical usage less	1	2	3	4
C	Large electricity rate changes are phased in over time	1	2	3	4
D	Rate structures which encourage energy savings and conservation	1	2	3	4

15. Do you think that charging higher-usage customers a 20% higher rate for electricity will result in lower energy use?

- ☐ 1 Yes
- ☐ 2 No

16. Why do you say that?

____

____

____

When you are done, please put your pencil down

and wait for the facilitator to provide further instructions.

Questionnaire

PART 2:

REACTION TO PRESENTATION OF

RATE REBALANCING AND RATE STRUCTURE OPTIONS

Instructions

- You have 15 minutes to complete this section
- When you are done this section, please turn your survey over
- When everyone is ready, the facilitator will provide further instructions
- Please don't disturb your neighbours (Thank you!)

Part 2: Reactions to Rate Rebalancing and Rate Structure Options

Questionnaire

Part 2: Reaction to Presentation on Rate Rebalancing and Rate Structure Options

1. The presentation by FortisBC provided information about rate rebalancing, which would help ensure all customer groups pay their fair share of the cost of electrical service.

   For each statement about rebalancing in Column A, please rate your level of agreement. Then, please write the reason **why** you say that in Column B.

   [CIRCLE ONE NUMBER ONLY FOR EACH STATEMENT IN COLUMN A]

	COLUMN A	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree	COLUMN B: REASON FOR SELECTING ANSWER
A	In my opinion, rate rebalancing is needed.	1	2	3	4	
B	For customers whose revenue to cost ratios are below 100%, capping their increases at 5% per year seems reasonable.	1	2	3	4	
C	It seems reasonable to recover more of the fixed costs by raising the basic customer charge.	1	2	3	4	

Thinking about the different rate structure options that are being considered by FortisBC, please answer the following questions about each option.

Questionnaire

2a. Please indicate whether you think the following **residential** rate structure option should definitely be considered, should probably be considered, probably not be considered or definitely not be considered by circling the number in the corresponding column. Then, in Column B, please provide the reason **why** if you selected 'Should Be Definitely Considered'.

[CIRCLE ONE NUMBER ONLY]

	COLUMN A	Definitely Should Be Considered	Probably Should Be Considered	Probably Not be Considered	Definitely Not be Considered	COLUMN B Reason Why Option Should Be 'Definitely Considered'
A	Lower basic bi-monthly charge with higher energy rates and a minimum bill	1	2	3	4	

2b. If this option was implemented (**lower basic bi-monthly charge with higher energy rates and minimum bill**), please indicate for each statement below whether you think each potential result definitely would, probably would, probably would not, or definitely would not occur by circling the number in the corresponding column.

[CIRCLE ONE NUMBER ONLY]

	Lower basic bi-monthly charge with higher energy rates and a minimum bill	Definitely Would	Probably Would	Probably Would Not	Definitely Would Not
A	My electricity bill will increase.	1	2	3	4
B	My electricity bill will stay the same.	1	2	3	4
C	My electricity bill will decrease.	1	2	3	4
D	Customers would reduce their energy consumption.	1	2	3	4
E	I would reduce my energy consumption.	1	2	3	4

Questionnaire

3a. Please indicate whether you think the following **residential** rate structure option should definitely be considered, probably should be considered, probably not be considered or definitely not be considered by circling the number in the corresponding column. Then, in Column B, please provide the reason **why** if you selected 'Should Be Definitely Considered'.

	COLUMN A	Definitely Should Be Considered	Probably Should Be Considered	Probably Not be Considered	Definitely Not be Considered	COLUMN B Reason Why Option Should Be 'Definitely Considered'
B	Inclining block rate with existing basic bi-monthly charge and higher energy rates	1	2	3	4	

3b. If this option was implemented (**inclining block rate with existing basic charge and higher energy rates**), please indicate for each statement below whether you think each potential result definitely would, probably would, probably would not, or definitely would not occur by circling the number in the corresponding column.

[CIRCLE ONE NUMBER ONLY]

	Inclining block rate with existing basic bi-monthly charge and higher energy rates	Definitely Would	Probably Would	Probably Would Not	Definitely Would Not
A	My electricity bill will increase.	1	2	3	4
B	My electricity bill will stay the same.	1	2	3	4
C	My electricity bill will decrease.	1	2	3	4
D	Customers would reduce their energy consumption.	1	2	3	4
E	I would reduce my energy consumption.	1	2	3	4

Questionnaire

4a. Please indicate whether you think the following **residential** rate structure option should definitely be considered, probably should be considered, probably not be considered or definitely not be considered by circling the number in the corresponding column. Then, in Column B, please provide the reason **why** if you selected 'Should Be Definitely Considered'.

	COLUMN A	Definitely Should Be Considered	Probably Should Be Considered	Probably Not be Considered	Definitely Not be Considered	COLUMN B Reason Why Option Should Be 'Definitely Considered'
c	Inclining block rate with higher basic bi-monthly charge and lower energy rates	1	2	3	4	

4b. If this option was implemented (**inclining block rate with higher basic charge and lower energy rates**), please indicate for each statement below whether you think each potential result definitely would, probably would, probably would not, or definitely would not occur by circling the number in the corresponding column.

[CIRCLE ONE NUMBER ONLY]

	Inclining block rate with higher basic bi-monthly charge and lower energy rates	**Definitely Would**	**Probably Would**	**Probably Would Not**	**Definitely Would Not**
A	My electricity bill will increase.	1	2	3	4
B	My electricity bill will stay the same.	1	2	3	4
C	My electricity bill will decrease.	1	2	3	4
D	Customers would reduce their energy consumption.	1	2	3	4
E	I would reduce my energy consumption.	1	2	3	4

Part 2: Reactions to Rate Rebalancing and Rate Structure Options

Questionnaire

5a. Please indicate whether you think the following **residential** rate structure option should definitely be considered, probably should be considered, probably not be considered or definitely not be considered by circling the number in the corresponding column. Then, in Column B, please provide the reason **why** if you selected 'Should Be Definitely Considered'.

	COLUMN A	Definitely Should Be Considered	Probably Should Be Considered	Probably Not be Considered	Definitely Not be Considered	COLUMN B Reason Why Option Should Be 'Definitely Considered'
D	Maintain existing rates	1	2	3	4	

5b. If this option was implemented (**maintain existing rates**), please indicate for each statement below whether you think each potential result definitely would, probably would, probably would not, or definitely would not occur by circling the number in the corresponding column.

[CIRCLE ONE NUMBER ONLY]

	Maintain existing rates	Definitely Would	Probably Would	Probably Would Not	Definitely Would Not
A	Customers would reduce their energy consumption.	1	2	3	4
B	I would reduce my energy consumption.	1	2	3	4

ENVIRONICS RESEARCH GROUP

Questionnaire

6a. Please indicate whether you think the following **general service** (commercial) rate structure option should definitely be considered, probably should be considered, probably not be considered or definitely not be considered by circling the number in the corresponding column. Then, in Column B, please provide the reason **why** if you selected 'Should Be Definitely Considered'.

	COLUMN A	Definitely Should Be Considered	Probably Should Be Considered	Probably Not be Considered	Definitely Not be Considered	COLUMN B Reason Why Option Should Be 'Definitely Considered'
B	Flattened blocks with higher basic customer charge and lower energy rates	1	2	3	4	

6b. If this option for **general service** customers was implemented (**flattened blocks with and higher basic customer charge and lower energy rate**), please indicate for each statement below whether you think each potential result definitely would, probably would, probably would not, or definitely would not occur by circling the number in the corresponding column.

[CIRCLE ONE NUMBER ONLY]

	Flattened blocks with higher basic customer charge and lower energy rates	Definitely Would	Probably Would	Probably Would Not	Definitely Would Not	N/A
A	My commercial electricity bill will increase.	1	2	3	4	5
B	My commercial electricity bill will stay the same.	1	2	3	4	5
C	My commercial electricity bill will decrease.	1	2	3	4	5
D	Commercial customers would reduce their energy consumption	1	2	3	4	5
E	I would reduce my commercial energy consumption	1	2	3	4	5

Questionnaire

7. The following statements are about residential and commercial rate design. For each statement in Column A, please rate whether you strongly agree, somewhat agree, somewhat disagree or strongly disagree with each statement. Then, please provide the reason **why** you say that in Column B.

[CIRCLE ONE NUMBER ONLY FOR EACH STATEMENT IN COLUMN A]

	COLUMN A	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree	COLUMN B: REASON FOR SELECTED ANSWER
A	Residential customers are billed every two months, but I would prefer to have my meter read and be billed monthly, even if there is a one-time one percent rate increase.	1	2	3	4	
B	It is important to flatten the rate structure for commercial customers.	1	2	3	4	
C	Introducing rate structures that encourage energy efficiency and conservation is important.	1	2	3	4	
E	A conservation rate for electricity usage that charges customers with higher electrical usage more and customers with lower electrical usage less will result in lower energy consumption.	1	2	3	4	

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Questionnaire

8. Considering all of the information from the presentation by FortisBC, please **RANK** the options in Column B, where a rank of **1 would be your most preferred** option and **4 would be your least preferred option.** Please do not provide tie rankings.

	COLUMN A: Energy Generation Option	COLUMN B: Your Rank (1 to 4)
A	Lower basic bi-monthly charge with higher energy rates and minimum bill	
B	Inclining block rate with existing basic bi-monthly charge and higher energy rates	
C	Inclining block rate with higher basic bi-monthly charge and lower energy rates	
D	Maintain existing rates	

Questionnaire

9. Of all the options presented tonight, which **ONE** is your preferred option?
   [CHECK ONE BOX ONLY]

- ☐ 1 Lower basic bi-monthly charge with higher energy rates and a minimum bill
- ☐ 2 Inclining block rate with existing basic bi-monthly charge and higher energy rates
- ☐ 3 Inclining block rate with higher basic bi-monthly charge and lower energy rates
- ☐ 4 Maintain existing rates
- ☐ 5 Other (Please Specify)____

10. Why is this your preferred option?

____

____

____

11. What problems or concerns, if any, do you have with your preferred option?

____

____

____

Part 2: Reactions to Rate Rebalancing and Rate Structure Options

Questionnaire

12. Thinking about all the information presented about rate design, rate rebalancing and the rate structure options, please indicate whether you agree or disagree with the following statement.

The cost of service analysis and rate design changes are revenue neutral to FortisBC and merely distribute the costs and revenue more equitably among customer groups.

- ❑ 1 Yes, I agree
- ❑ 2 No, I disagree

13. The following statements are about tonight's presentation by FortisBC. Please indicate your level of agreement with the following statements.

[CIRCLE ONE NUMBER ONLY FOR EACH STATEMENT IN COLUMN A]

	COLUMN A	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree	COLUMN B: Additional Comments and Feedback
A	The materials in the presentation were presented objectively.	1	2	3	4	
B	The presentation helped me understand cost of service and rate design, including rate rebalancing.	1	2	3	4	

Questionnaire

14a. Was there anything in the presentation that was confusing or difficult for you to understand?

- ❑ 1 Yes
- ❑ 2 No

14b. **IF YES**, what was confusing or difficult to understand?

____

____

____

Questionnaire

15. FortisBC is committed to assisting their customers transition to new rate structures. Please indicate how helpful you would find the following methods and/or materials to support your transition.

[CIRCLE ONE NUMBER ONLY FOR EACH OPTION IN COLUMN A]

	COLUMN A	Very Helpful	Somewhat Helpful	Not Very Helpful	Not at all Helpful
A	Information on how to read your meter so you can monitor usage.	1	2	3	4
B	Spreadsheet to track electricity usage and costs.	1	2	3	4
C	Website to view and forecast electricity usage and costs.	1	2	3	4
D	Assistance via telephone to identify savings opportunities.	1	2	3	4

16. What additional comments or suggestions do you have?

____

____

____

<u>When you are done, please turn your survey over
and wait for the facilitator to provide further instructions.</u>

Appendix 2:
Super Group
Question and Answer
Transcripts

Question and Answer Transcripts - Castlegar

ENVIRONICS WEST
Focus Group Transcription — Fortis Focus Group
August 17, 2009

EXPLANATION OF HOW THE MEETING IS GOING TO WORK, INTRODUCTION OF FACILITATORS AND THEIR FUNCTION IN THIS PROJECT.

EXPLANATION OF WORKSHOP GUIDELINES.

GOING OVER AGENDA FOR THE DISCUSSION.

Filling out questionnaire

Are we ready to talk?

Cory giving presentation.

I have a question. I fall into the residential as well ______ shows that the business pay ___ 40% so you are going to raise the residential say 5% a year meanwhile the business are still paying the 140%.

Lets be clear then. The residential customers under the _____ are already at 100% we don't touch them. In order to bring the 140 down we bring these guys up because they are underpaying, but if you are in a residential class through rate rebalancing if you end up sitting at 99% when all the discussion is done on this and we have had the model challenged as you are talking about the assumptions have been tested, which they will be. If we are still at 100% at that point they won't go anywhere so as a small business owner your interest in this primarily is the fact that depending on the small business that you have you are either in here somewhere, you are either here or you are here.

Then I will be overpaying for the next 5 years.

No you will be going down.

All talking at once.

We want to bring you down and the guys not paying enough up.

So you want everybody at 100%.

Ideally we have everybody at 100% and everybody would be paying their share.

Industrial should always pay more.

The problem is is what ________

Hopefully everybody has a clear understanding if not we will take a lot of questions after.

No confusion here it is 100% of the cost of the delivery plus a little bit of profit like 12%.

When we talk about the costs of running the utility.

It is not the same rate.

When we talk about the cost of running utility in the interest of time, the cost of running utility which we call our revenue requirement, the amount of revenue we require on an annual basis to run the business includes a component of rate of return for our shareholder yes, but again the revenue requirement is not changing as a result of this process.

Explanation of rate design.

When are you going to get to the point where you don't need the actual meter readers coming around?

We are going to talk about the smart reader program in a little bit so why don't we save that. *More explanation.*

So if we do it ourselves (meter reading) you will take 1% off? (laughter).

If you would like to propose that as one of the other options then you are free to.

Do you share these ideas with similar firms like Terasen. For example I am surprised if Terasen hasn't gone to the two month billing like you guys because it would cut down their costs and hopefully they would pass on their savings to us so we would pay less for our Terasen.

I can't speak to whether we talked to them on that particular issue, but we talk to other utilities quite widely. Terasen you may not know is owned by the same company that we are so we are sort of sister companies. We occupy separate parts of the buildings.

Are you trying to go the same way as Terasen is going? Because if you are we are going broke.

No.

Why wasn't a climbing block rate for commercial not an option?

We are not considering it at this time because currently our commercial customers are on the declining block rate so really for the short or medium term it is kind of a bitter bill to

ENVIRONICS RESEARCH GROUP

Question and Answer Transcripts - Castlegar

swallow to go to a situation where you have declining block rate with 3 tiers and suddenly have an inclining block rate. A lot of those customers have a limited ability to change how their operations work so we are walking before we can run basically. First we will flatten those rates out and then do this again and if it looks like it is warranted and we need to do that then we will look at it.

Showing graphs

How do you base the blocks _______

I will show you where that is. Here is our graph with a bunch of lines on it. I am going to break this graph down into sections on the next couple of slides and show you low consumption and high consumption. What is really telling on this graph when we are talking about the residential rates is all of these options don't produce a huge difference. At the upper end between the most extreme rates is about 9% difference for a customer in that upper consumption area. This point here is 1350 hours which is where we have set the block. That represents our median bill so half the bills we send out are lower and half are higher than that. In terms of picking a number where the block seems to be that seems reasonable. That is not to say that half are less than that dollar amount, that is number of bills. This line here is our average bill, just under 2100 kilowatt hours every couple of months.........*more explanation*

That depends on if the person has an electric furnace, their 1300 kilowatt is going to go up......

Yes. So your observation is quite correct. Your rates cannot be perfect. We are not only getting people who are inefficient, we are just getting people who are simply high users. They may have a house full of compact fluorescent lights and energy efficient stuff, but they happen to have a big house. Part of what we have to decide is it fair to penalize somebody because they are a big user as opposed to being inefficient. The rates are not perfect.

That only means they will use less of other utilities though.

If you want to think gas..............

Let me get this straight, the $24 one that is a bimonthly then I can choose to turn my lights out and I wouldn't pay as much as lets say the $32.

I am going to go ahead a slide here because we will look at the bills that are less.

If you guys were to implement the $24 bimonthly.

Are you talking about #2 or #4?

It is $24 bimonthly and then it says.......

1350 kilowatt.........

Yes. If I choose to get energy efficient stuff and insulation then my rates won't be as high, I can choose to keep my rates lower.

Through your behavior you can try to make sure all your consumption happens in the first block.

If I am paying the $32 I am set at that rate. I can choose to do lower, but I am still going to be fixed at $32 and not at $24.

Yes, but the kilowatt-hour rate drops even lower on that one. So basically what you have there is $8 differential. You have to decide if you can make up that $8 by having a rate that is slightly lower. You are paying a little bit more for a fixed charged, but your variable charge per kilowatt-hour is lower. It is going to move a little bit.

You are looking at an idea where you have control of what you can do with your home, but if you are renting you have no control over that.

Depending on your landlord and who is paying the bill. Certainly these rates are designed to do that very basic thing to make low users pay low and high users pay high, but it doesn't consider all situations and all people.

It feels like it is contradicting itself. When we started out residential weren't going to be effected and the last slide I thought it said it was so much, but if you cut back it would go up so now we are doing this.

Let me talk about the first point and by moving through the rest of the slides we will talk about the other one. When we talk about residential rates not being effected that was due to the rebalancing. That is to say none of this was happening and we were not changing the way the rates looked at all then that would be the case and we are still not talking about that class, but all the residences lumped together. The same thing applies here we are still revenue neutral on what the rates look like that is why if you put one up the other has to come down. They are not really related. The rate rebalancing deals with just the costs and whether everybody is paying their fair share in their class.

I really go for _______ and I am thinking why am I hear because I phone the electric company constantly. I ask all my friends and they say we don't even bother we just pay, but if you take that bill and follow it there are mistakes, discrepancies, it drives me nuts. I don't know if I am the only one in the world in the Kootenays that is having problems in their bill and understanding it.

Yes you are the only one having problems with their billing (laughter).

Question and Answer Transcripts - Castlegar

But the thing is there is a lot of stuff going on. You have to be very careful and read everything you get, but this seems like it is not very clear.

That is probably my fault.

What percentage of households are within that 1350?

Half of the bills we send out are higher and half are lower.

Can't make out his question.

Really what you are going to do then is set the first block higher, but what you are doing if you do that is you are giving everybody another 700 free kilowatt to do what they want so you are taking away some of the incentive to conserve. Anywhere you set it, the rate is going to change slightly because now you are going to have a higher percentage of people. Every time you raise that level you take away some of the conservation incentive.

So businesses, McDonalds bring in who knows what a year, their power bills, the more they use the cheaper it gets. The struggling family who I have to turn my baseboards on to heat my house and three kids at home I am going to get charged more for the more power I use.

We are talking about two different rates then. So first of all yes the industrial commercial customers are currently billed on a declining block, which is what we are trying to fix through this process, but we are trying to take the people such as (the lower consumption) the rates are designed to make your bills go down and to make the people at the other end who may be wasteful pick up that slack.

Don't you think people are already trying to conserve like turning off lights with what is going on in the economy right now. People are already doing that.

We think the people already doing that are going to benefit by this program.

I already do that and I haven't benefited.

I bought one of those fireplaces to try and get my gas rates down and they haven't gone down and if this implements that it is going to go up with the idea that we are paying less.......

We have a couple more slides to go through........

Correct me if I am wrong, but it seems like when we are dealing up to 1350 or up to 1500........the maximum cap between the lowest and highest billing. It is just about $20 per month.

We are not talking about huge dollars, but we are trying to have a principal discussion. This then is the slightly expanded bill for the customers using less than $200 worth of power every two months. The blue line on the top is our current rate, it is straight so under all these scenarios those customers in the lower consumption area and there is our $1350 line still up above that, these low users are paying less.

Why? Everybody should be in sync.

Everybody would pay the same if they were using the same amount of power.

But the rate should be the same.

The rates are the same. Once you go over that 1350 kilowatt it goes up, everybody's would.

You should have a questionnaire then, who has kids, single guy, basement and five kids in their house. Why is a struggling family going to pay more for family than a single guy?

Remember these are only example rates, but like I said the rates and the way we can design them are not going to be perfect so there are going to be customers in the situation where they have 5 kids, in a big house, living below the average income line, drafty house that leaks heat, they are going to probably be at that upper end and this rate is going to effect them. Dennis?

What ____________?

We are not saying we have to change to one of these, but if our customers overwhelmingly come out and say leave it alone we love it the way it is, that will resound with us as well.

This seems like a lot of work and you haven't showed a major change in the slope. There seems to be no green incentive there at all.

The change is not huge.

Contrary to what she said, I think you are trying to be a little greener, but there is no major change in the slope of those lines. There seems to be no ______ for over using.

Like I said these are four of the examples, they do keep the band fairly narrow and you are free to say you know what you are not doing enough.

You are not doing enough.

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That upper block should be twice as big as the lower one so when those guys crank up their 5000 square foot house and put their hot tubs on they really get hammered.

But really you are looking at people staying the same if you are charging more for the second block. I think we waste a lot of electricity, lights on, duh, duh, duh and I think if you actually (cough) you are paying more I think you will become more conscientious so really that is just showing you at a regular rate. If you want to save money you will conserve more.

We have a couple of different rates that are examples. We are not going to go to our death defending you. Customers that think that block differential should be bigger. If you want to change behavior make the block bigger. Put that on your forms and we will take that.

How will the block system relate to the seasonal _______ like in winter you use more than in the summer or would it be averaged on the annual consumption?

This graph is built with existing data so it takes that into account. We have looked at the monthly bills, averaged them and put them on here. Some of your bills will be higher and some lower. That is a fact. I want to speed ahead because we still have to go through the commercial stuff.............

I know my mother and I's case, our bills are the same heat wise for gas and electricity there is not that much difference, but if you are talking this scale, the people that heat their house with electricity, if it gets to 70 below they are going to be in the 2000 wattage.

They will be at the upper end for whatever months they are doing that in and your gas bill will go up as well during those months.

If you were heating with your power then you shouldn't be........

What I would say to that then is if you think that rate should be based on the way you heat your house that is valid, but _______.

Heating isn't really wasteful and yet you are being charged as a wasteful person.

It would be administratively burdensome I would imagine. Our predecessor company West Kootenay Power once upon a time had rates for electrical heated customers and it did differentiate like that. That was changed and we don't have that anymore.

It seems totally wrong.

We do have a preferred option and among these options Fortis BC preferred option is #3 with the slightly higher bimonthly rate and the as low as we can go energy rates. That is our preferred option, some of that has to do with the fixed cost recovery. The results of the cost of service study showed our residential fixed cost would be about $60 so we are not collecting anything that the study says we should collect. That is our preference, but that is why we are here.

There is no reason to have the block signs remain static throughout the year. Could you not have an alternating point where it is less in the summer and more in the winter.

That is a great thought. One we hadn't heard before, change the block size throughout the year. Absolutely. Okay so............other things that go into this mix, this gentleman asked about the advanced meters and meter reading. We did file last year an application with the utilities commission to put in place an AMI and advanced meter infrastructure or smart meter program. The utilities commission denied it. We are still hoping to get that in place within the next 5 years. The hoping is that they want BC hydro to go first and then we are to work closely with BC hydro to make sure we are putting similar technologies and infrastructure within the province to try and bring cost down for everybody, but within the next 5 years we do hope to have that. Once we have that we will have the ability to have the meters read automatically and we won't have meter readers coming around every couple of months to read the meters.

So would that lower the cost instead of making it more expensive? Would it balance out?

That is a good word when we mention the AMI program that is roughly about a 35 million dollar program, but because now that we offset a bunch of other costs such as meter reading it really doesn't have much of a rate impact at all. It is something fairly...........

So what _____ (can't make her out).

There were a lot of reasons, but a lot of it had to do with not jumping the gun, making sure the whole province was ready, working together with BC hydro. It is part of the energy plan. It is something that the government wants to see and what that will do once we get those because they do allow us ______ it will allow us to tell when you used it and then we can start talking about rates that are tied to time and the price of electricity. Once we get there that is really for us where the value is. Electricity on the market does vary with time and if we can change people's behavior so we don't have to buy electricity when it is expensive that helps everybody and brings everybody's rates down. That is something we are keen on.

If you get rid of the meter readers you also have more people unemployed again. One half fixes another.

Our situation with that is actually pretty positive because we have a core group of meter readers and they probably have 5 years notice on this coming out and a lot of them are

Question and Answer Transcripts - Castlegar

close to retirement age so if we can't do it all through attrition we are likely to find alternate ______ for all those folks.

I have heard so much that this is why people aren't going green is because of the job losses it would create.

We feel we have enough lead time and training options available and other positions coming up we likely won't see too many people affected. Time varying rates and the rates that will help us and allow us to respond to price signals effectively is what we will get out of the AMI meters.

So that ad where they say you should do your washing in the middle of the night is viable.

Yes right now if you do your washing in the middle of the night because we have a flat rate structure and there is no differential for rates unless you have a water rate it doesn't make a difference, but hopefully at some point we will. We will award customers who take those steps to bring those energy costs down.

I have been doing my laundry at 11 o'clock at night and there is no difference. Why thank you!

You are entrenching the type of behavior early that will make big rewards....

Oh yes I do all the things you tell me to do......

You are helping and the way you are helping is if you get more people doing that you are not immediately personally benefiting in a way you can see, but you are contributing to a fact that we are having to buy less power at the peak. If everybody rushed home at 6 o'clock and turned the washing machines and stoves on at 6 o'clock, you would see that and that would impact your rates directly.

If everybody didn't between 3 and 7 use any power whatsoever that would impact you guys?

That would impact our power purchase costs. We are not exposed to the spot market all that often, only for short periods, but during those periods, prices can tend to get very high. Sometimes that that costs 5 cents a kilowatt-hour is costing $200 a kilowatt-hour. When we are out there making public (cough) that is the reason.

How often do you purchase power?

A very short window just during our winter peak predominantly.

What about overall?

We have our four dams on the river and they serve about 55-60% of our energy needs and the bulk of it we have with long term power purchase contracts with entities like BC hydro, CPC. That gets us up almost to our total peak and every once in a while we see a spike. We set a peak when we had all that 40 degree weather............we are real well covered.

BC hydro purchased $1 million out of a 1/3........

I was willing to go a little off track, but now I am not comfortable.

Will that affect your rates?

All I will say about that is that we are interested in that transaction and we will be following it very closely. We do occasionally purchase from ______. Here are our conservation rates laid out 1 through 5. #1 implement the lower monthly charge and minimum bill. #2 is implement residential including block rates with the existing monthly charge and higher rates than #3, which is implement residential __ climbing block rates for a slightly higher monthly charge. Both of these in the first block would be lower a kilowatt basis charge that we charge now. #4 still a perfectly viable option if you think things are great maintain the existing rate structure. If you have any other ideas. You want us to tie the price of power to the stock market or something go ahead and suggest that.

Cory I am just going to interrupt, when you go to fill this out at the end there is another sheet in here that gives you those options one more time so when you are writing them down you make sure you have the right one.

These meters are they Canadian made?

We will go to tender for the meters once we get the program approved. There are a number of manufacturers that will be vying for that business depending on who we choose.

We are very patriotic.

I can see that. That is a good point.

As you stated earlier these options that we have won't cover all the situations that can arise. It is not going to be a perfect system regardless of which one we choose, but there could be some other things added to those things. Like in the case of the woman here and her five children and her incredible laundry bill, is there not room for some kind of service that allows for some limitation for people with large families?

Or on lower income?

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They are being penalized because they have a large family.

Apart from this and the rate design we (cough) with our power sense group working on some low-income programs. They will probably be structured like programs for helping people buy energy efficient appliances for example or go in and pick up old fridges. We are exploring a lot

I was also thinking of the home you talked about earlier this evening where somewhere purchasing who is rather wealthy has a large home and maybe there are a lot of people living there, but he has gone out of his way to have complete energy efficient stuff put in his place. I don't think he should be penalized for that as well.

Hopefully he has taken advantage of some of the power sense programs and got reimbursed in some fashion for doing some of that stuff. There is no way around it. We can't design rates that are going to perfectly apply to every situation.

Wouldn't it make more sense for business to have an inclining block and residential to have a declining for profit wise for you guys?

It doesn't make any difference profit wise to us. We are really talking about.......

It would make a huge difference if you charge McDonalds their normal rate than giving them a deal and the small guy gets more.

We would have to do another session on do utilities actually make money, which is not all that related to how much electricity will sell.

It is not fair.

If we put anybody on a new declining block rate I don't think that would sell.

The residential is facing the inclining I don't think that is fair.

That is the type of input we are looking for.

So I should be doing my laundry at work? Laughter.

What are we thinking makes sense to do to these guys?

This is really hard to say, if you are looking at lets say an auto shop that is using a fair amount of electricity at one point they are just going to pass it onto the consumer no matter which way you look at it. It just seems like we are getting bombarded from every corner.

Keep in mind then following your logic we are talking about exactly the same thing we are talking with the residential customers. The business customers use less energy, start to pay a lower rate and have a lower cost, those customers are using a lot of energy to pay more. If you are using a little bit you pay less, you use a lot you pay more. That is the basic thing we are trying to get across with the rates. Bimonthly basic charges, which are about the same as the residential rates.

Do you have any industrial or commercial customers in town who may have been enticed to the community ____________ and are there people that might pull out stakes if the ___________?

I of course find it impossible to answer that question, but I understand where it is coming from.

We still have some of the lowest prices in the world.

Whether or not the rate differential created by any of these would be sufficient to offset the rate or money it would cost somebody to pick up and move they would have to be a big user. Most of those big users are not affected by this. So we are looking at the same sort of bimonthly basic charge increase to get more of those costs back from these guys. Increase of their demand component and the demand component has a piece of that fixed cost element in it as well. If we do that so remember every time we increase the fixed portion of the charges the variable portion goes down so if we did that then their energy rate would go down at all levels. The general service 20 customers that right now are on an inclining block rate we are proposing to flatten that. They would have one rate across the board for everything. The GS 21 customers that are currently on a 3-tier rate, we are proposing to drop them down to a 2-tier rate. Do you think that is okay? Then put that down. We are going to slice this up a little bit like we did with the residential guys and I am not going to spend a lot of time on these. Looks like there are two lines when there are four rates because the rates are the same for these two classes. You can see that our current rate is on the top and new rate is on the bottom. The important thing we look at here is the low consumption, which is 95% of those small businesses so we are talking about impact on business, 95% of those GS customers fall into this graph and their rates would be lower. We have 40% of our GS 21 bills who fall into this chart and their rates would be lower. We have a fairly significant portion of our small customer base that are currently relatively low users of energy and their rates would go down. As we get into the medium consumption now you can see that our current GS 21 rate is here and as the consumption goes up we are looking at bills that are approaching $12,000 so this is 5% of the remaining small businesses and the other 55% of the GS 21 bills are also on here so the rates are starting to go up a little bit. Then we get up to the real high consumers, 0.1% of the GS 20 customers probably 1 guy who shouldn't be on this rate anyway. He is down here and paying quite a bit more than he was before as a real high user. The GS 21 customers at the upper end here now start to pay significantly more. The high uses pay more and the low uses pay less. That is the impact that these conservation rates are meant to have. Again not perfect, but overall should have a desired effect.

Summary.

Question and Answer Transcripts - Castlegar

We just have a couple of slides left we are doing alright. What happens now? So we have been out for the last couple of months doing presentations like this and getting in put from people, we have posted our cost of service study on our website, we did that in June. We are taking written feedback from any and all comers including what we have done here tonight up until the 28th of this month. What we do with all that information is put that in an application to the BC utilities commission based on a number of factors, customer input, which is one. We will likely make some recommendations on what we think should happen. That gets filed with the utilities commission at the end of September and that begins again a whole regulatory process, which in all likelihood before we get a decision from the commission on what we are to do could be 12 months, 18 months, it is a lengthy process.

How much did this cost to do this?

It is not cheap. There are lawyers involved.

If you produce _________ electricity for 5 cents why can't you sell it to everybody for 6 cents? If you make $10,000 you pay 10% on your tax. If you make a million dollars you pay 10% (cough). Why don't you have a flat rate price?

I am assuming you mean for everybody.

Electricity for a unified price for everybody.

The reason it is not structured like that……it goes back to at the beginning when we talked about cost of service. We are trying to match our revenues from each customer groups to the cost

It still costs a certain amount of money to produce electricity.

To produce or acquire it yes, but to deliver it to the different types of customers no. There is more to the electricity than spilling the water through the turbines. We have other things involved.

That is a basic customer charge, all included in that.

A portion of it yes, but because some of the customer groups like the transmission customers use the transmission system to a greater extent than the residential customers. So yes we have some of those fixed charges and we divide them up as well. If you are a transmission customer you may absorb more of that fixed cost that you would a residential customer. That is the whole premise behind doing the cost of service so we don't charge everybody exactly the same.

A lot of those lines have been paid for time and time again.

But we keep on maintaining then and building new ones.

We already have government regulations, why don't we simply ________?

I don't think I want to see that.

Why would a restaurant right beside a residential house using the same transmission why should they pay any different per kilowatt-hour than residents. Cost of delivery is the same.

We are not talking about that one hour and one restaurant and how much it costs to serve that one hour and restaurant we are talking about how much it serves the class that contains that one house and the class that contains that restaurant. Try to imagine it this way. You have 50,000 houses and they are all spread all over the place. We don't look individually where all those houses are and calculate what it costs to serve them. We lump them altogether and make some assumptions in the model and we determine what we think it costs to serve the whole class. That is really the only way we can do it. If we could go to each individual meter and realistically figure out exactly what it costs to generate, deliver and bill power for that specific point we may be able to design rates that everybody pay and paid a different cost. At some level we have to lump them together.

You are asking us to give us answers for stuff that only you guys know the answers to. We don't know what it costs to get electricity.

We are not asking you to delve into that. We are dealing with higher-level concepts of the rebalancing and rate design.

I feel very inadequate, I don't know a lot of the stuff.

I can appreciate that. The cost of service process itself is pretty complicated and all we have given you is the results. I can understand where you are coming from. Try to give us the best answers you can with the knowledge you have tonight. That is all you can do and all we can expect.

I am just curious, how much energy is lost on delivery with the delivery method of the power, is that being looked into?

Our system wide losses, which include everything from line losses, lost in transmission and for those individuals that have farming operations and may or may not be paying for their electricity, system wide is about 9%.

I am going back to the _________ restaurant next door. The restaurant that is way in the boonies, they pay yearly because I am one of it. Our business is way in the business and for Fortis to come over there and put a pole in there it is cost you $100 in town, $1000 in the boonies, so I don't buy that.

Question and Answer Transcripts - Castlegar

The money an individual pays to build an extension to their place of business is ___ by the customer but it doesn't go into our rate base that we earn rates on.

I put my own pole in for a tenth of the price.

I am just talking about how the rates are designed. We collect our revenue based on what is in our rate base. Basically how much money we have invested in the system. When you invest money in the system we don't get to put that in our rate base. We don't get to incorporate that in the rates.

But I am being charged for it. I paid for it.

Yes. If you built that line that is 10 km long and another 500 people signed up you would get 500 portions of that line back as well. You are being charged that, lets take it away from you for a minute, if a customer wants to build that line because that is where they want to be, yes they have to pay for that line because at that point it is not really fair for a single customer who wants something dedicated just for them to expect everybody else to pay for it.

If you have a set rate, whatever the household pays the business pays. The business pays more so you get more revenue from them.

I am sorry I am missing........we are not connecting here on some level so lets maybe we can work on it after.

What would it cost to implement a rate change like this?

Probably looking at $200,000.

Here is what I want to do now is get the last slide up, this is our information and I want to wrap it up at this point and get Michelle to come up and make sure we get the surveys done and collected.

Is it advantageous to change it?

In what sense?

It is going to cost x amount of dollars to change so..............

I hate standing up here and acting like I am cryptic or something, but the only thing I can say is............

Can't we keep it the same.

It is advantageous if you accept the goals of conservation and if you think that what we are doing tonight is going to get us there.

OK.

I think the only way it is going to be advantageous is if you go to the smart meters.

So one of the options is and it is on the sheet is don't do anything now and wait to get the smart meters and do it then.

A month and a half ago that was up for an option.

Are we going to change again once the smart meters come in. Are we going to spend another couple of hundred thousand dollars to change?

That is built into the smart meters.

Michelle. Before Michelle gets up here and gives you more instructions I just want to thank you again for all coming and asking good questions.

I want you to go home and tell my wife when to wash the clothes (laughter).

You give me your email address, I am not going to your house.

Nobody tells his wife anything (laughter).

The only instruction I have at this point is to please complete the questionnaire. I want to bring two things to your attention, this blue sheet at the back, some definitions on there and summary on the various options you can see if you need to refer back to them and question 8 asks you to rank the options. Please note that your first choice you will number number 1 and your least preferred choice will be 4. Thank you.

ENVIRONICS RESEARCH GROUP

Question and Answer Transcripts - Kelowna

ENVIRONICS WEST
Focus Group Transcription

Fortis Focus Group
August 18, 2009 - Kelowna

EXPLANATION OF HOW THE MEETING IS GOING TO WORK, INTRODUCTION OF FACILITATORS AND THEIR FUNCTION IN THIS PROJECT.

EXPLANATION OF WORKSHOP GUIDELINES.

GOING OVER AGENDA FOR THE DISCUSSION.

Explanation

You talk about recovering the cost of providing the service to these different classes of customers and that is the cost recovery that is your break even point. What is the profit margin?

The total cost of running a utility, which in utility terms we call it a revenue requirement, which is something we go before the utilities commission every year to have approved and it is on the basis of the revenue requirement that are rates are set to recover that and that revenue requirement contains a portion that is the rate of return for our shareholder. So when we talk about the total cost of running utilities that includes that piece. It is a percentage set by the utilities commission. It is our allowable rate of return.

I thought you already had the commercial rate different than the residential rate, more expensive.

Exactly and that is exactly why because each of these different groups costs differently to serve so they have different rates.

Yes but don't you already know that?

We do. That is what we are here to talk about. *More explanation.*

What percentage, like I am a farmer, I am paying for irrigation and it looks like I am getting a good deal.

I am glad you see it that way.

I am only using 2% of the electricity. The residents are using........

That is factored into the model. When we talk about the rebalancing where this is leading you don't have to do very much here to cause a big effect because of the ratio of how much that class as a whole is using.

Revenue to cost. Revenue ________. Cost to provide everything as you say is all broken down. Does that cost also include the percentage that goes to your investors?

Yes.

OK thank you.

That is all included in the revenue requirement, which is the big number we start with. *More explanation.*

Was data gathered before recession or no?

The data is historical for the most part. The load projections that form part of..........I know where you are going with it, but the data we collect is relevant and based on historical cost of utility infrastructure so that stuff doesn't really change. Recession doesn't impact us a whole bunch.

The industrial transmission pay 62%, how do they get that percentage? 40% less than what a normal person is paying.

What happens when you do the study is you take the costs and you allocate them out based on what you determine the costs that they are driving are. That customer group uses are high voltage system and creates much higher demand on our system and causes cost in different ways than residential customers so when you allocate the costs they may get a big chunk of something that another group doesn't get, which causes their percentage to fall.

But it costs more to provide, why wouldn't the cost go up?

What we are talking about is cost versus revenue so we have determined what the cost is now. We are looking at the rates we already have in place and determining whether they are sufficient to cover the costs. What we are finding is the rates we have now are really not sufficient to cover the costs.

That is for that particular group. If the residential ______ that should remain the same.

Yes. When we look at rebalancing, if you are already 100% we really don't need to do anything to you.

How do we know that your meters are true (laughter)?

Our meters are governed by measurement Canada and every year we have to pull a percentage of our meters from service in a batch and have them tested and verify they are running accurately. That goes on a 7 year rotating cycle. We pull meters every year, thousands of them and have them checked and very few of them are ever found to be bad

Question and Answer Transcripts - Kelowna

Is that the same as the gas pumps at Petro Canada?

Yes those as well. Oddly enough of any of the ones that typically are found to be running off they are usually always airing in the customer's favor.

Prove it.

So then at our residential home every 7 years have our meters tested.

They are pulling a batch so all the meters purchased at the same time as your meter, a sample will be taken. We don't take every meter off, but we sample a batch of them and test them.

So if we thought there was a problem you guys would come out and test it anyways.

If you think there is a problem with your meter there is actually a process that you can request to have your meter pulled. You phone up and say I think my meter is wonky, you are willing to pay $50 because you are confident your meter is wonky, we have it tested and if you are right you get your $50 and if not it goes to measurement Canada.

So they can test a meter at your house? If a guy comes along and says I tested your meter and your meter is fine that is hooie. If he didn't take it anywhere.

In order to do a real test on the meter it has to be sent away, opened up, tested properly and resealed and sent back to the population. This is where we talk about the reasonable thing to do with rate rebalancing.............

That would be every year?

That would be every year until we got there.

That is a long time.

In terms of time we can get most classes to 100% within about five years. The four really big outliers don't quite make it when we run most of the scenarios associated with this, but they get pretty close. Likely what would happen is you would go back three years and look at it and see how you are progressing and if you have to make adjustments you would, but it looks like in about five years you could fix that. What happens then if you get additional revenue from those groups you have been collecting on you can take all that money and give it to the classes that you have been over collecting on to help mitigate any rate increases or actually bring rates down if you are looking at a small increase in any one year.

At the same kind of percentage rate? Like if they are up 40% that is going to take a long time for those 5% to cover that or you ________.

No it comes down. You only have so much revenue to play with so the way it actually works if you get a bunch extra from here that is all you have got so you can't fix all this in one year because you might not have enough revenue to do it so you have to phase in.

So those customers who have about 100% are they going to have a decrease in their percentage they are paying?

What happens under this scenario, we will back up, we have got what we would be proposing to do under that scenario would be to take a customer such as industrial transmission who is at 62%, they are the lowest so they are going to get 5% every year for five years. Residential customers would not likely get anything because they are already at essentially 100%.

Once again farmers are 4% of the population, residential is using how much of the electricity?

But they are covering the cost to provide them with that electricity.

If you guys want to eat you are going to have pay for the irrigation.

The last time we did this was 1997 and things weren't as far off as they are now, but at that time irrigation was low again and we had a negotiated settlement of the rebalancing in that year and it was simply decided that irrigation customers would not be ______ and really what we are here to get is input like that so when you are filling out your form if you say you know what I think the concept is fairly sound, but I think irrigation customers maybe should be brought up to 100% because they are the bread basket.........

Well you say we are 4% of the population, if the population doesn't want to support the farmers we are out numbered.

This is a purely mathematical exercise and if you feel it is appropriate to bring social aspects into it then that is something that can be considered and like I said last time it was.

Could you speak to who is in each category? Industrial primary is?

Industrial primary is our big customers, sawmills, breweries that type.

What is the 30 and the 31?

The distinction between 30 and 31 is simply the voltage they receive their power at. These guys are industrial transmission they receive their power at 60,000 V. They own their own transformation without getting too overly technical. They are distinct from the other class and they cost differently.

Question and Answer Transcripts - Kelowna

Industrial transmission is the bigger industrial enterprises?

They are not necessarily bigger, but they are distinct because they are getting their feed directly off the largest pipes we have got. We don't have to provide transformation to lower voltages to those guys so their cost is different on utility than others.

What voltage is industrial primary supplied at?

Typically 13,000.

So the residents are going to vote in favor of this because there will be no change. Industrial will be in favor of it because they will get a cut.

There is no doubt that groups will look at this and jump up and down and other ones that are going to jump up and down in a different way. There are interests here for sure.

The lighting is street lighting?

Yes. Some people have dusk to dawn lights on their homes that may fall into that category. I think we were saying that these guys are going to go up and I think to your question these guys yes they are going to see decrease, not necessarily a decrease in their overall rate because this is just rate rebalancing. If you want to assume that we are going to have a 5% general rate increase and they were going to get an offsetting minus 5% rebalancing aspect to it then in that year when some got 5% they might get nothing.

Are you taking into account the HST that is coming next June?

HST is separate from this. It will affect power bills though.

What were the percentages in 1997 when you did this the last time?

Residential was a little bit lower. A lot of the other ones were closer to 100 than this. I don't know exactly. At the time in 1997 residential was the one out of whack the most we were ordered to increase residential ________

Although the increase will affect any customer because we use industry, lighting, everything so it doesn't matter what class we are, we are still getting the increase through the customer.

There is a lot of discussion that could be had about what is going to happen with the businesses that see a rate increase and what they are going to do to their prices.

Why in your opinion have these numbers been allowed to be so different? What has led to these discrepancies?

There are two main reasons for that. One is structural, it is the physical nature of our system. We have spent about one hundred million dollars a year over the last year on the infrastructure, building new lines, upgrading power plants. Most of that money has gone into the transmission system, the back bone and to a certain extent into the generation so those customers that are most affected by costs associated with generation and transmission see their numbers go down because they get allocated those costs on a higher basis or ratio than somebody else.

Shouldn't they be paying more for that though? That is an improvement for their service.

That is what is driving part of these numbers yes. Now we are assuming those customers that increased demand on our transmission system are going to be paying a higher percentage of the demand and there was a second half to that question, which I am trying to remember. Oh yes. The second part is the model that was used has some assumptions in it that differ from the ones we used in 1997 and that has created some of that spread as well.

What concerns me is once you get all the numbers in line and some big industrial saw mill go to you guys and say you have to reduce our rates or we are going to lay off or shut down, how often does that happen? Because I can't go to..............

Neither can the industrial customers without involving the BC utilities commission and a public process. The rates.............

Has it been done?

Yes we hear from industrial customers all the time saying what you said and they would like a break on their rates and we have to say we have cost driven rates and they are the same for everybody in the class. Anything like that has to go through the commission. We are not at liberty to change rates at hawk for any group based on what we want to do. It is very controlled.

You have 8 different rates? Each paying a different cost or are some of them paying the same cost?

All of these classes are distinct rates. We currently have a lighting rate that is x cents per kh and irrigation rate. The only two that would be the same would be BC hydro wholesale and municipal wholesale. We do have a couple of areas that are in BC hydro's service area that they don't have facilities to feed so we supply them on a wholesale basis.

The municipal wholesale, that is for say the city of Penticton to supply power to residents?

________.

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Just residents?

And their business community too. Anybody within the city of Penticton. But don't confuse the city of Penticton's residential customers with ours. These are only people who receive Fortis BC bills.

So regional district or non-municipal. What I am wondering is, is municipal wholesale buying power at a lower cost and reselling it to their residential clients or customers.

Are they getting it less than what we pay for it?

Sure they are buying it at wholesale. Then they turn around and retail it to their customers at roughly the same rates.

So there is the city buying power at 68%?

No. That is the cost and how it relates to the revenue. It is not that they are getting a discount on the power they are buying. All this is saying is we have figured out their cost for us to serve them and they are only paying 60% of it, but it doesn't relate to what we charge.

When you guys have excess electricity you sell it. Do those numbers go back into this?

Yes we don't have excess electricity.

You guys don't sell any power?

No.

Are you buying power on a regular basis?

Yes. Lets hang onto that for a second.

Other than the residential group have you surveyed these other groups about rebalancing their rates. If we are $1 for $1.

We have met with every one of our municipal customers separately. I don't know who showed up tonight, but this was a random sample of customers, but targeted to each group so we could get some small business owners in as well. We are being as inclusive as we can in our consultation.

The general service category to me seems to be unfair. I think it should be divided more. You are saying that general service includes restaurants and small businesses…...

I am going to talk about the general service categories when we get into rate design, whether we should differentiate them.

We are a private reseller. Where do we fall in there?

Like a trailer park?

No we are a company that has tenants. We buy electricity from you and sell it to them. We don't make any money on it.

If you are making money on it you would be a utility and then you would be regulated and you probably wouldn't like that too much. The odds are you are in here.

What about a winery?

In here as well. Just quickly before we move on, we have four generating plants on the Kootenay river generating electricity for us. They supply about 55% of the energy we need for our customers so we don't have any left over. We make up the difference primarily through long term purchase agreements with BC hydro, Columbia power corporation. At the very margins, peaks in the summer and winter we may be out in the general power market buying small amounts. We will talk in rate design how we would like to get out of that and lower that because that peak power is really expensive. We don't want to be buying that stuff.

Do you have any coal or gas fired generators?

No. All hydro.

Do you have any more coming on stream in the future?

Next month we are going to be filing a resource plan, which talks about how we are going to meet our needs for the next 20 years. There are a number of scenarios in there. Not a lot of opportunity in the province to build big hydro anymore. Not really going to be allowed to build it. We have to look at other means. Renewables. The man site management like the power sense program play a big role in that. Lets talk about rate design now. We are here after so if you have more questions before you fill out your things for personal interest, feel free to get us afterwards and we can talk about that. We are going to leave where we are talking about customer groups as a whole class and moving to where we are talking about individual bills and what they look like for you or your business and how those are structured. We are going to talk a little bit about the provincial policy and legislation that is driving this. Principles of rate design then we will look at some options and it is those options primarily that we are really interested in your

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input on. Again this has no effect on your bottom line, but it does with what we are trying to achieve, some conservation goals primarily through this stuff. We will put options up on here, you can like one of them, hate all of them, suggest something different. All we want is a sense of how you feel about it. *Explanation.*

I hate to ask this, but those fixed costs you are talking you send a bill out, has the electronic billing system saved you money?

Yes it saves money. Those are ways we have tried to bring those fixed costs down and there is an environmental component to that too of course. I don't work directly in the customer service part so I don't know what our uptake percentage has been on that.

I am just wondering if you have looked at all that and those initiatives and how they have affecting things over since 1997.

I don't think we have examined them that closely to know how it has changed over the last 12-13 years. All those changes are incorporated into the model. We know where we are today. We are doing things to get those costs down.

As a residential customer has there been any consideration done to extending the billing period from the two months it goes through now to say four months or six months so you would not have to send the meter reader out every two months and cut down on that cost?

Yes and no. Typically when we talk about providing metering information to people we are talking about the other way. We are trying to give people more information so they can make more decisions about it. We are looking at initiatives and we will get to one at a meter where we talk about meter reading costs specifically.

I think it something like $11 a month for the basic charge, about $22 every time I get my residential.....if you were doing that every four months can you not cut back on that charge because you don't have to send a reader out every two months and you don't have to send me a bill every two months and I have no problem with paying it on a four month basis.

That is an individual choice. What we hear predominantly loud and clearly from customers if that they don't like us doing that. We bill two months now and people get upset if we estimate in between.

Terrison does that right now and it is a pain in the back side every month when I receive my estimated billing that 1-1/2 times what I used. I don't have bank stamped across my forehead. I cannot pay that estimated billing and I phone my meter reading in and they have to go through all the paper work and computer generated process to reduce my billing because they have over estimated in my account.

That happens. The short answer to your question is no we haven't considered that and the other half is we could consider that. Generally speaking you have to look at people who are getting a bill every month for $100, but if they get a bill at the end of six months that is $600 that might be tough.

Same thing, people have to consider that they are going to have that bill and save the money.

Talking at once.

I just don't want the basic charge of $24 every two months.

We are going to talk about basic charge in great detail. Moving down to the third one, rates should be simple........*explanation.*

When you get condo developments and they are all individual meters do you guys have an electronic reading or do you send somebody there to read each meter?

We can do both. That is what the last one is getting at. One of the restrictions we have when we are talking about rate stuff is the meters we have on houses right now are pretty dumb. All they really tell us is how much you have used between point A and B. We go one month and it says 10 and later it says 20 and somewhere in between there you used 10. Point to point consumption. We are hoping to have an electronic meter system in place, which we call AMI (advanced meter infrastructure) something we will be applying for shortly and hope to have in wide scale used across the entire customer base within the next five years. At that point we would be able to do all the time based rates, time of use based rates.

So the meter would tell you when we are consuming most of our electricity.

What that allows us to do is allows us to say if we are on the market buying power and it is really expensive between 5 and 7 pm we can design a rate that rewards you for using it before that or penalizes you for using it between 5 and 7. That is helpful to the utility because that brings our overall costs down.

What is the relevance of what time you use your electricity?

Because our peak and a peak for most utilities is when everybody gets home from work from 5-7 and crank on the stove, there is a big concentration of energy used right then. If you have to go to the market, supply and demand is when everybody is using power at the same time, the price is higher. There is one in the morning, everybody gets up and gets ready for work and one when everybody gets home. We would like to stretch that out and the impact is lower.

I can't do laundry if I am not at home. Unless you design a washer that comes on automatically.

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So you are only home from 5-7?

I run out of gas some time in the evening.

There are a lot of dishwashers that have timing features available. That is what we talk about when we encourage people to make an investment in something like that and not following through on it long term. These meters don't need meter readers to read them. They are all read electronically.

So over long term it will be cost effective to switch to those meters and make people ________.

That program is about $35 million dollars.

Exactly that is a lot of money.

But our meter reading costs are very significant and over the life of that project it is actually........if everybody did what that project allows us to do with our rates it would be a decrease over the end of the life of the project.

Why don't they have a system with some kind of digital meter reading that goes into a system.

That is what AMI system allows us to do. Smart meters. *More explanation – net metering.*

When did Fortis come out with that? I haven't seen anything with regards to solar generation back into the grid.

That program was just approved about two weeks ago.

Solar generation is a DC power source so how do you manage to revert that back into an AC form that would subsidize the power Fortis provides to residential customers.

With an inverter which is part of the customers system. The point is we have this system in place and it allows people to offset their consumption if they want to invest in a generation program. It is really only designed to help people offset their own consumption as opposed to being a big generator of any kind. If you have excess we buy that from you.

What percentage do you pay back?

Exactly what we charge. Your retail rate for it...........

Because Fortis now owns Terrace why do we have two meter readers. About a month and a half ago we had Terrace and Fortis on our street on the same day. It is the same company why do two guys going around.

Part of the AMI project looks at those synergies that might be available. There are a number of reasons there are still two. We will look at as part of the AMI advantages we can take. Urban and rural rates................

Can't make out his question.

How many meter readers are employed here in Kelowna?

I don't know I am from Trail. I am looking for a house because I am moving here. Anybody have a house for sale? Let me finish the slide then you can put your hand down and you won't get tired.....

That would be good for the irrigation people. We only bill for six months of the year.

Then you go on the other rate and billed on the general service rate the rest of the year.

We don't use electricity for six months.

But you still have wires coming there. There are a lot of different things we can talk about.

Have you ever done a study of people who rent and don't rent. I rent and the person next door to me rents from the same people, but we use a lot of electricity because it is not insulted and he has no intention of doing it and we have no intention of doing it because we rent.

That is one of the factors when we talk about how we design rates and the impact on different people and whether or not it is inheritantly fair and we recognize that and we are going to talk about this. We haven't done studies we don't have rate differentiation based on ownership versus rental. If that is something people think we should have we could look at that. Part of what we look at with the rates, is by taking those people using large amounts of electricity and make them pay more. The people using less pay less. I suppose if your landlord is wasteful like that and doesn't care then the rates should impact accordingly.

But I am paying for it so it impacts me.

It is multiunit dwellings and rental situations are very hard to address in rate design. During regulatory processes such the one we will go through on this it comes up for sure. We are going to talk about residential rate options...............

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That would be an incentive for people to reduce their consumption.

The thinking on this one anytime people advocate for reducing the basic monthly charge is that it shifts a higher proportion of the bill directly to energy use therefore you have more incentive to control the number of kh you are using. The lower you bring it the more control you have. So some people advocate quite strongly for it. Again as a utility we like to make sure we are getting some of our fixed costs back from that.

Do you have a figure?

About $60 out of that cost of service model for residential bimonthly.

Are you considering charging everybody $60?

Not $60.

Why would you be losing money if you increased the rates if you decrease the basic service charge?

We are not. We are affecting individual customers.

But you just said that idea isn't really popular with you guys because you like to cover your basic costs.

We would cover it, but it is an issue of certainty and where the money comes from. It is almost like your basic thing you like to get your fixed costs through a fixed charge and your variable costs through variable charge.

If you reverse that and made $50 – would that be the charge and the power would go down?

Yes.

Do employees at Fortis get a better rate than any other residential?

No.

No employee incentive program?

No. Once upon a time that existed, but it doesn't anymore.

So over 1300 KW would take you to the second block?

Yes. The third option would be a slight increase in the bimonthly customer charge..........

That graph doesn't show that. It is basically showing the same......

I am going to blow it up for you in a minute and you will see it. It will show that.

I don't even know what 1350 kw is? Is that a family of four in a normal home?

Our average KWH consumption, the average bill is about 2100. So whatever you would consider to be an average family living in an average house would use about 2000 KWH. 1000 KWH a month is pretty average.

If you wanted to drop your usage by say 500 KW what it would take to reduce your consumption by that much?

A lot of sweaters.

It is going to be behavior or equipment. You can change your behavior or put in more energy efficient.

If a family of two people have that kind of bill ($400/every two months) who would have a $200 bimonthly bill?

This is one of the things we want to talk about a little bit. If we flip this over and look at the other end of the graph. So customers with bills above $200.............

What would you change the monthly fee to if you lower the rates of the power instead of the $24 it is now?

We can't lower the KWH charge and lower, you can't do both. In any of these scenarios where we lower the rate, this one we increase it to $32 to see your rates drop to 5.9 and 8.3 as opposed to 7.5. If you put that right up to recover our full fixed costs that the study tells us it is $60 these are going to be significantly lower. It is really how you collect it and whether or not you think doing any one of these things encourages conservation in some fashion.

If a household was using say 2700 KW bimonthly, using the 32 bimonthly fixed charge with the lower for the first block and the higher, it would pretty near average out what we are paying now not?

It is slightly above. Close. We had a fellow in the session last night in Castlegar that said I like this idea I am all about these residential including block rates, but $20 at this end doesn't do it for me. I think you should put this one way up and this one down to make an impact and somebody on the other end said look I am a single mother with four kids and I can't do anything about my consumption so I don't like it. Those are both valid arguments.

We have two forced air electric furnaces in our house. Our winter bill is fairly high $500/$600 dollars. Summer bill is $150, but over a 20 year period we have gone from

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on an annual basis of about $900 20 years ago to this year is going to be pushing very hard to $1600. That is not a big increase, $35 a year, but my concern is I like the idea of the higher monthly rate, but maybe end up costing us more in the winter, but we are not going to get an offset in the summer.

Yes depending on the characteristics of your bill that might happen. Depends on how you set the rate. If you set that high block compared to the low block then you are going to pay more here. Like I said it is not perfect.

Is one of your goals to reduce the total amount of electricity used by all your customers?

Yes.

Then user pay systems, which is what this is all about, how are you going to build into your system that the rich don't care whether they are residential customers, businesses who make insane amounts of money. How will this system pay discourage or bring down the overall use when we know there are going to be abusers that don't care what the cost is.

I think you are always going to have those outliers that you are not going to be able to do anything about, but our hope is overall that if you take that whole rate class and try to put some incentive in for some of them to bring their usage down they will do that. All those points you are bringing up are good. We are not overly married to any of those rates, but we are trying to get impact and feeling from everybody.

What percentage of savings do you hope to appreciate from AMI from your residential customers?

I won't be able to tell you that until we write the application. Anecdotally we have seen, there was actually a situation in Ontario by simply handing out fridge magnets and telling them they should use less energy at certain times they saw about 7% decrease in consumption by doing that. What these things allow you to do is connect the home directly to the meter that tells you what you are using and when, people pay attention and especially if it is tied to some sort of rate incentive, people's behavior will change.

There is a little red light or alarm that goes off.

This really helps us to address what is our concern as a utility is that we have that deficit of capacity and energy that we want to reduce and if we can get all of our customers to do that _____ it does drive costs down.

What about putting a meter inside the house? Who wants to go outside the house?

It is tied to an indoor display. You don't have to go outside in the freezing cold. These are the options they are in the same order as in your thing so I won't go through them all.

From the conservation side of things, how much more efficient are the little ____ coil light bulbs?

About 90 – 92% more efficient, plus they last a lot longer.

On a general 2200 sq. ft. house, how much difference if you converted all your bulbs to CFCs.

Lets talk about that after. They use only 8-10% of the power than the regular ones do.

What about the recycling?

You will see rebates for mercury..............we will talk about the general service rates before Jody comes in and yanks me out of here.

They get priority?

They don't get priority, but we make sure that if that group of customers is requiring us to build our system to a certain size to accommodate it that they are the ones paying for it.

They start the mill at 4 o'clock in the morning when everybody else is sleeping.

Most of them don't, but we do encourage soft starts and ways for them to reduce their peak. This is an example of the declining block rate.........

___ what the KWH cost is to start?

I believe it is about 8-1/2 cents in the first block, somewhere around 6-1/2 in the second block and 5-1/2 in the third block. They are in that range.

Will the flat rate stay ________

The flat rate is lower overall because of the increase in the other ones. I could get that one for you, but I can't remember exactly what it is.

Question on the general service rates. I have a commercial account with Fortis and I am quoted a KDA rating on my bill. How does that affect the number of KW that are used.

It doesn't really. That is the measure of your peak demand at any one time in the system. Like a point where you fire up your biggest motor or whatever is driving your demand. KWH is more a trickle or usage over time.

Am I billed based on the KDA?

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Yes. You will see a charge on there so many KDA at $5 and that is a one time charge. It only happens once during the month. This is what happens to the general service customers under that scenario............

Does that represent the 5% increase?

This is independent of that rate rebalancing we were talking about earlier.

That looks like a huge impact that would have on those businesses.

We are talking about, these are pretty big when you get out to here. We only have about 1% of our customers left by the time you get out to here, but you are talking about somebody using 134,000 KWH at a rate differential of about $2000.

Can you give an example of a business that would fall into that?

That is likely going to be at that range, small manufacturing plant who is using a lot of KWH, probably running 20 or 24 hours a day. This is not a corner store or McDonalds once you get up into here, you are talking larger businesses. Again they may not be doing something that is wasteful, just using a lot of power. That is something we need to consider. Once you get up into the high consumption we have in this whole range about 5% of our GS 20 customers, which are the slightly larger customers. Up in here at a million and a half KWH and I don't know who this is then you see a significant spread. Once up into here we only have 1 customer or something. Probably neither of these customers should be on that rate, they probably should be on a different rate by the time they get _________. There is a bit of a summary and this will be on your package.

________ comparing one group to another and how you are going to bill, but what is really going to happen across the board the price of electricity is going to go up for everybody.

No these are all taking the same amount of revenue within these customer groups and collecting them differently. There is no change in the overall revenue.

The price of electricity is not going up for everybody across the board?

Not as a result of this. Whether or not the industry or the costs outside of this are going to change. The trend is for increasing prices in just about everything, but that is not related to what we are talking about here.

That is what I mean. The real issue is that the price of electricity is going to go up.

The real issue is that the price of electricity is going up. I don't want to call that the real issue in this forum because what we are really talking about is this. We are all concerned about the fact that prices are going up for just about everything.

What I hear you saying Cory is you are playing with numbers, playing with the basic charge versus the cost of the electricity, whether breaking it into blocks or whether it is a flat rate. The basic concept is my associate here is saying is the rates are going to go up.

But the rates are going to go up and historically they have shown an upward pressure that they are going to rise, but this is going to apply whether they are down here or up here. This is independent of that.

This is to take your mind off of that.

It is a revenue neutral thing to us, but we are trying to create some rates that promote efficiency and conservation and the only way we can do that is to juggle the components we use to bill. Regardless of whether or not you want to talk about general pressure on rates, that is not really relevant to this discussion. That is the general service piece. That is also in your packages.

Feedback from?

We are talking about anybody that wants to provide any additional feedback, ideas, comment or anything else prior to the application being filed can put it in an email, letter, however and do that.

How long ago did you start doing these?

We started in May just talking about the cost of service then we were back out in June talking about rate rebalancing and rate design. This is the last session now. You are getting less time to react than anybody else. We started public consultation in May.

Sorry something about correspondence being sent could not make him out.

Not at this point. Until the process becomes formal and it is actually an application before the commission you can't register or send anything in that pertains to this to them. This is for if you have a comment you want included in the application.

This is to work you guys up so you don't do the wrong thing.....

Once it goes to BCUC then you can _______.

You can register. Make sure everybody has the information you need to fill out the questionnaires. Thanks a lot.

Cory on behalf of everybody in the room thank you very much to Fortis for allowing us the opportunity to partake in this.

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