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January 18, 2010

Via Email
Original via mail

Ms. Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: ***FortisBC Inc. ("FortisBC") 2009 Rate Design Application Project No. 3698564 - Responses to Information Requests***

Please find attached FortisBC's response to Information Requests from the British Columbia Utilities Commission ("Commission"), British Columbia Old Age Pensioners' Association, British Columbia Municipal Electrical Utilities, Zellstoff Celgar Ltd., International Forest Products, the Okanagan Environmental Industry Alliance et al., Roxul Inc., Mr. Andy Shadrack, and Mr. Alan Wait.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

1.0 Reference: Exhibit B-1, Application, p. 7

As noted on page 7 of the application, the Negotiated Settlement approved by Order G-193-08 states that:

"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."

Also on page 7, the application states that this directive is considered and incorporated into the Rate Design Application and is addressed in a later section. Later sections of the application appear only to discuss Rate Schedule 95, approved by Order G-92-09.

Q1.1 Is it FortisBC's view that Rate Schedule 95 fulfills the directive in the negotiated settlement, and that no amendments or additions to Rate Schedule 95 are required or desirable?

A1.1 FortisBC is of the opinion that Rate Schedule 95 fulfills the requirement noted above and that no further amendments or additions are necessary.

2.0 Reference: Exhibit B-1, Application, p. 8
Implementation of Rate Changes

Q2.1 Why can FortisBC not implement all or a portion of the proposed rate changes, if approved, before January 1st, 2011?

A2.1 The January 1, 2011 implementation date is based on the anticipated regulatory schedule and assumes that all changes would be made concurrently. FortisBC can implement portions of the rate changes prior to January 1, 2011 if directed to do so by the Commission.

Q2.2 Why does FortisBC not implement all, or a portion, of the proposed rate changes, if approved, before the 2010/11 winter peak demand occurs?

A2.2 FortisBC does not consider its ability to meet the 2010/2011 winter peak to be a driver of the introduction of the rate changes contained in the Application. Please see the response to BCUC IR No. 1 Q2.1.

3.0 Reference: Exhibit B-1, Application, p. 9

Approvals Sought: Wires-Based Charge

"... introduction of a wires-based charge to the Wholesale and Large General Service-Transmission TOU rates."

Q3.1 Is a wires-based charge a common feature of electric utility tariffs? What other utilities (in North America) use such a charge?

A3.1 The separation of wires and power supply charges are becoming increasingly more common, although various names apply to the charges. While FortisBC has not done a comprehensive survey of utilities using a wires charge, the following links show the use in a few representative cases.

City of Lethbridge (Alberta)

http://www.lethbridge.ca/home/City+Hall/Departments/Electric+Utility/Rates+Tariffs+and+Fees/Electric+Distribution+Tariff+%28DT%29/Distribution+Tariff.htm

PG&E (California)

http://www.pge.com/tariffs/ERS.SHTML#ERS

PacifiCorp (Oregon)

http://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Approved_Tariffs/Oregon_Price_Summary.pdf

http://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Approved_Tariffs/Rate_Schedules/Residential_Service_Delivery_Service.pdf

http://www.pacificpower.net/about/rr/ori.html

4.0 Reference: Exhibit B-1, p. 15

Summary of Rate Changes

Q4.1 Please provide a reconciliation of revenues generated through the proposed rates, fees and charges with the 2009 Revenue Requirement adjusted for the 4.6 per cent general rate increase and the BC Hydro wholesale tariff increase.

A4.1 The revenues generated through the proposed rates, as provided in the Application, incorporate the 4.6 percent adjustment and the BC Hydro wholesale tariff increase.

Q4.2 Provide a reconciliation of revenues assuming that all customers elect to receive service under an applicable time of use rate schedule.

A4.2 FortisBC does not have metering data by time of use period and therefore cannot provide revenues in the case where all customers were served on a time of use schedule.

5.0 Reference: Exhibit B-1, Executive Summary, p. 16
Changes in Timing & Structure of Rates: Coordination with AMI

"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...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."

Q5.1 What re-education will be required? What will it cost, and how have those costs been factored into the derivation of the proposed rates?

A5.1 Customers would need to be re-educated to understand that the best way to save money is no longer by reducing total consumption over the course of the month, but by conserving power at certain times of the day, week and/or year. Cost is not the primary consideration in the decision not to proceed at this time, rather, this is a potentially confusing message to send within two or three years of educating customers about inclining block rates. No cost estimates for this re-education process have been prepared and have therefore not been factored into the derivation of the proposed rates. These costs would not be expected to have any material impact on rates.

6.0 Reference: Exhibit B-1, pp. 16, 22, 24 and 55-60

Residential Rate Structure

Page 16 of the Application states:

"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."

On page 24, the Application states:

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

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.

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

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.

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."

Q6.1 When does FortisBC expect to complete the full planned implementation of AMI to residential customers?

A6.1 FortisBC currently expects to have AMI available to most residential customers by the end of 2013.

Q6.2 When does FortisBC expect to implement wide-scale time-based rates for its residential customers?

A6.2 FortisBC currently expects to be able to implement wide-scale TOU rates in 2014.

Q6.3 Can FortisBC confirm that the "rapidly increasing summer peak" (p. 5) is due largely to the growth in the air conditioning load which is in turn largely due to residential customers?

A6.3 The "rapidly increasing summer peak" is likely due at least in part to the increased use of air conditioning. It is not clear whether the use at peak is largely due to residential customers or other customer classes due to the lack of interval data for most customers.

Q6.4 Does FortisBC not believe that a residential rate having an inclining block structure implemented January 1st, 2011 would have at least some impact on consumption in the intervening period before the implementation of time-based rates and therefore meet, at least in part, Policy Action #4 of the 2007 BC Energy Plan which encourages utilities to develop new rate structures that encourage energy efficiency and conservation?

A6.4 FortisBC agrees that a residential inclining block rate would have at least some impact on residential consumption in the transition period before the implementation of time-based rates.

Q6.5 Does Fortis BC not believe that a residential rate having an inclining block structure could send appropriate price signals to its customers and in effect provide an effective method for educating customers and preparing them for the introduction of time-based rates?

A6.5 FortisBC believes that an inclining block rate structure would only send conservation price signals to customers with consumption in the second block. Any price signals arising out of an inclining block structure would not be time-based and therefore would not prepare customers to begin reducing power use at specific times and/or shifting their power use to off-peak periods.

Q6.6 Please elaborate on the comment that an inclining block rate structure requires "real-time energy consumption information to be available to customers for maximum effectiveness." What type of real-time information is required? How would real-time information provide the signals needed to customers to modify their behaviour patterns in order to reduce their cumulative energy consumption over a period of one month?

A6.6 If an inclining block customer cannot monitor cumulative energy use in "real-time" during the two month billing period, they will not know whether or not they are still in the first block of consumption, whether they are nearing the second block or whether they are already in the second block. The effect of the higher-priced second block would be most effective if the customer knew they were in it, or nearing it, rather than finding out two months after the fact that they had some consumption in the second block. FortisBC believes customers should have this information available to them in order to make informed conservation decisions.

Q6.7 What has been the impact on energy consumption by residential customers, of the introduction by BC Hydro of an inclining block rate?

A6.7 FortisBC does not have any statistics on the effectiveness of the BC Hydro inclining block rate with respect to reducing energy consumption. BC Hydro has been unable to confirm to FortisBC that there has been any significant impact.

Q6.8 What North American electric utilities have both time-of-use and inclining block rate options for their residential and general service customers?

A6.8 FortisBC is not aware of any utilities offering both options or a combined option to their residential and general service customers.

The following quote is from the Ontario Energy Board Smart Price Pilot: Final Report, July 2007 which was referenced on page 22:

"The rationale for tiered pricing was to provide a price signal to consumers to conserve until such time as smart meters are installed and TOU pricing can be applied across the province."

The reference to tiered pricing is in regards to implementing an inclining block structure whose threshold kWh and pricing are lower and higher, respectively, in the summer months than in the winter months. As well, BC Hydro introduced its Conservation Rate structure approximately one year ago, on October 1, 2008, with the knowledge that it would be required to implement AMI by the end of 2012, four years later.

Q6.9 Why does FortisBC not follow the evolution of the residential rate structure, as it is unfolding in BC Hydro's tariff?

A6.9 The reasons that FortisBC does not support an interim inclining block rate structure are summarized on pages 16-17 of the Rate Design Application ("RDA") and detailed further in Section 3 of the Application (Exhibit B-1). To reiterate, there are three main reasons:

1. The need to re-educate customers to understand the time-based pricing signals as described in the Application and in the responses to BCUC IR No. 1 Q6.4 and Q6.5.
2. The lack of real-time consumption information as described in the Application and in the response to BCUC IR No. 1 Q6.6.
3. The fact that an inclining block rate does not address the power supply issue at FortisBC, which is an increasing capacity constraint.

7.0 Reference: Exhibit B-1, p. 22

Rate Design and the 2009 Resource Plan

"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."

Q7.1 Please provide an electronic copy of the FortisBC 2009 Resource Plan.

A7.1 The requested document is available for viewing and download at:

http://www.fortisbc.com/about_fortisbc/rates/other_applications/2009_resourceplan.html

Hard copies of the 2009 Resource Plan are available upon request.

Q7.2 By referencing pages in the 2009 Resource Plan, please summarize the nature of the capacity constraints that have driven the rate design decision making process.

A7.2 FortisBC faces capacity shortfalls both in resource acquisition and its ability to deliver power under certain conditions to portions of its service area. These limitations are discussed in the 2009 Resource Plan, notably at the following points:

Beginning at Line 11, page 2,

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. The peak capacity city shortfall grows to approximately 239 MW in 2028 based on expected loads. Further, as described in Section 5.3, a peaking capacity shortfall is forecast for six months of the year in 2009, eight months of the year by 2013 and ten months of the year by 2026. The energy shortfall associated with the peak capacity gap – currently at about 18 GWh of annual requirements – will grow to approximately 131 GWh by 2028 net of demand side management ("DSM") savings.*

At page 6, line 24,

…..*the Okanagan region faces both reliability and capacity constraints within the planning period of this 2009 Resource Plan. In normal operations (all transmission elements in service) the Okanagan system is forecast to accommodate load growth until 2020. Prior to 2020, the Okanagan transmission system will no longer meet N-1 reliability when the combined Kelowna/Penticton area demand exceeds approximately 615 MW. This load level is currently forecast to be reached in about 2015.*

At page 55, lines 9 - 14,

Prior to 2020, the Okanagan transmission system will fail to meet N-1 reliability when the combined Kelowna / Penticton area demand exceeds approximately 615 MW. This load level is currently forecast to be reached in about 2015. A localized N-1 capacity violation occurs in the Kelowna area in approximately 2011/2012 as a result of insufficient transformation capacity. Finally, an N-1 capacity violation occurs throughout the Okanagan region in approximately 2016 as a result of insufficient transformation capacity at the Vaseux Lake Terminal Station.

And, at page 88, lines 16-21,

Collectively, the FortisBC Plants, the BC Hydro PPA and the Brilliant PPA provided, in 2008, about 99% of the Company's energy requirements, but only about 76% of *its peak capacity requirements. The capacity gap represents those hours during the year in which peak demand exceeds the Company's existing resources. FortisBC must address at least part of the capacity shortfall by making purchases in the short-term and spot wholesale electricity markets.*

8.0 Reference: Exhibit B-1, Rate Design Strategy, p. 22
Time-Based Rates: Reducing Peak Demand – Price Elasticity

"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."

Q8.1 Does FortisBC believe that -0.1 is a reasonable price elasticity figure for all of its customer classes? If so what is the basis for that belief? Please explain whether some classes are expected to have elasticity differing from -0.1.

A8.1 The elasticity of -0.1 is a conservative estimate and reflects the range of –0.075 to –0.15 used by BC Hydro in its 2008 Residential Inclining Block Application. Because elasticity impacts were not incorporated in this RDA, FortisBC has not conducted a comprehensive examination of appropriate elasticity rates.

Note that in designing rates, FortisBC has a set revenue requirement to collect. Any increase in one rate will lead to a decrease in another rate. The impacts of elasticity are therefore difficult to assess and must be differentiated between classes and between demand and energy to provide the true impacts of various rate changes.

9.0 Reference: Exhibit B-1, Rate Design Strategy, p. 24

Time-Based Rates: Implementation – Future Cost of Service Study

FortisBC states that, as part of the implementation strategy for time-based rates, it intends to "Submit [a] Rate Design Application supporting results of consultation and study."

Q9.1 Does FortisBC anticipate that the rate design application will contain an updated cost of service study? When does FortisBC anticipate that it will file its next Rate Design application and Cost of Service Analysis?

A9.1 Yes. Any future Rate Design Application will be supported by an updated cost of service study. FortisBC anticipates that it will likely update the 2009 COSA and RDA with the filing of the AMI Application and submit a new COSA and RDA in a further three to five years.

Q9.2 Please explain whether the implementation strategy includes an update to the Cost of Service Analysis provided with the 2009 Rate Design application.

A9.2 Please refer to the response to BCUC IR No. 1 Q9.1 above.

10.0 Reference: Exhibit B-1, Public Consultation, p. 25 and p. 28
Public Consultation: First Nations

"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);" [p. 25]

"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." [p. 28]

Q10.1 Please provide a copy of the notice(s) for the First Nations workshop, explain which media were used, and provide any distribution list that was used. (This applies only to any such information that is not already contained within the Application.)

A10.1 Attached as BCUC Appendix A10.1 are copies of notices dated June 29, 2009, which included an invitation for public Rate Design open houses as well as a First Nations specific workshop, which was proposed to review the COSA and present rate design options for discussion. The letters were sent to Chiefs of the Bands and Nations. This distribution followed the stakeholder list as outlined in Appendix I, page 7 of the Application (Exhibit B-1), and also included the Grand Chief Stewart Philip at Okanagan Nation Alliance and Chief Sophie Pierre at the Ktunaxa Nation (Exhibit B-1).

Advertisements for both the COSA and Rate Design public open houses were placed across the service area in print media as indicated in BCUC Appendix A10.1. No First Nations specific ads were placed.

It should also be noted that First Nations COSA consultation started in May 2009 with telephone invitations for meetings with Band Chief Financial

Officers (CFO) and Band Managers. FortisBC's First Nations Executive Liaison met with the Band representatives to review the COSA process and initial results as follows:

- Brian Titus, CFO for Osoyoos Indian Band on May 25, 2009
- Bill Joiner, CFO and Greg Gabriel, Band Manager for Penticton Indian Band on May 25, 2009
- Dan Bush, CFO and Edward Gus, Band Manager for Okanagan Indian Band on May 29, 2009
- Eliza Montgomery, Band Administrator for Lower Similkameen Indian Band on June 10, 2009
- Joe Pierre, President Lower Kootenay Development Corporation for Lower Kootenay Indian Band on June 10, 2009
- Philippe Bantini, Band Manager for Upper Similkameen Indian Band on May 25, 2009

Q10.2 Concerning the First Nations workshop, please confirm that no First Nations indicated an interest in attending and please explain when and how parties were notified that the workshop was cancelled.

A10.2 No First Nations indicated interest in attending the First Nations workshop. Phone calls were made on July 20, 2009 by FortisBC's Communications and Media Relations Advisor to the representatives addressed in the invitations to let them know that the meeting was cancelled.

Q10.3 Please provide any copies of communications from First Nations to FortisBC attesting that they were contacted in relation to the Application.

A10.3 No correspondence was received.

11.0 Reference: Exhibit B-1, Public Consultation, p. 31, and
Exhibit B-1, Appendix I, Public Consultation Report, p. 38
Consultation Results: Selection of 5 Years and 5 Percent

"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." [p. 31]

Q11.1 Please explain why 5 years was chosen as the timeframe, and why 5 percent was chosen as the cap, for the purposes of the consultation.

A11.1 In FortisBC's opinion, the 5 percent cap for increases arising out of rebalancing, along with an overall rate increase cap of 10 percent, reasonably balances the interests of those customer classes with a revenue-to-cost ratio (RCR) above the range of reasonableness with those classes whose RCR is below the range of reasonableness. The cap results in most rate classes achieving a revenue-to-cost ratio within the 95-105 percent range within five years.

Q11.2 Please confirm that, as indicated in the Public Consultation Report at p. 38, the only alternative presented was 5 years.

A11.2 The parameters discussed above were the only ones for which full rebalancing schedules were developed for consultation purposes. However, a full discussion of the appropriateness of the scenario was part of the consultation, as was the impact of varying either of the variables that were presented as the recommended option.

Q11.3 Does the absence of a strong preference for one particular rate option simply reflect different respondents wishing to avoid options that are disadvantageous to their particular rate class?

A11.3 FortisBC does not believe this to be the case without exception. For example, during consultation it was suggested by attendees on several occasions that in the interest of promoting conservation, the differential between block prices should be greater despite the bill impact that may follow.

12.0 Reference: Exhibit B-1, Public Consultation, p. 31

Consultation Results: Contract Demand Methodology

"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."

Q12.1 What other electric utilities use a contract demand methodology?

A12.1 In Alberta, transmission rates are set by the Alberta Electric System Operator (AESO) and the 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 AESO customers to which this principle is applied include generation and distribution companies and large industrial consumers of electricity including electric distribution companies such as ATCO Electric, ENMAX Power, EPCOR Utilities, FortisAlberta and City of Lethbridge. In addition, the use of contract demand as a billing determinant is a common feature of the rate schedules applied to large customers in many electric utility tariffs including BC Hydro, Southeastern Power Administration, Bonneville Power Administration, and Coast Electric Power Association and has been used by FortisBC in its Wholesale and Large Industrial customers since at least 1976.

Contract demand has been used in the gas industry as both a billing determinant and as an allocator within a COSA. For example AltaGas and Brooklyn Union Gas Company both apply these principles. 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. While these precedents demonstrate the use of contract demand the cost causation factors for each utility system are what should drive cost allocations for that specific utility. One size doesn't fit all from a COSA standpoint. The Company considers the approach it has taken in the COSA related to contract demand to be appropriate, particularly given its circumstance of serving a large portion, approximately 26 percent of its peak load, through wholesale contracts with municipal utilities that include a specific demand obligation.

13.0 Reference: Exhibit B-1, Public Consultation, pp. 31, 32
Consultation Results: Super Groups Composition

"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."

Q13.1 Please provide a table showing the distribution of survey respondents between rate classes.

A13.1 A table outlining participants by customer class is found in Appendix I, page 78 of the Application (Exhibit B-1). The participants by customer class were as follows:

Table BCUC A13.1

	Castlegar, Monday August 17, 2009	**Kelowna, Tuesday August 18, 2009**
Customer Class	**No. of participants**	**No. of participants**
Residential	42	40
General service	11	12
Industrial	0	1
Irrigation / Lighting	5	3
Total	**58**	**56**

14.0 Reference: Exhibit B-1, Principles and Objectives, p. 34
Price Changes, Supply Constraints and Resource Planning

"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."

Q14.1 Which specific rate design changes have been made to address the pressures on existing sources of supply and transmission infrastructure?

A14.1 The following rate changes were made in part to better reflect FortisBC's resource issues:

Rate 20 – the energy rate was changed from three declining blocks to a flat block;

Rate 21 – the energy rate was changed from three declining blocks to two declining blocks and the demand charge was increased;

Rate 30 – the demand charge was increased;

Rate 31 – a demand charge was added; and

Rate 40 and 41 – the demand charges were increased.

Q14.2 What general rate change was assumed in the 2009 FortisBC Resource Plan?

A14.2 The 2009 Resource Plan did not make assumptions about a general rate change.

Q14.3 Please confirm that the supply assumptions in the 2009 FortisBC Resource Plan are consistent with the supply assumptions in this Rate Design application.

A14.3 The supply assumptions for the 2009 forecast was consistent between the Resource Plan and the RDA. The RDA does not make any specific supply assumptions beyond 2009.

Q14.4 Please list any significant 2009 FortisBC Resource Plan assumptions that FortisBC believes may now be inconsistent with existing economic conditions, and explain how the 2009 Rate Design has been adjusted accordingly.

A14.4 FortisBC has not identified any significant assumptions that are inconsistent with existing economic conditions.

15.0 Reference: Exhibit B-1, Consideration for the 2009 COSA, p. 39
Price Changes, Supply Constraints and Resource Planning

"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."

Q15.1 Please show a table of forecast Capital Expenditures between 2010 and 2016, highlighting the amounts for each of expansion and replacement, for each of the transmission and distribution systems. Please also, to the extent possible, identify the percentage of expenditures in each year that are associated with energy, capacity or customer-related upgrades.

A15.1 The latest System Development Plan, filed by the Company with the 2009-2020 Capital Expenditure Plan contains the most recent 2010 projections. FortisBC is currently in the process of developing a 20 Year Integrated System Plan which will contain a schedule of proposed projects and capital expenditures for the years 2011 to 2030; thus, the requested information for these years is not yet available. Table BCUC A15.1 below shows the approved capital projects for 2010 with the requested categorization applied.

1 **Table BCUC A15.1**

T&D Forecast Expenditures for 2010						
		Forecast	**Nature of Project / Upgrade**			
Transmission Projects		**($000s)**	**Energy**	**Capacity**	**Customer**	**Prime Driver**
	Ellison Distribution Source	500		X		Expansion
	Okanagan Transmission Reinforcement	62,325		X		Expansion
	Benvoulin Distribution Source	13,301		X		Expansion
	Recreation Capacity Increase Stage 1,2,3	2,257		X		Expansion
	Kelowna Distribution Capacity Requirements	517		X		Expansion
	Huth Substation Upgrade	413		X		Expansion
	30 Line Conversion	2,340		X		Expansion
	Transmission Sustaining	4,871	X	X		Replacement
	Stations Sustaining	5,303	X	X		Replacement
	Transmission & Stations Total	**91,827**				
Distribution Projects						
	New Connects System Wide	10,670			X	Expansion
	Airport Way Upgrade (Ellison Feeder 3)	1,551		X		Expansion
	Hollywood Feeder 3 - Sexsmith Feeder 4 Tie	365		X		Expansion
	Beaver Park - Fruitvale Distribution Tie	1,227		X		Expansion
	Small Growth Projects	137		X		Expansion
	Small Capacity Improvements Unplanned	994		X		Expansion
	Distribution Sustaining	14,525	X	X		Replacement
	Total	**29,469**				
	Total for Transmission and Distribution:	**121,296**				
	Category totals:		**24,699**	**110,126**	**10,670**	
	Percentage of total T&D:		**20%**	**91%**	**9%**	

16.0 Reference: Exhibit B-1, Consideration for the 2009 COSA, p. 41
Study Methodology Changes: Support for BC Energy Plan

"The use of firm capacity reservations as a COSA assumption supports the Energy Plan by ensuring that capacity nominations are accurate."

Q16.1 Which sections of the BC Energy Plan is FortisBC referring to in this statement?

A16.1 Policy Action 13 states:

Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.

FortisBC believes that firm capacity reservations are supportive of the need to ensure adequate transmission system capacity by encouraging its large customers to provide accurate nominations which do not result in needless excess capacity. The assumption does not lead directly to a "congestion relief policy" which is why it is stated to support rather than directly result from the Policy Action.

17.0 Reference: Exhibit B-1, Consideration for the 2009 COSA, p. 41 Study Methodology Changes: Wholesale Customer Supply Agreements

"FortisBC has power supply agreements in place with each of its municipal Wholesale customers, all of which will expire in the near term."

Q17.1 Please provide a table showing the expiry dates for FortisBC supply agreements with Wholesale customers.

A17.1 Please see Table BCUC A17.1 below. Note that the Kelowna agreement has been extended to February 19, 2010.

Table BCUC A17.1

Wholesale Customer	Supply Agreement Expiry Date
City of Penticton	March 31, 2010
District of Summerland	March 31, 2010
City of Kelowna	October 31, 2009 – extended to February 19, 2010
City of Grand Forks	March 31, 2010
City of Nelson	December 31, 2014

Q17.2 To what extent does FortisBC anticipate that it will renew each of these agreements? To what extent do the renewals of these agreements involve simple roll-overs of the existing supply agreements versus re-negotiating many of the conditions of the existing agreements?

A17.2 FortisBC expects, as with past renewals, that the majority of the terms within the agreements will remain unchanged. The Company does anticipate nominations for capacity at both the points of delivery (contained in Appendix A of the agreements) and on the transmission system will involve greater discussion than in previous years.

18.0 Reference: Exhibit B-1, Consideration for the 2009 COSA, p. 41

Study Methodology Changes: System Investments

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

Q18.1 Please explain how planned future system investments over the period 2010 through 2015 are reflected in the COSA estimates.

A18.1 Future system investments are not considered in the COSA estimates. The estimates used are based on a particular test year and future investments are addressed as they occur, in future COSA estimates.

19.0 Reference: Exhibit B-1, p. 44

Small General and General Service Rate Classes

Q19.1 Has a stratification study been carried out to confirm that the 40 kW threshold delineating the Small General and General Service rate classes remains valid?

A19.1 FortisBC has not conducted a stratification study to examine whether the 40 kW threshold remains valid. Given the plan to introduce AMI metering which will provide significantly more metering data and allow more cost-effective demand metering, it is more appropriate to examine this issue at that time.

Q19.2 Have the billed demands of customers taking service under the Small General and General Service rates been reviewed and have any of these customers been reclassified from one rate to another as a result of this review and prior to the completion of the 2009 COSA study?

A19.2 The billed demands of customers taking service under Small General Service and General Service rates were reviewed. The number of Small General Service bills above the consumption limit of 40 kW at a load factor of 50 percent was approximately 4 percent, which is reasonable given the seasonal nature of billing. The Company reviews on a monthly basis those Small General Service customers that appear to have consumption that warrants moving them to the General Service rates and takes action as required.

The average demand of General Service bills was not less than 19 kVA, even in low energy consumption blocks. 94 percent of all General Service bills were above 24 kVA. Given the seasonal nature of billing, and the fact that General Service customers have a financial incentive to move the Small General Service rate if their consumption warranted it, this was also considered reasonable.

20.0 Reference: Exhibit B-1, p. 44
Irrigation Service

Q20.1 What types of customers receive service under Schedule 60, Irrigation and Drainage? Please show the composition of the customers in the rate class, as a table indicating the nature of business they are engaged in.

A20.1 FortisBC does not keep detailed information regarding the customers in the Schedule 60 rate class, but does ensure at the time a Schedule 60 account is created that it is used to provide electricity for motors used primarily for irrigation and drainage purposes. Typical customers are irrigation districts, wineries, golf courses and farms.

Q20.2 Have the types of customers receiving service under Schedule 60 changed since the last COSA study was completed in 1997? If so then please describe the new types of customers taking service under this schedule.

A20.2 FortisBC did not keep detailed information regarding the customers in the Schedule 60 rate class in 1997 and does not today. However, there is no reason to believe the customer composition would have changed significantly.

21.0 Reference: Exhibit B-1, Rate Rebalancing, p. 46
Rate Changes: Reasonability Range

"...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."

Q21.1 It could be argued that if the assumptions are reasonable, adopting a range of 0.95-1.05 leads to an under-correction of rates; that is, once the borders of the range are reached no further correction occurs and those customers who have revenue-cost ratios above 1.0 will continue indefinitely to cross-subsidize those whose revenue-cost ratios are below 1.0. How does FortisBC respond to this concern?

A21.1 The recommended ratios are reflective of the availability in the assumptions made of the interval load data. If the Company had perfect information with respect to load data and if there was no uncertainty or variation possible in the COSA methods, then the Company would agree that an indefinite cross-subsidy could occur. Those classes with hourly metering and better load data could move closer to 100 percent, however, FortisBC does not recommend this approach at this time.

FortisBC is already making significant shifts in revenue to cost ratios that are currently far outside of the 95-105 percent range using a gradual approach over the next several years. FortisBC expects to conduct an updated COSA in several years and most classes will not reach the 95-105 percent range within that time frame. In future RDAs FortisBC will continue to examine the appropriate revenue to cost ratio range.

22.0 Reference: Exhibit B-1, p. 47
Rate Rebalancing

"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."

Q22.1 What are the revenue to cost ratios of the Basic Charge component of the Small General and General Service rates?

A22.1 The revenue to cost ratio of the Small General Service Basic Charge is 41 percent and for General Service it is 24 percent.

"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."

Q22.2 What is FortisBC's view concerning how changes to each of energy, demand, and Basic charges influence energy conservation and energy efficiency?

A22.2 FortisBC is not aware of any research regarding the conservation effects of basic charges or demand charges. However, it is generally accepted that demand for energy is price responsive – higher marginal prices for energy result in lower demand for energy, with the inverse also being true. FortisBC would expect the same type of marginal price responsiveness in the demand for electrical demand. A change in the basic charge by itself would not be expected to result in any change to the demand for energy or electrical demand since such a change does not affect the marginal price to the customer.

On page 22 of the Application, FortisBC uses a price elasticity ratio of 0.1 to project a reduction in energy consumption (in the upper block) resulting from the implementation of an inclining block rate.

Q22.3 Is any real reduction (i.e. after accounting for the effect of inflation) in the energy charge resulting from the method of rate rebalancing being proposed expected to result in increased energy consumption by the customers in the affected rate classes?

A22.3 Yes, a real reduction in the energy charge would be expected to result in increased energy consumption by the customers in the affected rate classes.

23.0 Reference: Exhibit B-1, Rate Design, p. 53, footnote
Rate Design Considerations: "Rate DSM"

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

Q23.1 Please explain whether FortisBC believes that real rate increases (i.e., any rate increase that exceeds the general rate of inflation or CPI) are a form of "rate DSM," motivating customers to conserve energy.

A23.1 Yes, FortisBC believes that real rate increases result in reduced energy consumption.

Q23.2 If so, what is the extent of the expected reaction? How has that been incorporated into the 2009 Rate Design?

A23.2 FortisBC has not used an elasticity adjustment on sales of electricity in its rate design calculations for this RDA. Because this RDA addresses changes in the rate structure as opposed to the overall rate level, there are no real rate increases involved in the RDA.

24.0 Reference: Exhibit B-1, Residential Rates, p. 55
Rate Design Options: Customer Characteristics

"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."

Q24.1 What is the average annual energy consumption for each of heating and non-heating Residential customers in the FortisBC service area?

A24.1 Initial results from the Conservation Potential Review currently underway provides the following estimates for residential annual electrical load:

- Electric Heat = 15,703 kWh
- Non-Electric = 9,557 kWh

Q24.2 Approximately what proportion of Residential customers in the FortisBC currently has access to natural gas service? (i.e., already has, or could reasonably obtain, gas service.)

A24.2 Results from the 2009 Residential End-Use Survey indicates that 52 percent of FortisBC customers use natural gas as their primary heating source. Terasen Gas further estimates that 90 percent of residential customers that have reasonable access to gas service take gas service. Therefore, approximately 58 percent of FortisBC customers have, or could reasonably obtain, gas service.

25.0 Reference: Exhibit B-1, pp. 55 - 60
Residential Rate Design

On page 55 it states: "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)."

Q25.1 Please compare residential electricity costs to natural gas costs on a per gigajoule basis using the applicable customer and energy charges from Terasen\`s tariff. In making the comparison, include a component of a natural gas customer\`s monthly charge but not the electricity monthly charge, assume a natural gas furnace efficiency of 90 per cent, and use Terasen\`s residential use per account for its Inland customers. State all other assumptions used in making the comparison.

A25.1 The requested information is attached as BCUC Attachment A25.1, and is current as of January 1st, 2010.

RESIDENTIAL SPACE HEATING COST COMPARISON

FORTISBC PowerSense

Estimated Annual Energy Cost to heat a ***typical*** *existing single family dwelling.*
1200-1500 sq feet

January 1, 2010

Total Heat Req'd (net): 14,223 kWh

FUEL/Furnace	Seasonal Efficiency	Units Req'd	Units	Units Req'd	Units	Annual COST
Natural Gas *(Annual Cost includes monthly gas service charges)*						
Standard	65%	79	*GJ +*	900	**kWh*	$1,110
Mid-eff	80%	64	*GJ +*	900	*kWh*	$945
Hi-eff	95%	54	*GJ +*	900	*kWh*	$835
Electric						
Forced Air	100%	0	*GJ +*	15,122	*kWh*	$1,290
Baseboard	100%	0	*GJ +*	14,222	*kWh*	$1,210
Heat Pump						
ASHP w/ mid-eff gas	190%	22	*GJ +*	5,183	*kWh*	$845
ASHP w/ hi-eff gas	200%	19	*GJ +*	5,183	*kWh*	$805
ASHP w/ elec.	200%	0	*GJ +*	10,161	*kWh*	$865
GSHP w/ elec.	330%	0	*GJ +*	6,789	*kWh*	$580

COST OF FUEL

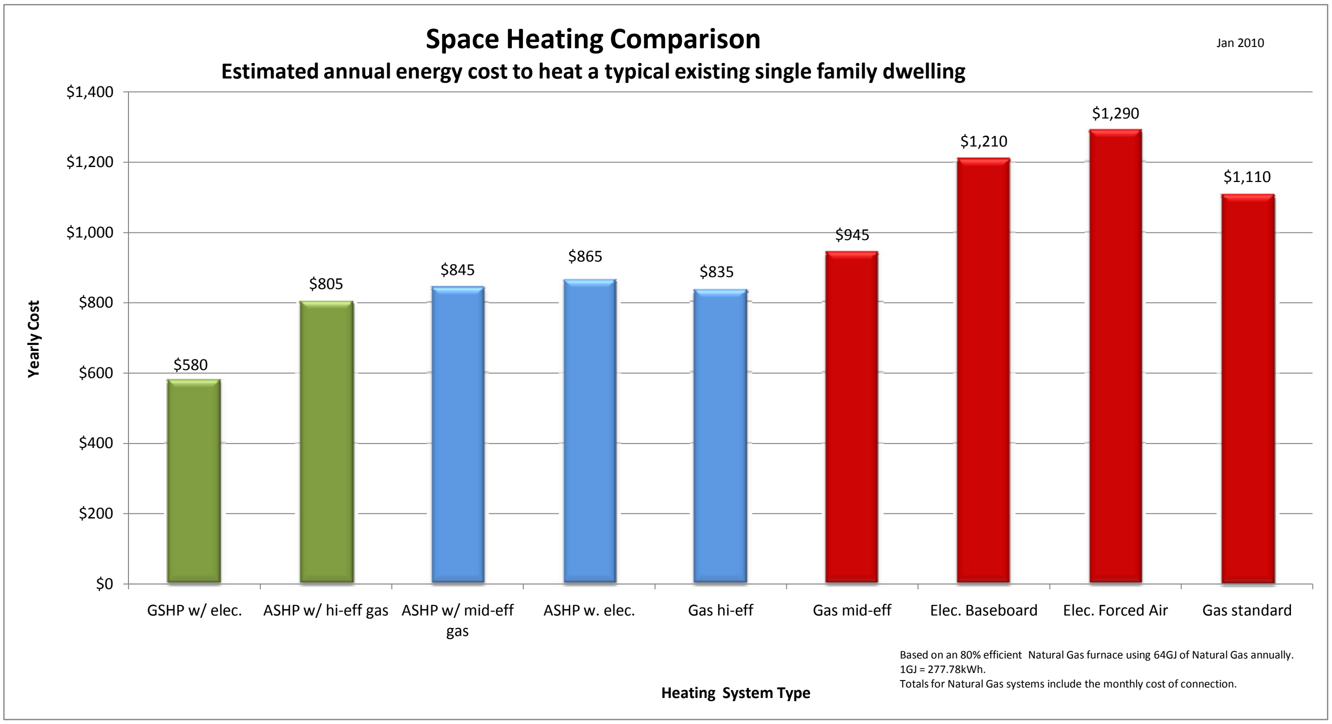
Units/Rate Block	Cost
Terasen Gas Rates as of	1-Jan-10
Inland rate	
Monthly Charge	$11.84
$ per GJ (year round)	$10.30
Includes: *Handling charges and carbon tax where applicable.*	
FortisBC Rates as of	01-Jan-10
Residential rate	
Cents per kWh:	8.09

NOTES:

1. The rates shown are subject the change without notice.
2. Annual Costs include applicable taxes and fees: 5% GST, 0.4% ICE Levy, 3.09% Franchise Fee.
3. Cost comparison excludes capital cost, rebates (e.g. GSHP), maintenance and equipment rental.
4. Ground Source Heat Pumps (GSHP) assumes 90% of the energy is produced at a Coefficient of Performance (COP) of 3.5 and the balance is produced by electric resistance heat at a COP of 1.0.
5. Air Source Heat Pumps (ASHP) assumes 65% of the energy is produced at a COP of 2.5 and the balance is produced by the auxillary heat source at a COP depending on the heat source.
6. Natural Gas assumes: a) Standard: continuous pilot light, open draft hood.
   b) Mid-eff: spark ignition and motorized flue damper.
   c) Hi-eff: condensing furnace (plastic vent through exterior wall)
7. *900kWh represents the furnace fan motor energy usage.

Technical Basis:

1. Gas: 947,800 Btu/GJ
2. Electric 3,412 Btu/kWh
3. Btu = British thermal unit
4. GJ = GigaJoule
5. kWh = kilo Watt Hour


Space Heating Comparison
Jan 2010
Estimated annual energy cost to heat a typical existing single family dwelling
Yearly Cost
$1,400
$1,200
$1,000
$800
$600
$400
$200
$0
$580
$805
$845
$865
$835
$945
$1,210
$1,290
$1,110
GSHP w/ elec.
ASHP w/ hi-eff gas
ASHP w/ mid-eff gas
ASHP w. elec.
Gas hi-eff
Gas mid-eff
Elec. Baseboard
Elec. Forced Air
Gas standard
Heating System Type
Based on an 80% efficient Natural Gas furnace using 64GJ of Natural Gas annually.
1GJ = 277.78kWh.
Totals for Natural Gas systems include the monthly cost of connection.

Q25.2 Would seasonal rates send appropriate price signals to residential customers allowing them to make informed choices concerning the appropriate use of energy for thermal applications?

A25.2 FortisBC is of the opinion that seasonal rates would unfairly discriminate against customers that have limited energy choices for thermal applications.

Figure 10.1a on page 56 shows a comparison of rate options.

Q25.3 Please define a typical low-use, average-use and high-use residential customer in terms of their load factor and average annual consumption.

A25.3 For the purposes of these questions, low-use is defined as customers with annual consumption below 6,000 kWh (approximately 22 percent of customers), average-use between 6,000 kWh and 18,000 kWh (approximately 54 percent of bills) and high-use above 18,000 kWh (approximately 24 percent of bills). Residential load factor (average power use divided by peak power use for a particular period) is not known since current residential metering does not collect demand data.

Q25.4 Please quantify the number of low-use customers: those whose consumption is at or below that of the typical low-use customer defined in response to the previous question.

A25.4 There are approximately 21,000 “low-use” customers as defined in BCUC IR No. 1 Q25.3.

Q25.5 Please quantify the number of average-use customers: those whose consumption is above that of a low-use customer, and below that of a high-use customer.

A25.5 There are approximately 51,000 “average-use” customers as defined in BCUC IR No. 1 Q25.3.

Q25.6 Please quantify the number of high-use customers: those whose consumption is above that of the high-use threshold defined previously.

A25.6 There are approximately 23,000 “high-use” customers as defined in BCUC IR No. 1 Q25.3.

Q25.7 Please provide a bill impacts to a low-use, average-use and high-use residential customer resulting from the implementation of rate design option one (No change in the Basic Charge with an inclining-block consumption rate) as compared to option four (the current rate structure).

A25.7 FortisBC assumes based on the wording of the question that it is to compare the bills impacts of Option #2 and Option #4 in Figure 10.1a, and further assumes that it is to choose a representative annual consumption level for each of the three groups for comparison purposes. The annual consumption level that FortisBC has chosen in each of the three consumption groups is based on 4,800 kWh, 12,000 kWh and 21,000 kWh annually. Table BCUC A25.7 below compares the two rate options requested:

Table BCUC A25.7

	Option 2	Option 4	Difference
Low-use (4,800 kWh)	$456	$504	-11%
Average-use (12,000 kWh)	$1,025	$1,044	-2%
High Use (21,000 kWh)	$1,844	$1,719	7%

Page 59 of the Application states:

"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."

Q25.8 What weight has been given to the results of the public consultation, as summarized in the above passage, as compared to the energy objectives of the Province.

A25.8 FortisBC did not assign particular weightings to the considerations used to evaluate the rate options because the results of the customer consultation were consistent with the objectives of the BC Energy Plan. For the reasons set out in the Application (Exhibit B-1, p. 16-17) the Company is of the opinion that the preferred way for FortisBC to meet the Energy Objectives set out in the BC Energy Plan is to implement time based rates when it is able to do so and not implement an inclined block rate. Specifically with respect to basic charge, factors such as cost causation and revenue certainty were primary considerations, which were consistent with the consultation results.

26.0 Reference: Exhibit B-1, Residential Rates, p. 56
Rate Design Options: Figure 10.1a

Q26.1 Please provide the information depicted in Figure 10.1a as a data table, with rows at 100kW intervals and with a column for each of the four Rate Options.

A26.1 The requested information is included in Table BCUC A26.1 below. For reference, the Rate Options are:

Option #1: $12 bi-monthly Customer Charge, $32 minimum bill, and a $0.080 energy rate;

Option #2: $24 bi-monthly Customer Charge, 1350 kWh block threshold with a $0.065 first block and $0.091 second block energy rate;

Option #3: $24 bi-monthly Customer Charge, 1350 kWh block threshold with a $0.059 first block and $0.083 second block energy rate;

Option #4: $24 bi-monthly Customer Charge with a $0.075 flat energy rate.

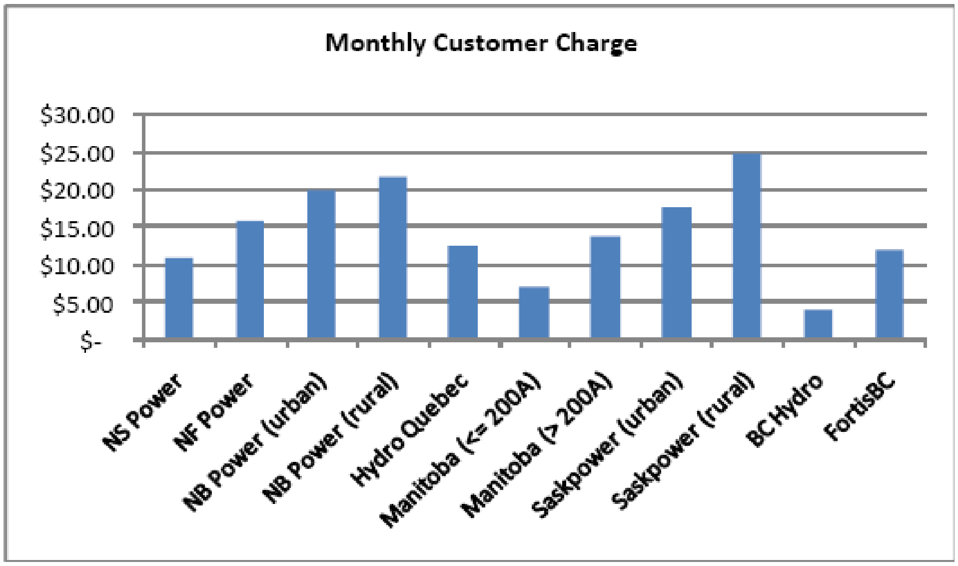
1 **Table BCUC A26.1**

kWh	Option #1	Option #2	Option #3	Option #4
100	$ 32.00	$ 26.93	$ 34.86	$ 27.25
200	$ 32.00	$ 34.35	$ 41.90	$ 36.13
300	$ 34.00	$ 41.15	$ 48.34	$ 44.27
400	$ 42.75	$ 47.97	$ 54.82	$ 52.44
500	$ 51.40	$ 54.72	$ 61.21	$ 60.52
600	$ 60.03	$ 61.44	$ 67.59	$ 68.58
700	$ 68.67	$ 68.18	$ 73.98	$ 76.64
800	$ 77.33	$ 74.93	$ 80.37	$ 84.72
900	$ 86.07	$ 81.74	$ 86.84	$ 92.88
1000	$ 94.96	$ 88.67	$ 93.41	$ 101.18
1100	$ 103.11	$ 95.02	$ 99.43	$ 108.78
1200	$ 112.03	$ 101.98	$ 106.02	$ 117.11
1300	$ 120.83	$ 109.12	$ 112.79	$ 125.33
1400	$ 129.47	$ 118.55	$ 121.73	$ 133.39
1500	$ 138.04	$ 127.89	$ 130.60	$ 141.39
1600	$ 146.68	$ 137.32	$ 139.53	$ 149.46
1700	$ 155.89	$ 147.36	$ 149.06	$ 158.05
1800	$ 164.16	$ 156.38	$ 157.61	$ 165.76
1900	$ 172.84	$ 165.85	$ 166.59	$ 173.87
2000	$ 181.58	$ 175.39	$ 175.63	$ 182.03
2100	$ 190.58	$ 185.20	$ 184.93	$ 190.43
2200	$ 198.77	$ 194.14	$ 193.41	$ 198.08
2300	$ 207.54	$ 203.71	$ 202.48	$ 206.26
2400	$ 216.32	$ 213.28	$ 211.56	$ 214.45
2500	$ 224.94	$ 222.69	$ 220.48	$ 222.51
2600	$ 233.89	$ 232.45	$ 229.74	$ 230.86
2700	$ 241.86	$ 241.14	$ 237.98	$ 238.29
2800	$ 251.09	$ 251.21	$ 247.53	$ 246.91
2900	$ 260.14	$ 261.09	$ 256.89	$ 255.36
3000	$ 268.20	$ 269.88	$ 265.23	$ 262.88
3100	$ 277.63	$ 280.16	$ 274.97	$ 271.68
3200	$ 285.76	$ 289.03	$ 283.39	$ 279.27
3300	$ 294.47	$ 298.53	$ 292.39	$ 287.40
3400	$ 303.31	$ 308.18	$ 301.54	$ 295.66
3500	$ 312.27	$ 317.96	$ 310.81	$ 304.02
3600	$ 320.30	$ 326.71	$ 319.11	$ 311.51
3700	$ 329.74	$ 337.00	$ 328.87	$ 320.32
3800	$ 338.63	$ 346.71	$ 338.08	$ 328.63
3900	$ 347.49	$ 356.37	$ 347.24	$ 336.89
4000	$ 354.86	$ 364.41	$ 354.86	$ 343.77

27.0 Reference: Exhibit B-1, Residential Rates, p. 58

Rate Design Options: Basic Charge

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."

Q27.1 What is the combined average Basic Charge used by the non-BC utilities depicted in Figure 10.1b?

A27.1 The combined average Basic Charge for the non-BC utilities is $15.83 per month.

28.0 Reference: Exhibit B-1, Residential Rates, p. 59
Rate Design Options: Inclining Blocks

Q28.1 Please explain why FortisBC chose 85 percent of the median bill amount for the threshold for the Inclining Block rate.

A28.1 The residential inclining block rate approved for BC Hydro used a figure of 90 percent of median consumption, resulting in a first block size of 1,350 kWh bi-monthly. FortisBC chose to match the 1,350 kWh first block size of BC Hydro, which is at 85 percent of the FortisBC median bill level.

29.0 Reference: Exhibit B-1, Residential Rates, p. 60
Rate Design Options: Inclining Blocks

"...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."

Q29.1 Is FortisBC relying on the results of BC Hydro's Residential Inclining Block rate in the above assertion? If so, please provide any performance evaluation of the BC Hydro RIB on which the statement is based. If not, please summarise FortisBC's view of the effectiveness of BC Hydro's RIB program.

A29.1 FortisBC does not have, and is not relying upon, the results of the BC Hydro Residential Inclining Block rate in its assertion. Please also refer to the response to BCUC IR No. 1 Q6.7 regarding the effectiveness of the BC Hydro RIB program.

30.0 Reference: Exhibit B-1, pp. 61 - 65
General Service Rate Design

Page 64 of the Application states:

“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.”

Q30.1 Did FortisBC consider greater increases of the demand charge component of Schedule 21 as part of a strategy to eliminate the declining block structure?

A30.1 FortisBC did consider increasing the demand component of Schedule 21 instead of moving to a two-step declining block rate structure. As with a flat Schedule 21 rate with the same demand charge, the flat energy rate with a higher demand charge would need to be lower than the Schedule 20 energy rate, making the transition between Schedule 20 and 21 problematic. Any rate structure with a flat energy charge would result in a significant bill change for Schedule 21 customers with low consumption, high consumption or non-standard load factors.

Q30.2 What types of customers receive service under Schedule 21?

A30.2 From page 44 of the Application (Exhibit B-1), “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.”

Typical customers in this class include small to medium sized manufacturing facilities, ski hill operations, recreation complexes, and large retail.

Q30.3 Are any of the customers receiving service under Schedule 21 able to adjust their behaviour in order to increase their load factor and thereby minimize the impact of an increase to the demand charge?

A30.3 Please refer to the response to BCUC IR No. 1 Q32.2

Q30.4 Will the rebalancing effort that is planned for a five-year period also further flatten the declining block structure of Schedule 21?

A30.4 The rebalancing adjustments for customers with revenue-to-cost ratios in excess of 105 percent will be applied only to the energy portion(s) of the rate (Exhibit B-1, p. 47), however the distribution of the adjustment within the blocks of a tiered rate has not been determined. It would be possible to weight the rebalancing adjustments more heavily to the first block in order to further flatten the rate.

Q30.5 If the answer to the previous question is "no" then provide an explanation of why further flattening of the declining block structure of Schedule 21 is not being contemplated.

A30.5 Please refer to the response to BCUC IR No. 1 Q30.4 above.

31.0 Reference: Exhibit B-1, General Service Rates, p. 64
General Service Customers and Rate Options

"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."

Q31.1 Please explain whether FortisBC considered using a continuous General Service rate structure, with no threshold point. If so, why was it not put forward? If not, why was it not considered?

A31.1 FortisBC considers the proposed Schedule 20 and 21 rate structures to be "continuous" in the sense that there is a smooth billing transition for customers between the rates. The two proposed schedules could have in fact been combined into one (as could the current schedules) because of the smooth threshold point at 40 kW. FortisBC did not make this change, however, since there are savings associated with the current separation of Schedule 20 and Schedule 21. The roughly 8,800 Schedule 20 customers do not require demand meters (since there are no demand charges below 40 kW), and therefore can be read bi-monthly. This saves approximately $160,000 per year in meter reading, printing, postage and administrative costs.

Q31.2 Does FortisBC have market information suggesting that most General Service customers would understand how a continuous rate structure would work?

A31.2 FortisBC does not have the market information described.

32.0 Reference: Exhibit B-1, pp. 66 - 67
Large General Service - Primary Rate Design

Q32.1 What types of customers receive service under Schedule 30?

A32.1 Schedule 30 customers are typified by large manufacturing facilities such as sawmills and educational/health institutions.

Q32.2 Are any of the customers receiving service under Schedule 30 able to adjust their behaviour in order to increase their load factor and thereby minimize the impact of an increase to the demand charge?

A32.2 Some Schedule 30 customers may be able to adjust some aspects of their operation, such as the staggered start of large motors in order to reduce their peak demands, or the alteration of plant shift schedules.

Q32.3 Since the revenue to cost ratio associated with Schedule 30 is greater than 1.00, will an additional goal of the five-year rebalancing effort be to bring the level of the demand charge within 95 to 105 per cent of the COSA recommended level?

A32.3 This additional goal has not been proposed. The rebalancing scenario proposed by the Company only considers the overall revenue-to-cost ratio target on a total cost to total revenue basis.

33.0 Reference: Exhibit B-1, General Service Rates, p. 67
General Service Customers and Rate Options

"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.

Q33.1 The citation says that a) demand charge increase does not necessarily affect system peak demand, yet b) it sends an improved price signal, what customer response does FortisBC expect due to a demand charge increase?

A33.1 FortisBC would expect based on price elasticity that individual customers would reduce their demand if there were a demand charge increase. The impact this would have on the overall system peak would be determined by how closely each customer's peak usage coincided with the system peak.

Q33.2 If all demand charges were increased by 10 percent in 2011, what impact would FortisBC expect on the present value of costs over the period 2011 through 2015?

A33.2 FortisBC does not have experience with price elasticity for electricity demand, and is not aware of any research or studies in this area. Therefore, FortisBC cannot estimate the effect of a 10 percent increase in demand charges.

Q33.3 What total conservation impact does FortisBC anticipate from the proposed changes in demand charges in the 2009 Rate Design?

A33.3 Please refer to the response to BCUC IR No. 1 Q33.2.

34.0 Reference: Exhibit B-1, pp. 67 - 69

Large General Service - Transmission Rate Design

Page 68 of the Application states:

"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'."

Page 69 states:

"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."

Q34.1 Why are demand charge revenues expected to increase? Please provide the details explaining the forecast increase.

A34.1 The revenues increase due to the fact that the wires charge will be billed on the basis of contract demand, which is generally higher than actual demand. When these two factors are combined, the demand revenues are projected to increase by 5.4 percent.

Q34.2 Based on the description of calculating demand charges presented on page 68, can FortisBC confirm that a hypothetical customer having a constant monthly demand equal to their Contract Demand would have the same billing kVA for purposes of calculating both the wires charge and the power supply charge?

A34.2 Confirmed.

Q34.3 What would be the bill impact to the hypothetical customer referred to in the previous question, assuming a constant monthly demand of 3,000 kVA, a 95 per cent power factor and an 80 per cent load factor?

A34.3 Please refer to the response to BCUC IR No. 1 Q34.4 below.

Q34.4 Please complete the following table for a monthly Contract Demand of 3,000 kVA, a 95 per cent power factor, an 80 per cent load factor, and ignoring the effect of the demand ratchet:

Monthly Billed Demand	Demand Charges @ Existing Rate	Energy Charges @ Existing Rate	Total Charges @ Existing Rate	Wires Charges @ Proposed Rate	Power Supply Charges @ Proposed Rate	Energy Charges @ Proposed Rate	Total Charges @ Propose d Rate	% Increase/ (Decrease)
4,000								
3,500								
3,000								
2,500								
2,000								
1,500								

A34.4 Please see Table BCUC A34.4 below. Note that Rate 31 applies to customers with loads of 5,000 kVA or more.

Table BCUC A34.4

Monthly Billed Demand (kVA)	Demand Charges @ Existing Rate	Energy Charges @ Existing Rate	Total Charges @ Existing Rate	Wires Charges @ Proposed Rate	Power Supply Charges @ Proposed Rate	Energy Charges @ Proposed Rate	Total Charges @ Proposed Rate	% Increase/ (Decrease)
4,000	$263,520	$1,119,318	$1,409,792	$168,000	$96,000	$1,103,900	$1,394,855	-1.1%
3,500	$230,580	$979,403	$1,209,983	$147,000	$84,000	$965,913	$1,196,913	-1.1%
3,000	$197,640	$839,488	$1,037,128	$126,000	$72,000	$827,925	$1,025,925	-1.1%
2,500	$164,700	$699,574	$864,274	$105,000	$60,000	$689,938	$854,938	-1.1%
2,000	$131,760	$559,659	$691,419	$84,000	$48,000	$551,950	$683,951	-1.1%
1,500	$98,820	$419,744	$518,564	$63,000	$36,000	$413,963	$512,963	-1.1%

Page 67 the Application states:

"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."

Q34.5 What customers receive service under Schedule 31?

A34.5 This Rate is applicable to industrial customers with loads of 5,000 kVA or more, taking service at transmission voltages, subject to written agreement.

Customers receiving service under this schedule include mining companies, lumber mills and manufacturers.

Q34.6 Did FortisBC consider implementing seasonal rates for Schedule 31?

A34.6 FortisBC considered seasonal rates generally, but did not implement them since they are discriminatory toward customers with limited energy choices. Due to the nature of Schedule 31 customers who tend to be large industrial facilities with loads that are fairly flat across seasons, efficacy of seasonal rates is doubtful.

Q34.7 Are any of the customers receiving service under Schedule 31 able to adjust their behaviour to minimize the impact, if any, of time of use rates if FortisBC were to make these mandatory for Schedule 31 customers?

A34.7 Some Schedule 31 customers may be able to adjust some aspects of their operation, such as the staggered start of large motors in order to reduce their peak demands, or the alteration of plant shift schedules.

35.0 Reference: Exhibit B-1, General Service Rates, p. 68

Curtailment Provisions

Q35.1 Please describe the curtailment provisions, if any, to which Rate Schedule 31 customers are subject.

A35.1 Rate Schedule 31 customers are not subject to any specific curtailment provisions.

36.0 Reference: Exhibit B-1, Wholesale Rates, p. 70
Wholesale Rate Summary Table

Q36.1 Please provide a version of Table 13.0 which includes a column showing the sum of proposed Demand rates for Wires and Power Supply.

A36.1 It is not useful to sum the two rates as the wires charge is applied to the higher of actual or contract demand and the power supply charge is applied to actual demand only so a simple sum of the two numbers produces a rate that should not be applied to either for billing purposes.

Q36.2 Please provide a table of the total revenues expected from each Wholesale account in 2011 under the current rate structure (plus any inflation adjustment) and the proposed rate structure.

A36.2 FortisBC does not have a monthly 2011 forecast of metered demand which is necessary to calculate revenue under proposed rates. However, because proposed rates are revenue neutral to current rates prior to incorporating any rate rebalancing the revenues at both current and proposed rates would be the same assuming the 2011 billing determinants were identical to the 2009 forecast used in the COSA. Therefore the only difference between the revenues at current and proposed rate structures in 2011 will be due to rate rebalancing. The 2011 forecast under current rate structures is provided below:

Revenue Forecast - Rates effective Jan 1, 2010	2011 Forecast Revenue ($)
BC Hydro - Kingsgate/Arrow Crk	271,719.67
BC Hydro - Lardeau	664,052.61
City of Grand Forks	2,374,728.02
Corp of the City of Kelowna	18,311,432.53
Corp of the City of Penticton	20,391,550.95
District of Summerland	5,762,200.87
Nelson Hydro	4,945,300.03
	52,720,984.67

37.0 Reference: Exhibit B-1, Time-of-Use Schedules, pp. 72, 73
Rate Schedules 2 and 22 Customer Acceptance

"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."

Q37.1 Have all five affected customers endorsed the changes described in the above? If not, provide any customer comments concerning the proposed change.

A37.1 No feedback has been received from the five affected customers.

38.0 Reference: Exhibit B-1, Time-of-Use Schedules, p. 74
Rate Schedule 33: Consumption Pattern

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

Q38.1 Please provide a table showing consumption under Rate Schedule 33 associated with each rate period, for the most recent 12 months available.

A38.1 Please refer to Table BCUC A38.1 below.

Table BCUC A38.1

Season	Read Date	On-Peak	UOM	Off-Peak	UOM2	Rate
Winter	11/30/2009	1,602,678	kWh	4,758,096	kWh	ID33
Shoulder	10/31/2009	726,390	kWh	426,930	kWh	ID33
Shoulder	09/30/2009	243,852	kWh	114,156	kWh	ID33
Summer	08/31/2009	455,070	kWh	1,337,910	kWh	ID33
Summer	07/31/2009	78,834	kWh	959,994	kWh	ID33
Shoulder	06/30/2009	446,334	kWh	624,456	kWh	ID33
Shoulder	05/31/2009	2,557,590	kWh	2,294,334	kWh	ID33
Shoulder	04/30/2009	974,736	kWh	707,574	kWh	ID33
Shoulder	03/31/2009	867,090	kWh	880,530	kWh	ID33
Winter	02/28/2009	249,144	kWh	449,694	kWh	ID33
Winter	01/31/2009	1,384,026	kWh	2,884,224	kWh	ID33
Winter	12/31/2008	728,448	kWh	1,851,066	kWh	ID33

39.0 Reference: Exhibit B-1, p. 75

Green Rates

Q39.1 What is the balance in the account holding funds collected through the Green Power rates?

A39.1 The balance is $193.74.

Q39.2 For each year beginning in 2005, how much revenue has been collected through the Green Power rates?

A39.2 Table BCUC A39.2 below outlines annual revenue collected by FortisBC through Green Power rates beginning in 2005. There is only one residential customer (August 12, 2008) on Green Power rates.

Table BCUC A39.2

Revenue Year	Annual Revenue
2005	$0.00
2006	$0.00
2007	$0.00
2008	$34.20
2009	$159.54

Q39.3 For each year beginning in 2005, how much electricity from "environmentally desirable technologies" has been purchased?

A39.3 Due to the small volume of customer take up on this rate, no purchases of environmentally desirable technologies power have been made in support of this tariff to date. The Company expects to make a purchase of about 20 MWh in 2010. The Company notes that BullFrog Power (http://www.bullfrogpower.com/) has recently announced the availability of made in BC wind power. It is likely the Company will purchase this, or a similar product.

Q39.4 What is FortisBC's definition of "environmentally desirable technologies"?

A39.4 A project must be EcoLogo certified and incremental to the Company's power supply resources. For example, the City of Nelson plant is EcoLogo certified and the Company purchased 569 MWh of power from this plant in 2008. However, this was done under a long-standing purchase arrangement predating the Green Power tariff and it is therefore not incremental power. Likewise, though the Company purchased 39 MWh of biogas power from the City of Kelowna in 2008 as an incremental supply, it is not Eco-Logo certified.

Q39.5 What is the certification process for ensuring that the electricity purchased with funds collected through the Green Power rates is in fact from "environmentally desirable technologies"?

A39.5 Please refer to the response to BCUC IR No. 1 Q39.4 above.

Q39.6 For each year beginning in 2005, how many kWh of "green credits" have been purchased?

A39.6 No power or green credits have been purchased over the life of the green power tariff except for the initial purchase of 50 MWh of wind credits made at the time of the initial Company application for a Green Power Tariff.

Q39.7 What is the certification process for ensuring the veracity of the green credits that are being purchased?

A39.7 Please refer to the response to BCUC IR No. 1 Q39.4 above.

40.0 Reference: Exhibit B-1, p. 76-77

On page 76 of the application, FortisBC states that it is proposing a new method for calculating the amount that the Company contributes towards a customer extension, and that amount is predicated on the amount of investment in distribution poles, conductors, and transformers for each rate class covered in the applicable rate.

FortisBC's proposed tariff states that 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

Q40.1 A general description of the method of calculating the contribution credit is provided on page 77. Please provide a spreadsheet or working papers that show the actual calculation of the maximum contribution rate for each customer category in the FortisBC table above.

A40.1 Please see BCUC Attachment A40.1.

	DIST Wire Demand	DIST Transformation Demand	Distribution Metered Customer	Distribution Service Customer	Total	Less Accum Depr	Less CIAC	Net	Customers	Resulting Credit	Billing kW	Credit per kW	Average Wattage	Per fixture
Allocation Basis:														
Residential	$244,241,215	$72,528,099	$8,222,852	$4,322,606	$329,314,772	-$87,307,671	-$71,865,085	$170,142,016	96,413	$1,765	N/A	N/A	N/A	N/A
Small GS	$28,536,084	$8,451,863	$2,306,441	$1,212,455	$40,506,842	-$10,739,142	-$8,391,412	$21,376,288	8,989	$2,378	9.698	$245	N/A	N/A
Gen Service	$26,991,379	$7,935,987	$987,673	$519,202	$36,434,241	-$9,659,417	-$7,923,931	$18,850,893	2,466	$7,643	67.811	$113	N/A	N/A
Combined GS	$55,527,462	$16,387,850	$3,294,114	$1,731,657	$76,941,083	-$20,398,559	-$16,315,343	$40,227,181	11,455	$4,475	28.300	$158	N/A	N/A
Lighting	$4,766,246	$1,416,303	$0	$0	$6,182,549	-$1,639,113	-$1,402,628	$3,140,809	1,980	$1,273	2.932	$434	123	$19.45
Irrigation	$5,058,979	$1,493,130	$89,637	$47,121	$6,688,867	-$1,773,347	-$1,486,469	$3,429,051	1,051	$1,390	20.671	$67	N/A	N/A
Total	$365,121,366	$108,213,231	$14,900,717	$7,833,041	$496,068,354									

Q40.2 Please compare the contribution required under the proposed tariff with the existing tariff for three extensions undertaken in 2009, with the three extensions representing a low contribution extension, an average extension and a high contribution extension.

A40.2 Please see Table BCUC A40.2 below.

Table BCUC A40.2

		Existing Tariff				Proposed Tariff			
Extension Cost	**Description**	**Customer Contribution**	**FortisBC Contribution**	**Extension Cost**	**Connection Charge**	**Customer Contribution**	**FortisBC Contribution**	**Extension Cost**	**Connection Charge**
Low	New 200 amp residential service, 46 meter secondary extension, 35 ft pole mid-span with anchoring	$4,282	$239	$4,521	$500	$2,756	$1,765	$4,521	$533
Mid-low	New 200 amp residential service, 25 kVA pole mount transformer, 46m span, 35 ft pole mid-span	$2,373	$3,842	$6,215	$500	$4,450	$1,765	$6,215	$533
Mid-high	Two new 200 amp residential services, 5 pole overhead extension, Two 25 kVA overhead transformers	$26,109	$4,323	$30,432	$1,000	$26,902	$3,530	$30,432	$1,066
High	42 unit multi-residential condo, 1000 amp underground service, 500 kVA padmount transformer, conversion of existing overhead system fronting property to be converted to underground	$75,855	$20,829	$96,684	$4,620	$22,554	$74,130	$96,684	Actual costs to connect service

BC Hydro's tariff provides a maximum contribution towards system extensions in Rate Zone 1 as follows:

Rate Class	Maximum BC Hydro Contribution
Residential	**$1,475 per Single-Family Dwelling**
General Service	**$200 per kWh of Estimated Billing Demand**
Street Lighting	**$150 per fixture**
Irrigation	**$150 per kW of Estimated Billing Demand**

(Table taken from Original Page 29 of the BC Hydro Tariff)

Q40.3 Is the FortisBC extension contribution for residential customers intended to be based on a single family dwelling or could it be applied to a multi-unit residential dwelling? If it is intended to be based on a single family dwelling, should the tariff be more explicit in stating so?

A40.3 The contribution is based on the average of the residential class and would apply equally to multi-family units provided they fall in the residential class. If the multi-unit has individual meters for each unit and they are billed individually, then each unit would be treated as a separate customer and would receive a credit.

Q40.4 Is the $200 per kWh for RS 20, 21 customers based on kWh of estimated billing demand? If not, what is it based on and should the tariff be more explicit?

A40.4 The Company does not know how BC Hydro implements its line extension credit for general service. The FortisBC line extension credit for general service customers is on a per kW basis and will be applied on the basis of the estimated (or installed) billing demand.

Q40.5 The Fortis contribution for RS 60, 61 (Irrigation and Drainage) customers appears to be a fixed amount, whereas BC Hydro's contribution for irrigation customers is a contribution per kW of Estimated Billing Demand.

A40.5 FortisBC elected to apply the line extension credit for irrigation customers on a fixed dollar amount as the customers within RS 60 and 61 are not metered or billed on the basis of demand. A credit based on estimated billing demand could be more equitable than a fixed credit only if that billing demand could be estimated with accuracy. Without accurate billing demand estimates or metering, any attempt to differentiate credits by demand levels would be inappropriate.

Q40.6 Why has Fortis BC adopted a fixed contribution for such customers, and why is that approach superior to one that bases the contribution on estimated billing demand?

A40.6 Please refer to the response to BCUC IR No. 1 Q40.5 above.

41.0 Reference: Exhibit B-1, Schedule 74 - Extensions, p. 78

FortisBC Contributions: Type II Lighting

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

Q41.1 Given the low overall R/C ratio for Lighting, explain why FortisBC offers any utility contribution to Type II under Rate Schedule 50.

A41.1 Fortis BC did not set line extension credits on the basis of the revenue to cost ratios for each customer class. It is the goal to move towards 95-105% revenue to cost ratio for each class over time, and the line extension credits reflect that goal.

42.0 Reference: Exhibit B-1, Time-of-Use Charges, p. 80
Load Analysis Service Charge

"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."

Q42.1 Explain how FortisBC will determine the applicable charge for the load analysis service under special request.

A42.1 FortisBC will charge the customer an amount equal to the Company's cost to perform the service. The Company will provide the customer with an estimate for approval prior to commencing any work.

43.0 Reference: Exhibit B-1, Schedule 82-New and Upgraded Services, p. 80

Service Types: Trends

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

Q43.1 The above table shows the different service types under Schedule 82. For the most recent 36 months, how many of each Service Type has been requested for each of a) new and b) upgrade installations? What trend has FortisBC observed concerning each type, and how has that been incorporated into the 2009 Rate Design?

A43.1 FortisBC is able to provide the number of services, disaggregated by new installations and service upgrades for services less than 200A and 400A, as shown below:

	2007	2008	2009
<= 200A			
New Install	402	354	208
Upgrade	941	745	629
400A			
New Install	44	81	33
Upgrade	60	46	37

FortisBC did not incorporate any trends into the 2009 Rate Design. It is based on forecast 2009 costs.

44.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 2

Q44.1 What is the basis of the forecast for the winter and summer peaks? Please provide the data and describe the method used to calculate those forecasts.

A44.1 Forecast system peak loads for revenue requirement purposes are based on a probable total system peak from actual historical peaks plus forecast increases due to load growth.

Seasonal Peak Forecasting Process

Step 1: Actual System Peaks (MW)

Year	1	2	3	4	5	6	7	8	9	10	11	12
1997	640	582	484	424	373	362	439	448	403	423	489	558
1998	630	479	459	399	374	394	487	489	436	424	481	630
1999	548	503	466	426	393	423	460	461	401	438	493	532
2000	551	513	463	427	376	422	451	464	373	425	522	614
2001	530	550	490	442	449	414	497	466	402	468	530	560
2002	572	541	568	447	423	491	515	482	392	500	523	556
2003	540	529	514	468	402	446	526	512	433	510	553	609
2004	718	568	505	422	392	501	498	511	398	487	577	606
2005	708	573	506	468	450	439	512	512	425	473	598	675
2006	591	616	549	473	467	521	554	481	434	480	718	647
2007	683	600	539	491	445	459	569	523	430	522	597	627
2008	663	601	504	516	434	495	528	537				

Step 2: Actual and Forecast Net Load Growth

1998	0.0%	Actual
1999	1.0%	Actual
2000	2.9%	Actual
2001	1.9%	Actual
2002	2.1%	Actual
2003	1.8%	Actual
2004	1.2%	Actual
2005	3.3%	Actual
2006	2.4%	Actual
2007	1.0%	Actual
2008	-1.1%	Forecast
2009	1.8%	Forecast
2010	1.5%	Forecast
2011	1.7%	Forecast
2012	1.7%	Forecast
2013	1.4%	Forecast
2014	1.2%	Forecast
2015	1.2%	Forecast
2016	1.2%	Forecast
2017	1.2%	Forecast
2018	1.2%	Forecast
2019	1.1%	Forecast
2020	1.1%	Forecast
2021	1.1%	Forecast
2022	1.1%	Forecast
2023	1.0%	Forecast
2024	1.0%	Forecast
2025	1.0%	Forecast

Step 3: Outcome: Forecast Seasonal Peaks (MW) - as per BCUC Order G-193-08 FortisBC 2009 RR Negotiated Settlement.

The individual historical years are escalated forward using the historical and forecast growth rates.

This produces individual monthly tables (not shown) of potential future peak loads based on the individual historical data years. From these tables, take the January peak number and the December peak number of the previous year for the winter peak. Do this for each table for the year in question.

For example: for 2010, take January 2010 and December 2009. The higher of these two numbers represents the seasonal peak for that historical year.

For the summer peak, July and August of the same year are used, and incorporates the same methodology of escalating the historical peaks.

Seasonal peaks are assumed to occur in January, but can occur in December as well.

This process will produce a spread of possible seasonal peaks for any year in question based on historical data and growth rates. To determine the expected seasonal peak for the year in question, simply average the data.

The final result is shown below.

Expected Winter Peak		Expected Summer Peak	
2009	701	2009	560
2010	712	2010	568
2011	724	2011	578
2012	736	2012	587
2013	746	2013	596
2014	755	2014	603
2015	764	2015	610
2016	774	2016	618
2017	783	2017	625
2018	792	2018	632
2019	801	2019	640
2020	810	2020	647
2021	819	2021	654
2022	827	2022	661
2023	836	2023	667
2024	844	2024	674
2025	852	2025	681

45.0 Reference: Exhibit B-1, Appendix A: Cost of Service Study, p. 5
Summary of Results: Assumptions

"Given a number of assumptions, the results show that when using present rates FortisBC is collecting insufficient revenues to meet current costs for 2009."

Q45.1 Please explain whether the "number of assumptions" referred to is the same set as outlined on page 3 of Appendix A. If not, please list the relevant assumptions.

A45.1 The assumptions are the same as provided on page 3 of Appendix A to the Application (Exhibit B-1).

46.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 6

The COS study states that:

"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."

Q46.1 Please identify the specific changes, in each of the three categories mentioned in the above quote, which have occurred and were considered when developing the COSA.

A46.1 EES has not identified each specific change that has occurred but they would include the following:

- Changes in the FortisBC system include increased transmission capital expenditures, greater reliance on outside power purchases during peak periods and growth in the summer peak for the system;
- Changes in the electric industry include greater reliance on wholesale power markets, unbundling of power products, availability of wholesale wheeling, risks shifted from the utility to its customers, and fewer full requirements wholesale power contracts; and
- Trends in rate design include separation of wires and power supply charges, other rate unbundling for items such as control area service, load following, reliability, standby service, etc., rates that are based on real-time market conditions, and more conservation-based rates.

47.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 6

The COS study states:

"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."

Q47.1 Please identify any financial policies or specific policy considerations from FortisBC that guided the COSA.

A47.1 The COSA was developed using the approved 2009 Revenue Requirements and any financial policies guiding that Revenue Requirements would apply. FortisBC has presented its principles used for setting rate design on page 33 of the Application (Exhibit B-1).

48.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 8-9

The COS study indicates that the percentage of rate base that was related to distribution, transmission, power production and general plant in 1997 as compared to 2009 was as follows:

	1997	2009
Distribution	57%	46%
Transmission	24%	29%
Power production	9%	13%
General plant	10%	12%

Q48.1 Was the rate base functionalized using the same methodology and accounting codes in 2009 as in 1997? If not, please describe any material changes. If so, what are the major changes to the FortisBC business responsible for the shift away from distribution assets towards assets in transmission, power production and general plant?

A48.1 Beginning in 1998, FortisBC began a major program of transmission and generation investment to address equipment that was reaching the end of its serviceable life. The 1998 Master Plan (and the succeeding 2005 System Development Plan) set a long-term direction for numerous transmission system improvements which culminated in the construction of 10 new greenfield substations, and major transmission projects such as the Kootenay 230-kV System Development, the South Okanagan Supply Reinforcement and the Okanagan Transmission Reinforcement. During the same period a generator life extension and upgrade (ULE) program was started which performed major refurbishment and rebuilds at the four Kootenay River generating stations.

49.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 9
Projected Revenues

"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."

Q49.1 Please confirm whether the reference to Schedule 8.1 in above quote is correct, or whether the passage should be modified to reference Schedule 7.1 of Appendix A.

A49.1 The reference should be to Schedule 7.1 of Appendix A of the Application (Exhibit B-1). Please also refer to Errata 2.

Q49.2 Please prepare a table comparing the forecast 2009 sales revenues for each class, as presented in the 2009 approved Revenue Requirement, with the revenues calculated for purposes of the COSA. Include a column showing the difference between the COSA calculated revenues and the forecast revenues for each class.

A49.2 Please see Table BCUC A49.2 below. Note that for the 2009 Revenue Requirements, customer classes were not shown in as much detail as provided for the COSA. Therefore the total calculated from the COSA has combined classes to match with the categories used for the 2009 Revenue Requirements.

Table BCUC A49.2

	Total Calculated from COSA	Total as Filed for 2009 Revenue Requirements	Total As Filed plus 4.6%	Difference	Percent Difference
Residential	$105,955,782	$100,413,000	$105,031,998	$923,784	0.9%
Small General Service	$59,125,382	$56,978,000	$59,598,988	-$473,606	-0.8%
Industrial	$13,891,231	$13,233,000	$13,841,718	$49,513	0.4%
Lighting & Irrigation	$4,677,870	$5,706,000	$5,968,476	-$1,290,606	-21.6%
Wholesale	$49,768,815	$46,518,000	$48,657,828	$1,110,987	2.3%
Total	$233,419,080	$222,848,000	$233,099,008	$320,072	0.1%

Q49.3 Referring to the table developed in response to the previous question, provide an explanation accounting for each difference.

A49.3 For the Residential, Small General Service and Industrial customers the difference was less than 1%. The difference is in part due to the impact of applying the 4.6% increase to the total revenues by class versus applying them to the individual rate components, which have a limited decimal place. Also, the revenues for the Revenue Requirement were calculated on an annual basis while the COSA revenues were calculated on a monthly basis.

This led to some minor differences in the number of bills for the year.

For the Lighting class, revenue was calculated using an average rate per kWh derived from past billings. The revenue calculation for the Revenue Requirements assumed an average rate of 14.34 cents. This was updated in the COSA to reflect the 2008 actual data that became available, and the average rate was changed to 14.24 cents. For the Irrigation class, the Revenue Requirement calculation was made on an annual basis using an average rate of the irrigation season rate and the three general service blocks for all energy. For the COSA, this was calculated monthly with the irrigation season energy at the irrigation rate and the remaining months at the first block general service rate. This led to lower energy charges for the class since the bulk of Irrigation energy occurs in the irrigation season and the Irrigation rate is lower than the average general service rate.

The difference in the Wholesale class occurred due to differences assumed for the demand billing determinants. The load forecast used in the Revenue Requirement did not have monthly peak loads forecast and relied on average kVA figures. The COSA calculated monthly peaks using historical load factors. Those peaks were then used for the demand charge calculations and the demand ratchet was also included in the amounts. This led to higher revenues from demand charges than was forecast for the Revenue Requirement filing.

50.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, pp. 10 -12
Embedded vs. Marginal COSA

On page 10 it states: "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."

Q50.1 Under what circumstances is an analysis of marginal costs valuable for designing rates?

A50.1 Marginal rates can be useful in setting the level or differential in energy rates when inverted block rates or time of use rates are designed.

On page 11 it states: "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."

Q50.2 Please explain why, in light of the situational context described in the passage above, where FortisBC has experienced significant growth in both its infrastructure and demand since 1997, and where both the 2007 BC Energy Plan and the changes to the UCA have raised the issue of energy efficiency and conservation, FortisBC did not undertake a marginal COS study?

A50.2 FortisBC believes that an embedded COSA is the most appropriate method for allocating costs between customer classes as it places all customers on equal footing and is consistent with the level of revenues that need to be collected to cover costs. FortisBC has chosen not to implement wide-scale conservation-based rates for this RDA given a number of different factors. FortisBC plans to look at the issue of conservation-based rates in conjunction with AMI metering over the next several years. At that point it may be more appropriate to look at the marginal cost of power supply when designing a new rate structure.

51.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 13

The study states that:

"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)."

The study then states, also on page 13 that

"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."

Q51.1 Why are customer-related services (e.g. meter reading, billing, collections, advertising, etc.) not functionalized into a separate 'customer service' category as suggested by the first quote, above? What would the impact on the COSA be if the customer-related services were functionalized as a separate category?

A51.1 Customer service related costs are applicable to all classes. The treatment of the customer-service related costs is no different in the COSA than it would be if a separate function was used for customer-service related costs as it is allocated across all customer classes (please see Schedule 1.2 of the Appendix A to the Application [Exhibit B-1]).

52.0 Reference: Ex. B-1, Appendix A: Cost of Service Study, p. 14
Functionalisation of Rate Base: FTEs

"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."

Q52.1 Do the FTEs assigned include those performing functions for non-regulated affiliates?

A52.1 No.

"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."

Q52.2 Was the $92.4 million assigned on the basis of the customer classes making the contributions? If not, why not?

A52.2 FortisBC does not track its contributions on the basis of customer class and therefore needed to use another metric to assign the $92.4 million.

53.0 Reference: Exhibit B-1, Appendix A: Cost of Service Study, p. 14
Functionalisation of Rate Base: FTEs

"[The] 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."

Q53.1 Are the Cost/benefit analyses referred to above the standard tests normally done as a measure of cost-effectiveness for DSM (e.g. Total Resource Cost test, Ratepayer Impact Measure) or is FortisBC referring to a different type of cost/benefit analysis? If the latter, please submit the cost/benefit analysis referred to.

A53.1 This does refer to the standard cost/benefit analyses used by FortisBC.

54.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, pp. 14, 39
Functionalization of Rate Base (General Plant)

"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."

Q54.1 Provide the data and calculations supporting the labour ratios used.

A54.1 Please refer to Table BCUC A54.1 below.

Table BCUC A54.1 – FortisBC 2008 Budgeted Head Count By Department

Department		General Administration	Generation	Transmission	Distribution	
10004	Human Resources	8				
10008	Safety	3				
10009	Training	2				
10012	Treasury/Insurance	5				
10013	Internal Audit	2				
10016	Safety - Environment	1				
10019	Facilities	3				
10022	Communications	4				
10024	Controller	2				
10027	Accounting	9				
10028	Budgets	4				
10070	Generation - Mech. Shop		5			
10071	Generation- Elect Shop		4			
10088	SCC- Resource		2			
10089	SCC-		9	7	4	
10099	Generation- Admin		7			
10120	Engineering		3	2		
10144	Key Acct Management	2				
10150	NS Okanagan-constr			0.25	0.75	
10151	NS Kootenay- CM			1	6	
10153	NS Kootenay-Ops			1	9	
10154	NS Kootenay-Admin				5	
10170	NS Okanagan- Kelowna Ops			2	5	
10171	NS Okanagan- OK CM			8	1	
10180	NS Okanagan - SOK OP			2.75	7.25	
10184	NS Okanagan- NS admin			1	1	
10185	Engineering - AM FM			1	2	
10202	Generation - Maint		7			
10218	Planning			1	1	
10220	Planning - Mtce Land			1	1	
10230	Generation - Ops		2			
10231	Generation - Engineering		3			
10305	Fleet Admin	14				
10502	Materials - Warehouse	16				
10503	Materials - Procurement	4				
10554	Legal	7				
10556	Corporate - Executive	8				
10561	Customer Serv- Metering	20				
10566	Customer Serv- Contact Ctr	27				
10567	Customer Serv- Billing	12				
10571	IT- Exec Admin	2				
10572	IT-Application Systems	7				
10577	IT-Infrastructure	7				
10584	Revenue Protection	1				
						Direct G/T/D
44	Total Cost Centers/Employees	170	42	28	43	113
			+42/113	+28/113	+43/113	
Total		% allocation	37%	25%	38%	

* includes PLP employees, as well as PT, Temp…etc.

Q54.2 Do the labour ratios reflect the number of full-time equivalents assigned to the customer service, accounts and sales functions?

A54.2 The labour ratios do not reflect the number of FTEs assigned to customer service, accounts and sales functions.

Q54.3 Provide reasons supporting the use of labour ratios to functionalize the general plant accounts, rather than assigning the accounts on the same basis as the sum of the investments in generation, transmission and distribution plant.

A54.3 General Plant primarily includes things like office buildings, office equipment and vehicles. These facilities are generally used by both employees assigned to various functions and employees that support the various functions, such as human resources or accounting. Because the cost of General Plant is more closely tied to the number of employees rather than the cost of other plant items, the Company determined it was appropriate to use labour ratios for classification.

55.0 Reference: Exhibit B-1, Appendix A: Cost of Service Study, p. 15

Functionalisation of Revenue Requirement: A&G Costs and Labour Ratios

"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."

Q55.1 Please confirm that the labour ratios and the number of employees used referred to in the citation are exclusive of employees assigned to non-regulated affiliates.

A55.1 Confirmed.

56.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 15 and Schedule 3.2

Functionalization of Revenue Requirements

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

A56.1 Please confirm that a portion of Supervision and Administration expenses (Account 901.00) have in fact been functionalized to production and transmission, as presented on Schedule 3.2.

A56.1 Yes, a small amount of costs in account 901 follow the functionalization used for account 911, which is split between production, transmission and generation.

"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."

Q56.2 Why is it appropriate to functionalize account 931.00 (insurance costs) on the basis of labour ratios rather than on total plant?

A56.2 The insurance coverage included in account 931 includes more than just property insurance. It includes liability insurance, general commercial insurance, auto insurance, directors & officers insurance, and fiduciary insurance. As such it was not directly related to utility plant alone and was therefore functionalized and classified using labour ratios, which is the treatment for other A&G costs.

57.0 Reference: Exhibit B-1, Appendix A: Cost of Service Study, p. 17

Classification of Power Supply Expenses: BC Hydro Rate Schedule 3808

"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."

Q57.1 Please submit a copy of the cited contract between BC Hydro and FortisBC.

A57.1 The contract is attached as BCUC Appendix A57.1.

Q57.2 Does the contract with BC Hydro require FortisBC to pay a demand charge? If so, is the charge based on the contracted maximum of 200 MW? If not, what is it based on?

A57.2 Yes, FortisBC pays a demand charge under its Power Purchase Agreement ("PPA") contract with BC Hydro. However, the charge is not based on the contracted maximum of 200 MW. It is based on the greatest of three calculations:

1. 50 percent of the nominated demand. Nominations are between zero and 200 MW and are made five years in advance. For many years now the Company has nominated 200 MW and expects to continue to do so for the foreseeable future;
2. The actual monthly usage;
3. 75 percent of the previous 11 months highest actual usage.

For all practical purposes, (1) above is never used except to establish a firm forward financial commitment to pay for 100 MW each month in the Company's forward looking financial reporting. Assuming the Company uses the 200 MW each winter, the actual monthly charge will be between 150 and 200 MW.

Q57.3 Please submit a copy of BC Hydro Rate Schedule 3808.

A57.3 The requested document is provided as BCUC Attachment A57.3.

SCHEDULE 3808 – TRANSMISSION SERVICE – FORTISBC

Availability: This schedule is available to FortisBC in accordance with the terms and conditions of the Agreement between BC Hydro and FortisBC entered into and deemed effective the 1st day of October 1993 (the "Power Purchase Agreement"). The Total Nominated Demand shall not exceed 200 MW.

Applicable in: For Electricity delivered to FortisBC at each Point of Interconnection and the Point of Supply as defined in the Power Purchase Agreement.

Rate: Demand Charge: $5.260 per kW of Billing Demand per Billing Month

plus

Energy Charge: 3.083¢ per kW.h of Purchase Energy per Billing Month.

Billing Demand: The Demand for billing purposes in any Billing Month shall be the greatest of:

1. the Total Purchase Capacity for that Billing Month, plus 1.2 times the Total Excess Capacity for that Billing month; or
2. 75% times the sum of the highest Total Purchase Capacity registered in any of the preceding eleven months, plus 1.2 times the highest Total Excess Capacity in any of the preceding eleven months; or
3. 50% of the Total Nominated Capacity, plus 1.2 times the Total Excess Capacity for that Billing Month.

Excess Energy Charge: 1.15 times the Energy Charge per kW.h for each kW.h of Total Excess Energy.

Note: The terms and conditions under which service is supplied to FortisBC are contained in the Power Purchase Agreement. This Schedule is subject to the same rate adjustments as Schedule 1827.

Taxes: The rates and charges contained herein are exclusive of the Goods and Services tax and the Social Services tax.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase: Effective April 1, 2009 the Rates and Minimum Charge under these schedules include an increase of 8.74% before rounding, approved by BCUC Order No. G-16-09 and its attached Reasons for Decision. The previous interim rate increases effective April 1, 2008 and October 1, 2008 have also been approved as final as a result of BCUC Order No. G-91-09 concerning BC Hydro's 2008 Long Term Acquisition Plan.

ACCEPTED: SEP 14 2009
ORDER NO. G 16 '09, G 91 09

EFFECTIVE: APRIL 1, 2009

COMMISSION SECRETARY

Q57.4 Please confirm that the rates quoted in the citation above are consistent with the current BC Hydro Rate Schedule 3808.

A57.4 Confirmed.

58.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, pp. 17-18 and 30 Classification of Generation

Q58.1 Describe the dispatch strategy for the utility owned generation and power purchases from all sources for meeting base and peak demand.

A58.1 There are two general dispatch scenarios: 1) build energy reserves to meet future load; and 2) make maximum use of owned generation to meet current load.

Under the first scenario, the Company will minimize the use of utility owned generation and rely on the BCH PPA and/or market purchases to meet load. This builds up energy reserves for the future and is generally done during periods of lighter loads. However, during periods of high demand, the Company will draw down energy reserves by maximizing the use of utility owned generation. If demands are high enough, this will be done in addition to maximizing PPA purchases and making market supply arrangements. Finally, if the opportunity presents itself due to market conditions, market supply may be used to displace PPA capacity and/or energy as the situation allows.

Q58.2 Is FortisBC's own generation dispatched as fully and as often as technically possible in order to supply as much of the utility's demand as possible?

A58.2 The Company's owned generation is limited by fuel supply (water). This water must be carefully managed to ensure it is used at the highest value times possible. Please refer to the response to BCUC IR No. 1 Q58.1 above for a description of this dispatch process. The Company expects to use all available water over the course of the season. The fact that the Company operates under the Canal Plant Agreement does not change the above, it only ensures that the amount of energy from owned generation (derived from the Company's water rights) is a known amount with no risk of a poor water year.

Q58.3 To what extent does the water coordination contract with BC Hydro and with other parties on the Kootenay River affect FortisBC's dispatch strategy and impede the full utilization of its own plants during times of peak demand?

A58.3 There is no negative impact—if anything, there is a positive impact since FortisBC draws from the BC Hydro grid and BC Hydro has to plan the actual dispatch of the resources, not FortisBC. This represents a savings of several full time staff planning resources. Please refer to the responses to BCUC IR No. 1 Q58.1 and Q58.2.

On page 17 the application states:

"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."

On page 18 it states: "... the generation split is equivalent to the 80% demand and 20% energy resulting from the full Rate 3808."

Q58.4 Please reconcile the demand/energy splits presented in the two statements above.

A58.4 Page 18 is in error and should be 20% demand and 80% energy. Please also see Errata 2.

BC Hydro Rate 3808 is based on BC Hydro's classification of its costs associated with serving baseload and peak demand. FortisBC has not undertaken a similar classification study. (On page 17 it states: "*In the case of FortisBC, the Kootenay River Plants are the only utility-owned generation, and the 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.*"

Q58.5 Can FortisBC confirm that its dispatch strategy is identical to BC Hydro's?

A58.5 Under the Canal Plant Agreement BC Hydro is responsible for the physical dispatch of the Company's generation units. However, in general, the dispatch of the resources those units represent will be similar—store water when the chance occurs and use it when it is needed to meet load.

Page 30 presents the monthly demands for both FortisBC and BC Hydro.

Q58.6 How could differences between FortisBC's and BC Hydro's annual demand profiles affect the classification of generation costs between the two utilities?

A58.6 In the case of FortisBC, the wholesale rate has a demand charge each month and therefore the amount of demand used under Rate 3808 is used to determine the demand-related costs associated with the purchase. A difference in the amount of demand used under the contract would change the amount assigned to the demand category. In general, the demand profiles between utilities will lead to different mixes of resources, whether utility-owned or purchased on the wholesale market. This different resource mix will lead to different amounts assigned as demand-related.

Q58.7 Did FortisBC consider further classifying the demand portion of generation into base and peak components; the former of which could be allocated based on non-coincident peak demand; the latter on coincident peak demand? If not, why not?

A58.7 Generally the splitting of resources into base and peak components is done as a method for classifying costs between demand and energy. Generation used to serve base loads rather than peaking are generally considered energy related and are not allocated on the basis of non-coincident peak (“NCP”).

59.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 17-18

The COSA states, on page 17, that in the 1997 COSA, generation rate base was all considered to be energy-related but that, because 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.

Q59.1 Please provide a graph showing for 2008, the daily peak load from the Kootenay River Plants, Rate Schedule 3808 purchases on a daily basis, and the daily peak demand on the FortisBC system.

A59.1 The requested data is not available on a daily basis without difficulty since the Company does not track it in the requested form. Extensive manual calculations for thousands of hours would be required to provide the requested information. However, for capacity purposes, the hour of interest is the peak hour of the month as this sets the planning requirements and the Company does prepare similar information to what is requested on a monthly basis. This information can be found in Table BCUC A59.1 below.

It is difficult to state exactly what resource was used to meet load as the Company has many resources and they all interact with each other. For example, both the Columbia Power Corporation and Teck Cominco control entitlement resources under the Canal Plant Agreement within the Joint System the Company shares with them. The Company tracks the overall use of Joint System entitlement capacity rather than any individual component of it. For the majority of hours, the overall Joint System has surplus resources to meet the aggregate Joint System requirements. When this is the case, it means Joint System entitlement use under the Canal Plant Agreement is less than the maximum allowable use since it is the only resource that can be backed down to balance the system. However, the available capacity will almost certainly have been used for planning purposes to either meet load or to provide a strategic hourly reserve to ensure reliability. Without detailed hourly analysis, it is not possible to state which portion of the overall Joint Entitlement is being underutilized since the Company makes use of all such capacity to meet its requirements. Therefore, it is extremely difficult to state what the overall Company actual plant use was—only to state how much was available for use.

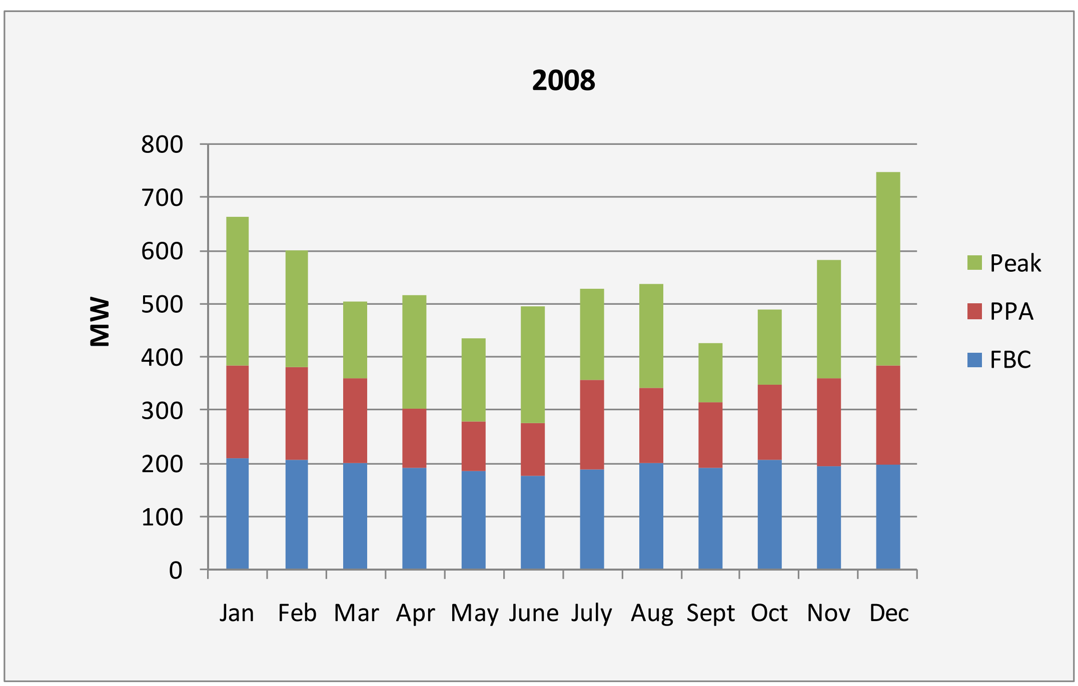
Company use of the BC Hydro PPA is also complex. If the Company does not have sufficient scheduled resources to meet load, then the PPA acts as the balancing resource to supply the shortfall. In hours where there is concern about the magnitude of the load and if there will be sufficient resources available to meet that load, the Company tends to resource to a higher level of hourly reserves than in hours that are not a concern. This is required to ensure the reliability of power supplies when they are needed the most. Therefore, hourly load uncertainty tends to ensure that peak use of the PPA capacity actually occurs on hours where the Company is not that concerned about the overall supply of electricity. The Company accepts this uncertainty since the cost of maintaining the higher overall hourly margins to prevent it would more than offset the increased PPA capacity charges and reliability of supply in these hours is not an issue. This explains why in many months the billed PPA capacity is slightly higher than the peak hour usage. For the other months, capacity ratchet provisions required a minimum payment for at least 148.5 MW.

BCUC Table A59.1

2008	FortisBC Plant [1]	BC Hydro PPA Peak Hour Usage	BC Hydro PPA Billed Amount [2]	FBC Peak Monthly Load
	(MW)			
January	210	175	187	663
February	206	175	187	601
March	200	160	171	504
April	192	110	150.75	516
May	187	93	148.5	434
June	178	98	148.75	495
July	188	168	179	528
August	202	140	165	537
September	191	125	148.5	427
October	207	140	150	490
November	194	165	179	581
December	198	185	191	746

Note 1 FortisBC Plant available for use is after outages and reserves
Note 2 BC Hydro PPA is the power flow for the peak hour of the month.

Figure BCUC A59.1



60.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 18

On page 18, the COSA states that for distribution rate base:

"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."

However, all transmission rate base accounts are classified as 100% demand-related.

Q60.1 Why is transmission classified as 100% demand- related, while distribution is classified based on a minimum system approach? Is the differing treatment of the transmission and distribution systems not inconsistent, and if not, why not?

A60.1 As distribution facilities are closer to the customer, the fact that the customer exists drives the need to build a portion of the facilities, regardless of the load size. For facilities that are farther from the customer, with the ability to benefit from the diversity of customers, it is the demand component that drives the need to build the facilities. Transmission, like distribution substations, is driven by the peak load or contractual reservation rather than the number and location of customers. Within the distribution function, some accounts are demand-related, some are customer-related, and some are split between the two.

Q60.2 Please provide a table showing the R/C ratios if all distribution lines and transformers were classified as 100% demand?

A60.2 Table BCUC A60.2 below provides the revenue to cost ratios by class if the COSA is changed as requested.

Table BCUC A60.2

	Adjusted Revenue to Cost Ratio
Residential	104.0%
Small General Service (20)	108.9%
General Service (21)	121.4%
Industrial Primary (30)	113.0%
Industrial Transmission (31)	109.9%
Industrial Transmission TOU (33)	23.5%
Lighting	88.3%
Irrigation	69.5%
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%

61.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 18
Classification of Transmission

Q61.1 Did FortisBC consider further classifying transmission into base and peak components; the former of which could be allocated based on non-coincident peak demand; the latter on coincident peak demand?

A61.1 FortisBC did not consider splitting transmission into peak and base components.

62.0 Reference: Exhibit b-1, Appendix A, Cost of Service Study, p. 21

The COS study states that for FortisBC, "…it was determined that the average PLCC for the FortisBC system is 1.0 kW per customer."

Q62.1 How was the 1.0 kW per customer PLCC determined?

A62.1 A description of the PLCC calculation can be found on pages B-10 through B-13 of the Cost of Service Study (Exhibit B-1, Appendix A).

Q62.2 Based on the consultants experience with other utilities, how commonly has the PLCC approach been used and what is the range of PLCC estimates for other distribution utilities?

A62.2 The PLCC adjustment has been used by North York Hydro, Hydro Quebec, Ontario Hydro and MEA Ontario. The adjustments range from 0.25 to 2.0 kW per customer.

63.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, pp. 22-23
Classification of Production/Power Supply Expenses

On page 22 it states: "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."

Q63.1 On what basis was it determined that the 3808 breakdown of demand and energy prices could be used as a proxy for the split between demand and energy components?

A63.1 The 3808 pricing structure is used to reflect the market for demand and energy prices at the wholesale level. FortisBC does not have a wide mix of resources that can be used to differentiate which plants are base load and which provide peaking for the system. Given the limited resources of FortisBC, it was necessary to determine a method to recognize both the contribution of the resources to energy and demand requirements. Some type of market pricing or shadow pricing for peaking units is generally used in these types of cases. The BC Hydro wholesale price reflects the market and has the advantage of already being approved by the BCUC.

Q63.2 Why would the costs associated with power purchases from the Brilliant hydro plant not be classified according to the energy/demand pricing structure associated with the charges pursuant to this power purchase agreement?

A63.2 The Brilliant power purchase contract is priced such that FortisBC pays a share of the annual costs associated with the plant and receives a share of actual output from the plant. There is not a specific demand and energy price structure associated with the contract.

64.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 23

Page 23 of the Application contains a table summarizing the output and costs associated with each of the power supply sources.

Q64.1 If each of the resources was dispatched with a view to minimizing FortisBC's overall power supply costs, in which order would it generally dispatch these resources?

A64.1 The order of dispatch can vary depending on loads and market conditions. Please refer to the response to BCUC IR No. 1 Q58.1 for a description of the Company's dispatch priorities. All dispatch is always done with the intent to minimize cost without undue risk to reliability. The Company notes that for all dispatch purposes, the Brilliant Hydro resource is fully integrated and treated exactly the same as the Company owned Kootenay River Plants.

65.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 24

The COS study states that:

"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."

Q65.1 Please explain why the employees are more closely tied to the asset value rather than the O&M associated with each function.

A65.1 The need to tie the labour ratios by either rate base or O&M is used as a way to allocate to the various customer classes, since employees are not specifically allocated across classes. The employees assigned to specific functions need to operate and maintain the facilities, as well as work on any new assets being built on the system. Their activities tie to both Rate Base and O&M. Second, A&G covers cost centers that include senior management, general accounting and information services. Senior management needs to oversee the existing assets, expenditures on new assets, as well as the staff that perform O&M functions. A great deal of time for accounting and information services is spent tracking all of the assets and inventory of the system, and not just the expenses. Finally, since the O&M accounts generally follow the treatment of the corresponding rate base accounts, use of O&M for the multiplier would have a similar impact as the use of Rate Base.

66.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, pp. 26, 31
Selection of the 2 CP Method

EES Consulting applied the FERC and OEB tests to determine which coincident peak methodology is appropriate for allocating transmission costs. Table 1 presents the results of these tests as applied to the actual and forecast monthly peak demands over the period 2004 – 2009.

Q66.1 In applying FERC Test #1, which months were included in the calculation of the average monthly peak during the peak months in each year over the period 2004 - 2009?

A66.1 The months January, February, November and December were used as the peak months, which represent the four highest months in each year.

Q66.2 In applying FERC Test #1, which months were included in the calculation of the average monthly peak during the off-peak months in each year over the period 2004-2009?

A66.2 The months March through October were used for the off-peak months.

Q66.3 In applying OEB Test #2, which four months were included in the calculation of the average monthly peak in each year over the period 2004-2009?

A66.3 As with FERC Test No. 1, the months January, February, November and December were used as the peak months, representing the four highest months in each year.

Q66.4 Please confirm that the FERC and OEB tests are determinants of whether a 1CP, 4CP or 12CP peak demand allocator should be used.

A66.4 The FERC and OEB tests are not standard tests designed for the selection process to be used by all utilities but rather are guidelines resulting from past precedents used in approving the appropriate peak metric for specific utilities.

Q66.5 Referring to the response of the previous question, please confirm whether the peak demands used in the determination of the 1CP and 4CP demand allocators, as defined by both the FERC and the OEB, are the single and four highest monthly peaks, respectively, in the calendar year, regardless of when they occur.

A66.5 The 1 CP and 4 CP allocators reflect the single and four highest peaks of the calendar year.

On page 28 it states: "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."

Q66.6 Considering the responses to the previous questions and the quote above, please comment on how the FERC and OEB tests can make a determination of an allocation method other than 1CP, 4CP or 12CP.

A66.6 The FERC and OEB tests are meant to look at whether a utility has a pronounced peak that should be used for allocation or relatively flat peaks across the year such that a 12CP approach should be used. These tests do not provide a comparison of summer to winter peaks.

On page 31 it states: "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."

Q66.7 What aspects of FortisBC system planning need to recognize the growth in the summer peak?

A66.7 From a planning perspective summer peaks must be considered primarily at the distribution substation and local distribution level in areas such as Osoyoos where summer peaks are growing quickly and approaching the winter peaks at certain locations. From a bulk transmission planning perspective, the winter peak is still the primary consideration. FortisBC does not expect transmission capacity expansion based on summer demand within the current planning horizon.

Q66.8 To what extent does FortisBC anticipate the need to expand its transmission capacity to meet its summer demand?

A66.8 Please refer to the response to BCUC IR No. 1 Q66.7 above.

Q66.9 To what extent does FortisBC anticipate the need to expand or purchase additional generation capacity to meet its summer demand?

A66.9 Please see the response to BCUC IR No. 1 Q66.7 above. The considerations that apply to bulk transmission planning apply equally to resource planning as well.

Q66.10 In what year does FortisBC expect the summer and winter peaks to be equal?

A66.10 FortisBC does not expect the system summer peak to be equal to the winter peak over the current planning horizon. However, the system cannot carry as much load in the summer due to higher ambient temperatures.

Q66.11 During the next 20 years, does FortisBC forecast the magnitude of the summer peak to exceed that of the winter peak?

A66.11 Please refer to the response to information request Q66.10 above.

Q66.12 Please show each customer (Residential, General Service, Wholesale, and Other Transmission) category's growth rate rates with respect to each of the summer and winter peaks to be used in the 2CP calculation.

A66.12 The relative growth rates of winter to summer peak by customer class are not used in determining the 2CP allocation factors. Only the percentage contribution of the customer class towards the overall system coincident peak is considered. FortisBC does not track the annual growth rate in seasonal load for each class separately.

67.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 28

Q67.1 Please provide the spreadsheet used to calculate the results of the tests to determine which of the peak demand allocation alternatives should be used, and which supports the table on page 28.

A67.1 The requested spreadsheet is provided in electronic Excel format only as BCUC Attachment A67.1.

Q67.2 Please provide a table comparing the revenue/cost ratios that would result from the use of 1CP, 4CP and 12 CP demand allocators with the 2CP demand allocator used in the COSA.

A67.2 Table BCUC A67.2 below provides the requested results.

Table BCUC A67.2
Revenue to Cost Ratios by Peak Allocation Method

	2 CP (As Filed)	**1CP**	**4CP**	**12 CP**
Residential	98.3%	95.3%	97.7%	100.1%
Small General Service (20)	113.4%	115.9%	118.1%	117.0%
General Service (21)	138.9%	138.2%	141.2%	139.2%
Industrial Primary (30)	122.4%	121.9%	121.1%	120.8%
Industrial Transmission (31)	109.9%	112.5%	111.3%	108.3%
Industrial Transmission TOU (33)	23.5%	25.4%	24.4%	22.7%
Lighting	81.9%	78.2%	78.2%	80.2%
Irrigation	78.6%	92.8%	85.1%	78.5%
Kelowna Wholesale	89.9%	92.8%	91.3%	88.5%
Penticton Wholesale	78.0%	77.8%	76.1%	74.3%
Summerland Wholesale	96.6%	95.1%	93.4%	92.1%
Grand Forks Wholesale	68.1%	67.0%	65.4%	64.0%
BC Hydro Lardeau Wholesale	101.8%	85.0%	96.6%	104.1%
BC Hydro Yahk Wholesale	103.5%	102.2%	99.7%	99.7%
Nelson Wholesale	80.0%	83.4%	81.4%	78.2%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**

68.0 Reference: Exhibit B-1, Appendix A: Cost of Service Study, p. 28

Selection of 2CP 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.

Q68.1 Please explain how the growth rates for winter and summer peaks were incorporated into the tests.

A68.1 The growth rates were not incorporated into the tests, however, since multiple years were used the tests would account for changes that occur over time.

Q68.2 Which years were the tests calculated for?

A68.2 The tests were calculated for the years 2004 through 2008 (actuals) and the 2009 forecast.

Q68.3 Please identify other electric utilities using a 2CP allocator.

A68.3 We have not completed a search of utilities using the 2CP allocator for this application. The use of the 2CP allocator was the precedent for the utility based on the 1997 approved RDA and there was no evidence that suggested a need to change the methodology.

Q68.4 Why did FortisBC elect not to use the 4CP allocator that appears to be recommended by the test results in Table 1?

A68.4 The tests show a recommendation of the use of either a 1CP or 4CP as opposed to the use of a 12 CP. The tests are limited to looking only at the use of the 12CP method to a distinct peak method and does not contemplate the case where a dual peak occurs. FortisBC did not rely on the tests as the only method in determining the appropriate peak allocation method. In making the decision, FortisBC followed these steps:

1. The precedent for peak allocation was 2 CP;
2. Given the precedent, whether circumstances at the utility had changed to warrant a different allocator;
3. The FERC and OEB tests were considered and they indicated that a 12CP allocator was not appropriate;
4. Trends in summer and winter peaks were examined and there was an indication that the summer peak was growing faster than the winter peak, therefore it was not indicated that a change to 1 CP or 4CP was needed;
5. FortisBC engineers indicated that in some cases summer peaks were considered along with winter peaks in planning for new facilities;
6. The BCUC recently approved a 4CP allocator for BC Hydro. To see if this was appropriate for FortisBC the monthly peaks for FortisBC were compared to those of BC Hydro. The shapes were significantly

different with no secondary summer peak occurring for BC Hydro as it does for FortisBC; and

7. Given these various analyses, there was nothing to indicate a need to change the past regulatory precedent of the 2CP allocator.

Q68.5 Please show the Revenue/Cost ratios that would result from the use of the 4CP allocator.

A68.5 Please refer to the response to BCUC IR No. 1 Q67.2.

"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."

Q68.6 Please provide a load duration curve for FortisBC for the most recent 12 months for which data are available, and also provide the associated, hour-specific data.

A68.6 The requested information is attached in an electronic version only as BCUC Attachment A68.6.

Q68.7 For the 50 highest load hours (in the above data), what is the load share (including losses) for each of Residential, General Service, Wholesale, and Other Transmission customer categories?

A68.7 FortisBC has the interval metering required to answer this question for only 22 customers (a total of 49 meters). Therefore, FortisBC cannot provide accurate load share information at the hours requested.

Q68.8 Can FortisBC confirm that its load duration curve is identical to BC Hydro's?

A68.8 FortisBC does not have access to the required BC Hydro information to definitively respond to this request, however given that BC Hydro and

FortisBC are distinct utilities with differing characteristics, it is unlikely that the respective load duration curves would be identical.

69.0 Reference: Exhibit B-1, Appendix A: Cost of Service Study, p. 31
Use of Contractual Demand: Curtailment Provisions

"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."

Q69.1 Please describe any curtailment provisions associated with the provision of service to Rate Classes 31 and 33, and Wholesale customers.

A69.1 The Company understands that in the context of the question, curtailment refers to the suspension or reduction in supply from the Company in response to resource availability as opposed to infractions of the Terms and Conditions of its Electric Tariff of the municipal wholesale contracts themselves which may result in suspension of supply in accordance with Section 8.2 therein.

The Wholesale Contracts provide for curtailment provisions set out in Sections 4.03 provided in BCMEU Appendix A34.2. These curtailment provisions allow for curtailment in certain specific situations including shortage of electricity or breakdown or failure of equipment. However, these provisions are not exhaustive and do not include for example, shortages in the event of system capacity constraints. The other rate classes do not have these provisions.

Q69.2 What curtailment priority is assigned to those and other Rate Classes?

A69.2 Please refer to the response to BCUC IR No. 1 Q69.1.

Q69.3 Please explain whether and how the curtailment provisions are reflected in the 2009 Rate Design.

A69.3 The curtailment priority discussed in the response to BCUC IR No. 1 Q69.1 represents an enhanced level of service and is inherently reflected in the COSA by choosing to allocate costs based on the contractual obligations contained in the supply agreements.

70.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 29-31

Page 31 of the COS study states that for FortisBC, the July and August peaks exceed the summer average and are approaching the winter average peak.

Q70.1 Please provide the data behind Tables 2 through 4, on pages 29 and 30, in tabular rather than graphical form, showing the data for each year from 2001 to 2007, and the average monthly peak for each of those years.

A70.1 The requested data is provided in electronic Excel format as BCUC Attachment A67.1.

71.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 31

The COS study states that "In the case of the wholesale customers, FortisBC is actually required to build new facilities once actual loads reach 95% of the contractual demand."

Q71.1 Please describe in more detail, the contact provision that establishes the threshold above which FortisBC must build new facilities. For example, is the 'actual load' stated in the quote, the hourly or daily load if it reaches the threshold level once? If possible, please supply a representative or pro- forma example of the clause or clauses in the Wholesale customer contracts that require Fortis to build the new facilities.

A71.1 The clause below is drawn from the City of Penticton contract and is typical of clauses contained in each Wholesale agreement.

Maintenance of Adequate Supply Capability

If at any time, except in an emergency condition described in subsection 6.03, City of Penticton notifies FortisBC that it has taken electricity in excess of 95 percent of the Demand Limit of a Point(s) of Delivery, FortisBC shall take appropriate measures at no cost to City of Penticton to increase the supply capability at the Point(s) of Delivery to bring City of Penticton's anticipated future demand to or below 95 percent of the Demand Limit.

FortisBC considers that each Wholesale utility may make notice pursuant to the above clause where loads exceed 95 percent of the demand limit at a point of delivery as recorded by the metering a sixty minute clock hour interval. A recent example of this occurred in 2006, where the City of Penticton, a municipal Wholesale Utility, was forecast to require an upgrade which supported their voltage conversion program when their load exceeded 95 percent of their contract demand at the Waterford Substation, a point of delivery set out in the Contract. The costs of the upgrade were to be borne by all of FortisBC's customers, but the bulk of the benefits from the voltage conversion program were to be for the City of Penticton. In other rate classes where facilities are dedicated for the sole use and benefit of that customer and require an upgrade, those costs are borne by that customer.

Q71.2 Please provide a table showing, for each wholesale customer the peak demand that would have been used in the COSA if the 1997 method had been used for the application and the current Contract demand.

A71.2 Please refer to Table BCUC A71.2 below.

Table BCUC A71.2
Wholesale Demand Comparison

Forecast of Monthly Peaks	Kelowna	Penticton	Summerland	Grand Forks	BCH Lardeau	BCH Yahk	Nelson
Jan-09	61,401	71,883	20,529	8,062	4,964	584	23,855
Feb-09	59,575	71,184	19,953	8,126	3,789	520	24,893
Mar-09	49,408	60,272	17,176	6,893	2,580	483	20,751
Apr-09	45,257	56,106	18,796	6,379	3,452	472	21,592
May-09	42,415	48,300	12,579	5,618	1,798	800	16,926
Jun-09	50,500	61,262	16,049	6,866	1,646	389	18,747
Jul-09	45,859	61,151	15,590	6,607	1,693	372	18,173
Aug-09	54,909	62,813	16,948	7,087	1,779	379	19,858
Sep-09	43,527	52,965	13,982	6,428	1,919	625	16,498
Oct-09	44,520	55,546	16,407	6,328	2,084	599	22,601
Nov-09	57,778	69,624	19,518	7,833	2,051	697	24,354
Dec-09	62,455	76,066	23,607	8,845	3,175	679	26,092

Contract Demand	Kelowna	Penticton	Summerland	Grand Forks	BCH Lardeau	BCH Yahk	Nelson
Jan-09	90,882	155,034	29,700	23,760		495	44,550
Feb-09	90,882	155,034	29,700	23,760		495	44,550
Mar-09	90,882	155,034	29,700	23,760		495	44,550
Apr-09	90,882	155,034	29,700	23,760		495	44,550
May-09	90,882	155,034	29,700	23,760		495	44,550
Jun-09	90,882	155,034	29,700	23,760		495	44,550
Jul-09	90,882	124,245	21,780	17,820		396	44,550
Aug-09	90,882	124,245	21,780	17,820		396	44,550
Sep-09	90,882	155,034	29,700	23,760		495	44,550
Oct-09	90,882	155,034	29,700	23,760		495	44,550
Nov-09	90,882	155,034	29,700	23,760		495	44,550
Dec-09	90,882	155,034	29,700	23,760		495	44,550

Q71.3 Please show the R/C ratios that would result if the 2009 COSA method was used and the wholesale customers were analyzed as individual rate classes, but the peak demand for the wholesale customers was used rather than the contract demand.

A71.3 Please refer to Table BCUC A71.3 below.

Table BCUC A71.3
Revenue to Cost Ratios with and without Contract Demand

	Contract Demands for Wholesale/Industrial (As Filed)	Actual Demands for Wholesale/Industrial (1997 Method)
Residential	98.3%	93.8%
Small General Service (20)	113.4%	107.9%
General Service (21)	138.9%	130.3%
Industrial Primary (30)	122.4%	114.6%
Industrial Transmission (31)	109.9%	111.7%
Industrial Transmission TOU (33)	23.5%	46.3%
Lighting	81.9%	81.0%
Irrigation	78.6%	74.1%
Kelowna Wholesale	89.9%	96.8%
Penticton Wholesale	78.0%	91.6%
Summerland Wholesale	96.6%	97.8%
Grand Forks Wholesale	68.1%	88.2%
BC Hydro Lardeau Wholesale	101.8%	93.5%
BC Hydro Yahk Wholesale	103.5%	98.1%
Nelson Wholesale	80.0%	95.4%
Total	100.0%	100.0%

72.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 32

The COSA states on page 32 that: "Because the contractual demand often exceeds actual loads, there is surplus capacity on the system." On page 35, the study states that:

"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."

Q72.1 To what extent, if at all, does the surplus capacity on the system add to the ability of FortisBC to generate "other revenues" which are then credited back to customers? For example, if other revenue is generated by the surplus capacity created by large general service/industrial or wholesale customers, are the revenues credited back to those customer classes?

A72.1 FortisBC does not have any ability to generate additional revenue from any surplus capacity that may exist.

73.0 Reference: Exhibit B-1, Appendix A: Cost of Service Study, p. 32
Use of Contractual Demand: Curtailment Provisions

"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."

Q73.1 Does AESO offer firm transmission service?

A73.1 The rate referred to on page 32 of the Application (Exhibit B-1) is for Demand Transmission Service. The tariff does not indicate whether that is considered firm service.

Q73.2 Please explain why FortisBC considers the AESO approach as being directly applicable to the FortisBC system.

A73.2 The AESO is an example in the electric utility industry of the utilization of contract demand to allocate costs and therefore is applicable as a precedent in support of the Application.

74.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 32

The COS study states that:

"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."

Q74.1 The first sentence of the paragraph indicates that NCP and 2CP allocation factors will be adjusted to reflect the actual demand if that is higher than the contractual demand. It appears to suggest that if a customer has consistently exceeded contractual levels, its demand would be higher than the contract demand and it would be used in the COSA allocation. The final sentence of the paragraph states that where customers have consistently exceeded contractual levels that added capability will not be used in the COSA allocation. Please reconcile these two apparently contradictory statements.

A74.1 The COSA model does take the greater of the contract demand and the 2009 forecast demand. This occurs specifically for Yahk where the contract demand is exceeded in several months. (See response to BCUC IR No. 1 Q71.2) FortisBC has not yet set a new contract demand level for Yahk. The forecast for 2009 includes a peak demand of 800 kW for Yahk compared to a contract demand of 495 kW. A new contract demand level would likely be higher than 800 kW to allow for variability in peaks due to extreme load conditions and future growth of the customer. It is that higher demand level for the next contract that has not yet been incorporated into the COSA.

Q74.2 Please explain how FortisBC charges customers for capacity used that exceeds contractual levels.

A74.2 Where a customer's actual demand exceeds its contract demand, the actual demand would become the level of demand used for billing. Depending on the rate under which the customer receives service, and the degree to which the contract demand was exceeded, a ratchet provision could be triggered.

Q74.3 Over the last 36 months for which data are available, what has been the average capacity utilisation (in percentage) by each of Industrial and Wholesale Rate Classes (as defined in the Application)?

A74.3 Over the last 36 months the average capacity utilization (measured demand divided by contract demand) for the Industrial rate class is as follows:

Table BCUC A74.3a

Schedule 31 Measured Demand	Contract Demand	Capacity Utilization
452,832	500,000	90.57%

The average capacity utilization for the Wholesale classes are:

Table BCUC A74.3b

Class	Measured Demand	Contract Demand	Capacity Utilization
Nelson Hydro	691,258	1,575,000	43.89%
City of Kelowna	1,840,650	3,213,000	57.29%
City of Grand Forks	246,890	828,000	29.82%
City of Penticton	2,051,018	5,481,000	37.42%
District of Summerland	589,039	1,002,000	58.79%
BC Hydro Kingsgate	20,497	17,100	119.86%

These average capacity utilisation figures are much less than the peak capacity utilisation at each point of delivery.

Q74.4 For the same period, how much of unused contracted capacity (by each of Industrial and Wholesale Rate Classes) was used to serve other customers?

A74.4 For the Wholesale and Industrial Rate Classes, the Company is not aware of a time when unused contracted capacity was used to serve other customers.

Q74.5 If unused contracted capacity is used to serve other customers, is the value of that reuse credited to Industrial and Wholesale customers? If so, please explain how, under the existing Rate Design.

A74.5 Please refer to the response to BCUC IR No. 1 Q74.4 above.

Q74.6 Please explain how the proposed Rate Design will credit Industrial and Wholesale Rate Classes for re-sale or reuse of unused contracted capacity.

A74.6 Please refer to the response to BCUC IR No. 1 Q74.4 above.

75.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 33

Q75.1 Customers Weighted for Meters and Services are weighted according to the typical cost of a new meter for the rate class. Was there any weight given to the differences in the average cost of a new service for the rate class? If not, why not?

A75.1 While the typical cost of a new meter is relatively standard and easy to obtain, the average cost of a new service is much more variable and depends on the circumstances of the customer location. Theoretically the cost of a new service would be a useful weighting factor for the Services account, however, it was not practical for this RDA.

Q75.2 Customers Weighted for Accounting/Metering are weighted according to "an allocation of cost performed by FortisBC staff". Please provide more detail on how that allocation factor was developed.

A75.2 The costs associate with cost centers 10561 and 10567 relating to customer service and billing are split between the various residential, general service, industrial, wholesale and irrigation/lighting classes using an estimated level of effort. The total costs assigned to each class are then divided by the number of customers in each class. The result is compared to the residential average cost per customer result to determine a multiplier compared to a residential weight of 1.

76.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 34

The COSA states on page 34 that 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.

Q76.1 Please explain why the NCPP is used for the 100% demand-related components of distribution, and the NCPP and NCPS are used together for (presumably the demand portion of) the accounts split between demand and customer components.

A76.1 Accounts 360.1 and 362 are for Land & Rights and Station Equipment. These two accounts are for facilities at the primary voltage level and are therefore classified on the basis of NCP at primary. They are also 100 percent demand-related. Accounts 364 (Poles), 365 (Conductors), and 368 (Line transformers) are split between customer and demand. In this case since the accounts include facilities for both primary and secondary service, the NCP at both primary and secondary are used. It is not the fact that certain accounts are 100 percent demand-related but the fact that they are at the primary level that indicate the use of the NCPP only.

77.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 37
Revenue to Cost Ratios

Q77.1 Prepare a table, similar to the one shown on page 37 of the Cost of Service Study, for each billing component. In other words, present revenue to cost ratios comparing the allocated customer costs for each rate class, to the revenues recovered through the customer charge. Prepare similar tables comparing the allocated energy costs, to the revenues recovered through the energy charge; and the allocated demand costs to the revenues recovered through the demand charge. For rates that do not have a demand charge, compare the sum of the allocated energy and demand charges to the revenues recovered through the energy charge.

A77.1 Please see the following table.

Table BCUC A77.1

	Customer Charge Revenue to Cost Ratio	Energy Charge Revenue to Cost Ratio	Demand Charge Revenue to Cost Ratio
Residential	40.4%	285.6%	
Small General Service	40.1%	304.9%	
General Service	23.8%	240.4%	68.5%
Rate 33 Industrial	42.7%	184.3%	
Industrial Primary	72.2%	178.1%	77.5%
Rate 31 Industrial	43.2%	161.9%	48.5%
Lighting	0.0%	152.9%	
Irrigation	38.6%	203.3%	
Kelowna Wholesale	50.0%	150.0%	46.5%
Penticton Wholesale	44.3%	149.9%	36.6%
Summerland Wholesale	54.9%	149.6%	55.3%
Grand Forks Wholesale	60.1%	150.5%	28.6%
BCH Lardeau Wholesale	63.1%	143.8%	78.8%
BCH Yahk Wholesale	67.9%	150.5%	72.4%
Nelson Wholesale	57.7%	148.8%	33.6%
Total	**39.5%**	**230.3%**	**26.3%**

78.0 Reference: Exhibit B-1, Appendix A: Cost of Service Study, p. 38
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.

Q78.1 Please provide a table showing the above unit cost figures, and adding columns for a) actual unit costs in 1997 and b) projected unit costs in 2015, with the a) and b) figures stated in 2009 dollars.

A78.1 Please see the following table comparing the 1997 COSA results and the 2009 COSA. FortisBC has not projected unit costs for the year 2015.

Table BCUC A78.1
Unit Costs for 1997 vs. 2009

	1997 COSA Cents per kWh (1997 Dollars)	**1997 COSA Cents per kWh (2009 Dollars)**	**2009 COSA Cents per kWh**
Residential	5.99	7.62	8.90
Other Retail	4.56	5.81	6.91
Wholesale	3.434	4.38	6.53
Total System	**4.72**	**6.00**	**7.58**

79.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p. 39

The table at the bottom of page 39 shows the revenue to cost ratios resulting from the 1997 COSA.

Q79.1 Please provide a table showing the Revenue to Cost ratios that arise from a COSA that uses the 1997 methodology, but current data.

A79.1 Please refer to the following table:

Table BCUC A79.1
Revenue to Cost Ratios Using 1997 Methodology

	2009 Methodology (As Filed)	**1997 Methodology With Current Data**
Residential	98.3%	93.3%
Small General Service (20)	113.4%	108.2%
General Service (21)	138.9%	133.4%
Industrial Primary (30)	122.4%	115.8%
Industrial Transmission (31)	109.9%	109.9%
Industrial Transmission TOU (33)	23.5%	48.3%
Lighting	81.9%	79.8%
Irrigation	78.6%	75.3%
Kelowna Wholesale	89.9%	96.7%
Penticton Wholesale	78.0%	91.6%
Summerland Wholesale	96.6%	97.8%
Grand Forks Wholesale	68.1%	88.0%
BC Hydro Lardeau Wholesale	101.8%	95.1%
BC Hydro Yahk Wholesale	103.5%	97.9%
Nelson Wholesale	80.0%	95.5%
Total	**100.0%**	**100.0%**

Q79.2 If the 1997 method had been used in the application, how would the demand allocator have been calculated, and what would the results have been?

A79.2 With the 1997 Methodology the demand allocator would use the 2CP factor without contract demands. Please refer to Table BCUC A79.2 for the results.

Table BCUC A79.2
Calculation of 2CP Peak Allocator Using 1997 Methodology

	Jan-09	Jul-09	Aug-09	Dec-09	Sum	% of Total
Residential	313,226	198,895	198,115	289,951	1,000,188	40.58%
Small General Service	36,855	50,165	35,412	31,972	154,404	6.26%
General Service	105,566	104,809	83,532	87,268	381,176	15.47%
Rate 33 Industrial	11,213	9,911	10,417	10,500	42,041	1.71%
Industrial Primary	28,559	22,374	24,545	28,115	103,592	4.20%
Rate 31 Industrial	8,059	8,370	7,516	8,183	32,127	1.30%
Lighting	2,617			2,364	4,981	0.20%
Irrigation	3,972	14,032	16,414	6,267	40,684	1.65%
Kelowna	61,401	45,859	54,909	62,455	224,625	9.11%
Penticton	71,883	61,151	62,813	76,066	271,914	11.03%
Summerland	20,529	15,590	16,948	23,607	76,674	3.11%
Grand Forks	8,062	6,607	7,087	8,845	30,602	1.24%
BCH Lardeau	4,964	1,693	1,779	3,175	11,611	0.47%
BCH Yahk	584	372	379	679	2,013	0.08%
Nelson	23,855	18,173	19,858	26,092	87,978	3.57%
Total Allocated	**701,345**	**558,002**	**539,724**	**665,540**	**2,464,611**	**100%**

80.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p.39

Q80.1 Please provide a table comparing, by rate class, the percent bill impact of a rate rebalancing that arises from the COSA based on the 1997 method and the 2009 method.

A80.1 The following tables show the rebalancing rate changes per year for the COSA as proposed and with current data and the 1997 methodology in place.

Table BCUC A80.1a
Rebalancing Rate Changes with 2009 COSA as Filed

	Year 1	Year 2	Year 3	Year 4	Year 5
Residential	0.0%	0.0%	0.0%	0.0%	0.0%
Small General Service	-3.3%	-3.0%	-1.3%	0.0%	0.0%
General Service	-3.3%	-3.0%	-2.8%	-3.5%	-1.0%
Large General Service-Transmission (33)	5.0%	5.0%	5.0%	5.0%	5.0%
Large General Service Primary (30)	-3.3%	-3.0%	-2.8%	-3.5%	-3.2%
Large General Service-Transmission (31)	-3.3%	-1.4%	0.0%	0.0%	0.0%
Lighting	5.0%	5.0%	5.0%	1.0%	0.0%
Irrigation	5.0%	5.0%	5.0%	5.0%	0.4%
Kelowna Wholesale	5.0%	0.9%	0.0%	0.0%	0.0%
Penticton Wholesale	5.0%	5.0%	5.0%	5.0%	1.2%
Summerland Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%
Grand Forks Wholesale	5.0%	5.0%	5.0%	5.0%	5.0%
BCH Lardeau Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%
BCH Yahk Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%
Nelson Wholesale	5.0%	5.0%	5.0%	3.5%	0.0%

Table BCUC A80.1b
Rebalancing Rate Changes with COSA Using 1997 Methodology

	Year 1	Year 2	Year 3	Year 4	Year 5
Residential	2.0%	0.0%	0.0%	0.0%	0.0%
Small General Service	-3.1%	0.0%	0.0%	0.0%	0.0%
General Service	-5.0%	-1.0%	-0.2%	-1.0%	-0.5%
Large General Service-Transmission (33)	5.0%	5.0%	5.0%	5.0%	5.0%
Large General Service Primary (30)	-5.0%	-1.0%	-0.2%	-1.0%	-0.5%
Large General Service-Transmission (31)	-4.7%	0.0%	0.0%	0.0%	0.0%
Lighting	5.0%	5.0%	5.0%	3.8%	0.0%
Irrigation	5.0%	5.0%	5.0%	5.0%	5.0%
Kelowna Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%
Penticton Wholesale	4.0%	0.0%	0.0%	0.0%	0.0%
Summerland Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%
Grand Forks Wholesale	5.0%	3.3%	0.0%	0.0%	0.0%
BCH Lardeau Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%
BCH Yahk Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%
Nelson Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%

81.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, p.39

Q81.1 Please provide a table, based on projected 2009 normalized load data, comparing by rate class the average kWh rate now, the rate indicated by the 2009 COSA method and the rate indicated if the 1997 method was used.

A81.1 Please refer to the following table:

Table BCUC A81.1
Average Cents per kWh by Customer Class

	Current Rates	Costs per COSA as Filed	Costs per COSA using 1997 Methodology
Residential	8.67	8.90	9.38
Small General Service	8.77	7.80	8.18
General Service	8.70	6.31	6.63
Rate 33 Industrial	5.40	23.12	11.27
Industrial Primary	6.90	5.69	6.01
Rate 31 Industrial	4.91	4.50	4.50
Lighting	14.24	17.54	18.0
Irrigation	5.66	7.26	7.58
Kelowna Wholesale	5.42	6.08	5.65
Penticton Wholesale	5.40	6.98	5.94
Summerland Wholesale	5.60	5.84	5.77
Grand Forks Wholesale	5.40	8.01	6.20
BCH Lardeau Wholesale	7.50	7.43	7.96
BCH Yahk Wholesale	6.40	6.28	6.64
Nelson Wholesale	5.00	6.30	5.28

82.0 Reference: Exhibit B-1, Appendix A: Cost of Service Study, p. 40 Comparison to 1997 COSA Methodology and Results: City of Nelson

"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."

Q82.1 Please describe the nature of the transmission facilities referred to in the citation. When are they proposed to be constructed and completed? What are they expected to cost? Why are the existing facilities inadequate?

A82.1 The transmission facilities needed to meet loads in the event Nelson's generating unit is off-line have already been accounted for in the contract demand for Nelson and are already in place consistent with FortisBC's obligation to have sufficient facilities in place to meet contract demands. The "need to build" reflects what was needed in the past to meet the obligation, not what is needed in the future. FortisBC maintains that Nelson is currently not paying the full cost of the facilities built to meet the back-up service provided to Nelson.

83.0 Reference: Exhibit B-1, Appendix A: Cost of Service Study, App. A, Schedule 5.1, p. 1 IPP Energy Rate

Q83.1 What is the basis for the IPP Rate of $28.49, shown in Schedule 5.1?

A83.1 $28.49 is the January BC Hydro Power Purchase Agreement rate used for the study. Since the major IPP on the FortisBC system is Zellstoff-Celgar and the rate it receives is tied to the January PPA rate FortisBC pays, for planning purposes, the IPP rate for the year is set to the January PPA rate.

84.0 Reference: Exhibit B-1, Appendix A: Cost of Service Study, App. A, Schedule 5.1, p. 2

Market Spot Purchase Charges

Q84.1 Please explain whether the monthly pattern of Market Spot Purchase Charges, shown in Schedule 5.1, is expected to be consistent over the period 2010 through 2015.

A84.1 The Company is beginning to run short of available energy from the BC Hydro PPA over the winter. Starting in 2012 additional purchases of market energy will be required to maintain energy reserves over the winter at acceptable levels. By 2015 FortisBC is anticipated to require an additional 81 GWh, which will cost about $5.3 million to meet.

Q84.2 Please explain how the costs of the purchases were caused by each of the FortisBC customer categories (Residential, General Service, Wholesale, and Other Transmission).

A84.2 Fortis BC has not segregated power supply resources or purchases by customer class. All classes contribute to the system load and the total system requirements in each month dictate what resources are projected to be used for each month. Power supply costs were split into monthly demand and energy categories and then the class contribution to the monthly system-wide demand and energy was used to allocate the monthly costs.

Q84.3 Please show the monthly values of expected Market Purchase charges for 2015.

A84.3 Table BCUC A84.3 below shows the expected purchases of energy from the market (not including capacity blocks) for 2015.

Table BCUC A84.3

2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Market Capacity - ENERGY	$435	$30	$450	$0	$0	$15	$727	$41	$0	$21	$94	$29	$1,841
Market Energy Purchase	$440	$967	$0	$0	$0	$0	$0	$0	$0	$0	$1,161	$2,692	$5,260

85.0 Reference: Exhibit B-1, Appendix A: Cost of Service Study, App. A, Schedule 5.1, p. 2

CPC Capacity Charge

Q85.1 Please explain why the CPC Capacity Charge, shown in Schedule 5.1, only applies to December.

A85.1 The Company only purchases capacity under this contract in December—which is the only month it is available.

Q85.2 Could CPC-supplied capacity be required in other months between now and 2015, and, if so, will applicable charges in the proposed Rate Design automatically be so-adjusted?

A85.2 Please refer to the response to BCUC IR No. 1 Q85.2 above.

86.0 Reference: Exhibit B-1, Appendix A: Cost of Service Study, App. A, Schedule 5.1, p. 2

BC Hydro RS3808 Energy Rate

Q86.1 Please explain whether the change to the BC Hydro Energy Rate, commencing in April in Schedule 5.1, creates any bias in the Rate Design. If so, describe whether there is a material impact on the resultant rates proposed and on the associated Revenue/Cost ratios.

A86.1 While the 3808 rate change results in added costs of roughly $2 million, the impact on the revenue to cost ratios by class and the resulting rate rebalancing by class is negligible.

87.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, Schedule 8.1

Schedule 8.1 on page 1 of 2 shows a table titled 'Historic Energy, Demand and Customer Count', and on page 2 of 2 shows a table titled 'Load Data and Customer Sales by Rate Class'. The customer count data (from the untitled table on page 1 of 2) and the energy sales data appears the same for the projected 2009 data and the 'historic' data.

Q87.1 Please confirm that the data in all of the tables in Schedule 8.1 is a combination of actual and projected data for 2009.

A87.1 The data in Schedule 8.1 reflects the forecast for 2009. By using a forecast test period the loads reflect normal weather conditions. They are also consistent with the revenue requirements approved for 2009.

88.0 Reference: Exhibit B-1, Appendix A: Cost of Service Study, App. B, p. B-1 and p. B-5

Minimum System Analysis: Residential Customer Service Type Impact

"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." [COSA, App. B, p. B-1]

"...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." [COSA, App. B, p. B-5]

Q88.1 Please explain whether an observed trend toward higher amperage residential services has implications for the minimum system results. If so, does the proposed change of allocation toward more weighting on Customer rather than Demand result in customers with lower amperage services subsidising customers with higher amperage services?

A88.1 To the extent that a utility changes its minimum service standards as a result of higher amperage services for new customers, over time minimum size used in the minimum system study could be impacted and thereby result in more costs assigned to the customer component. It has not been examined whether this is the case for FortisBC or whether other factors impacted the change in the split. A shift in the customer-related percent could be caused by either a higher standard for the minimum size, a lower level of investment required at the above-minimum sizes, or a reduction in the cost differential between the minimum and the other sizes.

If the shift towards customer-related costs did result due to the higher amperage, the COSA could result in a bias towards the newer customer with higher amp service. However, the PLCC adjustment compensates for this, increasing as the minimum size of facilities increases. This higher PLCC level would offset the amount allocated on the basis of the number of customers and shift costs to those users with higher consumption. This is one of the benefits of using the PLCC adjustment in the minimum system methodology. Also, because the customer charge proposed is far less than the results of the minimum system in the COSA would indicate, any shift would not result in a subsidization.

89.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, App. B, pp. B-2 through B-4

Minimum System Study – Power Poles

Q89.1 Please reconcile the customer/demand split of 81%/19% presented on page B-3 with the customer/demand split of 96%/4% presented on page B-2 and elsewhere in the COSA study.

A89.1 The percents provided on page B-3 are in error and should be Customer-Related at 96 percent and Demand-Related at 4 percent, as shown in other places. The other tables on page B-3 are correct and provide the numbers used to calculate the 96 percent/4 percent split. Please see Errata 2.

Q89.2 Please explain the derivation of the cost per pole calculation on page B-4, in particular the material loading amounts.

A89.2 An error occurred when page B-4 was produced. A corrected version of page B-4 is included in Errata 2. The correct derivation of the pole costs can be found in the table below. Note that the correct values were used throughout the COSA model and the results are correct.

Table BCUC A89.2

Pole	Pole	Other Material	Material Loading (7%)	Truck & Labor	Total Cost
35' Single	$433.00	$79.18	$36	$606.17	$1,154.20
40' Single	$615.00	$79.18	$49	$606.17	$1,348.94
40' Three	$615.00	$181.52	$56	$623.22	$1,475.50
45' Single	$640.00	$79.18	$50	$606.17	$1,375.69
45' Three	$640.00	$181.52	$58	$623.22	$1,502.25
50' Single	$752.00	$79.18	$58	$606.17	$1,495.53
50' Three	$752.00	$181.52	$65	$623.22	$1,622.09
Mimimum	**$433.00**	**$79.18**	**$35.85**	**$606.17**	**$1,154.20**

On page B-2 it states: "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."

Q89.3 Explain why the 1992 and 2009 minimum system studies produced such widely different results for the determination of the costs associated with a minimum pole size.

A89.3 For the minimum system study in 2009, FortisBC engineers determined that the size of the poles are a function of terrain as opposed to the size of the load at the specific location. This differs from the determination made for the 1992 study and provides a higher percent to the customer function.

90.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, App. B, pp. C-1 and C-2

Individual Load Factors and the Group Coincident Factor

***"Load data from BC Hydro for the Southern Interior was used to assist in developing load data for those classes without demand meters."* [p. C-1]**

and

***"The group coincidence factors were developed based on standard industry data and the BC Hydro Southern Interior load data."* [p. C-2]**

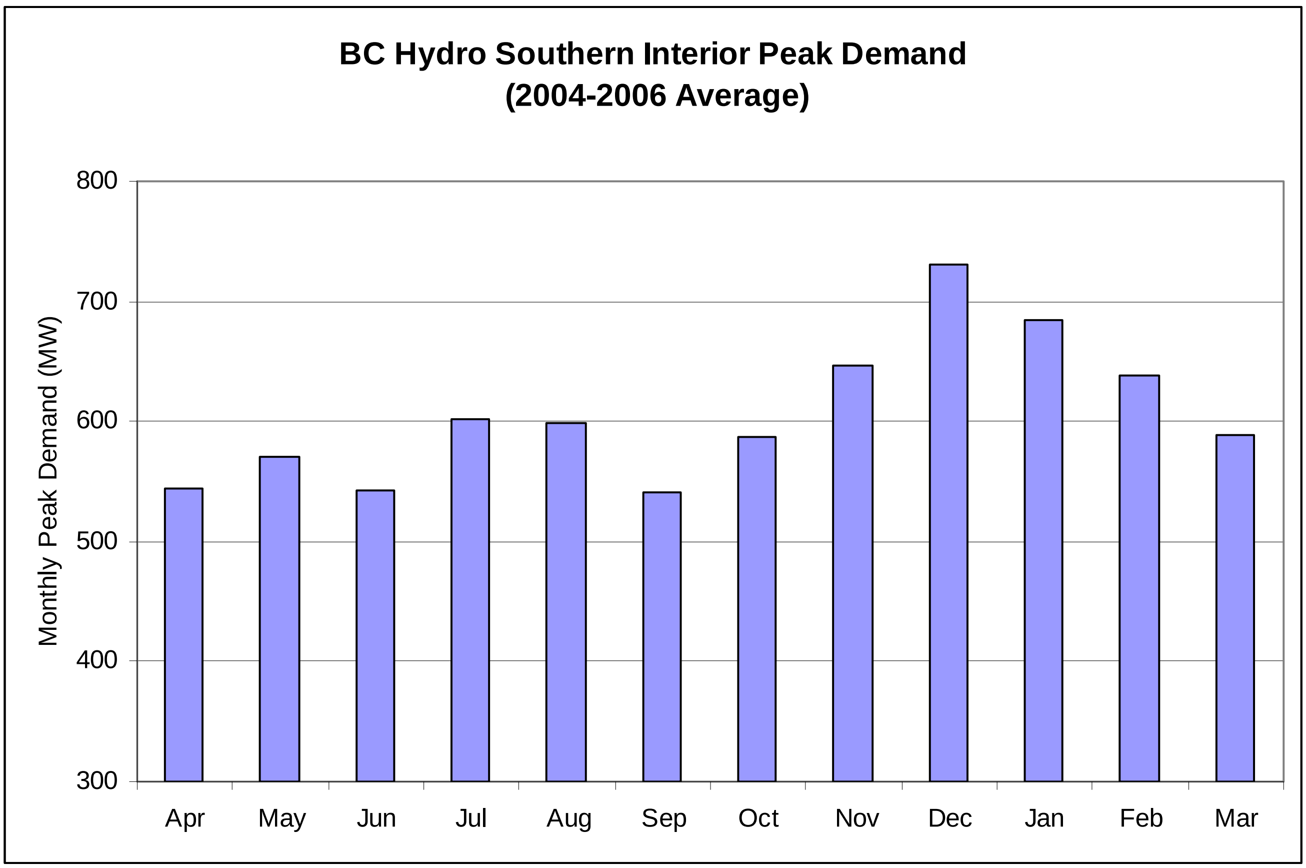
Q90.1 Does the BC Hydro Southern Interior load data exhibit a summer peak pattern similar to that experienced by the FortisBC system?

A90.1 The load data provided for the BC Hydro Southern Interior was hourly data by class for the residential and various general service categories. Adding those classes together and taking the maximum value per month results in a monthly peak load shape similar to that for FortisBC.

Q90.2 Please provide a chart showing the monthly peak demand associated with the BC Hydro Southern load data in a format similar to that of the charts on page 30 of the COSA study.

A90.2 Please see Figure BCUC A90.2 below showing the peak monthly demands for the sum of the residential and general service classes averaged for the 2004-2005 and 2005-2006 fiscal years.

Figure BCUC A90.2



91.0 Reference: Exhibit B-1, Appendix C, Lighting, p. 7
Type II and Type III Lighting

Q91.1 What was the average invoice amount for Type II and Type III lighting for the most recent 12 months for which data are available?

A91.1 As per the available data of the most recent 12 months, the average yearly invoice amounts for Type II and Type III lighting are respectively $81.76 and $194.83.

23 percent of lighting invoices have been left out of this analysis as they include more than one type of lighting, and are difficult to accurately disaggregate.

92.0 Reference: Exhibit B-1, Appendix D, Schedule 74 - Extensions, p. 6

FortisBC Contributions

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

Q92.1 Please provide the supporting calculations for the Maximum FortisBC Contribution for the Residential rate classes.

A92.1 Please refer to BCUC Attachment A40.1.

93.0 Reference: Exhibit B-1, Appendix E

Derivation of Updated Standard Charges

Q93.1 Please explain the difference between the loadings that are included in the labour rates, and the 15 per cent overhead loading added to the sum of the labour and vehicle charges.

A93.1 The loadings that are included in the labour rates are the fringe benefit loadings. The 15 percent overhead that is applied to the sum of the labour and vehicle charges is comprised of capitalized overhead at 7.7 percent and direct overhead at 7.3 percent. Capitalized overhead is related to the recovery of those indirect corporate support services required to support capital construction activities. Direct overhead is related to the recovery of those supervisory and administrative costs for Network Services for activity required to support capital construction activities.

94.0 Reference: Exhibit B-1, Appendix H, Terms and Conditions, p. 56
Metering Selection: Net Metering Customers

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.

Q94.1 Please confirm that FortisBC will provide Net Metering customers with the option of using existing electro mechanical meters, subject to the requirements of Measurement Canada Information Bulletin 2007-04-20, Section 7.2.

A94.1 Confirmed. FortisBC will allow the use of electromechanical meters at the request of the customer.

95.0 Reference: Exhibit B-1, Appendix H, Terms and Conditions, p. 67
Equal Payment Plan: Credit Balances

In the existing FortisBC Tariff, the Terms and Conditions for the Equal Payment Plan states as follows:

"11.5 Equal Payment Plan

The equal payment plan may be terminated by the Customer, or the Company if the Customer has not maintained their credit to the satisfaction of the Company. 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. ***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."*** **[Emphasis added]**

In the proposed Terms and Conditions, reference to payments in excess of charges has been removed:

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.

Q95.1 Under the proposed Terms and Conditions, what will happen to any credit balance that a customer has under the Equal Payment Plan? Please explain.

A95.1 If a customer has an Equal Payment Plan credit balance and terminates their account, the Company will refund the amount regardless of the size of the balance. If the customer has not terminated their account, and the credit balance is small, it will be carried forward.

96.0 Reference: Exhibit B-1, Appendix I, Public Consultation, p. 3
Open Houses: COSA Study

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.

Q96.1 How much time was available at each COSA open house for a question and answer session?

A96.1 The PowerPoint presentation was approximately 30 minutes. Questions were answered through the presentation if clarification was required and then after the presentation until all questions had been answered, which was typically 30-60 minutes. The minutes from these sessions are attached as BCUC Appendix A96.1.

Q96.2 How many (from the public) attended each COSA session?

A96.2 At each of the COSA open houses, participants signed in as follows:

- Two participants in Castlegar, May 26 2009
- Four participants in Kelowna, May 27, 2009
- Nine participants in Osoyoos, May 28, 2009

97.0 Reference: Exhibit B-1, Appendix I, Public Consultation, p. 5
First Nations

> **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.

Q97.1 Please list the First Nations and Bands within the FortisBC service area.

A97.1 The First Nations and Bands in the FortisBC service area include:

- Osoyoos Indian Band
- Penticton Indian Band
- Okanagan Indian Band
- Upper Similkameen Indian Band
- Lower Similkameen Indian Band
- Lower Kootenay Indian Band
- Okanagan Nation Alliance
- Ktunaxa Nation
- Westbank First Nation – Westbank First Nation is within FortisBC's service area but does not currently have electrical service requirements on their reserve land (Indian Reservation ["IR"] No. 8, No. 11 and No. 12).

Q97.2 Please list any First Nations and Bands within the areas served by FortisBC's Wholesale customers.

A97.2 The only band served by a wholesale customer at this time is the Penticton Indian Band, which has a small number of customers served by the City of Penticton utility.

- Penticton Indian Band IR No. 2 is within the City of Penticton service territory but has no electrical service requirements at this time
- City of Penticton serves a small number of customers on Penticton Indian Band IR No. 1 within the City of Penticton municipal boundary
- Penticton Indian Band IR No. 1 is within the District of Summerland service territory but has no electrical service requirements at this time

Q97.3 Please explain whether First Nations and Bands served by Wholesale customers were advised of the 2009 Rate Design application, and whether and how they were consulted with respect to it. If so, which First Nations and Bands were they?

A97.3 The only band served by a wholesale customer at this time is the Penticton Indian Band, which has a small number of customers served by the City of Penticton utility. Through the First Nations consultation process for COSA and RDA, FortisBC's First Nations Executive Liaison met with the Penticton Indian Band on May 25, 2009. Additionally, the band was invited by letter to public RDA open houses and a First Nations specific workshop on July 21, 2009. The band did not respond to the invitation or attend the workshop.

98.0 Reference: Exhibit B-1, Appendix I, Public Consultation, p. 63
Range of Reasonableness

The Discussion Guide (presented in Appendix I) states as follows concerning rate rebalancing:

"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."

Q98.1 Please explain whether and how the concept of the "range of reasonableness" was conveyed to the public during consultations. What comments did FortisBC receive from the public concerning the range of reasonableness?

A98.1 The concept of the range of reasonableness ("ROR") was discussed during public consultation in conjunction with the overall explanation of revenue-to-cost ratios and rebalancing in general. The ROR was described as necessary in order to recognize the availability of data and assumptions contained in the COSA. Generally speaking, customer classes that fall within the 95-105 percent ROR are considered to be paying an appropriate share of its costs. The concept of the ROR was new to most of the consultation attendees and while the general sentiment toward rebalancing and the Company's proposal in particular was positive (as described in Appendix I to the Application, Exhibit B-1), there was little feedback received on the ROR.

99.0 Reference: Exhibit B-1, Appendix I, Public Consultation, p. 73

Low Income Customers

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%)

Q99.1 The above table indicates a level of customer concern regarding Low Income ratepayers. Please list any features of the proposed Rate Design that are intended to help Low Income customers compared to the existing Rate Design.

A99.1 All of the alternate rate design options have features that result in low-consumption customers paying less and high-consumption customers paying more than the proposed rate design. These alternative rate design options may therefore help or harm low income customers depending on their electricity consumption. If they have consumption generally below 2,500 kWh bi-monthly, a customer will generally benefit from Options 1-3. If they have consumption above 2,500 kWh bi-monthly, they will generally be harmed by Options 1-3. FortisBC does not have access to information regarding customer incomes, and therefore cannot provide information on low-income electricity consumption. It should be noted that the proposed rate design does not change from the current rate design.

100.0 Reference: Exhibit B-1, Appendix I, Public Consultation, p. 73

Super Groups: Representativeness

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.

Q100.1 Was the Wholesale participant a representative from the City of Kelowna?

A100.1 No, the Wholesale participant was not a City of Kelowna Wholesale representative. The participant listed their occupation as 'retired' and responded that they also had Residential and Commercial accounts. The participant was recruited from the residential customer list.

Wholesale customers were not recruited for the Super Group since each of the Wholesale customers had individual meetings with FortisBC.

Q100.2 Does FortisBC believe that the Super Group composition reasonably represents the Dwelling Type and Square Footage characteristics of Residential customers in the service area? Please explain.

A100.2 Please refer to the response to BCUC IR No.1 Q100.3.

Q100.3 Given the representation in the Super Group, is FortisBC satisfied that the associated results are an unbiased source of customer information? Please explain.

A100.3 Environics, the consulting company hired to facilitate the Super Groups, followed standard market research protocols in sample development, sample selection and Super Group recruitment. Environics reduced the risks of bias on the topic to be discussed by not disclosing the topic of the Super Group until the respondent arrived and signed in. It is not possible to state categorically that no sources of bias exist, but Environics made every effort to ensure that the participants in the Super Groups were representative of the customer lists by customer type. As a representative sample, this would also assume that these participants reasonably represent the Dwelling Type and Square Footage characteristics of Residential customers in the service area. Therefore, FortisBC is satisfied that the associated results are an unbiased source of customer information.

FORTISBC

BOB GIBNEY
FIRST NATIONS EXECUTIVE LIAISON

FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, British Columbia V1Y 7V7
(250) 368-0345
www.fortisbc.com

June 29, 2009

Chief Johnathan Kruger
Penticton Indian Band
RR#2, Site 80, Comp 19
Penticton, BC V2A 6J7

Dear Chief Johnathan Kruger:

I would like to invite you or a band representative to a First Nations rate design open house at the Penticton Ramada on **Tuesday, July 21, 2009 from 10:00 am until 11:30 am**. The meeting will include a brief review of the Cost of Service Analysis (COSA) draft and will then present rate design options for discussion.

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Please let Jodie Foster Sexsmith in our Corporate Communications Department know if you'd like to attend the open house by emailing jodie.fostersexsmith@fortisbc.com or by phoning (250) 469-8007 **by July 15, 2009.**

If you are unable to attend the First Nations open house, please also feel free to attend one of the public open houses later in July.

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Osoyoos Thursday, July 30, 2009 from 6 - 8 pm
Sonora Community Centre, 8505 68th Ave

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We look forward to hearing from you about this and any other interests you may have with respect to FortisBC activities.

Sincerely,

Bob Gibney
First Nations Executive Liaison

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June 29, 2009

Chief Fabian Alexis
Okanagan Indian Band
12420 Westside Road
Vernon, BC V1H 2A4

Dear Chief Fabian Alexis:

I would like to invite you or a band representative to a First Nations rate design open house at the Penticton Ramada on **Tuesday, July 21, 2009 from 10:00 am until 11:30 am**. The meeting will include a brief review of the Cost of Service Analysis (COSA) draft and will then present rate design options for discussion.

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Sincerely,

Bob Gibney
First Nations Executive Liaison

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June 29, 2009

Grand Chief Stewart Philip
Okanagan Nation Alliance
3255C Shannon Lake Road
West Kelowna, BC V4T 1V4

Dear Grand Chief Stewart Philip:

I would like to invite you or a band representative to a First Nations rate design open house at the Penticton Ramada on **Tuesday, July 21, 2009 from 10:00 am until 11:30 am**. The meeting will include a brief review of the Cost of Service Analysis (COSA) draft and will then present rate design options for discussion.

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Sincerely,

Bob Gibney
First Nations Executive Liaison

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www.fortisbc.com

June 29, 2009

Chief Clarence Louie
Osoyoos Indian Band
Site 25 Comp 1 RR#3
Osoyoos, BC V0H 1T0

Dear Chief Clarence Louie:

I would like to invite you or a band representative to a First Nations rate design open house at the Penticton Ramada on **Tuesday, July 21, 2009 from 10:00 am until 11:30 am**. The meeting will include a brief review of the Cost of Service Analysis (COSA) draft and will then present rate design options for discussion.

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Sincerely,

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June 29, 2009

Chief Chris Luke Sr
Lower Kootenay Indian Band
830 Simon Road
Creston, BC V0B 1G2

Dear Chief Chris Luke Sr:

I would like to invite you or a band representative to a First Nations rate design open house at the Penticton Ramada on **Tuesday, July 21, 2009 from 10:00 am until 11:30 am**. The meeting will include a brief review of the Cost of Service Analysis (COSA) draft and will then present rate design options for discussion.

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June 29, 2009

Chief Richard Holmes
Upper Similkameen Indian Band
610 - 7th Avenue, Box 310
Keremeos, BC V0X 1N0

Dear Chief Richard Holmes:

I would like to invite you or a band representative to a First Nations rate design open house at the Penticton Ramada on **Tuesday, July 21, 2009 from 10:00 am until 11:30 am**. The meeting will include a brief review of the Cost of Service Analysis (COSA) draft and will then present rate design options for discussion.

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June 29, 2009

Chief Joseph Dennis
Lower Similkameen Indian Band
PO Box 100
Keremeos, BC V0X 1N0

Dear Chief Joseph Dennis:

I would like to invite you or a band representative to a First Nations rate design open house at the Penticton Ramada on **Tuesday, July 21, 2009 from 10:00 am until 11:30 am**. The meeting will include a brief review of the Cost of Service Analysis (COSA) draft and will then present rate design options for discussion.

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Kelowna, British Columbia V1Y 7V7
(250) 368-0345
www.fortisbc.com

June 29, 2009

Chief Sophie Pierre
Ktunaxa Nation
201-14th Ave N
Cranbrook, BC V1C 3W3

Dear Chief Sophie Pierre:

I would like to invite you or a band representative to a First Nations rate design open house at the Penticton Ramada on **Tuesday, July 21, 2009 from 10:00 am until 11:30 am**. The meeting will include a brief review of the Cost of Service Analysis (COSA) draft and will then present rate design options for discussion.

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Sincerely,

Bob Gibney
First Nations Executive Liaison

Outlet	Media Type	Address	City	Phone	Contact	Email	FYI	Booking Dates	
Castlegar News	Newspaper	#1, 425 Columbia Avenue	Castlegar	(250) 365-6397	Mathew Petterson	newsroom@castlegarnews.com	Matthew is also the editor for the Nelson Star and Trail Rossland News - all releases go to same email address	Booked through Trail Rossland News	5 13/16
Creston Valley Advance	Newspaper	Box 1279, 1018 Canyon Street	Creston	(250) 428-2266	Jim or Anita	advertising@cyberlink.bc.ca	Thursdays	May 14 and 21 - sent	5 inches
Grand Forks Gazette	Newspaper	Box 700	Grand Forks	(250) 368-8851	Barb at Trail Times books for Grand Forks too		Fridays Christina, Rock Creek, Midway, Westbride, Brideville and Grand Forks	Booked through Barb at Trail Daily Times May 15 and 22 - sent to Lonnie (Barb sick)	5"
Boundary Creek Times Mountaineer	Newspaper	Box 99, 318 S. Copper Street	Greenwood	(250) 445-2233	Dianne Stoochnoff	bctimesads@shaw.ca	Distribution in West Boundary area Greenwood, Midway, Rock Creek, Bridesville, Westbridge, Beaverdale (Greenwood side) on Wednesdays	May 13 and 20 - sent	
Pennywise	Newspaper & Trades	Box 430, 401A Avenue	Kaslo	(250) 353-7114	Julie	julie@pennywiseads.com	Published on Tuesday - Kaslo- Kootney Lake, Nelson, Castlegar, Fruitvale / Montrose - 27,500 copies	May 12 and 19 - sent	6.375
Kelowna Capital News	Newspaper	2495 Enterprise Way	Kelowna	(250) 763-3212		dniska@kelownacapnews.com	Wed, Fri, Sun editions	May 13,17 and 22 - sent	5.63 column inch
Kelowna Daily Courier	Newspaper	550 Doyle Avenue	Kelowna	(250) 762-4445	Rick Bac	ric.bach@ok.bc.ca	Kelowna Daily Courier and Penticton Herald	May 10,17,23 - sent	5.4
Keremeos Review	Newspaper	613 7th Avenue, Box 130	Keremeos	(250) 499-2653	Tammy	reviewads@nethop.net	Wednesdays, also same for OK Falls Review	May 13 and 20 - sent	5 13/16
Nelson Daily News and Weekender	Newspaper	266 Baker Street	Nelson	(250) 352-3552	Bob Hall	news@nelsondailynews.com		Booked through Barb Blatchford at Trail Weekender	
South Okanagan Review (OK Falls Review)	Newspaper	Box 220	Okanagan Falls			reviewnews@nethop.net		Booked through Keremeos Review	

Oliver Chronicle	Newspaper	Box 880, 36083 97th Street	Oliver	(250) 498-3711	Sylvia	ads@oliverchronicle.com	Wednesdays	May 13 and 20 - sent	1/4 page (3 columns is 5")
Osoyoos Times	Newspaper	Box 359, 8712 Main Street	Osoyoos	(250) 495-7225	Gary Enns	sales@osoyoostimes.com	Tuesdays	May 12 and 19 - sent	
Penticton Herald/Okan. Sat.	Newspaper	186 Nanaimo Ave West	Penticton				Booked through Ric Bach at the Kelowna Daily Courier	Booked through Kelowna Daily Courier for weekender	
Penticton Western News	Newspaper	2250 Camrose Street	Penticton	(250) 492-0444	Dan Ebenal	editor@pentictonwesternnews.com	No used Penticton Herald	No	
Similkameen News Leader	Newspaper	Box 956, 226A Bridge Street	Princeton	(250) 295-4149	W. George Elliott	george@thenewsleader.ca		May 11 and 18 - sent	6 x ?
Similkameen Spotlight	Newspaper	Box 340, 298 Bridge Street	Princeton	(250) 295-3535	Deara	editor@similkameenspotlight.com and lisa@similkameenspotlight.com	Publish Wednesdays	May 13 and 20 - sent	
Summerland Review	Newspaper	13226 North Victoria Road	Summerland	(250) 494-5406	Jo Freed (female)	ads@summerlandreview.com		May 14 and 21 - sent	5.85"
Trail Daily Times and Weekender	Newspaper	1163 Cedar Avenue	Trail	(250) 368-8551 ext.200	Barb Blatchford at Trail Times books for Grand Forks too	publisher@trailtimes.ca	Trail Daily Times and Nelson Daily News May 8, Boundary Creek Weekender Sister papers: Nelson, Creston, Grand Forks, etc. (Hollinger-owned)	May 15 and 22 Weekenders - booked and sent	5"
Trail Rossland News	Newspaper	860 Eldorado Street	Trail	250-364-0283	Matthew Peterson editor and Marilyn Berry publisher	publisher@trailrosslandnews.com	Publish all 3 papers Thursdays	May 14 and 21 - sent	5 13/`6

Outlet	Media Type	Address	City	Phone	Contact	Email	FYI	Notes	Booking Dates	Size - Wide
Castlegar News	Newspaper	#1, 425 Columbia Avenue	Castlegar	(250) 365-6397	Mathew Petterson	newsroom@castlegarnews.com	Matthew is also the editor for the Nelson Star and Trail Rossland News - all releases go to same email address	Booked through Trail Rossland News	-	5 13/16
Creston Valley Advance	Newspaper	Box 1279, 1018 Canyon Street	Creston	(250) 428-2266	Jim or Anita	advertising@cyberlink.bc.ca	Thursdays		July 16 & 21	5 inches
Grand Forks Gazette	Newspaper	Box 700	Grand Forks	(250) 368-8851	Barb at Trail Times books for Grand Forks too		Fridays Christina, Rock Creek, Midway, Westbride, Brideville and Grand Forks	Booked through Barb at Trail Daily Times (Grand Forks / Boudary Weekender)	July 17& 24	5"
Boundary Creek Times Mountaineer	Newspaper	Box 99, 318 S. Copper Street	Greenwood	(250) 445-2233	Dianne Stoochnoff	bctimesads@shaw.ca	Distribution in West Boundary area Greenwood, Midway, Rock Creek, Bridesville, Westbridge, Beaverdale (Greenwood side) on Wednesdays		July 15& 22	
Pennywise	Newspaper & Trades	Box 430, 401A Avenue	Kaslo	(250) 353-7114	Julie	julie@pennywiseads.com	Published on Tuesday - Kaslo- Kootney Lake, Nelson, Castlegar, Fruitvale / Montrose - 27,500 copies		July 14 &21	6.375
Kelowna Capital News	Newspaper	2495 Enterprise Way	Kelowna	(250) 763-3212		dniska@kelownacapnews.com	Wed, Fri, Sun editions		July 17 &24	5.63 column inch
Kelowna Daily Courier	Newspaper	550 Doyle Avenue	Kelowna	(250) 762-4445	Rick Bac	ric.bach@ok.bc.ca	Kelowna Daily Courier and Penticton Herald	Okanagan Weekender	July 18 &25	5.4
Keremeos Review	Newspaper	613 7th Avenue, Box 130	Keremeos	(250) 499-2653	Tammy	reviewads@nethop.net	Also same for OK Falls Review - Wendesdays		July 15&22	5 13/16
Nelson Daily News and Weekender	Newspaper	266 Baker Street	Nelson	(250) 352-3552	Bob Hall	news@nelsondailynews.com		Booked through Barb Blatchford at Trail Weekender	-	
South Okanagan Review (OK Falls Review)	Newspaper	Box 220	Okanagan Falls			reviewnews@nethop.net		Booked through Keremeos Review	-	

Oliver Chronicle	Newspaper	Box 880, 36083 97th Street	Oliver	(250) 498-3711	Sylvia	ads@oliverchronicle.com	Wednesdays		July 15&22	Just changed ownership and changed to tab size, 1/4 page (3 columns is 5")
Osoyoos Times	Newspaper	Box 359, 8712 Main Street	Osoyoos	(250) 495-7225	Gary Enns	sales@osoyoostimes.com	Tuesdays		July 14&21	
Penticton Herald/Okan. Sat.	Newspaper	186 Nanaimo Ave West	Penticton				Booked through Ric Bach at the Kelowna Daily Courier	Booked through Kelowna Daily Courier for weekender	-	
Similkameen News Leader	Newspaper	Box 956, 226A Bridge Street	Princeton	(250) 295-4149	W. George Elliott	george@thenewsleader.ca	Publish Mondays		July 13&20	6"
Summerland Review	Newspaper	13226 North Victoria Road	Summerland	(250) 494-5406	Jo Freed (female)	ads@summerlandreview.com	Thursdays		July 16&23	5.85"
Trail Daily Times and Weekender	Newspaper	1163 Cedar Avenue	Trail	(250) 368-8551 ext.200	Barb Blatchford at Trail Times books for Grand Forks too	publisher@trailtimes.ca	Trail Daily Times and Nelson Daily News May 8, Boundary Creek Weekender Sister papers: Nelson, Creston, Grand Forks, etc. (Hollinger-owned)	Fridays	July 17&24	5"
Trail Rossland News	Newspaper	860 Eldorado Street	Trail	250-364-0283	Matthew Peterson editor and Marilyn Berry publisher	publisher@trailrosslandnews.com	Publish all 3 papers Thursdays		July 16&23	5 13/`6

POWER PURCHASE AGREEMENT

MADE AS OF THE 1st DAY OF OCTOBER 1993.

BETWEEN: BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, having its Head Office at 333 Dunsmuir Street, City of Vancouver, Province of British Columbia (hereinafter called "B.C. HYDRO");

AND: WEST KOOTENAY POWER LIMITED, a body corporate having its Head Office at Waneta Plaza, 1290 Esplanade, City of Trail, Province of British Columbia (hereinafter called "WEST KOOTENAY POWER").

WHEREAS:

(a) West Kootenay Power and B.C. Hydro serve adjacent areas in British Columbia and have various points of electrical system interconnection which permit the transfer of electricity to and from their respective systems.

(b) West Kootenay Power, B.C. Hydro and Cominco Ltd. ("Cominco") entered into an agreement dated 1 August 1972 ("Canal Plant Agreement") which set out certain rights and obligations.

(c) West Kootenay Power and B.C. Hydro entered into an agreement dated 15 October 1986 regarding wheeling (the "General Wheeling Agreement").

(d) West Kootenay Power desires to purchase electricity from B.C. Hydro to supplement its resources to meet West Kootenay Power's domestic load requirements.

(e) B.C. Hydro is willing to sell to West Kootenay Power, electricity, at such rates and under the terms and conditions specified in this Agreement.

(f) B.C. Hydro and West Kootenay Power entered into a previous power purchase agreement dated 15 October 1986 (the "1986 Agreement:").

(g) On 16 December 1992, B.C. Hydro applied to the British Columbia Utilities Commission (the "Commission") to, inter alia, terminate and replace the 1986 Agreement.

(h) This Agreement replaces and supersedes the 1986 Agreement pursuant to Commission Order No. 6-27-93, dated 22 April 1993, (the "Order").

THIS AGREEMENT WITNESSES that in consideration of the covenants and agreements set forth in this Agreement and of other good and valuable consideration, the parties hereby covenant, agree and declare as follows:

1. DEFINITIONS

1.1 In this Agreement:

(a) "Agreement" means this Agreement, as amended from time to time, and any schedules or exhibits referred to in it as being attached to it;

(b) "Billing Month" means a calendar month;

(c) "Capacity Purchases" means transactions (other than under this Agreement) whereby West Kootenay Power purchases Electricity to meet its service area load during the Heavy Load Hours and returns the energy associated with such purchase within 168 hours of the commencement of the transaction during Light Load Hours.

(d) "Effective Date" means Oct 1, 1993, the date on which the Order specified that this Agreement would be in full force and effect;

(e) "Electricity" means inclusively electric capacity and electric energy unless the context requires otherwise;

(f) "Excess Energy" shall have the meaning ascribed to it and shall be determined in accordance with Sections 8.3, 8.4, 9.2, 9.3 and 9.4 as the situation dictates;

(g) "Excess Capacity" for each Point of Interconnection and for the Point of Supply shall have the meaning ascribed to it and shall be determined in accordance with Sections 9.2, 9.3 and 9.4, as the situation dictates;

(h) "Heavy Load Hours" means the hours of 07:00 to 22:00;

(i) "Interim Period" means 1 October 1993 through 30 September 1995;

(j) "Light Load Hours" means the hours of 22:00 to 07:00;

(k) "Nominated Demand" for each Point of Interconnection and the Point of Supply means the maximum rate as nominated by West Kootenay Power expressed in kilowatts at which B.C. Hydro is obligated to supply to such Point during any given Nomination Period;

(l) "Nomination Period" means the period from the Effective Date to 30 September 1994 and each succeeding twelve month period thereafter;

(m) "Point of Interconnection" means a point exclusive of the Point of Supply, as identified in accordance with Section 3.1;

(n) "Point of Interconnection Excess Capacity" shall have the meaning ascribed to it and shall be determined in accordance with Sections 9.2 and 9.4 as the situation dictates;

(o) "Point of Interconnection Purchase Capacity" shall have the meaning ascribed to it and shall be determined in accordance with Section 9.2;

(p) "Point of Supply" means the point where B.C. Hydro's 60L225 Line connects to West Kootenay Power's South Slocan switching station;

(q) "Point of Supply Excess Capacity" shall have the meaning ascribed to it and shall be determined in accordance with Section 9.3 and 9.4 as the situation dictates;

(r) "Point of Supply Purchase Capacity" shall have the meaning ascribed to it and shall be determined in accordance with Section 9.3;

(s) "Purchase Energy" shall have the meaning ascribed to it and shall be determined in accordance with Sections 8.2 and 8.3;

(t) "System Capacity Deficit" shall have the meaning ascribed to it in Section 9.1;

(u) "Total Excess Capacity" means, for any given Billing Month, the sum of the maximum Excess Capacity for each Point of Interconnection and for the Point of Supply. (The maximum Excess Capacity for a Point of Interconnection is the greater of the Excess Capacity as determined in Section 9.2 for that Point of Interconnection or the maximum hourly Excess Capacity as determined in Section 9.4 for that Point of Interconnection. For the Point of Supply, the maximum Excess Capacity is the greater of the Excess Capacity as determined in Section 9.3 or the maximum hourly Excess Capacity for the Point of Supply as determined in Section 9.4);

(v) "Total Excess Energy" means the sum of the hourly Excess Energy;

(w) "Total Purchase Capacity" shall be the total sum of the Points of Interconnection Purchase Capacities and the Point of Supply Purchase Capacity as such values are determined under Sections 9.2 and 9.3;

(x) "Total Purchase Energy" means the sum of the hourly Purchase Energy, excluding Excess Energy, for all hours of the Billing Month;

(y) "Total Nominated Demand" means the sum of Nominated Demand for each Point of Interconnection and the Nominated Demand for the Point of Supply which has been nominated by West Kootenay Power in accordance with Sections 7.1, 7.2 and 7.3;

(z) "Utilized Entitlement Resources" means the West Kootenay Power entitlement resources (as defined in the Canal Plant Sub-Agreement between Cominco and West Kootenay Power dated August 10, 1981) utilized on each hour;

(aa) "Wheeling" and all forms of the verb "to Wheel" means the transmission by B.C. Hydro of West Kootenay Power's Electricity from the Point of Supply to the Points of Interconnection to serve West Kootenay Power's loads in its service area.

2. PURPOSE AND TERM OF THE AGREEMENT

2.1 The Electricity purchased under this Agreement is solely for the purpose of supplementing West Kootenay Power's resources to enable it to meet its service area load requirements and shall not be Exported or stored provided that nothing contained herein shall prohibit West Kootenay Power from storing its entitlement resources in its entitlement account pursuant to the Canal Plant Agreement.

2.2 "Export" and all forms of the verb "to Export" means, for the purposes of this Agreement, any transaction by or on behalf of West Kootenay Power whereby Electricity leaves the West Kootenay Power service area save and except for the following:

(a) Wheeling losses scheduled to B.C. Hydro;

(b) Emergency exchanges as defined by the Northwest Power Pool;

(c) Capacity Purchases by West Kootenay Power; and

(d) Such exceptions as the parties may agree to provided that any dispute in this regard shall be referred to the Commission or such person as the Commission may designate from time to time.

2.3 This Agreement replaces the 1986 Agreement as of the Effective Date.

2.4 Pursuant to the Order, certain of the provisions contained herein are to have no force and effect during the Interim Period, and those provisions shall be specifically identified herein. All other provisions shall be applicable as of the Effective Date.

2.5 This Agreement shall continue until 30 September 2013 unless previously terminated as provided in Section 13.1 or renewed by the parties on mutually acceptable terms. Termination of the Agreement shall not relieve either party from any liability or obligation then accrued but unsatisfied.

3. POINTS OF INTERCONNECTION AND SUPPLY

3.1 The Points of Interconnection between B.C. Hydro and West Kootenay Power at which Electricity may be purchased under this Agreement are listed in Appendix I, which may be amended from time to time by mutual agreement. The Parties recognize that such an amendement may require a renegotiation of the nomination provisions contained herein.

3.2 Electricity may also be purchased at the Point of Supply.

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4. INTERCONNECTED OPERATION

4.1 Provision of Generation Reserves

B.C. Hydro and West Kootenay Power shall provide reserves for their respective systems in accordance with Northwest Power Pool requirements except that B.C.

Hydro shall be responsible for supplying those reserves associated with the firm sales to West Kootenay Power under this Agreement.

4.2 Maintenance of Voltage

B.C. Hydro shall operate its system facilities to maintain, under normal conditions and in accordance with generally accepted utility practices, the voltage at the Point of Supply and each Point of Interconnection within plus or minus 10 percent of the nominal voltage (500, 230, 138, 63 kV) provided that the West Kootenay Power flow taken at each Point of Interconnection is not greater than the Nominated Demand together with the nominations under the General Wheeling Agreement and is between unity power factor and 0.95 power factor, leading.

4.3 Reactive Power (var) Requirement

West Kootenay Power shall plan and use its reasonable efforts to operate in accordance with generally accepted utility practices to operate at reasonable reactive power (var) flow at the Point of Supply and zero var flow at each Point of Interconnection. If, in B.C. Hydro's opinion, actual operation indicates that excessive var flows occur at any of these Points, B.C. Hydro shall have the right to give notice to West Kootenay Power to either rectify the situation or pay for the supply, installation and operation of var flow equipment necessary to rectify the situation.

4.4 Loop Operations

All purchases under this Agreement shall be to radially-connected West Kootenay Power service areas (excluding the Point of Supply) except that if closed loop operation is desirable:

(a) West Kootenay Power shall give advance notice to B.C. Hydro of that need;

(b) B.C. Hydro shall make reasonable efforts to accommodate West Kootenay Power and shall give notice to West Kootenay Power of the times and extent to which closed loop operation will be acceptable to B.C. Hydro; and

(c) B.C. Hydro, in consultation with West Kootenay Power, shall correct for the effect of loop flows by making appropriate adjustments for billing purposes for periods of closed loop operation.

'LANNING AND OPERATING INFORMATION

5.1 General Information Requests

B.C. Hydro and West Kootenay Power agree to cooperate in the full exchange of such planning and operating information as may be reasonably necessary for the timely and efficient performance of the parties' obligations or the exercise of rights under this Agreement. Such information shall be provided on a timely basis and no reasonable request shall be refused.

5.2 Load-Resource Forecasts

By 30 June of each year, B.C. Hydro and West Kootenay Power shall exchange a forecast for the next ten years of loads and resources for their respective electrical systems. These forecasts shall include programs for resource acquisition, transmission and firm loads. The degree of detail in these forecasts shall be decided by mutual agreement.

6. USAGE OF PURCHASED CAPACITY AND PURCHASED ENERGY

6.1 B.C. Hydro shall, subject to Section 2.1, deliver energy to West Kootenay Power with associated capacity at all times and such capacity shall be used in the determination of billing demand. West Kootenay Power shall not take delivery of energy without associated capacity. Energy delivered under this Agreement is not returnable. Energy delivered under this Agreement shall be delivered to the Points of Interconnection and the Point of Supply with no charge for losses above and beyond the loss component built into Rate Schedule 3808.

6.2 The Total Purchase Capacity and Total Excess Capacity together with Total Purchase Energy and Total Excess Energy shall be paid for by West Kootenay Power in accordance with B.C. Hydro Electric Tariff Rate Schedule 3808 as amended or replaced from time to time.

6.3 B.C. Hydro shall not be obligated to reserve for or supply to West Kootenay Power Excess Capacity or any energy associated with such Excess Capacity. B.C. Hydro shall use reasonable efforts to supply Excess Capacity to meet West Kootenay Power's service area load requirements in accordance with Section 2.1 herein.

7. RESERVATION AND NOMINATIONS

7.1 Total Nominated Demand

During each year of this Agreement West Kootenay Power shall provide power purchase nominations to B.C. Hydro in accordance with Sections 7.2 and 7.3. If nominations are not received by B.C. Hydro in accordance with Sections 7.2 and 7.3 for any Nomination Period then the Nominated Demand for such Nomination Period shall be deemed to be the same as the Nominated Demand for the immediately preceding Nomination Period. The Total Nominated Demand for any Nomination Period shall not exceed 200 MW except for the Interim Period during which there shall be no limit on Total Nominated Demand.

7.2 Initial Nominations

Prior to the Effective Date of this Agreement, West Kootenay Power shall provide to B.C. Hydro for each of the initial five Nomination Periods, the Nominated Demand for each Point of Interconnection and for the Point of Supply. Such nominations for each Point of Interconnection and for the Point of Supply shall apply for each month of the Nomination Period in question.

7.3 Subsequent Nominations

Prior to 1 October of each subsequent year of this Agreement, West Kootenay Power shall provide B.C. Hydro with the then ensuing fifth Nomination Period nominations for Nominated Demand for each Point of Interconnection and for the Point of Supply. Such nominations for each Point of Interconnection and for the Point of Supply shall apply for each month of the said Nomination Period.

7.4 System Supply

Subject to Section 6.3 above, B.C. Hydro shall reserve on its system the amounts of capacity and associated energy resources necessary to meet the Nominated Demands, the Total Nominated Demand and the associated energy for each Nomination Period and, if requested by West Kootenay Power, shall supply capacity and associated energy up to the Nominated Demands for each Point of Interconnection and the Point of Supply for each Nomination Period.

7.5 Changes to Nomination Amounts

WKP may, on two years written notice, request changes to the Nominations made pursuant to this Section. B.C. Hydro shall make reasonable efforts to accommodate such changes.

8. PRESCHEDULING AND ENERGY ACCOUNTING

8.1 West Kootenay Power shall preschedule its energy requirements in the following manner:

(a) By 14:00 hours Pacific Time on each Thursday of each week West Kootenay Power shall provide B.C. Hydro with an hourly preschedule of West Kootenay Power's energy purchase requirements (not exceeding levels associated with Nominated Demand) from B.C. Hydro for delivery for the period commencing Sunday at 00:00 hours and ending on the next following Thursday at 24:00 hours.

(b) By 14:00 hours Pacific Time on each Wednesday of each week West Kootenay Power shall provide B.C. Hydro with an hourly preschedule of West Kootenay Power's energy purchase requirements (not exceeding levels associated with Nominated Demand) from B.C. Hydro for delivery for the period commencing Friday at 00:00 hours and ending on the next following Saturday at 24:00 hours.

(c) If B.C. Hydro does not receive a preschedule for any period defined above, then West Kootenay Power's energy requirement preschedule for such period shall be deemed to be the same as it was for the immediately preceding like period. The parties may make alternative arrangements to accommodate Statutory Holidays by mutual agreement.

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8.2 The Purchase Energy for each hour shall be the prescheduled energy for that hour.

8.3 If West Kootenay Power's requirements from B.C. Hydro for any hour exceed the amount prescheduled for that hour then the amount that exceeded the prescheduled amount shall be Excess Energy for that hour.

8.4 West Kootenay Power shall not Export any Electricity out of its service area during any given hour while West Kootenay Power is taking energy requirements from B.C. Hydro under this Agreement for that hour. If West Kootenay Power Exports Electricity out of its service area during hours in which it is taking energy from B.C. Hydro, then for those hours the Purchase Energy shall be zero and the greater of the prescheduled energy requirement or West Kootenay Power's requirement from B.C. Hydro for those hours shall be deemed to be Excess Energy.

9. CAPACITY ACCOUNTING

9.1 System Capacity Deficit

(a) The System Capacity Deficit shall be calculated for each and every hour during the term of this Agreement, as the greater of:

(i) zero, or
(ii) the gross West Kootenay Power service area hourly load, including export schedules and losses scheduled to B.C. Hydro under the General Wheeling Agreement, minus the total capacity resources dispatched with associated energy by West Kootenay Power, excluding capacity purchased under this Agreement;

(b) The total capacity resources dispatched by West Kootenay Power on an hourly basis in accordance with paragraph 9.1(a) (ii) shall be:

- Utilized Entitlement Resources; plus
- firm capacity obtained from any other West Kootenay Power resource not covered by the Canal Plant Agreement, excluding capacity purchased under this Agreement; plus
- the capacity purchased from Cominco; plus
- any other firm capacity transactions not covered under this Agreement.

9.2 Points of Interconnection Accounting

For each hour excluding hours during which West Kootenay Power is Exporting, the capacity required at each Point of Interconnection shall be calculated as the difference between the recorded demand at the Point of Interconnection and the sum of the capacity Wheeled to the Point of Interconnection from the Point of Supply under the terms and conditions of the General Wheeling Agreement together with the capacity associated with transactions not covered under this Agreement. The maximum capacity so required during all hours of any given Billing Month at each Point of Interconnection shall be its Point of Interconnection Purchase Capacity for that month, so long as it does not exceed the Nominated Demand for that Point of Interconnection. If in any month the maximum capacity so determined exceeds the Nominated Demand for that Point of Interconnection then the Point of Interconnection Purchase Capacity for that month at such point shall be the Nominated Demand for that Point of Interconnection and the capacity required which exceeds the Nominated Demand shall be the Point of Interconnection Excess Capacity for such point and the energy associated therewith shall be deemed Excess

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Energy.

9.3 Point of Supply Accounting

(a) For each hour, the capacity required at the Point of Supply shall be calculated as the greater of:
(i) zero, or
(ii) the System Capacity Deficit minus the sum of the capacity required in the concurrent hour at all Points of interconnection.

(b) The maximum capacity so required during the Heavy Load Hours of each day of any given Billing Month, excluding hours during which West Kootenay Power is Exporting, shall be the Point of Supply Purchase Capacity for that month, so long as it does not exceed the Nominated Demand for the Point of Supply. If in the Heavy Load Hours in any given Billing Month the maximum capacity exceeds the Nominated Demand then the Point of Supply Purchase Capacity for that month shall be the Nominated Demand for the Point of Supply and the capacity required which exceeds the Nominated Demand shall be the Point of Supply Excess Capacity for that month, and the energy associated with such Excess Capacity shall be deemed Excess Energy.

(c) Notwithstanding the Nominated Demand for the Point of Supply, West Kootenay Power may, during the Light Load Hours only, exceed such nomination without incurring excess charges provided that the maximum capacity during Light Load Hours for any given Billing Month does not exceed the lesser of 175MW or the maximum hourly System Capacity Deficit during the Heavy Load Hours of that Billing Month. If such levels are exceeded, the excess shall be deemed Point of Supply Excess Capacity for that month, and the energy associated with such Excess Capacity shall be deemed Excess Energy.

9.4 Exports

The capacity required at each Point of Interconnection and the Point of Supply during any hour of the Billing Month during which West Kootenay Power is Exporting shall be deemed to be Excess Capacity for that Point of Interconnection and the Point of Supply as the case may be and the associated energy shall be deemed to be Excess Energy in accordance with Section 8.4.

10. METERING FACILITIES

10.1 Metering

(a) The Electricity purchased under this Agreement shall be measured and recorded at each Point of Interconnection and at the Point of Supply by energy and demand meters having one hour integrating intervals, which meters shall be of types approved for revenue metering by the Canadian Department of Consumer and Corporate Affairs and shall comply with the provisions of the Electricity and Gas Inspection Act, as amended from time to time.

(b) Each party shall, if possible, make available to the other party the second set of secondaries of the metering transformers owned by it for the purpose of installing backup metering, telemetering and control equipment as may be mutually agreed by the parties and shall provide space for the location of such equipment. In cases where backup meters are installed, the parties shall designate one meter to be used for revenue billing.

10.2 Tests of Metering Installations

(a) Each party shall, at its expense, test its metering components associated with Agreement as provided by the Electricity and Gas Inspection Act and field test the metering installation at least once every two years. If requested to do so, each party shall make additional tests or inspections of such installations, the expense of which shall be paid by such other requesting party unless such additional tests or inspections show the measurements of such installations to be registering outside the prescribed limit of error. Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate shall be adjusted, repaired, or replaced to provide accurate metering.

(b) If a meter is found to be not functioning accurately, the Electricity purchased shall be determined as provided for in the Electricity and Gas Inspection Act.

10.3 Access to Equipment and Facilities

(a) If any equipment or facilities associated with any Point of Supply or Point of Interconnection and belonging to a party to this Agreement are or are to be located on the property of the other party, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this Agreement and to remove such equipment and facilities at the expiration of said term, together with the right of entry to said property at all reasonable times in such term, is hereby granted by the other party.

(b) Each party shall have the right, by giving suitable notice, to enter the property of the other party at all reasonable times for the purpose of reading any and all meters mentioned in this Agreement which are installed on such property.

(c) If either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modification which may affect the duties of the other party in regard to such equipment, and furnish the other party with accurate revised drawings, if possible.

10.4 Ownership of Facilities

(a) Except as otherwise expressly provided, ownership of any and all equipment installed or previously installed by either party on the property of

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the other party shall be and remain with the installing party.

(b) Each party shall identify all equipment which is installed by it on the property of the other, by permanently affixing thereto suitable markers plainly stating the name of the owner of the equipment so identified. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said equipment so installed.

10.5 Inspection of Facilities

Each party may, for any reasonable purpose under this Agreement, inspect the other party's electric installation at any reasonable time after giving suitable notice. Such inspection, or failure to inspect, shall not render such party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this Agreement. The inspecting party shall observe written instructions and rules posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this Agreement shall be subject to inspection.

11. INVOICES AND PAYMENT

11.1 B.C. Hydro shall render a billing invoice monthly which is due and payable upon presentation.

11.2 If the amount due on any invoice has not been paid in full after 20 days from the billing date shown on the invoice, a late payment charge shall be applied to the unpaid balance, and the resulting amount will be shown and identified on the next invoice to be rendered. The late payment charge shall be as specified in B.C. Hydro's Electric Tariff, as amended from time to time.

12. TECHNICAL COMMITTEE

12.1 There shall be established and maintained throughout the term of this Agreement, a Technical Committee consisting of one representative of each party, each of whom shall serve until notice has been given to the other party of the selection of a successor.

12.2 Each party may give notice to the other party of an alternate who shall serve during the inability or absence of the representative of the party giving notice.

12.3 The Technical Committee shall determine all matters relating to administration and operation of this Agreement and shall decide questions that arise in operations under this Agreement.

12.4 In reaching decisions the Technical Committee shall attempt to achieve a just and equitable resolution of disagreements based upon generally accepted utility practice and shall not vary or extend in any way the provisions of the Agreement.

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12.5 The Technical Committee shall keep a written record of its decisions and shall promptly forward to each of the parties a copy of the written record.

13. INVOLUNTARY AMENDMENT AND TERMINATION

13.1 If an applicable statutory or regulatory provision of any legislative body or governmental agency having requisite authority, or an order of a court of competent jurisdiction, renders or declares the purchases provided by this Agreement to be illegal or alters the arrangements or provisions of this Agreement, the Agreement shall terminate or be amended as the case may be, at a time the circumstances so provide.

14. FORCE MAJEURE

14.1 Neither party to this Agreement shall be considered to be in default in the performance of any of its obligations under this Agreement to the extent that performance of those obligations is prevented or delayed by any cause which is beyond the reasonable control of the party prevented or delayed by that cause. If either party is delayed or prevented from its performance at any time by any act, omission or neglect of the other party or its representatives, or by an act of God or the public enemy, or by expropriation or confiscation of facilities, compliance with any order of any governmental authority or order of a court of competent jurisdiction, acts of war, rebellion or sabotage, fire, flood, explosion, riot, strike or other labour dispute beyond the reasonable control of the party or any unforeseeable cause beyond the control and without the fault and negligence of the party, the party so prevented or delayed shall give notice to the other party of the cause of the prevention or delay but, notwithstanding giving of that notice, the party shall promptly and diligently use its best efforts to remove the cause of the prevention or delay.

15. INDEMNITY

15.1 Each party shall indemnify and save harmless the other party from and against any and all of the following:

(i) claims including those under any statute for the protection of workers, demands, awards, judgments, actions and proceedings by whomsoever made, brought or prosecuted; and

(ii) fines, delays, expenses and costs suffered or incurred by that other party;

by reason of any act or omission of the first party (its successors or assigns) servants, agents, invitees and licensees or any of them arising out of, or in connection with this Agreement.

15.2 Notwithstanding Section 15.1, neither party, its servants or agents, shall be liable to the other party for any loss, injury, damages or expense of the other party caused by or resulting from any suspension, discontinuance or defect in the supply of

Electricity, or the maintenance of unvaried frequency or voltage alleged or caused by an act or omission of the other party, its servants or agents, except for direct loss or damage to the physical property of one party resulting from willful misconduct or negligent acts or omissions by the other party, its servants or agents.

16. NOTICES

16.1 All notices, directions and other instruments required or permitted to be given under this Agreement (except those given pursuant to Section 12) shall be in writing, and shall be sufficient in all respects if delivered, or if sent by telecopier, or if sent by prepaid registered post mailed in British Columbia to the parties at the following addresses respectively:

(a) to B.C. Hydro
British Columbia Hydro & Power Authority
333 Dunsmuir Street
Vancouver, B.C.
V6B 5R3

Attention: Secretary
Telecopy Number 623-2742

(b) to West Kootenay Power
West Kootenay Power Limited
1290 Esplanade
Trail, B.C.
V1R 4L4

Attention: Secretary
Telecopy Number 364-1270

Either party shall have the right at any time to change its address by notice in writing sent to the other party at the address in effect hereunder.

16.2 Any notice, direction or other instrument shall be deemed to have been received on the following dates:

(a) if sent by telecopier, on the business day next following the date of transmission;

(b) if delivered, on the business day next following the date of delivery; or

(c) if sent by registered mail, on the seventh day following its mailing, provided that if there is at the time of mailing or within seven days thereafter a mail strike, slowdown, lockout or other labour dispute which might affect the delivery, then any notice, direction or other instrument, shall only be effective upon actual delivery or if delivered or sent by telecopier.

Accepted for filing: SEP 30 1993
Effective: OCT 01 1993
Order No.: G-85-93

SECRETARY
B.C. UTILITIES COMMISSION

17. GOVERNING LAW

17.1 This agreement and all the terms and conditions contained in it shall be subject to the provisions of the Utilities Commission Act of British Columbia, as amended or re-enacted from time to time and to the jurisdiction of the Commission.

18. ENUREMENT

18.1 This Agreement shall be binding upon and shall enure to the benefit of the parties and their respective successors and permitted assigns.

IN WITNESS WHEREOF THE PARTIES HAVE HEREUNTO EXECUTED THIS AGREEMENT.

REGISTERED 200104

The Common Seal of BRITISH COLUMBIA HYDRO AND POWER AUTHORITY was affixed in the presence of:

M. Eliesen

APPROVED as to form only ... citor ... HYDRO

Authorized Signatory M. ELIESEN, CHIEF EXECUTIVE OFFICER

D. Lamming

Authorized Signatory D. LAMMING, ASSISTANT CORPORATE SECRETARY

The Common Seal of WEST KOOTENAY POWER LIMITED was affixed in the presence of:

S Ash, Chief Operating Officer

Authorized Signatory

Authorized Signatory F Hobbs Corporate Secretary

Accepted for filing: SEP 30 1993
Effective: OCT 01 1993
Order No.: G-85-93

SECRETARY
B.C. UTILITIES COMMISSION

APPENDIX 1

POINTS OF INTERCONNECTION

The Points of Interconnection between B.C. Hydro and West Kootenay Power at which electricity may be purchased under this Agreement are as follows:

(a) West Kootenay Power's 230 kV bus at the Lambert Substation (Creston).

(b) B.C. Hydro's Vernon Substation.

(c) West Kootenay Power's tap on B.C. Hydro's transmission line 1L251 near Princeton.

Accepted for filing: SEP 30 1993
Effective: OCT 01 1993
Order No.: G-85-93

SECRETARY
B.C. UTILITIES COMMISSION

SCHEDULE 3808

TRANSMISSION SERVICE (5000 kV.A and over)
WEST KOOTENAY POWER LTD.

Availability: This schedule is available to West Kootenay Power Ltd. in accordance with the terms and conditions of the Agreement between B.C. Hydro and West Kootenay Power entered into and deemed effective the 1st day of October 1993 (the "Power Purchase Agreement"). The Total Nominated Demand shall not exceed 200 MW except during the Interim Period.

Applicable in: For Electricity delivered to West Kootenay Power at each Point of Interconnection and the Point of Supply as defined in the Power Purchase Agreement.

Rate:

Demand Charge: $4.411 per kW of Billing Demand per Billing Month

plus

Energy Charge: 2.599¢ per kW.h of Purchase Energy per Billing Month.

Billing Demand: The Demand for billing purposes in any Billing Month shall be the greatest of:

1. the Total Purchase Capacity for that Billing Month, plus 1.2 times the Total Excess Capacity for that Billing month; or
2. the appropriate percentage defined in the table below, times the sum of the highest Total Purchase Capacity registered in any of the preceding eleven months, plus 1.2 times the highest Total Excess Capacity in any of the preceding eleven months; or
3. 50% of the Total Nominated Capacity, plus 1.2 times the Total Excess Capacity for that Billing Month.

Billing Demand Computation Table:

Billing Month	Percentage
October 1993 - through September 1995	50%
October 1995 - through September 1996	55%
October 1996 - through September 1997	60%
October 1997 - through September 1998	65%
October 1998 - through September 1999	70%
October 1999 - through September 2013	75%

Accepted for filing: SEP 30 1993
Effective: OCT 01 1993
O. No.: G-85-93
SECRETARY
B.C. UTILITIES COMMISSION

SCHEDULE 3808

TRANSMISSION SERVICE (5000 kV.A and over)
WEST KOOTENAY POWER LTD. (Cont'd.)

Excess Energy Charge:	1.15 times the Energy Charge per kW.h for each kW.h of Total Excess Energy.
Taxes:	The Rates and Charges contained herein are exclusive of the Goods and Services Tax and Social Services Tax.
Note:	The terms and conditions under which service is supplied to West Kootenay Power are contained in the Power Purchase Agreement. This Schedule is subject to the same rate adjustments as Schedule 1821.

Accepted for filing: SEP 30 1993
Effective: OCT 01 1993
Order No.: G-85-93

SECRETARY
B.C. UTILITIES COMMISSION

POWER PURCHASE AGREEMENT AMENDING AGREEMENT

This Power Purchase Agreement Amending Agreement made the 1st day of April, 1999

BETWEEN: BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, having its Head Office at 333 Dunsmuir Street, Vancouver, British Columbia ("B.C. Hydro")

AND: WEST KOOTENAY POWER LTD., a body corporate having its Head Office at 1290 Esplanade Ave., Trail, British Columbia ("West Kootenay Power")

WITNESSES THAT:

A. Pursuant to the Power Purchase Agreement made October 1, 1993, West Kootenay Power and B.C. Hydro ("Parties") have agreed to terms and conditions governing the supply of electricity from B.C. Hydro to West Kootenay Power;

B. The Parties have agreed to enter into this Power Purchase Agreement Amending Agreement.

In consideration of the mutual promises contained in this agreement, the Parties agree that as and from the 1st day of April, 1999, the Power Purchase Agreement is amended as follows:

1. Section 6 is amended by the insertion of the new Section 6.4 as follows:

   For the purposes of this clause, and this clause only, capitalized items shall have the same meaning as contained in B.C. Hydro's Tariff Supplement No. 30 - Terms and Conditions applicable to wholesale transmission service.

   When the B.C. Hydro Transmission System is used by West Kootenay Power or an agent to transmit power purchased from any person other than B.C. Hydro to serve West Kootenay Power's Native Load Customers, to a Point of Interconnection or to the Point of Supply (as defined in the General Wheeling Agreement between B.C. Hydro and West Kootenay Power dated October 15, 1986), West Kootenay Power shall pay to B.C. Hydro an amount equal to the Hourly Price for Reserved Capacity which would have been payable for transmission of that energy under Rate Schedule 3001, times the amount of energy delivered.

This Power Purchase Agreement Amending Agreement supplements and amends the Power Purchase Agreement and this Power Purchase Agreement Amending Agreement and the Power Purchase Agreement as amended hereby shall in respect of all matters which occur on or after the 1st day of April, 1999 be read together and shall have effect so far as practicable as though in respect of all matters all provisions thereof and hereof were contained in one instrument.

THE PARTIES INTENDING TO BE LEGALLY BOUND have cause this agreement to be executed under seal.

The Common Seal of BRITISH COLUMBIA HYDRO AND POWER AUTHORITY was affixed in the presence of:

____
Authorized Signatory

____
Authorized Signatory

The Common Seal of WEST KOOTENAY POWER LTD. was affixed in the presence of:

____
Authorized Signatory

____
Authorized Signatory

POWER PURCHASE AGREEMENT AMENDING AGREEMENT (2002)

THIS AMENDING AGREEMENT is made as of the 13th day of December, 2002.

BETWEEN:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, a crown corporation having its head office at 333 Dunsmuir Street, Vancouver, British Columbia

("B.C. Hydro")

AND:

AQUILA NETWORKS CANADA (BRITISH COLUMBIA) LTD., formerly known as UtiliCorp Networks Canada (British Columbia) Ltd. and, before that, West Kootenay Power Ltd., a corporation established by a Special Act of the Legislature of the Province of British Columbia, and a body corporate having its Head Office at 1290 Esplanade Ave., Trail, British Columbia

("Aquila")

WHEREAS:

A. Pursuant to the Power Purchase Agreement (the "Power Purchase Agreement") made as of October 1, 1993, Aquila and B.C. Hydro (the "parties") have agreed to terms and conditions governing the supply of electricity from B.C. Hydro to Aquila; and

B. The parties have agreed to enter into this Power Purchase Agreement Amending Agreement (2002).

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the mutual agreements between the parties and for other good and valuable consideration, B.C. Hydro and Aquila agree that the Power Purchase Agreement shall be amended as follows:

1. For the purposes of this Agreement, Aquila will be referred to as West Kootenay Power.

2. The Power Purchase Agreement is amended by deleting Appendix 1 and replacing it with the following:

Accepted for filing: APR 17 2003
Effective APR 17 2003
Order No.: C-03-2003

SECRETARY
B.C. UTILITIES COMMISSION

"Appendix 1

Points of Interconnection

The Points of Interconnection between B.C. Hydro and West Kootenay Power at which electricity may be purchased under this Agreement are as follows:

(a) West Kootenay Power's 230 kV bus at the Lambert Substation (the "Creston Point of Interconnection").

(b) B.C. Hydro's 230 kV bus at the Vernon Substation and West Kootenay Power's 230 kV bus at the Vaseux Lake Terminal Station (collectively, the "Okanagan Point of Interconnection"). For the purposes of this Agreement, deliveries at the Okanagan Point of Interconnection will be summed and treated as a single delivery point.

(c) West Kootenay Power's tap on B.C. Hydro's transmission line 1L251 near Princeton (the "Princeton Point of Interconnection")."

3. Save as provided herein, the Power Purchase Agreement remains in full force and effect as amended herein and the effective date of the amendments provided for in this Agreement shall be the in-service date of the Vaseux Lake Terminal Station.

4. Each of the following are conditions precedent to all other provisions of this Agreement taking effect:

(a) the granting by the British Columbia Utilities Commission (the "BCUC") of:

(i) each of the orders sought in Section 2.2 of the application by Aquila to the BCUC for orders in respect of the South Okanagan Supply Reinforcement Project; and

(ii) the order sought in the application by BC Hydro to the BCUC to amend the General Wheeling Agreement made as of October 15, 1996 between BC Hydro and Aquila and the Power Purchase Agreement;

Accepted for filing: APR 17 2003
Effective: APR 17 2003
Order No.: C-03-2003

SECRETARY
B.C. UTILITIES COMMISSION

(b) the approval by the Aquila Board of Directors of: the letter dated December 13, 2002 from Aquila to BC Hydro (the "SOK/VAS Letter Agreement"); the Vaseux Lake Terminal Station Agreement dated December 13, 2002 between BC Hydro and Aquila (the "VLTS Agreement"); the General Wheeling Agreement Amending Agreement (2002) dated December 13, 2002 between BC Hydro and Aquila (the "GWA Amending Agreement (2002)"); and this Agreement; and

(c) the approval by the BC Hydro Board of Directors of: the SOK/VAS Letter Agreement; the VLTS Agreement; the GWA Amending Agreement (2002); and this Agreement.

IN WITNESS WHEREOF this Agreement has been executed as of the day and year first above written.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

By: ______________________
Beverly Van Ruyven
Senior Vice President, Distribution

AQUILA NETWORKS CANADA (BRITISH COLUMBIA) LTD.

By: ______________________
Don Debienne
Vice President, Utility Operations

Accepted for filing: APR 17 2003
Effective: APR 17 2003
Order No.: C-03-2003

SECRETARY
B.C. UTILITIES COMMISSION

POWER PURCHASE AGREEMENT AMENDING AGREEMENT (2004)

THIS AMENDING AGREEMENT is made as of the 5th day of April, 2004,

BETWEEN:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, a crown corporation having its head office at 333 Dunsmuir Street, Vancouver, British Columbia

("B.C. Hydro")

AND:

AQUILA NETWORKS CANADA (BRITISH COLUMBIA) LTD., formerly known as UtiliCorp Networks Canada (British Columbia) Ltd. and, before that, West Kootenay Power Ltd., a corporation established by a Special Act of the Legislature of the Province of British Columbia and having its head office at 1290 Esplanade Avenue, Trail, British Columbia

("Aquila")

WHEREAS:

A. Pursuant to the Power Purchase Agreement made as of October 1, 1993, as amended by the Power Purchase Agreement Amending Agreement made as of the 1st day of April, 1999 (the "Power Purchase Agreement"), Aquila and B.C. Hydro (the "parties") have agreed to terms and conditions governing the supply of electricity from B.C. Hydro to Aquila; and

B. The parties have agreed to enter into this Power Purchase Agreement Amending Agreement (2004);

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in the consideration of the mutual agreements between the parties and for other good and valuable consideration, B.C. Hydro and Aquila agree as follows:

1. For the purpose of this Agreement, Aquila may be referred to as "West Kootenay Power".

2. The Power Purchase Agreement is amended by deleting Section 1.1(p) and replacing it with the following:

   "(p) "Point of Supply" means:
   (i) the point where West Kootenay Power's 63kV Line 13 interconnects with B.C. Hydro's Line 60L225 between West Kootenay Power's South Slocan Substation and B.C. Hydro's Kootenay Canal Substation;

(ii) the point where West Kootenay Power's 230kV Line 79 (referred to by B.C. Hydro as Line 2L288) interconnects with B.C. Hydro's Kootenay Canal Substation; and

(iii) the point where West Kootenay Power's 63kV Line 12 (referred to by B.C. Hydro as Line 60L227) interconnects with B.C. Hydro's Kootenay Canal Substation.

For purposes of this Agreement, the above-numerated points will, except in respect of Sections 4 and 10, be deemed, collectively, to be a single point of supply."

3. Save as provided herein, the Power Purchase Agreement remains in full force and effect as amended herein and the effective date of the amendments provided for in this Agreement shall be the in-service date of the facilities required by the British Columbia Utilities Commission (the "BCUC") to be installed or modified on B.C. Hydro premises to connect Line 2L288 and Line 60L227 to the Kootenay Canal Substation.

4. The granting by the BCUC of each of the following orders is a condition precedent to all other provisions of this Agreement taking effect:

(a) an order approving the Interconnection Facilities Agreement for B.C. Hydro's Kootenay Canal Substation among British Columbia Transmission Corporation, B.C. Hydro and Aquila made the 5th day of April, 2004;

(b) an order approving this Agreement; and

(c) an order approving the General Wheeling Agreement Amending Agreement (2004) made as of the 5th day of April, 2004 between B.C. Hydro and Aquila.

5. This Agreement may be executed in counterparts, each of which when delivered shall be deemed to be an original, and each of which together shall constitute one and the same document and agreement. Each party may deliver an executed copy of this Agreement to the other party by fax, provided that such delivery by fax shall in a timely manner be followed by personal delivery to that other party of an originally executed copy of this Agreement.

IN WITNESS WHEREOF this Agreement has been executed as of the day and year first above written.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

By: ______________________

AQUILA NETWORKS CANADA (BRITISH COLUMBIA) LTD.

By: ______________________

Don Debienne, Vice President
Utility Operations

FortisBC
Cost of Service Analysis Open House
Meeting Notes

ATTENDEES:	Katherine McGeehan-Resident Dale Littejohn- CEA
LOCATION:	Castlegar Sandman Inn
MEETING DATE:	May 26, 2009 at 7pm

Question/ Comment #	ITEM DESCRIPTION	Org./ Group
1.	• Are the categories in which the rate payers are broken down into by the amount of customers in each class? • *No, the cut off for tariff generates which class the customer is in.*	
2.	• How are the residential customers placed, does the geographic aspect affect how they are rated? • *No, COSA does not look at the Geographic's of where the customers are located; residential is residential regardless of where you are located.*	
3.	• If you know it costs less to serve certain customers in certain areas, can you not lower their rates? • *Rural rates were looked into and they are not much different than the residential rates. They have a different hookup charge which rectifies the difference s in the density of rates which is a big driver in costs.*	
4.	• Are rates going to change? • *Depending on the class, rates will be changing to rectify any big ratio differences*	
5.	• In what ways can rates be changed? • *The amount you can pay, or the way charges are broken down, we can raise or lower basic charge rate.*	
6.	• There are a number of ways that the bill looks that can be changed in order to have people more aware of their use of power. • *FBC needs to have an incentive for people who are willing to be more aware of the usage of power.*	
7.	• Does FBC know the marginal rate for new production? • *BCH tender for renewable resources is around $.08 a kilowatt hour and it may go up to $.10 a kilowatt hour.* • *We buy power from BCH, Columbia Basin Trust, Tech Cominco, various sources when it is required.*	

Question/ Comment #	ITEM DESCRIPTION	Org./ Group
	• *The on the spot market load keeps growing so we have to buy more on the market which costs the company more.*	
8.	• Rate design?	
	• *We are revenue neutral.*	
9.	• What are the big changes to the system that have and are happening?	
	• *100 million a year is being spent on strengthening the backbone of the system which impacts customers that are allocated transmission/distribution more so than others.*	
10.	• Is Fortis going to be going to Smart Grid and Smart Metering?	
	• *We are actively pursuing putting in smart metering which allows customers to have immediate feedback on their energy usage. There are a lot of benefits but the technology is still relatively new.*	

FortisBC
Cost of Service Analysis Open House
Meeting Notes

ATTENDEES:	Kevin Reynolds- Rutland Water Works Pete Preston- Rutland Water Works John Seddon- resident Cindy McNeely- City of Kelowna (electric utility)
LOCATION:	Kelowna, Ramada Inn
MEETING DATE:	May 27, 2009 at 7pm

Question/ Comment #	ITEM DESCRIPTION	Org./ Group
1.	• What is a demand type customer? • *The system is driven by peak demand times, commercial customers that require large amounts of demands on the system, any change or assumption in the model will affect those customers more than others.*	
2.	• Doe BC Hydro do the same thing? • *They do relatively the same thing but they are30 demand, 70 energy and we are 20 demand 80 energy* • *We are reorganizing due to the capacity restraints that customers are putting on the system, the study that we are looking at is what we have contractually reserved for certain customers and the what we need to have to run the system. When engineers are planning for the system they have to look at load as well as what we are contractually obligated to supply.*	
3.	• Were the irrigation classes paying a lot less? • *It is not uncommon for them to pay less.* • *Municipalities work together on cost of service.* • *We are trying to break down the cost of service to see what the individual classes use to make the rates equitable for everyone.*	Rutland
4.	• What is an irrigation class customer? • *Irrigation defines a customer that uses the energy to water land, have pumping requirements; it is not intended for water utilities.*	
5.	• Are any rate design options mandated by the province? • *We have to consider conservation rates when we are looking at the rates but the province does not mandate any certain rate design.*	

Question/ Comment #	ITEM DESCRIPTION	Org./ Group
6.	• Demand rate- revenue requirements, as rates go up do they have to pass rate increase to their customers, do you see them going down? • *Logically there will be some attempt to re-balance the rates to make them more fair, but it takes times and is a lengthy process*	Resident
7.	• Residential is a huge class, do they all pay the same rates? • *Yes, regardless of where they live.*	Resident
8.	• What about schools, hospitals etc., do they pay a different rate? • *There is no special class for them, but some fall into the small commercial rate class.*	
9.	• Resident- more interested in the process, doesn't have any complaint regarding the rates	

FortisBC
Cost of Service Analysis Open House
Meeting Notes

ATTENDEES:	Alex Love- Nelson Hydro Ed Minshull- Village of Keremeos Buryl Slack and Eric Goodman John Cimbaro- Weyerhaeuser	Roger Mayers Joe A. Cardoso- Resident Kevin Huey- Irrigation District Jeff Iarsen- Weyerhaeuser
LOCATION:	Osoyoos, Best Western	
MEETING DATE:	May 28, 2009 at 7pm	

Question/ Comment #	ITEM DESCRIPTION	Org./ Group
1.	• What is the return requirement? • *The return requirement is 8.77% on 40%.*	
2.	• What is wholesale? • *We sell power to City of Nelson, Grandforks, Penticton and Summerland etc., and they have their own utility in which they re-sell the power to their own customers*	
3.	• Is the allocation of rates based on the number of customers in the class? • *There are many different allocation factors and are not based on the number of people in each class.*	
4.	• When will there be a draft available of the COSA? • *It will be ready next week on the website, as will the presentation and any other relevant documentation.*	
5.	• With respect to cost allocation- would residential rates be different in the Kootenays as opposed to the Okanagan? • *Geographic's do not enter into the allocation process for the residential class.* • The system we are operating on has changed over the past 10 yrs, is it a custom model. We use a basic model that we use for utilities- that is set up very open and for each utility it is customized. Methodologies are different here than other places.	
6.	• How are the rate classifications determined? • *They haven't changed since the last rate design, and we haven't gotten to the rate design piece yet.*	
7.	• Who defines the allocation factors?	

Question/ Comment #	ITEM DESCRIPTION	Org./ Group
	• *Some of them are obvious, the ones with options we have to use our discretion or use a consultant, and ultimately it is our choice.*	
8.	• If there is discretion in the rates, can an intervener question it? • *Yes, that is what this process is all about, having the customers be involved in the process and have a say in what the end result is but BCUC ultimately decides what is the end allocation* • *Once filed in Sept, the commission sets the timelines and we are looking at 12 to 18 months*	
9.	• All the upgrades that FBC has been doing, are those factored into this new model as well? • *Yes, they have been factored into the new model.*	
10.	• How does FBC deal with customers that have a variable low as opposed to a constant (residential/irrigation). • *The demand charge we allocate to the customer depending on the peak demand. Customers with constant use will be lower than someone who uses it at the peak times.*	
11.	• Is the data based on historic? • *It is based on the forecast which is basically based on historical data.*	
12.	• How are the rates competitive between utilities? • *Overall, provincially, there is not much difference between the utilities.*	
13.	• Once we go through the pricing formula, how do we see the cost for a large industrial, going up, staying the same or going down? • *The cost has to be re-balanced so it may go up slightly.*	
14.	• Do we ever foresee de- regulation? • *No, it was tried elsewhere but not much of a success rate. We can buy it at a wholesale level but it doesn't make sense to pass that power all the way down to the customer*	

Question #1

Reference: Exhibit B-1, Application, page 14, lines 18 - 21

> **'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'.**

Q1.1 Please list the rates that:

Q1.1a Embed conservation objectives, and

A1.1a The following rates embed conservation objectives:

- Time-of-use rate schedules 2A, 22A,23A, 32, 33, 40A - TOU, 40B – TOU, 40C – TOU, 40D – TOU, 40E – TOU, 40F – TOU, 43 and 61; and
- Rate Schedules 20, 21, 30 and 31.

Q1.1b Set the stage for their implementation when supportive technology is in place

A1.1b FortisBC's Rate Schedule 1 sets the stage for implementation of conservation rates when supportive technology is in place.

Q1.2 Describe why and how these rates meet conservation objectives.

A1.2 The conservation aspects of the rates are described in Section 2.4, pp 16-17 of the RDA, and can be summarized as:

Residential:

- Rather than move the Customer Charge closer to its higher COSA based amount, it remains at the same level so as to not result in a lower energy rate; and
- Develop a plan for the introduction of time-based rates that better address FortisBC's capacity constraint. (As detailed in Section 3.1 of the Application.)

General Service:

- Flatten Rate 20 to eliminate declining block structure;
- Reduce number of tiers in Rate 21 from three to two; and
- Slightly raise the demand charge rate to encourage the management of demand levels.

Large General Service - Primary:

- Raise the demand charge rate to encourage the management of demand levels.

Large General Service – Transmission & Wholesale:

- 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.

Question #2

Reference: Exhibit B-1, Application, page 16, lines 17 - 19

Q2.1 When does FortisBC expect to fully implement AMI and time-based and critical peak pricing rates?

A2.1 Please refer to the response to BCUC IR No. 1 Q6.1

Question #3

Reference: Exhibit B-1, Application, page 19, Table 2.4

Q3.1 Given FortisBC's capacity constraints and apparent focus on conservation rates, why is the Company not completely phasing out declining block rates for General Service customers?

A3.1 This is described in Section 11.1, page 64, lines 7-19 of the RDA as repeated below:

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.*

Question #4

Reference: Exhibit B-1, Application, page 22, line 27 – page 23, line 2

Q4.1 Please provide the basis for the assertion that time-based rates have been shown to reduce overall energy consumption by up to 6 percent. Which rate classes do these reductions apply to?

A4.1 The assertion was based on the Ontario pricing pilot and Brattle Group studies, both focused on residential customers, referenced in Section 3.1 of the Application. The phrase "An Ontario pricing pilot reached similar conclusions summarized in the following table:" on Page 23, lines 1-2 were made in error and should have simply read "The results of an Ontario pricing pilot are summarized in the following table:" Please refer to Errata 2.

Q4.2 Please provide the basis for the assertion that time-based rates could reduce peak demand by 25%. Which rate classes do these reductions apply to?

A4.2 Please refer to the response to BCOAPO IR No. 1 Q4.1. This assertion relates to the referenced studies and applies to residential customers.

Q4.3 Which North American utilities have implemented both time-based and critical peak pricing rates for their residential customers?

A4.3 A study by FERC (Federal Energy Regulatory Commission) completed in 2008 of 2,094 American utilities indicated that 503 of those utilities had implemented some sort of time based rate (see below).

Table III-1. Number of entities offering time-based rates

Time-based Rate	Number of Entities (2006 Survey)	Number of Entities (2008 Survey)
Time-of-Use Rates	366	315
Real-time Pricing	60	100
Critical Peak Pricing	36	88
TOTAL	462	503

Source: 2006 FERC Survey and 2008 FERC Survey

At this time, FortisBC does not have information on which of these utilities may have implemented a combination of these time based rates. However, the AMI Future Program Study expected to be complete in the first quarter of 2010 will provide a more comprehensive review of North American utilities that have implemented or piloted conservation rates both individually and in combination.

Q4.4 What steps does FortisBC plan to take to ensure that lower use and lower income residential customers are able to benefit from time-based rates? For example, lower income customers may be less able to reduce load relative to higher income customers.

A4.4 FortisBC has already introduced some low-income DSM programs which include the distribution of free energy savings kits and compact fluorescent light bulbs. These programs will be expanded in future years, the details of which will be outlined in the upcoming 2011 DSM Plan. These plans will help ensure that low income customers are able to reduce their load in response to time-based and other types of rates.

Question #5

Reference: Exhibit B-1, Application, page 29, line 12 – page 30, line25

Q5.1 During the last 5 years has FortisBC or its affiliates made any attempts to acquire any of the electric utilities who are members of the BCMEU?

A5.1 FortisBC or its affiliates have considered acquiring certain electric utilities that are members of the BCMEU on terms that would be beneficial to all FortisBC ratepayers. The Company has, at the request of certain municipal councils provided a preliminary estimate of the value of municipal utility assets.

Question #6

Reference: Exhibit B-1, Application, page 38, lines 5 – 6

Q6.1 Has FortisBC's load forecast prediction of a capacity shortfall of about 145 MW for 2009 materialized?

A6.1 The peak 2009 load was 714 MW compared to the predicted peak of 701 MW. On a planning basis, this peak would have resulted in a predicted shortfall of about 160 MW. Please refer to BCUC Attachment A68.6 which is provided as an electronic Excel attachment only.

Question #7

Reference: Exhibit B-1, Application, page 40, line 25 – page 41, line 3

Q7.1 Why did the 2007 COSA study take measured demand, and not contract demand, into consideration in setting rates for Wholesale customers?

A7.1 FortisBC assumes that the question intended to refer to the 1997 COSA Study. While it may have been appropriate to employ the contract demand allocation methodology in 1997 as well, the conditions discussed in Appendix A to the Application (p31-32, Exhibit B-1) were not recognized or contemplated by the Company until more recently.

Q7.2 What other Canadian electric utilities continue to use measured demand when setting wholesale rates?

A7.2 FortisBC does not have a complete list of Canadian utilities using measured demand during cost of service studies.

Question #8

Reference: Exhibit B-1, COSA Study, page 6

> **'The setting of electric utility rates that are 'fair and equitable' is a complex process. This process is directed, however, by generally accepted methodolgiges that can be used as a guide in developing ForisBC's electric rates. At teh same time, there are often a number of financial pricniples or guidelines that must be taken into consideration during this process. Therefore, the setting of electic rates that are 'fair and equitable' is an intergration of these generally accepted methodolgies and any related financila policies or specific policy consideration from FortisBC'**

Q8.1 Please describe the 'financial principles or guidelines' that were taken into consideration when setting electric utility rates.

A8.1 Please refer to the response to BCUC IR No. 1 Q47.1.

Q8.2 Please describe the 'related financial policies and specific policy considerations from FortisBC'

A8.2 Please refer to the response to BCUC IR No. 1 Q47.1.

Question #9

Reference: Exhibit B-1, Application, page 5, lines 7-15

Q9.1 Please clarify how FortisBC defines/interprets "conservation".

A9.1 In the context of the referenced section, conservation is defined as the reduction of energy usage or shifting energy usage to periods of lower demand.

Q9.2 Given that the FortisBC system has become increasingly capacity constrained, does FortisBC place a priority/preference on conservation initiatives (including rates) that reduce capacity (as opposed to energy) requirements?

A9.2 It is anticipated that energy conservation initiatives will continue to be enhanced, even as demand or capacity reduction initiatives are introduced in the coming years. Initiatives focused on demand or capacity reduction initiatives may result in energy conservation, and vice-versa.

Question #10

Reference: Exhibit B-1, Application, page 11, lines 22-24

Q10.1 How does FortisBC interpret the expression "energy efficiency" and how does it differ from conservation?

A10.1 FortisBC interprets "energy efficiency" as providing the same level of service with a more energy efficient technology. Energy efficiency is one form of conservation. Other forms of conservation would include behavioural changes (e.g. lower thermostat setting), a reduction in service (e.g. porch light turned off at bedtime, rather than left on overnight) or shifting energy use (e.g. setting the dishwasher to come on after the on-peak period has ended).

Question #11

Reference: Exhibit B-1, Application, page 23, Table 3.1 and lines 19-23

Q11.1 If, presumably TOU rates are higher in the on-peak periods, why is the overall conservation effect attributable to TOU-Only pricing higher (6%) than that attributed to the on-peak period (2.4%) or even the critical peak period (5.7%)?

A11.1 FortisBC cannot explain these results based on the information contained in the referenced report.

Q11.2 In seeking stakeholders' feedback on FortisBC's intended move to TOU pricing, were any estimates provided to participants regarding bill impacts based on current consumption profiles?

A11.2 No estimates were provided to participants. It would not have been useful information since without AMI customers do not generally have any information about their current consumption profiles.

Question #12

Reference: Exhibit B-1, Application, page 33, lines 16-17 and page 34, lines 29-30

Q12.1 Does FortisBC agree that in order to satisfy Principle #5 (i.e., be cost-effective), the savings from TOU, critical peak pricing and load control rates must more than offset the costs of implementing such rates? If not, why not?

A12.1 FortisBC believes that that the incremental cost of any measure implemented strictly for cost savings should be less than the present value of the cost savings. Therefore, if TOU, critical peak and load control rates were implemented strictly for cost savings, FortisBC agrees. If they were not implemented strictly for cost savings, then FortisBC does not agree.

Question #13

Reference: Exhibit B-1, Application, page 41, lines 14-20

Q13.1 What is the impact of the change in classification of generation rate base on the revenue to cost ratio for the Residential class?

A13.1 The revenue to cost ratio for the residential class is at 98.3 percent as filed. Without the change in the generation rate base classification, the revenue to cost ratio would be 98.4 percent.

Question #14

Reference: Exhibit B-1, Application, page 46, lines 5-12

Q14.1 Please confirm that, in the COSA, the costs allocated to any particular customer class will depend on their proportion of the overall loads for all customer classes. If so, isn't accurate metering data required for all customer classes in order to support a "goal" of 100% revenue to cost ratio for any customer class?

A14.1 There is a distinction between the accuracy and the sufficiency of data. For those customers with interval metering, such as some commercial, wholesale and industrial, data is both accurate and provides sufficient load data to support revenue to cost ratios closer to 100 percent. Metering data for the balance of the customers, while still accurate, does not provide the type of information (demand and/or interval data) necessary. There is accurate metering data for billing purposes for all customers, and sufficient data for accurate revenue to cost ratios for certain customers that have hourly metering.

Question #15

Reference: Exhibit B-1, Application, page 47, line 10-11

Q15.1 Why are BC Hydro flow-through increases excluded from the 10% total increase threshold?

A15.1 In practical terms, the magnitude and timing of BC Hydro's rate increases are typically not known at the time that FortisBC rates are set. In addition, FortisBC believes that rebalancing should be accomplished within a reasonable amount of time, such as the 5 years suggested in the Application. If increases outside of those driven by the revenue requirement are not excluded, there is every possibility that rebalancing would not occur in a timely fashion.

Question #16

Reference: Exhibit B-1, Application, page 57, Table 10.1 and lines 22-25

Q16.1 What would be the Residential Basic Charge if the customer costs associated with the Minimum System were excluded?

A16.1 The unit costs from the COSA show a residential customer cost of $12.95 every two months if the customer portion of the minimum system classification was excluded. It also results in a revenue to cost ratio of 106.1 percent for the residential class.

Q16.2 Based on the most recent 12 months of billing data, how many residential accounts does FortisBC have? How many of these accounts used less than 250 kWh over two months:

- **During each of the 6 billing periods?**
- **For at least one of the 6 billing periods?**

A16.2 Based on the most recent 12 months of billing data (Jan 1st, 2009 to Dec 31st, 2009), FortisBC has 96,532 residential accounts.

- 1.2 percent of customer accounts (1,187 customer accounts), used less than 250 kWh during each of the 6 billing periods
- 12.9 percent of customer accounts, (12,452 customer accounts) used less than 250 kWh for one or more of the 6 billing periods (including the 1,187 accounts above).

Question #17

Reference: Exhibit B-1, Application, page 60, lines 8-12

Q17.1 Please explain more fully why, to be effective, inclined block rates should be accompanied by real-time energy consumption information?

A17.1 Please see the response to BCUC IR No. 1 Q6.6.

Question #18

Reference: Exhibit B-1, Application, page 64, lines 2-4 and lines 22-23

Q18.1 Please confirm if the demand amount quoted on line 3 should be 4 kW or 40 kW.

A18.1 The sentence in question should read:

Customers receiving service under Schedule 21 are larger, averaging 16,000 kWh per month with demand generally above 40 kW, than those in Schedule 20 at average usage of 3,800 kWh per month.

Please refer to Errata 2.

Q18.2 Please confirm if the 100,000 kWh value reported on line 23 should be 8,000 kWh.

A18.2 Confirmed. Please refer to Errata 2.

Q18.3 What is the average load factor for customers receiving service under Schedule 21 and with monthly demands of between 40 kW and 60 kW?

A18.3 The average load factor for those customers taking service under Schedule 21 is 33 percent.

Q18.4 Based on the load factor reported in response to Question #18.3, please calculate the monthly bill for:

- **A customer with 41 kW demand on Schedule 21**
- **A customer on Schedule 20 using 10% less kWh than the customer in the preceding bullet.**
- **Please also compute the percentage difference between the two bills.**

A18.4 For a customer with 41 kW demand:

- The monthly bill for the customer on Schedule 21 would be $818.29
- The monthly bill for the customer on Schedule 20 would be $766.08
- The percentage difference between the bills is 7 percent.

Question #19

Reference: Exhibit B-1, Application, page 68

FortisBC's Current Rate Schedule
http://www.fortisbc.com/downloads/about_fortisbc/rates/FortisBC%20Tariff%20Effective%20October%201%202009%20.pdf

Q19.1 The Application states that the current Rate Schedule uses 100% of contract demand and 100% of maximum demand over the previous 11 months to determine the demand charge. However, the Rate Schedule on FortisBC's website uses 80% in each case. Please reconcile.

A19.1 The version of the Tariff on the FortisBC website is correct. The proposed rate was inadvertently placed at both lines 1 to 3 and 16 to 19 of page 68 of the Application (Exhibit B-1). Please refer to Errata 2.

Q19.2 Based on the most recent 12 months billing history, how many customers are there on Rate Schedule 31 and how many would see a lower demand charge billing determinant for at least one month (out of the 12) based on the proposal to only use maximum kVA for the Power Supply Charge as opposed to the greater of the three values as proposed for the Wires charge and currently used?

A19.2 There were three customers on Rate Schedule 31 in 2009. All three customers would have had at least one month in which the billing determinant for the Power Supply Charge was less than the Wires Charge with the proposed Schedule 31.

Q19.3 Please respond to part 19.1 using 2007 billing data.

A19.3 FortisBC assumes this question should have read "Please respond to part *19.2* using 2007 billing data". There were three customers on Rate Schedule 31 in 2007. All three customers would have had at least one month in which the billing determinant for the Power Supply Charge was less than the Wires Charge with the proposed Schedule 31.

Q19.4 What is the average monthly load factor for those customers on Rate Schedule 31? Please also provide a chart or histogram setting out the range of load factors for these customers.

A19.4 The following table provides the load factor for the 3 customers on Rate Schedule 31.

Table BCOAPO A19.4

Customer #1	74.26%
Customer #2	63.05%
Customer #3	79.19%
Average	73.16%

Question #20

Reference: Exhibit B-1, Application, pages 70-71

Q20.1 How is the billing determinant for the Wholesale Rate demand charge currently determined?

A20.1 The determination of the demand charge can be found in the Wholesale Tariff Schedules and is repeated below:

"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.

Q20.2 Page 71 (lines 12-14) makes reference to a Large General Service Transmission customer currently being on the Wholesale rates. Please clarify.

A20.2 The referenced lines appeared in this part of the Application in error and should have appeared at the end of page 69 in Section 12.2 Large General Service – Transmission Rate Design Options. Please refer to Errata 2.

Question #21

Reference: Exhibit B-1, Application, pages 77-78

Q21.1 Please provide a schedule setting out the calculation of each of the extension credits in Table 17.2.

A21.1 Please refer to the response to BCUC IR No. 1 Q40.1.

Q21.2 In order to determine the amount of capital covered by the retail tariff (page 77, lines 3-5) assumptions must be made regarding future use. What future use assumptions are incorporated in the calculation of the extension credits and on what are they based?

A21.2 The line extension credit is based on the capital costs embedded in the COSA study for the 2009 test period. It does not require an estimate of future use or revenues.

Q21.3 Please confirm that the system expansion methodology only considers spending to provide distribution system facilities and does not include spending on transmission facilities or to provide future commodity supply.

A21.3 The line extension credit applies only to distribution facilities. It is assumed that transmission expenditures will be paid for through rates, except in the case of Large General Service and Industrial Applicants as provided for in Schedule 74, Special Contracts.

Q21.4 For those customer classes where the revenue to cost ratio does not equal 1.0, how does FortisBC determine the portion of the retail charges that are contributing to distribution facility costs?

A21.4 FortisBC has not determined retail charges specifically used to contribute to distribution, transmission, power supply or other costs. The revenues associated with retail rates are compared to the total cost of service in total.

Question #22

Reference: Exhibit B-1, Application, page 79 and Appendix E

Q22.1 Why does the "travel time" vary by service (e.g. Disconnect/Reconnect vs. Transfer to Permanent Service)?

A22.1 A disconnection and reconnection requires two trips while a transfer to permanent service requires only one. In addition, the amount of preparation time differs (for example, material loading) for the jobs. These are the best estimates available based on the experience of crews in the field.

Question #23

Reference: Exhibit B-1, Application, page 80

Q23.1 Why is FortisBC eliminating the incremental meter charge for those customers who opt for TOU rates?

A23.1 There are primarily two reasons that FortisBC has chosen to eliminate this charge. First, the charge may serve as a disincentive to program participation which the Company feels it is appropriate to eliminate, and second, the cost premium for TOU capable meters continues to decline and with the planned introduction of the Advanced Metering Infrastructure, will disappear altogether.

Question #24

Reference: Exhibit B-1, COSA Study, page 13

Q24.1 Does FortisBC own any transmission or distribution lines for which their sole purpose is to incorporate generation into the grid or to interconnect with BC Hydro's system? If so, how are these lines functionalized – as generation or as transmission/distribution?

A24.1 FortisBC does not own any transmission or distribution lines which are used solely to integrate generation into the grid or to the BCTC/BC Hydro system. All of the lines above are functionalized as transmission/distribution.

Q24.2 If there are such lines and they are functionalized as transmission/distribution please provide the 2009 average gross and net book value for these assets – broken down as between transmission and distribution.

A24.2 Please see the response to BCOAPO IR1 Q24.1.

Question #25

Reference: Exhibit B-1, COSA Study, page 14

Q25.1 If O&M and purchased power costs are the primary bills paid by FortisBC, why is Working Capital functionalized on the same basis as all O&M costs as opposed to being functionalized on the same basis as all O&M costs plus purchased power costs?

A25.1 O&M costs as defined as a classification method in the COSA and as defined on page 14 does include purchased power costs.

Q25.2 Please provide a revised version of Schedule 1.1 and 1.5 assuming working capital is functionalized based on all O&M plus purchased power costs.

A25.2 Please see the response to BCOAPO IR No. 1 Q25.1.

Q25.3 Please provide a schedule that sets out the complete functionalization and classification of DSM costs.

A25.3 Please refer to the following table:

Table BCOAPO A25.3
DSM Functionalization and Classification

	Total Expenses	Production Demand	Production Energy	Transmission Demand	Distribution Demand	Distribution Customer
Energy Management Promotion	$56,000	$9,296	$40,096	$2,519	$1,733	$2,357
DSM Amortization	$934,000	$155,044	$668,744	$42,005	$28,901	$39,305

Question #26

Reference: Exhibit B-1, COSA Study, pages 15-16

Q26.1 How was the 12% of DSM costs that were functionalized as transmission and distribution further broken down between these two functions and subsequently classified?

A26.1 The T&D portion was broken out between Transmission and Distribution on the basis of total plant for each function (38% Transmission and 62% Distribution). Within each function, it was further broken out by classifier on the total classification of plant for the function. The resulting percents are 4.50 percent for transmission demand, 3.09 percent for distribution demand and 4.21 percent for distribution customer.

Q26.2 Please provide more details regarding calculation of the "labour ratios" used to functionalize A&G costs.

A26.2 Please refer to the response to BCUC IR No. 1 Q54.1.

Q26.3 Please confirm that revenue from connection charges and NSF cheques was credited to customer classes based on the <u>number of retail customers</u> in each class.

A26.3 Confirmed.

Question #27

Reference: Exhibit B-1, COSA Study, page B-4

Q27.1 Please explain how the total number of km of 2 ACSR line required for the minimum system was established.

A27.1 The total number of circuit kilometers was determined based on our existing distribution system extracted from FortisBC's graphical information system.

Question #28

Reference: Exhibit B-1, COSA Study, page B-7

Q28.1 Why is it assumed that the same number of transformers is required on the system when the capacity of each transformer is 15 kVA and the load for each customer is only 1 kWh/annum?

A28.1 Transformers are located on the basis of both distance and load and the number installed would not necessarily be reduced as a result of a reduced load.

Question #29

Reference: Exhibit B-1, COSA Study, pages B-11 – B-13 and Schedules 6.5 & 8.2

Q29.1 Please explain more fully what the data entries for each line segment represent and how the "max KVA" value was determined (per pages B-11 to B-13).

A29.1 The Max Demand value in Schedule 8.2 accounts for both the coincident peak for each customer and the contract demand for wholesale and industrial customers. It takes the higher of the two values in order to calculate the 2CP used for allocating transmission costs (Schedule 6.4). There is no Max kVA used in Schedule 6.5. The Max kVA on pages B11 to B13 reflects the max kVA capacity on the feeders listed in that table and is unrelated to the Max Demand from Schedule 8.2.

Q29.2 The 1 kW PLCC appears to be determined based on the carry capability of the conductors. Was the same 1 kW PLCC adjustment used for the allocation of the demand-related portion of transformer costs?

- **If yes, please explain why when the total installed transformer capacity of the minimum system is 427,185 kVA (i.e., 28,479 * 15 KVA) which suggests a carrying capability of 4.8 kVA per customer (i.e., 427,185 kVA / 89,616 customers)**
- **If no, what PLCC factor was used and in what Schedule is the use of this value shown.**

A29.2 The conductors, poles and transformers are an integrated system. The conductors were determined to be the limiting factor on the system and therefore the conductor capability was used to develop the Peak Load Carrying Capability. Note that the PLCC is not an adjustment that is made to the percentage split for each account in the minimum system. Rather it is used as an adjustment to the loads used for allocating the demand-related portion of the distribution costs.

Q29.3 Please clarify what, if any, of the NCP customer demand data in Schedules 6.5 and 8.2 has been adjusted for the PLCC.

A29.3 The NCP values in Schedule 6.5 and 8.2 have not been adjusted to reflect the PLCC. The PLCC adjustments are made individually for the poles, conductors and transformer accounts with both the customer and demand portion. The adjustment can be found starting at cell A224 in the C&A by Cust table in the Fortis COSA Model.

Q29.4 Please provide a schedule that sets out for each customer class with NCPP values the following:

- **The winter 1CP value**
- **The winter NCPP value – prior to the PLCC adjustment and any adjustment for contract demand**
- **The winter NCPP value – with the PLCC adjustment bur prior to any adjustment for contract demand.**

A29.4 Please see the attached table. Note that certain classes are not assigned an NCP after PLCC because they are not allocated any of the costs for the accounts for which the PLCC adjustment is made.

Table BCOAPO A29.4

	CP (kW)	NCPP (kW) before PLCC	NCPP (kW) after PLCC
Residential	313,226	368,488	268,665
Small General Service	36,855	67,446	57,834
General Service	105,566	132,470	128,778
Rate 33 Industrial	11,213	11,400	
Industrial Primary	28,559	36,539	29,198
Rate 31 Industrial	8,059	9,627	
Lighting	2,617	6,087	4,050
Irrigation	3,972	18,223	17,013
Kelowna Wholesale	61,401	60,152	
Penticton Wholesale	71,883	72,326	
Summerland Wholesale	20,529	22,217	
Grand Forks Wholesale	8,062	8,403	
BCH Lardeau Wholesale	4,964	4,751	
BCH Yahk Wholesale	584	790	
Nelson Wholesale	23,855	26,531	

Q29.5 With respect to Schedule 6.5, why is the NCP value for Lighting so much higher in the Summer than the Winter?

A29.5 The load factors for the lighting class were based on the number of hours of daylight when streetlights would be operating. This created a low load factor in the summer months as lights were on fewer hours. The lower load factors created a higher peak demand in the summer months.

Question #30

Reference: Exhibit B-1. COSA Study, Schedules 3.1 and 4.1

Q30.1 Are the maintenance costs associated with Conductors & Devices (Acct. #365), Transformers (Acct. #368) and Services (Acct. #369) included in with Distribution Line Maintenance (Acct. #583.1)? If not, where are the associated maintenance costs captured?

A30.1 Yes, the maintenance costs are included as indicated in the request.

Q30.2 Based on assets covered by Distribution Line Maintenance, why is the account classified based on only classification for Poles, Towers & Fixtures (Acct. #364)?

A30.2 The Distribution Line Maintenance Distribution ROW Maintenance in Schedule 3.1 are both classified and allocated on the same basis as rate base accounts 364 and 365, which includes Conductors as well as Poles, Towers and Fixtures.

Question #31

Reference: Exhibit B-1, COSA Study, page 25 and Schedule 6.5

Q31.1 The Study states that poles and conductors are split 80% to NCPP and 20% to NCPS based on industry experience. Please confirm that this implicitly means 80% of the poles and conductor costs are assumed to be associated with primary voltages and 20% with secondary voltages. Why is industry experience considered applicable/appropriate for FortisBC's system?

A31.1 The primary/secondary split used in the COSA would be equivalent to saying the facilities are split in that fashion. A detailed split of FortisBC facilities was not available at the time the COSA was done and therefore industry experience was used to determine the split.

Q31.2 Please explain why NCPP as opposed to CP is used to allocate the costs associated with distribution stations.

A31.2 Generally facilities that are close to the customer and driven by localized loads are based on the NCP allocator while facilities that are planned on the basis of total system loads, like generation and transmission, are allocated on the basis of CP, including contract demand where appropriate. Distribution substations are driven by loads of the customers in the specific region as opposed to the total FortisBC system load.

Q31.3 Which NCPP and NCPSS values are used in the allocation: winter, summer or annual (per Schedule 6.5)?

A31.3 The annual NCPP and NCPS are the values used as allocation factors.

Question #32

Reference: Exhibit B-1, COSA Study, pages 25-31

Q32.1 The Study devotes considerable discussion to the choice of CP factor to be used (i.e., 1CP vs. 2CP vs. 4CP) and reviews the results of various tests including ones developed by the OEB. Please confirm that the same referenced OEB Report also included similar tests for determining what NCP measure should be used.

A32.1 Confirmed.

Q32.2 Why isn't there a similar discussion regarding the choice of NCP allocation factor?

A32.2 The use of a single NCP is standard utility practice. That is not to say that the NCP is based on the single peak month for the system. Because the NCP is based on the time of the peak for each separate class, those peaks do not all occur at the same time of the year. For FortisBC the NCP occurs in January for residential, July for Schedules 20, 21 and 31, and various other months for other classes. Therefore it would not be appropriate to use the 4 winter months as the NCP allocator for the individual customer classes.

Q32.3 Please provide the results of the OEB's NCP allocation factor tests and reconcile the results with the NCP allocation factor(s) used in the study.

A32.3 The OEB test result for FortisBC using the 2009 forecast period is 92 percent. As this is above the 83 percent indicator in the OEB method, the 4 NCP method would be required by the OEB. As the OEB test for the NCP is not required in British Columbia, FortisBC is not required to use this method. Further, as described in the above response to BCOAPO IR No. 1 Q32.2, it would not be appropriate in this case.

Question #33

Reference: Exhibit B-1. COSA Study, pages 33-34 and Schedule 3.1

Q33.1 Do the weighting factors developed for Accounting/Metering for each customer class implicitly allow for the fact that some customers do not require meter reading and that all customers may not be billed at the same frequency?

A33.1 The weighting factors do account for the difference in meter reading frequency and cost between different types of customers.

Q33.2 The allocation factor CUSTM is based on the relative cost of the meter used for each customer class and is used to allocate both metering and services costs. Please confirm that, since the Lighting class required no meters, this class is not allocated any costs related to Services (Acct. #369). Why is this result appropriate?

A33.2 The lighting class is generally unmetered and is also connected differently than other types of customers. For most of the FortisBC overhead system, the lights are fed by short drops to the existing secondary system and do not require the same level of service drops used for other customer classes.

Q33.3 With respect to page 33, please explain more precisely how the "actual number of customers served" is determined (e.g., , is it billing accounts, number of separate physical locations, etc.?). For example, a lighting customer may have more than one fixture (multiple fixtures at multiple points on the distribution system – how is the customer count established?

A33.3 The customer count is derived from the number of "service agreements" in the billing system. There is generally one service agreement per metered location, so there may be more than one service agreement per customer. Non-metered accounts, such as street lighting accounts, are aggregated under one service agreement and are therefore counted as one customer.

Q33.4 Page 34 states (rate base) distribution accounts that are 100% customer-related are allocated on the basis of customers weighted according to the average cost of metes by class. Please provide a listing of those rate base distribution accounts that are 100% customer-related.

A33.4 Distribution accounts that are 100% customer-related are listed in Schedule 3.1 and include Services, Meters and Installations on Customer Premises.

Question #34

Reference: Exhibit B-1, COSA Study, Schedule 8.2

Q34.1 Please confirm that the NCP and CP values for each class were determined by applying individual, group and system coincidence factors to each class' monthly energy use. If not, please describe how the values were determined.

A34.1 These factors were used to develop the NCP and CP values by class, as described on pages C-1 to C-3 of the COSA Study (Appendix A, Exhibit B-1).

Q34.2 What is the source of the various coincidence factors use in the analysis and what is the accuracy associated with them? For example, if the values are based on load research, is there a statistical confidence level associated with the results?

A34.2 The source of the data is discussed on pages C-1 to C-3 of the COSA Study. FortisBC does not have direct load research data and relied in part on BC Hydro information. FortisBC does do not have the statistical confidence level for that load research. FortisBC recognizes that the load data it has for its residential and general service customers does not have a high level of accuracy and hopes to improve that accuracy once AMI metering is installed.

Q34.3 Based on the response to Question 34.2, what is the degree of confidence one can attribute to the revenue to cost ratios determined by the COSA?

A34.3 As stated on page 46 of the Application, the 95 to 105 percent revenue to cost range was considered reasonable given the absence of perfect data in the COSA (Exhibit B-1). As mentioned in the response to BCOAPO IR No. 1 Q34.2 above, a statistical confidence level is not available.

Question #35

Reference: Exhibit B-1, COSA Study, page 12

Q35.1 Why are Industrial Transmission (Rate 31) and Industrial Transmission TOU (Rate 33) considered as separate customer classes for purpose of the COSA? What differences are there between the customers that can not be addressed through rate design?

A35.1 There are two primary differences between the customers that make it appropriate to have separate rate classes in the COSA. First, the Rate Schedule 33 customer has a very different load shape than the rate 31 customers. Second, the Rate Schedule 33 customer has self-generation and relies on FortisBC for standby transmission and generation. This self-generation also contributes to the customer's ability to shift loads to off-peak periods.

Q35.2 What are the "different characteristics" of the seven customers served at the wholesale level and why can't the associated differences be addressed through rate design?

A35.2 The different characteristics of the municipal wholesale customers are consistent with those generally used to break out customer classes. Differences include size, voltage levels, load profiles, self-generation and reliability. The fact that the revenue to cost ratios differ so much among the customers indicates that they do indeed cause different costs on the system and as such should face different rates. However, a single rate class could be developed if desired (see also response to BCMEU IR No. 1 Q52.2).

Question #36

Reference: Exhibit B-1, Application, pages 63 (lines 6-7), 65 (lines 78), 67 (lines 12-13), page 69 and 71.

Q36.1 With respect to page 63 and the Schedule 20 customers, please provide a table that sets out the bill impacts associated with the proposed changes for different monthly consumption levels and, based on recent data, the number of bills associated with each consumption level.

A36.1 Please see Table BCOAPO A36.1 below.

Table BCOAPO A36.1

Monthly Consumption	**% of Bills**		**% Change**
0 - 8,500 kWh	97.4%		-0.7% to -1.4%
8,500 - 12,500 kWh	1.9%		0% to 7.8%
12,500 - 27,500 kWh	0.7%		8.0% to 18.6%
Above 27,500 kWh	0.0%		up to 22.2%

Q36.2 With respect to page 65 and the Schedule 21 customers, please provide a table that sets out range of bill impacts associated with the proposed changes (e.g. 0-1%, 1%-2%, etc.) and the number of bills/customers associated with each increment in the range.

A36.2 Please see Table BCOAPO A36.2 below.

Table BCOAPO A36.2

Bill Change	**% of Bills**
-0.8 to -1.4%	50.1%
-1.5 to 0.0%	48.2%
0.0 to 4.0%	1.3%
4.0 to 15.0%	0.3%
Above 15.0%	0.1%

Q36.3 With respect to page 67 and Schedule 30 &32 customers, please provide a table that sets out range of bill impacts associated with the proposed changes (e.g. 0-1%, 1%-2%, etc.) and the number of bills/customers associated with each increment in the range.

A36.3 Please see Table BCOAPO A36.3 below.

Table BCOAPO A36.3

Bill Change	% of Bills
-1.0 to -0.4%	3.2%
-0.3 to -0.0%	22.6%
0.1 to 1.0%	58.1%
Above 1.0% (avg 3.6%)	16.1%

Q36.4 There is no discussion of the bill impacts for Large General Service – Transmission customers. Please provide a schedule indicating the range of anticipated impacts and number of customers affected.

A36.4 There are three customers served under Rate Schedule 31 with estimated bill impacts of -1.1 percent, 0.1 percent and 8.6 percent. The bill increase results from a poor load factor.

Q36.5 On pages 46-48 of the Application FortisBC recommends limits on the total annual increase that a customer group should experience due to a combination of rate rebalancing and revenue requirement based rate increases. What are FortisBC's views as to whether limits should be established as to the bill impacts individual customers will experience as result of revenue requirement increases, rate rebalancing <u>and</u> rate design changes? If limits are appropriate, what does FortisBC recommend?

A36.5 Principle 6 on page 33 of the Application indicates that customer rate impacts should be managed (Exhibit B-1). This applies to individual customers as well as customer groups. FortisBC considered individual rate impacts when designing the proposed rates, but does not believe that specific limits for individual customer bill impacts are appropriate or practical.

Reference: Application, Page 40

Q1.1 On page 40 of the Rate Design Application, mention is made of the "demand limits," also referred to as "contract demands" for the wholesale customers. Please specify any changes to these limits since the last ECOS in 1997.

A1.1 FortisBC has been able to locate the Demand Limits as they existed in 2000, but not specifically 1997. These values, along with the comparative 2009 values are contained in Table BCMEU A1.1 below.

Table BCMEU A1.1

Municipality	**Point of Delivery & Demand Limit (Summer / Winter MVA)**				
Summerland	Trout Creek	Summerland			
2000	6 /10	16 /20			
2009	6 /10	16 /20			
Penticton	Huth Ave 13 kV	Huth Ave 8 kV	Waterford	Westminster	R.G. Anderson
2000	32 / 40	-	15 / 20	15 / 20	16 / 16
2009	32 / 40	10.5 / 13.6	32 / 40	31 / 38	20 / 25
Nelson	Rosemont	Coffee Creek			
2000	40 / 40	5 / 5			
2009	40 / 40	5 / 5			
Kelowna	Glenmore	Recreation	Saucier	Pollution Control	
2000	20 / 20	30 / 30	30 / 30	14.3 / 18.4	
2009	20 / 20	30 / 30	30 / 30	11.8 / 11.8	
Grand Forks	Ruckles 13 kV	Ruckles 4 kV	Donaldson Dr.		
2000	6 / 8	6 / 8	-		
2009	6 / 8	6 / 8	6 / 8		

2.0 Reference: Application, Appendix A, Page 32

Q2.1 On page 32 of Appendix A, it states that "in several cases, the contractual demand has been exceeded historically." For each year from 1997 onward, please provide, separately for each wholesale customer:

Q2.1a. The maximum non-totalized demand in kVA recorded for each customer in each year.

A2.1a. FortisBC has data available from 2004. Table BCMEU A2.1a below contains the requested information.

Table BCMEU A2.1a

	Maximum non-totalized demand in kVA recorded in each year					
Customer	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
City of Grand Forks	9,117	8,761	8,673	8,403	11,500	8,953
City of Kelowna	68,605	65,944	69,776	64,097	68,792	63,799
Nelson Hydro	28,384	26,242	25,681	25,819	50,750	29,191
City of Penticton	72,318	70,654	78,105	72,647	79,110	72,687
District of Summerland	20,609	20,867	22,889	21,504	24,037	21,945
BC Hydro – Lardeau	3,752	3,907	3,729	3,120	2,870	2,022
BC Hydro – Kingsgate	587	622	836	716	898	782

Q2.1b. The maximum totalized demand recorded for each customer in each year.

A2.1b. Table BCMEU A2.1b contains the requested information.

Table BCMEU A2.1b

	Maximum totalized demand recorded in each year(kVa)					
Customer	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
City of Grand Forks	9,014	8,760	8,546	8,312	9,019	8,625
City of Kelowna	63,787	64,128	68,880	62,722	64,967	60,869
Nelson Hydro	26,270	26,164	25,517	25,547	31,261	29,189
City of Penticton	71,367	69,116	77,043	70,925	77,813	70,881
District of Summerland	20,419	20,796	22,888	21,500	23,891	21,945
BC Hydro – Lardeau	3,752	3,907	3,729	3,120	2,870	2,022
BC Hydro – Kingsgate	587	622	836	716	898	782

Q2.1c. The contractual or demand limit for that customer.

A2.1c. Please refer to the response to BCEMU IR No. 1 Q1.1 above for information from 2000 and 2009.

3.0 Reference: Application, Page 71

Q3.1 On page 71 of the Rate Design Application, it states that the rates shown in Table 13.0 are designed to be revenue neutral with current rates. Please provide an arithmetic demonstration of that using the presumed billing determinants.

A3.1 During the completion of this response, it was determined that an error in methodology occurred in the derivation of the unit rates for the wholesale class. The error stems from the use of contract demand levels expressed in kW in determining the rate components. As the billing determinants are calculated using the kVA values from the wholesale contracts, a discrepancy results. The magnitude of the error is very small. The information below is presented using the corrected values which can be found in the replacement pages for Table 2.3 and 13.0 from the Application included in Errata 2.

Revenues are calculated using the rates found in the updated Table 13.0 and the billing determinants found in the summary table below.

Table BCMEU A3.1a: Summary of Annual Billing Determinants

Wholesale Account	# PODs	Annual Contract Demand or Ratcheted Actual Demand	Total kVA (with ratchet)	Total kVA (without ratchet)	Energy (kWh)
		kVA	Annual	Annual	Annual
Kelowna	4	1,101,600	672,467	654,739	300,580,396
Grand Forks	3	276,000	87,262	83,370	42,413,094
Summerland	2	344,000	242,452	218,155	98,651,430
Penticton	5	1,817,000	782,625	738,988	355,153,151
Nelson	3	540,000	326,826	246,474	112,532,033
BC Hydro - Yahk	1	8,642	7,577	6,508	2,817,036
BC Hydro - Lardeau	1	57,583	44,455	30,410	9,228,036

Annual revenues under the proposed rate structure are determined using the following components:

Basic Charge (BC)	= # of Points of Delivery * Basic Charge Rate * 12
Wires Charge (WC) [1]	= Annual Contract Demand (CD) * Wires Charge Rate
Power Supply (PS)	= Actual Annual Demand (AD) * Power Supply Rate
Energy (E)	= Annual consumption * Energy Rate

[1] Wires charge based on higher of actual and Contract Demand in the case of BC Hydro – Yahk

According to the following formula:

Proposed Annual Revenue = BC + WC + PS + E

Revenues at current rates are determined using the following components:

Basic Charge (BC) [2]	= # of Points of Delivery * Basic Charge Rate * 12
Demand Charge (DC)	= Actual Annual Demand (AD) [3] * Demand Rate
Energy (E)	= Annual consumption * Energy Rate

[2] Nelson Basic Charge under current rates is on a per customer basis, not per POD.
[3] Actual Demand includes any applicable Ratcheted amounts

According to the following formula:

Revenue at existing rates = BC + DC + E

It can be seen in the table below that revenue under current and proposed rates are equal within one decimal place of 100 percent.

1 **Table BCMEU A3.1b: Revenue Comparison Existing vs. Proposed Rates**

	Revenues ($s)										
	Current				Proposed						Ratio of New to Existing Rates
	Basic	Demand	Energy	Total	Basic	Wires	PS	Energy	Total		
Kelowna	82,996	5,030,053	11,536,276	16,649,325	82,996	7,380,720	2,304,681	6,883,291	16,651,688		100.0%
Grand Forks	62,247	652,720	1,627,815	2,342,781	62,247	1,313,760	233,436	732,898	2,342,341		100.0%
Summerland	41,498	1,813,541	3,786,242	5,641,281	41,498	2,318,560	850,805	2,431,758	5,642,620		100.0%
Penticton	103,745	5,854,035	13,630,778	19,588,558	103,745	10,029,840	2,394,321	7,067,548	19,595,454		100.0%
Nelson	47,427	1,451,107	4,252,586	5,751,120	62,247	2,478,600	1,047,515	2,163,991	5,752,352		100.0%
BC Hydro - Yahk	20,749	56,676	108,118	185,543	20,749	70,173	22,713	71,975	185,610		100.0%
BC Hydro - Lardeau	20,749	332,523	354,172	707,444	20,749	345,498	91,534	249,803	707,584		100.0%

4.0 Reference: Cost of Service Analysis ("COSA"), General

Q4.1 For each of the PODs serving the wholesale customers please provide the following data or information:

Q4.1a. The name of the customer.

A4.1a. Please refer to Table BCMEU A4.1 below.

Q4.1b. The capacity (MVA) of the substation.

A4.1b. Please refer to Table BCMEU A4.1 below.

Q4.1c. The high-side and low-side voltage.

A4.1c. Please refer to Table BCMEU A4.1 below.

Q4.1d. The total number of feeders.

A4.1d. Please refer to Table BCMEU A4.1 below.

Q4.1e. The installed book cost of the substation.

A4.1e. Please refer to Table BCMEU A4.1 below.

Q4.1f. The accumulated depreciation reserve of the substation.

A4.1f. Please refer to Table BCMEU A4.1 below.

Q4.1g. The number of feeders dedicated to serving the wholesale customer.

A4.1g. Please refer to Table BCMEU A4.1 below.

Q4.1h. The number of feeders that serve, or are available to serve, retail customers.

A4.1h. Please refer to Table BCMEU A4.1 below.

Table BCMEU A4.1 – Listing of Wholesale Municipal Customer PODs

Wholesaler (Municipal Utility)	Substation	Transformer Capacity (Maximum Nameplate)	High Voltage (kV)	Low Voltage (kV)	Number of Feeders	Installed Book Cost ($000s)	Accumulated Depreciation Reserve ($000s)
Grand Forks	Ruckles	T1 (13 kV) – 15 MVA T2 (4.3 kV) – 10 MVA	63	4.3 & 13	2 – Grand Forks 2 – FortisBC	770	483
Kelowna	Glenmore (Spall)	T2 – 31.5 MVA T3 – 40 MVA	132	13	1 – Kelowna 6 – FortisBC	5,597	1,528
	Recreation	T1 – 31.5 MVA	132	13	2 – Kelowna 0 – FortisBC	2,267	1,070
	Saucier	T1 – 32 MVA	132	13	2 – Kelowna 0 – FortisBC	2,204	936
	OK Mission	T1 – 31.5 MVA T2 – 32 MVA	132	13	1 – Kelowna 5 – FortisBC	3,306	1,468
Nelson[1]	Coffee Creek[2]	T3 – 8.4 MVA	63	25	1 – Nelson 1 – FortisBC	2,534	744
Penticton	RG Anderson[3] (Carmi)	T3 – 20 MVA	63	8.6	1 – Penticon 1 – FortisBC	11,148	4,489
	Huth	T4-5-6 (8.6 kV) – 5.6 MVA T7 (8.6 kV)– 8 MVA T8 (13kV) – 32 MVA	63	8.6 & 13	2 – Penticton 3 – FortisBC	2,855	955
	Waterford	T1 – 40 MVA	63	13	1 – Penticton 0 – FortisBC	3,780	675
	Westminster[4]	T1 – 15 MVA T2 – 16 MVA	63	8.6	1 – Penticton 0 – FortisBC	1,426	457
Summerland	Summerland (Prairie Valley)	T2 – 20 MVA	63	8.6	1 – Summerland 0 – FortisBC	1,317	458
	Trout Creek	T1 – 15 MVA	63	8.6	2 – Summerland 1 – FortisBC	672	138

[1] The City of Nelson also takes supply from FortisBC at the 63-kV transmission level (with no associated substation assets).
[2] The Coffee Creek substation also provides 161/63-kV transmission transformation for the Kootenay Lake area
[3] The RG Anderson substation also provides 230/161/63-kV transmission transformation for the Penticton area.
[4] There are a small number (~20) of FortisBC customers served from a City of Penticton feeder which is supplied by Westminster.

5.0 Reference: COSA, General

Q5.1 Please provide the voltage parameters or other criteria that the Company uses to functionalize substations as either Transmission (FERC Account 353) or Distribution (FERC Account 362).

A5.1 The distinction between distribution and transmission voltage occurs at 60 kV. 60 kV and above is considered Transmission for functionalization purposes.

6.0 Reference: COSA, General

Q6.1 Please provide a breakout of all substations in FERC Account 353, by capacity (MVA), showing:

Q6.1a. Capacity of substation.

A6.1a. Please refer to BCMEU Attachment A6.1.

Q6.1b. Number of substations.

A6.1b. Please refer to BCMEU Attachment A6.1.

Q6.1c. Net book value.

A6.1c. Please refer to BCMEU Attachment A6.1

Q6.1d. Estimated replacement cost.

A6.1a. Please refer to BCMEU Attachment A6.1. Please note, the estimated replacement costs provided are accurate to within +/- 50 percent.

Description	Net Book Value	Est. Replacement Cost	Installed Capacity
	($000s)		MVA
Transmission Stations (BCUC 353)			
A.S. Mawdsley Terminal	4,452	12,000	160
A.A. Lambert Terminal	10,573	20,000	205
Coffee Creek Terminal	1,785	10,000	41
D.G. Bell Terminal	7,648	17,000	232
F.A. Lee Terminal	12,969	25,000	336
Grand Forks Terminal	5,385	12,000	80
Oliver Terminal	5,769	15,000	142
R.G. Anderson Terminal	6,641	23,000	336
Vaseux Lake Terminal	18,912	25,000	500
Warfield Substation	17,167	25,000	400
Utility Interconnections	27,668	50,000	n/a
Total	**118.967**	**234,000**	**2432**
Number of substations: 10			
Distribution Stations (BCUC 362)			
Arawana Substation	5,813	6,000	10
Beaver Park Substation	528	6,000	10
Big White Substation	8,125	10,000	40
Black Mountain Substation	10,838	12,000	40
Blueberry Substation	716	6,000	15
Cascade Substation	2,235	7,000	20
Castlegar Substation	916	7,000	15
Christina Lake Substation	310	6,000	5
Cottonwood Substation	4,235	6,000	10
Crawford Bay Substation	3,706	10,000	20
Creston Substation	1,086	8,000	30
Duck Lake Substation	3,240	8,000	28
Ellison Substation	6,837	8,000	40
Fruitvale Substation	599	6,000	8
Glenmerry Substation	1,608	8,000	20
Glenmore Substation	4,069	12,000	72
Greenwood Substation	992	6,000	3
Hearns Substation	263	6,000	2
Hedley Substation	1,610	8,000	10
Hollywood Substation	1,386	12,000	63
Huth Substation	1,900	15,000	44
Joe Rich Substation	1,110	7,000	20
Kaleden Substation	794	6,000	10
Kaslo Substation	1,617	7,000	13.3
Keremeos Substation	1,171	8,000	20
Kettle Valley Substation	10,872	12,000	80

Description	**Net Book Value**	**Est. Replacement Cost**	**Installed Capacity**
	($000s)		**MVA**
Kraft Substation	86	250	n/a
Misc. distribution step-down stations	251	900	< 1
Nk'Mip Substation	5,771	8,000	40
OK Mission Substation	1,837	12,000	63.5
Okanagan Falls Substation	734	6,000	15
Ootischenia Substation	5,358	6,000	20
Osoyoos Substation	3,386	8,000	35
Passmore Substation	534	6,000	5.62
Pine Street Substation	2,743	8,000	35
Playmor Substation	776	7,000	16
Princeton Terminal	6,063	8,000	40
Recreation Substation	1,198	8,000	31.5
Rosemont Switching Station	74	1,000	n/a
Ruckles Substation	287	9,000	26
Salmo Substation	416	7,000	13.3
Saucier Substation	1,268	8,000	31.5
Sexsmith Substation	1,970	8,000	31.5
South Slocan Substation	176	500	n/a
Stoney Creek Substation	413	6,000	10
Summerland Substation	898	5,000	20
Tarrys Substation	268	6,000	2.5
Trout Creek Substation	534	6,000	15
Valhalla Substation	3,001	7,000	23
Waneta Generating Station	1,800	2,000	n/a
Waterford Substation	3,106	5,000	40
West Bench Substation	443	6,000	9
Westminster Substation	969	5,000	31
Ymir Substation	166	6,000	1.5
Total	**121,099**	**378,650**	**1204.22**
Number of substations: 54			
Other	**600**	**n/a**	**n/a**
Mobile Substations (four units)	**3,150**	**10,000**	**87**

7.0 Reference: COSA, General

Q7.1 Please provide a breakout of all substations in FERC Account 362, by capacity (MVA), showing:

Q7.1a. Capacity of substation.

A7.1a. Please refer to BCMEU Attachment A6.1.

Q7.1b. Number of substations.

A7.1b. Please refer to BCMEU Attachment A6.1.

Q7.1c. Net book value.

A7.1c. Please refer to BCMEU Attachment A6.1.

Q7.1d. Estimated replacement cost.

A7.1d. Please refer to BCMEU Attachment A6.1.

8.0 Reference: COSA, General

Q8.1 For each wholesale customer please provide interval data (in electronic format) for the 12-month period ended June 2009. If the data is metered at more than one point, please provide the data for each metering point separately.

A8.1 The requested data is provided in electronic format as BCMEU Attachment A8.1.

9.0 Reference: COSA, General

Q9.1 Please provide a load duration curve (in electronic format) for the FortisBC system for the 12-month period ended June 2009 in two formats: (a) chronologically; and (b) from highest demand to lowest.

A9.1 Please refer to BCUC Attachment A68.6 provided in electronic format only.

10.0 Reference: COSA, General

Q10.1 Please provide the FortisBC Maximum System total maximum demand for each of the years 2000 through 2009 to date, the date and time it was recorded, and the lowest temperature on that day.

A10.1 The requested information is provided in Table BCMEU A10.1 below.

Table BCMEU A10.1 FortisBC Peak Loads

Year	Month	Day	Hour	Peak (MW)	Min Daily Temp (°C)
2000	Dec	15	18	614	-14.1
2001	Dec	12	18	560	-2.7
2002	Jan	28	18	572	-9.8
2003	Dec	30	18	609	-9
2004	Jan	5	18	718	-20
2005	Jan	14	18	708	-18.2
2006	Nov	29	18	718	-19.5
2007	Jan	11	18	683	-15.8
2008	Dec	20	18	746	-22
2009	Jan	26	9	714	-15.4

11.0 Reference: COSA, General

Q11.1 Please provide FortisBC sales (MWh) (excluding off-system sales) for each of the years 2000 through 2008.

A11.1 Please see Table BCMEU A11.1 below.

Table BCMEU A11.1 - FortisBC Net Sales

Year	Net Sales (MWh)
2000	2,682
2001	2,733
2002	2,791
2003	2,834
2004	2,874
2005	2,969
2006	3,040
2007	3,090
2008	3,087

12.0 Reference: COSA, General

Q12.1 For each of its wholesale customers please provide the most recent documentation and/or communication that FortisBC has that indicates the amount of capacity the customer wishes the Company to plan on supplying.

A12.1 The requested correspondence is provided as BCMEU Appendix A12.1. The five municipal wholesalers have confirmed they have no objection to the emails being released in response to their request

13.0 Reference: COSA, General

Q13.1 When was the last time that FortisBC inquired of each of its wholesale customers the level of transmission capacity that the customer required?

A13.1 FortisBC has remained interested in receiving information from wholesale customers as to the level of transmission capacity they require. This continuing interest was expressed to counsel for BCMEU in December 2009. Please also refer to the response to BCMEU IR No. 1 Q12.1 above.

14.0 Reference: COSA, General

Q14.1 On page 30 of its Rate Design Application, FortisBC states that it requested a delay in filing the application because it was negotiating contract terms with its wholesale customers, including transmission capacity nominations. What is the understanding of FortisBC as to the level of those requests?

A14.1 FortisBC understands the level of the nominations to be those discussed in the correspondence included in the response to BCMEU IR No. 1 Q12.1. Had these nominations been agreed upon by the Company and the municipal wholesale utilities, they would have become billing determinants used in determining a Transmission Demand Charge.

15.0 Reference: COSA, General

15.1 FortisBC intends to file a long-term Integrated System Plan in 2010.

Q15.1a Please provide a copy of the previous long-term Integrated System Plan that the Company has filed.

A15.1a The Company has not previously filed a long-term Integrated System Plan. However, attached as BCMEU Appendix A15.1a is FortisBC's 2005 – 2024 System Development Plan ("SDP") as well as the 2006, 2007 and 2009 Updates to the SDP. Due to size limitations, BCMEU Appendix A15.1a is being provided in electronic format only with hard copies available upon request.

Q15.1b Please provide any preliminary drafts or PowerPoint presentations of the plan that is expected to be filed in 2010.

A15.1b FortisBC has not completed the plan and it is not appropriate to file anything until such time as the documents have been prepared.

16.0 Reference: COSA, General

Q16.1 Please provide the long-term Resource Plan that the Company filed on May 27, 2009.

A16.1 Please refer to the response to BCUC IR No. 1 Q7.1.

17.0 Reference: COSA, Page 8

Q17.1 On page 8 of the Electric Cost of Service Analysis (COSA) it states that the COSA is based on a forecast test year which assumes normal weather conditions. Does this imply that the system monthly load factors were predicated on normal weather conditions as well? If that is not the case, please explain the weather conditions that were assumed for this purpose and show how those assumptions were incorporated into the COSA.

A17.1 Both the monthly peaks and the monthly energy for the system were forecast for 2009 assuming normal weather conditions. This results in system load factors that reflect normal conditions.

18.0 Reference: COSA, General

Q18.1 Please provide any testimony, evidence or arguments filed by or on behalf of FortisBC in the most recent Commission proceeding concerning the setting of the rates for BC Hydro's Rate Schedule 3808.

A18.1 Due to size constraints, the requested information is provided in electronic format only as BCMEU Appendix A18.1. Hard copies of the appendix are available upon request.

19.0 Reference: Application, Rate Schedule, Table 6.2.4

Q19.1 Table 6.2.4 shows that the Rate Schedule 3808 demand charge is forecast to be $4.992 per MW/month in 2009 but increase to $5.313 per MW/month in 2010. On page 18 of the Electric Cost of Service Analysis (COSA) it states that the pricing of Rate Schedule 3808 includes a transmission component. Please provide the breakout of those demand charges between production and transmission.

A19.1 Rate 3808 does not include a separate transmission component. While the pricing does not differentiate transmission and power supply, a portion of the price must be considered as transmission-related. The transmission-related portion has not been quantified.

As stated in the COSA report on page 18, EES also looked at the underlying classification split of generation allocated to Rate 3808 in BC Hydro's most recent COSA. The COSA resulted in a 20 percent demand/80 percent energy split as well. (Note that the Report inadvertently transposed the results as 80 percent demand and 20 percent energy, please refer to Errata 2). This substantiates the use of the 3808 Rate without any need to adjust for the transmission component.

20.0 Reference: COSA, General

Q20.1 Please explain how "Total Excess Capacity" is defined and/or calculated for purposes of applying BC Hydro Rate Schedule 3808.

A20.1 The definition of Excess Capacity is found in Section 1.1 of the 1993 Power Purchase Agreement between West Kootenay Power and BC Hydro as follows:

> (g) "Excess Capacity" for each Point of Interconnection and for the Point of Supply shall have the meaning ascribed to it and shall be determined in accordance with Sections 9.2, 9.3 and 9.4, as the situation dictates;

where,

> 9.2 Points of Interconnection Accounting
>
> For each hour excluding hours during which West Kootenay Power is Exporting, the capacity required at each Point of Interconnection shall be calculated as the difference between the recorded demand at the Point of Interconnection and the sum of the capacity Wheeled to the Point of Interconnection from the Point of Supply under the terms and conditions of the General Wheeling Agreement together with the capacity associated with transactions not covered under this Agreement. The maximum capacity so required during all hours of any given Billing Month at each Point of Interconnection shall be its Point of Interconnection Purchase Capacity for that month, so long as it does not exceed the Nominated Demand for that Point of Interconnection. If in any month the maximum capacity so determined exceeds the Nominated Demand for that Point of Interconnection then the Point of Interconnection Purchase Capacity for that month at such point shall be the Nominated Demand for that Point of Interconnection and the capacity required which exceeds the Nominated Demand shall be the Point of Interconnection Excess Capacity for such point and the energy associated therewith shall be deemed Excess Energy.
>
> 9.3 Point of Supply Accounting
>
> (a) For each hour, the capacity required at the Point of Supply shall be calculated as the greater of:
>   (i) zero, or
>   (ii) the System Capacity Deficit minus the sum of the capacity required in the concurrent hour at all Points of interconnection.
>
> (b) The maximum capacity so required during the Heavy Load Hours of each day of any given Billing Month, excluding hours during which West Kootenay Power is Exporting, shall be the Point of Supply Purchase Capacity for that month, so long as it does not exceed the Nominated Demand for the Point of Supply. If in the

Heavy Load Hours in any given Billing Month the maximum capacity exceeds the Nominated Demand then the Point of Supply Purchase Capacity for that month shall be the Nominated Demand for the Point of Supply and the capacity required which exceeds the Nominated Demand shall be the Point of Supply Excess Capacity for that month, and the energy associated with such Excess Capacity shall be deemed Excess Energy.

(c) Notwithstanding the Nominated Demand for the Point of Supply, West Kootenay Power may, during the Light Load Hours only, exceed such nomination without incurring excess charges provided that the maximum capacity during Light Load Hours for any given Billing Month does not exceed the lesser of 175MW or the maximum hourly System Capacity Deficit during the Heavy Load Hours of that Billing Month. If such levels are exceeded, the excess shall be deemed Point of Supply Excess Capacity for that month, and the energy associated with such Excess Capacity shall be deemed Excess Energy.

9.4 Exports

The capacity required at each Point of Interconnection and the Point of Supply during any hour of the Billing Month during which West Kootenay Power is Exporting shall be deemed to be Excess Capacity for that Point of Interconnection and the Point of Supply as the case may be and the associated energy shall be deemed to be Excess Energy in accordance with Section 8.4.

21.0 Reference: COSA, General

Q21.1 Please provide a complete copy of the BCTC OATT tariff, referenced in Section 6.4 of the Revenue Requirements application.

A21.1 A copy of the requested document is provided as BCMEU Appendix A21.1. Due to size constraints, BCMEU Appendix A21.1 is provided in electronic format only with hard copies available upon request.

22.0 Reference: COSA, General

Q22.1 Please provide a copy of the BCTC Rate Schedule 21, referenced in Section 6.4 of the Revenue Requirements application.

A22.1 A copy of the requested document is provided as BCMEU Attachment A22.1.

SCHEDULE 21

GENERAL WHEELING SERVICE – FortisBC Inc.

Availability: This schedule is available to FortisBC Inc. for the Wheeling of electricity over BC Hydro's transmission facilities in accordance with the terms and conditions of the General Wheeling Agreement.

Applicable in: The Point of Supply and the Points of Interconnection specified in the General Wheeling Agreement.

Annual Rates: The Annual Rate for Wheeling to each Point of Interconnection identified in this Rate Schedule will be adjusted by the annual rate of inflation as published by Statistics Canada using the British Columbia Consumer Price Index (all items) for the month of July in the calendar year in which the adjustment is made. The Points of Interconnection with their base rates are:

1. Point of Supply to Lambert (Creston Point of Interconnection)
   On 1 February 2006, $12,382.36 per MW of Nominated Wheeling.

2. Point of Supply to Vernon Terminal and Vaseux Lake Terminal Station (Okanagan Point of Interconnection)
   On 1 February 2006, $19,000 per MW of Nominated Wheeling Demand.

3. Point of Supply to Princeton (Princeton Point of Interconnection)
   On 1 February 2006, $50,665.09 per MW of Nominated Wheeling Demand.

Monthly Charge: The monthly charge shall be one twelfth of the above annual rate per MW of Nominated Wheeling Demand for each Point of Interconnection.

Nominated Wheeling Demand: The maximum rate, as determined in Section 6 of the General Wheeling Agreement, at which BCTC will Wheel electricity for FortisBC, Inc. over each Point of Interconnection during a stated Year.

Emergency Wheeling: A rate of 0.110¢ per kW.h shall be charged for each kW.h of Emergency Wheeling. This charge would only apply to Wheeled energy which cannot be accommodated within the limits of Nominated Wheeling Demands.

Note: All terms capitalized above are defined in the General Wheeling Agreement

23.0 Reference: Application, Tables 6.2 and 6.3

Q23.1 Please provide Table 6.2 and Table 6.3 of the Revenue Requirements application, in electronic format that is readily manipulated such as Microsoft with all formulae and links intact.

A23.1 The requested Tables are provided in Microsoft Excel electronic format as BCMEU Attachment A23.1.

24.0 Reference: COSA, Page 8

Q24.1 On page 8 of the Electric Cost of Service Analysis (COSA), it states that "wholesale sales have increased much less than the retail sales classes combined." Please provide any and all quantitative data that support this observation.

A24.1 Please see Table BCMEU A24.1 below.

Table BCMEU A24.1

	1997 COSA	2009 COSA	% Growth
	MWh		%
Wholesale	957,815	981,536	2.5%
Retail	1,958,246	2,444,696	24.8%
Total	2,916,061	3,426,232	17.5%

25.0 Reference: COSA, General

Q25.1 How many customers in each rate classification had meters installed at the end of 2008 that were capable of obtaining interval data, i.e., the demand of the customer for each and every hour of the billing period?

A25.1 Please refer to the response to OEIA IR No. 1 Q8.2.

26.0 Reference: Application, Page 31

Q26.1 On page 31 of the Rate Design application, the statement is made that the Large General Service customers were supportive of the contract demand methodology.

Q26.1a Is that reference to Large General Service Primary Customers or Large General Service Transmission customers or both?

Q26.1a The consultations discussed in Section 4.6.2 of the Application were held with both the Primary and Transmission customers. The Primary customers expressed an understanding of the rationale and generally supported the concept. The Transmission customers understood the premise that a customer class provides revenue adequate to cover its costs, but did not express unconditional support because of the potential impact to them.

Q26.1b Please document how the Large General Service customers evinced that support.

Q26.1b The expressed support was oral during the face to face meeting.

Q26.1c What is the aggregate contract demand for the Large General Service Primary class as of 2009?

Q26.1c. As FortisBC is not proposing to use contract demand methodology for this class it is not relevant.

Q26.1d What is the aggregate contract demand for the Large General Service Transmission class as of 2009?

Q26.1d The total aggregate contract demand for the Large General Service Transmission class (Rate Schedule 31) as of 2009 is 11,100 kVA.

27.0 Reference: COSA, Page 9

Q27.1 On page 9 of the Electric Cost of Service Analysis (COSA), it states that the peak forecast is expected to occur in the winter at a level of 701 MW. However, in the Revenue Requirements application, Table 6.2, which depicts the forecast power expense for 2009, shows (on line 67) a capacity planning load of 714 MW. Please explain and reconcile this apparent discrepancy.

A27.1 The 701 MW projections included in the COSA was a forecast peak, while the 714 MW number is the actual recorded peak for January 2009.

28.0 Reference: COSA, General

Q28.1 For each class for which the Company did not have actual interval data for the entire class, please:

Q28.1a. Specify the annual and monthly load factors assumed and explain how those figures were derived or estimated. If the load factors were estimated from load samples, please provide the estimated error (i.e., plus or minus X percent), within a 90% confidence interval.

A28.1a. The monthly load factors and coincidence factors for each class can be found in Schedule 8.2 of Appendix A to the Application (Exhibit B-1). FortisBC does not have direct load research data for the classes without interval meters and relied in part on BC Hydro load research information for the Southern Interior region. FortisBC does not have the statistical confidence level for that load research. For those classes without interval meters, the load factors and coincidence factors were determined with guidance from the BC Hydro load research and by balancing to the total system peak for FortisBC.

Q28.1b. Specify the monthly coincidence factors assumed and explain how those figures were derived or estimated. If the coincidence factors were estimated from load samples, please provide the estimated error (i.e., plus or minus X percent), within a 90% confidence interval.

A28.1b. The monthly load factors and coincidence factors for each class can be found in Schedule 8.2 of Appendix A to the Application (Exhibit B-1). FortisBC does not have direct load research data for the classes without interval meters and relied in part on BC Hydro load research information for the Southern Interior region. FortisBC does not have the statistical confidence level for that load research. For those classes without interval meters, the load factors and coincidence factors were determined with guidance from the BC Hydro load research and by balancing to the total system peak for FortisBC.

Q28.1c. Please indicate whether those load samples were taken from customers of FortisBC or were borrowed data from another utility.

A28.1c. The monthly load factors and coincidence factors for each class can be found in Schedule 8.2 of Appendix A to the Application (Exhibit B-1). FortisBC does not have direct load research data for the classes without interval meters and relied in part on BC Hydro load research information for the Southern Interior region. FortisBC does not have the statistical confidence level for that load research. For those classes without interval meters, the load factors and coincidence factors were determined with guidance from the BC Hydro load research and by balancing to the total system peak for FortisBC.

Q28.1d. In either case, please provide the percentage of the entire class population that was sampled.

A28.1d. The monthly load factors and coincidence factors for each class can be found in Schedule 8.2 of Appendix A to the Application (Exhibit B-1). Fortis BC does not have direct load research data for the classes without interval meters and relied in part on BC Hydro load research information for the Southern Interior region. FortisBC does not have the statistical confidence level for that load research. For those classes without interval meters, the load factors and coincidence factors were determined with guidance from the BC Hydro load research and by balancing to the total system peak for FortisBC.

29.0 Reference: COSA, General

Q29.1 Please indicate whether FortisBC maintains its records in the form of the FERC Uniform System of Accounts.

A29.1 For its regulated operations, FortisBC maintains its records in accordance with the BCUC Uniform System of Accounts for Electric Utilities (”USA”), with the exception of certain Operating and Maintenance accounts, as approved by the BCUC. The USA in turn is based on the National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts for Electric Utilities in the United States.

30.0 Reference: COSA, General

Q30.1 Please identify whether it is FortisBC's current practice to model its wholesale customers in its power flow models for transmission planning at the contract demand for those customers rather than the forecasted coincident or non-coincident peak demand for those customers. To the extent this is the current practice of FortisBC, please identify how long this has been the practice of FortisBC and provide copies of all transmission planning studies performed over the past three years by FortisBC that indicate the contract demand of FortisBC wholesale customers was modeled in those studies rather than the coincident or non-coincident peak demand of those customers.

A30.1 One reason FortisBC conducts a power flow analysis is to assess the adequacy of the transmission system in its normal (N-0) operating state with all elements in service. For the purposes of this study, the wholesale contract demand limits are used to confirm compliance with the contractual requirements. The first study of this type was conducted in 2008 and the system was confirmed to meet the N-0 criteria. As long as no violations are identified, no report is produced.

FortisBC more often conducts power flow studies for contingency analysis to determine if the system is capable of meeting established reliability criteria with one or more transmission elements out of service. For these purposes, FortisBC uses the forecast actual demand for wholesale customers and should the contract demand limit be required to be supplied during a contingency event the Company would endeavour to honour its contractual obligations to the Wholesale utilities. The Company intends to conduct its future transmission planning so as to meet its contractual obligations at an N-1 criteria.

31.0 Reference: COSA, General

Q31.1 Please identify, quantify, and explain any and all difference in input, between the COSA distributed to the customers during the course of customer consultations this past summer, and the COSA (Appendix A) submitted as part of this application.

A31.1 The differences between the draft COSA and the COSA submitted as part of the application are detailed below:

1. Rate 33 was broken out as a separate class as that was determined to be more appropriate given the differences between Rate 31 and Rate 33 customers.
2. The billing demands and contract demands for industrial and wholesale customers were corrected in some cases where the kVA amounts were used rather than kW amounts.
3. The months using the summer contract demands were corrected from April through September to July and August.
4. The individual load factors for the residential and small general service classes were slightly changed to provide a true-up to the total system forecast after the other demand levels were corrected.

32.0 Reference: Appendix C, Page C-2

Q32.1 On page C-2 of Appendix C - Load Analysis, of the June 30 Draft Report of the COSA, it states as follows:

Because Nelson has its own generation, it self-generated during summer months. This results in system coincident factors in the range of 40% to 65% in the summer and between 80% and 100% in the winter.

However, on the same page of the September 30 Report accompanying the Rate Design application, that sentence was omitted. Please explain why that observation was inserted in the June 30 version, and the events that occurred in the interim to prompt its deletion. Please attach any accompanying studies or analyses pertinent to this interrogatory.

A32.1 The sentence was omitted because the system coincident factors originally calculated for Nelson were based on data that yielded inappropriate results, such as negative load factors. An average system coincidence factor of 95 percent was used in the summer months based on the average of other months with more reasonable data. An average individual load factor of 60 percent was used for the summer months based on the average of the other months. Combined, these two changes resulted in more realistic, and lower, CP values for Nelson than with the original data that was calculated.

Q32.2 On page C-2 of Appendix C - Load Analysis, of the June 30 Draft Report of the COSA, it states as follows:

Industrial transmission customers have (system coincident) factors in the 62% to 72% range.

However, on the same page of the September 30 Report accompanying the Rate Design application, that sentence was changed to show factors in a 68% to 93% range. Please explain why that observation was amended in the September 30 version, and the events that occurred in the interim to prompt this revision. Please attach any accompanying studies or analyses pertinent to this interrogatory.

A32.2 The system coincident factors for the industrial transmission customers changed as a result of excluding the data from Rate 33.

33.0 Reference: COSA, General

Q33.1 Please provide the most recent copy of any annual operating or statistical report filed by FortisBC to the Commission.

A33.1 Attached as BCMEU Appendix A33.1 is FortisBC's 2008 Annual Report to the British Columbia Utilities Commission.

34.0 Reference: COSA, General

Q34.1 Please file the 1997 Cost of Service Analysis Study prepared by EES Consulting.

A34.1 The requested document is provided as BCMEU Appendix A34.1.

Q34.2 Please file the current Wholesale Agreements between FortisBC and each of the BCMEU members.

A34.2 The requested Wholesale Agreements are attached as BCMEU Appendix A34.2.

Q34.3 Please file the Wholesale Agreements between FortisBC and the BCMEU members which were in place at the time the 1997 COSA study was prepared.

A34.3 FortisBC has been unable to locate copies of the agreements that were in place in 1997.

35.0 Reference: COSA, General

Q35.1 Where a substation is shared between a wholesale customer and FortisBC' customers, will FortisBC's customers served off the substation be allocated costs in the same manner as BCMEU customers?

A35.1 Yes, the cost allocation among customers using a common facility will always be driven by cost causation principles.

Q35.2 When a new substation is required by a wholesale customer, will FortisBC continue to engineer the substation for a 25 year life and does it propose to allocate transmission costs to the wholesale customer based on the maximum capacity of the new substation?

A35.2 FortisBC will continue to engineer substations that are serving wholesale utilities using prudent utility practice and in consideration of the requirements requested by the wholesale utilities. The allocation of transmission costs as proposed by the COSA will be based upon the contract demands. If the wholesale utilities choose to nominate new transmission capacity reservations as requested by the Company, then the Company would propose to base cost allocations on such nominations.

36.0 Reference: COSA, General

Q36.1 Where a FortisBC customer is served as a result of power being wheeled through a Wholesale Customer service area, such as the Spiller Road situation in Penticton, how does FortisBC propose to fairly allocate costs to those customers of FortisBC where the wholesale customer assists FortisBC in ensuring that service is provided to those FortisBC customers?

A36.1 All of the costs associated with transmission are allocated as described in the COSA. If FortisBC incurs wheeling charges as a result of using the facilities of another utility, those wheeling charges would be included in the transmission costs allocated to FortisBC customers. Any agreements for wheeling service and charges would be conducted outside of the RDA process.

37.0 Reference: COSA, Page 7

Q37.1 Page 7 of the September 30, 2009 Electric Cost of Service Analysis (COSA) states "Consistent with Commission Order G-193-08, an adjustment of $2.3 million was added to the approved revenue requirement...". Please describe how this $2.3 million adjustment was allocated to each customer class and provide a table summarizing the revenue requirement change by rate class.

A37.1 The $2.3 million in added costs results from new rates that were incorporated in the total power purchase cost forecast for 2009 and were not treated as a separate line item cost. The power purchase costs for each month were first split between demand and energy charges. Monthly demand charges were split between customer classes on the basis of each month's peak demand by class. Monthly energy charges were split between classes on the basis of monthly energy by class. Table BCMEU A37.1 below shows the impact on the revenue requirement by class. Please also refer to the response to BCUC IR No. 1 Q86.1

1 **Table BCMEU A37.1**

	Allocated Revenue Requirements (As Filed)	**Allocated Revenue Requirements (Without 3808 Increase)**	**Added Costs for 3808 Increase**
		($000s)	
Residential	$108,678	$107,844	$834
Small General Service	$15,874	$15,729	$145
General Service	$29,968	$29,605	$363
Rate 33 Industrial	$3,815	$3,794	$21
Industrial Primary	$8,018	$7,913	$105
Rate 31 Industrial	$3,004	$2,960	$44
Lighting	$2,433	$2,423	$10
Irrigation	$3,469	$3,425	$44
Kelowna Wholesale	$18,273	$18,063	$209
Penticton Wholesale	$24,781	$24,532	$249
Summerland Wholesale	$5,761	$5,692	$70
Grand Forks Wholesale	$3,396	$3,367	$29
BCH Lardeau Wholesale	$686	$678	$8
BCH Yahk Wholesale	$177	$175	$2
Nelson Wholesale	$7,093	$7,013	$80

38.0 Reference: COSA, Schedule 3.2, Page 1

Q38.1 With reference to page 1 of Schedule 3.2 of the September 30, 2009 Electric Cost of Service Analysis (COSA), please explain why Op. Supervision & Engineering expense is a negative amount of $-207,000?

A38.1 The Operating Supervision and Engineering expense is shown as a negative amount as a result of the manner in which the Company allocates its capitalized overhead credits approved in Order G-58-06 to the individual operating expense line items. This method of allocation has been consistently applied since 2005.

39.0 Reference: COSA, Page 7

Q39.1 The table of contents of the September 30, 2009 COSA schedules includes references to a Schedule 4.3 and a Schedule 4.4 showing rate base cost allocation classification and direct assignments by customers. However, those schedules do not appear to be included with the September 30, 2009 document. A version of schedule 4.3 was included with the June 30, 2009 version. Please a copy of Schedules 43 and 4.4 consistent with the September 30, 2009 COSA.

A39.1 Schedule 4.3 is provided as BCMEU Attachment A39.1. There is no Schedule 4.4 in the COSA. The Table of Contents is incorrect. Please also refer to Errata 2.

Fortis BC 2009 COSA

RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3

Account Description	Total Rate Base	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
Intangible Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Hydraulic Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Land & Rights	$847,000	$340,535	$55,872	$131,808	$6,337	$36,869	$16,119	$3,426	$13,431	$78,849	$93,613	$26,082	$11,051	$2,746	$733	$29,529
Structures & Improvements	$11,770,500	$4,732,317	$776,435	$1,831,690	$88,069	$512,356	$224,003	$47,613	$186,651	$1,095,742	$1,300,912	$362,451	$153,566	$38,155	$10,181	$410,358
Reservoirs, Dams, & Waterways	$22,146,000	$8,903,775	$1,460,849	$3,446,295	$165,700	$963,989	$421,458	$89,583	$351,181	$2,061,620	$2,447,645	$681,946	$288,932	$71,788	$19,156	$772,081
Water Wheels, Turbines, & Generators	$63,405,500	$25,492,113	$4,182,509	$9,866,976	$474,410	$2,759,967	$1,206,664	$256,483	$1,005,456	$5,902,559	$7,007,773	$1,952,459	$827,233	$205,533	$54,845	$2,210,520
Accessory Electric Equipment	$23,865,000	$9,594,897	$1,574,242	$3,713,801	$178,562	$1,038,816	$454,172	$96,537	$378,441	$2,221,646	$2,637,634	$734,880	$311,360	$77,360	$20,643	$832,011
Misc. Power Plant Equipment	$39,140,500	$15,736,396	$2,581,882	$6,090,929	$292,855	$1,703,740	$744,879	$158,328	$620,673	$3,643,676	$4,325,930	$1,205,261	$510,654	$126,876	$33,856	$1,364,564
Roads, RR, & Bridges	$1,053,000	$423,358	$69,461	$163,865	$7,879	$45,836	$20,040	$4,260	$16,698	$98,026	$116,381	$32,425	$13,738	$3,413	$911	$36,711
Total Hydraulic Production	$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 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
Transmission Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Land & Rights - R/W	$7,478,000	$2,345,011	$362,011	$893,693	$375,131	$242,879	$104,099	$11,679	$95,387	$852,317	$1,309,578	$241,397	$194,974	$27,223	$4,818	$417,802
Land & Rights - Clearing	$4,895,000	$1,535,013	$236,968	$585,000	$245,556	$158,986	$68,142	$7,645	$62,439	$557,915	$857,233	$158,015	$127,628	$17,820	$3,154	$273,488
Station Equipment	$183,076,500	$57,410,587	$8,862,762	$21,879,404	$9,183,967	$5,946,173	$2,548,551	$285,925	$2,335,261	$20,866,431	$32,061,113	$5,909,883	$4,773,367	$666,476	$117,959	$10,228,643
Poles Towers & Fixtures	$79,265,500	$24,856,707	$3,837,255	$9,472,990	$3,976,325	$2,574,478	$1,103,430	$123,795	$1,011,083	$9,034,410	$13,881,302	$2,558,765	$2,066,695	$288,560	$51,072	$4,428,632
Conductors & Devices	$75,972,500	$23,824,062	$3,677,841	$9,079,445	$3,811,133	$2,467,524	$1,057,589	$118,652	$969,079	$8,659,085	$13,304,618	$2,452,464	$1,980,836	$276,572	$48,950	$4,244,649
Roads, Railroads & Bridges	$1,016,500	$318,762	$49,209	$121,482	$50,992	$33,015	$14,150	$1,588	$12,966	$115,857	$178,014	$32,814	$26,503	$3,700	$655	$56,793
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
Distribution Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Land & Rights - R/W	$3,321,500	$1,310,182	$239,810	$471,006	$0	$129,917	$0	$21,642	$64,793	$323,137	$551,233	$105,600	$84,480	$16,891	$2,809	$0
Land & Rights - Clearing	$7,441,500	$2,935,335	$537,272	$1,055,243	$0	$291,067	$0	$48,486	$145,162	$723,957	$1,234,985	$236,587	$189,270	$37,843	$6,294	$0
Station Equipment	$117,123,000	$46,199,731	$8,456,205	$16,608,636	$0	$4,581,150	$0	$763,134	$2,284,735	$11,394,472	$19,437,629	$3,723,684	$2,978,947	$595,613	$99,064	$0
Poles, Towers, & Fixtures	$121,450,000	$103,913,882	$10,003,064	$3,829,747	$0	$315,266	$0	$2,119,937	$1,268,103	$0	$0	$0	$0	$0	$0	$0
Conductors & Devices	$192,810,000	$140,229,648	$18,325,590	$23,114,809	$0	$4,710,425	$0	$2,644,836	$3,784,690	$0	$0	$0	$0	$0	$0	$0
Line Transformers	$93,193,500	$73,353,532	$8,567,023	$8,302,322	$0	$0	$0	$1,429,100	$1,541,524	$0	$0	$0	$0	$0	$0	$0
Services	$7,292,000	$4,322,606	$1,212,455	$519,202	$94,590	$34,280	$283,769	$0	$47,121	$163,785	$204,731	$81,892	$122,839	$40,946	$40,946	$122,839
Meters	$13,871,500	$8,222,852	$2,306,441	$987,673	$179,937	$65,211	$539,811	$0	$89,637	$311,566	$389,458	$155,783	$233,675	$77,892	$77,892	$233,675
Installation on Customer Premises	$7,265,500	$4,306,898	$1,208,049	$517,315	$94,246	$34,156	$282,738	$0	$46,949	$163,190	$203,987	$81,595	$122,392	$40,797	$40,797	$122,392
0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Street Lights and Signal Systems	$7,318,000	$0	$0	$0	$0	$0	$0	$7,318,000	$0	$0	$0	$0	$0	$0	$0	$0
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
General Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Land & Rights	$5,800,000	$2,802,542	$408,023	$721,072	$90,219	$179,724	$65,295	$66,308	$88,312	$415,522	$576,102	$129,813	$80,206	$15,361	$3,824	$157,677
Structures - Frame & Iron	$337,000	$162,837	$23,708	$41,897	$5,242	$10,443	$3,794	$3,853	$5,131	$24,143	$33,474	$7,543	$4,660	$893	$222	$9,162
Structures - Masonry	$25,677,000	$12,407,045	$1,806,347	$3,192,235	$399,404	$795,650	$289,065	$293,549	$390,965	$1,839,545	$2,550,445	$574,692	$355,076	$68,004	$16,929	$698,049
Office Furniture & Equipment	$6,676,500	$3,226,064	$469,684	$830,041	$103,853	$206,884	$75,162	$76,328	$101,658	$478,316	$663,163	$149,431	$92,326	$17,682	$4,402	$181,506
Computer Equipment	$54,420,000	$26,295,571	$3,828,383	$6,765,643	$846,500	$1,686,306	$612,647	$622,150	$828,613	$3,898,744	$5,405,430	$1,218,006	$752,550	$144,128	$35,880	$1,479,450
Transportation Equipment	$20,180,000	$9,750,912	$1,419,639	$2,508,833	$313,899	$625,315	$227,181	$230,705	$307,266	$1,445,730	$2,004,439	$451,660	$279,060	$53,446	$13,305	$548,609
Tool and Work Environment	$10,973,000	$5,302,119	$771,938	$1,364,193	$170,684	$340,019	$123,531	$125,447	$167,078	$786,125	$1,089,926	$245,593	$151,741	$29,061	$7,235	$298,309
Communication Structures & Equipment	$23,907,000	$11,551,786	$1,681,829	$2,972,184	$371,872	$740,803	$269,139	$273,314	$364,014	$1,712,739	$2,374,634	$535,077	$330,599	$63,316	$15,762	$649,930
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
Less: Accumulated Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Hydraulic Production Plant	$26,537,500	$10,669,373	$1,750,532	$4,129,687	$198,558	$1,155,146	$505,033	$107,348	$420,820	$2,470,435	$2,933,007	$817,175	$346,227	$86,023	$22,955	$925,183
Transmission Plant	$50,333,500	$15,783,980	$2,436,653	$6,015,338	$2,524,962	$1,634,790	$700,677	$78,610	$642,037	$5,736,840	$8,814,610	$1,624,813	$1,312,349	$183,235	$32,431	$2,812,176
Distribution Plant	$151,406,000	$102,016,457	$13,482,878	$14,689,182	$97,769	$2,694,002	$293,306	$3,803,171	$2,458,375	$3,467,787	$5,838,461	$1,162,585	$989,319	$214,742	$71,000	$126,967
General Plant	$56,892,000	$27,490,033	$4,002,285	$7,072,969	$884,952	$1,762,906	$640,476	$650,410	$866,252	$4,075,842	$5,650,969	$1,273,333	$786,734	$150,675	$37,510	$1,546,653
CWIP	$4,528,500	$2,228,516	$321,687	$552,376	$70,878	$135,837	$48,136	$54,263	$68,899	$314,101	$440,863	$97,736	$62,098	$11,703	$2,915	$118,492
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
Working Capital		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Allowance for Working Capital	$7,018,000	$2,914,985	$444,050	$1,013,120	$91,301	$288,569	$118,755	$41,212	$103,061	$632,402	$788,298	$205,553	$98,710	$23,169	$6,034	$248,782
Adjustment for Capital Additions	$10,857,000	$4,509,545	$686,955	$1,567,318	$141,245	$446,423	$183,717	$63,756	$159,438	$978,340	$1,219,515	$317,995	$152,706	$35,842	$9,334	$384,871
1/12 Purchased Transmission Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
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
Less: Net Customer Contributions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution Plant CIAC	-$92,438,500	-$72,030,188	-$8,370,479	-$7,996,418	$0	-$1,140,173	$0	-$1,405,197	-$1,496,045	$0	$0	$0	$0	$0	$0	$0
Total Contributions	-$92,438,500	-$72,030,188	-$8,370,479	-$7,996,418	$0	-$1,140,173	$0	-$1,405,197	-$1,496,045	$0	$0	$0	$0	$0	$0	$0
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
Other Rate Base Items		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant CWIP not subject to AFUDC	$6,865,000	$3,317,146	$482,945	$853,476	$106,785	$212,725	$77,284	$78,483	$104,528	$491,821	$681,887	$153,650	$94,933	$18,182	$4,526	$186,630
Deferred DSM	$7,412,000	$3,101,943	$496,531	$1,110,457	$65,030	$305,298	$130,716	$33,915	$116,756	$659,327	$802,071	$216,246	$97,628	$23,035	$6,132	$246,915
Plant Acquisition Adjustment & Deferred	$24,974,000	$12,896,686	$1,808,760	$2,823,818	$442,520	$659,351	$209,217	$357,931	$375,903	$1,571,339	$2,337,246	$477,237	$345,674	$60,217	$14,610	$593,489
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

40.0 Reference: COSA, Schedules 6.1 and 6.2

Q40.1 With reference to Schedules 6.1 and 6.2:

Q40.1a Are all of these classification factors being used for the September 30, 2009 COSA? If not, please provide versions of Schedules 6.1 and 6.2 showing only the classification factors being used for the September 30, 2009 COSA.

A40.1a Please refer to BCMEU Attachment A40.1a.

Fortis BC 2009 COSA

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	
CP2	100.00%			100.00%			100.00%				100%
TCP2				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%
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%									
DA1			100.00%			100.00%				100.00%	100%
RBG	20.05%	79.95%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
RBT	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
RBT-D											
RBD	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	41.83%	0.00%	56.89%	1.28%	100%
RBGP	7.42%	29.58%	0.00%	25.00%	0.00%	0.00%	15.90%	0.00%	21.62%	0.49%	100%
OM	22.14%	58.46%	0.00%	11.88%	0.00%	0.00%	1.50%	0.00%	5.94%	0.09%	100%
GPLT	3.00%	11.95%	0.00%	32.41%	0.00%	0.00%	22.02%	0.00%	29.94%	0.67%	100%
NETPLT	3.57%	14.23%	0.00%	34.24%	0.00%	0.00%	20.06%	0.00%	27.28%	0.61%	100%
LABOR	7.42%	29.58%	0.00%	25.00%	0.00%	0.00%	15.90%	0.00%	21.62%	0.49%	100%
PURCHkWh		100.00%									
PURCHkW	100.00%										
DSM	16.60%	71.60%		4.50%			3.09%	0.00%	4.21%	0.00%	100%
RBASE	4.42%	17.07%	0.00%	36.92%	0.00%	0.00%	18.85%	0.00%	22.08%	0.66%	100%

CLASSIFICATION AND ALLOCATION BY CUSTOMER
Schedule 6.2

Classification Factors	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
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%
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%
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%	0.000%	3.911%	0.000%	0.652%	1.951%	9.729%	16.596%	3.179%	2.543%	0.509%	0.085%	0.000%
NCPS	100%	62.164%	11.378%	22.348%	0.000%	0.000%	0.000%	1.027%	3.082%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
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%
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%	0.000%	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%	0.000%	0.000%	0.000%	0.00%	0.00%	0.00%	0.00%
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%								
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%
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%
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%

Q40.1b For each classification factor provided in the response to part (a), please indicate where in the filing the supporting data can be found. (For example, Schedule 6.3, 6.4, 6.5 or 6.6). If the supporting data are not included in the filing, please provide copies of the supporting data used to calculate each classification factor.

A40.1b For each of the classification factors in Tables 6.1 and 6.2, a formula is provided in the COSA Model that links back to the underlying data used to develop the factors. Table 6.1 is found at tab “C&A by Funct” and Table 6.2 is found at tab “C&A by Cust” (Exhibit B-1).

41.0 Reference: COSA, Schedule 6.3

Q41.1 With reference to Schedule 6.3 of the September 30, 2009 COSA, please provide an explanation for the changes in the coincident peak demands for industrial primary, industrial Rate 31 and 33, and each of the two BCH wholesale customers, compared to Schedule 6.3 in the June 30, 2009 version of the COSA.

A41.1 For the June 30 version the demands for these classes were calculated by taking the 2008 monthly peaks and multiplying by the annual growth rate between 2009 and 2008. In some cases, the total did not result in the same total that was provided in the utility's load forecast. Note that the load forecast only provided the sum of the 12 month peaks by class, not the individual monthly peaks by class. Therefore, for the September 30 version the load forecast was used as the starting point. From there, the results were split between months on the basis of historical distribution between months.

42.0 Reference: COSA, Schedule 6.6

Q42.1 With reference to Schedule 6.6 of the September 30, 2009 COSA, the bottom line of each section of the table shows a weighted % allocation. Please provide a description of the weighting method used and the specific weighting used for each month and customer class used to calculate the weighted % allocation.

A42.1 The weighting is based on the total costs per month to the immediate left of the parentages. The total weighted number is equal to the percent in each month times the share of total costs for the month. For example, the kWh weighted percent allocation of 40.13 percent for the residential class was calculated by adding the January percent of 44.74 percent times the January energy cost of $5,711,582 divided by the annual energy cost of $52,500,770, plus the February percent of 47.09 percent times the February energy cost of $4,663,080 divided by the annual energy cost of $52,500,770, and so on for each month. The monthly costs come from Schedule 5.1 while the monthly percents come from the loads in Schedule 8.3 (Exhibit B-1).

43.0 Reference: COSA, Schedule 8.2

Q43.1 With reference to Schedule 8.2 of the September 30, 2009 Electric Cost of Service Analysis (COSA):

Q43.1a What months are defined by FortisBC as summer months, and what months as winter months?

A43.1a For purposes of Schedule 8.2, winter is defined as November through March (Exhibit B-1). Summer is all other months.

Q43.1b Are these definitions of summer or winter months the same for all customer classes? If not, please explain,

A43.1b Summer and winter periods are consistent across all rate classes.

Q43.1c On page 4 of the Schedule, please explain why contract demand limits changed compared to the same table in the June 30, 2009 version of the COSA? For example, the September 30,2009 version of the schedule shows a contract demand limit of 44,550 (no units indicated) for Nelson Wholesale while the June 2009 version of the schedule showed a contract demand limit of 45,000. Please indicate the units for these values (kW or kVA).

A43.1c The 45,000 number in June refers to kVA. The 44,550 number used in the September version represents kW. This was changed to be consistent with the fact that kW loads were used for the other classes. The number is labelled as kW in Table 8.1 contained in the Application (Exhibit B-1).

44.0 Reference: COSA, General

Q44.1 With reference to FortisBC system-wide peak loads:

Q44.1a Please confirm the total system forecast peak per page 23 of the COSA is 701 MW

A44.1a Confirmed.

Q44.1b Please confirm this is the same value shown in Schedule 6.3, page 1 as the value for January 1CP Production. If so, please confirm CP values shown in Schedule 6.3 are in units of kW (and not kVA)

A44.1b Confirmed.

Q44.1c Please confirm that the highest CP Production summer peak is 558 MW for July (per Schedule 6.3, page 1) or more than 20% below the winter peak.

A44.1c Confirmed.

Q44.1d Please confirm the 701 MW peak value per page 23 of the COSA is the same value as the January 2009 peak forecast value of 701 MW per Page 78 of the FortisBC 2009 Resource Plan.

A44.1d Confirmed.

Q44.1e Please confirm the proposed 1 CP value for transmission allocation is 891 MW per COSA Schedule 6.4. Please confirm the test year forecast peak load at transmission is not equal to 891 MW.

A44.1e Confirmed.

45.0 Reference: System Development Plan

Q45.1 Please provide a copy of the System Development Plan ("SDP") Update for 2009.

A45.1 A copy of the requested document is provided as part of BCMEU Appendix A15.1a.

Q45.2 Please provide a copy of the response to interrogatory #13 from BCOAPO (dated October 29, 2008) from the 2009 FortisBC Revenue Requirements Hearing.

A45.2 The response to Information Request 13 from BCOAPO in FortisBC's 2009 Revenue Requirements Application is provided below:

Q13a Are the forecast 2009 winter and summer peaks in the 2009 RRA consistent with the load forecast used in the 2009 SDP Update? If not, please indicate the size of variance and provide an explanation.

A13a Total SDP forecast system peak loads are based on probable peaks at the individual feeder level. The SDP peaks are determined for system planning purposes at the feeder level to ensure proper system capacity at the feeder, substation and transmission level.

Forecast system peak loads for Revenue Requirement purposes in the 2009 RRA are based on a probable coincidental total system peak from actual historical peaks plus forecast increases due to load growth. The RRA coincidental system peak load is utilized for power purchase planning. Because the load forecasts for the RRA do not use temperature extremes or feeder level data, RRA load forecasts will always be substantially lower than SDP forecasts. Please see Table A13a below.

Table A13a

	(MW)
2009 RRA forecast winter system peak	*701.0*
2009 SDP Update forecast winter system peak	*810.7*
Variance	*109.7 (13.5%)*
2009 RRA forecast summer system peak	*559.0*
2009 SDP Update forecast summer system peak	*727.2*
Variance	*168.2 (23.1%)*

Q45.3 Please confirm the peak load indicated in the 2009 SDP update for the year 2009 is 810.7 MW which is the sum of the non-coincident "probable" peaks on each of the major feeders. Please provide the non-coincident probable peak loads by feeder to indicate the composition of the 810.7 MW. Please specifically note in the response which of these feeders supply each of the municipal wholesale customers.

A45.3 The winter peak load indicated in the 2009 SDP update is 810.7 MW and represents the non-coincident sum of each station transformer. For the majority of municipal wholesale customers, FortisBC does not own the distribution feeders and hence does not have visibility of the feeder loads and hence the forecast is based solely on the station transformer. FortisBC can only provide feeder loads for their feeders.

Q45.4 Please provide the coincident forecast peaks for 2009 by major feeder (consistent with the list of feeders per part (c) of this interrogatory) to indicate the composition of the 701 MW peak value used in the COSA.

A45.4 The 701 MW peak value used in the COSA is not based on FortisBC's planning load forecast mentioned in the response to BCMEU IR No. 1 Q45.3 above, but rather determined by Resource Planning based on the total system load. The forecast does not look at major feeders.

Q45.5 Please provide a comparison of the values in parts (c) and (d) above indicating, for each feeder, the difference between the "non-coincident probable" peak and the "coincident forecast peak" indicating the portion of the different attributable to:

Q45.5i The use of non-coincident values as opposed to coincident values.

A45.5i For reasons explained in response to BCMEU IR No. 1 Q45.3 and Q45.4 this information cannot be provided.

Q45.5ii The use of probable peaks as opposed to forecast peaks (if any).

A45.5ii Please refer to the response to BCMEU IR No. 1 Q45.5i.

Q45.6 Please provide a copy of Exhibit B-3 from the FortisBC 2009-2010 Capital Expenditure Plan & 2009 System Development Plan review (an August 12,2008 PowerPoint presentation). Please provide the data underlying the chart on slide 7.

A45.6 Exhibit B-3 from FortisBC's 2009/10 Capital Expenditure Plan is provided as BCMEU Appendix A45.6. The input data for the chart on slide 7 is provided in Table BCMEU A45.6 below.

Table BCMEU A45.6

	Winter Historical and Projected Load (MW)							
	2002/3	2003/4	2004/5	2005/6	2006/7	2007/8	2008/9	2009/10
North Okanagan	224.39	257.20	254.26	249.15	271.61	276.63	308.24	340.41
South Okanagan	169.81	213.56	212.13	199.97	228.15	205.08	238.96	245.21
Kootenay	184.07	210.44	200.51	197.36	203.37	200.25	209.75	212.01
Boundary	44.76	51.42	51.47	52.78	53.64	52.50	53.77	54.36
Total	623.03	732.61	718.37	699.26	756.77	734.45	810.71	851.98

	Winter Historical and Projected Load (MW)			
	2010/11	2011/12	2012/13	2013/14
North Okanagan	363.88	388.53	408.50	422.58
South Okanagan	250.77	256.41	262.13	268.39
Kootenay	214.26	216.52	218.78	221.18
Boundary	54.95	55.55	56.15	56.83
Total	883.86	917.01	945.56	968.98

Q45.7 Please confirm the that peak loads indicated on slide 7 are consistent with the 810.7 MW value cited in interrogatory #13 from BCOAPO (dated October 29, 2008) from the 2009 FortisBC Revenue Requirements Hearing. If not, please indicate why not and provide a reconciliation of the two values.

A45.7 Confirmed.

46.0 Reference: Acquisition of Princeton Light and Power

Q46.1 Since filing the last COSA, FortisBC acquired Princeton Light and Power. Please advise whether Princeton Light and Power customer rates are now rolled into FortisBC rates or are they a separate rate class. If a separate rate class, are the customers subject to the same COSA principles and demand charges proposed for BCMEU members in this Application?

A46.1 Customers in the former Princeton Light and Power service area are subject to the same electric tariff as the rest of FortisBC customers.

47.0 Reference: Application, Page 31, Consultation Results

Q47.1 Generally speaking, would FortisBC agree that where customers are told that they may see their rates be reduced they are generally supportive of rate rebalancing proposals?

A47.1 There are a number of factors that would likely affect a customer's position on a rate rebalancing proposal including, but not limited to, the effect on rates. The Company notes that 87 percent of Supergroup participants supported some kind of rebalancing despite the fact that only 21 percent of participants would have their rates reduced by rebalancing.

48.0 Reference: Application, Page 31, Super Group Results

Q48.1 Please confirm whether representatives of the BCMEU were members of the "Super Group".

A48.1 BCMEU members were not specifically targeted for inclusion in the Supergroups as they were the focus of individual and group consultation activities that the Company believes were adequate to provide the COSA and RDA information and gather feedback from these customers. The demographic profile of Supergroup participants included on page 80 of Appendix I to the Application indicates that a participant identified them self with a Wholesale account type (Exhibit B-1). FortisBC has no way to further identify this individual or to determine if they were a BCMEU representative or a customer of the BCMEU utilities.

49.0 Reference: Application, Page 34, Conservation and the Energy Plan

Q49.1 Please describe how FortisBC believes that setting contract limits which are well in excess of the needs of a customer in allocating costs based on that contract limit will promote conservation if the effect is the customer is paying for capacity they do not require.

A49.1 FortisBC believes that rates based on nominated contract demands will promote conservation by creating more appropriate price signals by associating cost with future increases in contract demand amounts. The Company assumes that the current contract demand amounts negotiated by the municipal utilities were based on their needs. If any municipal utility considers that it requires a lower contract limit, then the amount should be lowered by an amendment to the contract. However, FortisBC must ensure that its broader customer base remains unharmed through the recovery of any costs related to existing infrastructure.

50.0 Reference: Application, Page 36, Lines 10 through 13

Q50.1 Please describe the genesis of the concept that the "Contract Limit" set out in the agreements between FortisBC and the Wholesale Customers would serve as the "Contract Demand." Was the concept created by FortisBC or EES?

A50.1 The use of Contact Demand as a billing determinant in the wholesale rate schedules is evident as far back as the 1976 version, which are the oldest copies that can be located. The 1976 Wholesale rate schedule specifies that the Billing Demand is determined by:

The greatest of:

a. "Contract Demand" which is the amount of power in K.V.A. reserved for the Customer by the Company and contracted for by the Customer, or

b. The maximum demand in K.V.A. fro the current month, or

c. Seventy-five per cent (75%) of the maximum demand in K.V.A. recorded during the preceding eleven months.

This version predates the use of EES as a rate design consultant. FortisBC has been unable to locate any evidence that the "Contract Demand" used for billing purposes has ever been based on anything other than the "Demand Limits" contained in the agreements.

Q50.2 Please provide documentation of any discussions with BCMEU members which explain prior to the production of the original draft COSA Study, the concept that the "Contract Limits" in the agreements were to be used for cost allocation purposes given these "Contract Limits" had not been used for that purpose in the past.

A50.2 Consultation with Wholesale customers, explaining the COSA allocation methodology including the use of Contract Demand, occurred as described in Section 4.5 of the Application (Exhibit B-1). During these meetings, customers were explicitly informed of the methodology and the potential impact that resulting rebalancing may have.

51.0 Reference: Application, Page 43

Q51.1 Please provide a table similar to table 7.0 - "2000 Revenue to Cost Ratios" which set out the revenue to cost ratios from the 1997 COSA Study.

A51.1 The revenue to cost ratios for the 1997 COSA can be found on page 39 of the COSA report attached as Appendix A to the Application (Exhibit B-1).

Rate Class	Revenue / Cost Ratio
Residential	91.3%
Small General Service (20/21)	114.2%
General Service (30)	114.5%
Industrial (31)	125.3%
Lighting	109.1%
Irrigation	75.8%
Wholesale at Primary	101.2%
Wholesale Transmission	116.7%
Total	100.0%

Q51.2 Please confirm whether this comparative information was set out in printed form for review by the public in the public consultation processes.

A51.2 The information provided in response to BCMEU IR No. 1 Q51.1 was contained on page 6 of the filing of the Draft COSA report which was circulated to consultation participants and posted to the FortisBC website in June 2009.

52.0 Reference: Application, Page 45

Q52.1 Please describe FortisBC's views as to what are the unique characteristics of each utility resulting in setting out a distinct rate schedule for each municipality.

A52.1 Please refer to the response to BCOAPO IR No. 1 Q35.2.

Q52.2 Does FortisBC oppose the concept of a single rate class for municipal electric utilities? If so, why?

A52.2 FortisBC believes that each customer should pay its fair share of costs, and that the characteristics of the municipal utilities indicate that a separate rate for each customer in this class is appropriate and would prevent one unique customer from subsidizing another. For example, in the proposed COSA, Summerland currently has a revenue to cost ratio of 96.6 percent and would be unaffected by rebalancing. However, if Summerland was grouped with the other municipal utilities, they would have a revenue to cost ratio of 80.4 percent and effectively be subsidizing other municipal wholesale utilities as the rates were rebalanced. Kelowna would also be negatively affected by the concept of a single rate class. However the Company does not object to the continuation of the current practice if it reflects the wishes of the wholesale utility group.

53.0 Reference: Application, Page 50, Schedule of Rate Design Changes

Q53.1 FortisBC is proposing a number of rate design changes. Please summarize what steps FortisBC is taking in its rate design changes to ensure that any revenue deficiency (or over recovery) is retained within the rate class and that there will be no inter-class shifting, or under recovery or over recovery of revenue, as a result of the rate design changes.

A53.1 All of the potential issues noted in the information request are precluded by the fact that all proposed rates are designed to be revenue-neutral with rates currently in place for each class.

From: Christopher P. Weafer [mailto:cweafer@owenbird.com]
Sent: Friday, September 18, 2009 9:02 AM
To: Swanson, Dennis; Sinclair, Corey
Subject: FW: Penticton Demand

Here is the Penticton information.

Best regards, Chris

From: Terry Andreychuk [mailto:terry.andreychuk@penticton.ca]
Sent: Friday, September 18, 2009 8:59 AM
To: Christopher P. Weafer
Subject: RE: Penticton Demand

Hi Chris:

Sorry to much going on at once....here you go.

Please see the attached doc. as per the December 2008 has been our highest recorded peak.
I think we would feel comfortable at about a 10-15% bandwidth on that peak if this was to be over a 5 year term.
We have a few large projects on the slate and should the economy turn and we experience a cold spell as such in the subject year, we could easily exceed a 5% cushion.

Cheers,

From: Christopher P. Weafer [mailto:cweafer@owenbird.com]
Sent: Friday, September 18, 2009 8:27 AM
To: Terry Andreychuk
Subject: Penticton Demand

Good Morning Terry;

Maybe I missed it but did you send the Penticton Demand for forwarding to Fortis?

Cheers, Chris

Month	Year	Penticton Peak kVA	This is the Fortis kVA demand from Spiller Rd. & Greyback areas which can be fed from 1 of 2 substations. The amount indicated has been subtracted from the Penticton peak but on our monthly's from Fortis it is included in the total and we are only credited the $$ value. NOTE: Pre 2006 the demand totals were incorrect. This has been corrected and the City has been compensated accordingly.
January	1996	69,720	
January	1997	63,603	
January	1998	67,052	
December	1999	57,787	
December	2000	65,640	
December	2001	60,525	
December	2002	59,462	
December	2003	65,028	
January	2004	71,223	
January	2005	68,965	
November	2006	76,734	309.36
January	2007	70,613	311.92
December	**2008**	**77,523**	290.28
January	2009	70,592	289.24

DEMAND LIMITS-MVA AS PER POWER PURCHASE AGREEMENT		
SUBSTATION	**WINTER**	**SUMMER**
Huth-13 kV	40	32
Huth-8.3 kV	13.6	10.5
Waterford-13kV	40	32
Westminster-8.3 kV	38	31
Carmi/RGA-8.3 kV	25	20
TOTALS	**156.6**	**125.5**

From: Christopher P. Weafer [mailto:cweafer@owenbird.com]
Sent: Wednesday, September 16, 2009 3:25 PM
To: Swanson, Dennis; Sinclair, Corey
Subject: FW: Kelowna- Demand

Dennis and Corey:

As per my earlier email here is the draft information re Kelowna. I may not receive any further information until tomorrow morning.

Best regards, Chris Weafer

From: Cindy McNeely [mailto:cmcneely@kelowna.ca]
Sent: Wednesday, September 16, 2009 2:18 PM
To: Christopher P. Weafer; alove@nelson.ca; Cecile Arnott; kostraat@summerland.ca; rcarle@newwestcity.ca; Terry Andreychuk; Victor Kumar
Subject: Kelowna- Demand

Here are Kelowna's projections. I still need to check with the planning group to see if there are any major developments in the City Electrical area that may affect this estimate.
We feel comfortable with the 75, 416 KVA

Tight =	**70,000**	KVA
Plus 5% =	**71,988**	KVA
Plus 10% =	**75,416**	KVA
Plus 20% =	**82,272**	KVA
Current FortisBC Contract Limits =	**98,400**	KVA

Cindy McNeely, Manager, Electrical/Administration
Civic Operations

TEL 250 469-8932
FAX 250 862-3330
CEL 250 317-8055

City of Kelowna 1435 Water Street, Kelowna, BC V1Y 1J4 **kelowna.ca**

From: Christopher P. Weafer [mailto:cweafer@owenbird.com]
Sent: Wednesday, September 16, 2009 3:56 PM
To: Swanson, Dennis; Sinclair, Corey
Subject: FW: FortisBC COSA

Dennis and Corey:
As per my emails earlier today here are the demand limits provided by Nelson on a non binding without prejudice basis.

Best regards, Chris Weafer

From: Alex Love [mailto:alove@nelson.ca]
Sent: Wednesday, September 16, 2009 3:52 PM
To: Christopher P. Weafer; Cecile Arnott; cmcneely@kelowna.ca; kostraat@summerland.ca; rcarle@newwestcity.ca; Terry Andreychuk; Victor Kumar
Subject: RE: FortisBC COSA

For Grand Forks the forecast demand limit for the next 5 years is 10 MVA,

For Nelson the demand limit would be 30 MVA,

For the 10 and 20% margin scenarios these numbers can be revised upward.

Chris I understand we are giving these numbers on a non-binding basis to run a what if scenario for discussion purposes.

Alex Love / Nelson Hydro

From: Christopher P. Weafer [mailto:cweafer@owenbird.com]
Sent: Wednesday, September 16, 2009 3:22 PM
To: Swanson, Dennis; Sinclair, Corey
Subject: FW: Summerland Power Supply Contract

Dennis and Corey:

As agreed we are providing information to you on the understanding they will be run through the draft COSA model to determine the impact on the BCMEU rates if implemented in a new Wholesale Agreement. The information below is provided on a draft non binding and without prejudice basis. The BCMEU concerns with the COSA model have been identified but our clients are interested in working with FortisBC to attempt to resolve the outstanding concerns.

I will forward additional emails with information as I receive it from our clients and the information will provided on the basis set out in this email.

Best regards, Chris Weafer

From: Ken Ostraat [mailto:kostraat@summerland.ca]
Sent: Wednesday, September 16, 2009 2:59 PM
To: Christopher P. Weafer
Cc: alove@nelson.ca; Terry Andreychuk; Victor Kumar; cmcneely@kelowna.ca; Cecile Arnott; rcarle@newwestcity.ca
Subject: Summerland Power Supply Contract

Our maximum peak load to date was the December 2008 which was 23,900 kva totalized. I think it would be unlikely that we would exceed 27,000 kva over the next five years. Our supply contract has a total demand limit of 30,000 kva in winter. If Summerland is at 96% recovery, there can be a large cushion without going outside the recovery band of +/- 5%.

Ken

FORTISBC

Dennis Swanson
Director, Regulatory Affairs

FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna BC V1Y 7V7
Ph: (250) 717-0890
Fax: 1-866-335-6295
dennis.swanson@fortisbc.com
www.fortisbc.com

April 24, 2009

Via Email
Original via Courier

Ms. Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: FortisBC Inc. - Annual Report to BC Utilities Commission

Please find enclosed twelve copies of FortisBC's Annual Report to the BC Utilities Commission to December 31, 2008.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

ELECTRIC UTILITIES

ANNUAL REPORT

FORTISBC INC.

Suite 100, 1975 Springfield Road
Kelowna, British Columbia
V1Y 7V7

TO THE

BRITISH COLUMBIA UTILITIES COMMISSION

For the Period January 1, 2008 to December 31, 2008

TABLE OF CONTENTS

SCHEDULE 1 - UTILITY RATE BASE

AS AT DECEMBER 31, 2008

	Acct		Reference	Actual 2007	Decision [1] 2008	Actual 2008	Change from Decision
					($000s)		
1	101	Plant in Service, January 1	p. 3	943,920	1,075,766	1,062,070	(13,696)
2		Net Additions	p. 6	118,150	108,640	103,387	(5,253)
3		Plant in Service, December 31		1,062,070	1,184,406	1,165,457	(18,949)
4							
5		**Add:**					
6	107	CWIP not subject to AFUDC	p. 8	13,112	6,787	7,214	427
7	114	Plant Acquisition Adjustment		11,912	11,912	11,912	-
8	186	Deferred and Preliminary Charges	p. 11	14,473	16,062	16,227	165
9							
10				1,101,567	1,219,167	1,200,810	(18,357)
11		**Less:**					
12		Accumulated Depreciation	p. 13				
13		and Amortization		250,323	275,031	275,128	97
14	252	Contributions in Aid of Construction		78,351	80,694	86,783	6,089
15				328,674	355,725	361,911	6,186
16							
17		Depreciated Rate Base		772,893	863,441	838,899	(24,542)
18							
19		Prior Year Depreciated Utility Rate Base		712,911	782,422	772,893	(9,529)
20							
21		Mean Depreciated Utility Rate Base		742,902	822,932	805,896	(17,036)
22		**Add:**					
23		Allowance for Working Capital	p. 14	6,519	7,188	8,261	1,073
24		Adjustment for Capital Additions	p. 15	(2,878)	(7,273)	(11,591)	(4,318)
25							
26		Mid-Year Utility Rate Base		746,543	822,847	802,566	(20,281)

[1] Commission Orders G-147-07 and G-70-08.

Note: Differences due to rounding.

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2008

Line	Account		December 31 2007	Additions	Retirements	December 31 2008
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	847	-	-	847
2	331	Structures and Improvements	10,947	333	-	11,280
3	332	Reservoirs, Dams & Waterways	19,433	1,611	(5)	21,040
4	333	Water Wheels, Turbines and Gen.	54,503	2,223	(181)	56,545
5	334	Accessory Equipment	22,370	683	(142)	22,911
6	335	Other Power Plant Equipment	38,277	102	(30)	38,349
7	336	Roads, Railroads and Bridges	1,053	-	-	1,053
8			147,430	4,952	(358)	152,024
9		**Transmission Plant**				
10	350	Land Rights	7,079	-	-	7,079
11	350.1	Land Rights - Clearing	4,496	-	-	4,496
12	353	Station Equipment	135,378	32,151	-	167,529
13	355	Poles Towers & Fixtures	65,142	9,372	(15)	74,499
14	356	Conductors and Devices	62,601	9,354	-	71,955
15	359	Roads and Trails	817	-	-	817
16			275,513	50,876	(15)	326,374
17		**Distribution Plant**				
18	360	Land Rights	1,736	1,250	-	2,986
19	360.1	Land Rights - Clearing	5,856	1,250	-	7,106
20	362	Station Equipment	115,295	1,720	(73)	116,942
21	364	Poles Towers & Fixtures	105,392	9,172	(354)	114,210
22	365	Conductors and Devices	175,985	11,144	(588)	186,542
23	368	Line Transformers	83,699	6,695	(1,462)	88,933
24	369	Services	7,292	-	-	7,292
25	370	Meters	12,754	733	(298)	13,189
26	371	Installation on Customers' Premises	938	4,398	-	5,336
27	373	Street Lighting and Signal System	7,318	-	(46)	7,272
28			516,264	36,363	(2,821)	549,806
29		**General Plant**				
30	389	Land	5,800	-	-	5,800
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	22,966	1,567	-	24,533
33	391	Office Furniture & Equipment	5,233	363	(1)	5,596
34	391.1	Computer Equipment	42,179	8,961	(163)	50,977
35	392	Transportation Equipment	16,447	1,628	(1,512)	16,563
36	394	Tools and Work Equipment	9,884	682	-	10,566
37	397	Communication Structures and Equipment	20,016	2,864	-	22,880
38			122,863	16,065	(1,675)	137,252
39						
40	101	**Plant in Service**	1,062,070	108,256	(4,869)	1,165,457
41	107.1	Plant under construction not subject				
42		to AFUDC	13,112			7,214
43	107.2	Plant under construction				
44		subject to AFUDC	44,956			54,177
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Plant held for future use	-			-
47						
48	105	Utility Plant per Balance Sheet	1,132,050			1,238,760

Note: Differences due to rounding.

2008 CAPITAL VARIANCE ANALYSIS

		Budget	Actual	Difference	Comments
1	**Hydraulic Production**		**($000s)**		
2	Lower Bonnington Unit 3 Upgrade & Life Extension	-	430	430	Initial project start in 2006 delayed due to long delivery times for major components.
3	Upper Bonnington Old Unit Repowering Phase 1	2,266	1,872	(394)	Carry over of work to 2009.
4	South Slocan Unit 1 Life Extension & Turbine	3,149	2,433	(716)	Project delayed due to long delivery time for new turbine.
5	South Slocan Poleyard Contaminated Site	-	115	115	Project closeout - final contractor reporting and Ministry of Environment review.
6	South Slocan Unit 1 Headgate Rebuild	61	1	(60)	Project delayed to 2009 in order to schedule outage with South Slocan Unit 1 Life Extension.
7	South Slocan Unit 3 Life Extension	9,322	7,714	(1,608)	2008 spending reduced by 2007 purchase of long delivery equipment items.
8	South Slocan Unit 3 Headgate Rebuild	580	460	(120)	Project advanced in 2007 to coincide with the ULE outage schedule.
9	South Slocan Unit 2 Bottom Ring Rebuild & Life Extension	-	53	53	Project closeout and document control.
10	South Slocan Completion	310	574	264	Purchase of the control protection equipment in 2008.
11	South Slocan Headgate Hoist Control, Wire Rope	669	181	(488)	Delay of project from 2008 to 2009 due to the late signing of the contract for material supply
12	Corra Linn Unit 1 Life Extension	881	650	(231)	CPCN application pending.
13	All Plants Upgrade Station Service Supply	473	498	25	
14	All Plants Spare Unit Transformer	-	43	43	Project added in 2008 due to insurance requirements.
15	Generating Sustaining & Misc Upgrades	1,368	1,170	(198)	Re-evaluation and further engineering resulted in scope and budget changes to various projects.
16		**19,079**	**16,195**	**(2,885)**	

Note: Differences due to rounding.

2008 CAPITAL VARIANCE ANALYSIS, cont'd

		Budget	Actual	Difference	Comments
17	**Transmission Plant**		**($000s)**		
18	Kootenay 230kV Transmission	-	64	64	Project closeout
19	South Okanagan Supply Reinforcement	-	(106)	(106)	Project closeout
20	Okanagan Transmission Reinforcement	13,631	3,418	(10,213)	CPCN approval received October 2008.
21	Big White Transmission and Substation	7,183	7,380	197	Unbudgeted costs for Big White Rate Design application.
22	Ellison Distribution Source Substation	12,990	7,810	(5,180)	Project delayed due to extended CPCN and rezoning processes.
23	Black Mountain Distribution Source Substation	9,960	6,811	(3,149)	Project delayed due to rezoning process.
24	Fault Level Reduction	-	58	58	Project closeout
25	Naramata Substation	1,815	541	(1,274)	Project delayed due to change in substation site as ordered by BCUC.
26	Nk'Mip Substation - New East Osoyoos Source	-	144	144	Project closeout.
27	Kettle Valley Distribution Source	2,605	4,802	2,197	Variance primarily due to increases in commodity, equipment and labour prices compared to estimate in $2005.
28	Princeton Transformer Replacement	-	8	8	Project closeout
29	Transmission Line Sustaining	3,528	3,038	(490)	Several transmission condition assessments, switch additions and rehabilitations have been shifted to 2009.
30	Station Sustaining	2,518	5,246	2,728	Projects carried over from 2007.
31	Ootischenia Substation	5,340	5,492	152	Accelerated activity in 2008. Overall Project is under budget.
32	Benvoulin Substation	4,812	-	(4,812)	CPCN approved in January 2009.
33	Crawford Bay Capacitor	-	9	9	Project closeout.
34	Glenmore Substation New Feeder	-	93	93	Project closeout.
35	Westbench Regulator Bank	-	2	2	Project closeout.
36	Hedley Stepup Transformer	-	6	6	Project closeout.
37	18 L Breaker - Waneta	1,800	1,797	(3)	
38	Capitalized Inventory	-	349	349	Changes in inventory levels related to project timing.
39		**66,182**	**46,961**	**(19,220)**	

Note: Differences due to rounding.

2008 CAPITAL VARIANCE ANALYSIS, cont'd

		Budget	Actual	Difference	Comments
40	**Distribution Plant**		**($000s)**		
41	Customer New Connects	15,954	24,434	8,480	Customer activity significantly higher than anticipated.
42	Distribution Sustaining	9,231	8,474	(757)	Some 2008 components completed in 2007.
43	Distribution Growth Greater than 1 Million	-	71	71	Project closeout
44	Distribution Growth Less than 1 Million	3,247	3,513	266	Carry over costs from 2007. Project complete.
45		**28,432**	**36,492**	**8,060**	
46	**General Plant**				
47	Communication and Automation	1,456	1,108	(348)	Some project components accelerated from 2009.
48	Protection and Communications Rehabilitation	1,088	1,764	676	Carryover of costs from 2007.
49	Vehicles	2,461	1,628	(833)	Vendor lead times delayed spending to 2009.
50	Metering	136	278	142	Increased customer growth and higher than anticipated replacement costs.
51	Telecommunications	175	258	83	Unexpected Telephone System Licensing and Fleet Radio equipment purchases.
52	Information Systems	3,776	4,543	767	Additional system requirements and higher than expected consulting and internal testing costs.
53	Buildings	1,312	1,527	215	Carryover of costs from 2007.
54	Furniture & Fixtures	187	237	50	Office relocations to the Springfield and Enterprise.
55	Tools & Equipment	650	587	(63)	Projects completed under budget..
56		**11,241**	**11,930**	**689**	
57					
58	**TOTAL Gross Expenditures**	**124,934**	**111,579**	**(13,356)**	
59					
60	Change to Work in Progress		(3,322)		
61	Plant Retirements		(4,869)		
62	Net Additions to Plant		**103,387**		

Note: Differences due to rounding.

UTILITY PLANT UNDER CONSTRUCTION

AS AT DECEMBER 31, 2008

		CWIP Dec. 31, 2007	Reclassification	Actual Expenditures	CWIP Dec 31, 2008	Additions to Plant in Service
				($000s)		
	Hydraulic Production					
1	P1U1 Upgrade & Life Extensions	-	-	-	-	-
2	P1U2 Headgate Rebuild	-	-	-	-	-
3	P1U3 Upgrade & Life Extension	23	-	430	-	453
4	P1U3 Headgate Rebuild	-	-	-	-	-
5	P1 Generator & Plant Cooling System	6	-	-	-	6
6	P2 Old Unit Repowering Phase 1	1,213	-	1,872	179	2,906
7	P3U1 Life Extension	3,183	-	2,433	5,616	-
8	P3U1 Headgate Rebuild	-	-	1	1	-
9	COR U1 Life Extension (replace Turbine)	-	102	650	752	-
10	P3U3 Life Extension	3,164	-	7,714	10,878	-
11	P3U3 Headgate Rebuild	449	-	460	-	910
12	P3 Poleyard Contaminated Site	-	-	115	-	115
13	P3U2 Bottom Ring Rebuild	-	-	53	-	53
14	P3 H/G Hoist Contr. Wire Rope	-	-	181	181	-
15	P1-P4 Upgrade Station Service Supply	-	672	498	1,170	-
16	All Plants Spare Unit Transformer	-	-	43	43	-
17	Generation Sustaining Under $500k	-	344	1,141	30	1,455
18	2007 PST Credit	-	(965)	29	-	(936)
19	P3 Completion	694	-	574	1,268	-
20	P3U2 Rebuild & Life Extension	(17)	-	-	-	(17)
21	P4U1 Headgate Rebuild	102	(102)	-	-	-
22	P1 Misc Upgrades	6	-	-	-	6
23	P2 Misc Upgrades	12	(12)	-	-	-
24	P3 Misc Upgrades	22	(22)	-	-	-
25	P4 Misc Upgrades	17	(17)	-	-	-
26		**8,875**	**-**	**16,195**	**20,118**	**4,952**
	Transmission Plant					
27	Kootenay 230 KV Development	-	-	64	-	64
28	SOK Project (Vaseux Lake Terminal)	-	-	(106)	-	(106)
29	Okanagan Transmission Reinforcement	3,838	-	3,418	7,256	-
30	Benvoulin Distribution Source	-	-	-	-	-
31	Big White 138 KV Line & Substation	6,268	-	7,380	-	13,648
32	Ellison Distribution Source	3,690	-	7,810	11,501	-
33	Black Mountain Distribution Source	712	-	6,811	7,523	-
34	Fault Level Reduction	143	-	58	-	201
35	Naramata Rehabilitation	2,813	-	541	3,384	(29)
36	New East Osoyoos Source (Nk'Mip Sub)	-	-	144	-	144
37	Kettle Valley	15,539	-	4,802	1,401	18,940
38	Lambert Transformer # 2	(277)	-	-	-	(277)
39	Princeton Transformer Replace	(15)	-	8	-	(7)
40	Transmission Line Sustaining	-	-	3,038	-	3,038
41	Station Sustaining	1,172	-	5,246	1,233	5,186
42	Ootischenia Project	492	-	5,492	-	5,983
43	Capitalized Inventory	6,865	-	349	7,214	-
44	Crawford Bay Cap Inc	2,183	-	9	-	2,192
45	Glenmore Substation New Feeder	-	-	93	-	93
46	WestBench Regulator Bank	-	-	2	-	2
47	Hedley Stepup Transformer	-	-	6	-	6
48	18 L Breaker @ Waneta	3	-	1,797	-	1,800
49		**43,426**	**-**	**46,961**	**39,511**	**50,876**

UTILITY PLANT UNDER CONSTRUCTION, cont'd

AS AT DECEMBER 31, 2008

		CWIP Dec. 31, 2007	Reclassification	Actual Expenditures	CWIP Dec 31, 2008	Additions to Plant in Service
				($000s)		
	Distribution Plant					
50	New Connects System Wide	-	-	24,434	-	24,434
51	Distribution Sustaining	-	-	8,475	-	8,475
52	Small Cap Improvements	-	-	73	-	73
53	Small Cap Improvements Unplanned - 2007	-	-	78	-	78
54	Small Cap Improvements Unplanned - 2008	-	-	754	-	754
55	HOL1 - OKM1 Tie KLO Rd	-	-	48	48	-
56	GLE6 Fdr High Rd - Clifton Rd	-	-	71	-	71
57	LEE2 - HOL5 Tie Add N.O.	-	-	163	163	-
58	Dilworth Development Loopfeed	-	-	384	-	384
60	GLE2 Spall/Springfield UG	-	-	1	-	1
61	HOL1-HOL2 Tie	20	-	138	-	157
62	LEE 2 Regulator	-	-	7	-	7
63	KER01 & KER02 Capacity Upgrades	-	-	7	-	7
64	PRI04 Capacity Upgrade	103	-	1,171	-	1,274
65	OKF03 Capacity Upgrade	120	-	112	-	232
66	CRA 02 Capacity Upgrade	-	-	4	-	4
67	Mckinley Landing Capacity Upgrade	1	-	413	-	414
68	VAL1 Feeder Capacity Upgrade	10	-	162	171	-
69		**253**	-	**36,492**	**382**	**36,363**
	General Plant					
70	Distribution Station Automation	181	-	1,108	656	633
71	Protection and Communications Rehabilitation	410	-	1,764	-	2,174
72	Vehicles	-	-	1,628	-	1,628
73	Metering	-	-	278	-	278
74	Information Systems	4,892	-	4,543	668	8,767
75	Telecommunications	-	-	258	-	258
76	Buildings	31	-	1,527	55	1,504
77	Furniture & Fixtures	-	-	237	-	237
78	Tools & Equipment	-	-	587	-	587
79		**5,514**	-	**11,930**	**1,379**	**16,065**
80	**TOTAL**	**58,068**	-	**111,579**	**61,391**	**108,256**
81	Less Closing CWIP subject to AFUDC	**(44,956)**	-		**(54,177)**	
82	TOTAL CWIP not subject to AFUDC	**13,112**	-		**7,214**	

Note: Differences due to rounding.

OPERATING AREA AND UTILITY PLANT DETAIL

AS AT DECEMBER 31, 2008

OPERATING AREA

Trail, Warfield, Rossland, Fruitvale, Montrose, Christina Lake, Grand Forks, Greenwood, Midway, Rock Creek, Westbridge, Beaverdell, Osoyoos, Oliver, Cawston, Keremeos, Hedley, Coalmont, Tulameen, Princeton, Penticton, Naramata, Summerland, Okanagan Falls, Kelowna, Castlegar, South Slocan, Slocan, Crawford Bay, Creston, Kaslo, Salmo, all within the Province of British Columbia.

PRODUCTION PLANT – HYDRAULIC

Site	Voltage	Cycles	Nameplate Rating (kVA)
Lower Bonnington	7,200	60	57,500
Upper Bonnington	7,200	60	68,950
South Slocan	7,200	60	59,000
Corra Linn	7,200	60	45,000

TRANSMISSION PLANT
Line Length (kilometers)

Area	63 kV	132/138 kV	161/170 kV	230 kV	Total
Boundary	186.9	0.0	102.8	0.0	289.7
Creston	78.3	3.1	29.3	0.0	110.7
Kelowna	0.0	112.7	0.0	113.9	226.6
Kootenay	320.0	0.0	83.3	51.5	454.8
Similkameen	2.0	93.4	0.0	0.0	95.4
South Okanagan	174.1	11.0	55.8	31.3	272.2
Total	**761.3**	**220.2**	**271.2**	**196.7**	**1449.4**

Terminal Transformers

Rating (MVA)	Quantity
22.4/30	1
45/60	2
60/80	2
61.5/82	1
65/75	1
100/134/168	4
120/160/200	3
150/200/250	2
Total Base Capacity	**1,419 MVA**

OPERATING AREA AND UTILITY PLANT DETAIL, cont'd

AS AT DECEMBER 31, 2008

DISTRIBUTION PLANT
Line Length (kilometres)

	1 Phase		2 Phase		3 Phase		Total
	OH	UG	OH	UG	OH	UG	
Boundary	450.5	10.3	24.9	0	354.5	1.5	841.7
Creston	320.5	11.5	9.1	0	295.3	2.9	639.3
Kelowna	402.9	253.6	19.1	1.5	353.9	190.3	1221.3
Kootenay	694.5	29.0	16.4	0	436.1	25.2	1201.2
Similkameen	283.6	13.5	26.0	0	392.2	5.8	721.1
South Okanagan	458.8	52.8	52.7	0.1	337.6	20.8	922.8
Total	**2,610.8**	**370.7**	**148.2**	**1.6**	**2,169.6**	**246.5**	**5,547.4**

OH = Overhead UG = Underground

Distribution Transformers (HV < 60 kV)

	Overhead		Underground		Total	
Rating (kVA)	**Quantity**	**Capacity (kVA)**	**Quantity**	**Capacity (kVA)**	**Quantity**	**Capacity (kVA)**
0-100	28,799	854,321	3,962	292,947	32,761	1,114,268
101-500	133	24,735	1,020	306,365	1,153	331,100
501-1,500	6	4,050	126	128,500	132	132,550
Total	**28,938**	**883,106**	**5,108**	**727,812**	**34,046**	**1,610,918**

Distribution Substation (HV > 60 kV)

Rating (kVA)	Quantity	Rating (kVA)	Quantity
500	1	8,000	1
1,000	2	10,000	3
1,500	4	11,200	1
2,000	2	11,250	9
2,800	1	12,000	7
3,500	1	13,400	1
3,750	1	13,500	1
4,200	3	15,000	1
4,500	1	16,000	2
5,000	1	20,000	1
6,000	8	24,000	17
7,500	5	28,500	1
		31,500	1
		926,500	**76**

ANALYSIS OF DEFERRED CHARGES AND CREDITS

FOR THE YEAR ENDING DECEMBER 31, 2008

		Balance at Dec. 31, 2007	Reclassification	Additions and Transfers	Amortized to Other Accounts	Amortization	Balance at Dec. 31, 2008
				($000s)			
1	Energy Management						
2	Energy Management Additions	19,126	72	2,693	-	(2,108)	19,783
3	Tax Impact	(12,905)	(72)	(835)	-	647	(13,165)
4	PLP Energy Management	113	-	-	-	(77)	36
5		**6,334**	**-**	**1,858**	**-**	**(1,539)**	**6,654**
6	Deferred Regulatory Expense						
7	Provision for True-up for 2006 Incentive	21	-	-	(21)	-	-
8	Deferred Revenue - Incentive Adjustment	(1,132)	-	-	1,305	-	173
9	2008 Incentive	-	-	(1,938)	-	-	(1,938)
10	2005 Revenue Requirements	353	-	-	-	(176)	176
11	Tax Impact	(101)	-	-	-	51	(50)
12	2006 Revenue Requirements	107	-	-	-	(53)	54
13	Tax Impact	(35)	-	-	-	18	(17)
14	2007 Revenue Requirements	36	-	1	-	(37)	-
15	Tax Impact	(11)	(1)	-	-	12	-
16	2008 Revenue Requirements	32	-	7	-	-	39
17	Tax Impact	(11)	-	(2)	-	-	(13)
18	2009 Revenue Requirements	-	-	15	-	-	15
19	Tax Impact	-	-	(5)	-	-	(5)
20	2008 COSA & rate design application	-	44	250	-	-	294
21	Tax Impact	-	(15)	(78)	-	-	(93)
22	2007 BC Hydro Rate Design	11	-	-	-	(11)	-
23	Tax Impact	(4)	-	-	-	4	-
24		**(735)**	**28**	**(1,750)**	**1,284**	**(193)**	**(1,366)**
25							
26	Preliminary and Investigative Charges	**321**	**-**	**614**	**(270)**	**-**	**664**
27	Other Deferred Charges and Credits						
28	Trail Office Lease Costs	191	-	-	-	(12)	179
29	Trail Office Rental to SD#20	(598)	-	-	(38)	-	(636)
30	Prepaid Pension Costs	6,657	1	1,895	-	-	8,553
31	Tax Impact	(480)	1	(587)	-	-	(1,067)
32	Post Retirement Benefits	(3,529)	-	(2,150)	-	-	(5,679)
33	Tax Impact	1,191	-	667	-	-	1,858
34	20 Year Transmission System Plan (2005 SDP)	329	-	-	-	(165)	164
35	Tax Impact	(16)	-	-	-	9	(7)
36	2008 System Development Plan Update	248	-	835	-	-	1,082
37	Tax Impact	(84)	-	(259)	-	-	(343)
38	2008 COSA & rate design application	44	(44)				-
39	Tax Impact	(15)	15				-
40	Automated Meter Reading Feasibility Study	68	-	174	-	-	243
41	Tax Impact	(23)	-	(54)	-	-	(77)
42	2005 Resource Plan	61	-	-	-	(30)	31
43	Tax Impact	(6)	-	-	-	3	(3)
44	2008 Resource Plan Update	217	-	188	-	-	405
45	Tax Impact	(74)	-	(58)	-	-	(132)
46	Renew BCH Power Purchase Agreement	4	-	14	-	-	18
47	Tax Impact	(1)	-	(4)	-	-	(6)
48	Revenue Protection	176	-	183	-	(176)	183
49	Tax Impact	(61)	-	(57)	-	61	(57)
50	Innovative Clean Energy Fund Levy Implementation	23	-	-	-	(23)	-
51	Tax Impact	(8)	-	-	-	8	-
52	PLP Potential Substation	25	-	-	-	(11)	14
53	PLP Settlement Costs	47	-	-	-	(16)	32
54	PLP Computer Software	109	-	-	-	(23)	86
55	PLP Deferred Pension Credit	(81)	-	-	-	12	(70)
56	PLP Deferred Rate Stabilization Account	(75)	-	-	-	75	-
57	ROW Reclamation (Pine Beetle Kill)	-	-	2,507	-	-	2,507
58	Tax Impact	-	-	(777)	-	-	(777)
59	International Financial Reporting Standards	-	-	131	-	-	131
60	Tax Impact	-	-	(40)	-	-	(40)
61	2008 City of Penticton - Carmi Substation	-	-	15	(15)	-	-
62	Tax Impact	-	-	(5)	5	-	-
63	Right of Way Encroachment Litigation	-	-	47	-	-	47
64	Tax Impact	-	-	(14)	-	-	(14)
65							
66							
67		**4,338**	**(28)**	**2,650**	**(49)**	**(288)**	**6,623**

ANALYSIS OF DEFERRED CHARGES AND CREDITS, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2008

		Balance at Dec. 31, 2007	Reclassification	Additions and Transfers	Amortized to Other Accounts	Amortization	Balance at Dec. 31, 2008
				($000s)			
68	Deferred Debt Issue Costs						
69	Series E	7	-	-	-	(3)	4
70	Series F	129	-	-	-	(13)	116
71	Series G	118	-	-	-	(9)	109
72	Series H	106	-	-	-	(14)	92
73	Series I	199	-	-	-	(14)	185
74	Series J	131	-	-	-	(65)	66
75	Series 04-1	1,501	-	-	-	(215)	1,286
76	Tax Impact	(51)	-	(20)	-	7	(63)
77	Series 05-1	1,156	-	-	-	(42)	1,114
78	Tax Impact	(238)	-	(85)	-	9	(314)
79	Series 07-1	1,241	-	5	-	(31)	1,216
80	Tax Impact	(85)	-	(79)	-	2	(160)
81		**4,215**	**-**	**(179)**	**-**	**(387)**	**3,651**
82							
83	TOTAL DEFERRED CHARGES (RATE BASE)	**14,473**	**-**	**3,193**	**965**	**(2,407)**	**16,227**
84	Non-Rate Base Deferred Charges						
85	Discount Forfeit Defence	**198**		**-**	**-**	**(198)**	**-**
86	Tax Impact	**(66)**		**-**	**-**	**66**	**-**
87	BC Hydro Amendment to 3808 (PPA Proceedings)	**-**		**37**	**-**	**-**	**37**
88	Tax Impact			**(11)**	**-**	**-**	**(11)**
89							
90	GRAND TOTAL DEFERRED CHARGES	**14,606**	**-**	**3,218**	**965**	**(2,539)**	**16,253**

Note: Pursuant to Order G-52-05, FortisBC records deferred charges (except deferred revenue and investigative costs) net of income tax.

Differences due to rounding.

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION

AS AT DECEMBER 31, 2008

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2007	Deprec. Rate	Asset Balance Dec. 31, 2007	Depreciation Expense Dec. 31, 2008	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2008
			($000s)			($000s)		
		Hydraulic Production Plant						
1	330	Land Rights	(467)	2.6%	847	22	(289)	(735)
2	331	Structures and Improvements	4,571	1.2%	10,947	131	(37)	4,666
3	332	Reservoirs, Dams and Waterways	2,812	1.7%	19,433	330	(9)	3,133
4	333	Water Wheels, Turbines & Generators	3,279	2.2%	54,503	1,199	(653)	3,825
5	334	Accessory Electrical Equipment	7,253	2.4%	22,370	537	(258)	7,532
6	335	Other Power Plant Equipment	6,338	2.3%	38,277	880	(44)	7,175
7	336	Roads, Railroads, and Bridges	201	1.4%	1,053	15	-	216
8			23,987	2.1%	147,430	3,115	(1,291)	25,811
9		Transmission Plant						
10	350	Land Rights - R/W	(72)	0.0%	7,079	-	-	(72)
11	350.1	Land Rights - Clearing	951	1.6%	4,496	72	-	1,023
12	353	Station Equipment	22,435	3.0%	135,378	4,061	(501)	25,996
13	355	Poles Towers & Fixtures	14,089	3.0%	65,142	1,955	(266)	15,779
14	356	Conductors and Devices	10,555	3.0%	62,601	1,879	(251)	12,183
15	359	Roads and Trails	9	2.9%	817	24	-	33
16			47,967	2.9%	275,513	7,992	(1,017)	54,942
17		Distribution Plant						
18	360	Land Rights - R/W	-	0.0%	1,736	-	-	-
19	360.1	Land Rights - Clearing	279	2.1%	5,856	123	-	402
20	362	Station Equipment	26,565	3.0%	115,295	3,459	(1,430)	28,594
21	364	Poles Towers & Fixtures	30,187	3.0%	105,392	3,162	(349)	33,001
22	365	Conductors and Devices	42,493	3.0%	175,985	5,280	(588)	47,185
23	368	Line Transformers	16,698	2.9%	83,699	2,427	(3,595)	15,530
24	369	Services	6,403	0.5%	7,292	36	-	6,439
25	370	Meters	4,545	3.5%	12,754	446	(134)	4,857
26	371	Installation on Customers' Premises	985	0.0%	938	-	-	985
27	373	Street Lighting and Signal Systems	1,471	2.4%	7,318	176	(47)	1,600
28			129,628	2.9%	516,264	15,108	(6,142)	138,594
29		General Plant						
30	389	Land	(11)	0.0%	5,800	-	-	(11)
31	390	Structures - Frame & Iron	528	0.8%	337	3	-	531
32	390.1	Structures - Masonry	2,474	2.9%	20,398	590	(72)	2,992
33	391	Office Furniture & Equipment	3,155	7.5%	5,233	393	(1)	3,547
34	391.1	Computer Equipment	25,810	10.6%	42,179	4,471	(163)	30,118
35	392	Transportation Equipment	4,036	0.4%	16,447	66	(1,161)	2,941
36	394	Tools and Work Equipment	4,668	9.5%	9,884	939	-	5,607
37	397	Communication Structures and Equipment	4,781	6.0%	20,016	1,201	(46)	5,936
38			45,442	6.4%	120,295	7,662	(1,443)	51,661
39								
40	108	Total Accumulated Depreciation	247,024	3.2%	1,059,502	33,877	(9,894)	271,008
41								
42		Deduct - Portion of CIAC Depreciated				(3,305)		
43								
44	403	Depreciation Expense				30,573		
45								
46		Other						
47	114	Utility Plant Acquisition Adjustment	4,466		11,912	186		4,652
48	390	Leasehold Improvements	1,238		2,568	407		1,645
49		Rate Stabilization Adjustment	(2,487)	10.0%		311		(2,176)
50		Manual entry for buy out of lease	82			-	(82)	-
51		Total Accumulated Amortization	3,299			904	(82)	4,121
52								
53		Accumulated Amortization per						
54		Balance Sheet	250,323			31,477		275,128

Note: Differences due to rounding.

ALLOWANCE FOR WORKING CAPITAL

FOR THE YEAR ENDING DECEMBER 31, 2008

	Lag Days Calculation	**Lag (Lead) Days**	**2008 Actual**	**2008 Extended**	**Weighted Average Lag Days**
			($000s)		
1	**Revenue**				
2	Tariff Revenue	50.5	220,909	11,156	
3	*Other Revenue:*				
4	Apparatus and Facilities Rental	26.6	2,450	65	
5	Contract Revenue	44.3	1,601	71	
6	Miscellaneous Revenue	31.8	652	21	
7	Investment Income	15.0	333	5	
8			**$ 225,945**	**$ 11,318**	**50.1**
9					
10	**Expenses**				
11	Power Purchases	42.2	66,010	2,785	
12	Wheeling	40.2	3,655	147	
13	Water Fees	(1.0)	7,878	(8)	
14	*Operating Labour:*				
15	Salaries & Wages	5.3	14,273	76	
16	Employee Benefits	13.2	10,348	137	
17	Contracted Manpower	50.6	4,720	239	
18	Property Tax	2.6	11,036	29	
19	Rental of T&D Facilities	47.8	3,252	155	
20	Office Lease - Kelowna	(15.2)	222	(3)	
21	Office Lease - Trail	91.3	753	69	
22	Materials	45.6	1,507	69	
23	Insurance	(182.5)	589	(107)	
24	Income Tax	15.2	5,869	89	
25	Interest	82.9	30,163	2,501	
26			**$ 160,274**	**$ 6,176**	**38.5**
27					
28	**Net Lag/(Lead) Days**				**11.6**
29					
30					
31	**Working Capital Allowance**				
32					
33	**Lead-Lag Study Allowance**				$ 5,075
34	Net Lag Days/365 times Expenses				
35					
36	**Add Funds Unavailable:**				
37	Average Customer Loans (related to energy management)			4,902	
38	Average Employee Loans			370	
39	Average of Uncollectable Accounts			1,106	
40	Average Inventory (forecast monthly average investment)			700	
41					$ 7,078
42	**Less Funds Available:**				
43	Average Customer Deposits			3,212	
44	Average Employee Payroll Deductions			-	
45	Average Provincial Services Tax			447	
46	Average Goods and Services Tax			234	
47					$ 3,893
48					
49	**2008 ALLOWANCE FOR WORKING CAPITAL**				**$ 8,261**

Note: Differences due to rounding.

ADJUSTMENT FOR CAPITAL ADDITIONS

FOR THE YEAR ENDING DECEMBER 31, 2008

		Additions to Plant in Service (1) ($000s)	Months in Rate Base	Weighted Value ($000s)
1	January	1,564	11.5	1,499
2	February	3,411	10.5	2,985
3	March	1,928	9.5	1,526
4	April	15,829	8.5	11,212
5	May	10,518	7.5	6,574
6	June	6,948	6.5	3,764
7	July	3,950	5.5	1,810
8	August	6,305	4.5	2,364
9	September	3,058	3.5	892
10	October	3,989	2.5	831
11	November	19,030	1.5	2,379
12	December	19,989	0.5	833
13	**Total**	**96,519**		**36,669**
14	Less Simple Average			48,260
15	Adjustment to Capital Additions			**(11,591)**

16 (1) Expenditures are reduced by Contributions in Aid of Construction (CIAC) as follows:

17	Gross Plant in Service Additions	108,256
18	CIAC	(11,737)
19	Net Capital Additions	**96,519**

Note: Differences due to rounding.

BALANCE SHEET – ASSETS

AS AT DECEMBER 31, 2008

Line	Acct.		Reference	December 31 2008	December 31 2007	Increase / (Decrease)
					($000s)	
1		Utility Plant				
2	101	Utility Plant In Service	p. 3	1,165,457	1,062,070	103,387
3	105	Utility Plant Held for Future Use				-
4	107	Plant Under Construction	p. 7			
5		Not Subject to AFUDC		7,214	13,112	(5,898)
6		Subject to AFUDC		54,177	44,956	9,221
7	114	Plant Acquisition Adjustment		11,912	11,912	-
8				1,238,760	1,132,050	158,618
9						
10	108	Accumulated Depreciation	p. 13	(271,008)	(247,024)	(23,984)
11	111	Accumulated Amortization		(6,297)	(5,786)	(511)
12		Rate Stabilization Account (1)		2,176	2,487	(311)
13				963,632	881,727	81,905
14						
15						
16		Current Assets				
17	131	Cash		-	-	-
18	142	Accounts Receivable		43,038	49,098	(6,060)
19	144	Allowance for Doubtful Accounts		(1,105)	(1,260)	155
20	146	Accounts Receivable - Affiliated Companies		440	3	437
21	154	Materials and Supplies		674	523	151
22	166	Prepayments		819	1,320	(501)
23				43,866	49,684	(5,818)
24						
25		Deferred Charges	p. 11			
26	186	Energy Management		6,654	6,334	320
27	186	Regulatory Expense		(1,366)	(735)	(631)
28	183	Preliminary Investigation		664	321	344
29	186	Other Deferred Charges & Credits		6,649	4,337	2,312
30	181	Debt Issue Expense		3,651	4,216	(565)
31				16,253	14,473	1,779
32						
33		Total Assets		1,023,751	945,884	77,867

(1) The Negotiated Settlement for 2000-2002 included a provision for a notional funding adjustment to prior years' depreciation, in order to ensure that rate increases would not exceed 5 percent per year during the term of the settlement. The adjustment was to be booked as utilized and was required only in 2001. As per the 2006 Revenue Requirements Decision Order G-58-06, the RSA is to be amortized over a ten-year period beginning in 2006.

Note: Differences due to rounding.

BALANCE SHEET – LIABILITIES

AS AT DECEMBER 31, 2008

Acct.		December 31 2008	December 31 2007	Increase / (Decrease)
			($000s)	
	Shareholders' Equity			
201	Common Shares	160,122	145,122	15,000
216	Retained Earnings	195,133	177,551	17,582
		355,255	322,673	32,582
	Long Term Debt			
221	Secured Debentures - Series E	-	4,500	(4,500)
221	Secured Debentures - Series F	15,000	15,000	-
221	Secured Debentures - Series G	25,000	25,000	-
221	Unsecured Debentures - Series H	25,000	25,000	-
221	Unsecured Debentures - Series I	25,000	25,000	-
221	Unsecured Debentures - Series J	-	50,000	(50,000)
221	Unsecured Debentures - Series 04-1	140,000	140,000	-
224	Unsecured Debentures - Series 05-1	100,000	100,000	-
224	Unsecured Debentures - Series 07-1	105,000	105,000	-
224	Term Bank Loans & Other	30,971	-	30,971
		465,971	489,500	(23,529)
	Current and Accrued Liabilities			
232	Accounts Payable and Accrued Liabilities	39,668	37,080	2,588
234	Bank Loans	7,257	3,989	3,268
235	Customers' Security Deposits	3,494	2,990	504
254	Income Taxes Payable	3,489	3,176	313
237	Accrued Interest	8,031	8,044	(14)
239	Long Term Debt Due Within One Year	53,750	-	53,750
261	Insurance Reserve	55	81	(26)
		115,743	55,360	60,383
	Deferred Credits			
252	Contributions in Aid of Construction	86,783	78,351	8,432
	Total Liabilities	1,023,751	945,884	77,867

Note: Differences due to rounding.

SCHEDULE 2 – EARNED RETURN

		Normalized 2007	Decision [1] 2008	Actual 2008	Normalized 2008	Change from Decision
1	SALES VOLUME (GWh)	3084	3087	3,087	3,057	(30)
2						
3				($000s)		
4						
5	ELECTRICITY SALES REVENUE	209,232	220,950	220,909	219,032	(1,918)
6						
7	EXPENSES					
8	Power Purchases	66,616	68,538	66,010	64,786	(3,752)
9	Water Fees	7,918	7,858	7,878	7,878	20
10	Wheeling	3,471	3,622	3,655	3,655	33
11	Net O&M Expense	34,165	36,248	35,663	35,663	(585)
12	Property Tax	10,642	11,176	11,036	11,036	(140)
13	Depreciation and Amortization	30,949	34,356	34,016	34,016	(340)
14	Other Income	(5,504)	(5,030)	(5,035)	(5,035)	(5)
15	Incentive Adjustments	(1,391)	(1,284)	654	654	1,938
16	UTILITY INCOME BEFORE TAX	62,366	65,466	67,032	66,378	912
17	Less:					
18	INCOME TAXES	5,760	3,989	5,869	5,666	1,677
19						
20	EARNED RETURN	56,606	61,477	61,163	60,712	(765)
21	RETURN ON RATE BASE					
22	Utility Rate Base	746,543	822,847	802,566	802,566	(20,281)
23	Return on Rate Base	7.58%	7.47%	7.62%	7.57%	0.09%

[1] Commission Orders G-147-07 and G-70-08

Note: Differences due to rounding.

WEATHER NORMALIZATION

FOR THE YEAR ENDING DECEMBER 31, 2008

Temperature	Heating Degree Days	Cooling Degree Days
Actual	3,584	231
Normal	3,265	242
Difference	318	(10)

Note: Differences due to rounding.

Notional Impact of Weather Normalization Adjustment

Energy Adjustment (GWh)	
Residential	(18)
Wholesale	(9)
Losses	(3)
	(30)
Revenue Adjustment ($000s)	
Residential	(1,432)
Wholesale	(445)
	(1,877)
Power Purchase Expense Adjustment ($000s)	
Energy	(897)
Capacity	(327)
	(1,224)

ELECTRIC OPERATING REVENUES BY RATE CLASS

FOR THE YEAR ENDING DECEMBER 31, 2008

		Customers at Dec. 31, 2008	Energy Sales (GWh)	Revenue ($000s)	Average Use (kWh)	Revenue per kWh Sold (cents)
1	Residential	95,502	1,221	102,600	12,908	8.40
2	Commercial	11,216	666	53,820	59,935	8.08
3	Industrial	36	252	14,470		5.74
4	Wholesale	7	892	45,614		5.11
5	Other	2,958	56	4,405		7.81
6		109,719	3,087	220,909	28,395	7.16

Note: Differences due to rounding.

ANALYSIS OF POWER PURCHASES AND GENERATION OF POWER

FOR THE YEAR ENDING DECEMBER 31, 2008

	Volume		Expense	
	2008	2007	2008	2007
Capacity	(MW Months)		($000s)	
B.C. Hydro	2,006	2,089	10,019	10,080
Market	238	370	2,605	2,139
Energy	(GWh)			
Columbia Power Corp.	921	914	30,195	29,924
B.C. Hydro	826	959	24,121	26,522
IPPs	29	18	694	512
Market	44	35	802	874
Surplus Sales	(48)	(35)	(2,180)	(1,419)
Energy Loss Adjustments [1]	18	20	-	-
	1,791	1,912	66,257	68,633
Generation	1,610	1,498		
Total System Load	3,400	3,409		
Adjustment for Upgrade Projects			(227)	(950)
Other Adjustments [2]			(20)	(1,054)
Company Use	(11)	(12)		
Line and Transformer Losses	(302)	(308)		
Total Electricity Sales	3,087	3,090	66,010	66,629

(1) Includes replacement energy for energy lost to the Company as a result of City of Nelson and Columbia Power Corporation activities.

(2) Includes insurance recovery costs and awards, and other adjustments.

ANALYSIS OF WHEELING EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2008

		2008	2007
		($000s)	
1	B.C. Hydro - Vernon	3,223	3,048
2	B.C. Hydro - Lambert	425	410
3	B.C. Hydro - Princeton	-	7
4	Miscellaneous	7	6
5	Total Wheeling Expense	3,655	3,471

Note: Differences due to rounding.

ELECTRIC OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2008

	Acct.		2008	2007 ($000s)	Change
1		GENERATION			
2	535R	Supervision & Administration	360	586	(226)
3	536	Water Fees	7,878	7,918	(40)
4	542	Structures	596	552	44
5	543	Dams & Waterways	168	203	(35)
6	544	Electric Plant	504	352	152
7	545	Other Plant	254	235	19
8			9,759	9,846	(87)
9					
10		OTHER POWER SUPPLY			
11	555	Purchased Power	66,010	66,629	(619)
12	556	System Control	1,371	960	411
13			67,381	67,589	(208)
14					
15		TRANSMISSION & DISTRIBUTION			
16	560R-1	Supervision & Administration	616	1,171	(555)
17	560R-2	System Planning	1,321	948	373
18	561	Load Dispatching	1,099	1,272	(173)
19	562	Transmission Station Expense	713	623	90
20	563R-1	Transmission Line Maintenance	296	171	125
21	563R-2	Transmission ROW Maintenance	505	650	(145)
22	565	Wheeling	3,655	3,471	184
23	567	Rents	3,252	3,268	(16)
24					
25	583R-1	Distribution Line Maintenance	3,294	2,545	749
26	583R-2	Distribution ROW Maintenance	1,628	1,516	112
27	586	Meter Expenses	922	1,027	(105)
28	592	Distribution Station Expense	1,153	1,112	41
29	596	Street Lighting	85	70	15
30	598	Other Plant	273	255	18
31			18,813	18,099	714
32					
33		CUSTOMER SERVICE			
34	901	Supervision & Administration	769	855	(86)
35	902	Meter Reading	1,762	1,841	(79)
36	903	Customer Billing	654	597	57
37	904	Credit & Collections	1,299	1,002	297
38	910	Customer Assistance	1,927	1,940	(13)
39			6,411	6,235	176

Note: Differences due to rounding.

ELECTRIC OPERATING AND MAINTENANCE EXPENSE, cont'd

FOR THE YEAR ENDING DECEMBER 31, 2008

Acct.		2008	2007	Change
			($000s)	
	ADMINISTRATIVE AND GENERAL			
920	Salaries			
920.1	Executive & Senior Management	1,318	1,234	84
920.2	Legal	664	336	328
920.3	Human Resources	719	390	329
920.4	Finance & Accounting	1,112	503	609
920.6	Information Services	958	478	480
920.7	Materials Management	384	(134)	518
	Other	199	249	(50)
		5,355	3,056	2,299
921	Expenses			
921.1	Executive & Senior Management	117	219	(101)
921.2	Legal	94	389	(295)
921.3	Human Resources	167	217	(50)
921.4	Finance & Accounting	103	63	40
921.6	Information Services	672	222	450
921.7	Materials Management	17	(5)	22
	Other	414	(35)	449
		1,584	1,069	515
923	Special Services	954	3,323	(2,369)
924	Insurance	589	944	(355)
932	Maintenance to General Plant	1,380	1,105	275
933	Transportation Equipment Expenses	980	917	63
		3,902	6,289	(2,387)
	TOTAL	113,206	112,183	1,023
Less:	Wheeling	(3,655)	(3,471)	(184)
	Power Purchases	(66,010)	(66,629)	619
	Water Fees	(7,878)	(7,918)	40
O & M Expense per Financial Statements		**35,663**	**34,165**	**1,498**

Note: Differences due to rounding.

SUMMARY OF INCENTIVE ADJUSTMENTS TO INCOME STATEMENT

FOR THE YEAR ENDING DECEMBER 31, 2008

Line	Description	($000s)	
1	**Amortization of Prior Year Incentives**		
2	Amortization of 2007 Approved Incentives	(1,305)	
3	Amortization of 2006 Incentive true-up	21	
4			
5	**Total Amortization of Prior Year Incentives**		**(1,284)**
6			
7	**Current Year Preliminary Flow Through Adjustments**		
8	2008 Preliminary Interest Expense	958	
9	2008 Preliminary Pension Expense	138	
10	2008 Preliminary BC Tax Reduction	60	
11	2008 Preliminary Pope & Talbot Bad Debt	(390)	
12	2008 Prelim. Net Variance from forecast (Canpar, P&T & Weyerhaeuser)	(331)	
13			
14	Total 2008 Flow Through Adjustments	**435**	
15			
16	**Current Year Preliminary ROE Incentive Adjustments**		
17	2008 Preliminary ROE Incentive	**1,181**	
18			
19			
20	**Total Regulatory Incentive Adjustments**		**1,616**
21			
22			
23	**Current Year True-up to Actual [1]**		**322**
24			
25			
26	**Incentive Adjustments per Income Statement**		**654**

[1] A provision for true-up of incentives of $322,000 was recorded in 2008. This true-up from preliminary to final incentives for 2008 will flow through to 2010 Revenue Requirements.

Note: Differences due to rounding.

SUMMARY OF INCENTIVE ADJUSTMENTS TO INCOME STATEMENT[1], cont'd

FOR THE YEAR ENDING DECEMBER 31, 2008

2008 Flow Through Adjustments	Approved	Forecast	Variance	Income Tax Shield	After Tax Amount	Customer Share	Flow Through Adjustment
				($000s)			
1 Interest Expense	31,789	30,400	(1,389)	(431)	(958)	100%	(958)
2 Pension Expense	2,739	2,539	(200)	(62)	(138)	100%	(138)
3 BC Tax Rate Reduction	-	-	-	60	(60)	100%	(60)
4 Pope & Talbot Bad Debt	-	565	565	175	390	100%	390
5 Net variance from forecast (Canpar / Pope / Weyerhaeuser)	1,291	811	480	149	331	100%	331
6 Flow Through Adjustment							**(435)**

2008 ROE Incentive Adjustment	Approved	Forecast	Variance	Customer Share	ROE Incentive Adjustment
			($000s)		
7 Net Income for ROE Incentive	29,687	32,049	2,362	50%	(1,181)
8 Common Equity	329,139	321,123			
9 Allowed ROE	9.02%	9.98%	0.96%	50%	0.48%

(1) Pursuant to Order G-193-08

Note: Differences due to rounding.

SCHEDULE 3 – INCOME TAX EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2008

		Normalized 2007	Decision[1] 2008	Actual 2008	Normalized 2008	Change from Decision
				($000s)		
1	UTILITY INCOME BEFORE TAX	62,366	65,466	67,032	66,378	912
2	Deduct:					
3	Interest on Non Rate Base Deferral Account		27	-	-	(27)
4	Interest Expense	28,731	31,762	30,163	30,163	(1,599)
5	ACCOUNTING INCOME	33,636	33,678	36,869	36,215	2,538
6						
7	Deductions					
8	Capital Cost Allowance	37,586	44,421	42,886	42,886	(1,535)
9	Capitalized Overhead	8,836	9,062	9,062	9,062	-
10	Additions to Deferred Charges for Tax Purpo	-	-	-	-	-
11	Incentive & Revenue Deferrals	1,391	1,284	(654)	(654)	(1,938)
12	Financing Fees	921	933	922	922	(11)
13	All Other (net effect)	(409)	281	611	611	330
14		48,325	55,981	52,827	52,827	(3,154)
15						
16	Additions					
17	Amortization of Deferred Charges	2,807	2,527	2,539	2,539	12
18	Depreciation	28,142	31,829	31,477	31,477	(352)
19		30,949	34,356	34,016	34,016	(340)
20						
21	TAXABLE INCOME	16,260	12,052	18,058	17,404	5,352
22						
23	Tax Rate	34.12%	31.50%	31.00%	31.00%	-0.50%
24						
25	Taxes Payable	5,548	3,796	5,598	5,395	1,599
26	Prior Years' Overprovisions/(Underprovisions)	31	-	87	87	87
27	Deferred Charges Tax Effect	181	193	184	184	(9)
28						
29	REGULATORY TAX PROVISION	5,760	3,989	5,869	5,666	1,677

[1] Commission Orders G-147-07 and G-70-08

Note: Differences due to rounding.

SCHEDULE 4 – COMMON EQUITY

FOR THE YEAR ENDING DECEMBER 31, 2008

		Normalized 2007	Decision 2008 (1)	Actual 2008	Normalized 2008	Change From Decision
				($000s)		
1	Share Capital	148,000	168,000	163,000	163,000	(5,000)
2	Retained Earnings	161,207	159,899	159,673	159,405	(494)
3						
4	COMMON EQUITY - OPENING BALANCE	309,207	327,899	322,673	322,405	(5,494)
5						
6	Less Common Dividends	(11,800)	(13,400)	(13,400)	(13,400)	-
7						
8	Add: Net Income	27,876	29,688	31,001	30,550	862
9	Share Adjustment	(17,878)	-	(19)	(19)	(19)
10	Shares Issued	15,000	20,000	15,000	15,000	(5,000)
11						
12	COMMON EQUITY - CLOSING BALANCE	322,405	364,187	355,255	354,536	(9,651)
13						
14	SIMPLE AVERAGE	315,806	346,043	338,964	338,470	(7,573)
15						
16	Adjustment for Shares Issued	(11,100)	(4,110)	(4,925)	(4,925)	(815)
17	Deemed Equity Adjustment	-	(12,794)	-	-	12,794
18						
19	COMMON EQUITY - AVERAGE	304,706	329,139	334,039	333,546	4,407

(1) Commission Orders G-147-07 and G-70-08

Note: Differences due to rounding.

SCHEDULE 5 – RETURN ON CAPITAL

FOR THE YEAR ENDING DECEMBER 31, 2008

		Normalized 2007	Decision 2008 [(1)]	Actual 2008	Normalized 2008	Change From Decision
				($000s)		
1	Secured and Senior Unsecured Debt	433,691	489,468	489,468	489,468	-
2	Proportion	57.46%	59.48%	61.04%	61.04%	1.56%
3	Embedded Cost	6.50%	6.36%	6.36%	6.36%	0.00%
4	Cost Component	3.74%	3.78%	3.88%	3.88%	0.10%
5	Return	28,202	31,126	31,116	31,116	(10)
6						
7	Short Term Debt	16,329	4,240	(21,633)	(21,633)	(25,873)
8	Proportion	2.16%	0.52%	(2.70%)	(2.70%)	(3.22%)
9	Embedded Cost	3.24%	15.00%	4.40%	4.40%	(10.60%)
10	Cost Component	0.07%	0.08%	(0.12%)	(0.12%)	(0.20%)
11	Return (including fees)	529	636	(953)	(953)	(1,589)
12						
13						
14	Common Equity	304,706	329,139	334,039	333,546	4,407
15	Proportion	40.37%	40.00%	41.66%	41.62%	1.62%
16	Embedded Cost	9.15%	9.02%	9.28%	9.16%	0.14%
17	Cost Component	3.69%	3.61%	3.87%	3.81%	0.20%
18	Return	27,876	29,688	31,001	30,550	862
19						
20	TOTAL CAPITALIZATION	754,726	822,847	801,875	801,381	(21,466)
21	RATE BASE	746,543	822,847	802,566	802,566	(20,281)
22						
23	Earned Return	56,606	61,450	61,164	60,713	(737)
24						
25	RETURN ON CAPITAL	7.50%	7.47%	7.63%	7.58%	0.11%
26	RETURN ON RATE BASE	7.58%	7.47%	7.62%	7.56%	0.09%

(1) Commission Orders G-147-07 and G-70-08

Note: Differences due to rounding.

EXECUTIVE SUMMARY
DIRECTORS, OFFICERS AND SHAREHOLDERS
AS AT DECEMBER 31, 2008

DIRECTORS

Stanley Marshall	Suite 1201, 139 Water Street St. John's, NL A1B 3T2	Governance Committee
John S. McCallum	26 Lake Lindero Road Winnipeg, MB R3T 4P3	Chair, Audit Committee
John Walker	617 Almandine Court Kelowna, BC V1W 4Z5	
Beth Campbell	2443 Westwood Penticton, BC V2A 8Y8	Chair, Governance Committee
Richard Deane	1835 Butte Street Rossland, BC VOG 1Y0	Audit Committee
Harry McWatters	10823 Dunham Crescent Summerland, BC VOH 1Z2	Chair of the Board Governance Committee
Roger Mayer	2794 River Road Keremeos, BC VOX 1N1	Audit Committee
Walter Gray	103 – 633 Denali Court Kelowna. BC V1V 2R2	Governance Committee
Randy Jespersen	16705 Fraser Highway Surrey, BC V3S 2X7	Governance Committee
William Daley	1130 Bertie Street Fort Erie, ON L2A 5Y2	Audit Committee

DIRECTORS, OFFICERS AND SHAREHOLDERS, cont'd

AS AT DECEMBER 31, 2008

OFFICERS

John Walker	FortisBC Inc. Suite 100 – 1975 Springfield Road Kelowna, BC V1Y 7V7	President and CEO
Michele Leeners	FortisBC Inc. Suite 100 – 1975 Springfield Road Kelowna, BC V1Y 7V7	Vice-President, Finance & Chief Financial Officer
Donald Debienne	FortisBC Inc. Suite 100 – 1975 Springfield Road Kelowna, BC V1Y 7V7	Vice President, Power Supply & Strategic Planning
Michael Mulcahy	FortisBC Inc. Suite 100 – 1975 Springfield Road Kelowna, BC V1Y 7V7	Vice-President, Customer & Corporate Services
Doyle Sam	FortisBC Inc. Suite 100 – 1975 Springfield Road Kelowna, BC V1Y 7V7	Vice President, Engineering & Operations
David Bennett	FortisBC Inc. Suite 100 – 1975 Springfield Road Kelowna, BC V1Y 7V7	Vice President, Regulatory Affairs & General Counsel

SHAREHOLDERS

Fortis Pacific Holdings Inc.	100% Common stock

IMPORTANT CHANGES IN THE YEAR

A. OPERATING

Turbine Upgrades and Generating Facilities

The South Slocan Unit 3 Life Extension (LE) began in the third quarter of 2008 and is on schedule to be complete in the first quarter of 2009.

The completion of South Slocan Unit 3 Headgate rehabilitation project was also achieved in 2008. This work was scheduled to coincide with the South Slocan Unit 3 LE.

The South Slocan Pole Yard Remediation project completed minor site clean-up (landscaping), as well as development and submission of a final report to the Ministry of Environment for review. A certificate of compliance is expected from the Ministry in 2009.

Supply contracts for major equipment having long delivery times continued to be prepared and negotiated for South Slocan Unit 1 and the Corra Linn Units 1 and 2 projects.

Okanagan Transmission Reinforcement (OTR) Project

The OTR project primarily consists of construction of the Bentley Terminal Station near Oliver, as well as the construction of two 230 kV transmission lines from Oliver to Penticton. It is required to address capacity constraints in the Okanagan region. The project received BCUC approval in October of 2008, and is currently in the detailed engineering and procurement stage with construction scheduled to start in the summer of 2009 and to be completed in the summer of 2011.

Kettle Valley Project

The Kettle Valley project consists of a new 161/25 kV distribution source substation to replace three aged substation in the area, and conversion of the existing 13 kV distribution system to 25 kV. The Kettle Valley Substation is complete with substation transformers energized on April 9, 2008. Construction of the main line to Midway, and the Midway and Greenwood 25/13 kV step-down stations, has been completed and energized. The final engineering of the Midway to Greenwood main line is currently underway.

Big White Supply Project

The Big White project consists of a new distribution source substation at Big White, fed by a 138 kV transmission line from the Joe Rich Substation, and an upgrade of the capacity-constrained distribution system at Big White. The project is substantially complete with station energization completed in November 2008 and project wrap-up activities completed in the first quarter of 2009.

IMPORTANT CHANGES IN THE YEAR, cont'd

A. OPERATING, cont'd

Ellison Substation Project

The Ellison Substation project consists of a new substation in the Ellison area of Kelowna, a 138 kV transmission line connecting the Ellison Substation with the Duck Lake Substation, and construction of all distribution facilities necessary to connect the new substation into the existing distribution network. Construction of the transmission line and three of four distribution feeders associated with this project are substantially complete. Work on the fourth feeder, along with the modifications at the Duck Lake Substation are well in hand. Detailed engineering is substantially complete. Significant portions of the substation work have been tendered.

Municipal rezoning of the substation site and application for reconsideration of the CPCN have delayed the project. The delay, coupled with the colder than normal winter weather, has created challenges maintaining voltage and service at the university and airport.

Black Mountain Substation Project

The Black Mountain Substation project consists of a new distribution substation in the Black Mountain area of Kelowna, and a high voltage ring bus to protect system reliability as well as a new distribution feeder. Project construction began in the fourth quarter of 2008 with site preparation completed and civil works underway at year end. Station energization is currently forecast for the end of the third quarter of 2009.

Distribution Substation Automation Program

The Distribution Substation Automation Program consists of installation of automated systems in distribution substations, with a focus on reducing operational costs, preventing power outages and restoring power more quickly when there is a failure, as well as improving the levels of employee and public safety. The program is on schedule with detailed scoping and estimating completed. Work is progressing on detailed engineering, procurement, scheduling and construction. Construction has been completed at Castlegar, DG Bell, Duck Lake, Fruitvale, Hollywood, and Keremeos Stations.

Ootischenia Substation Project

The Ootischenia Substation Project consists of a new distribution substation on the east side of the Columbia River in Ootischenia, and includes the installation of the necessary transmission and distribution interconnection ties to connect the new substation into the existing network. The project is substantially complete and began commercial service December 14, 2008. The project was placed in service just days ahead of a week of cold weather during which FortisBC set a new system peak. The new Ootischenia Substation performed as planned providing relief to the system in the Castlegar area.

IMPORTANT CHANGES IN THE YEAR, cont'd

B. CUSTOMER SERVICE

eBills

In early 2008, FortisBC launched an eBill program. The eBill program provides customers the option of receiving their bill via email. The program was designed to be easy and convenient for customers to enrol in and use. Customers can enrol over the phone or on the FortisBC website for online access to their eBills. By the end of 2008, 5.9 percent of customers had signed up for the eBill program. The Company has received many positive comments from customers regarding the program and has experienced a minimal "dropout" rate.

"Greener" Meter Reading

Two new environmental initiatives were undertaken by the meter reading department in 2008. The Company replaced two gas-powered fleet vehicles with hybrid vehicles. In addition, FortisBC introduced a bicycle into the meter reading fleet in the Kelowna area. After completing a safe work assessment and appropriate safety training, a meter reader has been using a bicycle to read meters on routes that are too long to walk and less efficient to drive. This method of meter reading has proven to be popular with customers as well as more efficient for the Company when appropriately used.

Collections

In mid 2008 the number of accounts in the 31 – 60 day arrears category was determined to be at an unacceptable level. The collections team took action by proactively contacting customers and working with them to make arrangements on the outstanding balances. Outstanding account balances in all aging categories were reduced substantially by the end of the year resulting in total AR being at the lowest level it has been for the past several years.

Telus Transfer Agreement

A Facilities Transfer Agreement was signed with Telus during the second quarter. This contract complements the Shared Pole Agreement of 1980 and will allow FortisBC construction crews to perform basic transfers of Telus plant during pole relocations and upgrades. Contract benefits include; productivity gains for operations staff by avoiding return trips to pull discarded poles; reduced customer calls and complaints regarding pole removals; and a reduction in liability associated with aged plant remaining in the field.

IMPORTANT CHANGES IN THE YEAR, cont'd

C. ENERGY MANAGEMENT

In 2008, FortisBC customers saved 27.3 GW.h through PowerSense energy efficiency programs. The overall benefit/cost ratio of the DSM portfolio was 2.0, compared to 2.1 for the prior year.

FortisBC earned an incentive of $127,000 under the Shared Savings Mechanism. Under the DSM mechanism the Company shares a portion of the net benefits that exceed a 3-year baseline. Benefits are defined as the value of avoided energy and capacity purchase costs and deferred capital expenditures. Utility incentive and program costs, plus the customer costs of their energy efficiency projects are deducted from the benefits to arrive at the net benefits. This mechanism sends FortisBC a signal to maximize the resource savings per dollar spent on DSM measures.

PowerSense exceeded energy savings targets in all three market sectors, as shown below:

2008 Energy Savings by Sector (GW.h)	Plan	Actual	% of Plan Achieved
Residential	8.4	12.9	154
General Service	9.1	11.1	121
Industrial	2.0	3.3	166
Total savings (GW.h)	**19.5**	**27.3**	**140**

Some activity highlights for the year:

- The Residential sector continued to be driven by the Heat Pump Program with a 1000 units installed in 2008 resulting in 8.5 GW.h of energy savings. The new home program achieved 1.6 GW.h, and the residential lighting program attained 2.6 GW.h in savings.
- In the General Service sector, 5.9 GW.h in savings were achieved through new and retrofit lighting projects. Energy management projects totalled 4.0 GW.h in the Building and Process Improvement program ("BIP").
- In the Industrial sector, a change of the chip handling process at a sawmill resulted in savings of 1.7 GW.h, while the compressed air program provided 0.2 GW.h of savings.

The LiveSmart BC program was created in 2008 to provide a single access point for provincial, utility and federal incentives for homeowners throughout British Columbia. FortisBC partnered with LiveSmart BC in early 2008 and extended its incentive initiatives for air and ground source heat pumps, as well as provided funding for a portion of the costs of the energy audits required by the program.

IMPORTANT CHANGES IN THE YEAR, cont'd

C. ENERGY MANAGEMENT, cont'd

In 2008, PowerSense partnered with the City of Kelowna and Terasen Gas to pilot the Cool Shops program in Kelowna. The program provided small businesses energy audits and distributed free compact fluorescent light bulbs and LED exit light bulbs. Two students hired for the summer visited more than 500 businesses and completed 293 walk-through audits. These activities resulted in annual savings of over 154,674 kWh, saving small businesses over $120,000 in energy costs and reducing their greenhouse gas emissions by 2.6 tonnes annually. Due to the program's success, the plan for 2009 is to expand the small business audit program to the south Okanagan and Kootenay regions as well, either with Cool Shops or a new in-house program.

During PowerSense month in October, a total of 51 Conservation Excellence awards were presented at three regional ceremonies in Kelowna, Penticton and Castlegar. The awards are given to customers who undertake projects that save over 100 MWh each, and to trade allies who support the PowerSense programs.

D. REGULATORY

BC Hydro Rate Increase Flow-Through

On March 14, 2008 the Commission, by Order G-40-08, approved BC Hydro's request for a refundable interim rate increase of 6.56 percent, and a reduction of the Deferral Account Rate Rider from 2.0 percent to 0.5 percent, effective April 1, 2008.

On April 17, 2008 the Commission, by Order G-70-08, approved an application by the Company requesting approval of a 0.8 percent interim rate increase, effective May 1, 2008, reflecting the impact of the BC Hydro Power Purchase interim rate increase.

2009 Revenue Requirements

FortisBC filed its 2009 Revenue Requirements Application on September 26, 2008 in accordance with its 2006 – 2009 PBR plan. The Company held its 2008 Annual Review and 2009 Revenue Requirements Workshop on November 13, 2008, and on November 14, 2008 reached a tentative Negotiated Settlement Agreement with stakeholders. On December 11, 2008, the Commission, by Order G-193-08, approved the terms of the 2008 Annual Review and 2009 Revenue Requirements NSA including a three year extension of the PBR Plan through 2011, as well as a general rate increase of 4.6 percent effective January 1, 2009.

Okanagan Transmission Reinforcement (OTR) Project

On December 14, 2007, FortisBC submitted an application for a CPCN for the construction of the OTR project as described on page 30 above. Following an oral hearing process approval for the project was received by Commission Order C-5-08 dated October 2, 2008.

IMPORTANT CHANGES IN THE YEAR, cont'd

D. REGULATORY, cont'd

Advanced Metering Infrastructure (AMI) Project

On December 19, 2007, FortisBC submitted a CPCN application for the AMI project. The project included the replacement of all meters currently in the FortisBC service territory with meters capable of remotely communicating a variety of meter data, including consumptive and power quality data, back to a central data repository.

On March 28, 2008, as a result of continued discussions between the Company and stakeholders including the Ministry of Energy, Mines, and Petroleum Resources, FortisBC submitted an amended CPCN application reflecting the addition of two functional enhancements to the preferred solution designed to provide further support to the BC Energy Plan.

Following a written hearing process, denial of FortisBC's Application and Amended Application for the AMI project was received by Order G-168-08 dated November 12, 2008. In its Reasons for Decision issued on December 3, 2008, the Commission encouraged the Company to continue development of the AMI project and to re-apply for approval to implement.

Copper Conductor Replacement (CCR) Project

On June 27, 2008, FortisBC submitted an application for a CPCN for the CCR project. The project was intended to address employee and public safety concerns related to the disproportionate number of legacy copper conductor failures in the FortisBC system. The project proposed the replacement of all No. 8, No. 6, and 90 MCM distribution copper conductor in excess of 50 years in age, pole replacements subject to safety and age assessment results, and updates to the Company's Geographical Information Systems ("GIS") database.

Following a written public hearing process, the CCR CPCN Application was denied by Commission Order G-165-08, dated November 7, 2008. In the Reasons for Decision accompanying the Order, the Commission directed FortisBC to address the integrity of the legacy copper system through the course of normal Capital Growth and Sustaining programs.

Benvoulin Substation Project

On September 24, 2008, FortisBC submitted an application for a CPCN for the construction of the Benvoulin Substation project required to address capacity and reliability issues in the south/central Kelowna area. Following a written public hearing process, approval for the project was received by Commission Order C-1-09 dated January 20, 2009.

Applications for Reconsideration of Ellison Substation CPCN

On September 18, 2008 and September 23, 2008, two groups of Registered Intervenors requested a reconsideration of Commission Orders C-04-07 and G-75-07 approving the Ellison Substation Project in Kelowna to address the question of whether the location of the substation would interfere with navigation systems at the Kelowna Airport.

Following a limited written hearing process to address the issue, the Commission issued Letter L-8-09 dated February 3, 2009 denying the applications for reconsideration.

IMPORTANT CHANGES IN THE YEAR, cont'd

D. REGULATORY, cont'd

2009/10 Capital Expenditure Plan and 2009 System Development Plan

On June 27, 2008, FortisBC submitted its 2009/10 Capital Expenditure Plan ("2009/10 CEP") Application and 2009 System Development Plan Update ("2009 SDP Update") outlining proposed expenditures of $178.8 million in 2009, and $181.1 million in 2010. The majority of the projects included in the 2009/10 CEP are necessary to provide service, ensure public and employee safety, and to ensure a continued reliable supply of electricity to FortisBC's growing customer base. The 2009 SDP Update provided an update on system development projects as outlined in FortisBC's 2005-2024 System Development Plan.

Following a written public hearing process, approval of the 2009/10 CEP was received by Commission Order G-11-09, subject to specific determinations and directions as set out in the Decision.

BC Hydro – Application to Amend Section 2.1 of Rate Schedule 3808 Power Purchase Agreement

On June 24, 2008, FortisBC filed the Umbrella Agreement for Short-Term Firm or Non-Firm Point-to-Point Transmission Service Agreement dated April 18, 2008 between FortisBC and the City of Nelson pursuant to the Terms and Conditions of Tariff Supplement 7.

On September 16, 2008 BC Hydro applied to the Commission for approval to amend section 2.1 of the Power Purchase Agreement ("PPA") between BC Hydro and FortisBC, to prevent the sale of electricity purchased by FortisBC under the PPA to FortisBC customers to replace electricity sold by those customers.

By Order G-148-08 the Commission established a written public hearing process to review the BC Hydro application, which concluded on February 2, 2009.

IMPORTANT CHANGES IN THE YEAR, cont'd

E. FINANCING

On April 15, 2008, the Company amended its operating credit facility provided by a syndicate of Canadian Chartered banks. The amendments included the extensions of maturity dates for the $50.0 million, three-year revolving facility to May 11, 2011 ("Facility A") and for the $100.0 million 364 day revolving credit facility to May 7, 2009 ("Facility B").

On April 24, 2008, Commission Order G-75-08 approved the issuance of up to 250,000 common shares to the Company's parent for total consideration of up to $25 million on or before December 31, 2008. Two separate share issuances took place in 2008. 100,000 shares were issued on September 29, 2008 for proceeds of $10 million and 50,000 shares were issued on December 29, 2008 for proceeds of $5 million.

The financings referred to above were necessary to fund ongoing capital expenditures and working capital requirements.

F. TAXATION

Income Taxes

For the year ended December 31, 2008, income tax expense was $5.9 million, which was comparable to the year ended December 31, 2007. An increase in pre-tax earnings was offset by an increase in income tax timing differences and a reduction in the Federal and Provincial income tax rates.

Property Taxes

Property tax for 2008 increased by $0.4 million compared to 2007. The increase in 2008 property tax was due to increased assessment base from net capital additions.

IMPORTANT CHANGES IN THE YEAR, cont'd

G. AUDIT

Internal Audit

The primary focus of Internal Audit during 2008 was the testing of Internal Controls over Financial Reporting ("ICFR"). In addition, the following internal audits were performed:

- **Transfer Pricing and Code of Conduct Audit –** an annual audit of compliance with the Transfer Pricing and Code of Conduct policies.
- **Executive Expense Account Audit –** an audit of discretionary expenses incurred by the executive management team.
- **Directors' Liabilities Audit** – an audit to test the timely reporting and remittance of statutory remittances (Payroll withholdings, WCB, Corporate Income Tax and Retail Sales Taxes.)
- **Disclosure Controls and Financial Reporting Process Audit** – an audit of internal controls over Disclosure Procedures and the Financial Close Process.
- **Fraud Risk Assessment** – annual Entity Level Assessment of Fraud Risk
- **Privacy Policy Review –** a review of compliance with applicable Privacy legislation.
- **Accounts Receivable Aging Review –** a review of accounts receivable aging methodology in FortisBC's billing system.

External Audit

In addition to their quarterly reviews and annual audit of the Financial Statements, Ernst & Young LLP performed the following:

- **IT General Controls audit –** a test of automated and manual internal controls within Information Technology (Computer Systems) to substantiate the external auditors' opinion of Internal Controls over Financial Reporting within the organization.
- **Internal Controls over Financial Reporting** – an independent assessment of the risk and control documentation for certain internal control processes and management's evaluation of the design adequacy and operating effectiveness of internal controls over financial reporting.

IMPORTANT CHANGES IN THE YEAR, cont'd

H. LEGAL PROCEEDINGS

Vaseux Lake Fire

The Province of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a Writ and Statement of Claim against FortisBC Inc. ("FortisBC"). In addition, private land owners have filed a separate Writ and Statement of Claim in relation to the same matter. FortisBC is communicating with its insurers and has filed a Statement of Defence in relation to both of the actions. The outcome cannot be reasonably determined and estimated at this time, and accordingly no amount has been accrued in the financial statements.

I. HUMAN RESOURCES

Labour Relations

The Collective Agreement between the Company and Local 213 of the International Brotherhood of Electrical Workers (IBEW) expired on January 31, 2009. IBEW represents approximately 270 employees in specified occupations in the areas of generation, transmission and distribution.

The Collective Agreement between the Company and Local 378 of the Canadian Office and Professional Employees Union (COPE) expires on January 31, 2011. COPE represents approximately 160 employees in office and professional occupations.

IMPORTANT CHANGES IN THE YEAR, cont'd

J. SAFETY AND HEALTH

Safety Indicators for the 12 month period October 1, 2007 to September 30 2008

Note: The reporting period is consistent with that required by FortisBC's Performance-Based Regulation (PBR) Plan.

All Injury Frequency Rate	**Year** 2008	**3 Year Average** 2006 – 2008
All Injury Rate (Incidents per 100 workers)	2.57	2.08

The 2008 All Injury Frequency Rate (AIFR) is based on the number of medical aid (MA) and lost time injuries (LTI) that occurred in the 12 month period from October 1, 2007 and September 30, 2008. The following formula is used to calculate the rate:

$$\frac{(\text{Number of Medical aid} + \text{Number of Lost Time Injuries}) \times 200{,}000}{\text{Exposure Hours}}$$

Injury Severity Rate	**Year** 2008	**3 Year Average** 2006 – 2008
Severity Rate (Incidents per 100 workers)	18.52	27.0

The 2007 Injury Severity Rate (SR) is based on the total number of lost days due to work related injuries or illnesses which occurred in the 12 month period from October 1, 2007 and September 30, 2008. The following formula is used to calculate the rate:

$$\frac{(\text{Number of days lost}) \times 200{,}000}{\text{Exposure Hours}}$$

Motor Vehicle Incidents	**Year** 2008	**3 Year Average** 2005 – 2007
Vehicle incident rate (Incidents per 1,000,000 kilometres)	1.12	1.77

The 2008 Recordable Vehicle Incident Rate (VIR) is based on the total number recordable vehicle incidents due to work related Vehicle Collisions or Injuries which occurred in the 12 month period from October 1, 2007 and September 30, 2008. The following formula is used to calculate the rate:

$$\frac{(\text{Number of recordable incidents}) \times 1{,}000{,}000 \text{ km}}{\text{Kilometres driven}}$$

IMPORTANT CHANGES IN THE YEAR, cont'd

J. SAFETY AND HEALTH, cont'd

Safety Initiatives

The Company's safety initiatives are designed to support continual improvement within the FortisBC management system. The 2008 initiatives delivered the 2008 safety plan and focused on hazard identification and control, incident investigations, and training. Expectations established by leadership for hazard identification and control make it clear to employees that hazards must be controlled before work begins. Incident investigation to "root causes" by health and safety committee employees is utilized to facilitate comprehensive incident investigations and recurrence prevention. The Company transitioned its safety management system database to Utility Risk Management system tool ("URM"). The URM safety system provides enhanced functionality.

An electrical worker made contact with a 7,200 volt potential transformer in 2008. The incident was investigated, required follow-up action taken, and the employee has since returned to work.

Audits are periodically used to review the overall safety management system and identify issues. A safety system audit was conducted in December 2007 which resulted in an audit score of 98 percent. The safety system audit is sanctioned by WorkSafeBC and the "Partnerships Program". Safety audit results were used to develop and implement the 2008 safety action plan.

IMPORTANT CHANGES IN THE YEAR, cont'd

K. SERVICE RELIABILITY

Reliability Indicators for the period: October 2007 to September 2008.

Note: The reporting period is consistent with that required by FortisBC's Performance-Based Regulation (PBR) Plan.

KPI	KPI Definitions	2007-08 (Normalized) [1] *as reported at 2008 Annual Review*	2007-08 (Normalized) [1] *Updated*	3 Year Average 2005 to 2007 (Normalized) [1]	BCUC Target 2007-08 (Normalized) [1]
SAIFI	Customer Interruptions / Total Customers Served	2.46[2]	2.60[3]	3.01	3.11
SAIDI	Customer Hours of Interruption / Total Customers Served	2.55[2]	2.98[3]	2.38	2.45
CAIDI	Customer Hours of Interruption / Customer Interruptions	1.04[2]	1.15[3]	0.79	0.79
Index of Reliability	Total Customer Hours Available – SAIDI / Total Customer Hours Available	99.97%[2]	99.97%[3]	99.97%	99.97%

1 *"Normalized" data excludes the impacts of October 29th, 2006 snow and wind storms, the December 9th, 2006 equipment failure outage, the June 29th, 2007 wind and lightning storms, and the July 10th, 2008 wind storm which all exceed the IEEE daily SAIDI threshold. There were no incidents in 2005 that exceeded the threshold.*

2 *SAIDI and SAIFI results as reported at the 2008 Annual Review.*

3 *SAIDI and SAIFI results updated with additional outage information not available during the 2008 Annual Review.*

Major Service Interruptions during September 2007 to October 2008:

November 12, 2007 – Okanagan and Kootenay area:

A major storm moved through the Okanagan and Kootenay regions where strong winds blew trees into lines and caused many distribution outages.

	Direct	Indirect
Customers Affected:	12736	0
Customer Hours:	10089	0

November 28, 2007 – Kelowna area:

A structure with a double circuit distribution feeder in the Joe Rich Valley was hit by a logging truck. The structure needed to be completely replaced with power subsequently restored approximately 11 hours after the incident.

	Direct	Indirect
Customers Affected:	1639	0
Customer Hours:	18403	0

IMPORTANT CHANGES IN THE YEAR, cont'd

K. SERVICE RELIABILITY, cont'd

June 30, 2008 –South Okanagan and Boundary Region:

During a major lightning storm, multiple lightning strikes caused outages to both transmission lines to the east and west of the Kettle Valley substation. Damage at the Grand Forks Terminal Station required crews to investigate the problem which delayed power restoration.

	Direct	Indirect
Customers Affected:	8,066	1,892
Customer Hours:	10,405	4,882

July 10, 2008 – Okanagan and Kootenay Areas:

A severe wind storm moved through the Okanagan and the Kootenays with record winds being observed in Penticton at 109 km/hr. There were many tree related outages occurring primarily on the distribution system. The event had a SAIDI impact of 1.1 which is the largest value for a single event since 2002.

	Direct	Indirect
Customers Affected:	21,016	4,858
Customer Hours:	114,440	28,570

July 10, 2008 qualified as a "Major Event Day" and for 2.5β Normalization.

August 17, 2008 – Kelowna area:

A lightning strike destroyed equipment in the Sexsmith Substation in Kelowna, which caused the system protection to trip and lockout a transmission line. Restoration efforts were delayed due to the breaker lockout and damaged equipment at the substation.

	Direct	Indirect
Customers Affected:	8,802	12,036
Customer Hours:	1,828	13,195

August 19, 2008 – South Okanagan:

A direct lightning strike at the Oliver Substation caused the system protection to correctly isolate the affected area. Where possible customers were reconnected through other routes, however due to the protection operation this outage required field investigation prior to re-energizing a transmission line.

	Direct	Indirect
Customers Affected:	11,362	0
Customer Hours:	12,227	0

COMPANY PROFILE

		Return on Equity								
		Allowed	Achieved	Normal	Bond Yield [1]	Common Equity	Rate Base ($000s)	Energy Sales (MW.h)	Temperature (% warm, HDD)	Direct Customers
1	1999	9.50%	10.48%	10.35%	5.72%	42.72%	279,665	2,607	4.9 %	86,713
2	2000	10.00%	10.00%	9.98%	5.71%	42.03%	307,426	2,682	(3.0)%	87,683
3	2001	9.75%	10.20%	10.34%	5.76%	45.14%	338,695	2,733	3.8 %	89,072
4	2002	9.53%	8.24%	8.32%	5.68%	46.73%	382,503	2,791	(3.1)%	92,804
5	2003	9.82%	10.88%	10.80%	5.34%	42.49%	442,688	2,834	7.9 %	95,070
6	2004	9.55%	10.70%	11.04%	5.14%	43.02%	498,974	2,874	5.5 %	97,317
7	2005	9.43%	9.88%	9.87%	4.40%	41.70%	589,845	2,969	0.1 %	99,745
8	2006	9.20%	9.94%	10.05%	4.28%	40.21%	671,138	3,040	(5.7)%	102,413
9	2007	8.77%	9.23%	9.15%	4.32%	40.38%	746,543	3,090	0.2 %	107,724
10	2008	9.02%	9.28%	9.16%	4.05%	41.66%	802,566	3,087	9.8 %	109,719

[1] Canada long-term benchmark bonds monthly average

TEN-YEAR SUMMARY

		2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
1	DISTRIBUTION OF ELECTRICITY (GW.h)										
2	Sales										
3	Residential	1,221	1,160	1,091	1,070	1,020	1,005	997	986	985	945
4	Wholesale	892	636	948	916	931	915	873	857	840	847
5	Industrial	252	352	344	357	345	338	347	323	290	273
6	General Service & Other	722	943	657	624	578	577	574	567	567	542
7		3,087	3,090	3,040	2,969	2,874	2,834	2,791	2,733	2,682	2,607
8											
9	EARNINGS ($000s)										
10	Operating Revenue	225,944	215,155	208,515	187,462	179,353	168,205	154,355	146,430	138,154	126,843
11											
12	Operating Expenses	35,663	34,165	32,337	37,680	36,042	30,061	32,094	25,943	25,901	25,475
13	Power Purchases	66,010	66,629	67,576	60,404	59,014	58,436	52,261	51,051	47,659	42,919
14	Wheeling	3,655	3,471	3,840	3,956	3,817	3,727	3,996	4,334	3,601	3,714
15	Property & Capital Taxes	11,036	10,642	10,275	9,540	10,047	9,115	9,593	10,123	9,709	9,349
16	Water Fees	7,878	7,918	8,371	7,679	7,399	7,370	7,120	7,178	7,157	7,351
17	Depreciation	34,016	30,949	26,746	18,840	16,817	14,637	14,344	12,695	9,620	9,626
18		158,258	153,774	149,144	138,098	133,135	123,345	119,407	111,323	103,647	98,434
19											
20	Earnings from Operations	67,686	61,380	59,371	49,364	46,218	44,860	34,948	35,107	34,506	28,408
21											
22	AFUDC	-	-	(2,360)	(3,335)	(2,434)	(3,370)	(2,451)	(846)	(590)	(435)
23	Interest Expense	30,163	28,731	26,112	22,389	19,033	19,120	15,200	14,519	14,565	13,053
24	Income Tax	5,869	5,898	6,504	7,148	8,333	7,578	5,892	8,566	6,858	5,409
25	Incentive Adjustment	654	(1,391)	2,431	(1,219)	(2,300)	1,281	1,676	149	(748)	(2,026)
26	Rate Stabilization	-	-	-	-	-	-	-	(3,109)	-	-
27	Net Earnings	31,001	28,143	26,684	24,380	23,585	20,250	14,630	15,827	14,422	12,407
28											
29	Return on Common Equity	9.28%	9.23%	9.94%	9.88%	10.70%	10.88%	8.24%	10.20%	10.00%	10.48%

Note: Differences due to rounding.

DECLARATIONS

1. UNIFORM SYSTEM OF ACCOUNTS

In my opinion, FortisBC Inc. classifies certain expenditures based on the Uniform System of Accounts as set out by the British Columbia Utilities Commission, with the exception of certain Operating and Maintenance accounts, which are classified according to FortisBC's Chart of Accounts. This variance to Commission Order G-28-80 was approved via Commission Letter L-34-99 dated July 6, 1999.

2. COMPLIANCE WITH COMMISSION'S FINANCIAL DIRECTIVES

In my opinion, FortisBC complies with the British Columbia Utilities Commission's financial directives contained in its Orders to FortisBC.

Signed by

Charles P. Lee, C.G.A.
Controller

OFFICER'S DECLARATION

I, Michele Leeners, do hereby certify:

1. That I am Vice-President, Finance and Chief Financial Officer with FortisBC Inc. with Head Office at Suite 100, 1975 Springfield Road, Kelowna, British Columbia;

2. That I have examined the content of this report and the information set out herein is complete and accurate, to the best of my knowledge, information and belief. I have read and understand Section 106 of the Utilities Commission Act.

Signed by

Michele Leeners, C.A.
Vice President, Finance and
Chief Financial Officer

Any inquiries regarding this report should be directed to:

Joyce Martin
Manager, Regulatory Affairs
FortisBC Inc.
1290 Esplanade - PO Box 130
Trail, BC V1R 4L4

APPENDIX A
RECONCILIATION OF FINANCIAL STATEMENTS

STATEMENT OF EARNINGS, CORPORATE AND REGULATORY
YEAR ENDED DECEMBER 31, 2008

	Corporate	($000s)	Regulated
REVENUE			
Sale of power	222,677	(1,768)	220,909
Other	6,563	(1,528)	5,035
	229,240	(3,296)	225,944
EXPENSES			
Operating and Maintenance	36,553	(890)	35,663
Power Purchases	68,190	(2,180)	66,010
Wheeling	3,655	-	3,655
Property & BC capital taxes	11,353	(317)	11,036
Water fees	7,982	(104)	7,878
Depreciation & Amortization of Deferreds	34,158	(142)	34,016
	161,891	(3,633)	158,258
EARNINGS FROM OPERATIONS	67,348	338	67,686
INTEREST EXPENSE			
Long-term debt	31,920	(804)	31,116
Short-term debt	493	(1,446)	(953)
Allowance for funds used during construction	(3,009)	3,009	-
	29,404	759	30,163
REGULATORY INCENTIVE ADJUSTMENTS	-	654	654
EARNINGS BEFORE INCOME TAXES	37,944	(1,075)	36,869
INCOME TAXES	5,280	589	5,869
NET EARNINGS	32,664	(1,663)	31,001

Note: Differences due to rounding.

RECONCILIATION OF STATEMENT OF EARNINGS
CORPORATE TO REGULATORY

	($000s)
Sale of Power	222,677
Walden Power Partnership	(1,768)
Regulatory	220,909
Other Revenue	6,563
Reclassify Incentive Adjustments	654
Reclass sale of surplus power	(2,180)
Reclass Walden interest income	(1)
Regulatory	5,035
Operating and Maintenance Expense	36,553
Non-regulated Affiliate	(362)
Walden Power Partnership	(528)
Regulatory	35,663
Property & B.C. Capital Taxes	11,353
Walden Power Partnership	(317)
Regulatory	11,036
Water Fees	7,982
Walden Power Partnership	(104)
Regulatory	7,878
Depreciation Expense	34,158
Warfield Garage Expansion (non-reg)	(7)
Walden Power Partnership	(135)
Regulatory	34,016

	($000s)
AFUDC	(3,009)
Reclass AFUDC	3,009
Regulatory	-
Long Term Interest Expense	31,920
Walden Power Partnership	(459)
Reallocated to Short Term Interest	(345)
Regulatory	31,116
Short Term Interest Expense	493
Reclass CWIP to Non-Regulated entity	(1,791)
Reclass from long term interest expense	345
Regulatory	(953)
Incentive Adjustments	-
Amortization of Prior Year Incentives	(1,284)
2008 Incentive Adjustments	1,939
Regulatory	654
Income Tax Expense	5,280
Walden Power Partnership & Non-Reg. Affiliates	589
Regulatory	5,869
Power Purchases	68,190
Reclass sale of surplus power	(2,180)
Regulatory	66,010

Note: Differences due to rounding.

BALANCE SHEET, CORPORATE AND REGULATORY
AS AT DECEMBER 31, 2008

	Corporate (external)	($000s)	Regulated
ASSETS			
Plant and Equipment	1,167,354	71,406	1,238,760
Less accumulated depreciation	(258,403)	(16,725)	(275,128)
	908,951	54,681	963,632
Deferred Charges and Other Assets	14,046	2,207	16,253
Regulated Assets	21,179	(21,179)	-
	35,225	(18,972)	16,253
Goodwill	1,209	(1,209)	-
Current Assets			
Cash	40	-	-
Accounts receivable	37,339	(11,860)	25,479
Unbilled revenue	-	16,894	16,894
Prepaid expenses	843	(24)	819
Deferred charges and other assets	997	(997)	-
Inventory	674	-	674
Regulated assets	299	(299)	-
	40,192	3,714	43,866
TOTAL ASSETS	985,577	38,174	1,023,751
CAPITAL AND LIABILITIES			
Capitalization			
Shareholder's Equity			
Common shares	181,851	(21,729)	160,122
Retained earnings	183,332	11,801	195,133
Total Shareholder's Equity	365,183	(9,928)	355,255
Long-Term Debt			
Secured debentures	40,000	-	40,000
Unsecured debentures	395,000	-	395,000
Debt issue costs	(4,189)	4,189	-
Term Bank Loan	34,685	(3,714)	30,971
Total Long-Term Debt	465,496	475	465,971
Contributions in Aid of Construction	-	86,783	86,783
Obligation under capital lease and other liabilities	39,204	(39,204)	-
Deferred Income Taxes	1,677	(1,259)	419
Accounts payable and accrued liabilities	42,180	1,034	43,214
Current portion of debt	61,775	(8,025)	53,750
Accrued interest	8,031	-	8,031
Income Taxes Payable	93	2,978	3,071
Bank Loans	-	7,257	7,257
Regulated liability	1,938	(1,938)	-
	114,017	1,306	115,323
Capitalization/Rate Base Differential	-	-	-
TOTAL CAPITAL AND LIABILITIES	985,577	38,174	1,023,751

Note: Differences due to rounding.

RECONCILIATION OF BALANCE SHEET

ASSETS	($000s)
Plant and Equipment	1,167,354
Reclassify CPCs	121,891
Warfield Garage Expansion	(246)
GAAP Variance - Capital Lease Asset	(27,228)
Walden Power Partnership	(23,012)
Regulated	1,238,760
Accumulated Depreciation	(258,403)
Reclassify Amortization of CPCs	(35,108)
Capital Lease Asset	5,360
Warfield Garage Expansion	(62)
Walden Power Partnership	13,085
Regulated	(275,128)
Deferred Charges	14,046
Net Liabilities re: GAAP variances	4,145
Reclassify Reg LT Liabilities	(1,938)
Regulated	16,253
Regulated Assets	21,179
Disallowed	(21,179)
Regulated	-
Accounts Receivable	37,339
Reclassify Unbilled Revenue	(16,894)
Reclassify LT Receivables (80%)	5,102
Walden Power Partnership	(68)
Regulated	25,479
Unbilled Revenue	-
Reclassify Accounts Receivable	16,894
Regulated	16,894
Prepaid Expenses	843
Walden Power Partenrship	(24)
Regulated	819
Deferred Charges and Other Assets	997
Disallowed (Current portion EM loans)	(997)
	-
Current Portion Regulated Assets	299
Disallowed	(299)
Regulated	-
Goodwill	1,209
Non Regulated	(1,209)
Regulated	-
Cash	40
Walden	(40)
Regulated	-

CAPITAL AND LIABILITIES	($000s)
Retained Earnings	183,332
Non-Regulated	11,801
Regulated	195,133
Common Shares	181,851
Non Reg Share Capital	(21,729)
Regulated	160,122
Debt Issue Costs	(4,189)
Disallowed Debt Issue Costs	4,189
Regulated	-
Bank Loan	34,685
Walden Bank Loan	(3,714)
Regulated	30,971
Contributions in Aid of Construction	-
Reclassify CIAC	121,891
Reclassify Amortization of CIAC	(35,108)
Regulated	86,783
Obligation under Capital Lease and Other Liabilities	39,204
Net Assets re: GAAP variances	(28,739)
Reclassify PLP Capital Lease & LTD	(10,465)
Regulated	-
Deferred Income Taxes	1,677
Walden Power Partnership	(1,259)
Regulated	419
Accounts Payable and Accrued Liabilities	42,180
Walden Power Partnership	(35)
Intercompany Accounts	1,199
Non-Regulated	(130)
Regulated	43,214
Current Portion of Debt	61,775
Reclass Current Portion Bank Loan	(7,257)
Reclass Current Walden	(768)
Regulated	53,750
Bank Loans	-
Reclass Current Portion Bank Loan	7,257
	7,257
Income Taxes Payable	93
Walden Power Partnership	818
Non Regulated	2,160
	3,071
Regulated Liability	1,938
Reclass to Deferred Charges	(1,938)
Regulated	-

Note: Differences due to rounding.

APPENDIX B
INCOME TAX ASSESSMENT

Canada Revenue Agency | Agence du revenu du Canada

Surrey BC V3T 5E1

FORTISBC INC.
C/O Ian Lorimer
Suite 100
1975 Springfield Road
Kelowna BC V1Y 7V7

Page 1 of 3

Date of mailing	November 28, 2008
Business Number	10564 5642 RC0001
Tax year-end	December 31, 2007

0014523

CORPORATION NOTICE OF ASSESSMENT

RESULTS

This notice explains the results of our assessment of the "T2 Corporation Income Tax Return" for the tax year indicated above. It also explains any changes we may have made to the return.

Result of this Assessment :	$	133,300.41 Cr
Amount refunded:	$	133,300.41
Prior balance:	$	0.00
Total balance:	$	0.00

We are sending you a cheque for $133,300.41 separately.

Please refer to the Summary and Explanation for additional information.

Canada Revenue Agency / Agence du revenu du Canada

FORTISBC INC.

Date of mailing	November 28, 2008
Business Number	10564 5642 RC0001
Tax year-end	December 31, 2007

CORPORATION NOTICE OF ASSESSMENT

SUMMARY OF ASSESSMENT

	$ Reported		$ Assessed
Federal Tax:			
Part I	2,965,381.00		2,965,382.00
Part I.3	0.00		0.00
Part II	0.00		0.00
Part III.1	0.00		0.00
Part IV	0.00		0.00
Part IV.1	0.00		0.00
Part VI	0.00		0.00
Part VI.1	0.00		0.00
Part XIII.1	0.00		0.00
Part XIV	0.00		0.00
Total Federal Tax:		$	2,965,382.00
Net Provincial and Territorial Tax/Credit:			
British Columbia	1,506,226.00		1,606,226.00
Total Net Provincial and Territorial Tax/Credit:		$	1,606,226.00
Instalment(s) applied			4,710,000.00 Cr
Net balance:		$	138,392.00 Cr
Interest:			
Instalment interest			9,239.28
Refund interest			4,147.69 Cr
Result of this assessment:		$	133,300.41 Cr
Amount refunded:		$	133,300.41
Prior balance:		$	0.00
Total balance:		$	0.00

William V. Baker
Commissioner of Revenue

EXPLANATION

We have revised Canadian Manufacturing and Processing Profits on Schedule 27, "Calculation of Canadian Manufacturing and Processing Profits Deduction," to $2,111,635.00, to agree with the calculated amount.

We have revised the manufacturing and processing profits deduction to $147,814.00, to agree with the calculated amount.

We have revised the claim for the general tax reduction for corporations other than Canadian-controlled private corporations to agree with the calculated amount.

We have provided a breakdown of the provincial and territorial tax and credit amounts.

Net British Columbia tax/credit consists of the following:		
British Columbia tax	$	1,621,726.00
British Columbia political contribution tax credit	$	500.00
British Columbia Training Tax Credit	$	15,000.00

We have charged instalment interest because one or more of your instalment payments

Canada Revenue Agency · Agence du revenu du Canada

FORTISBC INC.

Date of mailing	November 28, 2008
Business Number	10564 5642 RC0001
Tax year-end	December 31, 2007

0014524

CORPORATION NOTICE OF ASSESSMENT

were late or insufficient.

The amount of refund interest shown is taxable in the reporting period you receive it.

For your information we have attached a statement explaining how we have calculated interest.

Please visit our Web site at www.cra.gc.ca/requests-business for information about online requests available to business clients. This service allows clients to electronically request certain financial actions, additional remittance vouchers and other communication products, as well as reproductions of previously issued correspondence.

For general information regarding filing an objection, determining a corporation's losses, or reassessment periods, please refer to the "T2 Corporation Income Tax Guide," or visit our Web site at www.cra.gc.ca.

The Canada Revenue Agency also offers the convenience of Direct Deposit. For information about this service, please visit our Web site at www.cra.gc.ca or contact the number provided below.

Did you know you may be eligible to file your return using our Corporation Internet Filing service? For information on eligibility criteria and the service in general, please visit www.cra.gc.ca/corporation-internet.

If you require additional information or wish to request an adjustment, contact:

Surrey Tax Centre
9755 King George Highway
Surrey BC V3T 5E1
Fax (604) 585-5772

Southern Interior BC TSO
277 Winnipeg Street
Penticton BC V2A 1N6
Toll free number 1-800-959-5525

Canada Revenue Agency / Agence du revenu du Canada

Surrey BC V3T 5E1

FORTISBC INC.
C/O Ian Lorimer
Suite 100
1975 Springfield Road
Kelowna BC V1Y 7V7

Date	November 28, 2008
Business Number	10564 5642 RC0001

0014525

STATEMENT OF INTEREST CALCULATED

Program:	Corporation Income Tax	Filing Date:	June 30, 2008
Reporting Period End:	December 31, 2007	Balance Due Date:	February 29, 2008

Summary of Interest:

Instalment interest	9,239.28
Refund interest	1,319.28 Cr
	=================
Total	7,920.00

The interest rates that appear on this statement are displayed to two decimal places. The actual calculation has been made in accordance with the rates prescribed by law. To view these interest rates, please visit our Web site at www.cra.gc.ca.

Instalment Base Amounts

Reporting period starting	Jan. 1, 2007	Jan. 1, 2006	Jan. 1, 2005
Reporting period ending	Dec. 31, 2007	Dec. 31, 2006	Dec. 31, 2005
Effective date	Jan. 1, 2007	Jan. 1, 2006	Jan. 1, 2005
Federal tax	2,965,382.00	3,792,761.00	3,800,679.00
Provincial tax	1,621,226.00	2,057,415.00	1,625,163.00
Current tax credits	15,000.00 Cr	15,000.00 Cr	15,000.00 Cr
	=================	=================	=================
Instalment base	4,571,608.00	5,835,176.00	5,410,842.00
Effective date		Jan. 2, 2007	Jan. 2, 2007
Federal tax	0.00	3,882,977.00	3,826,774.00
Provincial tax	0.00	2,106,357.00	1,634,113.00
Current tax credits	15,000.00 Cr	15,000.00 Cr	15,000.00 Cr
	=================	=================	=================
Instalment base	0.00	5,974,334.00	5,445,887.00

Instalment Interest Calculation

Date	# of Days	Int. Rate	Interest	Item	Amount	Balance
Jan. 31, 2007	0000	0.00	0.00	Payment received	360,000.00 Cr	360,000.00 Cr
Jan. 31, 2007	0000	0.00	0.00	Payment due	380,967.33	20,967.33
Feb. 28, 2007	0028	9.00	145.24	Payment due	380,967.33	402,079.90
March 1, 2007	0001	9.00	99.14	Payment received	360,000.00 Cr	42,179.04
March 31, 2007	0030	9.00	313.13	Payment received	360,000.00 Cr	317,507.83 Cr
March 31, 2007	0000	0.00	0.00	Payment due	380,967.33	63,459.50
April 30, 2007	0030	9.00	471.11	Payment received	360,000.00 Cr	296,069.39 Cr
April 30, 2007	0000	0.00	0.00	Payment due	380,967.33	84,897.94
May 31, 2007	0031	9.00	651.35	Payment received	360,000.00 Cr	274,450.71 Cr
May 31, 2007	0000	0.00	0.00	Payment due	380,967.33	106,516.62
June 30, 2007	0030	9.00	790.75	Payment received	360,000.00 Cr	252,692.63 Cr
June 30, 2007	0000	0.00	0.00	Payment due	380,967.33	128,274.70
July 31, 2007	0031	9.00	984.15	Payment due	380,967.33	510,226.18
Aug. 1, 2007	0001	9.00	125.81	Payment received	360,000.00 Cr	150,351.99
[illegible]. 31, 2007	0030	9.00	1,116.18	Payment received	360,000.00 Cr	208,531.83 Cr
[illegible]. 31, 2007	0000	0.00	0.00	Payment due	380,967.33	172,435.50
Sep. 30, 2007	0030	9.00	1,280.12	Payment received	360,000.00 Cr	186,284.38 Cr
Sep. 30, 2007	0000	0.00	0.00	Payment due	380,967.33	194,682.95
Oct. 31, 2007	0031	9.00	1,493.64	Payment received	360,000.00 Cr	163,823.41 Cr
Oct. 31, 2007	0000	0.00	0.00	Payment due	380,967.33	217,143.92
Nov. 30, 2007	0030	9.00	1,612.03	Payment received	360,000.00 Cr	141,244.05 Cr

Canada Revenue Agency | Agence du revenu du Canada

FORTISBC INC.

Date
November 28, 2008
Business Number
10564 5642 RC0001

STATEMENT OF INTEREST CALCULATED

Instalment Interest Calculation

Date	# of Days	Int. Rate	Interest	Item	Amount	Balance
Nov. 30, 2007	0000	0.00	0.00	Payment due	380,967.33	239,723.28
Dec. 31, 2007	0031	9.00	1,839.20	Payment received	750,000.00 Cr	508,437.52 Cr
Dec. 31, 2007	0000	0.00	0.00	Payment due	380,967.33	127,470.19 Cr
Dec. 31, 2007	0000	0.00	0.00			127,470.19 Cr
Feb. 29, 2008	0060	8.00	1,682.57 Cr	Balance due date	129,152.76 Cr	
			9,239.28	Total Instalment Interest		

Arrears/Refund Interest Calculation

Date	# of Days	Int. Rate	Interest	Item	Amount	Balance
Feb. 29, 2008	0000	0.00	0.00	TAX CREDITS	15,000.00 Cr	15,000.00 Cr
Feb. 29, 2008	0000	0.00	0.00	Part I tax	2,965,382.00	2,950,382.00
Feb. 29, 2008	0000	0.00	0.00	Provincial tax	1,621,226.00	4,571,608.00
Feb. 29, 2008	0000	0.00	0.00	Instalment interest	9,239.28	4,580,847.28
Feb. 29, 2008	0000	0.00	0.00	Instalment payment	4,710,000.00 Cr	129,152.72 Cr
April 29, 2008	0000	0.00	0.00	Refund interest date	0.00	129,152.72 Cr
June 30, 2008	0062	6.00	1,319.28 Cr			130,472.00 Cr
Sep. 30, 2008	0092	5.00	1,650.05 Cr			132,122.05 Cr
Nov. 28, 2008	0059	5.00	1,069.15 Cr	Last interest date		133,191.20 Cr
			1,319.28 Cr	Total Refund Interest		

For reporting periods ending between January 1, 1985 and June 30, 2003, we pay refund interest on an overpayment from the later of:

a) 120 days after the reporting period end, if the return was filed on time; or

b) the date the return was filed, if the return was filed late; or

c) the date of the credit that created the overpayment.

For reporting periods ending on or after July 1, 2003, we pay refund interest on an overpayment from the later of:

a) 120 days after the reporting period end, if the return was filed on time; or

b) 30 days after the date the return was filed, if the return was late filed; or

c) the date of the credit that created the overpayment.

For further information, contact:

Surrey TC
9755 KING GEORGE HIGHWAY
Surrey BC V3T 5E1
Fax (604) 585-5772
Toll free number 1-800-959-5525

IN THE MATTER OF THE Utilities Commission Act
R.S.B.C. 1996, c. 473, as amended
-and-
IN THE MATTER OF AN APPLICATION by West Kootenay Power Ltd.
To implement certain rate design changes
- and -
To provide new service options

To: British Columbia Utilities Commission
6th floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

APPLICATION

West Kootenay Power Ltd. ("WKP" or "the Company") hereby applies, pursuant to Section 61 of the Utilities Commission Act (the "Act"), for approval to amend its Rate Schedules in accordance with the various proposals set forth in this Application and for the following Orders to:

1. RESIDENTIAL

   increase the rates, more than the level of rates that may be otherwise approved, in Schedule 1 - Residential Service effective the first day of each of 1998, 1999, and 2000 so as to increase revenues collected by $1,131,000, $1,181,000, and $2,656,000, respectively;

2. GENERAL SERVICE

   decrease the rates, less than the level of rates that may be otherwise approved, in Schedule 20 - Small General Service and Schedule 21 - General Service effective the first day of each of 1998, 1999 and 2000 so as to decrease revenues collected by $706,000, $666,000, and $1,602,000, respectively;

3. LARGE GENERAL SERVICE - PRIMARY

   decrease the rates, less than the level of rates that may be otherwise approved, in Schedule 30 - Large General Service - Primary effective the first day of each of 1998, 1999 and 2000 so as to decrease revenues collected by $189,000, $260,000, and $500,000, respectively;

4. LARGE GENERAL SERVICE - TRANSMISSION

decrease the rates, less than the level of rates that may be otherwise approved, in Schedule 31 - Large General Service - Transmission effective the first day of each of 1998, 1999 and 2000 so as to decrease revenues collected by $110,000, $131,000, and $282,000, respectively;

5. WHOLESALE - PRIMARY

decrease the rates, less than the level of rates that may be otherwise approved, in Schedule 40 - Wholesale - Primary effective the first day of each of 1998, 1999 and 2000 so as to decrease revenues collected by $78,000, $72,000, and $104,000, respectively;

6. WHOLESALE - TRANSMISSION

decrease the rates, less than the level of rates that may be otherwise approved, in Schedule 41 - Wholesale - Transmission effective the first day of each of 1998, 1999 and 2000 so as to decrease revenues collected by $78,000, $82,000, and $183,000, respectively;

7. LIGHTING

decrease the rates, less than the level of rates that may be otherwise approved, in Schedule 50 - Street Lighting and Schedule 51 - Outdoor Lighting effective the first day of each of 1998, 1999 and 2000 so as to decrease revenues collected by $25,000, $26,000, and $53,000, respectively;

8. IRRIGATION AND DRAINAGE

increase the rates, more than the level of rates that may be otherwise approved, in Schedule 60 - Irrigation and Drainage effective the first day of each of 1998, 1999, and 2000 so as to increase revenues collected by $55,000, $58,000, and $60,000, respectively;

9. TIME OF USE RATES

provide Time of Use Rates in accordance with the rates and terms and conditions of Schedule 2 - Residential Service - Time of Use, Schedule 22 - General Service - Time of Use, Schedule 32 - Large General Service - Primary - Time of Use, Schedule 33 - Large General Service - Transmission - Time of Use, Schedule 42 - Wholesale Service - Primary - Time of Use, Schedule 43 - Wholesale Service - Transmission - Time of Use, Schedule 62 - Irrigation and Drainage - Time of Use, the proposed forms of which are attached hereto at Tab - Tariff;

10. GREEN POWER RATES

provide Green Power Rates in accordance with the rates and terms and conditions of Schedule 3 - Residential Service - Green Power, Schedule 4 - Residential Service - Time of Use - Green Power, Schedule 23 - Small General Service - Green Power, Schedule 24 - General Service - Green Power, Schedule 25 - General Service - Time of Use - Green Power, Schedule 34 - Large General Service - Primary - Green Power, Schedule 35 - Large General Service - Time of Use - Green Power, Schedule 36 - Large General Service - Transmission - Green Power, Schedule 37 - Large General Service - Transmission - Time of Use - Green Power, Schedule 44 - Wholesale Service - Primary - Green Power, Schedule 45 - Wholesale Service - Primary - Time of Use - Green Power, Schedule 46 - Wholesale Service - Transmission - Green Power, Schedule 47 - Wholesale Service - Transmission - Time of Use - Green Power, Schedule 63 - Irrigation and Drainage - Green Power, Schedule 64 - Irrigation and Drainage - Time of Use - Green Power, the proposed forms of which are attached hereto at Tab - Tariff; and

11. PUBLIC PROCESS

adopt the negotiated settlement process established in the Negotiated Settlement Process, Policy, Procedures and Guidelines, issued January 1996.

In support of this Application, WKP respectfully files the submissions attached hereto.

DATED at Trail, British Columbia, this 2nd day of September, 1997.

WEST KOOTENAY POWER LTD.

Robert Hobbs
Director, Regulatory and Government Affairs

All notices and communications with regard to this Application should be sent to:

West Kootenay Power Ltd.
Attention: Robert Hobbs
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Trail, BC V1R 4L4

Telephone: (250) 368-0312
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EXECUTIVE SUMMARY

This Application proposes changes to West Kootenay Power Ltd.'s ("WKP") regulated retail rate structures. The proposed changes provide more customer choice and enhanced equity among and within rate classes. The proposed changes also provide more appropriate price signals and set the stage for the unbundling of rate schedules to retail customers.

All customer classes have been provided with the following service options: (1) standard easy to understand rates with fixed customer charges, flat energy charges, and flat demand charges where applicable, (2) unbundled cost based time of use rates, and (3) green rates which allow participating customers to purchase power produced by environmentally desirable technologies.

The proposed changes are implemented over three years, and the annual rate impact of the proposed changes does not exceed 4% to any class of customers. The changes in rates for each customer class at each stage of the restructuring is shown on the following table. The ratio of revenue collected to the cost of service by class is also shown in the following table, before and after rate design changes.

	Proposed Rate Changes by Class (percent change)				Revenue/Cost Ratios	
Customer Class	**Year One**	**Year Two**	**Year Three**	**Cumulative Rate Change (See Note 1)**	**Before Rate Design**	**After Rate Design (See Note 2)**
Residential (1)	3.55%	3.53%	3.54%	11.00%	90.1%	100.0%
General Service (20,21)	0.00%	-1.69%	-8.51%	-10.05%	111.6%	100.4%
Large General Service Primary (30)	-2.40%	-3.38%	-6.74%	-12.06%	114.5%	100.7%
Large General Service Transmission (31)	-4.12%	-5.12%	-11.62%	-19.60%	125.3%	100.7%
Wholesale Primary (40)	-0.28%	-0.26%	-0.38%	-0.91%	101.2%	100.3%
Wholesale Transmission (41)	-3.09%	-3.35%	-7.73%	-13.58%	116.7%	100.8%
Lighting (50,51)	-1.85%	-1.96%	-4.15%	-7.76%	109.1%	100.9%
Irrigation (60)	4.00%	4.00%	4.00%	12.49%	75.8%	85.3%
				Total	100.0%	100.0%

Note 1: To calculate the cumulative rate change, the individual rate changes in each year are multiplied together. For residential, the cumulative rate increase is calculated as 1.0355 x 1.0353 x 1.035 = 1.11 or an 11% increase.

Note 2: To calculate the Revenue/Cost Ratio After Rate Design, the cumulative rate change is multiplied by the Before Rate Design Revenue/Cost Ratio. For residential, the calculation is: 1.11 x .901 = 1.000 or 100.0%.

1. BACKGROUND

West Kootenay Power Ltd. ("WKP" or "the Company") is an investor-owned electrical utility serving 130,000 customers, direct and indirect, in the south central region of British Columbia. The Company's service area stretches from Creston in the east to Princeton in the west. The western portion of the Company's service area includes the Okanagan and Similkameen valleys which are fruit growing and recreational regions. This region is more densely populated than the rest of the service area and contains the only large cities in the service area, Penticton and Kelowna. The eastern portion of the service area is much less densely populated with the largest regional centre being at Trail, which is also the location of the Company's headquarters.

The Company owns four hydro-electric plants on the Kootenay River having a total rated capacity of 205 megawatts as compared to an annual system peak of over 600 megawatts. The resulting energy and capacity requirements are purchased under long-term power purchase agreements with Cominco Ltd., a joint venture of Columbia Power Corporation and CBT Power Corp., and B.C. Hydro, as well as from short-term market purchases.

In 1993, the Company applied to the British Columbia Utilities Commission ("Commission") for substantial changes to the design of rates it charges customers for service. By Decision dated June 17, 1994, the Commission approved changes that affected both the amount of revenue to be recovered from certain customer classes (i.e. interclass revenue shifts) and the amount of revenue to be recovered from individuals within a specific customer class (i.e. intraclass revenue shifts).

The interclass revenue shifts included an annual two percentage point increase to the residential class with the incremental revenues received to be offset by a decline in the rates charged small general service and general service customers. The intraclass revenue shifts included the implementation of an inverted rate structure for the residential class and seasonal rates for small general service and general service customers. The approved changes were implemented in three years; the final adjustment was implemented on January 1, 1997.

Several events have occurred since the 1993 Rate Design Application that are significant considerations for this Application. For example, the trend in the electric utility industry towards competition and customer choice has led to the establishment of the British Columbia Task Force on Electricity Market Reform. The establishment of the Task Force is expected to lead to the implementation of market reforms designed with the objective of ensuring competition and customer choice in British Columbia. The trend towards competition and customer choice that has occurred in many markets requires utilities to unbundle rates on a cost causation basis.

WKP filed its Transmission Access Application proposing wholesale and retail access on November 27, 1996. In support of the Transmission Access Application, the Company filed a Cost of Service Unbundled Electric Rate Study, November 1996. This fully allocated cost of service study again indicated substantial over-recovery from some classes and under-recovery from the residential and irrigation customer classes. In the Transmission Access Application, WKP committed to filing a rate design application in 1997.

For several years, WKP has been gathering customer input from Customer Advisory Panels and from many other discussions with customers. WKP believes that this Application represents the views of our customers, although as with any rate design proposals, some customers will see rate increases and others will see rate decreases.

2. PRINCIPLES AND OBJECTIVES

In the December 15, 1993 Rate Design Application, WKP supported three fundamental principles of rate design which are repeated below:

1. Rate design must result in the most efficient allocation of the Province's resources and give customers a proper price signal.
2. Enhanced competition dictates the pursuit of cost-based rates for all customers.
3. Interclass equity must be enhanced and maintained.

WKP continues to support these same fundamental principles. The advent of competition and customer choice discussed in the previous section only increases the need for WKP to adhere to these principles.

In this Application, the Company proposes rate design changes that more closely align rates with costs. Interclass revenue shifts are proposed in order to ensure that the amount of revenue recovered from each customer class recovers the costs of serving that class. Intraclass revenue shifts are proposed in order that the amounts recovered from each customer within a specific class recovers the cost of serving each customer.

The first objective of this Application is to provide customers with more choice. Input from customers and the Customer Advisory Panels indicate that customers would like more choice in the rate structures under which they are served. However, while many customers want choice, many other customers desire simplicity in rate structures. Therefore, the second objective of this Application is to provide customers with the option of a simple rate.

The third objective of this Application is to ensure that rates provide customers with price signals that reflect trends in evolving electricity markets. In the recent past, WKP's growing capacity and energy requirements were primarily supplied by purchases from B.C. Hydro under tariffed rates. As the market evolves, more diverse sources of supply at lower costs are becoming available. While the Company once faced incremental commodity costs that were greater than fully bundled (commodity plus delivery facilities) tariffed rates, short-term market commodity costs are now close to the embedded cost of the commodity. These new circumstances call for rate design changes to reflect the new realities of evolving markets. For example, an inverted rate structure may no longer be as appropriate as flat rate structures.

The fourth objective of this Application is to give customers an opportunity to support the development of environmentally desirable technologies.

WKP believes that it has satisfied all four objectives while holding to the three fundamental principles. This Application gives customers the choice of a simple standard rate, an unbundled time of use rate which reflects WKP's cost structure and market prices, and a green power rate which supports environmentally desirable technologies.

The current single inverted residential rate means that customers that use more pay more and have no other option. The proposed flat rate means that no kilowatt hour is cost differentiated. However, if a customer has a favourable load profile, the option of a time of use rate will lower the customer's bill. Similarly, customers who want to positively impact the environment may do so by choosing the "Green" rate. A discussion of the proposed service options follows.

3. OVERVIEW OF PROPOSED STANDARD RATES

Every customer class has the option of a simple, easy to understand standard rate ("standard rate") which meets the second objective of this Application, that is, to provide customers with the option of a simple rate. Many customers do not want and may not benefit from the added complexity of the time of use rates or the other service options discussed in Section 5. The proposed implementation schedule for each rate design change is set out in Appendix B.

3.1 Residential (1)

The residential rate currently has a fixed customer charge, combined with an inverted two-stage energy rate. With this Application, the inverted two-stage energy rate will be replaced with a flat energy rate. (see Appendix B, Table B4.1-1)

3.2 General Service (20, 21)

The general service rate currently has a fixed customer charge, combined with a declining block three-stage energy rate and a flat demand charge. The energy rate is seasonal, that is, the rate is different in the winter and summer months.

This Application proposes to replace the current rate with a fixed customer charge, a declining block two-stage energy rate, and a flat demand charge. Seasonal differentiation within this rate will be removed. (see Appendix B, Table B4.1-2,3, 4, and 5)

3.3 Large General Service - Primary (30)

The large general service rate currently has a seasonal, flat energy rate and a flat demand charge. The Company proposes to replace this rate with a customer charge, a flat energy rate and a flat demand charge. As discussed below, this rate will be renamed: Large General Service - Primary. (see Appendix B, Table B4.1-7)

3.4 Large General Service - Transmission (31)

The industrial rate currently applies to only three customers. Its intended application was large (greater than 5,000 kVA) high load factor customers supplied at transmission voltage and owning their own substations. The three customers currently on this rate do not fit these criteria well. The first of the three customers has a peak demand of only 2,000 kVA, the second customer has a demand of almost 8,000 kVA but only a moderately high load factor. The third customer is Celgar Pulp which contracts for only a portion of their load on a firm basis. Celgar has a very low load factor under its firm agreement. The total firm load of the three customers supplied under this rate is approximately four per cent of total load.

For these reasons, and recognizing the cost over-recovery for this class of customers, WKP proposes to merge this rate with the Large General Service rate with appropriate cost-based discounts recognizing supply voltage and metering arrangements. This rate will be renamed: Large General Service - Transmission. (see Appendix B, Table 4.1-8)

3.5 Wholesale - Primary (40)

This wholesale rate applies to customers served at primary distribution voltage and currently has a flat energy rate and a flat demand charge. This Application proposes to replace this rate with a fixed customer charge, a flat energy rate, and a flat demand charge. (see Appendix B, Table 4.1-6)

3.6 Wholesale - Transmission (41)

This wholesale rate applies to customers served at a transmission voltage and currently has a flat energy rate and a flat demand charge. This Application proposes to replace this rate with a fixed customer charge, a flat energy rate and a flat demand charge. (see Appendix B, Table 4.1-6)

3.7 Lighting (50, 51)

The lighting rates currently are flat charges as these are all un-metered services. No change is proposed in the structure of these rates.(see Appendix B, Table B4.1-9)

3.8 Irrigation (60)

The current irrigation rate has a basic charge and a flat energy charge. No change is proposed in the structure of these rates. (see Appendix B, Table B4.1-10)

4. REVENUE REALLOCATION

This Application is based on a 1997 revenue requirement. The cost of serving each class has been calculated from an Unbundled Cost of Service Study ("1997 UCOS"), July 1997 found under Appendix C. In Table 4-1, the results of the 1997 UCOS are presented. As can be seen from the resulting revenue to cost ratios ("RCR") and required rate increases to bring the RCRs to 100%, WKP's past efforts at rate restructuring have been largely successful, however, some further adjustments are required.

Based on the 1997 UCOS, the proposed revenue reallocations result in rates where the revenue collected from each class almost exactly equals the cost of serving the class, for all classes except irrigation. The revenue reallocations are revenue neutral and do not include any future general rate increases. WKP is currently estimating that general rate increases will on average be close to 2.5% annually from January 1, 1998 to January 1, 2000.

In the 1993 Rate Design Application, no immediate need for revenue reallocation for customer classes with a RCR between 90% and 100% was identified. With this Application, it is proposed that all RCRs be adjusted to unity over the three year implementation period, except the irrigation class. Relatively small adjustments are required to all customer classes over the three years.

4.1 Adjustments

Table 4-1 shows the RCRs for all customer classes. WKP proposes to adjust revenues to each rate class over three years. The adjustments can be found in Appendix B as Tables B4.1-1 to B4.1-10. A summary of the impacts on each class are shown in Table 4.1-1. The resulting RCRs are shown in Table 4-1. Note that the RCRs are within 1% of 100% for all classes, except the irrigation class.

Table 4-1: Revenue / Cost Ratios

Customer Class	1997 Revenue / Cost Ratios at Current Rates: Revenue ($000s)	Cost ($000s)	Revenue/ Cost ratio	Revenue Deficiency at Current Rates	Revenue/ Cost Ratios In Year Three: Proposed Revenue Change	Proposed Rate Change	Revenue/ Cost ratio
Residential (1)	$ 52,254	$ 57,222	91.3%	$ 4,968	$ 4,968	11.00%	100.0%
General Service (20,21)	$ 24,597	$ 21,539	114.2%	$ (3,058)	$ (2,974)	-10.05%	100.4%
Large General Service - Primary (30)	$ 7,870	$ 6,871	114.5%	$ (999)	$ (949)	-12.06%	100.7%
Large General Service - Transmission (31)	$ 2,668	$ 2,130	125.3%	$ (538)	$ (523)	-19.60%	100.7%
Wholesale - Primary (40)	$ 27,821	$ 27,483	101.2%	$ (338)	$ (254)	-0.91%	100.3%
Wholesale - Transmission (41)	$ 2,526	$ 2,165	116.7%	$ (361)	$ (343)	-13.58%	100.8%
Lighting (50,51)	$ 1,383	$ 1,268	109.1%	$ (115)	$ (104)	-7.76%	100.9%
Irrigation (60)	$ 1,380	$ 1,821	75.8%	$ 441	$ 173	12.49%	85.3%
Total	$ 120,499	$ 120,499	100.0%	$ -	$ (6)	0.00%	100.0%

Note: For the Residential and general service classes revenue changes are shown. Due to the accrual and amortization of restructuring revenue this is different from the impact on customers bills which is shown in Table 4.1-1.

Table 4.1-1 Summary of Revenue Reallocations by Class

Customer Class	Year One	Year Two	Year Three	Cumulativ
Residential (1)				
Proposed Revenue Change	$ 1,131	$ 1,181	$ 2,656	$ 4,968
% Change in Customer Rates	3.55%	3.53%	3.54%	11.00%
General Service (20,21)				
Proposed Revenue Change	$ (706)	$ (666)	$ (1,602)	$ (2,974)
% Change in Customer Rates	0.00%	-1.69%	-8.51%	-10.05%
Large General Service Primary (30)				
Proposed Revenue Change	$ (189)	$ (260)	$ (500)	$ (949)
% Change in Customer Rates	-2.40%	-3.38%	-6.74%	-12.06%
Large General Service Transmission (31)				
Proposed Revenue Change	$ (110)	$ (131)	$ (282)	$ (523)
% Change in Customer Rates	-4.12%	-5.12%	-11.62%	-19.60%
Wholesale Primary (40)				
Proposed Revenue Change	$ (78)	$ (72)	$ (104)	$ (254)
% Change in Customer Rates	-0.28%	-0.26%	-0.38%	-0.91%
Wholesale Transmission (41)				
Proposed Revenue Change	$ (78)	$ (82)	$ (183)	$ (343)
% Change in Customer Rates	-3.09%	-3.35%	-7.73%	-13.58%
Lighting (50,51)				
Proposed Revenue Change	$ (25)	$ (26)	$ (53)	$ (104)
% Change in Customer Rates	-1.85%	-1.96%	-4.15%	-7.76%
Irrigation (60)				
Proposed Revenue Change	$ 55	$ 58	$ 60	$ 173
% Change in Customer Rates	4.00%	4.00%	4.00%	12.49%
Total				
Proposed Revenue Change	$ -	$ 2	$ (8)	$ (6)

Customer Advisory Panels have indicated that rates should reflect costs, but that rate design changes should be introduced over time to prevent rate shock. Most customers believe that increases over 5% as a result of rate design changes are too high. Therefore, rate increases resulting from rate design changes of no more than 4% per annum are proposed.

The implementation period of three years resulted from three key considerations. First, the implementation period for the 1993 Rate Design Application was three years. Second, some form of direct access is expected within the next three years, given recent trends towards competition and customer choice. Finally, the three year implementation period resulted in an annual increase below the ceiling of 4% per annum. For example, the revenue shifts required to move the revenue to cost ratios to 100% resulted in an average increase of 3.5% per year for the residential class for each of three years. In year one, the maximum percentage rate impact on any residential customer was 4.1%. In years two and three, the maximum percentage impact is for customers with zero consumption. For those customers, the annual impacts are only $15.00 and $25.92 respectively. (see Appendix B, Table B4.1-1)

The Company also chose to make the percentage rate increases approximately equal in each of the three years. The percentage rate decreases vary from year to year depending on the revenue reallocated from the residential and irrigation classes.

4.2 Implementation

In order to simplify implementation over the three years, the Company proposes to calculate the rate changes each year based upon the revenues to be reallocated as set forth in Table 4.1-1. The Company further proposes the adjustments take place on January 1, 1998, January 1, 1999 and January 1, 2000. If the proposed adjustments are based upon the revenues to be reallocated as set forth in Table 4.1-1, then the required rate changes may vary from those set forth in Table 4.1-1 because of load variances from those assumed in the Application. However, given relative load stability, variances from the rate changes set forth in Table 4.1-1 are expected to be small.

5. NEW SERVICE OPTIONS

With this Application, the Company proposes two new service options. Every customer class, with the exception of lighting, has the option of a fully unbundled cost-based seasonally differentiated time of use rate. Such a rate is not applicable to the lighting class because this class is unmetered, and subject to automatic control through the use of photo cell controlled fixtures. In addition, every customer class, with the exception of lighting, has the option of a green power rate. These two new service options are described below.

5.1 Time of Use ("TOU") Rate

The time of use rate meets the first and third stated objective of this Application, that is, to provide customers with more choice and to provide customers with price signals that reflect trends in evolving electricity markets.

5.1.1 Pricing Periods

The starting point for the design of the time of use rate is the weather normalized 1996 hourly system load shape.

WKP's system exhibits two distinct peaks. The first peak occurs in the winter between November and February. This peak usually occurs on the coldest day of the year as electric heating loads climb in response to cold weather.

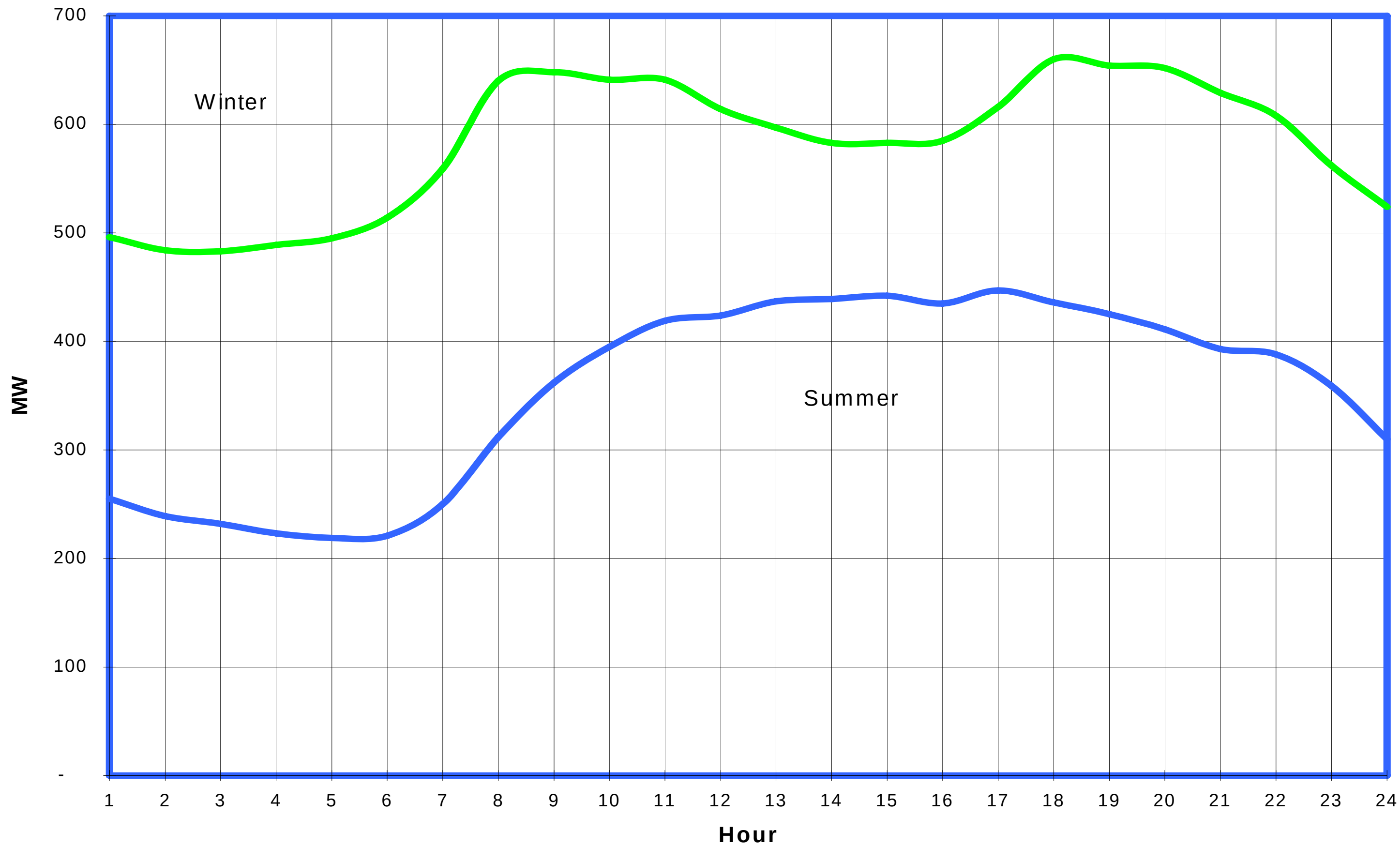
The second peak occurs in July or August and results from air conditioning loads. While the summer peak is not as high in absolute magnitude as the winter peak, its effect on constraining the capacity of transmission and some substation facilities is roughly equal to that of the winter peak. This occurs because the thermal capacity of these facilities is less in hot weather than it is in cold weather. Recognizing this phenomenon, transmission costs have been allocated according to each customer classes' contribution to the average of the winter and the summer peak in the 1997 UCOS.

Daily load shapes for the winter and summer peaks are show in Graph 5.2-1. From this graph it can be seen that the winter peak will be one of two separate peaks occurring either in the morning, or around 6:00 p.m. in the evening. The summer peak does not exhibit the same characteristics and occurs over a longer period of time between 10:00 a.m. and 9:00 p.m.

Considering the system load shape it was decided that three seasonal pricing periods were necessary, one for the July and August period ("summer period"), a second period from November to February ("winter period"), and the last being all other months ("shoulder period").

Within the three seasonal pricing periods the rate was further broken down between on-peak and off-peak hours. Based on the system load shape, winter on-peak hours are 7:00 a.m. to 12:00 p.m. and 4:00 p.m. to 10:00 p.m. business days; all other hours are off-peak. In the July August period, summer on-peak hours are 10:00 a.m. to 9:00 p.m. business days. The shoulder on-peak hours reflect the standard on-peak hours for market purchases.

Graph 5.2-1: Seasonal Peak Day Load Shapes



As far as the operating characteristics of WKP's delivery system are concerned, there is little daily variation in costs between on-peak and off-peak hours in shoulder and summer months. However, in order to reflect market conditions for the electricity commodity, the on-peak and off-peak hours in these periods were differentiated for costing purposes for the commodity only. All other costs were assumed to be spread pro-rata throughout the period.

The periods by season, as well as the corresponding on-peak hours and off-peak hours are shown in the following table.

Table 5.2-1: Pricing Periods

	On-Peak Hours	**Off-Peak Hours**
Winter (Nov. - Feb.)	7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays
Summer (July, August)	10:00 am - 9:00 pm business days	9:00 pm - 10:00 am All hours on weekends and statutory holidays
Shoulder (all other months)	6:00 am - 10:00 pm, Monday to Saturday	10:00 pm to 6:00 am - Monday to Saturday All day Sunday

5.1.2 Revenue Requirement Allocation Across Pricing Periods

Once the pricing periods had been determined, it was then necessary to assign components of the revenue requirement to the different revenue pricing periods. In this manner the total revenue requirement will be recovered over all hours in the pricing period. A summary of the revenue requirement by pricing period is shown in Table 5.2-2.

Power purchase costs were differentiated for each pricing period. WKP generation was not seasonally differentiated. Distribution costs were also not seasonally differentiated and are recovered on a pro-rata basis over all kilowatt hours in the year. Transmission costs were allocated one-half to on-peak hours in the summer months and one-half to on-peak hours in the winter months. Finally, customer related costs are recovered by a fixed monthly charge and are not seasonally differentiated.

Table 5.2-2: Functionalized Revenue Requirement by Pricing Periods for TOU Rates
($000s)

	Power Purchases On Peak Hours	Power Purchases Off Peak Hours	WKP Generation	Transmission	Substations	Distribution	Customer Costs	Total
January	$ 4,163	$ 1,641	$ 1,913	$ 2,655	$ 2,405	$ 765	$ 1,655	$ 15,197
February	3,728	1,143	1,913	2,655	2,405	765	1,655	14,264
March	1,580	968	1,913	-	-	765	1,655	6,881
April	813	1,564	1,913	-	-	765	1,655	6,710
May	201	1,517	1,913	-	-	765	1,655	6,051
June	201	1,357	1,913	-	-	765	1,655	5,891
July	201	1,452	1,913	5,312	-	765	1,655	11,298
August	168	1,785	1,914	5,312	-	765	1,655	11,599
September	291	1,613	1,914	-	-	766	1,655	6,239
October	1,151	1,239	1,914	-	-	765	1,659	6,728
November	4,157	1,225	1,914	2,655	2,405	765	1,655	14,776
December	4,047	1,424	1,914	2,655	2,405	765	1,655	14,865
	$ 20,701	$ 16,928	$ 22,961	$ 21,244	$ 9,620	$ 9,181	$ 19,864	$ 120,499

Summary of Functionalized Revenue Requirement by Pricing Periods

Winter	Peak Hours - Power Purchases	$ 16,095
	Off Peak Hours - Commodity	13,087
	Peak Hours - Transmission	10,620
	Winter Peak Hours - Substations	9,620
Summer	Commodity	7,433
	Transmission	10,624
Shoulder	Other Months Commodity	23,975
All Months	All Hours Distribution	9,181
	Customer Costs	19,864
	Total Revenue Requirement	$ 120,499

Once rates have been calculated based on the cost of service at each voltage level, they are further adjusted for losses. Finally, the rate for each customer class is differentiated by adjusting for the over or under recovery of costs that are included in the standard rate. These adjustments are shown in Appendix B beginning at Table B5.2-5.

Since the residential class under recovers costs by 9.5%, the resulting rate must be scaled down by this factor to be comparable with the standard rate. If this adjustment for under and over recovery of costs is not made, then residential customers would not take advantage of a time of use rate because, even if their load shape was exactly the same as the system, shifting to the time of use rate would result in a 9.5% cost increase. This results from losing the under recovery reflected in the standard rate.

Similarly, for industrial class customers, shifting to a time of use rate unadjusted for the 20% over recovery of costs would result in a 20% bill decrease. The purpose of the time of use rate is partly to give customers different service options, and partly to better reflect the cost of supply. Participating customers should not benefit from the TOU rate unless they have load shapes, or are capable of shaping their load, to be less costly to supply than others in the same class. As rate restructuring takes place and costs are reallocated among classes in each of the three years, the under and over recovery factors for the time of use rate must also be adjusted.

The resulting TOU rates for each customer class are shown in Table 5.2-3. A detailed tabulation of the calculation of these rates is found in Appendix B. Rate Schedules which recover the 1997 revenue requirement are found at tab, Tariff.

Table 5.2-3: Proposed TOU Rates by Class Before Restructuring

($ per kW.h)

Pricing Period	Residential (1)	General Service (20,21)	Large General Primary (30)	Large General Transm. (31)	Wholesale Primary (40)	Wholesale Transm. (41)	Irrigation (60)
Winter							
On Peak Hours	$ 0.10124	$ 0.12654	$ 0.11446	$ 0.08620	$ 0.10114	$ 0.07972	$ 0.08398
Off PeakHours	$ 0.02533	$ 0.03166	$ 0.02328	$ 0.02437	$ 0.02057	$ 0.02254	$ 0.02101
Summer							
On Peak Hours	$ 0.09742	$ 0.12178	$ 0.10988	$ 0.11498	$ 0.09709	$ 0.10635	$ 0.08081
Off PeakHours	$ 0.02104	$ 0.02631	$ 0.01814	$ 0.01898	$ 0.01603	$ 0.01756	$ 0.01746
Shoulder							
On Peak Hours	$ 0.02792	$ 0.03490	$ 0.02640	$ 0.02762	$ 0.02332	$ 0.02555	$ 0.02316
Off PeakHours	$ 0.01749	$ 0.02187	$ 0.01388	$ 0.01452	$ 0.01226	$ 0.01343	$ 0.01451
Customer							
per month	$ 18.97	$ 20.60	$ 1,127.20	$ 1,405.25	$ 2,383.19	$ 427.31	$ 22.51

A striking feature of these TOU rates is the differential between the summer on-peak and off-peak rate. For the irrigation class (Table B5.2-11), the on-peak summer rate is approximately eight cents per kilowatt-hour with the off-peak rate being about two cents per kilowatt-hour. This occurs because one-half of the transmission costs are allocated to a relatively small number of summer on-peak kilowatt-hours. The corresponding costs that are allocated to the winter period are spread over a much larger number of kilowatt-hours and the resulting rate differential is smaller. However, the existence of large differentials implies the opportunity for participating customers to make significant cost savings.

5.1.3 Revenue Shifts

If a customer is successful in moving their consumption from an on-peak period to an off-peak period, essentially two phenomena will occur. First, the commodity costs that WKP avoids because of the lower on-peak consumption will be reflected in a reduction in on-peak commodity costs, which will be matched in this cost-based rate by a reduction in on-peak commodity revenue. Therefore, this rate should have no impact on non-participating customers as a result of on-peak commodity costs.

The second impact occurs because some costs which are fixed in the short-term (capital costs such as substation and transmission equipment) are recovered in on-peak periods, and will not now be recovered. Therefore, this rate may impact non-participating customers in the short-term.

For instance, should an irrigation customer be successful in shifting load from the summer on-peak hours to the summer off-peak hours, transmission facilities will become less constrained, but there will be no difference in short-term total costs because the capital investment in the transmission system is fixed. In the long-term, when it is time to add new supply capabilities, this shift in consumption will result in lower total system costs.

In order to limit the short-term impacts on non-participating customers, the annual incremental customer participation in each class will be limited to 5% per annum of the previous year's total load for that customer class. In other words, a customer not on the TOU rate will not be able to utilize the TOU rate if in that year the total load of additional customers utilizing the rate exceeds 5% of the previous year's total load for that class.

The TOU rates will remain in effect for no less than three years from the date at which a customer chooses to participate. This gives the customer a minimum horizon over which to calculate the cost savings.

Customers opting for TOU must remain on the rate for a minimum of 12 consecutive months. This requirement is necessary to prevent rate hopping that can result in revenue loss, but no concomitant cost decrease.

5.1.4 Eligibility

Some customers will not be eligible for a TOU rate. The proposed TOU rate has no demand component. As a result, a customer who only requires power for a short period, perhaps in the shoulder months, will only be charged a small amount for his energy usage. This may not be enough to recover the cost of equipment installed to serve the customer. Another example would be a customer who takes power only for a short period on the winter peak. Again, the revenue collected would be small, but the cost impact due to power purchase commitments would be large. For this reason, the Company proposes to limit the applicability of TOU to customers with adequate load factors.

The proposed restriction (see TOU Tariffs, Applicable, lines 5 - 7) for customers with low load factors provides sufficient flexibility to meet the needs of participating customers while protecting the interests of non-participating customers.

5.1.5 Metering

All customers will require specialized metering to participate in the TOU rate. However, some customers currently have time of use metering. TOU metering is generally more expensive than standard metering. In order to participate, the customer must pay the incremental cost of the new metering. (see TOU Tariffs, Meter) The customer will have the option of paying this cost over time by a monthly surcharge on the bill. The meter will be financed based on the Company's weighted average cost of capital as approved by the Commission.

5.2 Green Power Rate

The green power rate meets the fourth stated objective of this Application, that is, to provide customers with an opportunity to support the development of environmentally desirable technologies. Customers have expressed a desire for rates that include a premium for power that was from “environmentally friendly” sources.

A green power rate may involve the installation of environmentally desirable generation technologies at the customer’s site. For instance, in Sacramento Municipal Utility District (“SMUD”) a flat monthly surcharge is placed on the customer’s bill. A photovoltaic array is then placed on site which generates electricity to offset the customer’s purchases from SMUD.

WKP is proposing a green power rate whereby participating customers would pay a premium of 1.5 cents per kW.h, and the Company would then purchase market energy that was generated by environmentally desirable technologies. Since, at least initially, the number of customers participating in such a service option may be small, WKP proposes to aggregate the premiums collected until a sufficient fund accumulated to provide an economic market purchase. As a result, it is possible that purchases from environmentally desirably technologies might not exactly match the energy consumption of participating customers.

The premium is the Company’s best estimate of the incremental cost of green power. By employing a rate premium reflective of the cost premium, the kilowatt-hours consumed by participating customers should be closely matched by kilowatt-hours purchased from environmentally desirable technologies. Provided that the market premium for green power remains stable over time, then the premiums paid by participating customers will be equal to the incremental cost of green purchases and green customers' kW.h use will be close to green kW.h purchases. However, the premium may need to be adjusted from time to time depending on the market premium for green power.

The premium collected for green power will be calculated as the difference between the price paid in the market for green power and average embedded commodity costs. The number of kilowatt-hours purchased would depend on the premium collected. Therefore, in the long-term, non-participating customers should not be impacted by the green power rate.

If in the future, there is sufficient participation in the green power rate to justify long-term commitments to developers of green facilities, the Company will file revised proposals at that time. However, at this time, in order to reduce the risk of long-term commitments and to minimize the administrative burden with the initial introduction of the rate, the proposal is to apply green power rates to market power purchases only.

5.2.1 Green Resources

There is much controversy as to what constitutes a "green" resource. Some argue that all hydroelectric generation is renewable and therefore "green". Others argue that since large scale hydro impacts fisheries and wildlife habitat, it is not green.

In order to avoid the controversy and gain acceptance of the rate, WKP will limit green resources to (1) small run of river hydro, less than 20 MW, (2) geothermal, (3) solar, (4) wind, and (5) biomass.

SCHEDULE 1 - RESIDENTIAL SERVICE

APPLICABLE:

To residential use including service to incidental motors of 5 HP or less.

BIMONTHLY RATE: Basic Charge $13.34 per period
First 6000 kW.h @ 5.121¢ per kW.h
All kW.h above 6000 @ 5.905¢ per kW.h

DISCOUNT: 10% if paid on or before the date shown on each bill.

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SCHEDULE 2 - RESIDENTIAL SERVICE - TIME OF USE

APPLICABLE: To residential use including service to incidental motors of 5 HP or less. This rate is not applicable where, in the Company's opinion, the Customer's load factor is unacceptably low. Service under this Schedule is for a minimum of 12 consecutive months.

ENERGY CHARGES (¢ per kW.h)

	Commodity Charge	Transmission Charge	Distribution Charge	Total Charge
WINTER RATE				
On-Peak Hours	4.132	2.726	3.266	10.124
Off-Peak Hours	1.939	0.000	0.594	2.533
SUMMER RATE				
On-Peak Hours	2.385	6.763	0.594	9.742
Off-Peak Hours	1.510	0.000	0.594	2.104
SHOULDER RATE				
On-Peak Hours	2.198	0.000	0.594	2.792
Off-Peak Hours	1.155	0.000	0.594	1.749

plus:

CUSTOMER CHARGE: $18.97 per month

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SCHEDULE 2 - RESIDENTIAL SERVICE - TIME OF USE (Cont'd)

DEFINITIONS:

Pricing Periods

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

METER: The Company's contribution to the cost of the meter will be limited to an amount equivalent to the cost of a standard meter.

OVERDUE ACCOUNTS: A late payment charge of 1½% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

SCHEDULE 3 - RESIDENTIAL SERVICE - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 1, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 1 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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 4 - RESIDENTIAL SERVICE - TIME OF USE - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 2, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 2 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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 20 - SMALL GENERAL 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.

BI-MONTHLY WINTER RATE: For a two month period

First	16000 kW.h	5.539¢ per kW.h
Next	184000 kW.h	4.316¢ per kW.h
Balance		3.286¢ per kW.h

BI-MONTHLY SUMMER RATE: For a two month period

First	16000 kW.h	5.225¢ per kW.h
Next	184000 kW.h	4.160¢ per kW.h
Balance		2.921¢ per kW.h

plus

BASIC CHARGE: $18.30 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 1½% 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 1½% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

DEFINITIONS: Winter months are the billing months of November of one year to March of the following year, inclusive.

Summer months are the billing months of April to October of the same year, inclusive.

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SCHEDULE 21 - GENERAL 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 WINTER RATE: A Demand Charge of:

$4.50 per kW of "Billing Demand" above 40 kW

plus

An Energy Charge of:

First	8000 kW.h	5.539¢ per kW.h
Next	92000 kW.h	4.316¢ per kW.h
Balance		3.286¢ per kW.h

MONTHLY SUMMER RATE: A Demand Charge of:

$4.50 per kW of "Billing Demand" above 40 kW

plus

An Energy Charge of:

First	8000 kW.h	5.225¢ per kW.h
Next	92000 kW.h	4.160¢ per kW.h
Balance		2.921¢ per kW.h

plus

CUSTOMER CHARGE: $9.15 per month

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SCHEDULE 21 - GENERAL SERVICE: (Cont'd)

"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 winter months in the previous eleven month period, or
(d) Twenty-five per cent (25%) of the maximum demand in kW registered during the summer months in the previous eleven month period.

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 40.8¢ per kVA
$4.50 per kW shall become $4.08 per kVA

where used in this Schedule.

DEFINITIONS: Winter months are the billing months of November of one year to March of the following year, inclusive.

Summer months are the billing months of April to October of the same year, inclusive.

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 22 - GENERAL SERVICE - TIME OF USE

APPLICABLE: To non-residential Customers whose electrical demand is 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. This rate is not applicable where, in the Company's opinion, the Customer's load factor is unacceptably low. Service under this Schedule is for a minimum of 12 consecutive months.

ENERGY CHARGES: (¢ per kW.h)

	Commodity Charge	Transmission Charge	Distribution Charge	Total Charge
WINTER RATE				
On-Peak Hours	5.165	3.408	4.082	12.655
Off-Peak Hours	2.423	0.000	0.743	3.166
SUMMER RATE				
On-Peak Hours	2.981	8.453	0.743	12.177
Off-Peak Hours	1.888	0.000	0.743	2.631
SHOULDER RATE				
On-Peak Hours	2.747	0.000	0.743	3.490
Off-Peak Hours	1.444	0.000	0.743	2.187

plus:

CUSTOMER CHARGE: $20.60 per month

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SCHEDULE 22 - GENERAL SERVICE - TIME OF USE (Cont'd)

DEFINITIONS:

Pricing Periods

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

METER: The Company's contribution to the cost of the meter will be limited to an amount equivalent to the cost of a standard meter.

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 23 - SMALL GENERAL SERVICE - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 20, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 20 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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 24 - GENERAL SERVICE - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 21, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 21 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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 25 - GENERAL SERVICE - TIME OF USE - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 22, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 22 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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 30 - LARGE GENERAL SERVICE - PRIMARY

APPLICABLE: To power service to Customers for a contract demand of 500 kVA or more, subject to written agreement.

WINTER RATE: A Demand Charge of:

$4.35 per kVA of "Billing Demand".

plus

An Energy Charge of:

3.229¢ per kW.h

SUMMER RATE: A Demand Charge of:

$4.35 per kVA of "Billing Demand".

plus

An Energy Charge of:

2.874¢ 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 winter months in the previous eleven month period, or

(d) twenty-five percent (25%) of the maximum demand in kW registered during the summer months in the previous eleven month period.

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SCHEDULE 30 - LARGE GENERAL 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 40.8¢ 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.

DEFINITIONS: Winter months are the billing months of November of one year to March of the following year, inclusive.

Summer months are the billing months of April to October of the same year, inclusive.

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 GENERAL SERVICE - TRANSMISSION

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 Customers with loads of 5,000 kVA or more, subject to written agreement.

MONTHLY RATE: A Demand Charge of:

$3.61 per kVA of "Billing Demand"

plus

An Energy Charge of:

3.352¢ per kW.h for first 100 kW.h per kVA of "Billing Demand"

2.451¢ per kW.h for balance of monthly consumption.

"Billing Demand"

The greatest of:

(a) 80% of the Contract Demand, or
(b) The maximum demand in kVA for the current billing month; or
(c) 80% of the maximum demand in kVA recorded during the billing months of November of one year to March of the following year inclusive in 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 32 - LARGE GENERAL SERVICE - PRIMARY - TIME OF USE

APPLICABLE: To power service to Customers for a contract demand of 500 kVA or more, subject to written agreement. This rate is not applicable where, in the Company's opinion, the Customer's load factor is unacceptably low. Service under this Schedule is for a minimum of 12 consecutive months.

ENERGY CHARGES: (¢ per kW.h)

	Commodity Charge	Transmission Charge	Substation Charge	Total Charge
WINTER RATE				
On-Peak Hours	4.963	3.275	3.209	11.447
Off-Peak Hours	2.328	0.000	0.000	2.328
SUMMER RATE				
On-Peak Hours	2.865	8.123	0.000	10.988
Off-Peak Hours	1.814	0.000	0.000	1.814
SHOULDER RATE				
On-Peak Hours	2.640	0.000	0.000	2.640
Off-Peak Hours	1.388	0.000	0.000	1.388

plus:

CUSTOMER CHARGE: $1,127.20 per month

SCHEDULE 32 - LARGE GENERAL SERVICE - PRIMARY - TIME OF USE (Cont'd)

DEFINITIONS:

Pricing Periods

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

METER: The Company's contribution to the cost of the meter will be limited to an amount equivalent to the cost of a standard meter.

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 GENERAL 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 not applicable where, in the Company's opinion, the Customer's load factor is unacceptably low. Service under this Schedule is for a minimum of 12 consecutive months.

ENERGY CHARGES: (¢ per kW.h)

	Commodity Charge	Transmission Charge	Distribution Charge	Total Charge
WINTER RATE				
On-Peak Hours	5.193	3.427	0.000	8.620
Off-Peak Hours	2.437	0.000	0.000	2.437
SUMMER RATE				
On-Peak Hours	2.998	8.500	0.000	11.498
Off-Peak Hours	1.898	0.000	0.000	1.898
SHOULDER RATE				
On-Peak Hours	2.762	0.000	0.000	2.762
Off-Peak Hours	1.452	0.000	0.000	1.452

plus:

CUSTOMER CHARGE: $1,405.25 per month

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SCHEDULE 33 - LARGE GENERAL SERVICE - TRANSMISSION - TIME OF USE (Cont'd)

DEFINITIONS:

Pricing Periods

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

METER: The Company's contribution to the cost of the meter will be limited to an amount equivalent to the cost of a standard meter.

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 34 - LARGE GENERAL SERVICE - PRIMARY - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 30, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 30 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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 35 - LARGE GENERAL SERVICE - PRIMARY - TIME OF USE - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 32, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 32 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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 36 - LARGE GENERAL SERVICE - TRANSMISSION - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 31, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 31 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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 37 - LARGE GENERAL SERVICE - TRANSMISSION - TIME OF USE - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 33, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 33 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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 - WHOLESALE SERVICE - PRIMARY

APPLICABLE: To power service to Grand Forks, Kelowna, Penticton, Princeton, Summerland, Lardeau and Yahk. To service at a primary voltage for resale, subject to written agreement.

MONTHLY RATE: A Demand Charge of:

$4.92 per kVA of "Billing Demand"

plus

An Energy Charge of:

2.419¢ 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 winter months in the previous eleven month period, or

(d) twenty-five percent (25%) of the maximum demand in kVA registered during the summer months in the previous eleven month period.

DEFINITIONS: Winter months are the billing months of November of one year to March of the following year, inclusive, or

Summer months are the billing months of April to October of the same year, inclusive.

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 41 - WHOLESALE SERVICE - TRANSMISSION

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.

MONTHLY RATE: A Demand Charge of:

$4.92 per kVA of "Billing Demand"

plus

An Energy Charge of:

2.419¢ per kW.h

minus

(a) A discount of 1 1/2% of the above rate if metered at transmission line voltage.

(b) A discount of 40.8¢ per kVA of "Billing Demand" for supply at transmission line voltage.

(c) If both discounts apply, the discount applicable to the metering at transmission line voltage is to be applied first.

"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 winter months in the previous eleven month period, or

(d) twenty-five percent (25%) of the maximum demand in kW registered during the summer months in the previous eleven month period.

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SCHEDULE 41 - WHOLESALE SERVICE - TRANSMISSION (Cont'd)

DEFINITIONS: Winter months are the billing months of November of one year to March of the following year, inclusive, and

Summer months are the billing months of April to October of the same year, inclusive.

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.

The Company will charge the City of Nelson $200 each time the City of Nelson requests such additional power for such emergency or shutdown.

SCHEDULE 42 - WHOLESALE SERVICE - PRIMARY -TIME OF USE

APPLICABLE: To power service to Grand Forks, Kelowna, Penticton, Princeton, Summerland, Lardeau and Yahk. To service at a primary voltage for resale, subject to written agreement. This rate is not applicable where, in the Company's opinion, the Customer's load factor is unacceptably low. Service under this Schedule is for a minimum of 12 consecutive months.

ENERGY CHARGES: (¢ per kW.h)

	Commodity Charge	Transmission Charge	Substation Charge	Total Charge
WINTER RATE				
On-Peak Hours	4.385	2.893	2.835	10.113
Off-Peak Hours	2.057	0.000	0.000	2.057
SUMMER RATE				
On-Peak Hours	2.531	7.178	0.000	9.709
Off-Peak Hours	1.603	0.000	0.000	1.603
SHOULDER RATE				
On-Peak Hours	2.332	0.000	0.000	2.332
Off-Peak Hours	1.226	0.000	0.000	1.226

plus:

CUSTOMER CHARGE: $2,383.19 per month

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SCHEDULE 42 - WHOLESALE SERVICE - PRIMARY - TIME OF USE: (Cont'd)

DEFINITIONS:

Pricing Periods

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

METER: The Company's contribution to the cost of the meter will be limited to an amount equivalent to the cost of a standard meter.

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 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 not applicable where, in the Company's opinion, the Customer's load factor is unacceptably low. Service under this Schedule is for a minimum of 12 consecutive months.

ENERGY CHARGES: (¢ per kW.h)

	Commodity Charge	Transmission Charge	Substation Charge	Total Charge
WINTER RATE				
On-Peak Hours	4.803	3.169	0.000	7.972
Off-Peak Hours	2.254	0.000	0.000	2.254
SUMMER RATE				
On-Peak Hours	2.773	7.862	0.000	10.635
Off-Peak Hours	1.756	0.000	0.000	1.756
SHOULDER RATE				
On-Peak Hours	2.555	0.000	0.000	2.555
Off-Peak Hours	1.343	0.000	0.000	1.343

plus:

CUSTOMER CHARGE: $427.31 per month

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SCHEDULE 43 - WHOLESALE SERVICE - TRANSMISSION - TIME OF USE (Cont'd)

DEFINITIONS:

Pricing Periods

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

METER: The Company's contribution to the cost of the meter will be limited to an amount equivalent to the cost of a standard meter.

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 44 - WHOLESALE SERVICE - PRIMARY - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 40, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 40 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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 45 - WHOLESALE SERVICE- PRIMARY - TIME OF USE - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 42, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 42 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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 46 - WHOLESALE SERVICE - TRANSMISSION - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 41, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 41 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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 47 - WHOLESALE SERVICE - TRANSMISSION - TIME OF USE - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 43, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 43 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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 - STREET LIGHTING

APPLICABLE : In all areas served by the Company to Municipal, Provincial and other forms of government and to community associations.

To lighting of streets, alleys and other public thoroughfares where the Customer will contract for service for a term of five years for Customer-owned street lighting fixtures and until terminated as below for Company-owned street lighting fixtures. The Company will supply service for street lighting from dusk to dawn daily.

SPECIFICATIONS: All street lighting equipment installed on and after the effective date of this Schedule will be Customer-owned and Company approved and be suitable to accept electrical service at the Company's available secondary voltage. Other requirements may be supplied under special contract.

All new and replacement street lighting fixtures shall be high pressure sodium vapour.

TYPES OF SERVICE:

1. Customer-Owned and Customer-Maintained

Type I - For a Customer-owned street lighting fixture or system where the Customer owns, installs and maintains at his own expense the light standards, light 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. 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.

2. Customer-Owned and Company Maintained

Type II - Customer-owned street lighting fixtures installed by the Company at the Customer's expense with all maintenance to be performed by the Company.

SCHEDULE 50 - STREET LIGHTING (Cont'd)

TYPES OF SERVICE: (Cont'd)

3. Company-Owned, Company-Installed and Maintained

Type III - (No new service on and after the effective date of this Schedule). For Company-owned street lighting fixtures on Company-owned poles where the Company performs all maintenance.

TERMS AND CONDITIONS: Installation

Type II 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, street lighting fixtures and standards, where required, of approved design and specifications at its laid-down cost plus 15% for overheads and handling costs.

Extension of Service

(a) Overhead Supply

If street lights are to be located where there are no suitable existing poles and/or supply circuits, the overhead supply circuit will be extended for service under this Schedule at the Customer's expense, it being understood that the facilities so installed and paid for by the Customer will be owned and maintained by the Company.

(b) Underground

The Company will install and maintain at the Customer's expense, all underground facilities required to supply Type II street lights, it being understood that the facilities so installed and paid for by the Customer will be owned by the Company.

SCHEDULE 50 - STREET LIGHTING (Cont'd)

TERMS AND CONDITIONS: (Cont'd)

Relocation

At the Customer's request, the location of a street light may be changed providing the Customer agrees to pay for the cost of removal and reinstallation including cost of extension of service if applicable.

Maintenance

(a) Routine Maintenance

Routine maintenance to the lamp, ballast, fuse and photoelectric cell of Type II and 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.

(b) Non-Routine Maintenance

The cost of non-routine repairs or replacements made to Type II or Type III fixtures (or parts thereof), will be to the Customer's account and will be billed as incurred.

TERMINATION: Company-owned service may be terminated by mutual agreement by the Customer and the Company, and subject to the following conditions; service may be terminated in whole or in part at any time on the condition that the Customer pays the installed cost, plus cost of removal, less salvage value, and less accrued annual depreciation at 5% of these facilities abandoned which are owned by the Company and which are solely for street lighting service.

SCHEDULE 50 - STREET LIGHTING (Cont'd)

MONTHLY RATE FOR EACH
TYPE OF SERVICE:

		Rate ($ per month)			
		Nominal	Customer-Owned		*Company-Owned
Type of Light	Watts	Lumens	Type I	Type II	Type III
Fluorescent	* 383	21,800	8.45		
Mercury Vapour	* 125	5,000	3.30	4.93	9.78
Open Type	* 175	7,000	4.76	6.40	9.89
	* 175	7,000	4.76	6.40	10.96
	* 250	10,000	6.45	8.13	12.78
	* 400	21,000	10.05	11.76	18.03
Sodium Vapour	70	6,000	1.98	4.64	9.66
	100	9,000	2.87	5.52	10.61
	150	14,000	4.22	6.42	11.75
	200	20,000	5.45	7.95	13.72
	250	23,000	6.70	9.22	14.94
	400	45,000	10.49	13.00	19.61

* No longer available at new locations or as replacement fixtures where existing fixtures are being replaced except at the sole discretion of the Company.

For fixtures with lamp rating different from those as set out above, the monthly rate shall be 2.23¢ per watt of the rating of the lamp and the ballast.

Service to Customer-owned decorative lighting is available under this Schedule to street lighting Customers where such decorative lighting has been approved and is attached to existing street lighting standards or fixtures. For periods of operation from dusk to dawn the monthly rate is 2.23¢ per watt of rating of the lamps and for 24-hour operation, the monthly rate is 4.46¢ per watt of the rating of the lamps plus ballast.

NO DISCOUNT:

OVERDUE ACCOUNTS: A late payment charge of 1.5% (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 51 - OUTDOOR-LIGHT

APPLICABLE: To off-street lighting by means of a Company-owned luminaire with a nominal rated luminosity of approximately 5000 lumens. The luminaire will be mounted on a Company installed pole in an approved location. If a new pole is required, it shall be paid for by the Customer and become the property of the Company.

HOURS OF LIGHTING: From one-half hour after sunset until one-half hour before sunrise as controlled by a photo-electric cell.

NEW FACILITIES: The Company may provide one span of duplex of not more than 30 metres. All additional extension required shall be at the Customer's expense.

OWNERSHIP: Facilities provided by the Company, including fixtures, lamp, control relay, support bracket, and conductor and energy for operation thereof are owned by the Company.

MAINTENANCE: All necessary repairs to the Company's property, including lamp renewal, will be performed by the Company at its expense. Maintenance will be conducted during regular working hours and the Company may be allowed five working days subsequent to notification by the Customer for performance of such maintenance. The Customer shall be responsible for any wilful damage to the Company's equipment.

RATE: Flat rate per lamp, which includes electrical energy, shall be added to and payable with the Customer's regular electric service accounts.

one month period	$11.10
two month period	$22.20

For Installations Completed on Company Owned Poles Prior to July 1, 1991

one month period	$13.71
two month period	$27.42

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 60 - IRRIGATION AND DRAINAGE

APPLICABLE: 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 general service rate and billings prorated for a partial first or final service month when read dates are outside of the 5 day band.

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.

RATE: During the Irrigation Season

Basic Monthly Charge:	$9.15
All Energy:	3.169¢ per kW.h

During the Non-Irrigation Season

Customers will be transferred to the applicable general 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.

SCHEDULE 62 - IRRIGATION AND DRAINAGE - TIME OF USE

APPLICABLE: 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 general service rate and billings prorated for a partial first or final service month when read dates are outside of the 5 day band. 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. This rate is not applicable where, in the Company's opinion, the Customer's load factor is unacceptably low. Service under this Schedule is for a minimum of 12 consecutive months.

ENERGY CHARGES: (¢ per kW.h)

	Commodity Charge	Transmission Charge	Distribution Charge	Total Charge
WINTER RATE				
On-Peak Hours	3.427	2.261	2.709	8.397
Off-Peak Hours	1.608	0.000	0.493	2.101
SUMMER RATE				
On-Peak Hours	1.979	5.610	0.493	8.082
Off-Peak Hours	1.253	0.000	0.493	1.746
SHOULDER RATE				
On-Peak Hours	1.823	0.000	0.493	2.316
Off-Peak Hours	0.958	0.000	0.493	1.451

plus:

CUSTOMER CHARGE: $22.51 per month

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SCHEDULE 62 - IRRIGATION AND DRAINAGE - TIME OF USE (Cont'd)

DEFINITIONS:

Pricing Periods

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

METER: The Company's contribution to the cost of the meter will be limited to an amount equivalent to the cost of a standard meter.

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 63 - IRRIGATION AND DRAINAGE - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 60, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 60 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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 64 - IRRIGATION AND DRAINAGE - TIME OF USE - GREEN POWER

APPLICABLE: On the same terms applicable to rate Schedule 62, for the purchase of electricity from environmentally desirable technologies.

RATE: In addition to all charges on rate Schedule 62 an additional charge, net of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

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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Table B4.1-1: Residential (1) Rate Restructuring at Current Rates

Historical Billed Consumption (ex. unbilled use)

	1995		1996		Combined	
First 6000 kwh	879	93.61%	923	92.58%	1,802	93.08%
all Else	60	6.39%	74	7.42%	134	6.92%
	939	100.00%	997	100.00%	1,936	100.00%

	1997 at Current Rates			Year One			Year Two			Year Three		
	Average Customers	Net Rate	Revenue ($000s)	Average Customers	Net Rate	Revenue ($000s)	Average Customers	Net Rate	Revenue ($000s)	Average Customers	Net Rate	Revenue ($000s)
Customer Charge	74,094	$ 12.00	**$ 5,335**	74,094	$ 12.50	**$ 5,557**	74,094	$ 15.00	**$ 6,668**	74,094	$ 19.32	**$ 8,589**
Energy												
First 6000 kW.h	890	$0.04609	$ 41,020	890	$0.04800	$42,720	890	$0.04900	$ 43,610	890	$0.04900	$ 43,610
All Else	66	$0.05315	$ 3,508	66	$0.05130	$ 3,386	66	$0.04900	$ 3,234	66	$0.04900	$ 3,234
	956		**$ 44,528**	956		**$46,106**	956		**$ 46,844**	956		**$ 46,844**
Discount Forefeit 1.79%			**$ 893**			**$ 925**			**$ 958**			**$ 992**
Other Revenues			**$ 797**			**$ 797**			**$ 797**			**$ 797**
Revenue from Rates			**$ 51,553**			**$53,385**			**$ 55,267**			**$ 57,222**
Percent Impact on Customers						**3.55%**			**3.53%**			**3.54%**
Restructuring Revenue			**701**			**0**			**-701**			**0**
Total Revenue			**$ 52,254**			**$53,385**			**$ 54,566**			**$ 57,222**
Revenue Change						**$ 1,131**			**$ 1,181**			**$ 2,656**
Percent Change in Total Revenue						**2.16%**			**2.21%**			**4.87%**

Note: (1) 1997 Revenue and consumption per 1997 Revenue Requirements, December 12, 1996, page 11.
(2) The maximum customer impact in phase one is 4.1% for a customer consuming exactly 6000 kW.h bimonthly. All other increases are less.
(3) In the last two phases the highest percentage increases are for zero consumption. The respective annual increases are $15.00 and $25.92.
(4) Revenue from rates shows the impact on the customers' bills, which is different from the Total Revenue due to the restructuring revenue accrued in 1997 and ultimately collected from customers in 1999.

Table B4.1-2: General Service (20, 21) Rate Restructuring at Current Rates

Monthly Rate:		Winter	Summer	Energy (GW.h) Winter	Energy (GW.h) Summer	Revenue ($000s) Winter	Revenue ($000s) Summer	Total
First 8000	kW.h	$ 0.05539	$ 0.05225	91	122	$ 5,040	$ 6,375	$ 11,415
Next 92000	kW.h	$ 0.04316	$ 0.04160	88	113	$ 3,798	$ 4,701	$ 8,499
Balance		$ 0.03286	$ 0.02921	10	17	$ 329	$ 497	$ 826
				189	252	$ 9,167	$ 11,573	$ 20,740

Revenue from the Basic Charge	**$ 9.15**	**891**
Accrued restructuring Revenue		**558**
Demand and other revenue		**2,408**
Total Revenue at Current Rates		**$ 24,597**

2

Table B4.1-3: General Service (20, 21) Rate Restructuring Year One

Monthly Rate:			Winter	Summer	Energy (GW.h) Winter	Energy (GW.h) Summer	Revenue ($000s) Winter	Revenue ($000s) Summer	Total
First	8000	kW.h	$ 0.05500	$ 0.05225	91	122	$ 5,005	$ 6,375	$ 11,380
Next	92000	kW.h	$ 0.04316	$ 0.04160	88	113	$ 3,798	$ 4,701	$ 8,499
	Balance		$ 0.03286	$ 0.02921	10	17	$ 329	$ 497	$ 826
					189	252	$ 9,132	$ 11,573	$ 20,705

Revenue from the Basic Charge	$ 9.52	927
Demand and other revenue		2,408
Sub Total		$ 24,040
less: Restructuring Revenue		-149
Revenue for rate Design Purposes		$ 23,891
Decreased Revenue		-$ 706
Percentage		-2.87%

3

Table B4.1-4: General Service (20, 21) Rate Restructuring Year Two

	Monthly Rate:		Winter	Summer	Energy (GW.h) Winter	Energy (GW.h) Summer	Revenue ($000s) Winter	Revenue ($000s) Summer	Total
First	8000	kW.h	$ 0.05170	$ 0.05170	91	122	$ 4,705	$ 6,307	$ 11,012
Next	92000	kW.h	$ 0.04160	$ 0.04160	88	113	$ 3,661	$ 4,701	$ 8,362
	Balance		$ 0.03286	$ 0.03286	10	17	$ 329	$ 559	$ 888
					189	252	$ 8,695	$ 11,567	**$ 20,262**

Revenue from the Basic Charge	**$ 9.90**	**964**
Demand and other revenue		**2,408**
Total Revenue at Proposed Rates		**$ 23,634**
less: Restructuring Revenue		**-409**
Revenue for rate Design Purposes		**$ 23,225**
Decreased Revenue		**-$ 666**
Percentage		**-2.71%**

4

Table B4.1-5: General Service (20, 21) Rate Restructuring Year Three

Monthly Rate:			Winter	Summer	Energy (GW.h) Winter	Energy (GW.h) Summer	Revenue ($000s) Winter	Revenue ($000s) Summer	Total
First	8000	kW.h	$ 0.04900	$ 0.04900	91	122	$ 4,459	$ 5,978	$ 10,437
Next	92000	kW.h	$ 0.03410	$ 0.03410	88	113	$ 3,001	$ 3,853	$ 6,854
	Balance		$ 0.03410	$ 0.03410	10	17	$ 341	$ 580	$ 921
					189	252	$ 7,801	$ 10,411	**$ 18,212**

Revenue from the Basic Charge	**$ 10.30**	**1,003**
Demand and other revenue		**2,408**
Total Revenue at Proposed Rates		**$ 21,623**
less: Restructuring Revenue		**0**
Revenue for rate Design Purposes		**$ 21,623**
Decreased Revenue		**-$ 1,602**
Percentage		**-6.51%**

Table B4.1-6: Wholesale Rate Restructuring

Wholesale - Primary (40)

		Current Rates Rate	Current Rates Revenue ($000s)	Year One Rate	Year One Revenue ($000s)	Year Two Rate	Year Two Revenue ($000s)	Year Three Rate	Year Three Revenue ($000s)
Customers	7	$ -	$ -	$ 2,500.00	$ 210	$ 2,500.00	$ 210	$ 2,500.00	$ 210
Energy (GW.h)	797	$ 0.02419	19,279	$ 0.02409	19,200	$ 0.02400	19,128	$ 0.02387	19,024
Demand (kVA)	1,740,000	$ 4.92	8,542	4.8	8,333	$ 4.80	8,333	$ 4.80	8,333
			$ 27,821		$ 27,743		$ 27,671		$ 27,567

Wholesale - Transmission (41)

		Current Rates Rate	Current Rates Revenue	Year One Rate	Year One Revenue	Year Two Rate	Year Two Revenue	Year Three Rate	Year Three Revenue
Customers	1	$ -	$ -	$ 2,500.00	$ 30	$ 2,500.00	$ 30	$ 2,500.00	$ 30
Energy (GW.h)	65	$ 0.02383	1,549	$ 0.02373	1,542	$ 0.02364	1,537	$ 0.02342	1,522
Demand (kVA)	220,000	$ 4.44	977	$ 3.98	876	$ 3.63	799	$ 2.87	631
			$ 2,526		$ 2,448		$ 2,366		$ 2,183

	Current Rates	Year One	Year Two	Year Three
Total Wholesale	$ 30,347	$ 30,191	$ 30,037	$ 29,750
Change in Transmission		$ (78)	$ (82)	$ (183)
Change in Primary		$ (78)	$ (72)	$ (104)
Percent Change Transmission		-3.09%	-3.35%	-7.73%
Percent ChangePrimary		-0.28%	-0.26%	-0.38%

Table B4.1-7: Large General Service - Primary (30) Rate Restructuring

		1997 at Current Rates		Year One		Year Two		Year Three	
		Rate	Revenue ($000s)	Rate	Revenue ($000s)	Rate	Revenue ($000s)	Rate	Revenue ($000s)
Customers	34	$ -	$ -	$ 1,500.00	$ 612	$ 1,500.00	$ 612	$ 1,500.00	$ 612
Summer Energy (GW.h)	99	$ 0.02874	2,845	$ 0.02585	2,559	$ 0.02465	2,440	$ 0.02295	2,272
Winter Energy (GW.h)	80	$ 0.03229	2,583	$ 0.02585	2,068	$ 0.02465	1,972	$ 0.02295	1,836
Total	179								
Annual Demand (kVA)	560,000	$ 4.35	2,442	4.35	2,442	$ 4.27	2,397	$ 3.92	2,201
			$ 7,870		$ 7,681		$ 7,421		$ 6,921
Change in Revenue					$ (189)		$ (260)		$ (500)
Percentage					-2.40%		-3.38%		-6.74%

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Table B4.1-8: Large General Service - Transmission (31) Rate Restructuring

		1997 at Current Rates		Year One		Year Two		Year Three	
		Rate	Revenue ($000s)	Rate	Revenue ($000s)	Rate	Revenue ($000s)	Rate	Revenue ($000s)
Customers	3	$ -	$ -	$ 1,500.00	$ 54	$ 1,500.00	$ 54	$ 1,500.00	$ 54
Block 1 Energy (GW.h)	27	$ 0.03352	905	$ 0.02548	688	$ 0.02428	656	0.02261	610
Block 2 Energy (GW.h)	33	$ 0.02451	809	$ 0.02548	841	$ 0.02428	801	0.02261	746
Total	60								
Annual Demand (kVA)	270,000	$ 3.61	954	3.59	975	$ 3.37	916	$ 2.70	735
			$ 2,668		$ 2,558		$ 2,427		$ 2,145
Change in Revenue					$ (110)		$ (131)		$ (282)
Percentage					-4.12%		-5.12%		-11.62%

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Table B4.1-9: Lighting (50, 51) Rate Restructuring

	Revenue at Current Rates	Year One Revenue	Year Two Revenue	Year Three Revenue
Lighting	$ 1,380	$ 1,355	$ 1,329	$ 1,276
Revenue Change		$ (25)	$ (26)	$ (53)
% Change		-1.85%	-1.96%	-4.15%

Table B4.1-10: Irrigation (60) Rate Restructuring

	Revenue at Current Rates	Year One Revenue	Year Two Revenue	Year Three Revenue
Irrigation	$ 1,383	$ 1,438	$ 1,496	$ 1,556
Revenue Change		$ 55	$ 58	$ 60
% Change		4.00%	4.00%	4.00%

Table B5.2-1: Derivation of the Winter TOU Rate

(Rates expressed per kW.h at System Input Level)

	Supply at Secondary Distribution Voltage		Supply at Primary Distribution Voltage		Supply at Trans-mission Voltage	
All Year Distribution	$	0.00558	$	-	$	-
Winter On-Peak Commodity						
Cost (000s)	$	16,095	$	16,095	$	16,095
MW.h		414,778		414,778		414,778
Rate per kW.h	$	0.03880	$	0.03880	$	0.03880
Winter Off-Peak Commodity						
Cost (000s)	$	13,087	$	13,087		13,087
MW.h		718,814		718,814		718,814
Rate per kW.h	$	0.01821	$	0.01821	$	0.01821
Winter On-Peak Transmission						
Cost (000s)	$	10,620	$	10,620	$	10,620
MW.h		414,778		414,778		414,778
Rate per kW.h	$	0.02560	$	0.02560	$	0.02560
Winter On-Peak Substation						
Cost (000s)	$	9,620	$	9,620		
MW.h		383,407		383,407		
Rate per kW.h	$	0.02509	$	0.02509		
Rate Summary						
On Peak	$	0.09508	$	0.08950	$	0.06441
Off Peak	$	0.02379	$	0.01821	$	0.01821
Rate Components						
On Peak						
Commodity	$	0.03880	$	0.03880	$	0.03880
All Else	$	0.05628	$	0.05069	$	0.02560
Off Peak						
Commodity	$	0.01821	$	0.01821	$	0.01821
All Else	$	0.00558	$	-	$	-

Table B5.2-2: Derivation of the Summer TOU Rate

(Rates expressed per kW.h at System Input Level)

	Supply at Secondary Distribution Voltage		Supply at Primary Distribution Voltage		Supply at Transmission Voltage	
All Year Distribution	$	0.00558	$	-	$	-
On Peak Commodity						
Cost (000s)	$	7,433	$	7,433	$	7,433
MW.h		427,158		427,158		427,158
Rate per kW.h	$	0.01740	$	0.01740	$	0.01740
Off Peak Commodity						
Cost (000s)						
MW.h						
Rate per kW.h	$	0.01740	$	0.01740	$	0.01740
On Peak Transmission						
Cost (000s)	$	10,624	$	10,624	$	10,624
MW.h		167,269		167,269		167,269
Rate per kW.h	$	0.06351	$	0.06351	$	0.06351
Rate Summary						
On Peak Hours	$	0.08650	$	0.08092	$	0.08092
Off Peak Hours	$	0.02298	$	0.01740	$	0.01740
Rate Components						
On Peak						
Commodity	$	0.01740	$	0.01740	$	0.01740
All Else	$	0.06910	$	0.06351	$	0.06351
Off Peak						
Commodity	$	0.01740	$	0.01740	$	0.01740
All Else	$	0.00558	$	-	$	-

Table B5.2-3: Derivation of the Shoulder TOU Rate

(Rates expressed per kW.h at System Input Level)

	Supply at Secondary Distribution Voltage		Supply at Primary Distribution Voltage		Supply at Transmission Voltage	
All Year Distribution	$	0.00558	$	-	$	-
Peak Commodity						
Cost (000s)	$	23,975	$	23,975	$	23,975
MW.h		1,359,154		1,359,154		1,359,154
Rate per kW.h	$	0.01764	$	0.01764	$	0.01764
Off Peak Commodity						
Cost (000s)						
MW.h						
Rate per kW.h	$	0.01764	$	0.01764	$	0.01764
Peak Substations						
Cost (000s)						
MW.h						
Rate per kW.h	$	-	$	-	$	-
Peak Transmission						
Cost (000s)						
MW.h						
Rate per kW.h	$	-	$	-	$	-
Rate Summary						
On Peak Hours	$	0.02322	$	0.01764	$	0.01764
Off Peak Hours	$	0.02322	$	0.01764	$	0.01764
Rate Components						
On Peak						
Commodity	$	0.01764	$	0.01764	$	0.01764
All Else	$	0.00558	$	-	$	-
Off Peak						
Commodity	$	0.01764	$	0.01764	$	0.01764
All Else	$	0.00558	$	-	$	-

Table B5.2-4: MW.H Billed by Supply Level

(Rates expressed per kW.h at System Input Level)

	System Input	Primary	Secondary	Total
Winter				
On Peak MW.h	31,371	149,709	233,698	414,778
Cost Rate	$ 0.06441	$ 0.08950	$ 0.09508	
Revenue (000s)	$ 2,021	$ 13,399	$ 22,220	$ 37,640
Off Peak MW.h	54,367	259,446	405,001	718,814
Cost Rate	$ 0.01821	$ 0.01821	$ 0.02379	
Revenue (000s)	$ 990	$ 4,724	$ 9,634	$ 15,348
Summer				
On Peak MW.h	12,651	60,374	94,244	167,269
Cost Rate	$ 0.08592	$ 0.08592	$ 0.09150	
Revenue (000s)	$ 1,087	$ 5,187	$ 8,623	$ 14,897
Off Peak MW.h	19,656	93,804	146,429	259,889
Cost Rate	$ 0.01418	$ 0.01418	$ 0.01976	
Revenue (000s)	$ 279	$ 1,331	$ 2,894	$ 4,504
Shoulder				
On Peak MW.h	71,298	340,243	531,126	942,667
Cost Rate	$ 0.02064	$ 0.02064	$ 0.02622	
Revenue (000s)	$ 1,472	$ 7,022	$ 13,926	$ 22,420
Off Peak MW.h	31,501	150,325	234,661	416,487
Cost Rate	$ 0.01085	$ 0.01085	$ 0.01643	
Revenue (000s)	$ 342	$ 1,631	$ 3,856	$ 5,829
Total MW.h	220,844	1,053,901	1,645,159	2,919,904
Total Revenue (000s)	$ 6,191	$ 33,294	$ 61,153	$ 100,638
plus: Basic Charge revenue				$ 19,864
Revenue Requirement				$ 120,502

Table B5.2-5: Derivation of the Residential TOU Rate

	Rate At Secondary Excluding Losses		Loss Adjustment	Over/Under Recovery	Final Rate adjusted for Losses and Rate subsidies		
Winter	Commodity	All Else			Commodity	All Else	**Total**
on Peak	$ 0.03880	$ 0.05628	1.1659	9.50%	$ 0.04132	$ 0.05992	$ 0.10124
off Peak	$ 0.01821	$ 0.00558	1.1659	9.50%	$ 0.01939	$ 0.00594	$ 0.02533
Summer							
on Peak	$ 0.02240	$ 0.06910	1.1659	9.50%	$ 0.02385	$ 0.07357	$ 0.09742
off Peak	$ 0.01418	$ 0.00558	1.1659	9.50%	$ 0.01510	$ 0.00594	$ 0.02104
Shoulder							
on Peak	$ 0.02064	$ 0.00558	1.1659	9.50%	$ 0.02198	$ 0.00594	$ 0.02792
off Peak	$ 0.01085	$ 0.00558	1.1659	9.50%	$ 0.01155	$ 0.00594	$ 0.01749

Table B5.2-6: Derivation of the General Service TOU Rate

	Rate At Secondary Excluding Losses		Loss	Over/Under	Final Rate adjusted for Losses and Rate subsidies		
Winter	Commodity	All Else	Adjustment	Recovery	Commodity	All Else	**Total**
on Peak	$ 0.03880	$ 0.05628	1.1659	-12.40%	$ 0.05165	$ 0.07490	$ 0.12654
off Peak	$ 0.01821	$ 0.00558	1.1659	-12.40%	$ 0.02423	$ 0.00743	$ 0.03166
Summer							
on Peak	$ 0.02240	$ 0.06910	1.1659	-12.40%	$ 0.02981	$ 0.09196	$ 0.12178
off Peak	$ 0.01418	$ 0.00558	1.1659	-12.40%	$ 0.01888	$ 0.00743	$ 0.02631
Shoulder							
on Peak	$ 0.02064	$ 0.00558	1.1659	-12.40%	$ 0.02747	$ 0.00743	$ 0.03490
off Peak	$ 0.01085	$ 0.00558	1.1659	-12.40%	$ 0.01444	$ 0.00743	$ 0.02187

Table B5.2-7: Derivation of the Large General Service - Primary TOU Rate

	Rate At Primary Excluding Losses		Loss Adjustment	Over/Under Recovery	Final Rate adjusted for Losses and Rate subsidies		
Winter	Commodity	All Else			Commodity	All Else	**Total**
on Peak	$ 0.03880	$ 0.05069	1.1165	-12.70%	$ 0.04963	$ 0.06483	$0.11446
off Peak	$ 0.01821	$ -	1.1165	-12.70%	$ 0.02328	$ -	$0.02328
Summer							
on Peak	$ 0.02240	$ 0.06351	1.1165	-12.70%	$ 0.02865	$ 0.08123	$0.10988
off Peak	$ 0.01418	$ -	1.1165	-12.70%	$ 0.01814	$ -	$0.01814
Shoulder							
on Peak	$ 0.02064	$ -	1.1165	-12.70%	$ 0.02640	$ -	$0.02640
off Peak	$ 0.01085	$ -	1.1165	-12.70%	$ 0.01388	$ -	$0.01388

Table B5.2-8: Derivation of the Large General Service - TransmissionTOU Rate

	Rate At Transmission Excluding Losses		Loss Adjustment	Over/Under Recovery	Final Rate adjusted for Losses and Rate subsidies		
Winter	Commodity	All Else			Commodity	All Else	**Total**
on Peak	$ 0.03880	$ 0.02560	1.0680	-20.20%	$ 0.05193	$ 0.03427	$ 0.08620
off Peak	$ 0.01821	$ -	1.0680	-20.20%	$ 0.02437	$ -	$ 0.02437
Summer							
on Peak	$ 0.02240	$ 0.06351	1.0680	-20.20%	$ 0.02998	$ 0.08500	$ 0.11498
off Peak	$ 0.01418	$ -	1.0680	-20.20%	$ 0.01898	$ -	$ 0.01898
Shoulder							
on Peak	$ 0.02064	$ -	1.0680	-20.20%	$ 0.02762	$ -	$ 0.02762
off Peak	$ 0.01085	$ -	1.0680	-20.20%	$ 0.01452	$ -	$ 0.01452

Table B5.2-9: Derivation of the Wholesale Primary TOU Rate

	Rate At Primary Excluding Losses		Loss Adjustment	Over/Under Recovery	Final Rate adjusted for Losses and Rate subsidies		
Winter	Commodity	All Else			Commodity	All Else	**Total**
on Peak	$ 0.03880	$ 0.05069	1.1165	-1.20%	$ 0.04385	$ 0.05729	$ 0.10114
off Peak	$ 0.01821	$ -	1.1165	-1.20%	$ 0.02057	$ -	$ 0.02057
Summer							
on Peak	$ 0.02240	$ 0.06351	1.1165	-1.20%	$ 0.02531	$ 0.07178	$ 0.09709
off Peak	$ 0.01418	$ -	1.1165	-1.20%	$ 0.01603	$ -	$ 0.01603
Shoulder							
on Peak	$ 0.02064	$ -	1.1165	-1.20%	$ 0.02332	$ -	$ 0.02332
off Peak	$ 0.01085	$ -	1.1165	-1.20%	$ 0.01226	$ -	$ 0.01226

Table B5.2-10: Derivation of the Wholesale Transmission TOU Rate

	Rate At Transmission Excluding Losses		Loss Adjustment	Over/Under Recovery	Final Rate adjusted for Losses and Rate subsidies		
Winter	Commodity	All Else			Commodity	All Else	**Total**
on Peak	$ 0.03880	$ 0.02560	1.0608	-14.30%	$ 0.04803	$ 0.03169	$ 0.07972
off Peak	$ 0.01821	$ -	1.0608	-14.30%	$ 0.02254	$ -	$ 0.02254
Summer							
on Peak	$ 0.02240	$ 0.06351	1.0608	-14.30%	$ 0.02773	$ 0.07862	$ 0.10635
off Peak	$ 0.01418	$ -	1.0608	-14.30%	$ 0.01756	$ -	$ 0.01756
Shoulder							
on Peak	$ 0.02064	$ -	1.0608	-14.30%	$ 0.02555	$ -	$ 0.02555
off Peak	$ 0.01085	$ -	1.0608	-14.30%	$ 0.01343	$ -	$ 0.01343

Table B5.2-11: Derivation of the Irrigation TOU Rate

	Rate At Secondary Excluding Losses		Loss Adjustment	Over/Under Recovery	Final Rate adjusted for Losses and Rate subsidies		
Winter	Commodity	All Else			Commodity	All Else	**Total**
on Peak	$ 0.03880	$ 0.05628	1.1659	32.00%	$ 0.03427	$ 0.04971	$ 0.08398
off Peak	$ 0.01821	$ 0.00558	1.1659	32.00%	$ 0.01608	$ 0.00493	$ 0.02101
Summer							
on Peak	$ 0.02240	$ 0.06910	1.1659	32.00%	$ 0.01979	$ 0.06103	$ 0.08081
off Peak	$ 0.01418	$ 0.00558	1.1659	32.00%	$ 0.01253	$ 0.00493	$ 0.01746
Shoulder							
on Peak	$ 0.02064	$ 0.00558	1.1659	32.00%	$ 0.01823	$ 0.00493	$ 0.02316
off Peak	$ 0.01085	$ 0.00558	1.1659	32.00%	$ 0.00958	$ 0.00493	$ 0.01451

Exhibits

West Kootenay Power
Exhibit A-1
REVENUE REQUIREMENTS
FOR CY1997

A-2

		Test Period CY 1997
	SOURCES OF FUNDS	
	Revenues from Rates	
440.0	Residential (Secondary)	$52,254,000
441.0	Irrigation	1,383,000
442.1	General Service	24,597,000
442.2	Large General Service - Primary	7,870,000
443.0	Large General Service - Transmission	2,668,000
444.0	Street Lights/Outdoor Lights	1,380,000
445.0	Wholesale - Primary	27,821,000
446.0	Wholesale - Transmission	2,526,000
	Total Rate Revenues at Present Rates	$120,499,000
	Other Revenues	
	Pole Rental	$1,050,000
	Connection Fees	430,000
	NSF Charges	28,000
	Collection Fees	4,000
320.2	Facilities Rental Cominco	80,000
745.0	Interest Income less Walden	450,000
750.0	Other Income - Cominco (O&M)	465,000
757.0	Sundry	415,000
	Total Operating Revenues	$2,922,000
	Total Sources of Funds	$123,421,000
	APPLICATIONS OF FUNDS	
	Operation & Maintenance Expenses	
	Hydraulic Power Generation Operation	
535.0	Operation, Supervision, Engineering	$751,000
536.0	Water Fees	6,808,000
538.0	Electric Expenses	282,000
539.0	Other Generation Exp.	127,000
	Total Hydraulic Power Generation Operation	$7,968,000
	Hydraulic Power Generation Maintenance	
541.0	Maintenance Supervision & Engineering	$10,000
542.0	Maintenance of Structures	257,000
543.0	Maintenance of Reservoirs, Dams, Waterways	91,000
544.0	Maintenance of Electric Plant	680,000
545.0	Maintenance of Miscellaneous Hydraulic Plant	75,000
549.0	Miscellaneous	90,000
	Total Hydraulic Power Generation Maintenance	$1,203,000
	Total Hydraulic Power Generation Expense	$9,171,000

West Kootenay Power
Exhibit A-1
REVENUE REQUIREMENTS
FOR CY1997

		Test Period CY 1997
	Other Power Supply Expenses	
555.1	Winter Demand	$6,065,000
555.2	Winter Energy	18,120,000
555.3	Summer Energy	13,444,000
556.0	System Control and Load Dispatch	826,000
	Total Other Power Supply Expenses	$38,455,000
	Total Power Supply Expenses	$47,626,000
	Transmission Operation	
560.0	Operation, Supervision, Engineering	$196,000
561.0	Load Dispatching	428,000
562.0	Station Expenses	24,000
563.0	Overhead Line Expense	161,000
565.0	Transmission of Electricity	3,508,000
566.0	Miscellaneous Transmission Expenses	15,000
567.0	Rents	216,000
	Total Transmission Operation	$4,548,000
	Transmission Maintenance	
568.0	Maintenance Supervision and Engineering	$588,000
569.0	Maintenance of Structures	20,000
570.0	Maintenance of Station Equipment	315,000
571.0	Maintenance of Overhead Lines	609,000
	Total Transmission Maintenance	$1,532,000
	Total Transmission Expense	$6,080,000
	Distribution Operation	
580.0	Operation Supervision & Eng.	$700,000
583.0	Overhead Line Expense	60,000
586.0	Meter Expense	787,000
587.0	Customer Installation Expense	68,000
	Total Distribution Operation	$1,615,000
	Distribution Maintenance	
590.0	Maint. Supervision & Eng.	$2,195,000
591.0	Maint. Structures and Improvements	$619,000
592.0	Maint. Station Equipment	426,000
593.0	Maint. Overhead Lines	1,895,000
594.0	Maint. Underground Lines	112,000
595.0	Maint. Line Transformers	123,000
596.0	Maint. of Street Lights and Signals	295,000
597.0	Maint. of Meters	54,000
598.0	Miscellaneous Maintenance	718,000
	Total Distribution Maintenance	$6,437,000
	Total Distribution Expense	$8,052,000

West Kootenay Power
Exhibit A-1
REVENUE REQUIREMENTS
FOR CY1997

		Test Period CY 1997
	Customer Accounts Expense	
901.0	Customer Acctg. Supervision	$1,633,000
902.0	Meter Reading Expenses	1,141,000
903.0	Cust. Records, Collection Exp.	908,000
904.0	Uncollectable Accounts	457,000
	Total Customer Accts Exp	$4,139,000
	Customer Service & Information Exp.	
909.0	Supervision	$142,000
910.0	Customer Assistance	260,000
	Total Cust Serv & Info Exp	$402,000
	Total O&M Exp Before A&G Exp	$66,299,000
	Administrative and General Expenses	
	Salaries	
920.90	Executive and Senior Management	$593,000
920.80	Engineering	252,000
920.81	T&D Administration	313,000
920.84	Legal	385,000
920.82	Human Resources	515,000
920.91	Accounting	371,000
920.95	Financial Administration	232,000
920.96	Office Services	440,000
920.93	Payroll	155,000
920.92	Information Services	588,000
920.85	Materials Management	318,000
	Total A&G Salaries	$4,162,000
	Labor Expenses	
921.90	Executive and Senior Management	168,000
921.80	Engineering	100,000
921.81	T&D Administration	146,000
921.84	Legal	323,000
921.82	Human Resources	283,000
921.91	Accounting	89,000
921.95	Financial Administration	126,000
921.96	Office Services	11,000
921.93	Payroll	38,000
921.92	Information Services	461,000
921.90	Other	1,314,000
	Total A&G Labor Expenses	$3,059,000

West Kootenay Power
Exhibit A-1
REVENUE REQUIREMENTS
FOR CY1997

		Test Period CY 1997
	Other A&G Expenses	
922.0	Administration & General Transferred	($1,708,000)
923.0	Special Services	$296,000
924.0	Insurance	$787,000
930.0	Conservation Promotion	$119,000
930.0	Rate Application and Other	$560,000
932.0	Maintenance of General Plant	$378,000
933.0	Transportation Equipment Expenses	($1,207,000)
	Total Other A&G Expenses	($775,000)
	Total Admin. & General Exp.	$6,446,000
	Less: Incentive Sharing	$402,000
	Less: DSM Sharing	$50,000
	Total O & M Expense	$72,293,000
	Taxes	
	Taxes - Property	$7,918,000
	Capital Tax	804,000
	Total Taxes	$8,722,000
	Total Operating Expenses	$81,015,000
	NET OPERATING REVENUES	$42,406,000
	DEPRECIATION	
	Other Production Plant	$41,000
	Plant Acquisition Adjustment	186,000
403.3	Hydraulic Production Plant	607,000
403.5	Transmission Plant	2,125,000
403.6	Distribution Plant	6,496,000
403.7	General Plant	2,040,000
	Leasehold Improvements	49,000
	Amortization of Customer Contributions	(1,350,000)
	Amortization of Deferred Charges	1,425,000
	Total Depreciation Expense	$11,619,000
	Less: AFUDC	
	Allowance for Funds Used During Construction	$300,000
	TOTAL OPERATING EXPENSES	$92,334,000
	Plus: Return on Plant	
	Return on Plant (@12.968%)	$31,087,000
	TOTAL REVENUE REQUIREMENT	$123,421,000
	BALANCE/(DEFICIENCY) OF FUNDS	$0
	Plus: Additional Taxes on Rate Adjustment	$0
	TOTAL BALANCE/(DEFICIENCY) OF FUNDS	$0
	RATE ADJUSTMENT AS A % OF RATES	0.0%

West Kootenay Pow...
Exhibit B-1
ANALYSIS OF LOAD DATA
For the Period of: January 1997 - December 1997

		Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Total
Hours in Month		744	672	744	720	744	720	744	744	720	744	720	744	8,760
Residential														
Kwh Sales at the Meter		113,000,000	100,000,000	91,000,000	74,000,000	61,000,000	55,000,000	57,000,000	57,000,000	56,000,000	78,000,000	98,000,000	116,000,000	956,000,000
Load Factor		0.27	0.26	0.23	0.21	0.20	0.21	0.21	0.22	0.17	0.23	0.27	0.27	
Individ. Noncoincident Peak (NCP)(kVA)		566,511	569,715	522,031	481,395	411,799	372,084	361,552	354,854	466,573	465,536	506,554	581,118	5,659,723
Group Coincidence Factor		0.44	0.42	0.42	0.35	0.33	0.33	0.37	0.38	0.35	0.36	0.41	0.44	
NCP @ Meter for Group (kVA)		249,265	239,280	219,253	168,488	135,894	122,788	133,774	134,844	163,301	167,593	207,687	255,692	2,197,859
NCP @ Primary (kVA) Losses =	1.50%	253,004	242,869	222,542	171,015	137,932	124,630	135,781	136,867	165,750	170,107	210,803	259,527	2,230,827
NCP @ Input (kVA) Losses =	12.73%	285,205	273,780	250,866	192,781	155,487	140,492	153,062	154,287	186,846	191,757	237,632	292,558	2,514,754
System Coincidence Factor		0.97	0.98	0.96	0.70	0.85	0.91	0.57	0.54	0.77	0.91	0.96	0.97	
Coincident Peak (CP) @ Input (kVA)		276,649	266,936	239,577	133,983	132,164	127,145	87,246	82,543	142,937	174,499	226,939	283,782	2,174,399
Kwh at Input Voltage		131,743,736	116,587,377	106,094,513	86,274,659	71,118,300	64,123,057	66,454,805	66,454,805	65,288,931	90,938,154	114,255,630	135,241,357	1,114,575,325
General Service														
Kwh Sales at the Meter		42,000,000	41,000,000	38,000,000	37,000,000	33,000,000	34,000,000	36,000,000	42,000,000	35,000,000	34,000,000	36,000,000	39,000,000	447,000,000
Load Factor		0.49	0.47	0.43	0.30	0.30	0.30	0.30	0.30	0.41	0.41	0.45	0.49	
Individ. Noncoincident Peak (NCP)(kVA)		115,207	129,813	118,780	171,296	147,849	157,407	161,290	188,172	118,564	111,461	111,111	106,978	1,637,929
Group Coincidence Factor		0.75	0.75	0.75	0.75	0.80	0.80	0.80	0.80	0.70	0.75	0.75	0.75	
NCP @ Meter for Group (kVA)		86,406	97,359	89,085	128,472	118,280	125,926	129,032	150,538	82,995	83,596	83,333	80,234	1,255,255
NCP @ Primary (kVA) Losses =	1.50%	87,702	98,820	90,421	130,399	120,054	127,815	130,968	152,796	84,239	84,850	84,583	81,437	1,274,083
NCP @ Input (kVA) Losses =	12.66%	98,807	111,333	101,871	146,912	135,256	144,000	147,552	172,144	94,907	95,594	95,294	91,750	1,435,421
System Coincidence Factor		0.62	0.61	0.72	0.61	0.63	0.57	0.72	0.69	0.70	0.72	0.71	0.77	
Coincident Peak (CP) @ Input (kVA)		61,261	67,913	73,347	89,616	85,211	82,080	106,238	118,780	66,435	68,828	67,659	70,647	958,014
Kwh at Input Voltage		48,929,949	47,764,950	44,269,954	43,104,955	38,444,960	39,609,958	41,939,956	48,929,949	40,774,957	39,609,958	41,939,956	45,434,952	520,754,453
Large General Service - Primary														
Kwh Sales at the Meter		17,000,000	16,000,000	17,000,000	15,000,000	15,000,000	13,000,000	13,000,000	13,000,000	14,000,000	15,000,000	16,000,000	15,000,000	179,000,000
Load Factor		0.49	0.47	0.47	0.46	0.46	0.46	0.45	0.47	0.45	0.48	0.51	0.49	
Individ. Noncoincident Peak (NCP)(kVA)		46,375	50,222	48,659	45,484	43,452	39,472	39,029	37,547	43,401	42,218	43,715	41,459	521,035
Group Coincidence Factor		0.90	0.90	0.90	0.90	0.90	0.97	0.90	0.90	0.90	0.90	0.90	0.90	
NCP @ Meter for Group (kVA)		41,738	45,200	43,793	40,936	39,107	38,288	35,126	33,792	39,061	37,996	39,344	37,313	471,695
NCP @ Primary (kVA) Losses =	0.00%	41,738	45,200	43,793	40,936	39,107	38,288	35,126	33,792	39,061	37,996	39,344	37,313	471,695
NCP @ Input (kVA) Losses =	10.44%	46,093	49,917	48,363	45,207	43,188	42,283	38,792	37,318	43,137	41,961	43,449	41,207	520,916
System Coincidence Factor		0.91	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.91	0.90	
Coincident Peak (CP) @ Input (kVA)		41,945	44,925	43,527	40,686	38,869	38,055	34,913	33,587	38,823	37,765	39,539	37,086	469,720
Kwh at Input Voltage		18,980,629	17,864,121	18,980,629	16,747,613	16,747,613	14,514,598	14,514,598	14,514,598	15,631,106	16,747,613	17,864,121	16,747,613	199,854,854
Large General Service - Transmission														
Kwh Sales at the Meter		5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	60,000,000
Load Factor		0.31	0.34	0.31	0.28	0.31	0.32	0.31	0.31	0.28	0.31	0.32	0.31	
Individ. Noncoincident Peak (NCP)(kVA)		22,000	22,000	22,000	25,000	22,000	22,000	22,000	22,000	25,000	22,000	22,000	22,000	270,000
Group Coincidence Factor		0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	
NCP @ Meter for Group (kVA)		19,800	19,800	19,800	22,500	19,800	19,800	19,800	19,800	22,500	19,800	19,800	19,800	243,000
NCP @ Primary (kVA) Losses =	0.00%	19,800	19,800	19,800	22,500	19,800	19,800	19,800	19,800	22,500	19,800	19,800	19,800	243,000
NCP @ Input (kVA) Losses =	5.73%	20,935	20,935	20,935	23,789	20,935	20,935	20,935	20,935	23,789	20,935	20,935	20,935	256,924
System Coincidence Factor		90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	
Coincident Peak (CP) @ Input (kVA)		18,841	18,841	18,841	21,410	18,841	18,841	18,841	18,841	21,410	18,841	18,841	18,841	231,232
Kwh at Input Voltage		5,303,914	5,303,914	5,303,914	5,303,914	5,303,914	5,303,914	5,303,914	5,303,914	5,303,914	5,303,914	5,303,914	5,303,914	63,646,971

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West Kootenay Po...
Exhibit B-1
ANALYSIS OF LOAD DATA
For the Period of: January 1997 - December 1997

		Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Total
Hours In Month		744	672	744	720	744	720	744	744	720	744	720	744	8,760
Wholesale - Primary														
Kwh Sales at the Meter		84,059,952	72,360,450	70,078,137	57,394,072	61,398,972	55,611,032	63,560,499	51,053,601	60,816,808	62,799,057	73,537,860	84,329,560	797,000,000
Load Factor		0.71	0.69	0.66	0.59	0.57	0.53	0.57	0.46	0.58	0.60	0.65	0.68	
Individ. Noncoincident Peak (NCP)(kVA)		158,974	156,730	142,513	134,818	144,861	145,240	149,090	148,226	146,082	139,842	156,577	167,193	1,790,146
Group Coincidence Factor		0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	
NCP @ Meter for Group (kVA)		143,077	141,057	128,262	121,336	130,375	130,716	134,181	133,403	131,474	125,858	140,919	150,474	1,611,132
NCP @ Primary (kVA) Losses =	0.00%	143,077	141,057	128,262	121,336	130,375	130,716	134,181	133,403	131,474	125,858	140,919	150,474	1,611,132
NCP @ Input (kVA) Losses =	10.34%	157,864	155,635	141,518	133,876	143,849	144,225	148,049	147,191	145,062	138,865	155,483	166,026	1,777,642
System Coincidence Factor		0.98	0.96	0.93	0.90	0.88	0.88	0.93	0.93	0.93	0.92	0.98	0.98	
Coincident Peak (CP) @ Input (kVA)		154,707	148,631	131,611	120,489	126,587	126,918	137,685	136,887	134,908	127,756	151,596	162,705	1,660,481
Kwh at Input Voltage		93,748,901	80,700,887	78,155,509	64,009,449	68,475,962	62,020,891	70,886,632	56,938,159	67,826,697	70,037,425	82,014,008	94,049,585	888,864,105
Wholesale - Transmission														
Kwh Sales at the Meter		9,940,048	7,639,550	6,921,863	4,605,928	3,601,028	2,388,968	2,439,501	1,946,399	3,183,192	5,200,943	7,462,140	9,670,440	65,000,000
Load Factor		0.59	0.52	0.53	0.38	0.33	0.25	0.36	0.29	0.49	0.77	0.53	0.57	
Individ. Noncoincident Peak (NCP)(Kw)		22,500	21,950	17,530	16,753	14,694	13,149	9,100	9,100	9,100	9,100	19,465	22,931	185,372
Group Coincidence Factor		0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	
NCP @ Meter for Group (Kw)		20,250	19,755	15,777	15,078	13,224	11,835	8,190	8,190	8,190	8,190	17,519	20,638	166,835
NCP @ Primary (Kw) Losses =	0.00%	20,250	19,755	15,777	15,078	13,224	11,835	8,190	8,190	8,190	8,190	17,519	20,638	166,835
NCP @ Input (Kw) Losses =	5.73%	21,410	20,887	16,681	15,942	13,982	12,513	8,659	8,659	8,659	8,659	18,523	21,820	176,394
System Coincidence Factor		100.00%	97.00%	94.00%	91.00%	89.00%	89.00%	94.00%	94.00%	94.00%	94.00%	99.50%	99.00%	
Coincident Peak (CP) @ Input (Kw)		21,410	20,260	15,680	14,507	12,444	11,136	8,140	8,140	8,140	8,140	18,430	21,602	168,029
Kwh @ Input Voltage		10,544,233	8,103,903	7,342,593	4,885,889	3,819,909	2,534,176	2,587,781	2,064,707	3,376,675	5,517,071	7,915,710	10,258,237	68,950,886
Lighting														
Kwh Sales at the Meter		1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	12,000,000
Load Factor		0.58	0.53	0.45	0.42	0.32	0.31	0.31	0.37	0.44	0.50	0.57	0.61	
Individ. Noncoincident Peak (NCP)(kVA)		2,317	2,808	2,987	3,307	4,200	4,480	4,336	3,682	3,157	2,688	2,437	2,203	38,602
Group Coincidence Factor		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
NCP @ Meter for Group (kVA)		2,317	2,808	2,987	3,307	4,200	4,480	4,336	3,682	3,157	2,688	2,437	2,203	38,602
NCP @ Primary (kVA) Losses =	1.50%	2,352	2,850	3,032	3,356	4,263	4,547	4,401	3,738	3,204	2,728	2,473	2,236	39,181
NCP @ Input (kVA) Losses =	12.67%	2,650	3,211	3,416	3,782	4,803	5,123	4,958	4,211	3,610	3,074	2,786	2,520	44,144
System Coincidence Factor		1.00	1.00	-	-	-	-	-	-	-	-	1.00	1.00	
Coincident Peak (CP) @ Input (kVA)		2,650	3,211	0	0	0	0	0	0	0	0	2,786	2,520	11,167
Kwh at Input Voltage		1,165,026	1,165,026	1,165,026	1,165,026	1,165,026	1,165,026	1,165,026	1,165,026	1,165,026	1,165,026	1,165,026	1,165,026	13,980,311
Irrigation														
Kwh Sales at the Meter		0	0	0	1,000,000	4,000,000	5,000,000	9,000,000	9,000,000	6,000,000	5,000,000	0	0	39,000,000
Load Factor		-	-	-	0.17	0.44	0.74	0.54	0.62	0.67	0.34	0.17	0.17	
Individ. Noncoincident Peak (NCP)(kVA)		0	0	0	7,996	12,158	9,433	22,364	19,454	12,360	20,019	0	0	103,785
Group Coincidence Factor		0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	
NCP @ Meter for Group (kVA)		0	0	0	6,397	9,727	7,546	17,891	15,564	9,888	16,015	0	0	83,028
NCP @ Primary (kVA) Losses =	1.50%	0	0	0	6,493	9,872	7,659	18,160	15,797	10,037	16,256	0	0	84,273
NCP @ Input (kVA) Losses =	12.66%	0	0	0	7,315	11,123	8,629	20,459	17,797	11,308	18,314	0	0	94,945
System Coincidence Factor		0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	
Coincident Peak (CP) @ Input (kVA)		0	0	0	6,583	10,010	7,766	18,413	16,018	10,177	16,483	0	0	85,450
Kwh at Input Voltage		0	0	0	1,164,999	4,659,995	5,824,994	10,484,989	10,484,989	6,989,993	5,824,994	0	0	45,434,952

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West Kootenay Pow...
Exhibit B-2
SUMMARY OF TEST PERIOD
LOAD DATA ANALYSIS

	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Total
System Kwh's @ Input Voltage- Winter													
Residential	131,743,736	116,587,377	106,094,513	0	0	0	0	0	0	0	114,255,630	135,241,357	603,922,613
General Service	48,929,949	47,764,950	44,269,954	0	0	0	0	0	0	0	41,939,956	45,434,952	228,339,760
Large General Service - Primary	18,980,629	17,864,121	18,980,629	0	0	0	0	0	0	0	17,864,121	16,747,613	90,437,113
Large General Service - Transmission	5,303,914	5,303,914	5,303,914	0	0	0	0	0	0	0	5,303,914	5,303,914	26,519,571
Wholesale - Primary	93,748,901	80,700,887	78,155,509	0	0	0	0	0	0	0	82,014,008	94,049,585	428,668,889
Wholesale - Transmission	10,544,233	8,103,903	7,342,593	0	0	0	0	0	0	0	7,915,710	10,258,237	44,164,676
Lighting	1,165,026	1,165,026	1,165,026	0	0	0	0	0	0	0	1,165,026	1,165,026	5,825,130
Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Winter	310,416,387	277,490,178	261,312,138	0	0	0	0	0	0	0	270,458,365	308,200,685	1,427,877,753
System Kwh's @ Input Voltage- Summer													
Residential	0	0	0	86,274,659	71,118,300	64,123,057	66,454,805	66,454,805	65,288,931	90,938,154	0	0	510,652,711
General Service	0	0	0	43,104,955	38,444,960	39,609,958	41,939,956	48,929,949	40,774,957	39,609,958	0	0	292,414,693
Large General Service - Primary	0	0	0	16,747,613	16,747,613	14,514,598	14,514,598	14,514,598	15,631,106	16,747,613	0	0	109,417,741
Large General Service - Transmission	0	0	0	5,303,914	5,303,914	5,303,914	5,303,914	5,303,914	5,303,914	5,303,914	0	0	37,127,400
Wholesale - Primary	0	0	0	64,009,449	68,475,962	62,020,891	70,886,632	56,938,159	67,826,697	70,037,425	0	0	460,195,216
Wholesale - Transmission	0	0	0	4,885,889	3,819,909	2,534,176	2,587,781	2,064,707	3,376,675	5,517,071	0	0	24,786,209
Lighting	0	0	0	1,165,026	1,165,026	1,165,026	1,165,026	1,165,026	1,165,026	1,165,026	0	0	8,155,181
Irrigation	0	0	0	1,164,999	4,659,995	5,824,994	10,484,989	10,484,989	6,989,993	5,824,994	0	0	45,434,952
Total Summer	0	0	0	222,656,504	209,735,680	195,096,616	213,337,702	205,856,148	206,357,300	235,144,156	0	0	1,488,184,105
Total Kwh's @ Input Voltage	310,416,387	277,490,178	261,312,138	222,656,504	209,735,680	195,096,616	213,337,702	205,856,148	206,357,300	235,144,156	270,458,365	308,200,685	2,916,061,858
System Coincident Peak (CP)(kVA) @ Input Voltage - Winter													
Residential	276,649	266,936	239,577	0	0	0	0	0	0	0	226,939	283,782	1,293,882
General Service	61,261	67,913	73,347	0	0	0	0	0	0	0	67,659	70,647	340,827
Large General Service - Primary	41,945	44,925	43,527	0	0	0	0	0	0	0	39,539	37,086	207,021
Large General Service - Transmission	18,841	18,841	18,841	0	0	0	0	0	0	0	18,841	18,841	94,205
Wholesale - Primary	154,707	148,631	131,611	0	0	0	0	0	0	0	151,596	162,705	749,250
Wholesale - Transmission	21,410	20,260	15,680	0	0	0	0	0	0	0	18,430	21,602	97,382
Lighting	2,650	3,211	0	0	0	0	0	0	0	0	2,786	2,520	11,167
Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Winter	577,462	570,717	522,583	0	0	0	0	0	0	0	525,790	597,183	2,793,736

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West Kootenay Pow...
Exhibit B-2
SUMMARY OF TEST PERIOD
LOAD DATA ANALYSIS

	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Total
System Coincident Peak (CP)(kVA) @ Input Voltage - Summer													
Residential	0	0	0	133,983	132,164	127,145	87,246	82,543	142,937	174,499	0	0	880,517
General Service	0	0	0	89,616	85,211	82,080	106,238	118,780	66,435	68,828	0	0	617,187
Large General Service - Primary	0	0	0	40,686	38,869	38,055	34,913	33,587	38,823	37,765	0	0	262,698
Large General Service - Transmission	0	0	0	21,410	18,841	18,841	18,841	18,841	21,410	18,841	0	0	137,026
Wholesale - Primary	0	0	0	120,489	126,587	126,918	137,685	136,887	134,908	127,756	0	0	911,230
Wholesale - Transmission	0	0	0	14,507	12,444	11,136	8,140	8,140	8,140	8,140	0	0	70,646
Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0
Irrigation	0	0	0	6,583	10,010	7,766	18,413	16,018	10,177	16,483	0	0	85,450
Total Summer	0	0	0	427,275	424,127	411,942	411,475	414,795	422,830	452,311	0	0	2,964,756
Total Sys. CP at Input Voltage	577,462	570,717	522,583	427,275	424,127	411,942	411,475	414,795	422,830	452,311	525,790	597,183	5,758,491
Noncoincident Peak (kVA) @ Input Voltage - Winter													
Residential	285,205	273,780	250,866	0	0	0	0	0	0	0	237,632	292,558	1,340,042
General Service	98,807	111,333	101,871	0	0	0	0	0	0	0	95,294	91,750	499,055
Large General Service - Primary	46,093	49,917	48,363	0	0	0	0	0	0	0	43,449	41,207	229,029
Large General Service - Transmission	20,935	20,935	20,935	0	0	0	0	0	0	0	20,935	20,935	104,673
Wholesale - Primary	157,864	155,635	141,518	0	0	0	0	0	0	0	155,483	166,026	776,525
Wholesale - Transmission	21,410	20,887	16,681	0	0	0	0	0	0	0	18,523	21,820	99,321
Lighting	2,650	3,211	3,416	0	0	0	0	0	0	0	2,786	2,520	14,583
Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Winter	632,964	635,697	583,649	0	0	0	0	0	0	0	574,102	636,815	3,063,227
Noncoincident Peak (kVA) @ Input Voltage - Summer													
Residential	0	0	0	192,781	155,487	140,492	153,062	154,287	186,846	191,757	0	0	1,174,712
General Service	0	0	0	146,912	135,256	144,000	147,552	172,144	94,907	95,594	0	0	936,365
Large General Service - Primary	0	0	0	45,207	43,188	42,283	38,792	37,318	43,137	41,961	0	0	291,887
Large General Service - Transmission	0	0	0	23,789	20,935	20,935	20,935	20,935	23,789	20,935	0	0	152,251
Wholesale - Primary	0	0	0	133,876	143,849	144,225	148,049	147,191	145,062	138,865	0	0	1,001,117
Wholesale - Transmission	0	0	0	15,942	13,982	12,513	8,659	8,659	8,659	8,659	0	0	77,074
Lighting	0	0	0	3,782	4,803	5,123	4,958	4,211	3,610	3,074	0	0	29,561
Irrigation	0	0	0	7,315	11,123	8,629	20,459	17,797	11,308	18,314	0	0	94,945
Total Summer	0	0	0	569,604	528,623	518,200	542,466	562,542	517,318	519,159	0	0	3,757,913
Total NCP @ Input Voltage	632,964	635,697	583,649	569,604	528,623	518,200	542,466	562,542	517,318	519,159	574,102	636,815	6,821,140
Season	W	W	W	S	S	S	S	S	S	S	W	W	
Winter Hours	744	672	744	0	0	0	0	0	0	0	720	744	3,624
Summer Hours	0	0	0	720	744	720	744	744	720	744	0	0	5,136

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West Kootenay Power
Exhibit B-3
DEVELOPMENT OF DEMAND ALLOCATION FACTORS
Average of Two CP

	Coincident Peak (CP) Allocation Factors				Noncoincident Peak (NCP) Allocation Factors*				For Acct. 360-2	
	Winter (CPW)	% of Total	Summer (CPS)	% of Total	Primary (NCPP)	% of Total	Secondary (NCPS)	% of Total	Primary (NCPP-II)	% of Total
Residential	280,215	47.71%	84,894	20.55%	196,295	61.11%	193,394	61.11%	196,295	39.38%
General Service	65,954	11.23%	112,509	27.23%	113,226	35.25%	111,552	35.25%	113,226	22.71%
Large General Service - Primary	39,515	6.73%	34,250	8.29%	0	0.00%	0	0.00%	36,992	7.42%
Large General Service - Transmission	18,841	3.21%	18,841	4.56%	0	0.00%	0	0.00%	0	0.00%
Wholesale - Primary	158,706	27.02%	137,286	33.23%	0	0.00%	0	0.00%	140,284	28.14%
Wholesale - Transmission	21,506	3.66%	8,140	1.97%	0	0.00%	0	0.00%	0	0.00%
Lighting	2,585	0.44%	0	0.00%	3,182	0.99%	3,135	0.99%	3,182	0.64%
Irrigation	0	0.00%	17,215	4.17%	8,489	2.64%	8,364	2.64%	8,489	1.70%
Total	587,322	100.00%	413,135	100.00%	321,191	100.00%	316,445	100.00%	498,468	100.00%
Allocation Factor		(CP-1)		(CP-2)		(NCP-1)		(NCP-2)		

Method of Coincident Peak Allocation is the Average of Two CP for winter and summer. Winter months are Jan & Dec, Summer are Jul & Aug.

* Average of 2 Winter and 2 Summer Months

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West Kootenay Power

Exhibit B-4

DEVELOPMENT OF ENERGY ALLOCATION FACTORS

Energy Allocation Factors (Kwh's at Input Voltage)

	Winter (EW)	% of Total	Summer (ES)	% of Total
Residential	603,922,613	42.30%	510,652,711	34.31%
General Service	228,339,760	15.99%	292,414,693	19.65%
Large General Service - Primary	90,437,113	6.33%	109,417,741	7.35%
Large General Service - Transmission	26,519,571	1.86%	37,127,400	2.49%
Wholesale - Primary	428,668,889	30.02%	460,195,216	30.92%
Wholesale - Transmission	44,164,676	3.09%	24,786,209	1.67%
Lighting	5,825,130	0.41%	8,155,181	0.55%
Irrigation	0	0.00%	45,434,952	3.05%
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Total	1,427,877,753	100.00%	1,488,184,105	100.00%
Allocation Factor		(E-1)		(E-2)

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West Kootena, ower
Exhibit B-5
DEVELOPMENT OF CUSTOMER ALLOCATION FACTORS

	1997 Average Customers	Percentage of Total	Percentage of Secondary	Weighting Factor for Cust. Acct. & Services	Weighted Customers	% of Total	Weighting Factor for Meters and Services	Weighted Meters and Services	% of Total
Residential	74,161	88.97%	89.01%	1.0	74,161	85.44%	$61	$4,571,401	69.01%
General Service	8,119	9.74%	9.75%	1.0	8,119	9.35%	99	814,518	12.30%
Large General Service - Primary	34	0.04%	0.00%	42.0	1,428	1.65%	23,224	789,616	11.92%
Large General Service - Transmission	3	0.00%	0.00%	120.0	360	0.41%	23,224	69,672	1.05%
Wholesale - Primary	7	0.01%	0.00%	120.0	840	0.97%	46,448	325,136	4.91%
Wholesale - Transmission	1	0.00%	0.00%	120.0	120	0.14%	0	0	0.00%
Lighting	149	0.18%	0.18%	0.0	0	0.00%	0	0	0.00%
Irrigation	884	1.06%	1.06%	2.0	1,768	2.04%	61	53,924	0.81%
Total	83,358	100.00%	100.00%		86,796	100.00%		$6,624,267	100.00%
Allocation Factor		(C-1)				(C-2)			(C-3)

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West Kootenay Power
Exhibit B-8
FUNCTIONALIZATION AND CLASSIFICATION
OF PLANT IN SERVICE (RATE BASE)
Minimum System Approach
As of December 1997

Acct. No.	Plant Description	Total Rate Base	Power Supply Demand Winter (CGPW)	Power Supply Demand Summer (CGPS)	Power Supply Energy Winter (GEW)	Power Supply Energy Summer (GES)	Transmission Related Demand Winter (CTPW)	Transmission Related Demand Summer (CTPS)	Transmission Related Energy Related Winter (EWT)	Transmission Related Energy Related Summer (EST)
	Hydraulic Production Plant									
330.0	Land & Land Rights	$99,000	$0	$0	$48,510	$50,490	$0	$0	$0	$0
331.0	Structures & Improvements	4,337,000	0	0	2,125,130	2,211,870	0	0	0	0
332.0	Reservoirs, Dams & Waterways	13,111,000	0	0	6,424,390	6,686,610	0	0	0	0
333.0	Water Wheels/Turbines/Generators	6,087,000	0	0	2,982,630	3,104,370	0	0	0	0
334.0	Accessory Electric Equipment	2,287,000	0	0	1,120,630	1,166,370	0	0	0	0
335.0	Miscellaneous Power Plant Equipment	4,340,000	0	0	2,126,600	2,213,400	0	0	0	0
336.0	Roads, Railroads and Bridges	268,000	0	0	131,320	136,680	0	0	0	0
	Total Hydraulic Production Plant	$30,529,000	$0	$0	$14,959,210	$15,569,790	$0	$0	$0	$0
	% of Total	100.0%	0.0%	0.0%	49.0%	51.0%	0.0%	0.0%	0.0%	0.0%
	Other Production Plant									
346.0	Other Production Plant Equipment	$1,353,000	$0	$0	$662,970	$690,030	$0	$0	$0	$0
	Generation Integration									
347.0	Generation Integration	$655,127	$0	$0	$321,012	$334,115	$0	$0	$0	$0
	Total Production Plant	$32,537,127	$0	$0	$15,943,192	$16,593,935	$0	$0	$0	$0
	% of Total	100.0%	0.0%	0.0%	49.0%	51.0%	0.0%	0.0%	0.0%	0.0%
	Transmission Plant									
350.0	Land & Land Rights - R/W	$1,767,000	$0	$0	$0	$0	$883,500	$883,500	$0	$0
350.1	Land Rights - Clearing	2,807,000	0	0	0	0	1,403,500	1,403,500	0	0
353.0	Station Equipment	29,201,000	0	0	0	0	14,600,500	14,600,500	0	0
355.0	Poles and Fixtures	26,486,000	0	0	0	0	13,243,000	13,243,000	0	0
356.0	Overhead Conductors & Devices	25,005,000	0	0	0	0	12,502,500	12,502,500	0	0
359.0	Roads and Trails	159,000	0	0	0	0	79,500	79,500	0	0
359.1	Transfer to Generation	(655,127)	0	0	0	0	(327,564)	(327,564)	0	0
	Total Transmission Plant	$84,769,873	$0	$0	$0	$0	$42,384,937	$42,384,937	$0	$0
	% of Total	100.0%	0.0%	0.0%	0.0%	0.0%	50.0%	50.0%	0.0%	0.0%
	Distribution Plant									
360.0	Land & Land Rights - R/W	$355,000	$0	$0	$0	$0	$0	$0	$0	$0
360.1	Land Rights - Clearing	272,000	0	0	0	0	0	0	0	0
362.0	Station Equipment	43,305,000	0	0	0	0	0	0	0	0
364.0	Poles, Towers & Fixtures	42,043,000	0	0	0	0	0	0	0	0
365.0	Overhead Conductors & Devices	37,418,000	0	0	0	0	0	0	0	0
367.0	Undergrd Conductors & Devices	38,981,000	0	0	0	0	0	0	0	0
368.0	Line Transformers	27,114,000	0	0	0	0	0	0	0	0
369.0	Services	6,005,000	0	0	0	0	0	0	0	0
370.0	Meters	8,078,000	0	0	0	0	0	0	0	0
371.0	Installation on Customers' Premises	933,000	0	0	0	0	0	0	0	0
373.0	Street Lighting & Signal Systems	916,000	0	0	0	0	0	0	0	0
	Total Distribution Plant	$205,510,000	$0	$0	$0	$0	$0	$0	$0	$0
	% of Total	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Total Plant Before General Plant	$322,817,000	$0	$0	$15,943,192	$16,593,935	$42,384,937	$42,384,937	$0	$0
	% of Total	100.0%	0.0%	0.0%	4.9%	5.1%	13.1%	13.1%	0.0%	0.0%
	General Plant									
389.0	Land & Land Rights	$1,249,000	$0	$0	$180,477	$187,843	$100,493	$100,493	$0	$0
390.0	Structures - Frame & Iron	290,000	0	0	41,904	43,615	23,333	23,333	0	0
390.1	Structures - Masonry	8,721,000	0	0	1,260,160	1,311,595	701,677	701,677	0	0
391.0	Office Furn. & Equipment	4,260,000	0	0	615,558	640,683	342,753	342,753	0	0
391.1	Computer Equipment	7,810,000	0	0	1,128,523	1,174,585	628,380	628,380	0	0
392.0	Transportation Equipment	7,421,000	0	0	1,072,313	1,116,081	597,082	597,082	0	0
394.0	Tools	3,129,000	0	0	452,132	470,586	251,754	251,754	0	0
397.0	Communication Equipment	3,797,000	0	0	548,656	571,050	305,500	305,500	0	0
	Total General Plant	$36,677,000	$0	$0	$5,299,721	$5,516,037	$2,950,972	$2,950,972	$0	$0
	% of Total	100.0%	0.0%	0.0%	14.4%	15.0%	8.0%	8.0%	0.0%	0.0%
	Total Plant In Service	$359,494,000	$0	$0	$21,242,914	$22,109,971	$45,335,908	$45,335,908	$0	$0
	% of Total	100.0%	0%	0%	6%	6%	13%	13%	0%	0%

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West .tenay Power
Exhibit B-6
FUNCTIONALIZATION AND CLASSIFICATION
OF PLANT IN SERVICE (RATE BASE)
Minimum System Approach
As of December 1997

Acct. No.	Plant Description	Total Rate Base	Power Supply Demand Winter (CGPW)	Power Supply Demand Summer (CGPS)	Power Supply Energy Winter (GEW)	Power Supply Energy Summer (GES)	Transmission Related Demand Winter (CTPW)	Transmission Related Demand Summer (CTPS)	Transmission Related Energy Related Winter (EWT)	Transmission Related Energy Related Summer (EST)
	Less: Accumulated Depreciation									
108.3	Hydro Plant	$7,459,000	$0	$0	$3,654,910	$3,804,090	$0	$0	$0	$0
108.4	Other Production Plant	1,477,000	0	0	723,730	753,270	0	0	0	0
108.5	Transmission Plant	25,675,000	0	0	0	0	12,837,500	12,837,500	0	0
108.6	Distribution Plant	68,237,000	0	0	0	0	0	0	0	0
108.7	General Plant	15,386,000	0	0	2,223,233	2,313,977	1,237,932	1,237,932	0	0
108.9	Generation Integration	207,172	0	0	101,514	105,658	0	0	0	0
	Total Accumulated Depreciation	$118,441,172	$0	$0	$6,703,387	$6,976,995	$14,075,432	$14,075,432	$0	$0
	Plus: Other Rate Base Items									
107.1	Plant not subject to AFUDC									
	Production	$2,777,000	$0	$0	$1,360,730	$1,416,270	$0	$0	$0	$0
107.2	Plant subject to AFDUC									
	Production	81,000	0	0	39,690	41,310	0	0	0	0
114.0	Plant Acquisition Adjustment	11,912,000	0	0	5,836,880	6,075,120	0	0	0	0
105.0	Plant for Future Use	291,000	0	0	0	0	0	0	0	0
186.0	Deferred Charges									
	DSM	6,256,250	397,272	397,272	2,213,336	2,303,676	472,347	472,347	0	0
	Prepaid Pension	4,735,000	0	0	684,194	712,120	380,970	380,970	0	0
	All Else	1,508,750	0	0	89,154	92,793	190,269	190,269	0	0
	Total Other Rate Base Items	$27,561,000	$397,272	$397,272	$10,223,984	$10,641,289	$1,043,586	$1,043,586	$0	$0
	Less: Working Capital									
111.0	Accumulated Amortization	$2,606,000	$0	$0	$147,491	$153,511	$309,694	$309,694	$0	$0
252.0	Contributions in Aid of Construction	36,500,000	0	0	0	0	0	0	0	0
	Total Working Capital	$39,106,000	$0	$0	$147,491	$153,511	$309,694	$309,694	$0	$0
	TOTAL DEPRECIATED RATE BASE	$229,507,828	$397,272	$397,272	$24,616,019	$25,620,755	$31,994,367	$31,994,367	$0	$0
	Prior Year Depreciated Rate Base	$229,715,000	$397,630	$397,630	$24,638,239	$25,643,882	$32,023,248	$32,023,248	$0	$0
	Mean Depreciated Rate Base	$229,611,414	$397,451	$397,451	$24,627,129	$25,632,318	$32,008,808	$32,008,808	$0	$0
	Add: Allowance for Working Capital									
	Production	$800,000	$0	$0	$392,000	$408,000	$0	$0	$0	$0
	Transmission	4,000,000	0	0	0	0	2,000,000	2,000,000	0	0
	Distribution	3,200,000	0	0	0	0	0	0	0	0
	General	2,000,000	0	0	98,775	102,807	262,594	262,594	0	0
	Total Allowance for Working Capital	$10,000,000	$0	$0	$490,775	$510,807	$2,262,594	$2,262,594	$0	$0
	TOTAL RATE BASE	$239,611,414	$397,451	$397,451	$25,117,905	$26,143,125	$34,271,402	$34,271,402	$0	$0
	Percentage of Rate Base	100.0%	0.2%	0.2%	10.5%	10.9%	14.3%	14.3%	0.0%	0.0%

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West Kootenay Power
Exhibit B-6
FUNCTIONALIZATION AND CLASSIFICATION
OF PLANT IN SERVICE (RATE BASE)
Minimum System Approach
As of December 1997

		Distribution Related								
		Demand								
Acct. No.	Plant Description	Primary (NCPP)	Primary (NCPP-II)	Secondary (NCPS)	Actual Customer (AC)	Weighted Acct/Mtr. Reading (WCA)	Meters & Services (WCMS)	Secondary Customer (SC)	Direct Assignment (DA)	Classification Factor
	Hydraulic Production Plant									
330.0	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	49% GEN, 51% GES
331.0	Structures & Improvements	0	0	0	0	0	0	0	0	49% GEN, 51% GES
332.0	Reservoirs, Dams & Waterways	0	0	0	0	0	0	0	0	49% GEN, 51% GES
333.0	Water Wheels/Turbines/Generators	0	0	0	0	0	0	0	0	49% GEN, 51% GES
334.0	Accessory Electric Equipment	0	0	0	0	0	0	0	0	49% GEN, 51% GES
335.0	Miscellaneous Power Plant Equipment	0	0	0	0	0	0	0	0	49% GEN, 51% GES
336.0	Roads, Railroads and Bridges	0	0	0	0	0	0	0	0	49% GEN, 51% GES
	Total Hydraulic Production Plant	$0	$0	$0	$0	$0	$0	$0	$0	
	% of Total	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Other Production Plant									
346.0	Other Production Plant Equipment	$0	$0	$0	$0	$0	$0	$0	$0	49% GEN, 51% GES
	Generation Integration									
347.0	Generation Integration	$0	$0	$0	$0	$0	$0	$0	$0	49% GEN, 51% GES
	Total Production Plant	$0	$0	$0	$0	$0	$0	$0	$0	
	% of Total	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Transmission Plant									
350.0	Land & Land Rights - R/W	$0	$0	$0	$0	$0	$0	$0	$0	50% CTPM, 50% CTPS
350.1	Land Rights - Clearing	0	0	0	0	0	0	0	0	50% CTPM, 50% CTPS
353.0	Station Equipment	0	0	0	0	0	0	0	0	50% CTPM, 50% CTPS
355.0	Poles and Fixtures	0	0	0	0	0	0	0	0	50% CTPM, 50% CTPS
356.0	Overhead Conductors & Devices	0	0	0	0	0	0	0	0	50% CTPM, 50% CTPS
359.0	Roads and Trails	0	0	0	0	0	0	0	0	50% CTPM, 50% CTPS
359.1	Transfer to Generation	0	0	0	0	0	0	0	0	50% CTPM, 50% CTPS
	Total Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	
	% of Total	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Distribution Plant									
360.0	Land & Land Rights - R/W	$0	$355,000	$0	$0	$0	$0	$0	$0	As 100% NCPP-II
360.1	Land Rights - Clearing	0	272,000	0	0	0	0	0	0	As 100% NCPP-II
362.0	Station Equipment	0	43,305,000	0	0	0	0	0	0	As 100% NCPP-II
364.0	Poles, Towers & Fixtures	10,090,320	0	0	0	0	0	31,952,680	0	As 24% NCPP/76% SC
365.0	Overhead Conductors & Devices	19,457,360	0	0	0	0	0	17,960,640	0	As 52% NCPP/48% SC
367.0	Undergrd Conductors & Devices	20,270,120	0	0	0	0	0	18,710,880	0	As 52% NCPP/48% SC
368.0	Line Transformers	0	0	7,591,920	0	0	0	19,522,080	0	As 28% NCPS/72% SC
369.0	Services	0	0	0	0	0	6,005,000	0	0	As WCMS
370.0	Meters	0	0	0	0	0	8,078,000	0	0	As WCMS
371.0	Installation on Customers' Premises	0	0	0	0	0	0	0	933,000	As Direct Assignment
373.0	Street Lighting & Signal Systems	0	0	0	0	0	0	0	916,000	As Direct Assignment
	Total Distribution Plant	$49,817,800	$43,932,000	$7,591,920	$0	$0	$14,173,000	$88,146,280	$1,849,000	
	% of Total	24.2%	21.4%	3.7%	0.0%	0.0%	6.9%	42.9%	0.9%	
	Total Plant Before General Plant	$49,817,800	$43,932,000	$7,591,920	$0	$0	$14,173,000	$88,146,280	$1,849,000	
	% of Total	15.4%	13.6%	2.4%	0.0%	0.0%	4.4%	27.3%	0.6%	
	General Plant									
389.0	Land & Land Rights	$184,765	$145,299	$25,109	$0	$0	$46,875	$291,531	$8,115	As Labor Ratios
390.0	Structures - Frame & Iron	38,256	33,736	5,830	0	0	10,884	67,689	1,420	As Labor Ratios
390.1	Structures - Masonry	1,150,454	1,014,532	175,322	0	0	327,300	2,035,583	42,699	As Labor Ratios
391.0	Office Furn. & Equipment	561,969	495,575	85,641	0	0	159,878	994,334	20,858	As Labor Ratios
391.1	Computer Equipment	1,030,277	908,554	157,008	0	0	293,110	1,822,945	38,239	As Labor Ratios
392.0	Transportation Equipment	978,961	863,300	149,188	0	0	278,511	1,732,148	36,334	As Labor Ratios
394.0	Tools	412,770	364,003	62,904	0	0	117,432	730,345	15,320	As Labor Ratios
397.0	Communication Equipment	500,891	441,713	76,333	0	0	142,502	886,264	18,591	As Labor Ratios
	Total General Plant	$4,838,345	$4,286,712	$737,333	$0	$0	$1,376,493	$8,560,839	$179,576	
	% of Total	13.2%	11.6%	2.0%	0.0%	0.0%	3.8%	23.3%	0.5%	
	Total Plant In Service	$54,656,145	$48,198,712	$8,329,253	$0	$0	$15,549,493	$96,707,119	$2,028,576	
	% of Total	15%	13%	2%	0%	0%	4%	27%	1%	

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West Kootenay Power
Exhibit B-6
FUNCTIONALIZATION AND CLASSIFICATION
OF PLANT IN SERVICE (RATE BASE)
Minimum System Approach
As of December 1997

Acct. No.	Plant Description	Distribution Related: Demand: Primary (NCPP)	Demand: Primary (NCPP-II)	Demand: Secondary (NCPS)	Actual Customer (AC)	Weighted Acct/Mtr. Reading (WCA)	Meters & Services (WCMS)	Secondary Customer (SC)	Direct Assignment (DA)	Classification Factor
	Less: Accumulated Depreciation									
108.3	Hydro Plant	$0	$0	$0	$0	$0	$0	$0	$0	As Total Hydraulic Production Plant
108.4	Other Production Plant	0	0	0	0	0	0	0	0	As Total Other Production Plant
108.5	Transmission Plant	0	0	0	0	0	0	0	0	As Total Transmission Plant
108.6	Distribution Plant	16,541,371	14,587,066	2,520,801	0	0	4,705,966	29,267,859	613,937	As Total Distribution Plant
108.7	General Plant	2,029,686	1,789,885	309,311	0	0	577,439	3,591,271	75,332	As Total General Plant
108.9	Generation Integration	0	0	0	0	0	0	0	0	As Generation Integration
	Total Accumulated Depreciation	$18,571,057	$16,376,951	$2,830,113	$0	$0	$5,283,405	$32,859,130	$689,269	
	Plus: Other Rate Base Items									
107.1	Plant not subject to AFUDC									
	Production	$0	$0	$0	$0	$0	$0	$0	$0	As Total Production Plant
107.2	Plant subject to AFDUC									
	Production	0	0	0	0	0	0	0	0	As Total Production Plant
114.0	Plant Acquisition Adjustment	0	0	0	0	0	0	0	0	As Total Production Plant
105.0	Plant for Future Use	291,000	0	0	0	0	0	0	0	As NCPP
186.0	Deferred Charges									
	DSM	0	0	0	0	0	0	0	0	As 72.2% Energy, 12.7% Capacity and 15.1% Trans.
	Prepaid Pension	624,630	550,832	95,190	0	0	177,705	1,105,204	23,183	As Labor Ratios
	All Else	229,385	202,284	34,957	0	0	65,259	405,867	8,514	As Total Plant in Service
	Total Other Rate Base Items	$1,145,015	$753,116	$130,147	$0	$0	$242,964	$1,511,071	$31,697	
	Less: Working Capital									
111.0	Accumulated Amortization	$408,609	$360,334	$62,270	$0	$0	$116,248	$722,982	$15,166	As Depreciation
252.0	Contributions In Aid of Construction	13,656,861	0	2,609,826	0	0	0	19,317,313	$916,000	As Acct. 365,367,368 and DA
	Total Working Capital	$14,065,470	$360,334	$2,672,095	$0	$0	$116,248	$20,040,296	$931,166	
	TOTAL DEPRECIATED RATE BASE	$23,164,633	$32,214,543	$2,957,192	$0	$0	$10,392,805	$45,318,764	$439,838	
	Prior Year Depreciated Rate Base	$23,185,543	$32,243,623	$2,959,862	$0	$0	$10,402,187	$45,359,672	$440,235	As Depreciated Rate Base
	Mean Depreciated Rate Base	$23,175,088	$32,229,083	$2,958,527	$0	$0	$10,397,496	$45,339,218	$440,037	As Depreciated Rate Base
	Add: Allowance for Working Capital									
	Production	$0	$0	$0	$0	$0	$0	$0	$0	As Total Production Plant
	Transmission	0	0	0	0	0	0	0	0	As Total Transmission Plant
	Distribution	775,714	684,066	118,214	0	0	220,688	1,372,527	28,791	As Total Distribution Plant
	General	308,644	272,179	47,035	0	0	87,808	546,107	11,455	As General Plant
	Total Allowance for Working Capital	$1,084,358	$956,245	$165,249	$0	$0	$308,496	$1,918,634	$40,246	
	TOTAL RATE BASE	$24,259,446	$33,185,328	$3,123,776	$0	$0	$10,705,992	$47,257,852	$480,283	
	Percentage of Rate Base	10.1%	13.8%	1.3%	0.0%	0.0%	4.5%	19.7%	0.2%	

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West Kootenay Power
Exhibit B-6
FUNCTIONALIZATION AND CLASSIFICATION
OF PLANT IN SERVICE (RATE BASE)
Minimum System Approach
As of December 1997

Acct. No.	Plant Description	CGPW	CGPS	GEW	GES	CTPW	CTPS	TEW	TES	NCPP	NCPP-II	NCPS	AC	WCA	WCMS	SC	DA
							BASIS OF CLASSIFICATION TO COST COMPONENTS										
	Hydraulic Production Plant																
330.0	Land & Land Rights	0.0%	0.0%	49.0%	51.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
331.0	Structures & Improvements	0.0%	0.0%	49.0%	51.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
332.0	Reservoirs, Dams & Waterways	0.0%	0.0%	49.0%	51.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
333.0	Water Wheels/Turbines/Generators	0.0%	0.0%	49.0%	51.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
334.0	Accessory Electric Equipment	0.0%	0.0%	49.0%	51.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
335.0	Miscellaneous Power Plant Equipment	0.0%	0.0%	49.0%	51.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
336.0	Roads, Railroads and Bridges	0.0%	0.0%	49.0%	51.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Total Hydraulic Production Plant																
	% of Total																
	Other Production Plant																
346.0	Other Production Plant Equipment	0.0%	0.0%	49.0%	51.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Generation Integration																
347.0	Generation Integration	0.0%	0.0%	49.0%	51.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Total Production Plant																
	% of Total																
	Transmission Plant																
350.0	Land & Land Rights - R/W	0.0%	0.0%	0.0%	0.0%	50.0%	50.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
350.1	Land Rights - Clearing	0.0%	0.0%	0.0%	0.0%	50.0%	50.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
353.0	Station Equipment	0.0%	0.0%	0.0%	0.0%	50.0%	50.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
355.0	Poles and Fixtures	0.0%	0.0%	0.0%	0.0%*	50.0%	50.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
356.0	Overhead Conductors & Devices	0.0%	0.0%	0.0%	0.0%	50.0%	50.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
359.0	Roads and Trails	0.0%	0.0%	0.0%	0.0%	50.0%	50.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
359.1	Transfer to Generation	0.0%	0.0%	0.0%	0.0%	50.0%	50.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Total Transmission Plant																
	% of Total																
	Distribution Plant																
360.0	Land & Land Rights - R/W	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
360.1	Land Rights - Clearing	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
362.0	Station Equipment	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
364.0	Poles, Towers & Fixtures	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	24.0%	0.0%	0.0%	0.0%	0.0%	0.0%	76.0%	0.0%
365.0	Overhead Conductors & Devices	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	52.0%	0.0%	0.0%	0.0%	0.0%	0.0%	48.0%	0.0%
367.0	Undergrd Conductors & Devices	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	52.0%	0.0%	0.0%	0.0%	0.0%	0.0%	48.0%	0.0%
368.0	Line Transformers	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	28.0%	0.0%	0.0%	0.0%	72.0%	0.0%
369.0	Services	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%
370.0	Meters	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%
371.0	Installation on Customers' Premises	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
373.0	Street Lighting & Signal Systems	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
	Total Distribution Plant																
	% of Total																
	Total Plant Before General Plant																
	% of Total																
	General Plant																
389.0	Land & Land Rights	As Labor Ratios															
390.0	Structures - Frame & Iron	As Labor Ratios															
390.1	Structures - Masonry	As Labor Ratios															
391.0	Office Furn. & Equipment	As Labor Ratios															
391.1	Computer Equipment	As Labor Ratios															
392.0	Transportation Equipment	As Labor Ratios															
394.0	Tools	As Labor Ratios															
397.0	Communication Equipment	As Labor Ratios															
	Total General Plant																
	% of Total																

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West Kootenay Po...
Exhibit B-6
FUNCTIONALIZATION AND CLASSIFICATION
OF PLANT IN SERVICE (RATE BASE)
Minimum System Approach
As of December 1997

Acct. No.	Plant Description	CGPW	CGPS	GEW	GES	CTPW	CTPS	TEW	TES	NCPP	NCPP-II	NCPS	AC	WCA	WCMS	SC	DA
		BASIS OF CLASSIFICATION TO COST COMPONENTS															
	Total Plant In Service																
	% of Total																
	Less: Accumulated Depreciation																
108.3	Hydro Plant	As Total Hydraulic Production Plant															
108.4	Other Production Plant	As Total Other Production Plant															
108.5	Transmission Plant	As Total Transmission Plant															
108.6	Distribution Plant	As Total Distribution Plant															
108.7	General Plant	As Total General Plant															
108.9	Generation Integration	As Generation Integration															
	Total Accumulated Depreciation																
	Plus: Other Rate Base Items																
107.1	Plant not subject to AFUDC																
	Production	As Total Production Plant															
107.2	Plant subject to AFDUC																
	Production	As Total Production Plant															
114.0	Plant Acquisition Adjustment	As Total Production Plant															
105.0	Plant for Future Use	As NCPP															
186.0	Deferred Charges																
	DSM	As 72.2% Energy, 12.7% Capacity and 15.1% Trans.															
	Prepaid Pension	As Labor Ratios															
	All Else	As Total Plant in Service															
	Total Other Rate Base Items																
	Less: Working Capital																
111.0	Accumulated Amortization	As Depreciation															
252.0	Contributions In Aid of Construction	As Acct. 365,367,368 and DA															
	Total Working Capital																
	TOTAL DEPRECIATED RATE BASE																
	Prior Year Depreciated Rate Base	As Depreciated Rate Base															
	Mean Depreciated Rate Base	As Depreciated Rate Base															
	Add: Allowance for Working Capital																
	Production	As Total Production Plant															
	Transmission	As Total Transmission Plant															
	Distribution	As Total Distribution Plant															
	General	As General Plant															
	Total Allowance for Working Capital																
	TOTAL RATE BASE																

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West Kootenay . .ver
Exhibit B-6A
SUMMARY OF DIRECT ASSIGNMENTS
- RATE BASE (PLANT IN SERVICE)
Minimum System Approach
As of December 1997

Acct. No.	Plant Description	Total Direct Assignment	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation	Basis of Assignment
	Hydraulic Production Plant										
330.0	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	
331.0	Structures & Improvements	0	0	0	0	0	0	0	0	0	
332.0	Reservoirs, Dams & Waterways	0	0	0	0	0	0	0	0	0	
333.0	Water Wheels/Turbines/Generators	0	0	0	0	0	0	0	0	0	
334.0	Accessory Electric Equipment	0	0	0	0	0	0	0	0	0	
335.0	Miscellaneous Power Plant Equipment	0	0	0	0	0	0	0	0	0	
336.0	Roads, Railroads and Bridges	0	0	0	0	0	0	0	0	0	
	Total Hydraulic Production Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	% of Total	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Other Production Plant										
	Other Production Plant Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	Generation Integration										
	Generation Integration	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	Total Production Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	% of Total	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Transmission Plant										
350.0	Land & Land Rights - R/W	$0	$0	$0	$0	$0	$0	$0	$0	$0	
350.1	Land Rights - Clearing	0	0	0	0	0	0	0	0	0	
353.0	Station Equipment	0	0	0	0	0	0	0	0	0	
355.0	Poles and Fixtures	0	0	0	0	0	0	0	0	0	
356.0	Overhead Conductors & Devices	0	0	0	0	0	0	0	0	0	
359.0	Roads and Trails	0	0	0	0	0	0	0	0	0	
	Transfer to Generation	0	0	0	0	0	0	0	0	0	
	Total Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	% of Total	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Distribution Plant										
360.0	Land & Land Rights - R/W	$0	$0	$0	$0	$0	$0	$0	$0	$0	
360.1	Land Rights - Clearing	0	0	0	0	0	0	0	0	0	
362.0	Station Equipment	0	0	0	0	0	0	0	0	0	
364.0	Poles, Towers & Fixtures	0	0	0	0	0	0	0	0	0	
365.0	Overhead Conductors & Devices	0	0	0	0	0	0	0	0	0	
367.0	Undergrd Conductors & Devices	0	0	0	0	0	0	0	0	0	
368.0	Line Transformers	0	0	0	0	0	0	0	0	0	
369.0	Services	0	0	0	0	0	0	0	0	0	
370.0	Meters	0	0	0	0	0	0	0	0	0	
371.0	Installation on Customers' Premises	933,000	0	0	0	0	0	0	933,000	0	As Lighting
373.0	Street Lighting & Signal Systems	916,000	0	0	0	0	0	0	916,000	0	As Lighting
	Total Distribution Plant	$1,849,000	$0	$0	$0	$0	$0	$0	$1,849,000	$0	
	% of Total	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	
	Total Plant Before General Plant	$1,849,000	$0	$0	$0	$0	$0	$0	$1,849,000	$0	
	% of Total	100.0%	0%	0%	0%	0%	0%	0%	100%	0%	

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West Kootenay Power
Exhibit B-6A
SUMMARY OF DIRECT ASSIGNMENTS
- RATE BASE (PLANT IN SERVICE)
Minimum System Approach
As of December 1997

Acct. No.	Plant Description	Total Direct Assignment	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation	Basis of Assignment
	General Plant										
389.0	Land & Land Rights	$6,115	$0	$0	$0	$0	$0	$0	$6,115	$0	As Labor Ratios
390.0	Structures - Frame & Iron	1,420	0	0	0	0	0	0	1,420	0	As Labor Ratios
390.1	Structures - Masonry	42,699	0	0	0	0	0	0	42,699	0	As Labor Ratios
391.0	Office Furn. & Equipment	20,858	0	0	0	0	0	0	20,858	0	As Labor Ratios
391.1	Computer Equipment	38,239	0	0	0	0	0	0	38,239	0	As Labor Ratios
392.0	Transportation Equipment	36,334	0	0	0	0	0	0	36,334	0	As Labor Ratios
394.0	Tools	15,320	0	0	0	0	0	0	15,320	0	As Labor Ratios
397.0	Communication Equipment	18,591	0	0	0	0	0	0	18,591	0	As Labor Ratios
	Total General Plant	$179,576	$0	$0	$0	$0	$0	$0	$179,576	$0	
	% of Total	100%	0%	0%	0%	0%	0%	0%	100%	0%	
	Total Plant In Service	$2,028,576	$0	$0	$0	$0	$0	$0	$2,028,576	$0	
	% of Total	100%	0%	0%	0%	0%	0%	0%	100%	0%	
	Less: Accumulated Depreciation										
108.3	Hydro Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	
108.4	Other Production Plant	0	0	0	0	0	0	0	0	0	
108.5	Transmission Plant	0	0	0	0	0	0	0	0	0	
108.6	Distribution Plant	613,937	0	0	0	0	0	0	613,937	0	As Distribution Plant
108.7	General Plant	75,332	0	0	0	0	0	0	75,332	0	As General Plant
108.9	Generation Integration	0	0	0	0	0	0	0	0	0	
	Total Accumulated Depreciation	$689,269	$0	$0	$0	$0	$0	$0	$689,269	$0	
	Plus: Other Rate Base Items										
107.1	Plant not subject to AFUDC	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	Production	0	0	0	0	0	0	0	0	0	
	Plant subject to AFDUC										
	Production	0	0	0	0	0	0	0	0	0	
	Plant Acquisition Adjustment	0	0	0	0	0	0	0	0	0	
	Plant for Future Use	0	0	0	0	0	0	0	0	0	
	Deferred Charges										
	DSM	0	0	0	0	0	0	0	0	0	
	Prepaid Pension	23,183	0	0	0	0	0	0	23,183	0	As Labor Ratios
	All Else	8,514	0	0	0	0	0	0	8,514	0	As Total Plant in Service
	Total Other Rate Base Items	$31,697	$0	$0	$0	$0	$0	$0	$31,697	$0	
	Less: Working Capital										
111.0	Accumulated Amortization	$15,166	$0	$0	$0	$0	$0	$0	$15,166	$0	As Total Electric Plant
252.0	Contributions In Aid of Construction	916,000	0	0	164,880	604,560	146,560	0	0	0	Utility Provided
	Total Working Capital	$931,166	$0	$0	$164,880	$604,560	$146,560	$0	$15,166	$0	
	TOTAL DEPRECIATED RATE BASE	$439,838	$0	$0	($164,880)	($604,560)	($146,560)	$0	$1,355,838	$0	

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West Kootenay Po
Exhibit B-6A
SUMMARY OF DIRECT ASSIGNMENTS
- RATE BASE (PLANT IN SERVICE)
Minimum System Approach
As of December 1997

Acct. No.	Plant Description	Total Direct Assignment	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation	Basis of Assignment
	Prior Year Depreciated Rate Base	$440,235	0	0	(165,029)	(605,106)	(146,692)	0	1,357,062	0	
	Mean Depreciated Rate Base	$440,037	0	0	(164,954)	(604,833)	(146,626)	0	1,356,450	0	
	Add: Allowance for Working Capital										
	Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	Transmission	0	0	0	0	0	0	0	0	0	
	Distribution	28,791	0	0	0	0	0	0	28,791	0	As Distribution Plant
	General	11,455	0	0	0	0	0	0	11,455	0	As General Plant
	Total Allowance for Working Capital	$40,246	$0	$0	$0	$0	$0	$0	$40,246	$0	
	TOTAL RATE BASE	$480,283	$0	$0	($164,954)	($604,833)	($146,626)	$0	$1,396,697	$0	
	Percentage of Rate Base	100.0%	0.0%	0.0%	-34.3%	-125.9%	-30.5%	0.0%	290.8%	0.0%	

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West Kootenay Power
Exhibit B-6B
CUSTOMER CLASSIFICATION AND ALLOCATION
OF PLANT IN SERVICE (RATE BASE)
Minimum System Approach
As of December 1997

Acct. No.	Plant Description	Total Rate Base	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation
	Hydraulic Production Plant									
330.0	Land & Land Rights	$99,000	$37,842	$17,678	$6,785	$2,161	$30,177	$2,341	$475	$1,541
331.0	Structures & Improvements	4,337,000	1,657,803	774,454	297,225	94,651	1,321,976	102,570	20,791	67,529
332.0	Reservoirs, Dams & Waterways	13,111,000	5,011,634	2,341,218	898,528	286,137	3,996,410	310,076	62,851	204,145
333.0	Water Wheels/Turbines/Generators	6,087,000	2,326,735	1,086,949	417,157	132,844	1,855,400	143,958	29,180	94,778
334.0	Accessory Electric Equipment	2,287,000	874,198	408,387	156,734	49,912	697,109	54,088	10,963	35,610
335.0	Miscellaneous Power Plant Equipment	4,340,000	1,658,950	774,989	297,431	94,717	1,322,891	102,641	20,805	67,576
336.0	Roads, Railroads and Bridges	268,000	102,442	47,856	18,367	5,849	81,690	6,338	1,285	4,173
	Total Hydraulic Production Plant	$30,529,000	$11,669,604	$5,451,532	$2,092,226	$666,270	$9,305,653	$722,013	$146,349	$475,353
	% of Total	100.0%	38.2%	17.9%	6.9%	2.2%	30.5%	2.4%	0.5%	1.6%
	Other Production Plant									
	Other Production Plant Equipment	$1,353,000	$517,180	$241,604	$92,724	$29,528	$412,413	$31,999	$6,486	$21,067
	Generation Integration									
	Generation Integration	$655,127	$250,420	$116,985	$44,897	$14,298	$199,692	$15,494	$3,141	$10,201
	Total Production Plant	$32,537,127	$12,437,204	$5,810,121	$2,229,848	$710,096	$9,917,757	$769,505	$155,975	$506,621
	% of Total	100.0%	38.2%	17.9%	6.9%	2.2%	30.5%	2.4%	0.5%	1.6%
	Transmission Plant									
350.0	Land & Land Rights - R/W	$1,767,000	$603,072	$339,816	$132,686	$68,634	$532,329	$49,758	$3,888	$36,816
350.1	Land Rights - Clearing	2,807,000	958,021	539,820	210,781	109,031	845,641	79,045	6,177	58,484
353.0	Station Equipment	29,201,000	9,966,222	5,615,709	2,192,739	1,134,236	8,797,133	822,295	64,259	608,408
355.0	Poles and Fixtures	26,486,000	9,039,600	5,093,581	1,988,866	1,028,779	7,979,208	745,841	58,284	551,840
356.0	Overhead Conductors & Devices	25,005,000	8,534,136	4,808,767	1,877,656	971,254	7,533,040	704,136	55,025	520,984
359.0	Roads and Trails	159,000	54,266	30,578	11,940	6,176	47,901	4,477	350	3,313
359.1	Transfer to Generation	(655,127)	(223,593)	(125,989)	(49,194)	(25,447)	(197,364)	(18,448)	(1,442)	(13,650)
	Total Transmission Plant	$84,769,873	$28,931,727	$16,302,281	$6,365,474	$3,292,663	$25,537,888	$2,387,105	$186,542	$1,766,195
	% of Total	100.0%	34.1%	19.2%	7.5%	3.9%	30.1%	2.8%	0.2%	2.1%
	Distribution Plant									
360.0	Land & Land Rights - R/W	$355,000	$139,798	$80,637	$26,345	$0	$99,908	$0	$2,266	$6,046
360.1	Land Rights - Clearing	272,000	107,113	61,784	20,186	0	76,549	0	1,736	4,632
362.0	Station Equipment	43,305,000	17,053,360	9,836,613	3,213,762	0	12,187,336	0	276,420	737,508
364.0	Poles, Towers & Fixtures	42,043,000	34,609,321	6,670,853	0	0	0	0	157,101	605,725
365.0	Overhead Conductors & Devices	37,418,000	27,878,943	8,609,352	0	0	0	0	224,869	704,836
367.0	Undergrd Conductors & Devices	38,981,000	29,043,484	8,968,976	0	0	0	0	234,262	734,277
368.0	Line Transformers	27,114,000	22,017,341	4,578,742	0	0	0	0	110,121	407,796
369.0	Services	6,095,000	4,206,155	749,439	726,527	64,105	299,158	0	0	49,616
370.0	Meters	8,078,000	5,574,621	993,268	962,902	84,962	396,489	0	0	65,758
371.0	Installation on Customers' Premises	933,000	0	0	0	0	0	0	933,000	0
373.0	Street Lighting & Signal Systems	916,000	0	0	0	0	0	0	916,000	0
	Total Distribution Plant	$205,510,000	$140,630,136	$40,549,665	$4,949,722	$149,067	$13,059,440	$0	$2,855,775	$3,316,194
	% of Total	100.0%	68.4%	19.7%	2.4%	0.1%	6.4%	0.0%	1.4%	1.6%
	Total Plant Before General Plant	$322,817,000	$181,999,067	$62,662,067	$13,545,044	$4,151,827	$48,515,083	$3,156,610	$3,198,293	$5,589,010
	% of Total	100.0%	56%	19%	4%	1%	15%	1%	1%	2%

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West Kootenay Power
Exhibit B-6B
CUSTOMER CLASSIFICATION AND ALLOCATION
OF PLANT IN SERVICE (RATE BASE)
Minimum System Approach
As of December 1997

Acct. No.	Plant Description	Total Rate Base	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation
	General Plant									
389.0	Land & Land Rights	$1,249,000	$674,499	$238,535	$56,705	$16,338	$216,010	$14,371	$11,653	$20,890
390.0	Structures - Frame & Iron	290,000	156,609	55,384	13,166	3,793	50,154	3,337	2,706	4,850
390.1	Structures - Masonry	8,721,000	4,709,610	1,665,541	395,933	114,078	1,508,267	100,340	81,366	145,864
391.0	Office Furn. & Equipment	4,260,000	2,300,532	813,577	193,404	55,725	736,752	49,014	39,745	71,251
391.1	Computer Equipment	7,810,000	4,217,642	1,491,558	354,574	102,162	1,350,712	89,859	72,866	130,627
392.0	Transportation Equipment	7,421,000	4,007,570	1,417,266	336,913	97,073	1,283,436	85,383	69,237	124,121
394.0	Tools	3,129,000	1,689,757	597,578	142,057	40,930	541,150	36,001	29,193	52,335
397.0	Communication Equipment	3,797,000	2,050,498	725,153	172,384	49,668	656,678	43,687	35,425	63,507
	Total General Plant	$36,677,000	$19,806,717	$7,004,591	$1,665,135	$479,768	$6,343,160	$421,991	$342,191	$613,447
	% of Total	100.0%	54.0%	19.1%	4.5%	1.3%	17.3%	1.2%	0.9%	1.7%
	Total Plant In Service	$359,494,000	$201,805,784	$69,666,658	$15,210,179	$4,631,595	$54,858,243	$3,578,601	$3,540,484	$6,202,456
	% of Total	100.0%	56.1%	19.4%	4.2%	1.3%	15.3%	1.0%	1.0%	1.7%
	Less: Accumulated Depreciation									
108.3	Hydro Plant	$7,459,000	$2,851,177	$1,331,946	$511,183	$162,787	$2,273,604	$176,406	$35,757	$116,141
108.4	Other Production Plant	1,477,000	564,578	263,746	101,222	32,234	450,210	34,931	7,080	22,998
108.5	Transmission Plant	25,675,000	8,762,808	4,937,616	1,927,967	997,278	7,734,885	723,004	56,500	534,943
108.6	Distribution Plant	68,237,000	46,694,461	13,464,004	1,643,493	49,496	4,336,222	0	948,224	1,101,100
108.7	General Plant	15,386,000	8,308,917	2,938,426	698,524	201,263	2,660,955	177,025	143,549	257,341
108.9	Generation Integration	207,172	79,191	36,994	14,198	4,521	63,149	4,900	993	3,226
	Total Accumulated Depreciation	$118,441,172	$67,261,131	$22,972,732	$4,896,588	$1,447,579	$17,519,025	$1,116,265	$1,192,103	$2,035,748
	Plus: Other Rate Base Items									
107.1	Plant not subject to AFUDC Production	$2,777,000	$1,061,499	$495,886	$190,314	$60,606	$846,467	$65,676	$13,312	$43,239
107.2	Plant subject to AFDUC Production	81,000	30,962	14,464	5,551	1,768	24,690	1,916	388	1,261
114.0	Plant Acquisition Adjustment	11,912,000	4,553,321	2,127,114	816,358	259,970	3,630,939	281,720	57,103	185,476
105.0	Plant for Future Use	291,000	177,844	102,583	0	0	0	0	2,883	7,691
186.0	Deferred Charges									
	DSM	6,256,250	2,320,209	1,141,075	440,163	166,136	1,900,812	155,804	25,481	106,570
	Prepaid Pension	4,735,000	2,557,047	904,293	214,969	61,938	818,902	54,479	44,177	79,196
	All Else	1,508,750	846,953	292,382	63,835	19,438	230,233	15,019	14,859	26,031
	Total Other Rate Base Items	$27,561,000	$11,547,834	$5,077,796	$1,731,191	$569,856	$7,452,043	$574,614	$158,203	$449,465

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West Kootenay Power
Exhibit B-6B
CUSTOMER CLASSIFICATION AND ALLOCATION
OF PLANT IN SERVICE (RATE BASE)
Minimum System Approach
As of December 1997

Acct. No.	Plant Description	Total Rate Base	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation
	Less: Working Capital									
111.0	Accumulated Amortization	$2,606,000	$1,479,912	$505,457	$107,737	$31,850	$385,462	$24,561	$26,229	$44,792
252.0	Contributions in Aid of Construction	36,500,000	27,136,618	7,616,794	164,880	604,560	146,560	0	195,688	634,900
	Total Working Capital	$39,106,000	$28,616,530	$8,122,251	$272,617	$636,410	$532,022	$24,561	$221,917	$679,692
	TOTAL DEPRECIATED RATE BASE	$229,507,828	$117,475,957	$43,649,470	$11,772,165	$3,117,461	$44,259,238	$3,012,389	$2,284,667	$3,936,481
	Prior Year Depreciated Rate Base	$229,715,000	$117,582,000	$43,688,872	$11,782,792	$3,120,275	$44,299,190	$3,015,108	$2,286,729	$3,940,034
	Mean Depreciated Rate Base	$229,611,414	$117,528,978	$43,669,171	$11,777,479	$3,118,868	$44,279,214	$3,013,749	$2,285,698	$3,938,257
	Add: Allowance for Working Capital									
	Production	$800,000	$305,797	$142,855	$54,826	$17,459	$243,851	$18,920	$3,835	$12,456
	Transmission	4,000,000	1,365,189	769,249	300,365	155,370	1,205,045	112,639	8,802	83,341
	Distribution	3,200,000	2,189,754	631,400	77,072	2,321	203,349	0	44,467	51,637
	General	2,000,000	1,127,568	388,220	83,918	25,722	300,573	19,557	19,815	34,626
	Total Allowance for Working Capital	$10,000,000	$4,988,309	$1,931,724	$516,181	$200,872	$1,952,818	$151,116	$76,920	$182,060
	TOTAL RATE BASE	$239,611,414	$122,517,287	$45,600,895	$12,293,659	$3,319,741	$46,232,032	$3,164,865	$2,362,617	$4,120,318
	Percentage of Rate Base	100.0%	51.1%	19.0%	5.1%	1.4%	19.3%	1.3%	1.0%	1.7%

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West Kootenay Power
Exhibit B-7
FUNCTIONALIZATION AND CLASSIFICATION OF
NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

			Power Supply				Transmission Related			
			Demand		Energy		Demand		Energy Related	
Acct. No.	Account Description	Total Expenses	Winter (CGPW)	Summer (CGPS)	Winter (GEW)	Summer (GES)	Winter (CTPW)	Summer (CTPS)	Winter (EWT)	Summer (EST)
	Hydraulic Power Generation Operation									
535.0	Operation, Supervision, Engineering	$751,000	$0	$0	$367,990	$383,010	$0	$0	$0	$0
536.0	Water Fees	6,808,000	0	0	3,335,920	3,472,080	0	0	0	0
538.0	Electric Expenses	282,000	0	0	138,180	143,820	0	0	0	0
539.0	Other Generation Exp.	127,000	0	0	62,230	64,770	0	0	0	0
	Total Hydraulic Power Generation Operation	$7,968,000	$0	$0	$3,904,320	$4,063,680	$0	$0	$0	$0
	Hydraulic Power Generation Maintenance									
541.0	Maintenance Supervision & Engineering	$10,000	$0	$0	$4,900	$5,100	$0	$0	$0	$0
542.0	Maintenance of Structures	257,000	0	0	125,930	131,070	0	0	0	0
543.0	Maintenance of Reservoirs, Dams, Waterways	91,000	0	0	44,590	46,410	0	0	0	0
544.0	Maintenance of Electric Plant	680,000	0	0	333,200	346,800	0	0	0	0
545.0	Maintenance of Miscellaneous Hydraulic Plant	75,000	0	0	36,750	38,250	0	0	0	0
549.0	Miscellaneous	90,000	0	0	44,100	45,900	0	0	0	0
	Total Hydraulic Power Generation Maintenance	$1,203,000	$0	$0	$589,470	$613,530	$0	$0	$0	$0
	Total Hydraulic Power Generation Expense	$9,171,000	$0	$0	$4,493,790	$4,677,210	$0	$0	$0	$0
	Other Power Supply Expenses									
555.1	Winter Demand	$6,065,000	$6,065,000	$0	$0	$0	$0	$0	$0	$0
555.2	Winter Energy	18,120,000	0	0	18,120,000	0	0	0	0	0
555.3	Summer Energy	13,444,000	0	0	0	13,444,000	0	0	0	0
556.0	System Control and Load Dispatch	826,000	826,000	0	0	0	0	0	0	0
	Total Other Power Supply Expenses	$38,455,000	$6,891,000	$0	$18,120,000	$13,444,000	$0	$0	$0	$0
	% of Total	100.0%	17.9%	0.0%	47.1%	35.0%	0.0%	0.0%	0.0%	0.0%
	Total Power Supply Costs	$47,626,000	$6,891,000	$0	$22,613,790	$18,121,210	$0	$0	$0	$0
	% of Total	100.0%	14.5%	0.0%	47.5%	38.0%	0.0%	0.0%	0.0%	0.0%
	Transmission Operation									
560.0	Operation, Supervision, Engineering	$196,000	$0	$0	$0	$0	$98,000	$98,000	$0	$0
561.0	Load Dispatching	428,000	0	0	0	0	214,000	214,000	0	0
562.0	Station Expenses	24,000	0	0	0	0	12,000	12,000	0	0
563.0	Overhead Line Expense	161,000	0	0	0	0	80,500	80,500	0	0
565.0	Transmission of Electricity	3,508,000	0	0	0	0	1,754,000	1,754,000	0	0
566.0	Miscellaneous Transmission Expenses	15,000	0	0	0	0	7,500	7,500	0	0
567.0	Rents	216,000	0	0	0	0	108,000	108,000	0	0
	Total Transmission Operation	$4,548,000	$0	$0	$0	$0	$2,274,000	$2,274,000	$0	$0
	Transmission Maintenance									
568.0	Maintenance Supervision and Engineering	$588,000	$0	$0	$0	$0	$294,000	$294,000	$0	$0
569.0	Maintenance of Structures	20,000	0	0	0	0	10,000	10,000	0	0
570.0	Maintenance of Station Equipment	315,000	0	0	0	0	157,500	157,500	0	0
571.0	Maintenance of Overhead Lines	609,000	0	0	0	0	304,500	304,500	0	0
	Total Transmission Maintenance	$1,532,000	$0	$0	$0	$0	$766,000	$766,000	$0	$0
	Total Transmission Expense	$6,080,000	$0	$0	$0	$0	$3,040,000	$3,040,000	$0	$0

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Acct. No.	Account Description	Total Expenses	Power Supply Demand Winter (CGPW)	Power Supply Demand Summer (CGPS)	Power Supply Energy Winter (GEW)	Power Supply Energy Summer (GES)	Transmission Related Demand Winter (CTPW)	Transmission Related Demand Summer (CTPS)	Transmission Related Energy Related Winter (EWT)	Transmission Related Energy Related Summer (EST)
	Distribution Operation									
580.0	Operation Supervision & Eng.	$700,000	$0	$0	$0	$0	$0	$0	$0	$0
583.0	Overhead Line Expense	60,000	0	0	0	0	0	0	0	0
586.0	Meter Expense	787,000	0	0	0	0	0	0	0	0
587.0	Customer Installation Expense	68,000	0	0	0	0	0	0	0	0
	Total Distribution Operation	$1,615,000	$0	$0	$0	$0	$0	$0	$0	$0
	Distribution Maintenance									
590.0	Maint. Supervision & Eng.	$2,195,000	$0	$0	$0	$0	$0	$0	$0	$0
591.0	Maint. Structures and Improvements	619,000	0	0	0	0	0	0	0	0
592.0	Maint. Station Equipment	426,000	0	0	0	0	0	0	0	0
593.0	Maint. Overhead Lines	1,895,000	0	0	0	0	0	0	0	0
594.0	Maint. Underground Lines	112,000	0	0	0	0	0	0	0	0
595.0	Maint. Line Transformers	123,000	0	0	0	0	0	0	0	0
596.0	Maint. of Street Lights and Signals	295,000	0	0	0	0	0	0	0	0
597.0	Maint. of Meters	54,000	0	0	0	0	0	0	0	0
598.0	Miscellaneous Maintenance	718,000	0	0	0	0	0	0	0	0
	Total Distribution Maintenance	$6,437,000	$0	$0	$0	$0	$0	$0	$0	$0
	Total Distribution Expense	$8,052,000	$0	$0	$0	$0	$0	$0	$0	$0
	Customer Accounts Expense									
901.0	Customer Acctg. Supervision	$1,633,000	$0	$0	$0	$0	$0	$0	$0	$0
902.0	Meter Reading Expenses	1,141,000	0	0	0	0	0	0	0	0
903.0	Cust. Records, Collection Exp.	908,000	0	0	0	0	0	0	0	0
904.0	Uncollectable Accounts	457,000	0	0	0	0	0	0	0	0
	Total Customer Accts Exp	$4,139,000	$0	$0	$0	$0	$0	$0	$0	$0
	% of Total	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Customer Service & Information Exp.									
909.0	Supervision	$142,000	$0	$0	$0	$0	$0	$0	$0	$0
910.0	Customer Assistance	260,000	0	0	0	0	0	0	0	0
	Total Cust Serv & Info Exp	$402,000	$0	$0	$0	$0	$0	$0	$0	$0
	Total O&M Exp Before A&G Exp	$66,299,000	$6,891,000	$0	$22,613,790	$18,121,210	$3,040,000	$3,040,000	$0	$0
	% Total O&M Exp. Before A&G Exp.	100.0%	10.4%	0.0%	34.1%	27.3%	4.6%	4.6%	0.0%	0.0%
	Total O&M Exp Before A&G and Purchased Power	$27,844,000	$0	$0	$4,493,790	$4,677,210	$3,040,000	$3,040,000	$0	$0
	% of Total	100.0%	0.0%	0.0%	16.1%	16.8%	10.9%	10.9%	0.0%	0.0%

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			Power Supply				Transmission Related			
			Demand		Energy		Demand		Energy Related	
Acct. No.	Account Description	Total Expenses	Winter (CGPW)	Summer (CGPS)	Winter (GEW)	Summer (GES)	Winter (CTPW)	Summer (CTPS)	Winter (EWT)	Summer (EST)
	Salaries									
920.90	Executive and Senior Management	$593,000	$0	$0	$85,687	$89,184	$47,712	$47,712	$0	$0
920.80	Engineering	252,000	0	0	36,413	37,900	20,276	20,276	0	0
920.81	T&D Administration	313,000	0	0	45,228	47,074	25,183	25,183	0	0
920.84	Legal	385,000	0	0	55,631	57,902	30,976	30,976	0	0
920.82	Human Resources	515,000	0	0	74,416	77,453	41,436	41,436	0	0
920.91	Accounting	371,000	0	0	53,608	55,797	29,850	29,850	0	0
920.95	Financial Administration	232,000	0	0	33,523	34,892	18,666	18,666	0	0
920.96	Office Services	440,000	0	0	63,579	66,174	35,402	35,402	0	0
920.93	Payroll	155,000	0	0	22,397	23,311	12,471	12,471	0	0
920.92	Information Services	588,000	0	0	84,964	88,432	47,310	47,310	0	0
920.85	Materials Management	318,000	0	0	45,950	47,826	25,586	25,586	0	0
	Total A&G Salaries	$4,162,000	$0	$0	$601,397	$625,944	$334,868	$334,868	$0	$0
	Labor Expenses									
921.90	Executive and Senior Management	$168,000	$0	$0	$24,276	$25,266	$13,517	$13,517	$0	$0
921.80	Engineering	100,000	0	0	14,450	15,039	8,046	8,046	0	0
921.81	T&D Administration	146,000	0	0	21,097	21,958	11,747	11,747	0	0
921.84	Legal	323,000	0	0	46,673	48,578	25,988	25,988	0	0
921.82	Human Resources	283,000	0	0	40,893	42,562	22,770	22,770	0	0
921.91	Accounting	89,000	0	0	12,860	13,385	7,161	7,161	0	0
921.95	Financial Administration	126,000	0	0	18,207	18,950	10,138	10,138	0	0
921.96	Office Services	11,000	0	0	1,589	1,654	885	885	0	0
921.93	Payroll	38,000	0	0	5,491	5,715	3,057	3,057	0	0
921.92	Information Services	461,000	0	0	66,613	69,332	37,091	37,091	0	0
921.90	Other	1,314,000	0	0	189,869	197,619	105,722	105,722	0	0
	Total A&G Labor Expenses	$3,059,000	$0	$0	$442,017	$460,058	$246,122	$246,122	$0	$0
	Other A&G Expenses									
922.00	Administration & General Transferred	($1,708,000)	$0	$0	($246,801)	($256,875)	($137,423)	($137,423)	$0	$0
923.00	Special Services	$296,000	0	0	42,771	44,517	23,816	23,816	0	0
924.00	Insurance	$787,000	0	0	46,505	48,403	99,249	99,249	0	0
930.00	Conservation Promotion	$119,000	0	0	58,310	60,690	0	0	0	0
930.00	Rate Application and Other	$560,000	17,798	17,798	133,803	139,265	46,753	46,753	0	0
932.00	Maintenance of General Plant	$378,000	0	0	54,620	56,849	30,413	30,413	0	0
933.00	Transportation Equipment Expenses	($1,207,000)	0	0	(174,408)	(181,527)	(97,113)	(97,113)	0	0
	Total Other A&G Expenses	($775,000)	$17,798	$17,798	($85,200)	($88,677)	($34,306)	($34,306)	$0	$0
	Total Admin. & General Exp.	$6,446,000	$17,798	$17,798	$958,214	$997,325	$546,684	$546,684	$0	$0
	Less: Incentive Sharing	$402,000	$0	$0	$40,921	$42,592	$41,520	$41,520	$0	$0
	Less: DSM Sharing	$50,000	$3,175	$3,175	$17,689	$18,411	$3,775	$3,775	$0	$0
	Total O & M Expense	$72,293,000	$6,905,623	$14,623	$23,513,394	$19,057,532	$3,541,389	$3,541,389	$0	$0

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NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

			Power Supply				Transmission Related			
			Demand		Energy		Demand		Energy Related	
Acct. No.	Account Description	Total Expenses	Winter (CGPW)	Summer (CGPS)	Winter (GEW)	Summer (GES)	Winter (CTPW)	Summer (CTPS)	Winter (EWT)	Summer (EST)
	Taxes									
	Taxes - Property	$7,918,000	$0	$0	$1,160,865	$1,208,247	$1,392,345	$1,392,345	$0	$0
	Capital Tax	804,000	1,334	1,334	84,281	87,722	114,995	114,995	0	0
	Total Taxes	$8,722,000	$1,334	$1,334	$1,245,146	$1,295,969	$1,507,341	$1,507,341	$0	$0
	Total Operating Expenses	$81,015,000	$6,906,956	$15,956	$24,758,540	$20,353,501	$5,048,730	$5,048,730	$0	$0
	DEPRECIATION									
	Other Production Plant	$41,000	$0	$0	$20,090	$20,910	$0	$0	$0	$0
	Plant Acquisition Adjustment	186,000	0	0	91,140	94,860	0	0	0	0
403.3	Hydraulic Production Plant	607,000	0	0	297,430	309,570	0	0	0	0
403.5	Transmission Plant	$2,125,000	0	0	0	0	1,062,500	1,062,500	0	0
403.6	Distribution Plant	6,496,000	0	0	0	0	0	0	0	0
403.7	General Plant	2,040,000	0	0	294,774	306,806	164,135	164,135	0	0
	Leasehold Improvements	49,000	706	706	18,177	18,919	1,855	1,855	0	0
	Amortization of Customer Contributions	(1,350,000)	0	0	0	0	0	0	0	0
	Amortization of Deferred Charges	1,425,000	45,289	45,289	340,482	354,379	118,969	118,969	0	0
	Total Depreciation Expense	$11,619,000	$45,995	$45,995	$1,062,093	$1,105,444	$1,347,459	$1,347,459	$0	$0
	Less: AFUDC									
	Allowance for Funds Used During Construction	$300,000	$498	$498	$31,448	$32,732	$42,909	$42,909	$0	$0
	TOTAL OPERATING EXPENSES	$92,334,000	$6,952,454	$61,454	$25,789,185	$21,426,213	$6,353,280	$6,353,280	$0	$0
	Plus: Return on Plant									
	Return on Plant (@12.968%)	$31,087,000	$51,565	$51,565	$3,258,778	$3,391,789	$4,446,345	$4,446,345	$0	$0
	Less: Other Income									
	Pole Rental	$1,050,000	$0	$0	$0	$0	$0	$0	$0	$0
	Connection Fees	430,000	0	0	0	0	0	0	0	0
	NSF Charges	28,000	0	0	0	0	0	0	0	0
	Collection Fees	4,000	0	0	0	0	0	0	0	0
320.2	Facilities Rental Cominco	80,000	42	42	20,684	21,528	10,089	10,089	0	0
745.0	Interest Income less Walden	450,000	0	0	26,591	27,676	56,750	56,750	0	0
750.0	Other Income - Cominco (O&M)	465,000	244	244	120,223	125,130	58,643	58,643	0	0
757.0	Sundry	415,000	0	0	24,523	25,524	52,336	52,336	0	0
	Total Operating Revenues	$2,922,000	$286	$286	$192,020	$199,858	$177,817	$177,817	$0	$0
	NET REVENUE REQUIREMENT	$120,499,000	$7,003,733	$112,733	$28,855,942	$24,618,144	$10,621,808	$10,621,808	$0	$0

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FUNCTIONALIZATION AND CLASSIFICATION OF
NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

		Distribution Related								
		Demand				Weighted				
Acct. No.	Account Description	Primary (NCPP)	Primary (NCPP-II)	Secondary (NCPS)	Actual Customer (AC)	Acct/Mtr. Reading (WCA)	Meters & Services (WCMS)	Secondary Customer (SC)	Direct Assignment (DA)	Classification Factor
	Hydraulic Power Generation Operation									
535.0	Operation, Supervision, Engineering	$0	$0	$0	$0	$0	$0	$0	$0	As Hydraulic Production Plant
536.0	Water Fees	0	0	0	0	0	0	0	0	As Hydraulic Production Plant
538.0	Electric Expenses	0	0	0	0	0	0	0	0	As Hydraulic Production Plant
539.0	Other Generation Exp.	0	0	0	0	0	0	0	0	As Hydraulic Production Plant
	Total Hydraulic Power Generation Operation	$0	$0	$0	$0	$0	$0	$0	$0	
	Hydraulic Power Generation Maintenance									
541.0	Maintenance Supervision & Engineering	$0	$0	$0	$0	$0	$0	$0	$0	As Hydraulic Production Plant
542.0	Maintenance of Structures	0	0	0	0	0	0	0	0	As Hydraulic Production Plant
543.0	Maintenance of Reservoirs, Dams, Waterways	0	0	0	0	0	0	0	0	As Hydraulic Production Plant
544.0	Maintenance of Electric Plant	0	0	0	0	0	0	0	0	As Hydraulic Production Plant
545.0	Maintenance of Miscellaneous Hydraulic Plant	0	0	0	0	0	0	0	0	As Hydraulic Production Plant
549.0	Miscellaneous	0	0	0	0	0	0	0	0	As Hydraulic Production Plant
	Total Hydraulic Power Generation Maintenance	$0	$0	$0	$0	$0	$0	$0	$0	
	Total Hydraulic Power Generation Expense	$0	$0	$0	$0	$0	$0	$0	$0	
	Other Power Supply Expenses									
555.1	Winter Demand	$0	$0	$0	$0	$0	$0	$0	$0	As 100% CGPW
555.2	Winter Energy	0	0	0	0	0	0	0	0	As 100% GEW
555.3	Summer Energy	0	0	0	0	0	0	0	0	As 100% GES
556.0	System Control and Load Dispatch	0	0	0	0	0	0	0	0	As 100% CGPW
	Total Other Power Supply Expenses	$0	$0	$0	$0	$0	$0	$0	$0	
	% of Total	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Total Power Supply Costs	$0	$0	$0	$0	$0	$0	$0	$0	
	% of Total	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Transmission Operation									
560.0	Operation, Supervision, Engineering	$0	$0	$0	$0	$0	$0	$0	$0	As Transmission Plant
561.0	Load Dispatching	0	0	0	0	0	0	0	0	As Transmission Plant
562.0	Station Expenses	0	0	0	0	0	0	0	0	As Transmission Plant
563.0	Overhead Line Expense	0	0	0	0	0	0	0	0	As Transmission Plant
565.0	Transmission of Electricity	0	0	0	0	0	0	0	0	As Transmission Plant
566.0	Miscellaneous Transmission Expenses	0	0	0	0	0	0	0	0	As Transmission Plant
567.0	Rents	0	0	0	0	0	0	0	0	As Transmission Plant
	Total Transmission Operation	$0	$0	$0	$0	$0	$0	$0	$0	
	Transmission Maintenance									
568.0	Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	As Transmission Plant
569.0	Maintenance of Structures	0	0	0	0	0	0	0	0	As Transmission Plant
570.0	Maintenance of Station Equipment	0	0	0	0	0	0	0	0	As Transmission Plant
571.0	Maintenance of Overhead Lines	0	0	0	0	0	0	0	0	As Transmission Plant
	Total Transmission Maintenance	$0	$0	$0	$0	$0	$0	$0	$0	
	Total Transmission Expense	$0	$0	$0	$0	$0	$0	$0	$0	

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Minimum System Approach
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Acct. No.	Account Description	Distribution Related: Demand: Primary (NCPP)	Demand: Primary (NCPP-II)	Demand: Secondary (NCPS)	Actual Customer (AC)	Weighted Acct/Mtr. Reading (WCA)	Meters & Services (WCMS)	Secondary Customer (SC)	Direct Assignment (DA)	Classification Factor
	Distribution Operation									
580.0	Operation Supervision & Eng.	$169,687	$149,639	$25,859	$0	$0	$48,276	$300,240	$6,298	As Distribution Plant
583.0	Overhead Line Expense	0	60,000	0	0	0	0	0	0	As Acct. 364
586.0	Meter Expense	0	0	0	0	0	787,000	0	0	As Meters
587.0	Customer Installation Expense	0	0	0	0	0	0	0	68,000	As Acct. 371
	Total Distribution Operation	$169,687	$209,639	$25,859	$0	$0	$835,276	$300,240	$74,298	
	Distribution Maintenance									
590.0	Maint. Supervision & Eng.	$532,091	$469,227	$81,087	$0	$0	$151,378	$941,468	$19,749	As Distribution Plant
591.0	Maint. Structures and Improvements	0	619,000	0	0	0	0	0	0	As Acct. 364
592.0	Maint. Station Equipment	0	426,000	0	0	0	0	0	0	As Acct. 362
593.0	Maint. Overhead Lines	454,800	0	0	0	0	0	1,440,200	0	As Acct. 364
594.0	Maint. Underground Lines	58,240	0	0	0	0	0	53,760	0	As Acct. 367
595.0	Maint. Line Transformers	0	0	34,440	0	0	0	88,560	0	As Acct. 368
596.0	Maint. of Street Lights and Signals	0	0	0	0	0	0	0	295,000	As Acct. 373
597.0	Maint. of Meters	0	0	0	0	0	54,000	0	0	As Acct. 370
598.0	Miscellaneous Maintenance	131,212	190,106	14,504	0	0	25,784	316,878	39,516	As All Other Dist Expense
	Total Distribution Maintenance	$1,178,344	$1,704,332	$130,031	$0	$0	$231,163	$2,840,866	$354,264	
	Total Distribution Expense	$1,348,031	$1,913,972	$155,891	$0	$0	$1,066,438	$3,141,106	$428,562	
	Customer Accounts Expense									
901.0	Customer Acctg. Supervision	$0	$0	$0	$0	$1,335,202	$0	$0	$297,798	As All Other Cust. Expenses
902.0	Meter Reading Expenses	0	0	0	0	1,141,000	0	0	0	As WCA
903.0	Cust. Records, Collection Exp.	0	0	0	0	908,000	0	0	0	As WCA
904.0	Uncollectable Accounts	0	0	0	0	0	0	0	457,000	As DA
	Total Customer Accts Exp	$0	$0	$0	$0	$3,384,202	$0	$0	$754,798	
	% of Total	0.0%	0.0%	0.0%	0.0%	81.8%	0.0%	0.0%	18.2%	
	Customer Service & Information Exp.									
909.0	Supervision	$0	$0	$0	$0	$116,105	$0	$0	$25,895	As Cust. Acct. Exp.
910.0	Customer Assistance	0	0	0	0	212,586	0	0	47,414	As Cust. Acct. Exp.
	Total Cust Serv & Info Exp	$0	$0	$0	$0	$328,690	$0	$0	$73,310	
	Total O&M Exp Before A&G Exp	$1,348,031	$1,913,972	$155,891	$0	$3,712,893	$1,066,438	$3,141,106	$1,256,670	
	% Total O&M Exp. Before A&G Exp.	2.0%	2.9%	0.2%	0.0%	5.6%	1.6%	4.7%	1.9%	
	Total O&M Exp Before A&G and Purchased Power	$1,348,031	$1,913,972	$155,891	$0	$3,712,893	$1,066,438	$3,141,106	$1,256,670	
	% of Total	4.8%	6.9%	0.6%	0.0%	13.3%	3.8%	11.3%	4.5%	

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West Kootenay Power
Exhibit B-7
FUNCTIONALIZATION AND CLASSIFICATION OF
NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

Acct. No.	Account Description	Distribution Related: Demand: Primary (NCPP)	Primary (NCPP-II)	Secondary (NCPS)	Actual Customer (AC)	Weighted Acct/Mtr. Reading (WCA)	Meters & Services (WCMS)	Secondary Customer (SC)	Direct Assignment (DA)	Classification Factor
	Salaries									
920.90	Executive and Senior Management	$78,227	$68,985	$11,921	$0	$0	$22,255	$138,413	$2,903	As Labor Ratios
920.80	Engineering	33,243	29,316	5,066	0	0	9,458	58,820	1,234	As Labor Ratios
920.81	T&D Administration	41,290	36,412	6,292	0	0	11,747	73,058	1,532	As Labor Ratios
920.84	Legal	50,788	44,788	7,740	0	0	14,449	89,863	1,885	As Labor Ratios
920.82	Human Resources	67,938	59,911	10,353	0	0	19,328	120,207	2,522	As Labor Ratios
920.91	Accounting	48,941	43,159	7,458	0	0	13,924	86,596	1,816	As Labor Ratios
920.95	Financial Administration	30,605	26,989	4,664	0	0	8,707	54,151	1,136	As Labor Ratios
920.96	Office Services	58,044	51,186	8,846	0	0	16,513	102,701	2,154	As Labor Ratios
920.93	Payroll	20,447	18,031	3,116	0	0	5,817	36,179	759	As Labor Ratios
920.92	Information Services	77,568	68,403	11,821	0	0	22,068	137,246	2,879	As Labor Ratios
920.85	Materials Management	41,950	36,994	6,393	0	0	11,935	74,225	1,557	As Labor Ratios
	Total A&G Salaries	$549,041	$484,174	$83,670	$0	$0	$156,200	$971,459	$20,378	
	Labor Expenses									
921.90	Executive and Senior Management	$22,162	$19,544	$3,377	$0	$0	$6,305	$39,213	$823	As Labor Ratios
921.80	Engineering	13,192	11,633	2,010	0	0	3,753	23,341	490	As Labor Ratios
921.81	T&D Administration	19,260	16,984	2,935	0	0	5,479	34,078	715	As Labor Ratios
921.84	Legal	42,609	37,575	6,493	0	0	12,122	75,392	1,581	As Labor Ratios
921.82	Human Resources	37,333	32,922	5,689	0	0	10,621	66,055	1,386	As Labor Ratios
921.91	Accounting	11,741	10,354	1,789	0	0	3,340	20,774	436	As Labor Ratios
921.95	Financial Administration	16,622	14,658	2,533	0	0	4,729	29,410	617	As Labor Ratios
921.96	Office Services	1,451	1,280	221	0	0	413	2,568	54	As Labor Ratios
921.93	Payroll	5,013	4,421	764	0	0	1,426	8,870	186	As Labor Ratios
921.92	Information Services	60,814	53,629	9,268	0	0	17,301	107,603	2,257	As Labor Ratios
921.90	Other	173,340	152,860	26,416	0	0	49,315	306,703	6,434	As Labor Ratios
	Total A&G Labor Expenses	$403,536	$355,860	$61,496	$0	$0	$114,805	$714,006	$14,977	
	Other A&G Expenses									
922.00	Administration & General Transferred	($225,315)	($198,695)	($34,337)	$0	$0	($64,101)	($398,667)	($8,363)	As Labor Ratios
923.00	Special Services	39,048	34,434	5,951	0	0	11,109	69,090	1,449	As Labor Ratios
924.00	Insurance	119,653	105,516	18,234	0	0	34,041	211,710	4,441	At Total Plant in Service
930.00	Conservation Promotion	0	0	0	0	0	0	0	0	As Total Production Plant
930.00	Rate Application and Other	38,260	33,740	5,831	0	0	10,885	67,696	1,420	As Acct. 186
932.00	Maintenance of General Plant	49,865	43,974	7,599	0	0	14,186	88,230	1,851	As Labor Ratios
933.00	Transportation Equipment Expenses	(159,225)	(140,413)	(24,265)	0	0	(45,299)	(281,728)	(5,910)	As Labor Ratios
	Total Other A&G Expenses	($137,715)	($121,445)	($20,987)	$0	$0	($39,179)	($243,669)	($5,111)	
	Total Admin. & General Exp.	$814,863	$718,589	$124,180	$0	$0	$231,826	$1,441,796	$30,244	
	Less: Incentive Sharing	$57,075	$50,332	$8,698	$0	$0	$16,238	$100,987	$2,118	As 50% Labor Ratios, 50% Plant in Service
	Less: DSM Sharing	$0	$0	$0	$0	$0	$0	$0	$0	As Deferred DSM
	Total O & M Expense	$2,103,819	$2,582,230	$271,373	$0	$3,712,893	$1,282,026	$4,481,915	$1,284,795	

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Exhibit B-7
FUNCTIONALIZATION AND CLASSIFICATION OF
NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

		Distribution Related								
		Demand			Actual	Weighted	Meters &	Secondary	Direct	
Acct. No.	Account Description	Primary (NCPP)	Primary (NCPP-II)	Secondary (NCPS)	Customer (AC)	Acct/Mtr. Reading (WCA)	Services (WCMS)	Customer (SC)	Assignment (DA)	Classification Factor
	Taxes									
	Taxes - Property	$515,742	$1,091,451	$78,596	$0	$0	$146,727	$912,540	$19,142	28.8% Gen, 23.6% (T&D) Subs, 24.3% Trans, 19.5%
	Capital Tax	81,401	111,351	10,482	0	0	35,923	158,571	1,612	As Total Rate Base
	Total Taxes	$597,143	$1,202,802	$89,077	$0	$0	$182,650	$1,071,110	$20,753	
	Total Operating Expenses	$2,700,962	$3,785,032	$360,450	$0	$3,712,893	$1,464,676	$5,553,026	$1,305,549	
	DEPRECIATION									
	Other Production Plant	$0	$0	$0	$0	$0	$0	$0	$0	As Other Production Plant
	Plant Acquisition Adjustment	0	0	0	0	0	0	0	0	As Acct. 114
403.3	Hydraulic Production Plant	0	0	0	0	0	0	0	0	As Hydraulic Production Plant
403.5	Transmission Plant	0	0	0	0	0	0	0	0	As Transmission Plant
403.6	Distribution Plant	1,574,699	1,388,654	239,974	0	0	447,997	2,786,231	58,445	As Distribution Plant
403.7	General Plant	269,112	237,317	41,011	0	0	76,562	476,160	9,988	As General Plant
	Leasehold Improvements	2,036	1,339	231	0	0	432	2,686	56	As Total Other Rate Base Items
	Amortization of Customer Contributions	(505,117)	0	(96,528)	0	0	0	(714,476)	(33,879)	As Acct. 252
	Amortization of Deferred Charges	97,358	85,855	14,837	0	0	27,698	172,262	3,613	As Deferred Charges
	Total Depreciation Expense	$1,438,088	$1,713,166	$199,526	$0	$0	$552,688	$2,722,863	$38,224	
	Less: AFUDC									
	Allowance for Funds Used During Construction	$30,373	$41,549	$3,911	$0	$0	$13,404	$59,168	$601	As Total Rate Base
	TOTAL OPERATING EXPENSES	$4,108,676	$5,456,648	$556,065	$0	$3,712,893	$2,003,960	$8,216,720	$1,343,171	
	Plus: Return on Plant									
	Return on Plant (@12.968%)	$3,147,402	$4,305,439	$405,276	$0	$0	$1,388,987	$6,131,197	$62,312	As Total Rate Base
	Less: Other Income									
	Pole Rental	$252,000	$0	$0	$0	$0	$0	$798,000	$0	As Acct. 364
	Connection Fees	0	0	0	430,000	0	0	0	0	As 100% AC
	NSF Charges	0	0	0	28,000	0	0	0	0	As 100% AC
	Collection Fees	0	0	0	4,000	0	0	0	0	As 100% AC
320.2	Facilities Rental Cominco	4,249	3,747	647	0	0	1,209	7,517	158	As 47% P, 12% D, 22% T, 19% A&G
745.0	Interest Income less Walden	68,416	60,333	10,426	0	0	19,464	121,054	2,539	As Total Plant in Service
750.0	Other Income - Cominco (O&M)	24,695	21,778	3,763	0	0	7,028	43,695	917	As 47% P, 12% D, 22% T, 19% A&G
757.0	Sundry	63,095	55,641	9,615	0	0	17,950	111,639	2,342	As Total Plant in Service
	Total Operating Revenues	$412,455	$141,498	$24,452	$462,000	$0	$45,649	$1,081,905	$5,955	
	NET REVENUE REQUIREMENT	$6,843,623	$9,620,589	$936,889	($462,000)	$3,712,893	$3,347,299	$13,266,013	$1,399,527	
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West Kootenay Power
Exhibit B-7
FUNCTIONALIZATION AND CLASSIFICATION OF
NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

Acct. No.	Account Description	BASIS OF CLASSIFICATION TO COST COMPONENTS															
		CGPW	CGPS	GEW	GES	CTPW	CTPS	TEW	TES	NCPP	NCPP-II	NCPS	AC	WCA	WCMS	SC	DA
	OPERATION & MAINT. EXPENSE																
	Hydraulic Power Generation Operation																
535.0	Operation, Supervision, Engineering	As Hydraulic Production Plant															
536.0	Water Fees	As Hydraulic Production Plant															
538.0	Electric Expenses	As Hydraulic Production Plant															
539.0	Other Generation Exp.	As Hydraulic Production Plant															
	Total Hydraulic Power Generation Operation																
	Hydraulic Power Generation Maintenance																
541.0	Maintenance Supervision & Engineering	As Hydraulic Production Plant															
542.0	Maintenance of Structures	As Hydraulic Production Plant															
543.0	Maintenance of Reservoirs, Dams, Waterways	As Hydraulic Production Plant															
544.0	Maintenance of Electric Plant	As Hydraulic Production Plant															
545.0	Maintenance of Miscellaneous Hydraulic Plant	As Hydraulic Production Plant															
549.0	Miscellaneous	As Hydraulic Production Plant															
	Total Hydraulic Power Generation Maintenance																
	Total Hydraulic Power Generation Expense																
	Other Power Supply Expenses																
555.1	Winter Demand	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
555.2	Winter Energy	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
555.3	Summer Energy	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
556.0	System Control and Load Dispatch	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Total Other Power Supply Expenses																
	% of Total																
	Total Power Supply Costs																
	% of Total																
	Transmission Operation																
560.0	Operation, Supervision, Engineering	As Transmission Plant															
561.0	Load Dispatching	As Transmission Plant															
562.0	Station Expenses	As Transmission Plant															
563.0	Overhead Line Expense	As Transmission Plant															
565.0	Transmission of Electricity	As Transmission Plant															
566.0	Miscellaneous Transmission Expenses	As Transmission Plant															
567.0	Rents	As Transmission Plant															
	Total Transmission Operation																
	Transmission Maintenance																
568.0	Maintenance Supervision and Engineering	As Transmission Plant															
569.0	Maintenance of Structures	As Transmission Plant															
570.0	Maintenance of Station Equipment	As Transmission Plant															
571.0	Maintenance of Overhead Lines	As Transmission Plant															
	Total Transmission Maintenance																
	Total Transmission Expense																

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West Kootenay Power
Exhibit B-7
FUNCTIONALIZATION AND CLASSIFICATION OF
NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

Acct. No.	Account Description	BASIS OF CLASSIFICATION TO COST COMPONENTS															
		CGPW	CGPS	GEW	GES	CTPW	CTPS	TEW	TES	NCPP	NCPP-II	NCPS	AC	WCA	WCMS	SC	DA
	Distribution Operation																
580.0	Operation Supervision & Eng.	As Distribution Plant															
583.0	Overhead Line Expense	As Acct. 364															
586.0	Meter Expense	As Meters															
587.0	Customer Installation Expense	As Acct. 371															
	Total Distribution Operation																
	Distribution Maintenance																
590.0	Maint. Supervision & Eng.	As Distribution Plant															
591.0	Maint. Structures and Improvements	As Acct. 364															
592.0	Maint. Station Equipment	As Acct. 362															
593.0	Maint. Overhead Lines	As Acct. 364															
594.0	Maint. Underground Lines	As Acct. 367															
595.0	Maint. Line Transformers	As Acct. 368															
596.0	Maint. of Street Lights and Signals	As Acct. 373															
597.0	Maint. of Meters	As Acct. 370															
598.0	Miscellaneous Maintenance	As All Other Dist Expense															
	Total Distribution Maintenance																
	Total Distribution Expense																
	Customer Accounts Expense																
901.0	Customer Acctg. Supervision																
902.0	Meter Reading Expenses	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%
903.0	Cust. Records, Collection Exp.	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%
904.0	Uncollectable Accounts	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
	Total Customer Accts Exp																
	% of Total																
	Customer Service & Information Exp.																
909.0	Supervision	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%
910.0	Customer Assistance	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%
	Total Cust Serv & Info Exp																
	Total O&M Exp Before A&G Exp																
	% Total O&M Exp. Before A&G Exp.																
	Total O&M Exp Before A&G and Purchased Power																
	% of Total																

West Kootenay Po...r
Exhibit B-7
FUNCTIONALIZATION AND CLASSIFICATION OF
NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

Acct. No.	Account Description	BASIS OF CLASSIFICATION TO COST COMPONENTS															
		CGPW	CGPS	GEW	GES	CTPW	CTPS	TEW	TES	NCPP	NCPP-II	NCPS	AC	WCA	WCMS	SC	DA
	Salaries																
920.90	Executive and Senior Management	As Labor Ratios															
920.80	Engineering	As Labor Ratios															
920.81	T&D Administration	As Labor Ratios															
920.84	Legal	As Labor Ratios															
920.82	Human Resources	As Labor Ratios															
920.91	Accounting	As Labor Ratios															
920.95	Financial Administration	As Labor Ratios															
920.96	Office Services	As Labor Ratios															
920.93	Payroll	As Labor Ratios															
920.92	Information Services	As Labor Ratios															
920.85	Materials Management	As Labor Ratios															
	Total A&G Salaries																
	Labor Expenses																
921.90	Executive and Senior Management	As Labor Ratios															
921.80	Engineering	As Labor Ratios															
921.81	T&D Administration	As Labor Ratios															
921.84	Legal	As Labor Ratios															
921.82	Human Resources	As Labor Ratios															
921.91	Accounting	As Labor Ratios															
921.95	Financial Administration	As Labor Ratios															
921.96	Office Services	As Labor Ratios															
921.93	Payroll	As Labor Ratios															
921.92	Information Services	As Labor Ratios															
921.90	Other	As Labor Ratios															
	Total A&G Labor Expenses																
	Other A&G Expenses																
922.00	Administration & General Transferred																
923.00	Special Services																
924.00	Insurance																
930.00	Conservation Promotion																
930.00	Rate Application and Other																
932.00	Maintenance of General Plant																
933.00	Transportation Equipment Expenses																
	Total Other A&G Expenses																
	Total Admin. & General Exp.																
	Less: Incentive Sharing																
	Less: DSM Sharing																
	Total O & M Expense																

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West Kootenay Power
Exhibit B-7
FUNCTIONALIZATION AND CLASSIFICATION OF
NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

Acct. No.	Account Description	CGPW	CGPS	GEW	GES	CTPW	CTPS	TEW	TES	NCPP	NCPP-II	NCPS	AC	WCA	WCMS	SC	DA
		BASIS OF CLASSIFICATION TO COST COMPONENTS															
	Taxes																
	Taxes - Property	28.8% Gen, 23.6% (T&D) Subs, 24.3% Trans, 19.5% Dist, 3.8% Gen Plant															
	Capital Tax	As Total Rate Base															
	Total Taxes																
	Total Operating Expenses																
	DEPRECIATION																
	Other Production Plant	As Other Production Plant															
	Plant Acquisition Adjustment	As Acct. 114															
403.3	Hydraulic Production Plant	As Hydraulic Production Plant															
403.5	Transmission Plant	As Transmission Plant															
403.6	Distribution Plant	As Distribution Plant															
403.7	General Plant	As General Plant															
	Leasehold Improvements	As Total Other Rate Base Items															
	Amortization of Customer Contributions	As Acct. 252															
	Amortization of Deferred Charges																
	Total Depreciation Expense																
	Less: AFUDC																
	Allowance for Funds Used During Construction																
	TOTAL OPERATING EXPENSES																
	Plus: Return on Plant																
	Return on Plant (@12.968%)																
	Less: Other Income																
	Pole Rental	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
	Connection Fees	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	NSF Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
	Collection Fees	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
320.2	Facilities Rental Cominco																
745.0	Interest Income less Walden																
750.0	Other Income - Cominco (O&M)																
757.0	Sundry																
	Total Operating Revenues																
	NET REVENUE REQUIREMENT																

West Kootenay Power
Exhibit B-7A
SUMMARY OF DIRECT ASSIGNMENTS
- NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

Acct. No.	Account Description	Total Direct Assignment	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation	Basis of Assignment
	Hydraulic Power Generation Operation										
535.0	Operation, Supervision, Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	
536.0	Water Fees	0	0	0	0	0	0	0	0	0	
538.0	Electric Expenses	0	0	0	0	0	0	0	0	0	
539.0	Other Generation Exp.	0	0	0	0	0	0	0	0	0	
	Total Hydraulic Power Generation Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	Hydraulic Power Generation Maintenance										
541.0	Maintenance Supervision & Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	
542.0	Maintenance of Structures	0	0	0	0	0	0	0	0	0	
543.0	Maintenance of Reservoirs, Dams, Waterways	0	0	0	0	0	0	0	0	0	
544.0	Maintenance of Electric Plant	0	0	0	0	0	0	0	0	0	
545.0	Maintenance of Miscellaneous Hydraulic Plant Miscellaneous	0	0	0	0	0	0	0	0	0	
	Total Hydraulic Power Generation Maintenance	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	Total Hydraulic Power Generation Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	Other Power Supply Expenses										
555.1	Winter Demand	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	Winter Energy	0	0	0	0	0	0	0	0	0	
555.3	Summer Energy	0	0	0	0	0	0	0	0	0	
556.0	System Control and Load Dispatch	0	0	0	0	0	0	0	0	0	
	Total Other Power Supply Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	% of Total										
	Total Power Supply Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	% of Total										
	Transmission Operation										
560.0	Operation, Supervision, Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	
561.0	Load Dispatching	0	0	0	0	0	0	0	0	0	
562.0	Station Expenses	0	0	0	0	0	0	0	0	0	
563.0	Overhead Line Expense	0	0	0	0	0	0	0	0	0	
565.0	Transmission of Electricity	0	0	0	0	0	0	0	0	0	
566.0	Miscellaneous Transmission Expenses	0	0	0	0	0	0	0	0	0	
567.0	Rents	0	0	0	0	0	0	0	0	0	
	Total Transmission Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	Transmission Maintenance										
568.0	Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	
569.0	Maintenance of Structures	0	0	0	0	0	0	0	0	0	
570.0	Maintenance of Station Equipment	0	0	0	0	0	0	0	0	0	
571.0	Maintenance of Overhead Lines	0	0	0	0	0	0	0	0	0	
	Total Transmission Maintenance	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	Total Transmission Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	

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West Kootenay Power
Exhibit B-7A
SUMMARY OF DIRECT ASSIGNMENTS
- NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

Acct. No.	Account Description	Total Direct Assignment	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation	Basis of Assignment
	Distribution Operation										
580.0	Operation Supervision & Eng.	$6,298	$0	$0	$0	$0	$0	$0	$6,298	$0	As Distribution Plant
583.0	Overhead Line Expense	0	0	0	0	0	0	0	0	0	As Distribution Plant
586.0	Meter Expense	0	0	0	0	0	0	0	0	0	
587.0	Customer Installation Expense	68,000	0	0	0	0	0	0	68,000	0	As Acct. 371
	Total Distribution Operation	$74,298	$0	$0	$0	$0	$0	$0	$74,298	$0	
	Distribution Maintenance										
590.0	Maint. Supervision & Eng.	$19,749	$0	$0	$0	$0	$0	$0	$19,749	$0	As Distribution Plant
591.0	Maint. Structures and Improvements	0	0	0	0	0	0	0	0	0	As Distribution Plant
592.0	Maint. Station Equipment	0	0	0	0	0	0	0	0	0	
593.0	Maint. Overhead Lines	0	0	0	0	0	0	0	0	0	
594.0	Maint. Underground Lines	0	0	0	0	0	0	0	0	0	
595.0	Maint. Line Transformers	0	0	0	0	0	0	0	0	0	
596.0	Maint. of Street Lights and Signals	295,000	0	0	0	0	0	0	295,000	0	As Acct. 373
597.0	Maint. of Meters	0	0	0	0	0	0	0	0	0	
598.0	Miscellaneous Maintenance	39,516	0	0	0	0	0	0	39,516	0	As All Other Dist Expense
	Total Distribution Maintenance	$354,264	$0	$0	$0	$0	$0	$0	$354,264	$0	
	Total Distribution Expense	$428,562	$0	$0	$0	$0	$0	$0	$428,562	$0	
	Customer Accounts Expense										
901.0	Customer Acctg. Supervision	$297,798	$191,180	$89,992	$6,516	$0	$0	$0	$5,060	$5,049	As all other CS Accts.
902.0	Meter Reading Expenses	0	0	0	0	0	0	0	0	0	
903.0	Cust. Records, Collection Exp.	0	0	0	0	0	0	0	0	0	
904.0	Uncollectable Accounts	457,000	293,385	138,102	10,000	0	0	0	7,765	7,748	As Res,GS,Irr,Lighting and (10K to
	Total Customer Accts Exp	$754,798	$484,565	$228,094	$16,516	$0	$0	$0	$12,825	$12,797	
	% of Total	100.0%	64.2%	30.2%	2.2%	0.0%	0.0%	0.0%	1.7%	1.7%	
	Customer Service & Information Exp.										
909.0	Supervision	$25,895	$16,624	$7,825	$567	$0	$0	$0	$440	$439	As CS Accts.
910.0	Customer Assistance	47,414	30,439	14,328	1,038	0	0	0	806	804	As CS Accts.
	Total Cust Serv & Info Exp	$73,310	$47,063	$22,154	$1,604	$0	$0	$0	$1,246	$1,243	
	Total O&M Exp Before A&G Exp	$1,256,670	$531,628	$250,248	$18,121	$0	$0	$0	$442,633	$14,040	
	% Total O&M Exp. Before A&G Exp.	100%	42%	20%	1%	0%	0%	0%	35%	1%	
	Total O&M Exp Before A&G and Purchased Power	$1,256,670	$531,628	$250,248	$18,121	$0	$0	$0	$442,633	$14,040	
	% of Total	100.0%	42.3%	19.9%	1.4%	0.0%	0.0%	0.0%	35.2%	1.1%	

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West Kootenay Pc
Exhibit B-7A
SUMMARY OF DIRECT ASSIGNMENTS
- NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

Acct. No.	Account Description	Total Direct Assignment	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation	Basis of Assignment
	Salaries										
920.9	Executive and Senior Management	$2,903	$0	$0	$0	$0	$0	$0	$2,903	$0	As Labor Ratios
920.8	Engineering	1,234	0	0	0	0	0	0	1,234	0	As Labor Ratios
920.8	T&D Administration	1,532	0	0	0	0	0	0	1,532	0	As Labor Ratios
920.8	Legal	1,885	0	0	0	0	0	0	1,885	0	As Labor Ratios
920.8	Human Resources	2,522	0	0	0	0	0	0	2,522	0	As Labor Ratios
920.9	Accounting	1,816	0	0	0	0	0	0	1,816	0	As Labor Ratios
921.0	Financial Administration	1,136	0	0	0	0	0	0	1,136	0	As Labor Ratios
921.0	Office Services	2,154	0	0	0	0	0	0	2,154	0	As Labor Ratios
920.9	Payroll	759	0	0	0	0	0	0	759	0	As Labor Ratios
920.9	Information Services	2,879	0	0	0	0	0	0	2,879	0	As Labor Ratios
920.9	Materials Management	1,557	0	0	0	0	0	0	1,557	0	As Labor Ratios
	Total A&G Salaries	$20,378	$0	$0	$0	$0	$0	$0	$20,378	$0	
	Labor Expenses										
922	Executive and Senior Management	$823	$0	$0	$0	$0	$0	$0	$823	$0	As Labor Ratios
922	Engineering	490	0	0	0	0	0	0	490	0	As Labor Ratios
922	T&D Administration	715	0	0	0	0	0	0	715	0	As Labor Ratios
922	Legal	1,581	0	0	0	0	0	0	1,581	0	As Labor Ratios
922	Human Resources	1,386	0	0	0	0	0	0	1,386	0	As Labor Ratios
922	Accounting	436	0	0	0	0	0	0	436	0	As Labor Ratios
922	Financial Administration	617	0	0	0	0	0	0	617	0	As Labor Ratios
922	Office Services	54	0	0	0	0	0	0	54	0	As Labor Ratios
922	Payroll	186	0	0	0	0	0	0	186	0	As Labor Ratios
922	Information Services	2,257	0	0	0	0	0	0	2,257	0	As Labor Ratios
922	Other	6,434	0	0	0	0	0	0	6,434	0	As Labor Ratios
	Total A&G Labor Expenses	$14,977	$0	$0	$0	$0	$0	$0	$14,977	$0	
	Other A&G Expenses										
922	Administration & General Transferred	($8,363)	$0	$0	$0	$0	$0	$0	($8,363)	$0	As Labor Ratios
923	Special Services	1,449	0	0	0	0	0	0	1,449	0	As Labor Ratios
924	Insurance	4,441	0	0	0	0	0	0	4,441	0	As Labor Ratios
930	Conservation Promotion	0	0	0	0	0	0	0	0	0	
930	Rate Application and Other	1,420	0	0	0	0	0	0	1,420	0	As Labor Ratios
932	Maintenance of General Plant	1,851	0	0	0	0	0	0	1,851	0	As Labor Ratios
933	Transportation Equipment Expenses	(5,910)	0	0	0	0	0	0	(5,910)	0	As Labor Ratios
	Total Other A&G Expenses	($5,111)	$0	$0	$0	$0	$0	$0	($5,111)	$0	
	Total Admin. & General Exp.	$30,244	$0	$0	$0	$0	$0	$0	$30,244	$0	
	Less: Incentive Sharing	$2,118	$0	$0	$0	$0	$0	$0	$2,118	$0	As 50% Labor Ratios, 50% Plant in S
	Less: DSM Sharing	$0								$0	As Deferred DSM
	Total O & M Expense	$1,284,795	$531,628	$250,248	$18,121	$0	$0	$0	$470,758	$14,040	

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West Kootenay Power
Exhibit B-7A
SUMMARY OF DIRECT ASSIGNMENTS
- NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

Acct. No.	Account Description	Total Direct Assignment	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation	Basis of Assignment
	Taxes										
	Taxes - Property	$19,142	$0	$0	($6,574)	($24,106)	($5,844)	$0	$55,666	$0	As Total Rate Base
	Capital Tax	1,612	0	0	(553)	(2,029)	(492)	0	4,687	0	As Total Rate Base
	Total Taxes	$20,753	$0	$0	($7,128)	($26,135)	($6,336)	$0	$60,352	$0	
	Total Operating Expenses	$1,305,549	$531,628	$250,248	$10,993	($26,135)	($6,336)	$0	$531,111	$14,040	
	DEPRECIATION										
	Other Production Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	Plant Acquisition Adjustment	0	0	0	0	0	0	0	0	0	
403.3	Hydraulic Production Plant	0	0	0	0	0	0	0	0	0	
403.5	Transmission Plant	0	0	0	0	0	0	0	0	0	
403.6	Distribution Plant	58,445	0	0	0	0	0	0	58,445	0	As Distribution Plant
403.7	General Plant	9,988	0	0	0	0	0	0	9,988	0	As General Plant
	Leasehold Improvements	56	0	0	0	0	0	0	56	0	As Total Other Rate Base Items
	Amortization of Customer Contributions	(33,879)	0	0	(6,098)	(22,360)	(5,421)	0	0	0	As Acct. 252
	Amortization of Deferred Charges	3,613	0	0	0	0	0	0	3,613	0	As Deferred Charges
	Total Depreciation Expense	$38,224	$0	$0	($6,098)	($22,360)	($5,421)	$0	$72,103	$0	
	Less: AFUDC										
	Allowance for Funds Used During Construction	$601	$0	$0	($207)	($757)	($184)	$0	$1,749	$0	As Total Rate Base
	TOTAL OPERATING EXPENSES	$1,343,171	$531,628	$250,248	$5,101	($47,739)	($11,573)	$0	$601,465	$14,040	
	Plus: Return on Plant										
	Return on Plant (@12.968%)	$62,312	$0	$0	($21,401)	($78,471)	($19,023)	$0	$181,206	$0	As Total Rate Base
	Less: Other Income										
	Pole Rental	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	Connection Fees	0	0	0	0	0	0	0	0	0	
	NSF Charges	0	0	0	0	0	0	0	0	0	
	Collection Fees	0	0	0	0	0	0	0	0	0	
320.2	Facilities Rental Cominco	158	0	0	0	0	0	0	158	0	As 81% PTD, 19% A&G
745.0	Interest Income less Walden	2,539	0	0	0	0	0	0	2,539	0	As Total Plant in Service
750.0	Other Income - Cominco (O&M)	917	0	0	0	0	0	0	917	0	As 81% PTD, 19% A&G
757.0	Sundry	2,342	0	0	0	0	0	0	2,342	0	As Total Plant in Service
	Total Operating Revenues	$5,955	$0	$0	$0	$0	$0	$0	$5,955	$0	
	NET REVENUE REQUIREMENT	$1,399,527	$531,628	$250,248	($16,300)	($126,209)	($30,596)	$0	$776,716	$14,040	

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West Kootenay Power
Exhibit B-7B
CUSTOMER CLASSIFICATION AND ALLOCATION OF
NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

Acct. No.	Account Description	Total Expenses	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation
	Hydraulic Power Generation Operation									
535.0	Operation, Supervision, Engineering	$751,000	$287,067	$134,105	$51,468	$16,390	$228,915	$17,761	$3,600	$11,693
536.0	Water Fees	6,808,000	2,602,334	1,215,698	466,569	148,579	2,075,171	161,010	32,636	106,004
538.0	Electric Expenses	282,000	107,794	50,356	19,326	6,154	85,957	6,669	1,352	4,391
539.0	Other Generation Exp.	127,000	48,545	22,678	8,704	2,772	38,711	3,004	609	1,977
	Total Hydraulic Power Generation Operation	$7,968,000	$3,045,740	$1,422,838	$546,066	$173,895	$2,428,754	$188,444	$38,197	$124,066
	Hydraulic Power Generation Maintenance									
541.0	Maintenance Supervision & Engineering	$10,000	$3,822	$1,786	$685	$218	$3,048	$237	$48	$156
542.0	Maintenance of Structures	257,000	98,237	45,892	17,613	5,609	78,337	6,078	1,232	4,002
543.0	Maintenance of Reservoirs, Dams, Waterways	91,000	34,784	16,250	6,236	1,986	27,738	2,152	436	1,417
544.0	Maintenance of Electric Plant	680,000	259,928	121,427	46,602	14,840	207,273	16,082	3,260	10,588
545.0	Maintenance of Miscellaneous Hydraulic Plant	75,000	28,668	13,393	5,140	1,637	22,861	1,774	360	1,168
549.0	Miscellaneous	90,000	34,402	16,071	6,168	1,964	27,433	2,129	431	1,401
	Total Hydraulic Power Generation Maintenance	$1,203,000	$459,843	$214,818	$82,444	$26,254	$366,691	$28,451	$5,767	$18,731
	Total Hydraulic Power Generation Expense	$9,171,000	$3,505,583	$1,637,656	$628,511	$200,150	$2,795,445	$216,895	$43,964	$142,797
	Other Power Supply Expenses									
555.1	Winter Demand	$6,065,000	$2,893,650	$681,074	$408,057	$194,563	$1,638,880	$222,084	$26,693	$0
555.2	Winter Energy	18,120,000	7,663,876	2,897,669	1,147,662	336,538	5,439,878	560,457	73,922	0
555.3	Summer Energy	13,444,000	4,613,149	2,641,624	988,461	335,403	4,157,325	223,914	73,673	410,452
556.0	System Control and Load Dispatch	826,000	394,090	92,756	55,574	26,498	223,201	30,246	3,635	0
	Total Other Power Supply Expenses	$38,455,000	$15,564,764	$6,313,123	$2,599,753	$893,001	$11,459,283	$1,036,701	$177,923	$410,452
	Total Power Supply Costs	$47,626,000	$19,070,347	$7,950,779	$3,228,264	$1,093,150	$14,254,728	$1,253,596	$221,886	$553,249
	% of Total	100.0%	40.0%	16.7%	6.8%	2.3%	29.9%	2.6%	0.5%	1.2%
	Transmission Operation									
560.0	Operation, Supervision, Engineering	$196,000	$66,894	$37,693	$14,718	$7,613	$59,047	$5,519	$431	$4,084
561.0	Load Dispatching	428,000	146,075	82,310	32,139	16,625	128,940	12,052	942	8,917
562.0	Station Expenses	24,000	8,191	4,615	1,802	932	7,230	676	53	500
563.0	Overhead Line Expense	161,000	54,949	30,962	12,090	6,254	48,503	4,534	354	3,354
565.0	Transmission of Electricity	3,508,000	1,197,271	674,631	263,420	136,259	1,056,825	98,785	7,720	73,090
566.0	Miscellaneous Transmission Expenses	15,000	5,119	2,885	1,126	583	4,519	422	33	313
567.0	Rents	216,000	73,720	41,539	16,220	8,390	65,072	6,083	475	4,500
	Total Transmission Operation	$4,548,000	$1,552,220	$874,636	$341,515	$176,655	$1,370,137	$128,071	$10,008	$94,758
	Transmission Maintenance									
568.0	Maintenance Supervision and Engineering	$588,000	$200,683	$113,080	$44,154	$22,839	$177,142	$16,558	$1,294	$12,251
569.0	Maintenance of Structures	20,000	6,826	3,846	1,502	777	6,025	563	44	417
570.0	Maintenance of Station Equipment	315,000	107,509	60,578	23,654	12,235	94,897	8,870	693	6,563
571.0	Maintenance of Overhead Lines	609,000	207,850	117,118	45,731	23,655	183,468	17,149	1,340	12,689
	Total Transmission Maintenance	$1,532,000	$522,867	$294,622	$115,040	$59,507	$461,532	$43,141	$3,371	$31,919
	Total Transmission Expense	$6,080,000	$2,075,087	$1,169,258	$456,555	$236,162	$1,831,669	$171,212	$13,379	$126,678

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West Kootenay Power
Exhibit B-7B
CUSTOMER CLASSIFICATION AND ALLOCATION OF
NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

Acct. No.	Account Description	Total Expenses	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation
	Distribution Operation									
580.0	Operation Supervision & Eng.	$700,000	$479,009	$138,119	$16,860	$508	$44,483	$0	$9,727	$11,295
583.0	Overhead Line Expense	60,000	23,628	13,629	4,453	0	16,886	0	383	1,022
586.0	Meter Expense	787,000	543,108	96,769	93,811	8,277	38,628	0	0	6,406
587.0	Customer Installation Expense	68,000	0	0	0	0	0	0	68,000	0
	Total Distribution Operation	$1,615,000	$1,045,745	$248,517	$115,123	$8,785	$99,996	$0	$78,110	$18,724
	Distribution Maintenance									
590.0	Maint. Supervision & Eng.	$2,195,000	$1,502,035	$433,101	$52,867	$1,592	$139,485	$0	$30,502	$35,419
591.0	Maint. Structures and Improvements	619,000	243,760	140,604	45,937	0	174,205	0	3,951	10,542
592.0	Maint. Station Equipment	426,000	167,757	96,765	31,614	0	119,889	0	2,719	7,255
593.0	Maint. Overhead Lines	1,895,000	1,559,943	300,675	0	0	0	0	7,081	27,302
594.0	Maint. Underground Lines	112,000	83,448	25,770	0	0	0	0	673	2,110
595.0	Maint. Line Transformers	123,000	99,880	20,771	0	0	0	0	500	1,850
596.0	Maint. of Street Lights and Signals	295,000	0	0	0	0	0	0	295,000	0
597.0	Maint. of Meters	54,000	37,265	6,640	6,437	568	2,650	0	0	440
598.0	Miscellaneous Maintenance	718,000	463,779	128,600	17,182	271	54,767	0	42,739	10,661
	Total Distribution Maintenance	$6,437,000	$4,157,866	$1,152,925	$154,037	$2,431	$490,997	$0	$383,165	$95,578
	Total Distribution Expense	$8,052,000	$5,203,611	$1,401,442	$269,160	$11,216	$590,993	$0	$461,275	$114,302
	Customer Accounts Expense									
901.0	Customer Acctg. Supervision	$1,633,000	$1,332,016	$214,888	$28,484	$5,538	$12,922	$1,846	$5,060	$32,246
902.0	Meter Reading Expenses	1,141,000	974,904	106,730	18,772	4,732	11,042	1,577	0	23,242
903.0	Cust. Records, Collection Exp.	908,000	775,822	84,935	14,939	3,766	8,787	1,255	0	18,496
904.0	Uncollectable Accounts	457,000	293,385	138,102	10,000	0	0	0	7,765	7,748
	Total Customer Accts Exp	$4,139,000	$3,376,126	$544,656	$72,194	$14,036	$32,752	$4,679	$12,825	$81,732
	Customer Service & Information Exp.									
909.0	Supervision	$142,000	$115,827	$18,686	$2,477	$482	$1,124	$161	$440	$2,804
910.0	Customer Assistance	260,000	212,078	34,214	4,535	882	2,057	294	806	5,134
	Total Cust Serv & Info Exp	$402,000	$327,906	$52,900	$7,012	$1,363	$3,181	$454	$1,246	$7,938
	Total O&M Exp Before A&G Exp	$66,299,000	$30,053,078	$11,119,035	$4,033,185	$1,355,928	$16,713,323	$1,429,941	$710,611	$883,899
	% Total O&M Exp. Before A&G Exp.	100.0%	45.3%	16.8%	6.1%	2.0%	25.2%	2.2%	1.1%	1.3%
	Total O&M Exp Before A&G and Purchased Power	$60,234,000	$27,159,428	$10,437,961	$3,625,128	$1,161,365	$15,074,443	$1,207,857	$683,919	$883,899
	% of Total	100.0%	45.1%	17.3%	6.0%	1.9%	25.0%	2.0%	1.1%	1.5%

8/27/97

Wes. ..ootenay Power
Exhibit B-7B
CUSTOMER CLASSIFICATION AND ALLOCATION OF
NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

Acct. No.	Account Description	Total Expenses	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation
	Salaries									
920.9	Executive and Senior Management	$593,000	$320,238	$113,251	$26,922	$7,757	$102,557	$6,823	$5,533	$9,918
920.8	Engineering	252,000	136,088	48,127	11,441	3,296	43,583	2,899	2,351	4,215
920.8	T&D Administration	313,000	169,030	59,777	14,210	4,094	54,132	3,601	2,920	5,235
920.8	Legal	385,000	207,912	73,527	17,479	5,036	66,584	4,430	3,592	6,439
920.8	Human Resources	515,000	278,116	98,355	23,381	6,737	89,067	5,925	4,805	8,614
920.9	Accounting	371,000	200,351	70,854	16,843	4,853	64,163	4,269	3,461	6,205
921.0	Financial Administration	232,000	125,287	44,307	10,533	3,035	40,124	2,669	2,165	3,880
921.0	Office Services	440,000	237,614	84,031	19,976	5,756	76,096	5,062	4,105	7,359
920.9	Payroll	155,000	83,705	29,602	7,037	2,028	26,807	1,783	1,446	2,592
920.9	Information Services	588,000	317,538	112,297	26,695	7,692	101,693	6,765	5,486	9,835
920.9	Materials Management	318,000	171,730	60,732	14,437	4,160	54,997	3,659	2,967	5,319
	Total A&G Salaries	$4,162,000	$2,247,609	$794,861	$188,955	$54,443	$719,804	$47,886	$38,831	$69,612
	Labor Expenses									
921.9	Executive and Senior Management	$168,000	$90,725	$32,085	$7,627	$2,198	$29,055	$1,933	$1,567	$2,810
921.8	Engineering	100,000	54,003	19,098	4,540	1,308	17,295	1,151	933	1,673
921.8	T&D Administration	146,000	78,845	27,883	6,628	1,910	25,250	1,680	1,362	2,442
921.8	Legal	323,000	174,430	61,687	14,664	4,225	55,862	3,716	3,014	5,402
921.8	Human Resources	283,000	152,829	54,047	12,848	3,702	48,944	3,256	2,640	4,733
921.9	Accounting	89,000	48,063	16,997	4,041	1,164	15,392	1,024	830	1,489
922.0	Financial Administration	126,000	68,044	24,064	5,720	1,648	21,791	1,450	1,176	2,107
922.0	Office Services	11,000	5,940	2,101	499	144	1,902	127	103	184
921.9	Payroll	38,000	20,521	7,257	1,725	497	6,572	437	355	636
921.9	Information Services	461,000	248,954	88,042	20,929	6,030	79,728	5,304	4,301	7,711
921.9	Other	1,314,000	709,601	250,948	59,656	17,188	227,252	15,118	12,259	21,978
	Total A&G Labor Expenses	$3,059,000	$1,651,955	$584,209	$138,879	$40,014	$529,043	$35,196	$28,540	$51,164
	Other A&G Expenses									
922.0	Administration & General Transferred	($1,708,000)	($922,373)	($326,195)	($77,543)	($22,342)	($295,393)	($19,652)	($15,935)	($28,567)
923.0	Special Services	296,000	159,849	56,530	13,438	3,872	51,192	3,406	2,762	4,951
924.0	Insurance	787,000	441,791	152,513	33,298	10,139	120,095	7,834	7,751	13,578
930.0	Conservation Promotion	119,000	45,487	21,250	8,155	2,597	36,273	2,814	570	1,853
930.0	Rate Application and Other	560,000	256,445	104,731	32,210	11,089	132,158	10,094	3,786	9,488
932.0	Maintenance of General Plant	378,000	204,132	72,191	17,161	4,945	65,374	4,349	3,527	6,322
933.0	Transportation Equipment Expenses	(1,207,000)	(651,817)	(230,513)	(54,798)	(15,789)	(208,746)	(13,887)	(11,261)	(20,188)
	Total Other A&G Expenses	($775,000)	($466,487)	($149,493)	($28,078)	($5,489)	($99,048)	($5,042)	($8,801)	($12,562)
	Total Admin. & General Exp.	$6,446,000	$3,433,077	$1,229,577	$299,755	$88,968	$1,149,799	$78,040	$58,570	$108,213
	Less: Incentive Sharing	$402,000	$221,380	$77,339	$17,630	$5,219	$65,435	$4,313	$3,855	$6,830
	Less: DSM Sharing	$50,000	$18,543	$9,110	$3,518	$1,328	$15,191	$1,245	$204	$852
	Total O & M Expense	$72,293,000	$33,246,232	$12,262,153	$4,311,793	$1,438,350	$17,782,496	$1,502,422	$765,123	$984,431

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West Koot...ay Power
Exhibit B-7B
CUSTOMER CLASSIFICATION AND ALLOCATION OF
NET REVENUE REQUIREMENTS
Minimum System Approach
FY 1997 Test Period

Acct. No.	Account Description	Total Expenses	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation
	Taxes									
	Taxes - Property	$7,918,000	$3,562,582	$1,522,984	$463,381	$137,305	$1,869,582	$134,446	$87,637	$140,081
	Capital Tax	804,000	411,099	153,011	41,251	11,139	155,128	10,619	7,928	13,825
	Total Taxes	$8,722,000	$3,973,680	$1,675,995	$504,632	$148,444	$2,024,711	$145,066	$95,565	$153,907
	Total Operating Expenses	$81,015,000	$37,219,912	$13,938,148	$4,816,425	$1,586,794	$19,807,207	$1,647,488	$860,688	$1,138,338
	DEPRECIATION									
	Other Production Plant	$41,000	$15,672	$7,321	$2,810	$895	$12,497	$970	$197	$638
0.0	Plant Acquisition Adjustment	186,000	71,098	33,214	12,747	4,059	56,695	4,399	892	2,896
403.3	Hydraulic Production Plant	607,000	232,024	108,391	41,599	13,247	185,022	14,356	2,910	9,451
403.5	Transmission Plant	$2,125,000	725,257	408,663	159,569	82,540	640,180	59,840	4,676	44,275
403.6	Distribution Plant	6,496,000	4,445,202	1,281,741	156,457	4,712	412,798	0	90,269	104,822
403.7	General Plant	2,040,000	1,101,663	389,600	92,616	26,685	352,811	23,471	19,033	34,120
	Leasehold Improvements	49,000	20,531	9,028	3,078	1,013	13,249	1,022	281	799
	Amortization of Customer Contributions	(1,350,000)	(1,003,683)	(281,717)	(6,098)	(22,360)	(5,421)	0	(7,238)	(23,483)
	Amortization of Deferred Charges	1,425,000	652,560	266,503	81,962	28,216	336,294	25,684	9,635	24,145
	Total Depreciation Expense	$11,619,000	$6,260,322	$2,222,745	$544,739	$139,007	$2,004,126	$129,741	$120,654	$197,664
	Less: AFUDC									
	Allowance for Funds Used During Construction	$300,000	$153,395	$57,094	$15,392	$4,156	$57,884	$3,962	$2,958	$5,159
	TOTAL OPERATING EXPENSES	$92,334,000	$43,326,840	$16,103,800	$5,345,772	$1,721,645	$21,753,449	$1,773,267	$978,384	$1,330,843
	Plus: Return on Plant									
	Return on Plant (@12.968%)	$31,087,000	$15,895,298	$5,916,225	$1,594,970	$430,701	$5,998,108	$410,607	$306,524	$534,567
	Less: Other Income									
	Pole Rental	$1,050,000	$864,348	$166,601	$0	$0	$0	$0	$3,924	$15,128
	Connection Fees	430,000	382,558	41,882	175	15	36	5	769	4,560
	NSF Charges	28,000	24,911	2,727	11	1	2	0	50	297
	Collection Fees	4,000	3,559	390	2	0	0	0	7	42
320.2	Facilities Rental Cominco	80,000	35,044	14,892	4,836	1,721	20,085	1,569	490	1,362
745.0	Interest Income less Walden	450,000	252,612	87,206	19,039	5,798	68,669	4,480	4,432	7,764
750.0	Other Income - Cominco (O&M)	465,000	203,693	86,563	28,112	10,003	116,741	9,119	2,851	7,918
757.0	Sundry	415,000	232,965	80,423	17,559	5,347	63,328	4,131	4,087	7,160
	Total Operating Revenues	$2,922,000	$1,999,689	$480,683	$69,735	$22,885	$268,862	$19,304	$16,610	$44,231
	NET REVENUE REQUIREMENT	$120,499,000	$57,222,449	$21,539,342	$6,871,007	$2,129,461	$27,482,695	$2,164,570	$1,268,299	$1,821,179

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West Kootenay Power
Exhibit B-8
ALLOCATION OF RATE BASE
(PLANT IN SERVICE)
Minimum System Approach for Allocating Costs

	Total Rate Base	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation
Power Supply									
Demand									
- Winter	$397,451	$189,626	$44,632	$26,741	$12,750	$107,399	$14,554	$1,749	$0
- Summer	397,451	81,672	108,237	32,949	18,126	132,074	7,831	0	16,562
Total Demand	$794,902	$271,298	$152,869	$59,690	$30,876	$239,473	$22,384	$1,749	$16,562
Energy									
- Winter	$25,117,905	$10,623,648	$4,016,742	$1,590,886	$466,508	$7,540,747	$776,904	$102,470	$0
- Summer	26,143,125	8,970,703	5,136,887	1,922,156	652,222	8,084,310	435,423	143,263	798,162
Total Energy	$51,261,030	$19,594,351	$9,153,629	$3,513,042	$1,118,730	$15,625,056	$1,212,327	$245,733	$798,162
Total Power Supply	$52,055,932	$19,865,649	$9,306,499	$3,572,732	$1,149,606	$15,864,530	$1,234,711	$247,483	$814,724
Transmission									
Demand									
- Winter	$34,271,402	$16,351,101	$3,848,535	$2,305,801	$1,099,414	$9,260,792	$1,254,927	$150,833	$0
- Summer	34,271,402	7,042,372	9,333,083	2,841,163	1,562,952	11,388,505	675,227	0	1,428,101
Total Demand	$68,542,804	$23,393,472	$13,181,617	$5,146,964	$2,662,365	$20,649,297	$1,930,154	$150,833	$1,428,101
Energy									
- Winter	$0	$0	$0	$0	$0	$0	$0	$0	$0
- Summer	0	0	0	0	0	0	0	0	0
Total Energy	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Transmission	$68,542,804	$23,393,472	$13,181,617	$5,146,964	$2,662,365	$20,649,297	$1,930,154	$150,833	$1,428,101
Distribution									
Non-Coincident Demand									
- Primary	$57,444,774	$27,894,333	$16,089,837	$2,462,758	$0	$9,339,354	$0	$452,143	$1,206,348
- Secondary	3,123,776	1,909,084	1,101,186	0	0	0	0	30,945	82,562
Total Distribution	$60,568,551	$29,803,417	$17,191,022	$2,462,758	$0	$9,339,354	$0	$483,088	$1,288,911
Customer Related									
Actual	$57,963,844	$49,454,749	$5,921,757	$1,276,160	$112,602	$525,478	$0	$84,517	$588,582
Revenue Related	$0	$0	$0	$0	$0	$0	$0	$0	$0
Direct Assignment	$480,283	$0	$0	($164,954)	($604,833)	($146,626)	$0	$1,396,697	$0
Total Rate Base	$239,611,414	$122,517,287	$45,600,895	$12,293,659	$3,319,741	$46,232,032	$3,164,865	$2,362,617	$4,120,318
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West Kootenay Power
Exhibit B-9
ALLOCATION OF NET REVENUE REQUIREMENTS
Minimum System Approach for Allocating Costs

	Total Net Revenue Requirements	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation
Power Supply									
Demand									
- Winter	$7,003,733	$3,341,525	$786,490	$471,215	$224,677	$1,892,543	$256,458	$30,824	$0
- Summer	112,733	23,165	30,700	9,346	5,141	37,462	2,221	0	4,698
Total Demand	$7,116,466	$3,364,690	$817,190	$480,561	$229,818	$1,930,005	$258,679	$30,824	$4,698
Energy									
- Winter	$28,855,942	12,204,655	4,614,512	1,827,641	535,933	8,662,958	892,523	117,720	0
- Summer	24,618,144	8,447,424	4,837,242	1,810,033	614,176	7,612,736	410,024	134,906	751,603
Total Energy	$53,474,086	$20,652,079	$9,451,754	$3,637,674	$1,150,110	$16,275,693	$1,302,546	$252,626	$751,603
Total Power Supply	$60,590,552	$24,016,770	$10,268,944	$4,118,235	$1,379,928	$18,205,698	$1,561,225	$283,451	$756,301
Transmission									
Demand									
- Winter	$10,621,808	$5,067,731	$1,192,785	$714,642	$340,744	$2,870,217	$388,942	$46,748	$0
- Summer	10,621,808	2,182,657	2,892,622	880,567	484,409	3,529,664	209,274	0	442,614
Total Demand	$21,243,616	$7,250,388	$4,085,407	$1,595,209	$825,153	$6,399,880	$598,217	$46,748	$442,614
Energy									
- Winter	$0	$0	$0	$0	$0	$0	$0	$0	$0
- Summer	0	0	0	0	0	0	0	0	0
Total Energy	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Transmission	$21,243,616	$7,250,388	$4,085,407	$1,595,209	$825,153	$6,399,880	$598,217	$46,748	$442,614
Distribution									
Non-Coincident Demand									
- Primary	$16,464,212	$7,971,008	$4,597,787	$713,966	$0	$2,707,525	$0	$129,203	$344,723
- Secondary	936,889	572,576	330,270	0	0	0	0	9,281	24,762
Total Distribution	$17,401,101	$8,543,584	$4,928,057	$713,966	$0	$2,707,525	$0	$138,484	$369,485
Customer Related									
Actual	$19,864,204	$16,880,079	$2,006,686	$459,897	$50,589	$200,188	$5,128	$22,899	$238,738
Revenue Related	$0	$0	$0	$0	$0	$0	$0	$0	$0
Direct Assignment	$1,399,527	$531,628	$250,248	($16,300)	($126,209)	($30,596)	$0	$776,716	$14,040
Total Net Revenue Requirement	$120,499,000	$57,222,449	$21,539,342	$6,871,007	$2,129,461	$27,482,695	$2,164,570	$1,268,299	$1,821,179

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West Kootenay Power
Exhibit B-10
SUMMARY OF COST OF SERVICE ANALYSIS
Minimum System Approach for Allocating Costs

	Total	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation
Present Rate Revenues	$120,499,000	$52,254,000	$24,597,000	$7,870,000	$2,668,000	$27,821,000	$2,526,000	$1,383,000	$1,380,000
Plus: Miscellaneous Revenues	2,922,000	1,999,689	480,683	69,735	22,885	268,862	19,304	16,610	44,231
	$123,421,000	$54,253,689	$25,077,683	$7,939,735	$2,690,885	$28,089,862	$2,545,304	$1,399,610	$1,424,231
Less: Allocated Revenue Requirement	$92,334,000	$43,326,840	$16,103,800	$5,345,772	$1,721,645	$21,753,449	$1,773,267	$978,384	$1,330,843
Net Income	$31,087,000	$10,926,849	$8,973,883	$2,593,963	$969,240	$6,336,413	$772,038	$421,226	$93,388
Rate Base	$239,611,414	$122,517,287	$45,600,895	$12,293,659	$3,319,741	$46,232,032	$3,164,865	$2,362,617	$4,120,318
% Actual Rate of Return	12.97%	8.92%	19.68%	21.10%	29.20%	13.71%	24.39%	17.83%	2.27%
% Allowed Rate of Return	12.97%	12.97%	12.97%	12.97%	12.97%	12.97%	12.97%	12.97%	12.97%
Required Net Income	$31,087,000	$15,895,298	$5,916,225	$1,594,970	$430,701	$5,998,108	$410,607	$306,524	$534,567
Required Net Revenue Requirement Before Taxes	$120,499,000	$57,222,449	$21,539,342	$6,871,007	$2,129,461	$27,482,695	$2,164,570	$1,268,299	$1,821,179
Balance (Deficiency) of Rate Revenues	$0	($4,968,449)	$3,057,658	$998,993	$538,539	$338,305	$361,430	$114,701	($441,179)
Rate Adjustment Required	0.0%	9.5%	-12.4%	-12.7%	-20.2%	-1.2%	-14.3%	-8.3%	32.0%

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West Kootenay Power
Exhibit B-11
DEVELOPMENT OF AVERAGE UNIT COSTS
FY 1997
Minimum System Approach for Allocating Costs

Functional Costs	Total System	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation
Power Supply									
Demand ($/kVA/Month)									
- Winter	$ 1.533	$ -	$ -	$ 2.045	$ 2.043	$ 2.420	$ 2.457	$ -	$ -
- Summer	0.020	-	-	0.032	0.032	0.037	0.027	-	-
- Annual	$ 0.697	$ -	$ -	$ 0.922	$ 0.851	$ 1.078	$ 1.395	$ -	$ -
Energy (cents/kWh)									
- Winter	2.307	3.001	2.756	2.256	2.144	2.254	2.144	2.971	#DIV/0!
- Summer	1.888	1.934	1.939	1.847	1.755	1.845	1.755	1.927	1.939
- Annual	2.093	2.512	2.297	2.032	1.917	2.042	2.004	2.362	1.939
Transmission									
Demand ($/kVA/Month)									
- Winter	$ 2.326	$ -	$ -	$ 3.101	$ 3.098	$ 3.670	$ 3.726	$ -	$ -
- Summer	1.884	-	-	3.030	3.028	3.501	2.584	-	-
- Annual	$ 2.081	$ -	$ -	$ 3.062	$ 3.056	$ 3.575	$ 3.227	$ -	$ -
or Energy (cents/kWh)									
- Winter	-	0.978	0.609	-	-	-	-	0.935	#DIV/0!
- Summer	-	0.498	1.152	-	-	-	-	-	1.135
- Annual	-	0.758	0.914	-	-	-	-	0.390	1.135
Distribution									
Non-Coincident Demand ($/kVA/Month)									
- Primary	$ 1.613	$ -	$ -	$ 1.370	$ -	$ 1.512	$ -	$ -	$ -
- Secondary	0.126	-	-	-	-	-	-	-	-
- Total	$ 1.739	$ -	$ -	$ 1.370	$ -	$ 1.512	$ -	$ -	$ -
or Energy (cents/kWh)									
- Winter	3.178	1.539	2.346	-	-	-	-	2.584	#DIV/0!
- Summer	0.214	0.131	0.132	-	-	-	-	0.133	0.063
- Annual	1.820	0.894	1.102	-	-	-	-	1.154	0.947
Customer Related									
Actual ($/customer/month)	$ 19.86	$ 18.97	$ 20.60	$ 1,127.20	$ 1,405.25	$ 2,383.19	$ 427.31	$ 12.81	$ 22.51
Revenue Related									
- $/kVA/month	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
- or cents/kWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Direct Assignment									
- $/kVa/month	0.137	0.094	0.153	(0.031)	(0.467)	(0.017)	0.000	20.121	0.135
- or cents/kWh	0.055	0.056	0.056	(0.009)	(0.210)	(0.004)	0.000	6.473	0.036

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West Kootenay Power
Exhibit B-11
DEVELOPMENT OF AVERAGE UNIT COSTS
FY 1997
Minimum System Approach for Allocating Costs

Unit Costs	Total System	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation
Demand ($/kVA/Month)									
Winter	$ 5.598	$ -	$ -	$ 6.517	$ 5.140	$ 7.603	$ 6.183	$ -	$ -
Summer	3.643	-	-	4.433	3.060	5.051	2.611	-	-
Annual	$ 4.518	$ -	$ -	$ 5.354	$ 3.907	$ 6.166	$ 4.623	$ -	$ -
Energy (cents/kWh)									
Winter	5.485	5.518	5.710	2.256	2.144	2.254	2.144	6.490	#DIV/0!
Summer	2.102	2.563	3.223	1.847	1.755	1.845	1.755	2.060	3.138
Annual	3.913	4.164	4.314	2.032	1.917	2.042	2.004	3.906	4.022
Customer ($/customer/month)	$19.86	$18.97	$20.60	$1,127.20	$1,405.25	$2,383.19	$427.31	$12.81	$22.51
Total Cents Per kWh	4.716	5.986	4.819	3.839	3.549	3.448	3.330	10.569	4.670

8/27/97

West Kootenay Power
Exhibit B-12
DEVELOPMENT OF WHEELING RATES
FY 1997
Minimum System Approach for Allocating Costs
Using Annual Peak (Contract) Demand For Calculation of Per Unit Costs

Charge	Total System	Residential	General Service	Large General Service (Primary)	Large General Service (Transmission)	Wholesale (Primary)	Wholesale (Transmission)	Lighting	Irrigation
Customer Charge ($/customer/month)	$ 19.86	$ 18.97	$ 20.60	$ 1,127.20	$ 1,405.25	$ 2,383.19	$ 427.31	$ 12.81	$ 22.51
Access Fee									
- (cents/kWh)									
Transmission	0.831	0.758	0.914	0.891	1.375	0.803	0.920	0.390	1.135
Substations, Land	0.377	0.396	0.489	0.399	-	0.340	-	0.512	0.420
Poles, Towers, Conductors	0.268	0.437	0.540	-	-	-	-	0.565	0.464
Transformers	0.037	0.060	0.074	-	-	-	-	0.077	0.063
Total	1.513	1.652	2.016	1.290	1.375	1.143	0.920	1.544	2.082
- or ($/kVA/month)									
Transmission	$ 1.668	$ 1.040	$ 1.809	$ 2.647	$ 2.751	$ 3.190	$ 2.174	$ 0.870	$ 3.299
Substations, Land	0.755	0.543	0.968	1.185	-	1.349	-	1.142	1.221
Poles, Towers, Conductors	0.537	0.600	1.068	-	-	-	-	1.261	1.348
Transformers	0.074	0.082	0.146	-	-	-	-	0.173	0.185
Total	$ 3.034	$ 2.265	$ 3.992	$ 3.832	$ 2.751	$ 4.539	$ 2.174	$ 3.445	$ 6.052
Revenue Related									
- (cents/kWh)	-	-	-	-	-	-	-	-	-
- or ($/kW/month)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Direct Assignment									
- (cents/kWh)	0.055	0.056	0.056	(0.009)	(0.210)	(0.004)	0.000	6.473	0.036
- or ($/kVA/month)	$ 0.110	$ 0.076	$ 0.111	$ (0.027)	$ (0.421)	$ (0.015)	$ -	$ 14.447	$ 0.105
Total Wheeling Charge									
Customer Charge ($/customer/month)	$ 20	$ 19	$ 21	$ 1,127	$ 1,405	$ 2,383	$ 427	$ 13	$ 23
- (cents/kWh)	1.567	1.708	2.072	1.281	1.165	1.139	0.920	8.016	2.118
- or ($/kVA/month)	$ 3.144	$ 2.341	$ 4.103	$ 3.805	$ 2.330	$ 4.524	$ 2.174	$ 17.892	$ 6.157
Power Supply									
- (cents/kWh)	2.371	2.512	2.297	2.301	2.300	2.284	2.402	2.362	1.939
- or ($/kVA/month)	$ 4.757	$ 3.444	$ 4.548	$ 6.833	$ 4.600	$ 9.074	$ 5.674	$ 5.272	$ 5.636
Bundled Power Rate									
Customer Charge ($/customer/month)	$ 20	$ 19	$ 21	$ 1,127	$ 1,405	$ 2,383	$ 427	$ 13	$ 23
- (cents/kWh)	3.939	4.220	4.370	3.582	3.465	3.423	3.322	10.378	4.058
- or ($/kVA/month)	$ 7.901	$ 5.785	$ 8.650	$ 10.638	$ 6.930	$ 13.598	$ 7.848	$ 23.164	$ 11.793

Assumes a constant 12.968 percent rate of return across customer classes.

8/27/97

FORTISBC

AGREEMENT FOR THE SUPPLY OF ELECTRICITY WHOLESALE SERVICE

LWD05002

BETWEEN

The Corporation of the City Of Grand Forks
420 Market Avenue
Grand Forks, BC V0H 1H0

And

FortisBC Inc.
1628 Dickson Avenue
Kelowna, BC V1Y 9X1

Accepted for filing: JUN 19 2008

Effective: APR 1 2006

Order No.: G 1 01 '08

SECRETARY
B.C. UTILITIES COMMISSION

Agreement for the Supply of Electricity Wholesale Service

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Accepted for filing: JUN 19 2008

Effective: APR 1 2006

Order No.: G 1 0 1 08

E Hamilton

SECRETARY

B.C. UTILITIES COMMISSION

THIS AGREEMENT is made as of the 1st day of April 2006.

BETWEEN:

FORTISBC INC., a corporation established by a special Act of the Legislature of the Province of British Columbia, having its head office in the City of Kelowna in the Province of British Columbia,. ("FortisBC"),

AND:

THE CORPORATION OF THE CITY OF GRAND FORKS, a company incorporated under the laws of British Columbia and having an office in the City of Grand Forks in the Province of British Columbia. ("City of Grand Forks"),

WHEREAS FortisBC is a supplier of electricity in the southern interior region of the Province of British Columbia;

AND WHEREAS the City of Grand Forks wishes to purchase electricity from FortisBC for its own use and for resale to City of Grand Forks customers within the City of Grand Forks' Service Area as hereinafter described;

AND WHEREAS both FortisBC and the City of Grand Forks have agreed to the principles set forth in the Proposed Settlement Agreement resulting from the British Columbia Utilities Commission Decision dated March 10, 1999.

Accepted for filing: JUN 19 2008 E Hamilton
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NOW THEREFORE this Agreement witnesses that in consideration of the terms and conditions hereinafter set forth the Parties covenant and agree as follows:

1. DEFINITIONS

In this Agreement:

(a) **"Check Metering"** means any measurement device or system installed, owned and maintained by the City of Grand Forks to check the measurements and calculations carried out by the Metering System.

(b) **"Commission"** means the British Columbia Utilities Commission.

(c) **"Commodity Service"** means the supply of power, expressly excluding the services set forth in the Transmission Services Tariff, to the City of Grand Forks by a third party and may include full or partial supply of the load requirements of the City of Grand Forks.

(d) **"Demand"** has the meaning given to it in subsection 9.04.

(e) **"Demand Limit"** means the capability of FortisBC's facilities at each of the Points of Delivery, specified in Appendix A attached hereto.

(f) **"Demand Period"** has the meaning given to it in subsection 9.04.

(g) **"Good Utility Practice"** means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the WECC region.

(h) **"Maximum Demand"** means the highest clock hour of taking of electricity by the City of Grand Forks recorded in kilovolt-amperes by FortisBC from time to time.

(i) **"Metering System"** means the measurement device or system installed, owned and maintained by FortisBC used to determine the City of Grand Forks' electricity consumption.

(j) **"Parties"** means both FortisBC and the City of Grand Forks.

(k) **"Point of Delivery"** means the point or points at which the City of Grand Forks' distribution system attaches to FortisBC's facilities, as specifically described in Appendix A attached hereto.

(l) **"Power Factor"** means the percentage determined by dividing the City of Grand Forks' demand measured in kilowatts by the same demand measured in kilovolt-amperes.

(m) **"APSA"** means the Access Principles Settlement Agreement, also known as the Proposed Settlement Agreement, as amended from time to time, attached as Appendix A to the Commission Order Number G-27-99 dated March 10, 1999 in the matter of the Access Principles Application .

(n) **"Service Area"** means the City of Grand Forks' service area, the boundaries of which are shown by the red line on the map identified as the City of Grand Forks'

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Electrical Service Boundaries, attached hereto as Appendix B and shall include any area(s) added from time to time by the municipality.

(o) **"Services"** means the supply and delivery of power to the City of Grand Forks by FortisBC under this Agreement.

(p) **"Term"** means the period defined by subsection 2.01 herein.

(q) **"Transmission Services Tariff"** means the tariff as approved from time to time by the Commission for the use by a third party supplier to deliver power to the City of Grand Forks or by the City of Grand Forks to deliver power to a third party on the transmission and distribution facilities of FortisBC, including ancillary services required for the delivery of power.

(r) **"WECC"** means Western Electricity Coordinating Council or a successor organization.

2. TERM OF AGREEMENT

2.01 Term

This Agreement shall be effective as of April 1, 2006 and shall continue for a term of four years thereafter, terminating on March 31, 2010. Upon mutual agreement in writing by both parties, this agreement may be renewed prior to March 31, 2010 for an additional five year term on the same terms and conditions.

2.02 Early Termination

If the City of Grand Forks elects to engage any third party supplier to perform the Commodity Services and notice as provided for in the APSA is given to FortisBC the City of Grand Forks may terminate this Agreement prior to expiry of the Term. If this Agreement terminates pursuant to this subsection, the City of Grand Forks may then be liable to pay such costs, including stranded costs, if any, as directed by the Commission.

3. ACCESS PRINCIPLES SETTLEMENT AGREEMENT

3.01 Access Principles Settlement Agreement Rights

Nothing contained in this Agreement shall be construed as affecting in any way the rights of either Party as set forth in the APSA nor as affecting in any way the rights of either Party to unilaterally make application to the Commission for further directions or orders from the Commission related to the terms and conditions of the APSA.

3.02 Regulatory Principles

If any provision of this Agreement is declared by the Commission to be inconsistent with the regulatory principles set forth in the APSA, the Parties shall amend that provision in such reasonable manner as achieves the intention of the declaration of the Commission. In the event the Parties cannot agree on such amendments, either Party shall be entitled to seek further direction from the Commission and the Parties hereby agree to be bound by such direction from the Commission.

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4. CONDITIONS OF SUPPLY

4.01 Supply of Electricity

During the term of this Agreement, except in an emergency described in subsection 6.03, FortisBC shall supply up to the Demand Limit electricity required by the City of Grand Forks solely for its own use and for supplying the needs of its customers within the Service Area. FortisBC shall supply electricity to the Points of Delivery through suitable plant and equipment in accordance with Good Utility Practice on a continuous basis, except as provided in this Agreement. The responsibility of FortisBC for the delivery of electricity to the City of Grand Forks shall cease at the Points of Delivery.

4.02 Duty to Act Prudently in Arranging for Electricity Supply

Notwithstanding the provisions of subsection 4.03 and 4.04 FortisBC has a duty not to be imprudent in arranging for the supply of electricity required pursuant to subsection 4.01 of this Agreement and FortisBC will, subject to subsections 4.04 and 4.09, be liable to the City of Grand Forks for any loss, injury, damage or expense caused to the City of Grand Forks if the British Columbia Utilities Commission determines that FortisBC has failed to meet its duty not to be imprudent.

4.03 Failure to Deliver

At any time during an actual or anticipated shortage of electricity, or in the event of a breakdown or failure of generating, transmitting or distributing plant, lines or equipment, or in order to comply with the requirements of any law, FortisBC shall have the right to curtail or discontinue the supply of electricity to the City of Grand Forks or reduce the voltage or frequency of the electricity supplied. To the extent that it is practical and reasonable, FortisBC will not unduly discriminate in favour of or against the City of Grand Forks in the supply of electricity.

4.04 Interruptions and Defect in Service

The City of Grand Forks acknowledges and agrees that FortisBC's responsibility and liability for loss, injury, damage or expense caused by or resulting from any interruption, termination, failure or defect in the supply of electricity by FortisBC pursuant to this Agreement is limited by the terms and conditions of FortisBC's Electric Tariff B.C.U.C. No. 1 (including, without limitation, Section 8.1 thereof), as approved from time to time by the Commission.

4.05 Commodity Services

The City of Grand Forks shall have the rights set forth in the APSA to purchase power from a third party supplier and to meet part or all of its load requirements from Commodity Services.

4.06 Limits on Other Supply

Unless the City of Grand Forks has exercised its rights pursuant to the APSA, the City of Grand Forks shall, during the Term, only purchase electricity from FortisBC and the City of Grand Forks' own customers for its own use and the use of its customers within the Service Area. The City of Grand Forks may obtain up to 15 MWs of electricity from new

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generation owned and operated by the City of Grand Forks or the City of Grand Forks' customers.

4.07 Retail Access on the City of Grand Forks' Facilities
The City of Grand Forks shall give notice, consistent with the APSA requirements, in writing to FortisBC prior to providing the City of Grand Forks' transmission and distribution services for the direct delivery of third party supply to a customer of the City of Grand Forks.

4.08 Sales out of Service Area
If service to a customer outside or within the Service Area would require duplication of existing electrical plant which duplication could be avoided, then the Party that has the right to serve that customer pursuant to this Agreement may consent to the other Party serving that customer, such consent not to be unreasonably delayed or withheld.

4.09 No Liability for Consequential Damages
Neither Party, nor its directors, officers, employees or agents, will be liable to the other Party, or its directors, officers, employees or agents, in contract, tort, warranty, strict liability or any other legal theory for any indirect, consequential, incidental, punitive or exemplary damages arising under or in connection with this Agreement.

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5. CONDITIONS OF SERVICE

5.01 Supply Characteristics

The electricity to be supplied to the City of Grand Forks shall be three-phase alternating current, having a nominal frequency of 60 hertz and the nominal voltages designated in Appendix A for the Points of Delivery, as amended from time to time.

FortisBC is a signatory of the WECC Reliability Management System (RMS) Agreement. FortisBC is committed to the service reliability standards detailed in this document and is liable for financial sanctions that WECC can impose for non-adherence to those standards.

The Commission may exercise its authority by whatever means it deems appropriate in the event that frequency or voltage excursions occur that could reasonably have been prevented.

5.02 Underground Facilities

When the City of Grand Forks requests the construction or installation of underground facilities, the City of Grand Forks shall be responsible for the difference between the cost of constructing or installing the facilities underground and the cost of constructing or installing similar facilities above ground.

5.03 Ownership of Facilities

Notwithstanding the payment of any contribution by the City of Grand Forks toward the cost of facilities pursuant to subsection 5.02, FortisBC shall retain full title to all facilities.

5.04 Revenue Guarantee

The City of Grand Forks may be required to provide a revenue guarantee if FortisBC's facilities must be upgraded significantly to meet a proposed increase in the City of Grand Forks' load in excess of 5000 kVA resulting from either a new City of Grand Forks customer or the increased load of an existing City of Grand Forks customer. The revenue guarantee will be equal to the cost of upgrading the facilities and will be refunded, with interest, in equal installments over a period of five years at the end of each year of continued service to that customer at the increased load. The revenue guarantee shall be in the form of cash, surety bond or other form of security satisfactory to FortisBC.

6. INTERCONNECTED OPERATION

6.01 Obligation of FortisBC

The maintenance by FortisBC of the agreed frequency and voltage at the Points of Delivery, set out in Appendix A, shall constitute delivery of electricity under this Agreement, whether or not any electricity is taken by the City of Grand Forks, and shall, subject to subsection 10.01 constitute the complete discharge by FortisBC of its obligations to the City of Grand Forks for Services.

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6.02 Use of Facilities
Each Party shall cooperate with the other to secure the most efficient use of the plant and equipment of the other Party, which may include wheeling power through the other Party's transmission and distribution circuits to facilitate supply to either Party or its customers.

6.03 Exceeding Demand Limit
The City of Grand Forks shall not take electricity in excess of the Demand Limit of a Point of Delivery without the prior written consent of FortisBC, unless an emergency condition requires that the City of Grand Forks take in excess of the Demand Limit, and then only for the duration of the emergency condition. The City of Grand Forks shall immediately advise FortisBC when such an emergency condition occurs. The City of Grand Forks shall reduce immediately its use of electricity to the Demand Limit for that Point of Delivery or to a specified limit above the Demand Limit upon the oral or written request of FortisBC.

6.04 Restrict or Suspend Service
If the City of Grand Forks fails to comply with the request of FortisBC pursuant to the previous paragraph, FortisBC may, when necessary in the opinion of FortisBC, restrict or suspend the supply of electricity to the City of Grand Forks at the Point of Delivery summarily without further notice.

6.05 Avoidance of Excess Loads
The City of Grand Forks shall provide for interconnection of its lines so as to transfer and arrange the loads taken at each Point of Delivery to balance as far as is practicable the loads at each Point of Delivery given the Demand Limit at each Point of Delivery.

6.06 Maintenance of Adequate Supply Capability
If at any time, except in an emergency condition described in subsection 6.03, the City of Grand Forks notifies FortisBC that it has taken electricity in excess of 95 percent of the Demand Limit of a Point(s) of Delivery, FortisBC shall take appropriate measures at no cost to the City of Grand Forks to increase the supply capability at the Point(s) of Delivery to bring the City of Grand Forks' anticipated future demand to or below 95 percent of the Demand Limit.

6.07 City of Grand Forks' Facilities
The City of Grand Forks shall be responsible for designing, constructing, installing and maintaining all auxiliary and interconnecting equipment on the City of Grand Forks' side of the Point of Delivery and the City of Grand Forks shall have ownership rights in all such auxiliary and interconnection equipment. FortisBC shall have no fiscal or other responsibilities in ensuring that such City of Grand Forks facilities meet the requirements of the City of Grand Forks' customers.

6.08 Installation of Facilities
All electrical facilities owned by the City of Grand Forks from the Points of Delivery up to and including the City of Grand Forks' overload and/or overcurrent protection and isolation devices shall be approved and coordinated in a manner satisfactory to FortisBC,

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and may be inspected by FortisBC from time to time. Notwithstanding the foregoing, FortisBC shall not require a higher standard for the City of Grand Forks' electrical facilities than the standard of FortisBC facilities supplying that portion of the City of Grand Forks' facilities.

6.09 Coordination of Protective Devices
Either Party shall notify the other Party in advance of any changes to its facilities that may affect the proper coordination of protective devices between the two systems.

6.10 Power Factor
The City of Grand Forks shall endeavor to regulate its load so that the Power Factor at each Point of Delivery will be no less than 90 percent, lagging.

6.11 Load Fluctuations
The City of Grand Forks shall maintain and operate its equipment, and shall endeavor to ensure that its customers equipment is operated in a manner that will not cause sudden fluctuations to FortisBC's line voltage, or introduce any influence into FortisBC's system deemed by FortisBC to threaten to disturb or disrupt its system or the plant or property of any other customer of FortisBC or of any other person.

6.12 Hazard to Property and Public Safety
Each of the Parties shall operate and maintain electrical plant within the Service Area so as to avoid hazard to the property of the other Party or danger to persons. To avoid hazard to property and to ensure public safety, the Parties agree that:

(a) All electrical generating facilities intended to be operated within the Service Area and in parallel with FortisBC's electrical system shall be installed only after FortisBC has been provided with full particulars of the facilities and FortisBC has given its written approval that the proposed operation of the facilities is satisfactory to FortisBC, acting reasonably. Upon completion, FortisBC shall be permitted to inspect the installation.

(b) The City of Grand Forks shall ensure that any parallel generating facility installed shall not backfeed into FortisBC's system or facilities unless the City of Grand Forks receives express permission in writing from FortisBC, which will not be unreasonably withheld.

(c) The City of Grand Forks shall ensure that all standby generation facilities within the Service Area to provide electrical service in the event of a disruption of service shall be installed so that they remain at all times electrically isolated from FortisBC'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 FortisBC's electrical system.

6.13 Permit to Install & Access
If any equipment or facilities associated with any Point of Delivery and belonging to a Party to this Agreement are or are to be located on the property of the other Party, a permit to install, test, maintain, inspect, replace, repair and operate during the term of this Agreement and to remove such equipment and facilities at the expiration of the Term,

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together with the right of entry to said property at all reasonable times is hereby granted by the other Party.

The rights hereby granted shall be exercised subject to prior notification and to any reasonable requirement of the granting Party necessary for the safety or security of that Party's facilities and employees and the continuity of that Party's operations.

6.14 Use of City Streets and Lanes

During the existence of this Agreement FortisBC shall have the right and easement to enter upon and use the streets and lanes within the boundaries of the City of Grand Forks for all purposes connected with the furnishing of electricity to the City of Grand Forks, and, without limiting generality, for the purpose of erecting, maintaining, repairing, replacing, removing or using poles, wires, meters, machinery and equipment, subject to the plan of any new erection of pole lines receiving such reasonable approvals as the City of Grand Forks deems necessary.

6.15 Drawings to be Provided

If either Party is required or permitted to install, test, maintain, inspect, replace, repair, remove or operate equipment on the property of the other, the owner of such property shall furnish the other Party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other Party of any subsequent modification which may affect the duties of the other Party in regard to such equipment, and furnish the other Party with accurate revised drawings, if possible.

6.16 Inspection of Facilities

Each Party may, for any reasonable purpose under this Agreement, inspect the other Party's electrical installation at any reasonable time after giving suitable notice. Such inspection, or failure to inspect, shall not render such Party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this Agreement. The inspecting Party shall observe written instruction and rules posted in facilities and such other necessary instructions or standards for inspection as the Parties agree to. Only those electric installations used in complying with the terms of this Agreement shall be subject to inspection.

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7. PLANNING AND OPERATING INFORMATION

7.01 Increases in Maximum Demand

The City of Grand Forks shall notify FortisBC in writing of any anticipated additional single load in excess of 5000 kVA resulting from a new customer or the increased load of an existing customer, providing as much advance notice of the increase as can be given in the circumstances. FortisBC shall endeavor to provide the service requested by the date the increase is intended to become effective, or as soon thereafter as is practicable.

7.02 Records and Forecasts

Each Party shall retain and make available upon request for the other Party log sheets, records of recording meters, and any other readily available information of an operational character relating to the electricity supplied under this Agreement, excluding non-public records of a financial or business nature relating to the City of Grand Forks' utility undertaking.

7.03 General Information Requests

The Parties agree to cooperate in the full exchange of such planning and operating information as may be reasonably necessary for the timely and efficient performance of the Parties' obligations or the exercise of rights under this Agreement. Such information shall be provided on a timely basis and no reasonable request shall be refused.

7.04 Load-Resource Forecast

By June 30 of each year, the Parties agree to exchange a five year forecast of loads and resources for their respective electrical systems including a forecast of their Maximum Demand at each Point of Delivery normalized for average weather conditions and shall also provide a forecast of energy consumption for each year. These forecasts shall include programs for resource acquisition, transmission and firm loads. The degree of detail in these forecasts shall be decided by mutual agreement.

7.05 Load from Previous Year

Before the end of February in each year, the City of Grand Forks shall provide FortisBC with a record of the number of customers and load by customer class for the previous calendar year.

7.06 Scheduled and Maintenance Outages

Each party shall submit to the other Party a list of outages scheduled for inspection, testing, preventative maintenance, corrective maintenance, repairs, replacement or improvements that might affect the delivery of electricity under this Agreement, providing as much advance notice of the outage as can be given in the circumstances. The Parties shall use reasonable efforts to keep such schedules current and to revise such schedules so as to minimize the impact on the other Party's system.

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8. METERING

8.01 Installation
FortisBC shall furnish, install and maintain the Metering System and the City of Grand Forks, in accordance with subsection 8.03, may furnish, install and maintain the Check Metering, each at their own expense, at the Points of Delivery, which shall accurately measure and record electricity within the limits prescribed by the federal Department of Consumer and Corporate Affairs ("Prescribed Limits") and pursuant to subsection 8.07.

8.02 Totalizing Metering
FortisBC shall also, at its expense, install totalizing metering to compensate for demand diversity at the different Points of Delivery.

8.03 Check Metering
Check Metering and connecting equipment and facilities to be furnished by the City of Grand Forks shall be satisfactory to FortisBC, and shall be installed in accordance with Good Utility Practice and in a manner satisfactory to FortisBC, acting reasonably.

8.04 Meter Tests and Adjustments
Unless otherwise agreed to by the Parties, each Party shall, at its own expense, arrange to have its meters tested by an inspector or accredited meter verifier authorized pursuant to the federal Electricity and Gas Inspection Act and regulations, as amended from time to time.

8.05 Inspection of Metering Equipment
Notwithstanding subsection 8.04, either Party may, after giving two days' notice, inspect in the presence of the other Party, the metering equipment installed in accordance with this subsection by the other Party, and may request that that metering equipment be tested by an inspector or authorized meter verifier.

If the result of any test performed pursuant to this subsection shows that any of the metering equipment is not recording within the Prescribed Limits, then the owner of that metering equipment shall pay for the costs of testing.

If after testing the metering equipment is found to be recording within the Prescribed Limits, the Party that made the request shall pay for the costs of testing.

8.06 Calculating the Amount to be Paid
The measurements recorded by the Metering System shall be used for calculating the amount to be paid for the electricity delivered to the City of Grand Forks, except in the following circumstances:

(a) if a totalizing meter is temporarily not in service or is found after testing to be not recording within the Prescribed Limits then the measurements recorded by the City of Grand Forks' totalizing meter shall be used to determine the total consumption and demand, or, in the absence of a City of Grand Forks totalizing meter, FortisBC's meters shall be used to determine the total consumption and

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demand taking into account established load diversity until FortisBC's totalizing meter has been recalibrated;

(b) if the Metering System is not in service or is found after testing to be not recording within the Prescribed Limits then the measurements recorded by the City of Grand Forks' totalizing meter or , in the absence of a totalizing meter, the City of Grand Forks' meters shall be used for calculating the amount to be paid for electricity delivered to the City of Grand Forks;

(c) if neither the Metering System nor the Check Metering are in service or are found after testing to be not recording within the Prescribed Limits then the amount of electricity delivered since the previous billing shall be estimated from the best information available.

8.07 Prescribed Limits

If at any time the testing described in subsections 8.04 and 8.05 shows that the metering equipment was not recording within the Prescribed Limits, and if such recordings were used for billing purposes, then the billings shall be adjusted as prescribed by the Electricity and Gas Inspection Act.

8.08 Access to Meters

Each Party shall have the right, by giving suitable notice, to enter the property of the other Party at all reasonable times for the purpose of reading any and all meters mentioned in this Agreement which are installed on such property.

9. INVOICES AND PAYMENT

9.01 Meter Reading

Meters shall be read at the end of each month. An accurate record of all meter readings shall be kept by FortisBC and shall be the basis for determination of all bills rendered for service.

9.02 Invoices and Payment

FortisBC shall render a billing invoice monthly pursuant to the terms of FortisBC's Electric Tariff, as amended from time to time.

9.03 Rates for Electricity

The City of Grand Forks shall pay for Services during the Term in accordance with the tariff applicable to the City of Grand Forks filed with the Commission, as amended from time to time.

9.04 Demand Period and Demand

For billing purposes, Demand Period means the period, expressed in minutes, over which meter readings are integrated to obtain the Demand, which is the power measured in kilovolt amperes (kVA), or multiples thereof, at the Point of Delivery. In this Agreement and for billing purposes, the Demand Period shall be a sixty minute clock hour interval.

Accepted for filing: JUN 19 2008
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9.05 Billing Adjustments
If FortisBC suspends or reduces Service for reasons other than a request by the City of Grand Forks or an interruption of Service caused by the City of Grand Forks' system, and the suspension or reduction results in a peak Demand which would otherwise be used for billing purposes, the Demand in the Demand Period immediately following restoration of service may be reduced, by mutual agreement, to an estimate of what the Demand would have been if Service had not been suspended or reduced. The estimate shall be determined in consideration of weather conditions and previous load experience.

9.06 Late Payments
If the amount due on any invoice has not been paid in full after twenty calendar days from the billing date shown on the invoice, a late payment charge shall be applied to the unpaid balance, and the resulting amount will be shown and identified on the next invoice to be rendered. The late payment charge shall be as specified in FortisBC's Electric Tariff, as amended from time to time.

9.07 Taxes
In addition to payments for electricity, the City of Grand Forks shall pay to FortisBC the amount of any sales tax, goods and services tax, or any other tax or assessment levied by any competent taxing authority on any electricity delivered pursuant to this Agreement.

9.08 Payment of Accounts
The City of Grand Forks shall pay to FortisBC the amount of the billing within 20 calendar days from the date appearing on the invoice .

10. CONTINUITY OF SUPPLY

10.01 Standard of Performance
FortisBC shall perform the Services with skill, care, and diligence consistent with Good Utility Practice and consistent with directions from the Commission, including the quality performance standards, if any, approved by the Commission from time to time.

10.02 Interruptions and Defects in Service
FortisBC shall avoid interruption of delivery of electricity, but nevertheless shall not be liable to the City of Grand Forks for any loss or damage owing to failure to supply electricity, or owing to other abnormal conditions of supply resulting from force majeure as defined in subsection 12.01.

10.03 Suspension of Supply
Either Party shall have the right to demand the temporary suspension of, or to suspend temporarily, the delivery or taking of electricity, as the case may be, whenever necessary to safeguard life or property, or for the purpose of replacing, repairing or maintaining any of its apparatus, equipment, or works. Such reasonable notice of the suspension as the circumstances permit shall be given by one Party to the other.

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10.04 Discontinue Service

FortisBC may discontinue the supply of electricity to the City of Grand Forks at a Point of Delivery for the failure by the City of Grand Forks to commence remedial action acceptable to FortisBC, within 15 days of receiving notice from FortisBC, to correct the breach of any significant practice, term or condition to be observed or performed by the City of Grand Forks under this Agreement. FortisBC shall be under no obligation to resume service until the City of Grand Forks gives assurances satisfactory to FortisBC that the breach which resulted in the discontinuance shall not recur.

10.05 Obligations Continue

Discontinuance of Services by FortisBC pursuant to the provisions of this Agreement shall not relieve the City of Grand Forks of any obligation under this Agreement, or alter any of the obligations of the City of Grand Forks under this Agreement.

10.06 Other Remedies

FortisBC's right to discontinue the supply of electricity under this Agreement shall not operate to prevent FortisBC from pursuing, separately or concurrently, any other remedy it may have under this Agreement or by operation of law.

11. REMOVAL OF FACILITIES UPON TERMINATION

After the termination of this Agreement, FortisBC shall have the right to, and must expeditiously if requested by the City of Grand Forks, remove from the property owned or controlled by the City of Grand Forks any and all electrical apparatus and equipment which FortisBC owns and has installed on the property and FortisBC shall leave the property in good repair after such removal.

12. GENERAL PROVISIONS

12.01 Force Majeure

Neither Party to this Agreement shall be considered to be in default in the performance of any of its obligations under this Agreement to the extent that performance of those obligations is prevented or delayed by any cause which is beyond the reasonable control of the Party prevented or delayed by that cause. If either Party is delayed or prevented from its performance at any time by any act, omission or neglect of the other Party or its representatives, or by an act of God or the public enemy, or by expropriation or confiscation of facilities, compliance with any order of any governmental authority or order of a court of competent jurisdiction, acts of war, rebellion or sabotage, fire, flood, explosion, riot, strike or other labour dispute beyond the reasonable control of the Party or any unforeseeable cause beyond the control and without the fault and negligence of the Party, the Party so prevented or delayed shall give notice to the other Party of the cause of the prevention or delay but, notwithstanding giving of that notice, the Party shall promptly and diligently use reasonable efforts to remove the cause of the prevention or delay.

12.02 Notices

Accepted for filing: JUN 19 2008
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Any notice, direction or other instrument required or permitted to be given under this Agreement in writing shall be sufficient in all respects if delivered, or if sent by fax, or if sent by prepaid registered post in Canada to the Parties at their respective addresses as they appear in subsection 12.03, or to any substitute address of which the Party sending notice has had notice in writing.

12.03 Addresses

Any notice, direction or other instrument shall be delivered or sent to the following addresses:

(a) To FortisBC:

FortisBC Inc.
1628 Dickson Avenue
Kelowna, BC VIY 9X1
Attention: Legal Department

(b) To the City of Grand Forks:

The Corporation of the City of Grand Forks
420 Market Avenue
Grand Forks, BC V0H 1H0
Attention: Administrator

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12.04 Dates

Any notice, direction, or other instrument shall be deemed to have been received on the following dates if,

(a) sent by fax, on the business day next following the date of transmission.

(b) delivered, on the business day next following the date of delivery.

(c) 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, directions or other instrument shall only be deemed to be effective if delivered or sent by fax.

12.05 Disputes

If any difference or dispute occurs regarding any matter arising under this Agreement, either Party may request that the Commission settle the difference or dispute. If the Commission declines to settle the dispute then the dispute shall be arbitrated pursuant to the Commercial Arbitration Act of British Columbia.

12.06 Invalidity

If any provision of this Agreement or the application of any provision to any Party or circumstance is declared or held to be wholly or partially invalid, this Agreement shall be interpreted as if the invalid provision had not been a part hereof so that the invalidity shall not affect the validity of the remainder which shall be construed as if this Agreement had been executed without the invalid portion. FortisBC and the City of Grand Forks shall, either independently, jointly or in concert with other wholesale customer's of FortisBC, make all reasonable efforts to validate any portion of this Agreement declared or held to be invalid.

12.07 Headings

The headings in this Agreement have been inserted for convenience of reference only, and shall not affect the construction or interpretation of this Agreement.

12.08 Enurement

This Agreement shall be binding upon and shall enure to the benefit of the Parties hereto and of their respective successors and assigns.

12.09 Governing Law

Notwithstanding anything to the contrary in this Agreement, FortisBC shall comply fully with all applicable federal and provincial has and municipal laws of general application (including bylaws) in effect from time to time.

12.10 Entire Agreement

This Agreement and the Appendices attached hereto are intended by the Parties to be the final expression of their agreement and are intended also as a complete and exclusive statement of the terms of this Agreement.

Accepted for filing: JUN 19 2008 .... SECRETARY
Effective: APR 1 2006 B.C. UTILITIES COMMISSION
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12.11 Commission Approval

This Agreement and all the terms and conditions contained in it shall be subject to the provisions of the Utilities Commission Act of British Columbia, as amended or re-enacted from time to time and to the jurisdiction of the Commission and the parties agree to make such amendments to the agreement as required or ordered by the Commission from time to time.

IN WITNESS WHEREOF the Parties have executed this Agreement by their duly authorized signatories.

The Seal of THE CORPORATION OF THE CITY OF GRAND FORKS was hereunto affixed the 17 day of March 2006 in the presence of

Signature

Victor Kumar

Print Name

City Manager

Title

Signature

Print Name

Title

FORTISBC INC.

Signature

David Bennett

Print Name

General Counsel and Corporate Secretary

Title

Accepted for filing: JUN 19 2008

Effective: APR 1 2006

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B.C. UTILITIES COMMISSION

Appendix A to the Agreement for the Supply of Electricity - Wholesale Service between FortisBC Inc. and The Corporation of the City of Grand Forks

City of Grand Forks - Points of Delivery

1. Ruckles Substation

Description: Line side of City's 13 kV Gang Switch in City's yard adjacent to Ruckles Substation

Nominal Voltage Supplied: 13 kV

Demand Limit:	Summer	6 MVA
	Winter	8 MVA

2. Ruckles Substation

Description: End of FortisBC's 4kV Flat Bar Bus at Ruckles Substation

Nominal Voltage Supplied: 4 kV

Demand Limit:	Summer	6 MVA
	Winter	8 MVA

3. Donaldson Drive

Description: Line side of City's recolser disconnects on Donaldson Drive at southwest corner of intersection of Donaldson Drive and Coalchute Road

Nominal Voltage Supplied: 13kV

Demand Limit:	Summer	6 MVA
	Winter	8 MVA

Accepted for filing: JUN 19 2008
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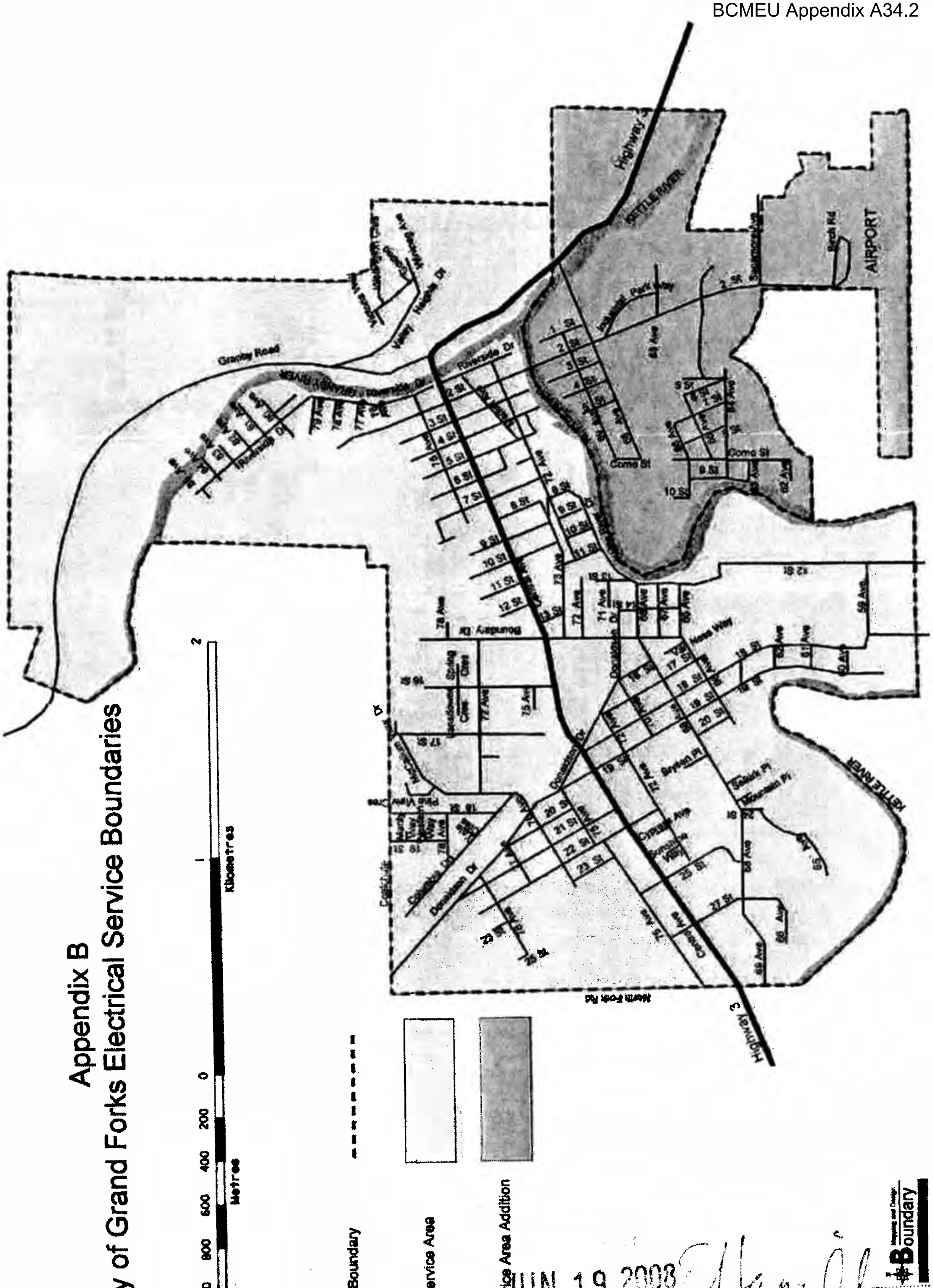
Appendix B
City of Grand Forks Electrical Service Boundaries



Accepted for filing: JUN 19 2008

Effective: APR 1 2006

Order No.: G1 01 08-006

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B.C. UTILITIES COMMISSION

AGREEMENT FOR THE SUPPLY OF ELECTRICITY

WHOLESALE SERVICE

FORTISBC

and

THE CITY OF KELOWNA

Accepted for filing: JUN 19 2008
Effective: NOV 1, 2004
Order No.: G 1 01 08

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FORTISBC

THE CITY OF KELOWNA

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Accepted: JUN 19 2008
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E Hamilton
[Secre]tary
B.C. UTILITIES COMMISSION

THIS AGREEMENT is made as of the 1st of November 2004.

BETWEEN:

FORTISBC

(the "Company")

AND:

THE CITY OF KELOWNA

(the "Customer")

WHEREAS the Company is a supplier of electricity in the southern interior region of the Province of British Columbia;

AND WHEREAS the Customer wishes to purchase electricity from the Company for its own use and for resale to customers within the Customer's Service Area as hereinafter described;

AND WHEREAS both the Company and the Customer have agreed to the principles set forth in the Proposed Settlement Agreement resulting from the British Columbia Utilities Commission Decision dated March 10, 1999.

Accepted for filing: JUN 19 2008 E Hamilton
Effective: NOV 1 2004 SECRETARY
Order No.: 101 08 B.C. UTILITIES COMMISSION

NOW THEREFORE this Agreement witnesses that in consideration of the terms and conditions hereinafter set forth the Parties covenant and agree as follows:

1. DEFINITIONS

In this Agreement:

(a) **"Check Metering"** means any measurement device or system installed, owned and maintained by the Customer to check the measurements and calculations carried out by the Metering System.

(b) **"Commission"** means the British Columbia Utilities Commission.

(c) **"Commodity Service"** means the supply of power, expressly excluding the services set forth in the Transmission Services Tariff, to the Customer by a third party and may include full or partial supply of the load requirements of the Customer.

(d) **"Demand Limit"** means the capability of the Company's facilities at each of the Points of Delivery, specified in Appendix A attached hereto.

(e) **"Good Utility Practice"** means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

(f) **"Maximum Demand"** means the highest months rate of taking of electricity by the Customer recorded in kilovolt-amperes by the Company from time to time.

(g) **"Metering System"** means the measurement device or system installed, owned and maintained by the Company used to determine the Customer's electricity consumption.

(h) **"Parties"** means both the Company and the Customer.

(i) **"Point of Delivery"** means the point or points at which the Customer's distribution system attaches to the Company's facilities, as specifically described in Appendix A attached hereto.

(j) **"Power Factor"** means the percentage determined by dividing the Customer's demand measured in kilowatts by the same demand measured in kilovolt-amperes.

(k) **"APSA"** means the Access Principles Settlement Agreement, also known as the Proposed Settlement Agreement, as amended from time to time, attached as Appendix A to the Commission Decision dated March 10, 1999 in the matter of the Access Principles Application and attached hereto as Appendix C.

(l) **"Service Area"** means the Customer's service area, the boundaries of which are shown by the taupe filled area on the map identified as the Customer's Electrical Service Boundaries, attached hereto as Appendix B and shall include any area(s) added/and or adjusted from time to time by the municipality.

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(m) **"Services"** means the supply and delivery of power to the Customer by the Company under the Agreement.

(n) **"Term"** means the period defined by subsection 2.01 herein.

(o) **"Transmission Services Tariff"** means the tariff as approved from time to time by the Commission for the use by a third party supplier to deliver power to the Customer or by the Customer to deliver power to a third party on the transmission and distribution facilities of the Company, including ancillary services required for the delivery of power.

2. TERM OF AGREEMENT

2.01 Term

This Agreement shall be effective as of November 1, 2004 and shall continue for a term of five years thereafter, terminating on October 31, 2009.

2.02 Early Termination

If the Customer elects to engage any third party supplier to perform the Commodity Services and notice as provided for in the APSA is given to the Company the Customer may terminate this Agreement prior to expiry of the Term. If this Agreement terminates pursuant to this subsection, the Customer may then be liable to pay such costs, including stranded costs, if any, as directed by the Commission.

3. Access Principles Settlement Agreement

3.01 Access Principles Settlement Agreement Rights

Nothing contained in this Agreement shall be construed as affecting in any way the rights of either Party as set forth in the APSA (Appendix A to Commission Order No. G-27-99) nor as affecting in any way the rights of either Party to unilaterally make application to the Commission for further directions or orders from the Commission related to the terms and conditions of the APSA.

3.02 Regulatory Principles

If any provision of this Agreement is declared by the Commission to be inconsistent with the regulatory principles set forth in the APSA, the Parties shall amend that provision in such reasonable manner as achieves the intention of the declaration of the Commission. In the event the Parties cannot agree on such amendments, either Party shall be entitled to seek further direction from the Commission and the Parties hereby agree to be bound by such direction from the Commission.

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4. CONDITIONS OF SUPPLY

4.01 Supply of Electricity

During the term of this Agreement, except in an emergency described in subsection 6.03, the Company shall supply up to the Demand Limit electricity required by the Customer solely for its own use and for supplying the needs of its customers within the Service Area. The Company shall supply electricity to the Points of Delivery through suitable plant and equipment in accordance with Good Utility Practice on a continuous basis, except as provided in this Agreement. The responsibility of the Company for the delivery of electricity to the Customer shall cease at the Points of Delivery.

4.02 Duty to Act Prudently in Arranging for Electricity Supply

Notwithstanding the provisions of subsection 4.03 and 4.04 the Company has a duty not to be imprudent in arranging for the supply of electricity required pursuant to subsection 4.01 of this Agreement and the Company will be liable to the Customer for any loss, injury, damage or expense caused to the Customer if the British Columbia Utilities Commission determines that the Company has failed to meet its duty not to be imprudent.

4.03 Failure to Deliver

At any time during a Company actual or anticipated shortage of electricity, or in the event of a breakdown or failure of generating, transmitting or distributing plant, lines or equipment, or in order to comply with the requirements of any law, the Company shall have the right to curtail or discontinue the supply of electricity to the Customer or reduce the voltage or frequency of the electricity supplied. To the extent that it is practical and reasonable, the Company will not unduly discriminate in favour of or against the Customer in the supply of electricity.

4.04 Liability, Indemnity, Limitations and Requirements for Notice with respect to Variations or Defects in Supply

The Company does not warrant a continuous supply of electricity or the maintenance of unvaried frequency or voltage and the Company, its servants or agents, shall not be liable to the Customer for any loss, injury, damage or expense of the Customer caused by or resulting from any suspension, discontinuance or defect in the supply of electricity, alleged or caused by an act or omission of the Company, its servants or agents, except for direct loss or damage to the physical property of the Customer, resulting from willful misconduct or negligent acts or omissions by the Company, its servants or agents.

It is also further agreed that the Company shall not be liable for loss or damage which could have been prevented, in whole or in part, if the Customer had taken reasonable protective measures.

It is also further agreed that the Company shall not be liable under this subsection unless the Customer has given notice to the Company of a potential claim within 30 days of when the Customer knew or ought to have known of the alleged loss or damage.

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The liability of the Company under this clause applies only when the loss or damage arising from a single occurrence exceeds the sum of $10,000.00. In no event shall the liability of the Company exceed the sum of $10,000,000.00 for any single occurrence.

4.05 Mutual Indemnity

(a) The Company will indemnify and save harmless the Customer from and against any and all actions, proceedings, claims and demands that may be made against, and all loss or damage suffered by, the Customer by reason of any damage or injury to any person or property, including the property of the Customer, resulting from any electrical facilities owned by the Company located within the Service Area.

(b) The Customer will indemnify and save harmless the Company from and against any and all actions, proceedings, claims and demands that may be made against, and all loss or damage suffered by, the Company by reason of any damage or injury to any person or property, including the property of the Company, resulting from any electrical facilities owned by the Customer.

4.06 Commodity Services

The Customer shall have the rights set forth in the APSA to purchase power from a third party supplier and to meet part or all of its load requirements from Commodity Services.

4.07 Limits on Other Supply

Unless the Customer has exercised its rights pursuant to the APSA, the Customer shall, during the Term, only purchase electricity from the Company and the Customer's own customers for its own use and the use of its customers within the Service Area. The Customer may obtain 15 MWs of electricity from new generation owned and operated by the Customer or the Customer's customers.

4.08 Retail Access on the Customer's Facilities

The Customer shall give notice, consistent with the APSA requirements, in writing to the Company prior to providing the Customer's transmission and distribution services for the direct delivery of third party supply to a customer of the Customer.

4.09 Sales out of Service Area

If service to a customer outside or within the Service Area would require duplication of existing electrical plant which duplication could be avoided, then the Party that has the right to serve that customer pursuant to this Agreement may consent to the other Party serving that customer, such consent not to be unreasonably delayed or withheld.

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5. CONDITIONS OF SERVICE

5.01 Supply Characteristics

The electricity to be supplied to the Customer shall be three-phase alternating current, having a nominal frequency of 60 hertz and the nominal voltages designated in Appendix A for the Points of Delivery, as amended from time to time.

The Company is a signatory of the Western Systems Coordination Council (WSCC) Reliability Management System (RMS) Agreement. The Company is committed to the service reliability standards detailed in this document and is liable for financial sanctions that WSCC can impose for non-adherence to those standards.

Additionally, the Commission may exercise its authority by whatever means it deems appropriate in the event that frequency or voltage excursions occur that could reasonably have been prevented.

5.02 Underground Facilities

When the Customer requests the construction or installation of underground facilities, the Customer shall be responsible for the difference between the cost of constructing or installing the facilities underground and the cost of constructing or installing similar facilities above ground.

5.03 Ownership of Facilities

Notwithstanding the payment of any contribution by the Customer toward the cost of facilities pursuant to subsection 5.02, the Company shall retain full title to all facilities.

5.04 Revenue Guarantee

The Customer may be required to provide a revenue guarantee if the Company's facilities must be upgraded significantly to meet a proposed increase in the Customer's load in excess of 5000 kVA resulting from either a new customer or the increased load of an existing customer. The revenue guarantee will be equal to the cost of upgrading the facilities and will be refunded, with interest, in equal installments over a period of five years at the end of each year of continued service to that customer at the increased load. The revenue guarantee shall be in the form of cash, surety bond or other form of security satisfactory to the Company.

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6. INTERCONNECTED OPERATION

6.01 Obligation of the Company

The maintenance by the Company of the agreed frequency and voltage at the Points of Delivery, set out in Appendix B, shall constitute delivery of electricity under this Agreement, whether or not any electricity is taken by the Customer, and shall, subject to subsection 10.01 constitute the complete discharge by the Company of its obligations to the Customer for Services.

6.02 Use of Facilities

Each Party shall cooperate with the other to secure the most efficient use of the plant and equipment of the other Party, which may include wheeling power through the other Party's transmission and distribution circuits to facilitate supply to either Party or its customers.

6.03 Exceeding Demand Limit

The Customer shall not take electricity in excess of the Demand Limit of a Point of Delivery without the prior written consent of the Company, unless an emergency condition requires that the Customer take in excess of the Demand Limit, and then only for the duration of the emergency condition. The Customer shall immediately advise the Company when such an emergency condition occurs. The Customer shall reduce immediately its use of electricity to the Demand Limit for that Point of Delivery or to a specified limit above the Demand Limit upon the oral or written request of the Company.

6.04 Restrict or Suspend Service

If the Customer fails to comply with the request of the Company pursuant to the previous paragraph, the Company may, when necessary in the opinion of the Company, restrict or suspend the supply of electricity to the Customer at the Point of Delivery summarily without further notice.

6.05 Avoidance of Excess Loads

The Customer shall provide for interconnection of its lines so as to transfer and arrange the loads taken at each Point of Delivery to balance as far as is practicable the loads at each Point of Delivery given the Demand Limit at each Point of Delivery.

6.06 Maintenance of Adequate Supply Capability

If at any time, except in an emergency condition described in subsection 6.03, the Customer notifies the Company that it has taken electricity in excess of 95 percent of the Demand Limit of a Point(s) of Delivery, the Company shall take appropriate measures at no cost to the Customer to increase the supply capability at the Point(s) of Delivery to bring the Customer's anticipated future demand to or below 95 percent of the Demand Limit.

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6.07 Customer's Facilities

The Customer shall be responsible for designing, constructing, installing and maintaining all auxiliary and interconnecting equipment on the Customer's side of the Point of Delivery and the Customer shall have ownership rights in all such auxiliary and interconnection equipment.

6.08 Installation of Facilities

All electrical facilities owned by the Customer from the Points of Delivery up to and including the Customer's overload and overcurrent protection and isolation devices shall be approved and coordinated in a manner satisfactory to the Company, and may be inspected by the Company from time to time. Notwithstanding the foregoing, the Company shall not require a higher standard for the Customer's electrical facilities than the standard of the Company facilities supplying that portion of the Customer's facilities.

6.09 Coordination of Protective Devices

Either Party shall notify the other Party in advance of any changes to its facilities that may affect the proper coordination of protective devices between the two systems.

6.10 Power Factor

The Customer shall endeavor to regulate its load so that the Power Factor at each Point of Delivery will be no less than 90 percent, lagging.

6.11 Load Fluctuations

The Customer shall maintain and operate its equipment, and shall endeavor to ensure that its customers' equipment is operated in a manner that will not cause sudden fluctuations to the Company's line voltage, or introduce any influence into the Company's system deemed by the Company to threaten to disturb or disrupt its system or the plant or property of any other customer of the Company or of any other person.

6.12 Hazard to Property and Public Safety

Each of the Parties shall operate and maintain electrical plant within the Service Area so as to avoid hazard to the property of the other Party or danger to persons. To avoid hazard to property and to ensure public safety, the Parties agree that:

(a) All electrical generating facilities intended to be operated within the Service Area and in parallel with the Company's electrical system shall be installed only after the Company has been provided with full particulars of the facilities and the Company has given its written approval that the proposed operation of the facilities is satisfactory to the Company, acting reasonably. Upon completion, the Company shall be permitted to inspect the installation.

(b) The Customer shall ensure that any parallel generating facility installed shall not backfeed into the Company's system or facilities unless the Customer receives express permission in writing from the Company, which will not be unreasonably withheld.

(c) The Customer shall ensure that all standby generation facilities within the Service Area to provide electrical service in the event of a disruption of service shall be installed so that they remain at all times electrically isolated from the Company's

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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.

6.13 Permit to Install & Access

If any equipment or facilities associated with any Point of Delivery and belonging to a Party to this Agreement are or are to be located on the property of the other Party, a permit to install, test, maintain, inspect, replace, repair and operate during the term of this Agreement and to remove such equipment and facilities at the expiration of the Term, together with the right of entry to said property at all reasonable times is hereby granted by the other Party.

The rights herby granted shall be exercised subject to prior notification and to any reasonable requirement of the granting Party necessary for the safety or security of Party's facilities and employees and the continuity of the Party's operations.

6.14 Use of City Streets and Lanes

During the existence of this Agreement the Company shall have the right and easement to enter upon and use the streets and lanes within the boundaries of the Customer for all purposes connected with the furnishing of electricity to the Customer, and, without limiting generality, for the purpose of erecting, maintaining, repairing, replacing, removing or using poles, wires, meters, machinery and equipment, subject to the plan of any new erection of pole lines receiving such reasonable approvals as the Customer deems necessary.

6.15 Drawings to be Provided

If either Party is required or permitted to install, test, maintain, inspect, replace, repair, remove or operate equipment on the property of the other, the owner of such property shall furnish the other Party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other Party of any subsequent modification which may affect the duties of the other Party in regard to such equipment, and furnish the other Party with accurate revised drawings, if possible.

6.16 Inspection of Facilities

Each Party may, for any reasonable purpose under this Agreement, inspect the other Party's electrical installation at any reasonable time after giving suitable notice. Such inspection, or failure to inspect, shall not render such Party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this Agreement. The inspecting Party shall observe written instruction and rules posted in facilities and such other necessary instructions or standards for inspection as the Parties agree to. Only those electric installations used in complying with the terms of this Agreement shall be subject to inspection.

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7. PLANNING AND OPERATING INFORMATION

7.01 Increases in Maximum Demand

The Customer shall notify the Company in writing of any anticipated additional single load in excess of 5000 kVA resulting from a new customer or the increased load of an existing customer, providing as much advance notice of the increase as can be given in the circumstances. The Company shall endeavor to provide the service requested by the date the increase is intended to become effective, or as soon thereafter as is practicable.

7.02 Records and Forecasts

Each Party shall retain and make available upon request for the other Party log sheets, records of recording meters, and any other readily available information of an operational character relating to the electricity supplied under this Agreement, excluding non-public records of a financial or business nature relating to the Customer's utility undertaking.

7.03 General Information Requests

The Parties agree to cooperate in the full exchange of such planning and operating information as may be reasonably necessary for the timely and efficient performance of the Parties' obligations or the exercise of rights under this Agreement. Such information shall be provided on a timely basis and no reasonable request shall be refused.

7.04 Load-Resource Forecast

By June 30 of each year, the Parties agree to exchange a five year forecast of loads and resources for their respective electrical systems including a forecast of their Maximum Demand at each Point of Delivery normalized for average weather conditions and shall also provide a forecast of energy consumption for each year. These forecasts shall include programs for resource acquisition, transmission and firm loads. The degree of detail in these forecasts shall be decided by mutual agreement.

7.05 Load from Previous Year

Before the end of February in each year, the Customer shall provide the Company with a record of the number of customers and load by customer class for the previous calendar year.

7.06 Scheduled and Maintenance Outages

Each party shall submit to the other Party a list of outages scheduled for inspection, testing, preventative maintenance, corrective maintenance, repairs, replacement or improvements that might affect the delivery of electricity under this Agreement, providing as much advance notice of the outage as can be given in the circumstances. The Parties shall use reasonable efforts to keep such schedules current and to revise such schedules so as to minimize the impact on the other Party's system.

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8. METERING

8.01 Installation

The Company shall furnish, install and maintain the Metering System and the Customer, in accordance with subsection 8.03, may furnish, install and maintain the Check Metering, each at their own expense, at the Points of Delivery, which shall accurately measure and record electricity within the limits prescribed by the federal Department of Consumer and Corporate Affairs ("Prescribed Limits") and pursuant to subsection 8.07.

8.02 Totalizing Metering

The Company shall also, at its expense, install totalizing metering to compensate for demand diversity at the different Points of Delivery.

8.03 Check Metering

Check Metering and connecting equipment and facilities to be furnished by the Customer shall be satisfactory to the Company, and shall be installed in accordance with Good Utility Practice and in a manner satisfactory to the Company, acting reasonably.

8.04 Meter Tests and Adjustments

Unless otherwise agreed to by the Parties, each Party shall, at its own expense, arrange to have its meters tested by an inspector or accredited meter verifier authorized pursuant to the federal Electricity and Gas Inspection Act and regulations, as amended from time to time.

8.05 Inspection of Metering Equipment

Notwithstanding subsection 8.04, either Party may, after giving two days' notice, inspect in the presence of the other Party, the metering equipment installed in accordance with this subsection by the other Party, and may request that that metering equipment be tested by an inspector or authorized meter verifier.

(a) If the result of any test performed pursuant to this subsection shows that any of the metering equipment is not recording within the Prescribed Limits, then the owner of that metering equipment shall pay for the costs of testing.

(b) If after testing the metering equipment is found to be recording within the Prescribed Limits, the Party that made the request shall pay for the costs of testing.

8.06 Calculating the Amount to be Paid

The measurements recorded by the Metering System shall be used for calculating the amount to be paid for the electricity delivered to the Customer, except in the following circumstances:

(a) if a totalizing meter is temporarily not in service or is found after testing to be not recording within the Prescribed Limits then the measurements recorded by the Customer's totalizing meter shall be used to determine the total consumption and demand, or, in the absence of a Customer totalizing meter, the Company's meters shall be used to determine the total consumption and demand taking into account established load diversity until the Company's totalizing meter has been recalibrated;

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(b) if the Metering System is not in service or is found after testing to be not recording within the Prescribed Limits then the measurements recorded by the Customer's totalizing meter or , in the absence of a totalizing meter, the Customers' meters shall be used for calculating the amount to be paid for electricity delivered to the Customer;

(c) if neither the Metering System nor the Check Metering are in service or are found after testing to be not recording within the Prescribed Limits then the amount of electricity delivered since the previous billing shall be estimated from the best information available.

8.07 Prescribed Limits

If at any time the testing described in subsections 8.04 and 8.05 shows that the metering equipment was not recording within the Prescribed Limits, and if such recordings were used for billing purposes, then the billings shall be adjusted as prescribed by the Electricity and Gas Inspection Act.

8.08 Access to Meters

Each Party shall have the right, by giving suitable notice, to enter the property of the other Party at all reasonable times for the purpose of reading any and all meters mentioned in this Agreement which are installed on such property.

9. INVOICES AND PAYMENT

9.01 Meter Reading

Meters shall be read at the end of each month. 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.

9.02 Invoices and Payment

The Company shall render a billing invoice monthly pursuant to the terms of the Company's Electric Tariff, as amended from time to time.

9.03 Rates for Electricity

The Customer shall pay for Services during the term of this Agreement in accordance with the tariff applicable to the Customer filed with the Commission, as amended from time to time.

9.04 Demand Period and Demand

For billing purposes, Demand Period means the period, expressed in minutes, over which meter readings are integrated to obtain the Demand, which is the power measured in kilovolt amperes (kVA), or multiples thereof, at the Point of Delivery. In this Agreement and for billing purposes, the Demand Period shall be a rolling window until January 1, 2001 and thereafter shall be a sixty minute clock hour interval.

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9.05 Billing Adjustments

If the Company suspends or reduces Service for reasons other than a request by the Customer or an interruption of Service caused by the Customer's system, and the suspension or reduction results in a peak Demand which would otherwise be used for billing purposes, the Demand in the Demand Period immediately following restoration of service may be reduced, by mutual agreement, to an estimate of what the Demand would have been if Service had not been suspended or reduced. The estimate shall be determined in consideration of weather conditions and previous load experience.

9.06 Late Payments

If the amount due on any invoice has not been paid in full after twenty calendar days from the billing date shown on the invoice, a late payment charge shall be applied to the unpaid balance, and the resulting amount will be shown and identified on the next invoice to be rendered. The late payment charge shall be as specified in the Company's Electric Tariff, as amended from time to time.

9.07 Taxes

In addition to payments for electricity, the Customer shall pay to the Company the amount of any sales tax, goods and services tax, or any other tax or assessment levied by any competent taxing authority on any electricity delivered pursuant to this Agreement.

9.08 Payment of Accounts

The Customer shall pay to the Company the amount of the billing within 20 calendar days from the date appearing on the statement.

10. CONTINUITY OF SUPPLY

10.01 Standard of Performance

The Company shall perform the Services with skill, care, and diligence consistent with Good Utility Practice and consistent with directions from the Commission, including the quality performance standards, if any, approved by the Commission from time to time.

10.02 Interruptions and Defects in Service

The Company shall avoid interruption of delivery of electricity, but nevertheless shall not be liable to the Customer for any loss or damage owing to failure to supply electricity, or owing to other abnormal conditions of supply resulting from force majeure as defined in subsection 12.01.

10.03 Suspension of Supply

Either Party shall have the right to demand the temporary suspension of, or to suspend temporarily, the delivery or taking of electricity, as the case may be, whenever necessary to safeguard life or property, or for the purpose of replacing, repairing or maintaining any of its apparatus, equipment, or works. Such reasonable notice of the suspension as the circumstances permit shall be given by one Party to the other.

Accepted for filing: JUN 15 2008 [signature] SECRETARY
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10.04 Discontinue Service

The Company may discontinue the supply of electricity to the Customer at a Point of Delivery for the failure by the Customer to commence remedial action acceptable to the Company, within 15 days of receiving notice from the Company, to correct the breach of any significant practice, term or condition to be observed or performed by the Customer under this Agreement. 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 discontinuance shall not recur.

10.05 Obligations Continue

Discontinuance of Services by the Company pursuant to the provisions of this Agreement shall not relieve the Customer of any obligation under this Agreement, or alter any of the obligations of the Customer under this Agreement.

10.06 Other Remedies

The Company's right to discontinue the supply of electricity under this Agreement shall not operate to prevent the Company from pursuing, separately or concurrently, any other remedy it may have under this Agreement or by operation of law.

11. REMOVAL OF FACILITIES UPON TERMINATION

After the termination of this Agreement, the Company shall have the right to, and must expeditiously if requested by the Customer, remove from the property owned or controlled by the Customer any and all electrical apparatus and equipment which the Company owns and has installed on the property and the Company shall leave the property in good repair after such removal.

Accepted for filing: JUN 19 2008 [signature]

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12. GENERAL PROVISIONS

12.01 Force Majeure

Neither Party to this Agreement shall be considered to be in default in the performance of any of its obligations under this Agreement to the extent that performance of those obligations is prevented or delayed by any cause which is beyond the reasonable control of the Party prevented or delayed by that cause. If either Party is delayed or prevented from its performance at any time by any act, omission or neglect of the other Party or its representatives, or by an act of God or the public enemy, or by expropriation or confiscation of facilities, compliance with any order of any governmental authority or order of a court of competent jurisdiction, acts of war, rebellion or sabotage, fire, flood, explosion, riot, strike or other labour dispute beyond the reasonable control of the Party or any unforeseeable cause beyond the control and without the fault and negligence of the Party, the Party so prevented or delayed shall give notice to the other Party of the cause of the prevention or delay but, notwithstanding giving of that notice, the Party shall promptly and diligently use reasonable efforts to remove the cause of the prevention or delay.

12.02 Notices

Any notice, direction or other instrument required or permitted to be given under this Agreement in writing shall be sufficient in all respects if delivered, or if sent by fax, or if sent by prepaid registered post in Canada to the Parties at their respective addresses as they appear in subsection 12.03, or to any substitute address of which the Party sending notice has had notice in writing.

12.03 Addresses

Any notice, direction or other instrument shall be delivered or sent to the following addresses:

(a) To the Company:
FortisBC.
1290 Esplanade
PO Box 130
Trail, BC VIR 4L4
Attention: Secretary
Fax Number: 250-364-1270

(b) To the Customer:
City of Kelowna
City Hall
1435 Water Street
Kelowna, BC V1Y 1J4
Attention: City Clerk

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12.04 Dates

Any notice, direction, or other instrument shall be deemed to have been received on the following dates if,

(a) sent by fax, on the business day next following the date of transmission.

(b) delivered, on the business day next following the date of delivery.

(c) 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, directions or other instrument shall only be deemed to be effective if delivered or sent by fax.

12.05 Disputes

If any difference or dispute occurs regarding any matter arising under this Agreement, either Party may request that the Commission settle the difference or dispute. If the Commission declines to settle the dispute then the dispute shall be arbitrated pursuant to the Commercial Arbitration Act of British Columbia.

12.06 Invalidity

If any provision of this Agreement or the application of any provision to any Party or circumstance is declared or held to be wholly or partially invalid, this Agreement shall be interpreted as if the invalid provision had not been a part hereof so that the invalidity shall not affect the validity of the remainder which shall be construed as if this Agreement had been executed without the invalid portion. The Company and the Customer shall, either independently, jointly or in concert with other wholesale customers of the Company, make all reasonable efforts to validate any portion of this Agreement declared or held to be invalid.

12.07 Headings

The headings in this Agreement have been inserted for convenience of reference only, and shall not affect the construction or interpretation of this Agreement.

12.08 Enurement

This Agreement shall be binding upon and shall enure to the benefit of the Parties hereto and of their respective successors and assigns.

12.09 Governing Law

Notwithstanding anything to the contrary in this Agreement, this Agreement the Company shall comply fully with all applicable federal, provincial and municipal laws (including bylaws) in effect from time to time.

12.10 Entire Agreement

This Agreement and the Appendices attached hereto are intended by the Parties to be the final expression of their agreement and are intended also as a complete and exclusive statement of the terms of the Agreement.

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12.11 Commission Approval

This agreement and all the terms and conditions contained in it shall be subject to the provisions of the Utilities Commission Act of British Columbia, as amended or re-enacted form time to time and to the jurisdiction of the Commission.

This agreement and subsequent amendments including changes to the Service Area, shall not be binding on the parties until it has been approved by the Commission.

IN WITNESS WHEREOF the Parties, by the signatures of their duly authorized officers set out below, have executed this Agreement.

The CITY OF KELOWNA this day 8th of November, 2004 by

Walter Gray

Signature WALTER GRAY, MAYOR

Title

Stephen Fleming

Signature

STEPHEN FLEMING, ACTING CITY CLERK

Title

FORTISBC this 3rd day of November, 2004 by

Signature

Vice President, Customer & Corporate Services

Title

Signature

Title

Accepted for filing: JUN 19 2008

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E Hamilton

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B.C. UTILITIES COMMISSION

This is Appendix A to the Agreement for the Supply of Electricity - Wholesale Service between FortisBC and the City of Kelowna

City of Kelowna - Points of Delivery

1. Glenmore Substation

Description: Load side of billing current transformers on 13 kV Feeder No. 4

Nominal Voltage Supplied: 13 kV

Demand Limit:	Summer	20 MVA
	Winter	20 MVA

2. Recreation Substation

Description: Load side of disconnect switches on 13 kV bus where Customer facilities join Company facilities

Nominal Voltage Supplied: 13 kV

Demand Limit:	Summer	30 MVA
	Winter	30 MVA

3. Saucier Avenue Substation

Description: Load side of disconnect switches on 13 kV bus where Customer facilities join Company facilities

Nominal Voltage Supplied: 13 kV

Demand Limit:	Summer	30 MVA
	Winter	30 MVA

4. Delivery to Kelowna Pollution Control Centre

Description: Delivery is from the OK mission substation via feed No. 5 to the Customer's primary metering point

Demand Limit:	Summer	~~14.3~~ 11.8 MVA
	Winter	~~18.4~~ 11.8 MVA

B. Sabey
Nov 18/04

Accepted for filing: JUN 19 2008
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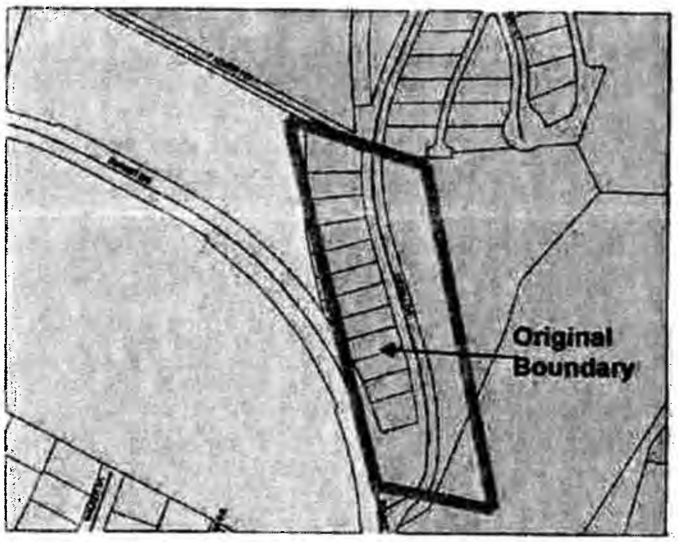
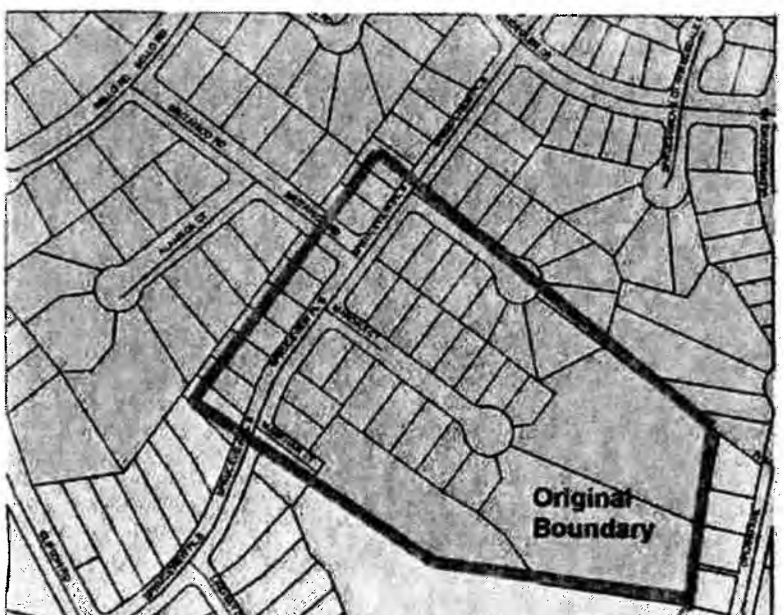
This is Appendix B to the Agreement for the Supply of Electricity - Wholesale Service between FortisBC and the City of Kelowna

2004/05 Boundary Adjustments

City of Kelowna have adjusted the service boundary due to Aquila/FortisBC servicing new developments on Denali Dr. just off Summit Dr.(estimated 12 lots) and new development East on Spruce view Pl. South, including Markham Ct, Marona Ct and Spruce view Ct.(estimated 34 lots) that were originally in the City's service area prior to 2004.





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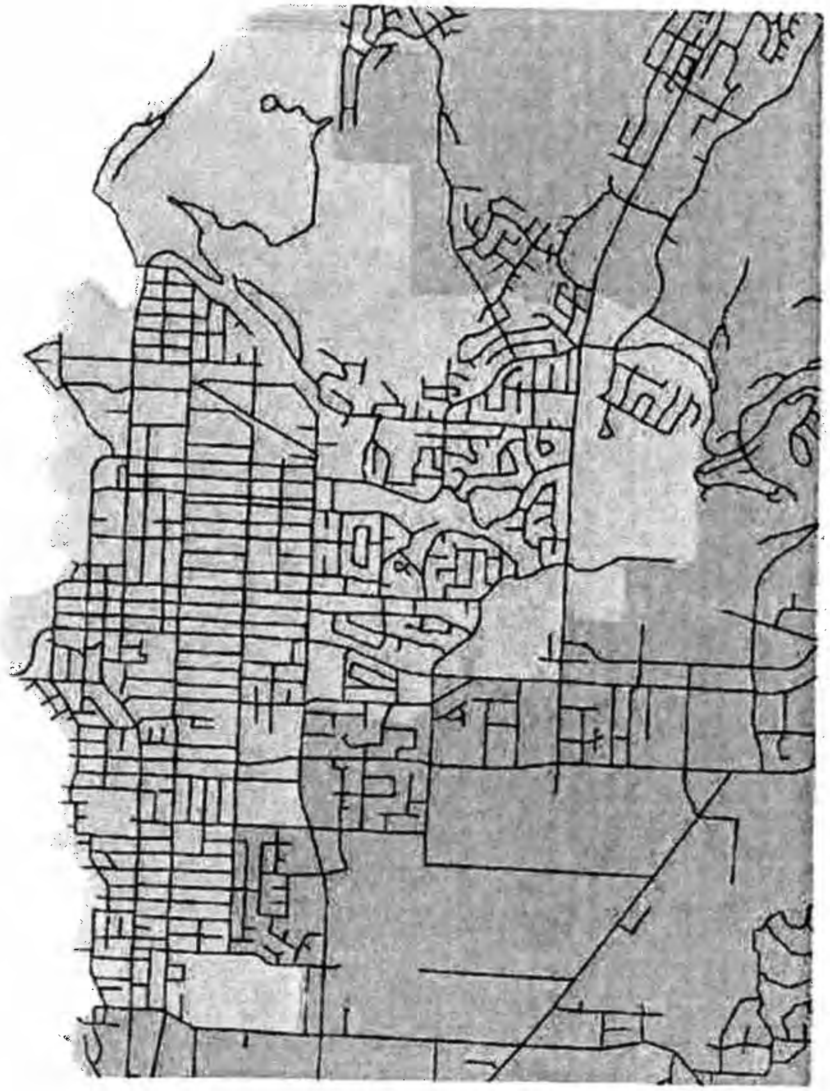
CITY OF KELOWNA INTERIM SERVICE AREA



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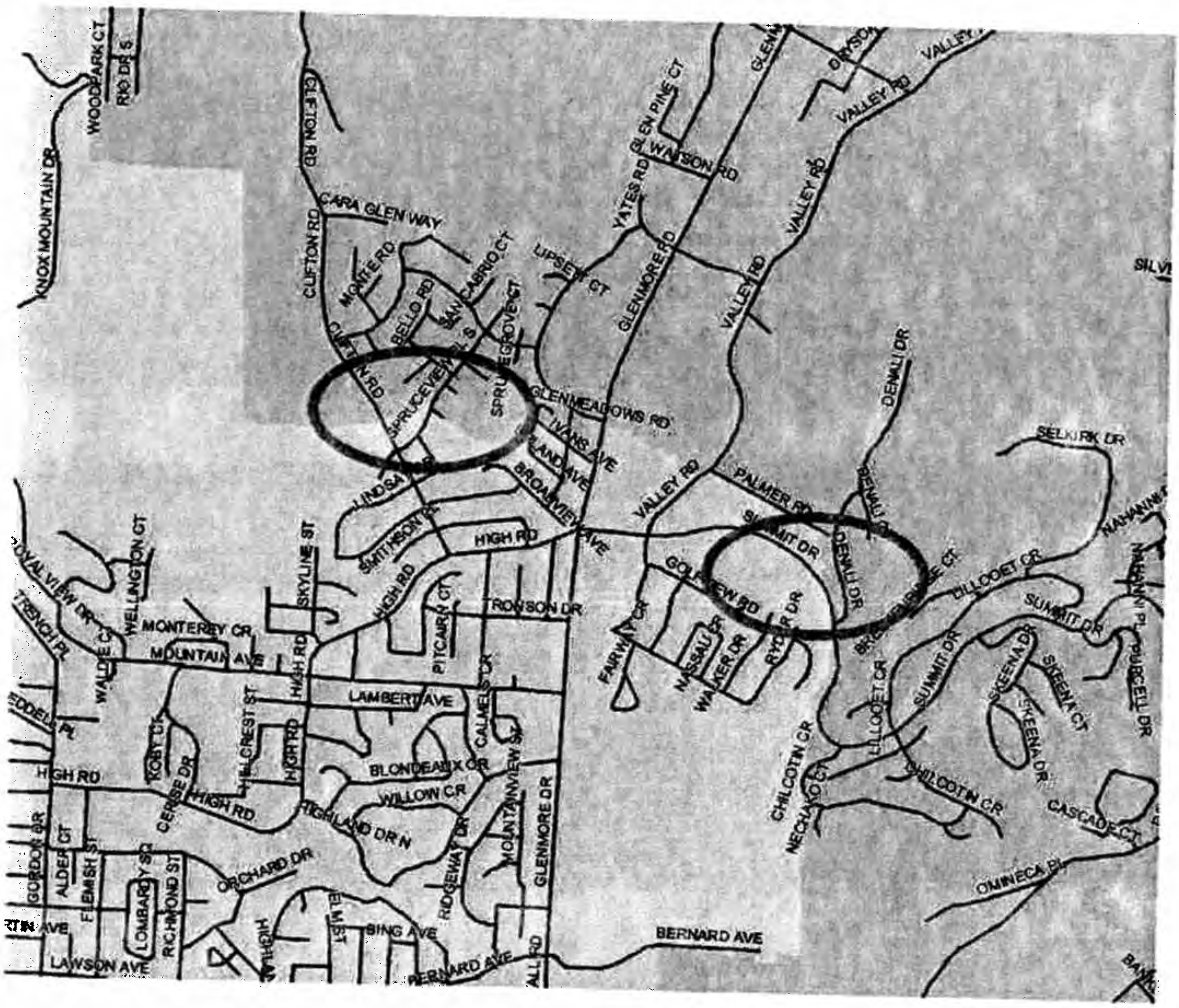

Both the City of Kelowna and FortisBC agree that once new development occurs north on Skyline, the City of Kelowna will service an equal amount of lots taken out of the original City service area. (estimated 46 lots) Further adjustments to the boundary and total lot adjustment will be reconciled at that time.

An interim boundary map has been inserted into the Agreement ForThe Supply OF Electricity Whole – Sale Service (dated November 1st, 2004) and will be adjusted after the future development occurs.

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West Kootenay Power Ltd. Access Principles Application ("APA") Proposed Settlement Agreement

PURPOSE

Through its Transmission Access Application, West Kootenay Power proposes to open its transmission system to all Eligible Customers. The goal of open access is to encourage the development of a competitive generation market resulting in efficient resource allocation. The purpose of the APA is to ensure that this occurs in a way that results in the Fair Treatment of Utility shareholders, of customers who remain with Utility supply and of Eligible Customers who choose to obtain some or all supply from non-Utility resources.

DEFINITIONS

Commission means:

The British Columbia Utilities Commission.

Eligible Customer means:

Those West Kootenay Power bundled service customers eligible for transmission access as determined by the Commission from time to time.

Embedded Cost of Power means:

West Kootenay Power's cost of generation related transmission assets, generation assets, power purchase contracts, market purchases and other costs of power as determined by the Commission from time to time.

Fair Treatment means:

(i) For shareholders, the opportunity to earn a rate of return on equity does not change as a result of the exit, partial exit or re-entry of Eligible Customers;

(ii) For customers who remain with Utility supply, the exit, partial exit or re-entry of Eligible Customers must, at a minimum, make them no worse off than if Eligible Customers had always remained with the Utility. Any payments, made by Eligible Customers to ensure that those customers who remain with Utility supply are made no worse off, will be allocated by the Utility in such a way that no customer class is made worse off. Each remaining customer class is made no worse off if their rates for bundled service are no higher after an Eligible Customer makes its election. The rates before election are determined by a prospective calculation of the Utility's total net revenue requirement allocated to customer classes using embedded cost methodologies as accepted by the Commission from time to time. Similarly, the rates after election are calculated prospectively considering the change in total net revenue requirement due to the change in load, again allocated to customer classes using embedded cost methodologies as accepted by the Commission from time to time;

(iii) For Eligible Customers,

a) the maintenance of West Kootenay Power's obligation to serve continues for an Eligible Customer as long as the Eligible Customer elects to receive embedded cost service from West Kootenay Power for all or part of its load;

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b) the right to elect to leave the embedded cost service of West Kootenay Power in whole or in part;
c) the right to return to West Kootenay Power's embedded cost service as set out under the Re-entry Provisions; and
d) notwithstanding the general principle that remaining customers are to be made no worse off by the exit of Eligible Customers, the right to take with them any benefits accruing from their load characteristics (that is, size and load factor), without additional payment or compensation to customers who remain on Utility supply.

OBLIGATION TO SERVE

West Kootenay Power retains the obligation to serve every customer until that customer elects to leave the embedded cost power service of West Kootenay Power. In the event of partial supply customers, West Kootenay Power retains an obligation to serve the portion of a customer's load that remains with the Utility (subject to the provisions set out below under the section entitled Partial Supply). West Kootenay Power retains the obligation to provide transmission and distribution service to all customers within its service territory.

West Kootenay Power also retains the obligation to serve at embedded cost rates any new load entering its service territory, any additional load attributable to its existing customers, and returning Eligible Customers, under the Re-entry Provisions outlined below.

West Kootenay Power will provide short term backup service on a reasonable-efforts basis to Eligible Customers within its service territory for the period required by those Eligible Customers for the unanticipated loss of firm supply. For this service, West Kootenay Power will charge the higher of the market buy price or the cost of the marginal unit in West Kootenay Power's supply portfolio if West Kootenay Power supplies from its portfolio. The price charged will be determined retrospectively and will apply to the full period of service. In addition, West Kootenay Power may charge additional administrative costs reasonably incurred by the Utility to provide this power supply.

It is acknowledged that existing contracts between the Utility and Eligible Customers will not be abrogated. However, it is recognized that West Kootenay Power has a need for notice before the departure of any Eligible Customer and, therefore, it will be desirable if contracts are renegotiated in a timely fashion. In this regard, the City of Kelowna and the City of Nelson will provide notice of intent to leave the Utility or to enter into a new contract for bundled service by April 1, 1999. All other Eligible Customers that have contracts with an expiry date beyond 1999 will provide notice of intent to leave or to enter into a new contract for bundled service at least two years prior to the expiration of their bundled service contracts. Failure to provide such notice of intent to leave will expose these Eligible Customers to any costs imposed on remaining customers, as defined in the Re-entry Provisions below. If after giving notice of intent to stay, the Eligible Customer and West Kootenay Power are unable to conclude a mutually satisfactory contract and one or both parties believes this to be the result of the conduct of the other party, the Commission may be asked to grant protection from any costs implied by other parts of this agreement.

West Kootenay Power will enter into good faith negotiations with any Eligible Customer desiring to enter into a new contract at embedded cost rates. Any new contract will be subject to Commission approval. In any case, West Kootenay Power will include in all new contracts a condition that any Eligible Customer must provide at least two years' notice of early termination, West Kootenay Power will use reasonable efforts to accommodate, in a manner that results in Fair Treatment, a departure such that no stranded cost payment is required.

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If such an accommodation cannot be found, Eligible Customers that leave West Kootenay Power during the notice period, taking with them 25% of their prior year's load or less, will pay mitigated stranded costs, if any, for the lesser of the remaining term of the notice period or two years. If an Eligible Customer takes with it more than 25% of its prior year's load, or if an Eligible Customer's monthly load factor in any month decreases by more than 20% as a result of going to market, or if the combined departure of all Eligible Customers' load exceeds 10% in any year of the Eligible Customers' total aggregate load at the end of the previous year, the Eligible Customer will pay mitigated stranded costs, if any, for a period of five years less any part of the notice period during which the Eligible Customer remained with West Kootenay Power for its total load. Within 15 business days of a request, West Kootenay Power will calculate for both a two-year and a five-year period the payments required to ensure that the revenue requirement of remaining customers is not increased from that which is expected to have occurred if the Eligible Customer had not departed early.

New Eligible Customers have the right to be served entirely through an alternate supplier without attracting any of the stranded cost provisions described above.

PARTIAL SUPPLY

An Eligible Customer may elect to meet any or all of its load requirements from West Kootenay Power. If any Eligible Customer elects to meet part of its load requirements from West Kootenay Power, then the rate for partial supply requirements shall be determined so as to ensure that all other customers receive Fair Treatment. For example, if by taking part of its load to market, an Eligible Customer materially worsens the load factor of that portion of its load which remains with the Utility, the Eligible Customer will compensate for these costs consistent with Fair Treatment. In contrast, if an Eligible Customer materially improves its load factor for the portion of its load remaining with the Utility - for example, by taking its peaking requirements to market - the Eligible Customer will realize the benefits of this in the price it pays for its remaining load (to the extent that this can be accomplished in a manner consistent with Fair Treatment and recovery of the embedded cost of service).

In order to satisfy the informational needs of potential partial load Eligible Customers, West Kootenay Power will respond within 15 business days to an Eligible Customer's inquiry about Utility rate changes (both generation and transmission) that the Eligible Customer will face as a result of its partial load election. New rates will be incorporated by reference in a new contract, and subject to Commission approval.

STRANDED COSTS AND BENEFITS

West Kootenay Power is not seeking any specific compensation for stranded costs as part of this agreement. Any person may raise the issue of Fair Treatment in any future stranded cost application before the Commission. However, before asking for stranded cost relief, West Kootenay Power is expected to have exhausted all reasonable avenues of stranded cost mitigation. In addition, the amount of any stranded costs attributable to an Eligible Customer's departure will be reduced by any benefits to remaining customers which result from that departure. However, in no case will this confer to a departing Eligible Customer a claim to stranded benefits.

Where a stranded cost or benefit determination is required, the amount of the stranded costs or benefits will be calculated by West Kootenay Power, disclosed to all interested parties, and submitted to the Commission for approval.

West Kootenay Power acknowledges the likelihood that open access may produce stranded benefits. If this is the case, these benefits will accrue to those customers that remain with the Utility. Departing Eligible Customers may not take these benefits with them, either in the form of exit payments or generation entitlements. Departing Eligible Customers retain claim to the inherent benefits implied by West Kootenay Power's low cost power, as provided for in the Re-entry Provisions.

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Where a market opportunity to obtain power is available to an Eligible Customer which would not be viable without additional incentives, the Eligible Customer may seek to negotiate a sharing of stranded benefits under the auspices of the Commission. Such negotiations will be conducted pursuant to the Commission's Alternate Dispute Resolution Guidelines as they may exist from time to time.

Stranding caused by transmission or distribution bypass will be the subject of Commission consideration if and when it arises. As in other stranded cost recovery scenarios, West Kootenay Power will be required to have taken all reasonable steps to protect its assets from stranding and such steps will not create obligations or create a greater burden on the Utility than arises from regulatory principles, including prudent investment obligations.

RE-ENTRY PROVISIONS

An Eligible Customer that has previously taken bundled service may, at any time, return to power service from West Kootenay Power at a rate calculated to ensure Fair Treatment, subject to the conditions set out below, West Kootenay Power will make reasonable efforts to accommodate returning Eligible Customers as quickly as possible.

Returning Eligible Customers and new Eligible Customers who initially chose an alternative supplier should receive rates reflecting the embedded cost of service within the lesser of:

- the period in which West Kootenay Power can adjust its supply portfolio to serve these Eligible Customers, consistent with Fair Treatment; or
- two years from the date of their notice to return to West Kootenay Power's supply.

For the interim period (that is, the lesser of the time it takes West Kootenay Power to adjust its supply portfolio or two years) West Kootenay Power may charge rates reflective of its additional cost of serving these Eligible Customers over the interim period, while maintaining Fair Treatment. If market circumstances are such that market energy is reasonably anticipated to be less expensive than West Kootenay Power's embedded cost of power for the interim period, then the Eligible Customers will return to embedded cost tariffs immediately.

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NH File #300.3.1

AGREEMENT FOR THE SUPPLY OF ELECTRICITY

WHOLESALE SERVICE

FORTISBC INC.

and

THE CORPORATION OF THE CITY OF NELSON

dba

"Nelson Hydro"

Accepted for filing: JUN 19 2008 SECRETARY B.C. UTILITIES COMMISSION

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FORTISBC INC.

THE CORPORATION OF THE CITY OF NELSON

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Accepted for filing: JUN 19 2008

SECRETARY

B.C. UTILITIES COMMISSION

Effective: JAN 1 2005

Order No.: G 1 0 1 08

THIS AGREEMENT is made as of the 1st of November 2004.

BETWEEN:

FORTISBC INC.

(the "Company")

AND:

THE CORPORATION OF THE CITY OF NELSON

(the "Customer")

WHEREAS the Company is a supplier of electricity in the southern interior region of the Province of British Columbia;

AND WHEREAS the Customer wishes to purchase electricity from the Company for its own use and for resale to customers within the Customer's Service Area as hereinafter described;

AND WHEREAS both the Company and the Customer have agreed to the principles set forth in the Proposed Settlement Agreement resulting from the British Columbia Utilities Commission Decision dated March 10, 1999.

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NOW THEREFORE this Agreement witnesses that in consideration of the terms and conditions hereinafter set forth the Parties covenant and agree as follows:

1. **DEFINITIONS**

In this Agreement:

(a) **"Check Metering"** means any measurement device or system installed, owned and maintained by the Customer to check the measurements and calculations carried out by the Metering System.

(b) **"Commission"** means the British Columbia Utilities Commission.

(c) **"Commodity Service"** means the supply of power, expressly excluding the services set forth in the Transmission Services Tariff, to the Customer by a third party and may include full or partial supply of the load requirements of the Customer.

(d) **"Demand Limit"** means the capability of the Company's facilities at each of the Points of Delivery, specified in Appendix A attached hereto.

(e) **"Good Utility Practice"** means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

(f) **"Maximum Demand"** means the highest months rate of taking of electricity by the Customer recorded in kilovolt-amperes by the Company from time to time.

(g) **"Metering System"** means the measurement device or system installed, owned and maintained by the Company used to determine the Customer's electricity consumption.

(h) **"Parties"** means both the Company and the Customer.

(i) "**Point of Delivery**" means the point or points at which the Customer's distribution system attaches to the Company's facilities, as specifically described in Appendix A attached hereto.

(j) **"Power Factor"** means the percentage determined by dividing the Customer's demand measured in kilowatts by the same demand measured in kilovolt-amperes.

(k) **"APSA"** means the Access Principles Settlement Agreement, also known as the Proposed Settlement Agreement, as amended from time to time, attached as Appendix A to the Commission Decision dated March 10, 1999 in the matter of the Access Principles Application and attached hereto as Appendix C.

(l) **"Service Area"** means the Customer's service area, the boundaries of which are shown by the red line on the map identified as the Customer's Electrical Service Boundaries, attached hereto as Appendix B and shall include any area(s) added from time to time by the municipality.

(m) **"Services"** means the supply and delivery of power to the Customer by the Company under the Agreement.

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(n) **"Term"** means the period defined by subsection 2.01 herein.
(o) **"Transmission Services Tariff"** means the tariff as approved from time to time by the Commission for the use by a third party supplier to deliver power to the Customer or by the Customer to deliver power to a third party on the transmission and distribution facilities of the Company, including ancillary services required for the delivery of power.

2. TERM AND RENEWAL:

2.01 Term
The term of this Agreement shall be for a period of five years commencing on January 1, 2005. Upon expiration of that period this Agreement shall automatically be renewed for one additional five year period, unless the Customer, not less than one year nor more than 2 years before the expiration of the initial five year term, notifies the Company in writing of the termination of this Agreement, effective as of the end of the initial term.

2.02 Early Termination
If the Customer elects to engage any third party supplier to perform the Commodity Services and notice as provided for in the APSA is given to the Company the Customer may terminate this Agreement prior to expiry of the Term. If this Agreement terminates pursuant to this subsection, the Customer may then be liable to pay such costs, including stranded costs, if any, as directed by the Commission.

3. Access Principles Settlement Agreement

3.01 Access Principles Settlement Agreement Rights
Nothing contained in this Agreement shall be construed as affecting in any way the rights of either Party as set forth in the APSA (Appendix A to Commission Order No. G-27-99) nor as affecting in any way the rights of either Party to unilaterally make application to the Commission for further directions or orders from the Commission related to the terms and conditions of the APSA.

3.02 Regulatory Principles
If any provision of this Agreement is declared by the Commission to be inconsistent with the regulatory principles set forth in the APSA, the Parties shall amend that provision in such reasonable manner as achieves the intention of the declaration of the Commission. In the event the Parties cannot agree on such amendments, either Party shall be entitled to seek further direction from the Commission and the Parties hereby agree to be bound by such direction from the Commission.

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4. CONDITIONS OF SUPPLY

4.01 Supply of Electricity

During the term of this Agreement, except in an emergency described in subsection 6.03, the Company shall supply up to the Demand Limit electricity required by the Customer solely for its own use and for supplying the needs of its customers within the Service Area. The Company shall supply electricity to the Points of Delivery through suitable plant and equipment in accordance with Good Utility Practice on a continuous basis, except as provided in this Agreement. The responsibility of the Company for the delivery of electricity to the Customer shall cease at the Points of Delivery.

4.02 Duty to Act Prudently in Arranging for Electricity Supply

Notwithstanding the provisions of subsection 4.03 and 4.04 the Company has a duty not to be imprudent in arranging for the supply of electricity required pursuant to subsection 4.01 of this Agreement and the Company will be liable to the Customer for any loss, injury, damage or expense caused to the Customer if the British Columbia Utilities Commission determines that the Company has failed to meet its duty not to be imprudent.

4.03 Failure to Deliver

At any time during a Company actual or anticipated shortage of electricity, or in the event of a breakdown or failure of generating, transmitting or distributing plant, lines or equipment, or in order to comply with the requirements of any law, the Company shall have the right to curtail or discontinue the supply of electricity to the Customer or reduce the voltage or frequency of the electricity supplied. To the extent that it is practical and reasonable, the Company will not unduly discriminate in favour of or against the Customer in the supply of electricity.

4.04 Liability, Indemnity, Limitations and Requirements for Notice with Respect to Variations or Defects in Supply

The Company does not warrant a continuous supply of electricity or the maintenance of unvaried frequency or voltage and the Company, its servants or agents, shall not be liable to the Customer for any loss, injury, damage or expense of the Customer caused by or resulting from any suspension, discontinuance or defect in the supply of electricity, alleged or caused by an act or omission of the Company, its servants or agents, except for direct loss or damage to the physical property of the Customer, resulting from willful misconduct or negligent acts or omissions by the Company, its servants or agents.

It is also further agreed that the Company shall not be liable for loss or damage which could have been prevented, in whole or in part, if the Customer had taken reasonable protective measures.

It is also further agreed that the Company shall not be liable under this subsection unless the Customer has given notice to the Company of a potential claim within 30 days of when the Customer knew or ought to have known of the alleged loss or damage.

The liability of the Company under this clause applies only when the loss or damage arising from a single occurrence exceeds the sum of $10,000.00. In no event shall the liability of the Company exceed the sum of $10,000,000.00 for any single occurrence.

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4.05 Mutual Indemnity

(a) The Company will indemnify and save harmless the Customer from and against any and all actions, proceedings, claims and demands that may be made against, and all loss or damage suffered by, the Customer by reason of any damage or injury to any person or property, including the property of the Customer, resulting from any electrical facilities owned by the Company located within the Service Area.

(b) The Customer will indemnify and save harmless the Company from and against any and all actions, proceedings, claims and demands that may be made against, and all loss or damage suffered by, the Company by reason of any damage or injury to any person or property, including the property of the Company, resulting from any electrical facilities owned by the Customer.

4.06 Commodity Services

The Customer shall have the rights set forth in the APSA to purchase power from a third party supplier and to meet part or all of its load requirements from Commodity Services.

4.07 Limits on Other Supply

Unless the Customer has exercised its rights pursuant to the APSA, the Customer shall, during the Term, only purchase electricity from the Company and the Customer's own customers for its own use and the use of its customers within the Service Area. The Customer may obtain up to 15 MWs of electricity from new generation owned and operated by the Customer or the Customer's customers.

4.08 Retail Access on the Customer's Facilities

The Customer shall give notice, consistent with the APSA requirements, in writing to the Company prior to providing the Customer's transmission and distribution services for the direct delivery of third party supply to a customer of the Customer.

4.09 Sales out of Service Area

If service to a customer outside or within the Service Area would require duplication of existing electrical plant which duplication could be avoided, then the Party that has the right to serve that customer pursuant to this Agreement may consent to the other Party serving that customer, such consent not to be unreasonably delayed or withheld.

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5. CONDITIONS OF SERVICE

5.01 Supply Characteristics

The electricity to be supplied to the Customer shall be three-phase alternating current, having a nominal frequency of 60 hertz and the nominal voltages designated in Appendix A for the Points of Delivery, as amended from time to time.

The Company is a signatory of the Western Systems Coordination Council (WSCC) Reliability Management System (RMS) Agreement. The Company is committed to the service reliability standards detailed in this document and is liable for financial sanctions that WSCC can impose for non-adherence to those standards.

5.02 Underground Facilities

When the Customer requests the construction or installation of underground facilities, the Customer shall be responsible for the difference between the cost of constructing or installing the facilities underground and the cost of constructing or installing similar facilities above ground.

5.03 Ownership of Facilities

Notwithstanding the payment of any contribution by the Customer toward the cost of facilities pursuant to subsection 5.02, the Company shall retain full title to all facilities.

5.04 Revenue Guarantee

The Customer may be required to provide a revenue guarantee if the Company's facilities must be upgraded significantly to meet a proposed increase in the Customer's load in excess of 5000 kVA resulting from either a new customer or the increased load of an existing customer. The revenue guarantee will be equal to the cost of upgrading the facilities and will be refunded, with interest, in equal installments over a period of five years at the end of each year of continued service to that customer at the increased load. The revenue guarantee shall be in the form of cash, surety bond or other form of security satisfactory to the Company.

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6. INTERCONNECTED OPERATION

6.01 Obligation of the Company

The maintenance by the Company of the agreed frequency and voltage at the Points of Delivery, set out in Appendix B, shall constitute delivery of electricity under this Agreement, whether or not any electricity is taken by the Customer, and shall, subject to subsection 10.01 constitute the complete discharge by the Company of its obligations to the Customer for Services.

6.02 Use of Facilities

Each Party shall cooperate with the other to secure the most efficient use of the plant and equipment of the other Party, which may include wheeling power through the other Party's transmission and distribution circuits to facilitate supply to either Party or its customers.

6.03 Exceeding Demand Limit

The Customer shall not take electricity in excess of the Demand Limit of a Point of Delivery without the prior written consent of the Company, unless an emergency condition requires that the Customer take in excess of the Demand Limit, and then only for the duration of the emergency condition. The Customer shall immediately advise the Company when such an emergency condition occurs. The Customer shall reduce immediately its use of electricity to the Demand Limit for that Point of Delivery or to a specified limit above the Demand Limit upon the oral or written request of the Company.

6.04 Restrict or Suspend Service

If the Customer fails to comply with the request of the Company pursuant to the previous paragraph, the Company may, when necessary in the opinion of the Company, restrict or suspend the supply of electricity to the Customer at the Point of Delivery summarily without further notice.

6.05 Avoidance of Excess Loads

The Customer shall provide for interconnection of its lines so as to transfer and arrange the loads taken at each Point of Delivery to balance as far as is practicable the loads at each Point of Delivery given the Demand Limit at each Point of Delivery.

6.06 Maintenance of Adequate Supply Capability

If at any time, except in an emergency condition described in subsection 6.03, the Customer notifies the Company that it has taken electricity in excess of 95 percent of the Demand Limit of a Point(s) of Delivery, the Company shall take appropriate measures at no cost to the Customer to increase the supply capability at the Point(s) of Delivery to bring the Customer's anticipated future demand to or below 95 percent of the Demand Limit.

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6.07 Customer's Facilities
The Customer shall be responsible for designing, constructing, installing and maintaining all auxiliary and interconnecting equipment on the Customer's side of the Point of Delivery and the Customer shall have ownership rights in all such auxiliary and interconnection equipment.

6.08 Installation of Facilities
All electrical facilities owned by the Customer from the Points of Delivery up to and including the Customer's overload and overcurrent protection and isolation devices shall be approved and coordinated in a manner satisfactory to the Company, and may be inspected by the Company from time to time. Notwithstanding the foregoing, the Company shall not require a higher standard for the Customer's electrical facilities than the standard of the Company facilities supplying that portion of the Customer's facilities.

6.09 Coordination of Protective Devices
Either Party shall notify the other Party in advance of any changes to its facilities that may affect the proper coordination of protective devices between the two systems.

6.10 Power Factor
The Customer shall endeavor to regulate its load so that the Power Factor at each Point of Delivery will be no less than 90 percent, lagging.

6.11 Load Fluctuations
The Customer shall maintain and operate its equipment, and shall endeavor to ensure that its customers' equipment is operated in a manner that will not cause sudden fluctuations to the Company's line voltage, or introduce any influence into the Company's system deemed by the Company to threaten to disturb or disrupt its system or the plant or property of any other customer of the Company or of any other person.

6.12 Hazard to Property and Public Safety
Each of the Parties shall operate and maintain electrical plant within the Service Area so as to avoid hazard to the property of the other Party or danger to persons. To avoid hazard to property and to ensure public safety, the Parties agree that:

(a) All electrical generating facilities intended to be operated within the Service Area and in parallel with the Company's electrical system shall be installed only after the Company has been provided with full particulars of the facilities and the Company has given its written approval that the proposed operation of the facilities is satisfactory to the Company, acting reasonably. Upon completion, the Company shall be permitted to inspect the installation.

(b) The Customer shall ensure that any parallel generating facility installed shall not backfeed into the Company's system or facilities unless the Customer receives express permission in writing from the Company, which will not be unreasonably withheld.

(c) The Customer shall ensure that all standby generation facilities within the Service Area to provide electrical service in the event of a disruption of service 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.

6.13 Permit to Install & Access

If any equipment or facilities associated with any Point of Delivery and belonging to a Party to this Agreement are or are to be located on the property of the other Party, a permit to install, test, maintain, inspect, replace, repair and operate during the term of this Agreement and to remove such equipment and facilities at the expiration of the Term, together with the right of entry to said property at all reasonable times is hereby granted by the other Party.

The rights herby granted shall be exercised subject to prior notification and to any reasonable requirement of the granting Party necessary for the safety or security of Party's facilities and employees and the continuity of the Party's operations.

6.14 Use of City Streets and Lanes

During the existence of this Agreement the Company shall have the right and easement to enter upon and use the streets and lanes within the boundaries of the Customer for all purposes connected with the furnishing of electricity to the Customer, and, without limiting generality, for the purpose of erecting, maintaining, repairing, replacing, removing or using poles, wires, meters, machinery and equipment, subject to the plan of any new erection of pole lines receiving such reasonable approvals as the Customer deems necessary.

6.15 Drawings to be Provided

If either Party is required or permitted to install, test, maintain, inspect, replace, repair, remove or operate equipment on the property of the other, the owner of such property shall furnish the other Party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other Party of any subsequent modification which may affect the duties of the other Party in regard to such equipment, and furnish the other Party with accurate revised drawings, if possible.

6.16 Inspection of Facilities

Each Party may, for any reasonable purpose under this Agreement, inspect the other Party's electrical installation at any reasonable time after giving suitable notice. Such inspection, or failure to inspect, shall not render such Party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this Agreement. The inspecting Party shall observe written instruction and rules posted in facilities and such other necessary instructions or standards for inspection as the Parties agree to. Only those electric installations used in complying with the terms of this Agreement shall be subject to inspection.

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7. PLANNING AND OPERATING INFORMATION

7.01 Increases in Maximum Demand
The Customer shall notify the Company in writing of any anticipated additional single load in excess of 5000 kVA resulting from a new customer or the increased load of an existing customer, providing as much advance notice of the increase as can be given in the circumstances. The Company shall endeavor to provide the service requested by the date the increase is intended to become effective, or as soon thereafter as is practicable.

7.02 Records and Forecasts
Each Party shall retain and make available upon request for the other Party log sheets, records of recording meters, and any other readily available information of an operational character relating to the electricity supplied under this Agreement, excluding non-public records of a financial or business nature relating to the Customer's utility undertaking.

7.03 General Information Requests
The Parties agree to cooperate in the full exchange of such planning and operating information as may be reasonably necessary for the timely and efficient performance of the Parties' obligations or the exercise of rights under this Agreement. Such information shall be provided on a timely basis and no reasonable request shall be refused.

7.04 Load-Resource Forecast
By June 30 of each year, the Parties agree to exchange a five year forecast of loads and resources for their respective electrical systems including a forecast of their Maximum Demand at each Point of Delivery normalized for average weather conditions and shall also provide a forecast of energy consumption for each year. These forecasts shall include programs for resource acquisition, transmission and firm loads. The degree of detail in these forecasts shall be decided by mutual agreement.

7.05 Load from Previous Year
Before the end of February in each year, the Customer shall provide the Company with a record of the number of customers and load by customer class for the previous calendar year.

7.06 Scheduled and Maintenance Outages
Each party shall submit to the other Party a list of outages scheduled for inspection, testing, preventative maintenance, corrective maintenance, repairs, replacement or improvements that might affect the delivery of electricity under this Agreement, providing as much advance notice of the outage as can be given in the circumstances. The Parties shall use reasonable efforts to keep such schedules current and to revise such schedules so as to minimize the impact on the other Party's system.

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8. METERING

8.01 Installation

The Company shall furnish, install and maintain the Metering System except the 63 kV metering units at Bonnington and Rosemont which are owned by the Customer. The Customer shall provide metering quantities to the Company. The Customer, in accordance with subsection 8.03, may furnish, install and maintain the Check Metering, each at their own expense, at the Points of Delivery, which shall accurately measure and record electricity within the limits prescribed by the federal Department of Consumer and Corporate Affairs ("Prescribed Limits") and pursuant to subsection 8.07.

8.02 Totalizing Metering

The Company shall also, at its expense, install totalizing metering to compensate for demand diversity at the different Points of Delivery.

8.03 Check Metering

Check Metering and connecting equipment and facilities to be furnished by the Customer shall be satisfactory to the Company, and shall be installed in accordance with Good Utility Practice and in a manner satisfactory to the Company, acting reasonably.

8.04 Meter Tests and Adjustments

Unless otherwise agreed to by the Parties, each Party shall, at its own expense, arrange to have its meters tested by an inspector or accredited meter verifier authorized pursuant to the federal Electricity and Gas Inspection Act and regulations, as amended from time to time.

8.05 Inspection of Metering Equipment

Notwithstanding subsection 8.04, either Party may, after giving two days' notice, inspect in the presence of the other Party, the metering equipment installed in accordance with this subsection by the other Party, and may request that that metering equipment be tested by an inspector or authorized meter verifier.

(a) If the result of any test performed pursuant to this subsection shows that any of the metering equipment is not recording within the Prescribed Limits, then the owner of that metering equipment shall pay for the costs of testing.

(b) If after testing the metering equipment is found to be recording within the Prescribed Limits, the Party that made the request shall pay for the costs of testing.

8.06 Calculating the Amount to be Paid

The measurements recorded by the Metering System shall be used for calculating the amount to be paid for the electricity delivered to the Customer, except in the following circumstances:

(a) if a totalizing meter is temporarily not in service or is found after testing to be not recording within the Prescribed Limits then the measurements recorded by the Customer's totalizing meter shall be used to determine the total consumption and demand, or, in the absence of a Customer totalizing meter, the Company's meters shall be used to determine the total consumption and demand taking into account established load diversity until the Company's totalizing meter has been recalibrated;

(b) if the Metering System is not in service or is found after testing to be not recording within the Prescribed Limits then the measurements recorded by the Customer's totalizing meter or , in the absence of a totalizing meter, the Customers' meters shall be used for calculating the amount to be paid for electricity delivered to the Customer;

(c) if neither the Metering System nor the Check Metering are in service or are found after testing to be not recording within the Prescribed Limits then the amount of electricity delivered since the previous billing shall be estimated from the best information available.

8.07 Prescribed Limits

If at any time the testing described in subsections 8.04 and 8.05 shows that the metering equipment was not recording within the Prescribed Limits, and if such recordings were used for billing purposes, then the billings shall be adjusted as prescribed by the Electricity and Gas Inspection Act.

8.08 Access to Meters

Each Party shall have the right, by giving suitable notice, to enter the property of the other Party at all reasonable times for the purpose of reading any and all meters mentioned in this Agreement which are installed on such property.

9. INVOICES AND PAYMENT

9.01 Meter Reading

Meters shall be read at the end of each month. 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.

9.02 Invoices and Payment

The Company shall render a billing invoice monthly pursuant to the terms of the Company's Electric Tariff, as amended from time to time.

9.03 Rates for Electricity

The Customer shall pay for Services during the term of this Agreement in accordance with the tariff applicable to the Customer filed with the Commission, as amended from time to time.

9.04 Demand Period and Demand

For billing purposes, Demand Period means the period, expressed in minutes, over which meter readings are integrated to obtain the Demand, which is the power measured in kilovolt amperes (kVA), or multiples thereof, at the Point of Delivery. In this Agreement and for billing purposes, the Demand Period shall be a a sixty minute clock hour interval.

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9.05 Billing Adjustments

If the Company suspends or reduces Service for reasons other than a request by the Customer or an interruption of Service caused by the Customer's system, and the suspension or reduction results in a peak Demand which would otherwise be used for billing purposes, the Demand in the Demand Period immediately following restoration of service may be reduced, by mutual agreement, to an estimate of what the Demand would have been if Service had not been suspended or reduced. The estimate shall be determined in consideration of weather conditions and previous load experience.

9.06 Late Payments

If the amount due on any invoice has not been paid in full after twenty calendar days from the billing date shown on the invoice, a late payment charge shall be applied to the unpaid balance, and the resulting amount will be shown and identified on the next invoice to be rendered. The late payment charge shall be as specified in the Company's Electric Tariff, as amended from time to time.

9.07 Taxes

In addition to payments for electricity, the Customer shall pay to the Company the amount of any sales tax, goods and services tax, or any other tax or assessment levied by any competent taxing authority on any electricity delivered pursuant to this Agreement.

9.08 Payment of Accounts

The Customer shall pay to the Company the amount of the billing within 20 calendar days from the date appearing on the statement.

10. CONTINUITY OF SUPPLY

10.01 Standard of Performance

The Company shall perform the Services with skill, care, and diligence consistent with Good Utility Practice and consistent with directions from the Commission, including the quality performance standards, if any, approved by the Commission from time to time.

10.02 Interruptions and Defects in Service

The Company shall avoid interruption of delivery of electricity, but nevertheless shall not be liable to the Customer for any loss or damage owing to failure to supply electricity, or owing to other abnormal conditions of supply resulting from force majeure as defined in subsection 12.01.

10.03 Suspension of Supply

Either Party shall have the right to demand the temporary suspension of, or to suspend temporarily, the delivery or taking of electricity, as the case may be, whenever necessary to safeguard life or property, or for the purpose of replacing, repairing or maintaining any of its apparatus, equipment, or works. Such reasonable notice of the suspension as the circumstances permit shall be given by one Party to the other.

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10.04 Discontinue Service

The Company may discontinue the supply of electricity to the Customer at a Point of Delivery for the failure by the Customer to commence remedial action acceptable to the Company, within 15 days of receiving notice from the Company, to correct the breach of any significant practice, term or condition to be observed or performed by the Customer under this Agreement. 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 discontinuance shall not recur.

10.05 Obligations Continue

Discontinuance of Services by the Company pursuant to the provisions of this Agreement shall not relieve the Customer of any obligation under this Agreement, or alter any of the obligations of the Customer under this Agreement.

10.06 Other Remedies

The Company's right to discontinue the supply of electricity under this Agreement shall not operate to prevent the Company from pursuing, separately or concurrently, any other remedy it may have under this Agreement or by operation of law.

11. REMOVAL OF FACILITIES UPON TERMINATION

After the termination of this Agreement, the Company shall have the right to, and must expeditiously if requested by the Customer, remove from the property owned or controlled by the Customer any and all electrical apparatus and equipment which the Company owns and has installed on the property and the Company shall leave the property in good repair after such removal.

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12. COFFEE CREEK SUBSTATION

12.01 Supply Equipment
The Customer takes delivery of electricity at the Coffee Creek Substation. The Customer has contributed transformers, metering units, reclosers, cables and other equipment necessary for the supply of electricity at 25 kV at the Company's substation located near Coffee Creek ("Coffee Creek Substation").

12.02 Transfer of Ownership
On June 30, 1997 the Customer transferred its interest in the equipment described in Section 12.01 to the Company so that all equipment on the line side of the Customer's disconnect switch 25D71 at the Coffee Creek Substation is owned solely by the Company, except for the Customer's check meter.

12.03 Operation and Maintenance Costs
The Company is responsible for all costs incurred to operate and maintain, and subject to section 12.04, replace as necessary, all equipment at the Coffee Creek Substation on the line side of the Customer's disconnect switch 25D71, except for the Customer's check meter..

12.04 Transformation Upgrades
Each party is entitled to the use of a 5 MVA share of the total transformation capacity of 10 MVA at the Coffee Creek Substation. Except in the event of an emergency condition, which event shall be governed pursuant to Section 6.03, if the Customer requires transformation capacity at the Coffee Creek Substation in excess of the Demand Limit, then the Company shall endeavor to provide the additional transformation capacity by the date the increase is required, or a soon thereafter as practicable. Notwithstanding Section 6.06, the total cost to increase the transformation capacity above the Demand Limit at Coffee Creek Substation shall be borne by the Customer.

12.05 Annual Payments
During the term of this Agreement, the Customer shall on June 30 of each year, pay to the Company, the sum of $5,000 in recognition of on-going operation and maintenance expense. If this Agreement expires prior to June 30 of any year of this Agreement, no amount will be payable in the year this Agreement expires.

12.06 Deemed Nominal Voltage
Notwithstanding that the nominal voltage supplied is 25 kV at the Coffee Creek Substation, the supply voltage to the Customer at the Coffee Creek Substation shall be deemed to be 63 kV for the purposes of determining applicable rates including, without limiting the generality of the foregoing, transformation and metering discounts, for purchases under this Agreement and Company rate Schedules 41 - Wholesale Service - transmission, Schedule 100 - Network Integration Transmission Service and Schedule 101 - Long-term and Short-term Firm Point-to-Point Transmission Service - Wholesale Customer not using Substation Equipment.

12.07 Coffee Creek Operating Order

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The parties have agreed on an operating order for the Coffee Creek substation, as may be modified from time to time..

13. GENERAL PROVISIONS

13.01 Force Majeure

Neither Party to this Agreement shall be considered to be in default in the performance of any of its obligations under this Agreement to the extent that performance of those obligations is prevented or delayed by any cause which is beyond the reasonable control of the Party prevented or delayed by that cause. If either Party is delayed or prevented from its performance at any time by any act, omission or neglect of the other Party or its representatives, or by an act of God or the public enemy, or by expropriation or confiscation of facilities, compliance with any order of any governmental authority or order of a court of competent jurisdiction, acts of war, rebellion or sabotage, fire, flood, explosion, riot, strike or other labour dispute beyond the reasonable control of the Party or any unforeseeable cause beyond the control and without the fault and negligence of the Party, the Party so prevented or delayed shall give notice to the other Party of the cause of the prevention or delay but, notwithstanding giving of that notice, the Party shall promptly and diligently use reasonable efforts to remove the cause of the prevention or delay.

13.02 Notices

Any notice, direction or other instrument required or permitted to be given under this Agreement in writing shall be sufficient in all respects if delivered, or if sent by fax, or if sent by prepaid registered post in Canada to the Parties at their respective addresses as they appear in subsection 13.03, or to any substitute address of which the Party sending notice has had notice in writing.

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13.03 Addresses
Any notice, direction or other instrument shall be delivered or sent to the following addresses:

(a) To the Company:
FortisBC Inc.
1290 Esplanade
PO Box 130
Trail, BC VIR 4L4
Attention: Secretary
Fax Number: 250-364-1270

(b) To the Customer:
General Manager
Nelson Hydro
502 Vernon Street
Nelson, BC V1L 4E8

13.04 Dates
Any notice, direction, or other instrument shall be deemed to have been received on the following dates if,

(a) sent by fax, on the business day next following the date of transmission.
(b) delivered, on the business day next following the date of delivery.
(c) 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, directions or other instrument shall only be deemed to be effective if delivered or sent by fax.

13.05 Disputes
If any difference or dispute occurs regarding any matter arising under this Agreement, either Party may request that the Commission settle the difference or dispute. If the Commission declines to settle the dispute then the dispute shall be arbitrated pursuant to the Commercial Arbitration Act of British Columbia.

13.06 Invalidity
If any provision of this Agreement or the application of any provision to any Party or circumstance is declared or held to be wholly or partially invalid, this Agreement shall be interpreted as if the invalid provision had not been a part hereof so that the invalidity shall not affect the validity of the remainder which shall be construed as if this Agreement had been executed without the invalid portion. The Company and the Customer shall, either independently, jointly or in concert with other wholesale customers of the Company, make all reasonable efforts to validate any portion of this Agreement declared or held to be invalid.

13.07 Headings
The headings in this Agreement have been inserted for convenience of reference only, and shall not affect the construction or interpretation of this Agreement.

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13.08 Enurement
This Agreement shall be binding upon and shall enure to the benefit of the Parties hereto and of their respective successors and assigns.

13.09 Governing Law
Notwithstanding anything to the contrary in this Agreement, this Agreement the Company shall comply fully with all applicable federal, provincial and municipal laws (including bylaws) in effect from time to time.

13.10 Entire Agreement
This Agreement and the Appendices attached hereto are intended by the Parties to be the final expression of their agreement and are intended also as a complete and exclusive statement of the terms of the Agreement.

13.11 Commission Approval
This Agreement and all the terms and conditions contained in it shall be subject to the provisions of the Utilities Commission Act of British Columbia, as amended or re-enacted from time to time and to the jurisdiction of the Commission.

This Agreement and subsequent amendments including changes to the Service Area, shall not be binding on the parties until it has been approved by the Commission.

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IN WITNESS WHEREOF the Parties, by the signatures of their duly authorized officers set out below, have executed this Agreement.

The CORPORATION OF THE CITY OF NELSON this day 22 of DECEMBER, 2004 by

Marla Olsen

Signature

Marla Olson
City Clerk

Title

Signature

Title

FORTISBC INC. this day 4 of April, 2005 by

Signature

Vice President, Customer & Corporate Services

Title

Signature

Title

Accepted for filing: JUN 19 2008
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This is Appendix A to the Agreement for the Supply of Electricity - Wholesale Service between FortisBC Inc. and The Corporation of the City of Nelson

City of Nelson - Points of Delivery

1. **Rosemont Substation**

Description: Line side of the City of Nelson's No. 60D27 Disconnect Switch at Rosemont Substation

Nominal Voltage Supplied: 63 kV

Demand Limit:	Summer	40 MVA
	Winter	40 MVA

Alternative Point of Delivery: Line side of City of Nelson's disconnect No. 60D28 at Bonnington

2. **Coffee Creek Substation**

Description: Line side of City of Nelson's disconnect switch, designated 25D71, located on a pole adjacent to the Coffee Creek Substation

Nominal Voltage Supplied: 25 kV

Demand Limit:	Summer	5 MVA
	Winter	5 MVA

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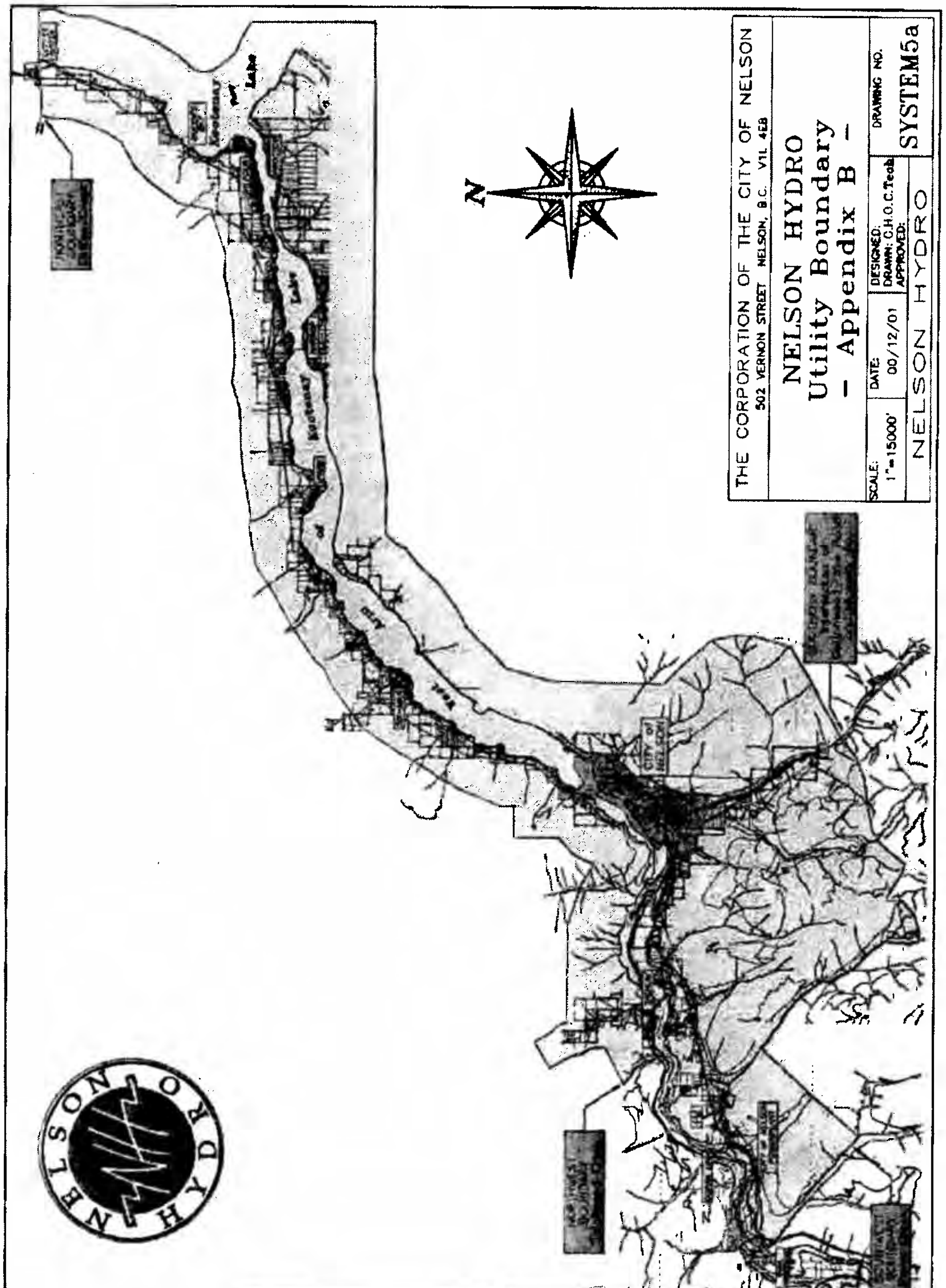
Appendix B



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West Kootenay Power Ltd. Access Principles Application ("APA") Proposed Settlement Agreement

PURPOSE

Through its Transmission Access Application, West Kootenay Power proposes to open its transmission system to all Eligible Customers. The goal of open access is to encourage the development of a competitive generation market resulting in efficient resource allocation. The purpose of the APA is to ensure that this occurs in a way that results in the Fair Treatment of Utility shareholders, of customers who remain with Utility supply and of Eligible Customers who choose to obtain some or all supply from non-Utility resources.

DEFINITIONS

Commission means:

The British Columbia Utilities Commission.

Eligible Customer means:

Those West Kootenay Power bundled service customers eligible for transmission access as determined by the Commission from time to time.

Embedded Cost of Power means:

West Kootenay Power's cost of generation related transmission assets, generation assets, power purchase contracts, market purchases and other costs of power as determined by the Commission from time to time.

Fair Treatment means:

(i) For shareholders, the opportunity to earn a rate of return on equity does not change as a result of the exit, partial exit or re-entry of Eligible Customers;

(ii) For customers who remain with Utility supply, the exit, partial exit or re-entry of Eligible Customers must, at a minimum, make them no worse off than if Eligible Customers had always remained with the Utility. Any payments, made by Eligible Customers to ensure that those customers who remain with Utility supply are made no worse off, will be allocated by the Utility in such a way that no customer class is made worse off. Each remaining customer class is made no worse off if their rates for bundled service are no higher after an Eligible Customer makes its election. The rates before election are determined by a prospective calculation of the Utility's total net revenue requirement allocated to customer classes using embedded cost methodologies as accepted by the Commission from time to time. Similarly, the rates after election are calculated prospectively considering the change in total net revenue requirement due to the change in load, again allocated to customer classes using embedded cost methodologies as accepted by the Commission from time to time;

(iii) For Eligible Customers,

a) the maintenance of West Kootenay Power's obligation to serve continues for an Eligible Customer as long as the Eligible Customer elects to receive embedded cost service from West Kootenay Power for all or part of its load;

b) the right to elect to leave the embedded cost service of West Kootenay Power in whole or in part;
c) the right to return to West Kootenay Power's embedded cost service as set out under the Re-entry Provisions; and
d) notwithstanding the general principle that remaining customers are to be made no worse off by the exit of Eligible Customers, the right to take with them any benefits accruing from their load characteristics (that is, size and load factor), without additional payment or compensation to customers who remain on Utility supply.

OBLIGATION TO SERVE

West Kootenay Power retains the obligation to serve every customer until that customer elects to leave the embedded cost power service of West Kootenay Power. In the event of partial supply customers, West Kootenay Power retains an obligation to serve the portion of a customer's load that remains with the Utility (subject to the provisions set out below under the section entitled Partial Supply). West Kootenay Power retains the obligation to provide transmission and distribution service to all customers within its service territory.

West Kootenay Power also retains the obligation to serve at embedded cost rates any new load entering its service territory, any additional load attributable to its existing customers, and returning Eligible Customers, under the Re-entry Provisions outlined below.

West Kootenay Power will provide short term backup service on a reasonable-efforts basis to Eligible Customers within its service territory for the period required by those Eligible Customers for the unanticipated loss of firm supply. For this service, West Kootenay Power will charge the higher of the market buy price or the cost of the marginal unit in West Kootenay Power's supply portfolio if West Kootenay Power supplies from its portfolio. The price charged will be determined retrospectively and will apply to the full period of service. In addition, West Kootenay Power may charge additional administrative costs reasonably incurred by the Utility to provide this power supply.

It is acknowledged that existing contracts between the Utility and Eligible Customers will not be abrogated. However, it is recognized that West Kootenay Power has a need for notice before the departure of any Eligible Customer and, therefore, it will be desirable if contracts are renegotiated in a timely fashion. In this regard, the City of Kelowna and the City of Nelson will provide notice of intent to leave the Utility or to enter into a new contract for bundled service by <u>April 1, 1999</u>. All other Eligible Customers that have contracts with an expiry date beyond 1999 will provide notice of intent to leave or to enter into a new contract for bundled service at least two years prior to the expiration of their bundled service contracts. Failure to provide such notice of intent to leave will expose these Eligible Customers to any costs imposed on remaining customers, as defined in the Re-entry Provisions below. If after giving notice of intent to stay, the Eligible Customer and West Kootenay Power are unable to conclude a mutually satisfactory contract and one or both parties believes this to be the result of the conduct of the other party, the Commission may be asked to grant protection from any costs implied by other parts of this agreement.

West Kootenay Power will enter into good faith negotiations with any Eligible Customer desiring to enter into a new contract at embedded cost rates. Any new contract will be subject to Commission approval. In any case, West Kootenay Power will include in all new contracts a condition that any Eligible Customer must provide at least two years' notice of early termination, West Kootenay Power will use reasonable efforts to accommodate, in a manner that results in Fair Treatment, a departure such that no stranded cost payment is required.

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If such an accommodation cannot be found, Eligible Customers that leave West Kootenay Power during the notice period, taking with them 25% of their prior year's load or less, will pay mitigated stranded costs, if any, for the lesser of the remaining term of the notice period or two years. If an Eligible Customer takes with it more than 25% of its prior year's load, or if an Eligible Customer's monthly load factor in any month decreases by more than 20% as a result of going to market, or if the combined departure of all Eligible Customers' load exceeds 10% in any year of the Eligible Customers' total aggregate load at the end of the previous year, the Eligible Customer will pay mitigated stranded costs, if any, for a period of five years less any part of the notice period during which the Eligible Customer remained with West Kootenay Power for its total load. Within 15 business days of a request, West Kootenay Power will calculate for both a two-year and a five-year period the payments required to ensure that the revenue requirement of remaining customers is not increased from that which is expected to have occurred if the Eligible Customer had not departed early.

New Eligible Customers have the right to be served entirely through an alternate supplier without attracting any of the stranded cost provisions described above.

PARTIAL SUPPLY

An Eligible Customer may elect to meet any or all of its load requirements from West Kootenay Power. If any Eligible Customer elects to meet part of its load requirements from West Kootenay Power, then the rate for partial supply requirements shall be determined so as to ensure that all other customers receive Fair Treatment. For example, if by taking part of its load to market, an Eligible Customer materially worsens the load factor of that portion of its load which remains with the Utility, the Eligible Customer will compensate for these costs consistent with Fair Treatment. In contrast, if an Eligible Customer materially improves its load factor for the portion of its load remaining with the Utility - for example, by taking its peaking requirements to market - the Eligible Customer will realize the benefits of this in the price it pays for its remaining load (to the extent that this can be accomplished in a manner consistent with Fair Treatment and recovery of the embedded cost of service).

In order to satisfy the informational needs of potential partial load Eligible Customers, West Kootenay Power will respond within 15 business days to an Eligible Customer's inquiry about Utility rate changes (both generation and transmission) that the Eligible Customer will face as a result of its partial load election. New rates will be incorporated by reference in a new contract, and subject to Commission approval.

STRANDED COSTS AND BENEFITS

West Kootenay Power is not seeking any specific compensation for stranded costs as part of this agreement. Any person may raise the issue of Fair Treatment in any future stranded cost application before the Commission. However, before asking for stranded cost relief, West Kootenay Power is expected to have exhausted all reasonable avenues of stranded cost mitigation. In addition, the amount of any stranded costs attributable to an Eligible Customer's departure will be reduced by any benefits to remaining customers which result from that departure. However, in no case will this confer to a departing Eligible Customer a claim to stranded benefits.

Where a stranded cost or benefit determination is required, the amount of the stranded costs or benefits will be calculated by West Kootenay Power, disclosed to all interested parties, and submitted to the Commission for approval.

West Kootenay Power acknowledges the likelihood that open access may produce stranded benefits. If this is the case, these benefits will accrue to those customers that remain with the Utility. Departing Eligible Customers may not take these benefits with them, either in the form of exit payments or generation entitlements. Departing Eligible Customers retain claim to the inherent benefits implied by West Kootenay Power's low cost power, as provided for in the Re-entry Provisions.

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Where a market opportunity to obtain power is available to an Eligible Customer which would not be viable without additional incentives, the Eligible Customer may seek to negotiate a sharing of stranded benefits under the auspices of the Commission. Such negotiations will be conducted pursuant to the Commission's Alternate Dispute Resolution Guidelines as they may exist from time to time.

Stranding caused by transmission or distribution bypass will be the subject of Commission consideration if and when it arises. As in other stranded cost recovery scenarios, West Kootenay Power will be required to have taken all reasonable steps to protect its assets from stranding and such steps will not create obligations or create a greater burden on the Utility than arises from regulatory principles, including prudent investment obligations.

RE-ENTRY PROVISIONS

An Eligible Customer that has previously taken bundled service may, at any time, return to power service from West Kootenay Power at a rate calculated to ensure Fair Treatment, subject to the conditions set out below, West Kootenay Power will make reasonable efforts to accommodate returning Eligible Customers as quickly as possible.

Returning Eligible Customers and new Eligible Customers who initially chose an alternative supplier should receive rates reflecting the embedded cost of service within the lesser of:

- the period in which West Kootenay Power can adjust its supply portfolio to serve these Eligible Customers, consistent with Fair Treatment; or
- two years from the date of their notice to return to West Kootenay Power's supply.

For the interim period (that is, the lesser of the time it takes West Kootenay Power to adjust its supply portfolio or two years) West Kootenay Power may charge rates reflective of its additional cost of serving these Eligible Customers over the interim period, while maintaining Fair Treatment. If market circumstances are such that market energy is reasonably anticipated to be less expensive than West Kootenay Power's embedded cost of power for the interim period, then the Eligible Customers will return to embedded cost tariffs immediately.

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FORTISBC

AGREEMENT FOR THE SUPPLY OF ELECTRICITY WHOLESALE SERVICE

LWD05001

BETWEEN

The Corporation of the City Of Penticton
171 Main Street
Penticton, BC V2A 5A9

And

FortisBC Inc.
1628 Dickson Avenue
Kelowna, BC V1Y 9X1

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Agreement for the Supply of Electricity Wholesale Service

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SECRETARY
Effective: APR 1 2006
B.C. UTILITIES COMMISSION
Order No.: G-101-08

THIS AGREEMENT is made as of the 1st day of April 2006.

BETWEEN:

FORTISBC INC., a corporation established by a special Act of the Legislature of the Province of British Columbia, having its head office in the City of Kelowna in the Province of British Columbia,. ("FortisBC"),

AND:

THE CORPORATION OF THE CITY OF PENTICTON, a company incorporated under the laws of British Columbia and having an office in the City of Penticton, in the Province of British Columbia. ("City of Penticton"),

WHEREAS FortisBC is a supplier of electricity in the southern interior region of the Province of British Columbia;

AND WHEREAS the City of Penticton wishes to purchase electricity from FortisBC for its own use and for resale to City of Penticton customers within the City of Penticton's Service Area as hereinafter described;

AND WHEREAS both FortisBC and the City of Penticton have agreed to the principles set forth in the Proposed Settlement Agreement resulting from the British Columbia Utilities Commission Decision dated March 10, 1999.

JUN 19 2008

Accepted for Filing:

Effective: APR 1 2006 4 B.C. UTILITIES COMMISSION

Order No.: G101 08

NOW THEREFORE this Agreement witnesses that in consideration of the terms and conditions hereinafter set forth the Parties covenant and agree as follows:

1. DEFINITIONS

In this Agreement:

(a) **"Check Metering"** means any measurement device or system installed, owned and maintained by the City of Penticton to check the measurements and calculations carried out by the Metering System.

(b) **"Commission"** means the British Columbia Utilities Commission.

(c) **"Commodity Service"** means the supply of power, expressly excluding the services set forth in the Transmission Services Tariff, to the City of Penticton by a third party and may include full or partial supply of the load requirements of the City of Penticton.

(d) **"Demand"** has the meaning given to it in subsection 9.04.

(e) **"Demand Limit"** means the capability of FortisBC's facilities at each of the Points of Delivery, specified in Appendix A attached hereto.

(f) **"Demand Period"** has the meaning given to it in subsection 9.04.

(g) **"Good Utility Practice"** means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the WECC region.

(h) **"Maximum Demand"** means the highest clock hour of taking of electricity by the City of Penticton recorded in kilovolt-amperes by FortisBC from time to time.

(i) **"Metering System"** means the measurement device or system installed, owned and maintained by FortisBC used to determine the City of Penticton's electricity consumption.

(j) **"Parties"** means both FortisBC and the City of Penticton.

(k) **"Point of Delivery"** means the point or points at which the City of Penticton's distribution system attaches to FortisBC's facilities, as specifically described in Appendix A attached hereto.

(l) **"Power Factor"** means the percentage determined by dividing the City of Penticton's demand measured in kilowatts by the same demand measured in kilovolt-amperes.

(m) **"APSA"** means the Access Principles Settlement Agreement, also known as the Proposed Settlement Agreement, as amended from time to time, attached as Appendix A to the Commission Order Number G-27-99 dated March 10, 1999 in the matter of the Access Principles Application .

(n) **"Service Area"** means the City of Penticton's service area, the boundaries of which are shown by the red line on the map identified as the City of Penticton's

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Electrical Service Boundaries, attached hereto as Appendix B and shall include any area(s) added from time to time by the municipality.

(o) **"Services"** means the supply and delivery of power to the City of Penticton by FortisBC under this Agreement.

(p) **"Term"** means the period defined by subsection 2.01 herein.

(q) **"Transmission Services Tariff"** means the tariff as approved from time to time by the Commission for the use by a third party supplier to deliver power to the City of Penticton or by the City of Penticton to deliver power to a third party on the transmission and distribution facilities of FortisBC, including ancillary services required for the delivery of power.

(r) **"WECC"** means Western Electricity Coordinating Council or a successor organization.

2. TERM OF AGREEMENT

2.01 Term

This Agreement shall be effective as of April 1, 2006 and shall continue for a term of four years thereafter, terminating on March 31, 2010. Upon mutual agreement in writing by both parties, this agreement may be renewed prior to March 31, 2010 for an additional five year term on the same terms and conditions.

2.02 Early Termination

If the City of Penticton elects to engage any third party supplier to perform the Commodity Services and notice as provided for in the APSA is given to FortisBC the City of Penticton may terminate this Agreement prior to expiry of the Term. If this Agreement terminates pursuant to this subsection, the City of Penticton may then be liable to pay such costs, including stranded costs, if any, as directed by the Commission.

3. ACCESS PRINCIPLES SETTLEMENT AGREEMENT

3.01 Access Principles Settlement Agreement Rights

Nothing contained in this Agreement shall be construed as affecting in any way the rights of either Party as set forth in the APSA nor as affecting in any way the rights of either Party to unilaterally make application to the Commission for further directions or orders from the Commission related to the terms and conditions of the APSA.

3.02 Regulatory Principles

If any provision of this Agreement is declared by the Commission to be inconsistent with the regulatory principles set forth in the APSA, the Parties shall amend that provision in such reasonable manner as achieves the intention of the declaration of the Commission. In the event the Parties cannot agree on such amendments, either Party shall be entitled to seek further direction from the Commission and the Parties hereby agree to be bound by such direction from the Commission.

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4. CONDITIONS OF SUPPLY

4.01 Supply of Electricity

During the term of this Agreement, except in an emergency described in subsection 6.03, FortisBC shall supply up to the Demand Limit electricity required by the City of Penticton solely for its own use and for supplying the needs of its customers within the Service Area. FortisBC shall supply electricity to the Points of Delivery through suitable plant and equipment in accordance with Good Utility Practice on a continuous basis, except as provided in this Agreement. The responsibility of FortisBC for the delivery of electricity to the City of Penticton shall cease at the Points of Delivery.

4.02 Duty to Act Prudently in Arranging for Electricity Supply

Notwithstanding the provisions of subsection 4.03 and 4.04 FortisBC has a duty not to be imprudent in arranging for the supply of electricity required pursuant to subsection 4.01 of this Agreement and FortisBC will, subject to subsections 4.04 and 4.09, be liable to the City of Penticton for any loss, injury, damage or expense caused to the City of Penticton if the British Columbia Utilities Commission determines that FortisBC has failed to meet its duty not to be imprudent.

4.03 Failure to Deliver

At any time during an actual or anticipated shortage of electricity, or in the event of a breakdown or failure of generating, transmitting or distributing plant, lines or equipment, or in order to comply with the requirements of any law, FortisBC shall have the right to curtail or discontinue the supply of electricity to the City of Penticton or reduce the voltage or frequency of the electricity supplied. To the extent that it is practical and reasonable, FortisBC will not unduly discriminate in favour of or against the City of Penticton in the supply of electricity.

4.04 Interruptions and Defect in Service

The City of Penticton acknowledges and agrees that FortisBC's responsibility and liability for loss, injury, damage or expense caused by or resulting from any interruption, termination, failure or defect in the supply of electricity by FortisBC pursuant to this Agreement is limited by the terms and conditions of FortisBC's Electric Tariff B.C.U.C. No. 1 (including, without limitation, Section 8.1 thereof), as approved from time to time by the Commission.

4.05 Commodity Services

The City of Penticton shall have the rights set forth in the APSA to purchase power from a third party supplier and to meet part or all of its load requirements from Commodity Services.

4.06 Limits on Other Supply

Unless the City of Penticton has exercised its rights pursuant to the APSA, the City of Penticton shall, during the Term, only purchase electricity from FortisBC and the City of Penticton's own customers for its own use and the use of its customers within the Service

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Area. The City of Penticton may obtain up to 15 MWs of electricity from new generation owned and operated by the City of Penticton or the City of Penticton's customers.

4.07 Retail Access on the City of Penticton's Facilities

The City of Penticton shall give notice, consistent with the APSA requirements, in writing to FortisBC prior to providing the City of Penticton's transmission and distribution services for the direct delivery of third party supply to a customer of the City of Penticton.

4.08 Sales out of Service Area

If service to a customer outside or within the Service Area would require duplication of existing electrical plant which duplication could be avoided, then the Party that has the right to serve that customer pursuant to this Agreement may consent to the other Party serving that customer, such consent not to be unreasonably delayed or withheld.

4.09 No Liability for Consequential Damages

Neither Party, nor its directors, officers, employees or agents, will be liable to the other Party, or its directors, officers, employees or agents, in contract, tort, warranty, strict liability or any other legal theory for any indirect, consequential, incidental, punitive or exemplary damages arising under or in connection with this Agreement.

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5. CONDITIONS OF SERVICE

5.01 Supply Characteristics

The electricity to be supplied to the City of Penticton shall be three-phase alternating current, having a nominal frequency of 60 hertz and the nominal voltages designated in Appendix A for the Points of Delivery, as amended from time to time.

FortisBC is a signatory of the WECC Reliability Management System (RMS) Agreement. FortisBC is committed to the service reliability standards detailed in this document and is liable for financial sanctions that WECC can impose for non-adherence to those standards.

The Commission may exercise its authority by whatever means it deems appropriate in the event that frequency or voltage excursions occur that could reasonably have been prevented.

5.02 Underground Facilities

When the City of Penticton requests the construction or installation of underground facilities, the City of Penticton shall be responsible for the difference between the cost of constructing or installing the facilities underground and the cost of constructing or installing similar facilities above ground.

5.03 Ownership of Facilities

Notwithstanding the payment of any contribution by the City of Penticton toward the cost of facilities pursuant to subsection 5.02, FortisBC shall retain full title to all facilities.

5.04 Revenue Guarantee

The City of Penticton may be required to provide a revenue guarantee if FortisBC's facilities must be upgraded significantly to meet a proposed increase in the City of Penticton's load in excess of 5000 kVA resulting from either a new City of Penticton customer or the increased load of an existing City of Penticton customer. The revenue guarantee will be equal to the cost of upgrading the facilities and will be refunded, with interest, in equal installments over a period of five years at the end of each year of continued service to that customer at the increased load. The revenue guarantee shall be in the form of cash, surety bond or other form of security satisfactory to FortisBC.

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6. INTERCONNECTED OPERATION

6.01 Obligation of FortisBC

The maintenance by FortisBC of the agreed frequency and voltage at the Points of Delivery, set out in Appendix A, shall constitute delivery of electricity under this Agreement, whether or not any electricity is taken by the City of Penticton, and shall, subject to subsection 10.01 constitute the complete discharge by FortisBC of its obligations to the City of Penticton for Services.

6.02 Use of Facilities

Each Party shall cooperate with the other to secure the most efficient use of the plant and equipment of the other Party, which may include wheeling power through the other Party's transmission and distribution circuits to facilitate supply to either Party or its customers.

6.03 Exceeding Demand Limit

The City of Penticton shall not take electricity in excess of the Demand Limit of a Point of Delivery without the prior written consent of FortisBC, unless an emergency condition requires that the City of Penticton take in excess of the Demand Limit, and then only for the duration of the emergency condition. The City of Penticton shall immediately advise FortisBC when such an emergency condition occurs. The City of Penticton shall reduce immediately its use of electricity to the Demand Limit for that Point of Delivery or to a specified limit above the Demand Limit upon the oral or written request of FortisBC.

6.04 Restrict or Suspend Service

If the City of Penticton fails to comply with the request of FortisBC pursuant to the previous paragraph, FortisBC may, when necessary in the opinion of FortisBC, restrict or suspend the supply of electricity to the City of Penticton at the Point of Delivery summarily without further notice.

6.05 Avoidance of Excess Loads

The City of Penticton shall provide for interconnection of its lines so as to transfer and arrange the loads taken at each Point of Delivery to balance as far as is practicable the loads at each Point of Delivery given the Demand Limit at each Point of Delivery.

6.06 Maintenance of Adequate Supply Capability

If at any time, except in an emergency condition described in subsection 6.03, the City of Penticton notifies FortisBC that it has taken electricity in excess of 95 percent of the Demand Limit of a Point(s) of Delivery, FortisBC shall take appropriate measures at no cost to the City of Penticton to increase the supply capability at the Point(s) of Delivery to bring the City of Penticton's anticipated future demand to or below 95 percent of the Demand Limit.

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6.07 City of Penticton's Facilities
The City of Penticton shall be responsible for designing, constructing, installing and maintaining all auxiliary and interconnecting equipment on the City of Penticton's side of the Point of Delivery and the City of Penticton shall have ownership rights in all such auxiliary and interconnection equipment. FortisBC shall have no fiscal or other responsibilities in ensuring that such City of Penticton facilities meet the requirements of the City of Penticton's customers.

6.08 Installation of Facilities
All electrical facilities owned by the City of Penticton from the Points of Delivery up to and including the City of Penticton's overload and overcurrent protection and isolation devices shall be approved and coordinated in a manner satisfactory to FortisBC, and may be inspected by FortisBC from time to time. Notwithstanding the foregoing, FortisBC shall not require a higher standard for the City of Penticton's electrical facilities than the standard of FortisBC facilities supplying that portion of the City of Penticton's facilities.

6.09 Coordination of Protective Devices
Either Party shall notify the other Party in advance of any changes to its facilities that may affect the proper coordination of protective devices between the two systems.

6.10 Power Factor
The City of Penticton shall endeavor to regulate its load so that the Power Factor at each Point of Delivery will be no less than 90 percent, lagging.

6.11 Load Fluctuations
The City of Penticton shall maintain and operate its equipment, and shall endeavor to ensure that its customers equipment is operated in a manner that will not cause sudden fluctuations to FortisBC's line voltage, or introduce any influence into FortisBC's system deemed by FortisBC to threaten to disturb or disrupt its system or the plant or property of any other customer of FortisBC or of any other person.

6.12 Hazard to Property and Public Safety
Each of the Parties shall operate and maintain electrical plant within the Service Area so as to avoid hazard to the property of the other Party or danger to persons. To avoid hazard to property and to ensure public safety, the Parties agree that:

(a) All electrical generating facilities intended to be operated within the Service Area and in parallel with FortisBC's electrical system shall be installed only after FortisBC has been provided with full particulars of the facilities and FortisBC has given its written approval that the proposed operation of the facilities is satisfactory to FortisBC, acting reasonably. Upon completion, FortisBC shall be permitted to inspect the installation.

(b) The City of Penticton shall ensure that any parallel generating facility installed shall not backfeed into FortisBC's system or facilities unless the City of Penticton receives express permission in writing from FortisBC, which will not be unreasonably withheld.

(c) The City of Penticton shall ensure that all standby generation facilities within the Service Area to provide electrical service in the event of a disruption of service

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shall be installed so that they remain at all times electrically isolated from FortisBC'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 FortisBC's electrical system.

6.13 Permit to Install & Access

If any equipment or facilities associated with any Point of Delivery and belonging to a Party to this Agreement are or are to be located on the property of the other Party, a permit to install, test, maintain, inspect, replace, repair and operate during the term of this Agreement and to remove such equipment and facilities at the expiration of the Term, together with the right of entry to said property at all reasonable times is hereby granted by the other Party.

The rights hereby granted shall be exercised subject to prior notification and to any reasonable requirement of the granting Party necessary for the safety or security of that Party's facilities and employees and the continuity of that Party's operations.

6.14 Use of City Streets and Lanes

During the existence of this Agreement FortisBC shall have the right and easement to enter upon and use the streets and lanes within the boundaries of the City of Penticton for all purposes connected with the furnishing of electricity to the City of Penticton, and, without limiting generality, for the purpose of erecting, maintaining, repairing, replacing, removing or using poles, wires, meters, machinery and equipment, subject to the plan of any new erection of pole lines receiving such reasonable approvals as the City of Penticton deems necessary.

6.15 Drawings to be Provided

If either Party is required or permitted to install, test, maintain, inspect, replace, repair, remove or operate equipment on the property of the other, the owner of such property shall furnish the other Party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other Party of any subsequent modification which may affect the duties of the other Party in regard to such equipment, and furnish the other Party with accurate revised drawings, if possible.

6.16 Inspection of Facilities

Each Party may, for any reasonable purpose under this Agreement, inspect the other Party's electrical installation at any reasonable time after giving suitable notice. Such inspection, or failure to inspect, shall not render such Party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this Agreement. The inspecting Party shall observe written instruction and rules posted in facilities and such other necessary instructions or standards for inspection as the Parties agree to. Only those electric installations used in complying with the terms of this Agreement shall be subject to inspection.

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7. PLANNING AND OPERATING INFORMATION

7.01 Increases in Maximum Demand

The City of Penticton shall notify FortisBC in writing of any anticipated additional single load in excess of 5000 kVA resulting from a new customer or the increased load of an existing customer, providing as much advance notice of the increase as can be given in the circumstances. FortisBC shall endeavor to provide the service requested by the date the increase is intended to become effective, or as soon thereafter as is practicable.

7.02 Records and Forecasts

Each Party shall retain and make available upon request for the other Party log sheets, records of recording meters, and any other readily available information of an operational character relating to the electricity supplied under this Agreement, excluding non-public records of a financial or business nature relating to the City of Penticton's utility undertaking.

7.03 General Information Requests

The Parties agree to cooperate in the full exchange of such planning and operating information as may be reasonably necessary for the timely and efficient performance of the Parties' obligations or the exercise of rights under this Agreement. Such information shall be provided on a timely basis and no reasonable request shall be refused.

7.04 Load-Resource Forecast

By June 30 of each year, the Parties agree to exchange a five year forecast of loads and resources for their respective electrical systems including a forecast of their Maximum Demand at each Point of Delivery normalized for average weather conditions and shall also provide a forecast of energy consumption for each year. These forecasts shall include programs for resource acquisition, transmission and firm loads. The degree of detail in these forecasts shall be decided by mutual agreement.

7.05 Load from Previous Year

Before the end of February in each year, the City of Penticton shall provide FortisBC with a record of the number of customers and load by customer class for the previous calendar year.

7.06 Scheduled and Maintenance Outages

Each party shall submit to the other Party a list of outages scheduled for inspection, testing, preventative maintenance, corrective maintenance, repairs, replacement or improvements that might affect the delivery of electricity under this Agreement, providing as much advance notice of the outage as can be given in the circumstances. The Parties shall use reasonable efforts to keep such schedules current and to revise such schedules so as to minimize the impact on the other Party's system.

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8. METERING

8.01 Installation

FortisBC shall furnish, install and maintain the Metering System and the City of Penticton, in accordance with subsection 8.03, may furnish, install and maintain the Check Metering, each at their own expense, at the Points of Delivery, which shall accurately measure and record electricity within the limits prescribed by the federal Department of Consumer and Corporate Affairs ("Prescribed Limits") and pursuant to subsection 8.07.

8.02 Totalizing Metering

FortisBC shall also, at its expense, install totalizing metering to compensate for demand diversity at the different Points of Delivery.

8.03 Check Metering

Check Metering and connecting equipment and facilities to be furnished by the City of Penticton shall be satisfactory to FortisBC, and shall be installed in accordance with Good Utility Practice and in a manner satisfactory to FortisBC, acting reasonably.

8.04 Meter Tests and Adjustments

Unless otherwise agreed to by the Parties, each Party shall, at its own expense, arrange to have its meters tested by an inspector or accredited meter verifier authorized pursuant to the federal Electricity and Gas Inspection Act and regulations, as amended from time to time.

8.05 Inspection of Metering Equipment

Notwithstanding subsection 8.04, either Party may, after giving two days' notice, inspect in the presence of the other Party, the metering equipment installed in accordance with this subsection by the other Party, and may request that that metering equipment be tested by an inspector or authorized meter verifier.

If the result of any test performed pursuant to this subsection shows that any of the metering equipment is not recording within the Prescribed Limits, then the owner of that metering equipment shall pay for the costs of testing.

If after testing the metering equipment is found to be recording within the Prescribed Limits, the Party that made the request shall pay for the costs of testing.

8.06 Calculating the Amount to be Paid

The measurements recorded by the Metering System shall be used for calculating the amount to be paid for the electricity delivered to the City of Penticton, except in the following circumstances:

(a) if a totalizing meter is temporarily not in service or is found after testing to be not recording within the Prescribed Limits then the measurements recorded by the City of Penticton's totalizing meter shall be used to determine the total consumption and demand, or, in the absence of a City of Penticton totalizing meter, FortisBC's meters shall be used to determine the total consumption and

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demand taking into account established load diversity until FortisBC's totalizing meter has been recalibrated;

(b) if the Metering System is not in service or is found after testing to be not recording within the Prescribed Limits then the measurements recorded by the City of Penticton's totalizing meter or , in the absence of a totalizing meter, the City of Penticton's meters shall be used for calculating the amount to be paid for electricity delivered to the City of Penticton;

(c) if neither the Metering System nor the Check Metering are in service or are found after testing to be not recording within the Prescribed Limits then the amount of electricity delivered since the previous billing shall be estimated from the best information available.

8.07 Prescribed Limits

If at any time the testing described in subsections 8.04 and 8.05 shows that the metering equipment was not recording within the Prescribed Limits, and if such recordings were used for billing purposes, then the billings shall be adjusted as prescribed by the Electricity and Gas Inspection Act.

8.08 Access to Meters

Each Party shall have the right, by giving suitable notice, to enter the property of the other Party at all reasonable times for the purpose of reading any and all meters mentioned in this Agreement which are installed on such property.

9. INVOICES AND PAYMENT

9.01 Meter Reading

Meters shall be read at the end of each month. An accurate record of all meter readings shall be kept by FortisBC and shall be the basis for determination of all bills rendered for service.

9.02 Invoices and Payment

FortisBC shall render a billing invoice monthly pursuant to the terms of FortisBC's Electric Tariff, as amended from time to time.

9.03 Rates for Electricity

The City of Penticton shall pay for Services during the Term in accordance with the tariff applicable to the City of Penticton filed with the Commission, as amended from time to time.

9.04 Demand Period and Demand

For billing purposes, Demand Period means the period, expressed in minutes, over which meter readings are integrated to obtain the Demand, which is the power measured in kilovolt amperes (kVA), or multiples thereof, at the Point of Delivery. In this Agreement and for billing purposes, the Demand Period shall be a sixty minute clock hour interval.

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9.05 Billing Adjustments

If FortisBC suspends or reduces Service for reasons other than a request by the City of Penticton or an interruption of Service caused by the City of Penticton's system, and the suspension or reduction results in a peak Demand which would otherwise be used for billing purposes, the Demand in the Demand Period immediately following restoration of service may be reduced, by mutual agreement, to an estimate of what the Demand would have been if Service had not been suspended or reduced. The estimate shall be determined in consideration of weather conditions and previous load experience.

9.06 Late Payments

If the amount due on any invoice has not been paid in full after twenty calendar days from the billing date shown on the invoice, a late payment charge shall be applied to the unpaid balance, and the resulting amount will be shown and identified on the next invoice to be rendered. The late payment charge shall be as specified in FortisBC's Electric Tariff, as amended from time to time.

9.07 Taxes

In addition to payments for electricity, the City of Penticton shall pay to FortisBC the amount of any sales tax, goods and services tax, or any other tax or assessment levied by any competent taxing authority on any electricity delivered pursuant to this Agreement.

9.08 Payment of Accounts

The City of Penticton shall pay to FortisBC the amount of the billing within 20 calendar days from the date appearing on the invoice .

10. CONTINUITY OF SUPPLY

10.01 Standard of Performance

FortisBC shall perform the Services with skill, care, and diligence consistent with Good Utility Practice and consistent with directions from the Commission, including the quality performance standards, if any, approved by the Commission from time to time.

10.02 Interruptions and Defects in Service

FortisBC shall avoid interruption of delivery of electricity, but nevertheless shall not be liable to the City of Penticton for any loss or damage owing to failure to supply electricity, or owing to other abnormal conditions of supply resulting from force majeure as defined in subsection 12.01.

10.03 Suspension of Supply

Either Party shall have the right to demand the temporary suspension of, or to suspend temporarily, the delivery or taking of electricity, as the case may be, whenever necessary to safeguard life or property, or for the purpose of replacing, repairing or maintaining any of its apparatus, equipment, or works. Such reasonable notice of the suspension as the circumstances permit shall be given by one Party to the other.

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10.04 Discontinue Service

FortisBC may discontinue the supply of electricity to the City of Penticton at a Point of Delivery for the failure by the City of Penticton to commence remedial action acceptable to FortisBC, within 15 days of receiving notice from FortisBC, to correct the breach of any significant practice, term or condition to be observed or performed by the City of Penticton under this Agreement. FortisBC shall be under no obligation to resume service until the City of Penticton gives assurances satisfactory to FortisBC that the breach which resulted in the discontinuance shall not recur.

10.05 Obligations Continue

Discontinuance of Services by FortisBC pursuant to the provisions of this Agreement shall not relieve the City of Penticton of any obligation under this Agreement, or alter any of the obligations of the City of Penticton under this Agreement.

10.06 Other Remedies

FortisBC's right to discontinue the supply of electricity under this Agreement shall not operate to prevent FortisBC from pursuing, separately or concurrently, any other remedy it may have under this Agreement or by operation of law.

11. REMOVAL OF FACILITIES UPON TERMINATION

After the termination of this Agreement, FortisBC shall have the right to, and must expeditiously if requested by the City of Penticton, remove from the property owned or controlled by the City of Penticton any and all electrical apparatus and equipment which FortisBC owns and has installed on the property and FortisBC shall leave the property in good repair after such removal.

12. GENERAL PROVISIONS

12.01 Force Majeure

Neither Party to this Agreement shall be considered to be in default in the performance of any of its obligations under this Agreement to the extent that performance of those obligations is prevented or delayed by any cause which is beyond the reasonable control of the Party prevented or delayed by that cause. If either Party is delayed or prevented from its performance at any time by any act, omission or neglect of the other Party or its representatives, or by an act of God or the public enemy, or by expropriation or confiscation of facilities, compliance with any order of any governmental authority or order of a court of competent jurisdiction, acts of war, rebellion or sabotage, fire, flood, explosion, riot, strike or other labour dispute beyond the reasonable control of the Party or any unforeseeable cause beyond the control and without the fault and negligence of the Party, the Party so prevented or delayed shall give notice to the other Party of the cause of the prevention or delay but, notwithstanding giving of that notice, the Party shall promptly and diligently use reasonable efforts to remove the cause of the prevention or delay.

12.02 Notices

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Any notice, direction or other instrument required or permitted to be given under this Agreement in writing shall be sufficient in all respects if delivered, or if sent by fax, or if sent by prepaid registered post in Canada to the Parties at their respective addresses as they appear in subsection 12.03, or to any substitute address of which the Party sending notice has had notice in writing.

12.03 Addresses

Any notice, direction or other instrument shall be delivered or sent to the following addresses:

(a) To FortisBC:

FortisBC Inc.
1628 Dickson Avenue
Kelowna, BC VIY 9X1
Attention: Legal Department

(b) To the City of Penticton:

The Corporation of the City of Penticton
171 Main Street
Penticton, BC V2A 5A9
Attention: Administrator

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12.04 Dates

Any notice, direction, or other instrument shall be deemed to have been received on the following dates if,

(a) sent by fax, on the business day next following the date of transmission.

(b) delivered, on the business day next following the date of delivery.

(c) 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, directions or other instrument shall only be deemed to be effective if delivered or sent by fax.

12.05 Disputes

If any difference or dispute occurs regarding any matter arising under this Agreement, either Party may request that the Commission settle the difference or dispute. If the Commission declines to settle the dispute then the dispute shall be arbitrated pursuant to the Commercial Arbitration Act of British Columbia.

12.06 Invalidity

If any provision of this Agreement or the application of any provision to any Party or circumstance is declared or held to be wholly or partially invalid, this Agreement shall be interpreted as if the invalid provision had not been a part hereof so that the invalidity shall not affect the validity of the remainder which shall be construed as if this Agreement had been executed without the invalid portion. FortisBC and the City of Penticton shall, either independently, jointly or in concert with other wholesale customer's of FortisBC, make all reasonable efforts to validate any portion of this Agreement declared or held to be invalid.

12.07 Headings

The headings in this Agreement have been inserted for convenience of reference only, and shall not affect the construction or interpretation of this Agreement.

12.08 Enurement

This Agreement shall be binding upon and shall enure to the benefit of the Parties hereto and of their respective successors and assigns.

12.09 Governing Law

Notwithstanding anything to the contrary in this Agreement, FortisBC shall comply fully with all applicable federal and provincial has and municipal laws of general application (including bylaws) in effect from time to time.

12.10 Entire Agreement

This Agreement and the Appendices attached hereto are intended by the Parties to be the final expression of their agreement and are intended also as a complete and exclusive statement of the terms of this Agreement.

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12.11 Commission Approval

This Agreement and all the terms and conditions contained in it shall be subject to the provisions of the Utilities Commission Act of British Columbia, as amended or re-enacted from time to time and to the jurisdiction of the Commission and the parties agree to make such amendments to the agreement as required or ordered by the Commission from time to time.

IN WITNESS WHEREOF the Parties have executed this Agreement by their duly authorized signatories.

The Seal of THE CORPORATION OF THE CITY OF PENTICTON was hereunto affixed the 9th day of May, 2006 in the presence of

Signature

Gerald Jacques Kimberley, Mayor

Print Name

Title

Signature

Cathy Ingram, City Clerk

Print Name

Title

Council Approval

Res. No. 229/2006

Date APRIL 3, 2006

FORTISBC INC.

Signature

Michael Mulcahy

Print Name

Vice President, Corporate &

Title

Customer Services

Accepted for filing: JUN 19 2008

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Appendix A to the Agreement for the Supply of Electricity - Wholesale Service between FortisBC Inc. and The Corporation of the City of Penticton

City of Penticton - Points of Delivery

1. **Huth Avenue Substation**

Description: 13 kV supply at Huth Substation

Nominal Voltage Supplied: 13 kV

Demand Limit:	Summer	32 MVA
	Winter	40 MVA

2. **Huth Avenue Substation**

Description: Load side of billing C.T.'s on 8 kV Feeder to City of Penticton

Nominal Voltage Supplied: 8.3 kV

Demand Limit:	Summer	10.5 MVA
	Winter	13.6 MVA

3. **Waterford Substation**

Description: 13kV Supply at Waterford Substation

Nominal Voltage Supplied: 13 kV

Demand Limit:	Summer	32 MVA
	Winter	40 MVA

4. **Westminster Substation**

Description: Load side of FortisBC's 2000 Amp disconnect on 8 kV Feeder to City

Nominal Voltage Supplied: 8.3 kV

Demand Limit:	Summer	31 MVA
	Winter	38 MVA

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5. R.G. Anderson Substation

Description: Load side of FortisBC's 8 kV disconnect switch on 8 kV Feeder to City

Nominal Voltage Supplied: 8.3 kV

Demand Limit:	Summer	20 MVA
	Winter	25 MVA

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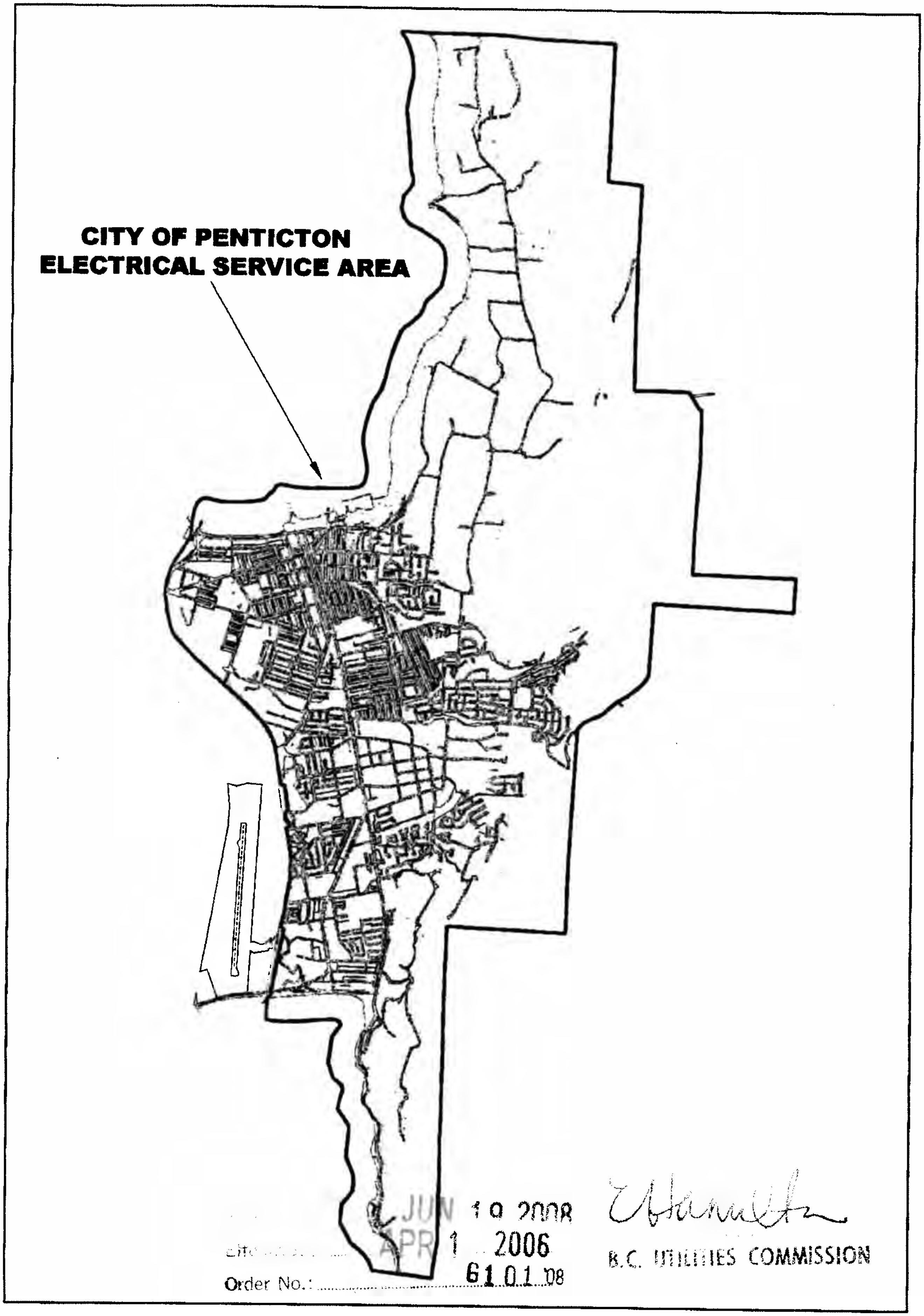
CITY OF PENTICTON
ELECTRICAL SERVICE AREA
JUN 19 2008
APR 1 2006
Order No.: 61 01 08
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FORTISBC

AGREEMENT FOR THE SUPPLY OF ELECTRICITY WHOLESALE SERVICE

LWD05003

BETWEEN

The Corporation of the District of Summerland
13211 Henry Avenue
Summerland, BC V0H 1Z0

And

FortisBC Inc.
1628 Dickson Avenue
Kelowna, BC V1Y 9X1

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Agreement for the Supply of Electricity Wholesale Service

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Accepted for filing: JUN 1 5 2006

Effective: APR 1 2006

Order No.: G1 01 08

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B.C. UTILITIES COMMISSION

THIS AGREEMENT is made as of the 1st day of April 2006.

BETWEEN:

FORTISBC INC., a corporation established by a special Act of the Legislature of the Province of British Columbia, having its head office in the City of Kelowna in the Province of British Columbia,. ("FortisBC"),

AND:

THE CORPORATION OF THE DISTRICT OF SUMMERLAND, a company incorporated under the laws of British Columbia and having an office in the District of Summerland, in the Province of British Columbia. ("Summerland"),

WHEREAS FortisBC is a supplier of electricity in the southern interior region of the Province of British Columbia;

AND WHEREAS Summerland wishes to purchase electricity from FortisBC for its own use and for resale to Summerland's customers within Summerland's Service Area as hereinafter described;

AND WHEREAS both FortisBC and Summerland have agreed to the principles set forth in the Proposed Settlement Agreement resulting from the British Columbia Utilities Commission Decision dated March 10, 1999.

Accepted for filing: JUN 19 2006 E Hamilton
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NOW THEREFORE this Agreement witnesses that in consideration of the terms and conditions hereinafter set forth the Parties covenant and agree as follows:

1. DEFINITIONS

In this Agreement:

(a) **"Check Metering"** means any measurement device or system installed, owned and maintained by Summerland to check the measurements and calculations carried out by the Metering System.

(b) **"Commission"** means the British Columbia Utilities Commission.

(c) **"Commodity Service"** means the supply of power, expressly excluding the services set forth in the Transmission Services Tariff, to Summerland by a third party and may include full or partial supply of the load requirements of Summerland.

(d) **"Demand"** has the meaning given to it in subsection 9.04.

(e) **"Demand Limit"** means the capability of FortisBC's facilities at each of the Points of Delivery, specified in Appendix A attached hereto.

(f) **"Demand Period"** has the meaning given to it in subsection 9.04.

(g) **"Good Utility Practice"** means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the WECC region.

(h) **"Maximum Demand"** means the highest clock hour of taking of electricity by Summerland recorded in kilovolt-amperes by FortisBC from time to time.

(i) **"Metering System"** means the measurement device or system installed, owned and maintained by FortisBC used to determine Summerland's electricity consumption.

(j) **"Parties"** means both FortisBC and Summerland.

(k) **"Point of Delivery"** means the point or points at which Summerland's distribution system attaches to FortisBC's facilities, as specifically described in Appendix A attached hereto.

(l) **"Power Factor"** means the percentage determined by dividing Summerland's demand measured in kilowatts by the same demand measured in kilovolt-amperes.

(m) **"APSA"** means the Access Principles Settlement Agreement, also known as the Proposed Settlement Agreement, as amended from time to time, attached as Appendix A to the Commission Order Number G-27-99 dated March 10, 1999 in the matter of the Access Principles Application .

(n) **"Service Area"** means Summerland's service area, the boundaries of which are shown by the red line on the map identified as Summerland's Electrical Service Boundaries, attached hereto as Appendix B and shall include any area(s) added from time to time by the municipality.

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(o) **"Services"** means the supply and delivery of power to Summerland by FortisBC under this Agreement.

(p) **"Term"** means the period defined by subsection 2.01 herein.

(q) **"Transmission Services Tariff"** means the tariff as approved from time to time by the Commission for the use by a third party supplier to deliver power to Summerland or by Summerland to deliver power to a third party on the transmission and distribution facilities of FortisBC, including ancillary services required for the delivery of power.

(r) **"WECC"** means Western Electricity Coordinating Council or a successor organization.

2. TERM OF AGREEMENT

2.01 Term

This Agreement shall be effective as of April 1, 2006 and shall continue for a term of four years thereafter, terminating on March 31, 2010. Upon mutual agreement in writing by both parties, this agreement may be renewed prior to March 31, 2010 for an additional five year term on the same terms and conditions.

2.02 Early Termination

If Summerland elects to engage any third party supplier to perform the Commodity Services and notice as provided for in the APSA is given to FortisBC Summerland may terminate this Agreement prior to expiry of the Term. If this Agreement terminates pursuant to this subsection, Summerland may then be liable to pay such costs, including stranded costs, if any, as directed by the Commission.

3. Access Principles Settlement Agreement

3.01 Access Principles Settlement Agreement Rights

Nothing contained in this Agreement shall be construed as affecting in any way the rights of either Party as set forth in the APSA nor as affecting in any way the rights of either Party to unilaterally make application to the Commission for further directions or orders from the Commission related to the terms and conditions of the APSA.

3.02 Regulatory Principles

If any provision of this Agreement is declared by the Commission to be inconsistent with the regulatory principles set forth in the APSA, the Parties shall amend that provision in such reasonable manner as achieves the intention of the declaration of the Commission. In the event the Parties cannot agree on such amendments, either Party shall be entitled to seek further direction from the Commission and the Parties hereby agree to be bound by such direction from the Commission.

Accepted for filing: JUN 19 2006

Effective: APR 1 2006

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4. CONDITIONS OF SUPPLY

4.01 Supply of Electricity

During the term of this Agreement, except in an emergency described in subsection 6.03, FortisBC shall supply up to the Demand Limit electricity required by Summerland solely for its own use and for supplying the needs of its customers within the Service Area. FortisBC shall supply electricity to the Points of Delivery through suitable plant and equipment in accordance with Good Utility Practice on a continuous basis, except as provided in this Agreement. The responsibility of FortisBC for the delivery of electricity to Summerland shall cease at the Points of Delivery.

4.02 Duty to Act Prudently in Arranging for Electricity Supply

Notwithstanding the provisions of subsection 4.03 and 4.04 FortisBC has a duty not to be imprudent in arranging for the supply of electricity required pursuant to subsection 4.01 of this Agreement and FortisBC will, subject to subsections 4.04 and 4.09, be liable to Summerland for any loss, injury, damage or expense caused to Summerland if the British Columbia Utilities Commission determines that FortisBC has failed to meet its duty not to be imprudent.

4.03 Failure to Deliver

At any time during an actual or anticipated shortage of electricity, or in the event of a breakdown or failure of generating, transmitting or distributing plant, lines or equipment, or in order to comply with the requirements of any law, FortisBC shall have the right to curtail or discontinue the supply of electricity to Summerland or reduce the voltage or frequency of the electricity supplied. To the extent that it is practical and reasonable, FortisBC will not unduly discriminate in favour of or against Summerland in the supply of electricity.

4.04 Interruptions and Defect in Service

The District of Summerland acknowledges and agrees that FortisBC's responsibility and liability for loss, injury, damage or expense caused by or resulting from any interruption, termination, failure or defect in the supply of electricity by FortisBC pursuant to this Agreement is limited by the terms and conditions of FortisBC's Electric Tariff B.C.U.C. No. 1 (including, without limitation, Section 8.1 thereof), as approved from time to time by the Commission.

4.05 Commodity Services

Summerland shall have the rights set forth in the APSA to purchase power from a third party supplier and to meet part or all of its load requirements from Commodity Services.

4.06 Limits on Other Supply

Unless Summerland has exercised its rights pursuant to the APSA, Summerland shall, during the Term, only purchase electricity from FortisBC and Summerland's own customers for its own use and the use of its customers within the Service Area. Summerland may obtain up to 15 MWs of electricity from new generation owned and operated by Summerland or Summerland's customers.

Accepted for filing: JUN 19 2008

Effective: APR 1 2006

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4.07 Retail Access on Summerland's Facilities

Summerland shall give notice, consistent with the APSA requirements, in writing to FortisBC prior to providing Summerland's transmission and distribution services for the direct delivery of third party supply to a customer of Summerland.

4.08 Sales out of Service Area

If service to a customer outside or within the Service Area would require duplication of existing electrical plant which duplication could be avoided, then the Party that has the right to serve that customer pursuant to this Agreement may consent to the other Party serving that customer, such consent not to be unreasonably delayed or withheld.

4.09 No Liability for Consequential Damages

Neither Party, nor its directors, officers, employees or agents, will be liable to the other Party, or its directors, officers, employees or agents, in contract, tort, warranty, strict liability or any other legal theory for any indirect, consequential, incidental, punitive or exemplary damages arising under or in connection with this Agreement.

Accepted for filing: JUN 19 2008
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5. CONDITIONS OF SERVICE

5.01 Supply Characteristics

The electricity to be supplied to Summerland shall be three-phase alternating current, having a nominal frequency of 60 hertz and the nominal voltages designated in Appendix A for the Points of Delivery, as amended from time to time.

FortisBC is a signatory of the WECC Reliability Management System (RMS) Agreement. FortisBC is committed to the service reliability standards detailed in this document and is liable for financial sanctions that WECC can impose for non-adherence to those standards.

The Commission may exercise its authority by whatever means it deems appropriate in the event that frequency or voltage excursions occur that could reasonably have been prevented.

5.02 Underground Facilities

When Summerland requests the construction or installation of underground facilities, Summerland shall be responsible for the difference between the cost of constructing or installing the facilities underground and the cost of constructing or installing similar facilities above ground.

5.03 Ownership of Facilities

Notwithstanding the payment of any contribution by Summerland toward the cost of facilities pursuant to subsection 5.02, FortisBC shall retain full title to all facilities.

5.04 Revenue Guarantee

Summerland may be required to provide a revenue guarantee if FortisBC's facilities must be upgraded significantly to meet a proposed increase in Summerland's load in excess of 5000 kVA resulting from either a new Summerland customer or the increased load of an existing Summerland customer. The revenue guarantee will be equal to the cost of upgrading the facilities and will be refunded, with interest, in equal installments over a period of five years at the end of each year of continued service to that customer at the increased load. The revenue guarantee shall be in the form of cash, surety bond or other form of security satisfactory to FortisBC.

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6. INTERCONNECTED OPERATION

6.01 Obligation of FortisBC

The maintenance by FortisBC of the agreed frequency and voltage at the Points of Delivery, set out in Appendix A, shall constitute delivery of electricity under this Agreement, whether or not any electricity is taken by Summerland, and shall, subject to subsection 10.01 constitute the complete discharge by FortisBC of its obligations to Summerland for Services.

6.02 Use of Facilities

Each Party shall cooperate with the other to secure the most efficient use of the plant and equipment of the other Party, which may include wheeling power through the other Party's transmission and distribution circuits to facilitate supply to either Party or its customers.

6.03 Exceeding Demand Limit

Summerland shall not take electricity in excess of the Demand Limit of a Point of Delivery without the prior written consent of FortisBC, unless an emergency condition requires that Summerland take in excess of the Demand Limit, and then only for the duration of the emergency condition. Summerland shall immediately advise FortisBC when such an emergency condition occurs. Summerland shall reduce immediately its use of electricity to the Demand Limit for that Point of Delivery or to a specified limit above the Demand Limit upon the oral or written request of FortisBC.

6.04 Restrict or Suspend Service

If Summerland fails to comply with the request of FortisBC pursuant to the previous paragraph, FortisBC may, when necessary in the opinion of FortisBC, restrict or suspend the supply of electricity to Summerland at the Point of Delivery summarily without further notice.

6.05 Avoidance of Excess Loads

Summerland shall provide for interconnection of its lines so as to transfer and arrange the loads taken at each Point of Delivery to balance as far as is practicable the loads at each Point of Delivery given the Demand Limit at each Point of Delivery.

6.06 Maintenance of Adequate Supply Capability

If at any time, except in an emergency condition described in subsection 6.03, Summerland notifies FortisBC that it has taken electricity in excess of 95 percent of the Demand Limit of a Point(s) of Delivery, FortisBC shall take appropriate measures at no cost to Summerland to increase the supply capability at the Point(s) of Delivery to bring Summerland's anticipated future demand to or below 95 percent of the Demand Limit.

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6.07 Summerland's Facilities

Summerland shall be responsible for designing, constructing, installing and maintaining all auxiliary and interconnecting equipment on Summerland's side of the Point of Delivery and Summerland shall have ownership rights in all such auxiliary and interconnection equipment. FortisBC shall have no fiscal or other responsibilities in ensuring that such Summerland facilities meet the requirements of Summerland's customers.

6.08 Installation of Facilities

All electrical facilities owned by Summerland from the Points of Delivery up to and including Summerland's overload and overcurrent protection and isolation devices shall be approved and coordinated in a manner satisfactory to FortisBC, and may be inspected by FortisBC from time to time. Notwithstanding the foregoing, FortisBC shall not require a higher standard for Summerland's electrical facilities than the standard of FortisBC facilities supplying that portion of Summerland's facilities.

6.09 Coordination of Protective Devices

Either Party shall notify the other Party in advance of any changes to its facilities that may affect the proper coordination of protective devices between the two systems.

6.10 Power Factor

Summerland shall endeavor to regulate its load so that the Power Factor at each Point of Delivery will be no less than 90 percent, lagging.

6.11 Load Fluctuations

Summerland shall maintain and operate its equipment, and shall endeavor to ensure that its customers equipment is operated in a manner that will not cause sudden fluctuations to FortisBC's line voltage, or introduce any influence into FortisBC's system deemed by FortisBC to threaten to disturb or disrupt its system or the plant or property of any other customer of FortisBC or of any other person.

6.12 Hazard to Property and Public Safety

Each of the Parties shall operate and maintain electrical plant within the Service Area so as to avoid hazard to the property of the other Party or danger to persons. To avoid hazard to property and to ensure public safety, the Parties agree that:

(a) All electrical generating facilities intended to be operated within the Service Area and in parallel with FortisBC's electrical system shall be installed only after FortisBC has been provided with full particulars of the facilities and FortisBC has given its written approval that the proposed operation of the facilities is satisfactory to FortisBC, acting reasonably. Upon completion, FortisBC shall be permitted to inspect the installation.

(b) Summerland shall ensure that any parallel generating facility installed shall not backfeed into FortisBC's system or facilities unless Summerland receives express permission in writing from FortisBC, which will not be unreasonably withheld.

(c) Summerland shall ensure that all standby generation facilities within the Service Area to provide electrical service in the event of a disruption of service shall be installed so that they remain at all times electrically isolated from FortisBC's

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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 FortisBC's electrical system.

6.13 Permit to Install & Access

If any equipment or facilities associated with any Point of Delivery and belonging to a Party to this Agreement are or are to be located on the property of the other Party, a permit to install, test, maintain, inspect, replace, repair and operate during the term of this Agreement and to remove such equipment and facilities at the expiration of the Term, together with the right of entry to said property at all reasonable times is hereby granted by the other Party.

The rights hereby granted shall be exercised subject to prior notification and to any reasonable requirement of the granting Party necessary for the safety or security of that Party's facilities and employees and the continuity of that Party's operations.

6.14 Use of City Streets and Lanes

During the existence of this Agreement FortisBC shall have the right and easement to enter upon and use the streets and lanes within the boundaries of Summerland for all purposes connected with the furnishing of electricity to Summerland, and, without limiting generality, for the purpose of erecting, maintaining, repairing, replacing, removing or using poles, wires, meters, machinery and equipment, subject to the plan of any new erection of pole lines receiving such reasonable approvals as Summerland deems necessary.

6.15 Drawings to be Provided

If either Party is required or permitted to install, test, maintain, inspect, replace, repair, remove or operate equipment on the property of the other, the owner of such property shall furnish the other Party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other Party of any subsequent modification which may affect the duties of the other Party in regard to such equipment, and furnish the other Party with accurate revised drawings, if possible.

6.16 Inspection of Facilities

Each Party may, for any reasonable purpose under this Agreement, inspect the other Party's electrical installation at any reasonable time after giving suitable notice. Such inspection, or failure to inspect, shall not render such Party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this Agreement. The inspecting Party shall observe written instruction and rules posted in facilities and such other necessary instructions or standards for inspection as the Parties agree to. Only those electric installations used in complying with the terms of this Agreement shall be subject to inspection.

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7. PLANNING AND OPERATING INFORMATION

7.01 Increases in Maximum Demand

Summerland shall notify FortisBC in writing of any anticipated additional single load in excess of 5000 kVA resulting from a new customer or the increased load of an existing customer, providing as much advance notice of the increase as can be given in the circumstances. FortisBC shall endeavor to provide the service requested by the date the increase is intended to become effective, or as soon thereafter as is practicable.

7.02 Records and Forecasts

Each Party shall retain and make available upon request for the other Party log sheets, records of recording meters, and any other readily available information of an operational character relating to the electricity supplied under this Agreement, excluding non-public records of a financial or business nature relating to Summerland's utility undertaking.

7.03 General Information Requests

The Parties agree to cooperate in the full exchange of such planning and operating information as may be reasonably necessary for the timely and efficient performance of the Parties' obligations or the exercise of rights under this Agreement. Such information shall be provided on a timely basis and no reasonable request shall be refused.

7.04 Load-Resource Forecast

By June 30 of each year, the Parties agree to exchange a five year forecast of loads and resources for their respective electrical systems including a forecast of their Maximum Demand at each Point of Delivery normalized for average weather conditions and shall also provide a forecast of energy consumption for each year. These forecasts shall include programs for resource acquisition, transmission and firm loads. The degree of detail in these forecasts shall be decided by mutual agreement.

7.05 Load from Previous Year

Before the end of February in each year, Summerland shall provide FortisBC with a record of the number of customers and load by customer class for the previous calendar year.

7.06 Scheduled and Maintenance Outages

Each party shall submit to the other Party a list of outages scheduled for inspection, testing, preventative maintenance, corrective maintenance, repairs, replacement or improvements that might affect the delivery of electricity under this Agreement, providing as much advance notice of the outage as can be given in the circumstances. The Parties shall use reasonable efforts to keep such schedules current and to revise such schedules so as to minimize the impact on the other Party's system.

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8. METERING

8.01 Installation

FortisBC shall furnish, install and maintain the Metering System and Summerland, in accordance with subsection 8.03, may furnish, install and maintain the Check Metering, each at their own expense, at the Points of Delivery, which shall accurately measure and record electricity within the limits prescribed by the federal Department of Consumer and Corporate Affairs ("Prescribed Limits") and pursuant to subsection 8.07.

8.02 Totalizing Metering

FortisBC shall also, at its expense, install totalizing metering to compensate for demand diversity at the different Points of Delivery.

8.03 Check Metering

Check Metering and connecting equipment and facilities to be furnished by Summerland shall be satisfactory to FortisBC, and shall be installed in accordance with Good Utility Practice and in a manner satisfactory to FortisBC, acting reasonably.

8.04 Meter Tests and Adjustments

Unless otherwise agreed to by the Parties, each Party shall, at its own expense, arrange to have its meters tested by an inspector or accredited meter verifier authorized pursuant to the federal Electricity and Gas Inspection Act and regulations, as amended from time to time.

8.05 Inspection of Metering Equipment

Notwithstanding subsection 8.04, either Party may, after giving two days' notice, inspect in the presence of the other Party, the metering equipment installed in accordance with this subsection by the other Party, and may request that that metering equipment be tested by an inspector or authorized meter verifier.

If the result of any test performed pursuant to this subsection shows that any of the metering equipment is not recording within the Prescribed Limits, then the owner of that metering equipment shall pay for the costs of testing.

If after testing the metering equipment is found to be recording within the Prescribed Limits, the Party that made the request shall pay for the costs of testing.

8.06 Calculating the Amount to be Paid

The measurements recorded by the Metering System shall be used for calculating the amount to be paid for the electricity delivered to Summerland, except in the following circumstances:

(a) if a totalizing meter is temporarily not in service or is found after testing to be not recording within the Prescribed Limits then the measurements recorded by Summerland's totalizing meter shall be used to determine the total consumption and demand, or, in the absence of a Summerland totalizing meter, FortisBC's meters shall be used to determine the total consumption and demand taking into

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account established load diversity until FortisBC's totalizing meter has been recalibrated;

(b) if the Metering System is not in service or is found after testing to be not recording within the Prescribed Limits then the measurements recorded by Summerland's totalizing meter or , in the absence of a totalizing meter, Summerland's meters shall be used for calculating the amount to be paid for electricity delivered to Summerland;

(c) if neither the Metering System nor the Check Metering are in service or are found after testing to be not recording within the Prescribed Limits then the amount of electricity delivered since the previous billing shall be estimated from the best information available.

8.07 Prescribed Limits

If at any time the testing described in subsections 8.04 and 8.05 shows that the metering equipment was not recording within the Prescribed Limits, and if such recordings were used for billing purposes, then the billings shall be adjusted as prescribed by the Electricity and Gas Inspection Act.

8.08 Access to Meters

Each Party shall have the right, by giving suitable notice, to enter the property of the other Party at all reasonable times for the purpose of reading any and all meters mentioned in this Agreement which are installed on such property.

9. INVOICES AND PAYMENT

9.01 Meter Reading

Meters shall be read at the end of each month. An accurate record of all meter readings shall be kept by FortisBC and shall be the basis for determination of all bills rendered for service.

9.02 Invoices and Payment

FortisBC shall render a billing invoice monthly pursuant to the terms of FortisBC's Electric Tariff, as amended from time to time.

9.03 Rates for Electricity

Summerland shall pay for Services during the Term in accordance with the tariff applicable to Summerland filed with the Commission, as amended from time to time.

9.04 Demand Period and Demand

For billing purposes, Demand Period means the period, expressed in minutes, over which meter readings are integrated to obtain the Demand, which is the power measured in kilovolt amperes (kVA), or multiples thereof, at the Point of Delivery. In this Agreement and for billing purposes, the Demand Period shall be a sixty minute clock hour interval.

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9.05 Billing Adjustments

If FortisBC suspends or reduces Service for reasons other than a request by Summerland or an interruption of Service caused by Summerland's system, and the suspension or reduction results in a peak Demand which would otherwise be used for billing purposes, the Demand in the Demand Period immediately following restoration of service may be reduced, by mutual agreement, to an estimate of what the Demand would have been if Service had not been suspended or reduced. The estimate shall be determined in consideration of weather conditions and previous load experience.

9.06 Late Payments

If the amount due on any invoice has not been paid in full after twenty calendar days from the billing date shown on the invoice, a late payment charge shall be applied to the unpaid balance, and the resulting amount will be shown and identified on the next invoice to be rendered. The late payment charge shall be as specified in FortisBC's Electric Tariff, as amended from time to time.

9.07 Taxes

In addition to payments for electricity, Summerland shall pay to FortisBC the amount of any sales tax, goods and services tax, or any other tax or assessment levied by any competent taxing authority on any electricity delivered pursuant to this Agreement.

9.08 Payment of Accounts

Summerland shall pay to FortisBC the amount of the billing within 20 calendar days from the date appearing on the invoice .

10. CONTINUITY OF SUPPLY

10.01 Standard of Performance

FortisBC shall perform the Services with skill, care, and diligence consistent with Good Utility Practice and consistent with directions from the Commission, including the quality performance standards, if any, approved by the Commission from time to time.

10.02 Interruptions and Defects in Service

FortisBC shall avoid interruption of delivery of electricity, but nevertheless shall not be liable to Summerland for any loss or damage owing to failure to supply electricity, or owing to other abnormal conditions of supply resulting from force majeure as defined in subsection 12.01.

10.03 Suspension of Supply

Either Party shall have the right to demand the temporary suspension of, or to suspend temporarily, the delivery or taking of electricity, as the case may be, whenever necessary to safeguard life or property, or for the purpose of replacing, repairing or maintaining any of its apparatus, equipment, or works. Such reasonable notice of the suspension as the circumstances permit shall be given by one Party to the other.

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10.04 Discontinue Service

FortisBC may discontinue the supply of electricity to Summerland at a Point of Delivery for the failure by Summerland to commence remedial action acceptable to FortisBC, within 15 days of receiving notice from FortisBC, to correct the breach of any significant practice, term or condition to be observed or performed by Summerland under this Agreement. FortisBC shall be under no obligation to resume service until Summerland gives assurances satisfactory to FortisBC that the breach which resulted in the discontinuance shall not recur.

10.05 Obligations Continue

Discontinuance of Services by FortisBC pursuant to the provisions of this Agreement shall not relieve Summerland of any obligation under this Agreement, or alter any of the obligations of Summerland under this Agreement.

10.06 Other Remedies

FortisBC's right to discontinue the supply of electricity under this Agreement shall not operate to prevent FortisBC from pursuing, separately or concurrently, any other remedy it may have under this Agreement or by operation of law.

11. REMOVAL OF FACILITIES UPON TERMINATION

After the termination of this Agreement, FortisBC shall have the right to, and must expeditiously if requested by Summerland, remove from the property owned or controlled by Summerland any and all electrical apparatus and equipment which FortisBC owns and has installed on the property and FortisBC shall leave the property in good repair after such removal.

12. GENERAL PROVISIONS

12.01 Force Majeure

Neither Party to this Agreement shall be considered to be in default in the performance of any of its obligations under this Agreement to the extent that performance of those obligations is prevented or delayed by any cause which is beyond the reasonable control of the Party prevented or delayed by that cause. If either Party is delayed or prevented from its performance at any time by any act, omission or neglect of the other Party or its representatives, or by an act of God or the public enemy, or by expropriation or confiscation of facilities, compliance with any order of any governmental authority or order of a court of competent jurisdiction, acts of war, rebellion or sabotage, fire, flood, explosion, riot, strike or other labour dispute beyond the reasonable control of the Party or any unforeseeable cause beyond the control and without the fault and negligence of the Party, the Party so prevented or delayed shall give notice to the other Party of the cause of the prevention or delay but, notwithstanding giving of that notice, the Party shall promptly and diligently use reasonable efforts to remove the cause of the prevention or delay.

12.02 Notices

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Any notice, direction or other instrument required or permitted to be given under this Agreement in writing shall be sufficient in all respects if delivered, or if sent by fax, or if sent by prepaid registered post in Canada to the Parties at their respective addresses as they appear in subsection 12.03, or to any substitute address of which the Party sending notice has had notice in writing.

12.03 Addresses

Any notice, direction or other instrument shall be delivered or sent to the following addresses:

(a) To FortisBC:

FortisBC Inc.
1628 Dickson Avenue
Kelowna, BC VlY 9X1
Attention: Legal Department

(b) To Summerland:

The Corporation of the District of Summerland
13211 Henry Avenue
Summerland, BC V0H 1Z0
Attention: Administrator

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12.04 Dates

Any notice, direction, or other instrument shall be deemed to have been received on the following dates if,

(a) sent by fax, on the business day next following the date of transmission.

(b) delivered, on the business day next following the date of delivery.

(c) 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, directions or other instrument shall only be deemed to be effective if delivered or sent by fax.

12.05 Disputes

If any difference or dispute occurs regarding any matter arising under this Agreement, either Party may request that the Commission settle the difference or dispute. If the Commission declines to settle the dispute then the dispute shall be arbitrated pursuant to the Commercial Arbitration Act of British Columbia.

12.06 Invalidity

If any provision of this Agreement or the application of any provision to any Party or circumstance is declared or held to be wholly or partially invalid, this Agreement shall be interpreted as if the invalid provision had not been a part hereof so that the invalidity shall not affect the validity of the remainder which shall be construed as if this Agreement had been executed without the invalid portion. FortisBC and Summerland shall, either independently, jointly or in concert with other wholesale customer's of FortisBC, make all reasonable efforts to validate any portion of this Agreement declared or held to be invalid.

12.07 Headings

The headings in this Agreement have been inserted for convenience of reference only, and shall not affect the construction or interpretation of this Agreement.

12.08 Enurement

This Agreement shall be binding upon and shall enure to the benefit of the Parties hereto and of their respective successors and assigns.

12.09 Governing Law

Notwithstanding anything to the contrary in this Agreement, FortisBC shall comply fully with all applicable federal and provincial has and municipal laws of general application (including bylaws) in effect from time to time.

12.10 Entire Agreement

This Agreement and the Appendices attached hereto are intended by the Parties to be the final expression of their agreement and are intended also as a complete and exclusive statement of the terms of this Agreement.

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12.11 Commission Approval

This Agreement and all the terms and conditions contained in it shall be subject to the provisions of the Utilities Commission Act of British Columbia, as amended or re-enacted from time to time and to the jurisdiction of the Commission and the parties agree to make such amendments to the agreement as required or ordered by the Commission from time to time.

IN WITNESS WHEREOF the Parties have executed this Agreement by their duly authorized signatories.

The Seal of THE CORPORATION OF THE DISTRICT OF SUMMERLAND was hereunto affixed the 31st day of March, 2006 in the presence of

Signature

Print Name David E. Gregory, Mayor

Title

Signature

Print Name Gillian D. Matthews, Municipal Clerk

Title

FORTISBC INC.

Signature

Print Name Michael Mulcahy

Title Vice President, Customer & Corporate Services

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Appendix A to the Agreement for the Supply of Electricity - Wholesale Service between FortisBC Inc. and The Corporation of the District of Summerland

District of Summerland - Points of Delivery

1. Trout Creek Substation

Description: Load side of Billing C.T.'s on 8kV Bus supplied by T1 transformer

Nominal Voltage Supplied: 8.3kV

Demand Limit:	Summer	6 MVA
	Winter	10 MVA

2. Summerland Substation

Description: Load side of FortisBC's 2000 Amp Disconnect Switch on the 8 kV Bus Supplied by T2 transformer

Nominal Voltage Supplied: 8.3 kV

Demand Limit:	Summer	16 MVA
	Winter	20 MVA

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District of Summerland

Accepted: JUN 19 2008
Eff. Date: APR 1 2006
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B.C. UTILITIES COMMISSION

OWEN • BIRD
LAW CORPORATION

PO Box 49130
Three Bentall Centre
2900-595 Burrard Street
Vancouver, BC
Canada V7X 1J5

Telephone 604 688-0401
Fax 604 688-2827
Website www.owenbird.com

Direct Line: 604 691-7557
Direct Fax: 604 632-4482
E-mail: cweafer@owenbird.com
Our File: 24265/0003

November 23, 2009

VIA ELECTRONIC MAIL

FortisBC Inc.
Suite 100 – 1975 Springfield Road
Kelowna, BC
V1Y 7V7

Attention: Dennis Swanson, Director, Regulatory Affairs

Dear Sirs/Mesdames:

Re: Agreement for the Supply of Electricity Wholesale Services made as of the 1st day of November, 2004 between FortisBC Inc. and the City of Kelowna (the "Wholesale Agreement")

Enclosed please find a copy of your letter dated November 2, 2009 agreed to and accepted by Shawn Shepherd on behalf of the City of Kelowna with respect to the above-noted matter.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jlb
Enclosure

CPW20111

FORTISBC

Dennis Swanson
Director, Regulatory Affairs

FortisBC Inc.
Suite 100 - 1975 Springfield Road
Kelowna, BC V1Y 7V7
Ph: (250) 717-0890
Fax: 1-866-335-6295
regulatory@fortisbc.com
www.fortisbc.com

November 2, 2009

City of Kelowna
City Hall
1435 Water Street
Kelowna, B.C.
V1Y 1J4

Attention: City Clerk

Dear Sirs/Mesdames:

Re: ***Agreement for the Supply of Electricity Wholesale Service made as of the 1st day of November, 2004 between FortisBC Inc. and the City of Kelowna (the "Wholesale Service Agreement")***

We write to confirm that FortisBC Inc. and City of Kelowna have agreed that the term of the Wholesale Service Agreement shall be extended for an additional period commencing on November 1, 2009 and terminating on February 19, 2010, unless earlier terminated as set out in the Wholesale Service Agreement, and that subsection 2.01 of the Wholesale Service Agreement shall be and is hereby deemed to be amended to read as follows:

> **2.01 Term**
> This Agreement shall be effective as of November 1, 2004 and shall continue thereafter until February 19, 2010, subject to earlier termination pursuant to subsection 2.02.

Please indicate your consent to and agreement with the foregoing by endorsing this letter in the space provided below and returning to us a copy.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

Agreed and accepted this 13th day of November, 2009
on behalf of the City of Kelowna

By:

SHEPHE[illegible]

Stephen Fleming,
City Clerk

FORTISBC

2009 – 2010 Capital Expenditure Plan
and
2009 SDP Update

August 12, 2008
Kelowna, BC

FORTISBC

Regulatory Timetable

Intervenor Registration	August 13
Participant Assistance Budgets Submitted	August 15
Commission Information Request No. 2 and Intervenor Information Request No. 1	August 28
FortisBC Responses to Information Requests	September 11
FortisBC Final Submission	September 16
Intervenor Final Submission	September 22
FortisBC Reply Submission	September 29

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2009 – 2010 Capital Expenditure Plan
2009 System Development Plan Update

9:00	Opening Remarks	Joyce Martin
9:10	System Development Plan	Doug Ruse
9:30	2009/10 CEP Overview	Doug Ruse
9:40	Generation	Steve Hope
10:00	Transmission, Stations	Paul Chernikhowsky
10:30	BREAK	
10:45	Telecommunications	Paul Chernikhowsky
11:00	Distribution	Gary Williams / Marko Aaltomaa
11:45	General Plant	Tim Swanson
12:10	Demand Side Management	Mark Warren
12:30	LUNCH	
2:00	Copper Conductor Replacement CPCN Application	Doug Ruse
3:50	WRAP UP	Joyce Martin

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2009 System Development Plan Update
and
2009/10 Capital Expenditure Plan

Doug Ruse
Director of Planning

August 12, 2008
Kelowna, BC

FORTISBC

2009 System Development Plan Update

SDP Overview

Transmission and Distribution system reinforcements
Regional distribution
Protection and control, communication systems
System sustaining plan
SDP included a 20 year high level with a 5 year detailed plan

2009 SDP Update (changes since 2007 Update)

Project timing
Detailed engineering
New projects – Condition Assessments
New projects – Load Forecast
Deferred projects
Cancelled projects

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System Planning Overview

- Why We Need A Plan
- Current Plan Created in 2004
- Minor Updates Annually
- A New Plan Will be Developed in 2010
- Generation and DSM

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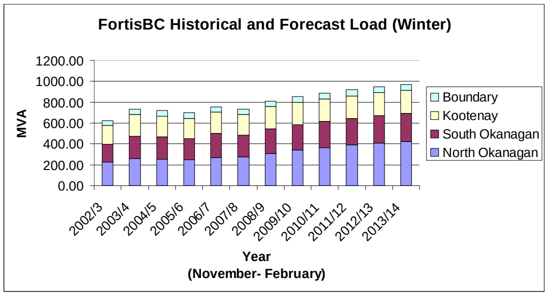
Load Forecast by Area



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Building Permits FortisBC Territory

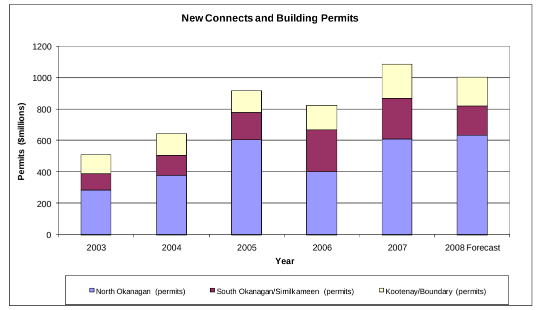

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Table 1.2 2009-10 Expenditures

2009/10 Expenditures - 2007 Update
Vs.
2009/10 Expenditures - 2009 Update

	2007 Update 2009/10	2009 Plan 2009/10	Change
		($million)	
Transmission Growth	85.4	160.6	75.2
Transmission Sustaining	7.3	14.1	6.8
Station Sustaining	6.6	10.1	3.5
Distribution	45.5	62.0	16.5
Telecommunication	5.6	4.4	(1.2)
TOTAL	150.4	251.1	100.7

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Changes to 2009/10 Transmission and Stations Growth

Timing Changes (Schedule and Inflation $32.0 million)

+ **Naramata Substation** - rescheduled from 2005/07 to 2008/09 Extensive consultation with stakeholders regarding location
+ **Black Mountain Substation** - schedule extended to 2009 Extensive consultation with stakeholders regarding feeders
+ **Benvoulin Substation** - schedule extended to 2009 Extensive consultation with stakeholders prior to submitting CPCN Application
+ **OTR** - Schedule extended to 2010 due to timing associated with the detailed engineering and CPCN Application filing
- **Ellison Transmission Loop** - Dependent on Ellison Completion
- **Huth** - Deferred until OTR work on 76 Line complete
- **Grand Forks Conversion** - Load uncertainty

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Changes to 2009/10 Transmission Growth (cont'd)

Detailed Engineering (Project scope and accuracy $44.0 million)

OTR - More station upgrades required

Benvoulin - Anticipated location has changed

30 Line Conversion - More station upgrades required

Cancellations (-$4.2 million)

2010 Fault Level Reduction - no longer required

Coffee Creek T3 - no longer required due to 30 Line Conversion

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Changes to 2009/10 Transmission Sustaining

New Projects - Condition Assessments ($7.3 million)

Transmission Pine Beetle Hazard Allocation

20 Line Rebuild

27 Line Rebuild

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Changes to 2009/10 Stations Sustaining

New Projects – Condition Assessments ($6.9 million)

- Slocan City - Valhalla Substation Upgrade
- Passmore Substation Upgrade
- Princeton Substation Recloser Replacement

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Changes to 2009/10 Distribution

Distribution Growth ($4.8 million)

New Projects - Growth

- **Airport Way Upgrade**
- **Glenmore New Feeder**
- **Christina Lake Upgrade**
- **Beaver Park - Fruitvale Tie**

Distribution Sustaining ($12.7 million)

New Projects - Condition Assessments

- **Distribution Pine Beetle Hazard Allocation**
- **Copper Conductor Replacement Program**

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Changes to 2009/10 Telecommunications

Schedule Change (-$1.2 million)

+ Distribution Automation – shift from 2007/08 to 2009/10

- High capacity communications link between Grand Forks and Trail - deferred in conjunction with Grand Forks Conversion Project

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2009 SDP Update

Questions / Comments

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2009/10 Capital Expenditure Plan (CEP)

Overview and Summary of Expenditures

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CEP Overview Table 1.1 , Page 6

	2009 Plan	2010 Plan	2009/10 Total
		($million)	
Generation	21.9	22.6	44.5
Transmission & Stations	96.1	88.7	184.8
Distribution	28.2	33.8	62.0
Telecommunication	2.2	2.2	4.4
Information Systems	5.2	4.5	9.7
General Plant	22.6	26.7	49.3
Demand Side Management	2.5	2.7	5.2
TOTAL	178.8	181.1	359.9
Annual Operating Savings	0.2	0.72	0.92

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CEP Summary of Expenditures Table 1.4, Page 15

	2009 Plan	2010 Plan	2009/10 Total
		($million)	
Previously Approved	31.0	18.1	49.1
CPCN Submitted	81.8	78.1	159.9
CPCN to be Submitted	7.7	20.1	27.9
Subtotal	120.5	116.4	236.9
Remainder	58.3	64.7	123.0
Total	178.8	181.1	359.9

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CEP Overview

Category	Approval Requested ($millions)
Generation	11.1
Transmission & Stations	34.6
Distribution	48.2
Telecommunication	1.6
Information Systems	9.7
General Plant	12.6
Demand Side Management	5.2
TOTAL	123.0

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2009/10 Capital Expenditure Plan

Questions / Comments

Generation

Steve Hope
ULE Project Manager

August 12, 2008
Kelowna, BC

FortisBC Generating Plants

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FortisBC Generating Plants

FortisBC — Generation Projects Table 2.1

		Previously Approved	Expenditures to Dec 31\08	2009	2010	Future	Total
			($000s)				
	Sustaining						
1	South Slocan Unit 1 Life Extension	G-52-05	6,729	7,832	3,261	39	17,861
2	South Slocan Unit 3 Life Extension	G-147-06	11,010	2,051	-	-	13,061
3	Corra Linn Unit 1 Life Extension	G-147-06	874	4,487	8,476	5,113	18,950
4	Corra Linn Unit 2 Life Extension		-	104	5,264	17,313	22,681
5	South Slocan Plant Completion	G-147-06	1,012	940	1,598	-	3,550

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FortisBC — Generation Projects Table 2.1

		Previously Approved	Expenditures to Dec 31\08[(1)]	2009	2010	Future	Total
			($000s)				
	Sustaining						
6	Upper Bonnington Civil \ Structural Upgrade and Old Unit Repowering (Phase 1)	G-147-06	4,142	1,094	651	-	5,887
7	South Slocan Unit 1 Headgate Rebuild	G-147-06	-	577	279	-	856
8	South Slocan Headgate Hoist, Control, Wire Rope Upgrade	G-147-06	669	434	-	-	1,103
9	Generating Plants Upgrade Station Service Supply	G-147-06	1,144	484	1,191	2,192	5,011
10	Generating Plants Area Lighting		-	478	338	-	816
11	All Plants Spare Unit Transformer		469	1,380	-	-	1,849
12	Subtotal Major Projects		26,049	19,861	21,058	24,657	91,625
13	Subtotal Minor Projects from Table 2.2		-	2,074	1,499	-	3,573
14	Total Generation		26,049	21,935	22,557	24,657	95,198

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FortisBC — Corra Linn Unit 2 LE - Objectives

- Low cost energy for customers
- Longer term reliability

Corra Linn

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FortisBC — Corra Linn Unit 2 LE - Scope

- Turbine maintenance

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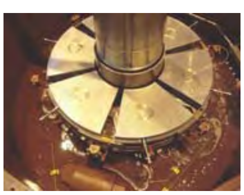
FortisBC — Corra Linn Unit 2 LE - scope

- Generator maintenance



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FortisBC — Upgrade and Life Extension Program - schedule

Plant	Upper Bonnington	Lower Bonnington	South Slocan	Corra Linn
Units Completed	Unit 5 ULE Unit 6 LE	Units 1 & 2 ULE Unit 3 LE	Unit 2 ULE	Unit 3 LE
2009 Schedule			Unit 3 LE	
2010 Schedule			Unit 1 LE	
2011 Schedule				Unit 1 LE
2012 Schedule				Unit 2 LE
Total Units	2	3	3	3

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Generation Plants Upgrade Area Lighting

All plants station Area Lighting

- Safety
- Reliability

Upper Bonnington basement lighting – completed

Corra Linn – basement lighting

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Generation Plants Spare Unit Transformer

All plants Spare Unit Transformer

- Aging equipment
- Reliability

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Generation Small Sustaining Projects Table 2.2

	Generation Small Sustaining Projects	2009	2010
		($000s)	
1	All Plants Fire Safety Upgrade Phase 1	241	
2	All Plants Public Safety & Security Phase 1	82	52
3	Lower Bonnington Power House Crane Upgrade	174	
4	Corra Linn Power House Crane Upgrade	172	
5	Corra Linn East Wingdam Handrail Upgrade	78	
6	All Plants Portable Headgate Closing Device	50	
7	All Plants Spare Exciter Transformer	24	116
8	South Slocan Water Supply Phase 3	47	50
9	All Plants 2009 Pump Upgrades	233	
10	Upper Bonnington & Corra Linn Deluge Valves	50	
11	Lower Bonnington, Upper Bonnington, & Corra Linn Sump Oil Alarm System Upgrade	128	

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Generation Small Sustaining Projects Table 2.2

	Generation Small Sustaining Projects	2009	2010
		($000s)	
12	Lower Bonnington & Upper Bonnington Upgrade Spillway Gate Control Phase 1	40	
13	Upper Bonnington & South Slocan Airwash Tank Rehabilitation	108	
14	South Slocan Tailrace Gate Corrosion Control		114
15	Queen's Bay Level Gauge Building Phase 1	67	
16	Upper Bonnington Unit 5 & Unit 6 Tailrace Gate Corrosion Control		139
17	Upper Bonnington Trashrack Gantry Replacement.		417
18	Lower Bonnington Forebay Access Rd. and Intake Upgrade Phase 1 & 2	393	102
19	Corra Linn Spillway Gate Isolation Study	46	
20	South Slocan Dam Rehabilitation Study	46	
21	Lower Bonnington & Upper Bonnington Plant Totalizer Upgrade		212
22	Lower Bonnington & Upper Bonnington Communications Network Completion	95	297
23	Total	2,074	1,499

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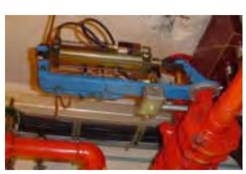
Small Sustaining Projects

Projects primarily focus:

- Safety
- Environment
- Reliability



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Questions / Comments

Upper Bonnington

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2009/10 Transmission Projects

Paul Chernikhowsky
Chief Planning Engineer

August 12, 2008
Kelowna, BC

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Okanagan Area Development

"UBC Okanagan bucks B.C. trends, enrolment grows by 17 per cent"
UBC press release – Aug 2007

"The Best Place to Build a Data Center in North America"
CIO Magazine – February 2008

"First quarter ranks Kelowna as 9th busiest airport in Canada"
City of Kelowna news release – April 2008

"Thompson-Okanagan leads the province in job and population growth in last five years"
2008 BC Check-Up - Chartered Accountants of BC

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Transmission & Stations Growth Table 3.1 (Page 42)

	Previously Approved	CPCN Filed	Expenditures to Dec 31/08	2009	2010	Total
GROWTH			($000s)			
Ellison Distribution Source	C-4-07		15,434	1,734		17,168
Black Mountain Source	C-7-07		9,913	4,517		14,430
Naramata Substation	G-124-07		3,562	3,962		7,524
Okanagan Transmission Reinforcement		Dec 14, 2007	18,250	65,265	57,893	141,408
Ootischenia Substation	C-10-07		7,702	389		8,091
Benvoulin Substation		Q3 2008	1,200	2,930	13,554	17,684

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Transmission & Stations Growth Table 3.1 (Page 42)

	Expenditures to Dec 31/08	2009	2010	Future	Total
GROWTH		($000s)			
Recreation Capacity Increase		178	3,401		3,579
Kelowna Distribution Capacity Requirements		518	517		1,035
Tarrys Capacity Increase		403			403
Huth Substation Upgrade			413	3000	3,413
30 Line Conversion		4,500			4,500
Kelowna Static var Compensator			400		400
SUBTOTAL GROWTH	56,061	84,396	76,178	3,000	219,635

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Benvoulin Substation

Project justification:
- Provides capacity in a growing area of the city
- Allows redistribution of load from the heavily loaded Hollywood and OK Mission substations
- Provides distribution backup for other substations
- Defers the Braeloch Substation
- In-service Q4 of 2009

Project scope:
- New 2.5 acre substation (5 acre property) off Casorso Rd
- Tie into the existing 51 Line between DG Bell and OK Mission
- 32 MVA 138/13 kV transformer
- Four 13-kV distribution feeders
- Room for additional two transformers and eight feeders

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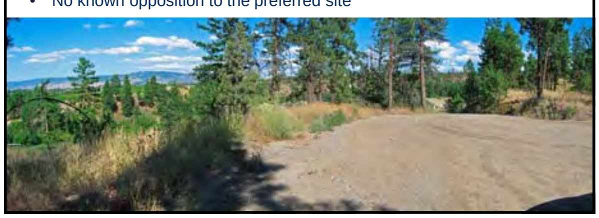
Benvoulin Substation

Substation Siting Considerations:
- Balance of numerous, often competing interests
- Extensive public consultation
- Three rounds of open houses
- Site selected is a former gravel mining operation
- Station site is still central to area load growth
- No known opposition to the preferred site



FORTISBC — Recreation Transformer Addition

Project justification:
- Supply for downtown Kelowna (Prospera Place, Cultural District, Waterfront)
- Load forecast shows transformer overloading in winter 2010/11
- Provides capacity in a densely populated, growing area of the city

Project scope:
- Doubles the station transformation capacity
- Addition of a second 32 MVA 138/13 kV transformer
- Connection to existing station buswork
- No additional property required

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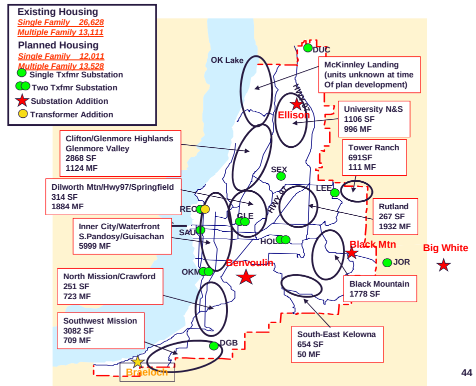
FORTISBC — Kelowna Official 2020 Community Plan New Residential Development



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FORTISBC — Kelowna Distribution Capacity Requirements

- Kelowna peak load expected to grow **100 MW (36%) by 2012**
- Detailed investigation and recommendation to provide an integrated solution for capacity increases in the greater Kelowna area
- Long term vision
  - **Develop/formalize criteria**
  - **Future transmission needs**
  - **Evaluation of economic reach of feeders**
  - **13-kV vs. 25-kV distribution**
  - **Compact station designs**
  - **Leverage existing infrastructure as much as possible**

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FORTISBC — Huth Station Upgrade

- Major supply point for South Penticton, West Bench, Trout Creek and Summerland
- Combined peak load over 80 MW in 2010
- Originally constructed in the 1950's
- Modified many times / non-standard arrangement
- Normal supply via one of two 63-kV lines from RG Anderson
- Both lines cannot be operated in parallel
- Large amount of load is exposed to outages due to a single-contingency (N-1) event
- Circuit breaker and protection upgrades will allow N-1 reliability

- **Construction is deferred until 2011 (due to work on 76 Line as per OTR schedule)**
- **Engineering and some procurement in 2010**

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FORTISBC — Huth Station Upgrade

Project scope:

- Addition of three 63-kV circuit breakers
- Fibre-optic communications from Huth to RG Anderson
- Modifications to allow 52 Line and 53 Line to operate in parallel

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FORTISBC — 30 Line Voltage Conversion

History:
- 161-kV line built in 1952 to supply power from South Slocan to the Sullivan Mine in Kimberley
- 30 Line section (Teck Cominco owned) from Crawford Bay to Kimberly retired in 2004
- Only remaining backup supply for area load is via 32 Line from Creston at 63-kV
- Seven aging transformers at South Slocan, Coffee Creek and Crawford Bay which require rehabilitation or replacement

- **No longer have full backup for loss of the South Slocan to Coffee Creek section (does not meet N-1 criteria)**

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30 Line Voltage Conversion

Proposed solution:

- Reduce the line voltage from 161-kV to 63-kV
- No changes to the transmission line itself
- Removal of step-up/step-down transformers at South Slocan, Coffee Creek, Crawford Bay (saves approximately $10 million in replacement costs)
- Station reconfiguration at Coffee Creek and Crawford Bay
- Installation of capacitor banks at Kaslo and Coffee Creek
- Restores N-1 capability

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Transmission Sustaining Table 3.2 (Page 55)

		2009	2010
		($000s)	
1	Transmission Line Urgent Repairs	288	293
2	Right-of-Way Easements	311	345
3	Right-of-Way Reclamation	550	602
4	Transmission Pine Beetle Hazard Allocation	1,218	821
5	Transmission Condition Assessment	427	496
6	Transmission Line Rehabilitation	1,639	1,888
7	Switch Additions		132
8	20 Line Rebuild	1,943	1,540
9	27 Line Rebuild	648	642
10	30 Line Lake Crossing Rehabilitation		350
11	Total	7,024	7,109

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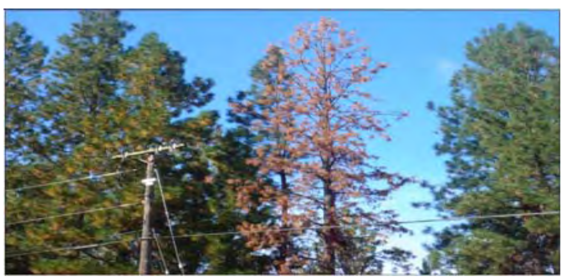
Pine Beetle Kill Hazard Trees

Removal of Trees killed by Pine Beetle to Minimize Risk:
Falling Trees can break Conductor
Downed Conductor can remain energized
Fire and Electrocution Risk
Negatively impacts Reliability



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Transmission Line Rehabilitation

- Remediation of defects identified in previous years' assessments
- In 2009/10 rehab lines assessed during 2008/09
- Also includes pole stubbing, replacement of poles or cross-arms and other miscellaneous repairs
- Project cost estimates based on historical information
- Required to ensure both safety and reliability

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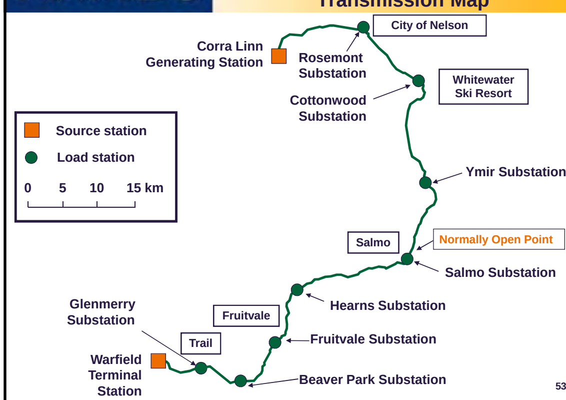
20 Line (20L) and 27 Line (27L) Transmission Map



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Transmission Rehabilitation

20L & 27L 63 kV Transmission Line Rebuilds

- 20L and 27L originally constructed in 1930/31
- 20L = 46 km / about 194 structures to be replaced
- 27L = 57 km / about 111 structures to be replaced
- Based on detailed Engineering assessments

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20L and 27L Condition Issues

2009/10 Transmission Projects

Questions / Comments

2009/10 Stations Projects

Paul Chernikhowsky
Chief Planning Engineer

August 12, 2008
Kelowna, BC

Stations Sustaining
Table 3.3 (Page 66)

		2009	2010
		($000s)	
1	Station Assessments & Minor Planned Projects	620	680
2	Ground Grid Upgrades	572	
3	Station Urgent Repairs	473	448
4	Bulk Oil Breaker Replacement Program		292
5	Transformer Load Tap Changer Oil Filtration Project	32	64
6	Slocan City-Valhalla Substation Upgrade	2,173	
7	Passmore Substation Upgrade		1,987
8	Pine Street Substation –Distribution Breaker Replacement	345	
9	Princeton Substation Distribution Recloser Replacement		1,513
10	Joe Rich Transformer Protection Upgrade		404
11	Creston Substation Protection Upgrade	488	
12	Total	4,703	5,388

Station Condition Assessment

Condition Assessments

- Conduct an assessment of all FortisBC Stations over a ten year Period
  - Visual Inspection
  - Infra Red Scan
  - CMMS Data Collection
  - Identify Future Minor Projects

Assessment Information:

Operational Issues
Environmental and Safety
Substation Standards
Reliability and Future Use

Station Minor Projects

Minor Projects

- Replace DC Protection systems
- Replace Gap-Type Silicon Carbide Arrestors

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Replace DC Protection Systems

- DC protection batteries are critical substation components
- Directly impact the safe and reliable operation of protection systems
- Ensures that power is always available to operation protection equipment when needed

Existing batteries requiring replacement

New replacement batteries

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Replace DC Protection Systems

Criteria for Replacement:

1. Gel Type banks not kept in temperature controlled environment or older than 10 years; and
2. Any bank below 70% capacity or older than 20 years.

2009	2010
Glenmerry	Tarrys
Cascade	Glenmore
Playmor	Hollywood
	OK Mission

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Replace Gap-Type Silicon Arrestors

Replace aging and failing Gapped Silicon Carbide Arresters with modern MOV arresters

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Replace Gap-Type Silicon Arrestors

- Failures can result in arrester explosion
- Replacements will improve:
  - work site safety
  - equipment protection from lightning and switching surges

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Ground Grid Upgrades Castlegar

Substation Grounding

Normal operating conditions ground potential ~ 0 Volts

Ground Potential Rise (GPR) is caused by
- Switching operations
- Fault on the system

Consequence:
- Voltages imposed on grounded metallic objects

Impact:
- Public and employee safety

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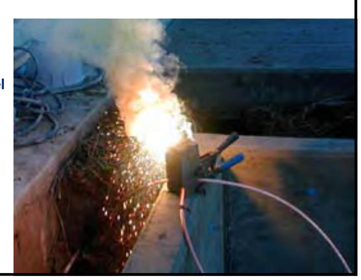
Ground Grid Upgrades Castlegar

Substation Grounding

Proposed Solution for Castlegar Substation:

- New ground grid
- Ground rods
- Ground wells
- Additional insulating gravel



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Slocan City - Valhalla Substation Upgrade

Slocan City Substation

- **Legacy substation built to serve the mill**
- **Transformer Purchased in 1965**
- **Transformer Weeping Oil**
- **30 Meters from Springer Creek – floodplain area**

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Slocan City - Valhalla Substation Upgrade

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Slocan City - Valhalla Substation Upgrade

Slocan City –Proposed Solution

- Valhalla Substation is located 1 kilometre away
- Install 10 MVA refurbished Transformer at Valhalla
- Transfer Load to Valhalla

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Passmore Substation Upgrade

19 Line

- **48 km radial 63-kV from South Slocan Generating Station**
- **Supplies:**
  - **Passmore Substation**
  - **Valhalla Substation**
  - **Slocan City Substation**

- **Experiences frequent and long duration outages**
- **Causes unnecessary outages to Passmore Substation**
- **Also: station is currently too small to house the mobile substation**

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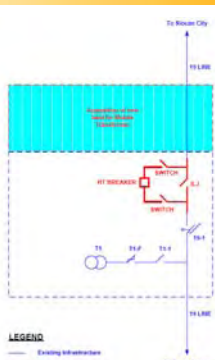
Passmore Substation Upgrade

Proposed solution:

- **Install 63-kV circuit breaker**
- **Protection and control equipment**
- **Remote communications**
- **Expand site to allow mobile installation**

- **Ensures that faults north of Passmore do not affect that station**
- **Allows safe installation of the mobile substation for maintenance**



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Princeton Substation Recloser Replacement

- Replacement necessary for increased reliability and safety.
- Under-rated for fault duty
- Two units are at end-of-life
- Station infrastructure is in poor condition

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Princeton Substation Recloser Replacement

Princeton Transformer Replacement Project (completed in 2007)

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2009/10 Stations Projects

Questions / Comments

Telecommunications, SCADA, Protection & Control

Paul Chernikhowsky
Chief Planning Engineer

August 12, 2008
Kelowna, BC

Telecommunications

This does not include:

Corporate communications

- **Desk phones and faxes**
- **Cell phones**
- **Wide-area network (WAN)**
- **Computers for business purposes**
- **SCADA Master Station hardware and software**

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Telecommunications

This does include:

- Teleprotection (relay to relay communications for system protection)
- SCADA communications for the System Control Centre
- Remote access to substation metering, relaying and recording equipment
- Remedial Action Schemes (wide-area protection systems)

There are potential synergies – communications infrastructure can be used to provide corporate communications for IT group

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Telecommunications

Communications between:

- 11 Terminal Stations
- 4 Generating Stations
- 49 Distribution Stations
- 12 Mountain-top Radio Repeater Sites
- 6 Business Offices

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Telecommunications Growth Table 5.1 (Page 101)

	CPCN Approved	Expenditure to Dec 31\08	2009	2010	Future	Total
		($000s)				
GROWTH						
Distribution Substation Automation Program	C-11-07	1,982	1,338	1,438	1,621	6,379
SUSTAINING						
Harmonic Remediation			117	119		236
Protection Upgrades			448	508		956
Communication Upgrades			299	111		410
SUBTOTAL SUSTAINING			864	738		1,602
TOTAL		1,982	2,202	2,176	1,621	7,981

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Distribution Substation Automation, Metering and Communications

- **CPCN approved in 2007**
- **Multi-year program to improve protection, communications and monitoring at legacy substations**
- **Applies technology that is already included in new substation designs**
- **Main components:**
  - Metering (power quality, data logging)
  - Communications (SCADA visibility, remote access)
  - Upgrading protection to modern standards

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Protection Upgrades

Why upgrade?

Increased safety and reliability
- **Older devices fail more frequently**
- **No spare parts**
- **Self-monitoring**

Faster restoration
- **SCADA monitoring (real-time)**
- **Direct crews to the correct location**
- **Remote access for interrogation**

81

Protection Upgrades

Why upgrade?

82

Protection Upgrades

Continuation of upgrade programs started in late 1990s
- **Kootenay 230 kV System Development**
- **Vaseux Lake / South Okanagan**
- **Kelowna Capacity Increase**
- **Okanagan Transmission Reinforcement**
- **Distribution Substation Automation Program**

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Protection Upgrades

Transformer Differential Relay Replacements
2009 Projects:
- **Hollywood T1 and T3**
- **Sexsmith T1**

2010 Projects:
- **Saucier T1**
- **Summerland T2**
- **Westminster T1 and T2**

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Protection Upgrades

Out with the old…

- By the end of 2011 all T&D protection equipment will be microprocessor-based relays
- No electromechanical relays left in service
- What does this mean for the customer?

Improved safety
Improved reliability
Reduced operating costs

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Telecommunications, SCADA, Protection & Control

Questions / Comments

FORTISBC

2009/10 Distribution Projects

Marko Aaltomaa / Gary Williams
Distribution Planning Engineers

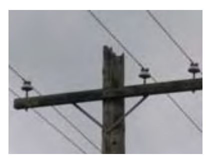
August 12, 2008
Kelowna, BC

FORTISBC

2009/10 Distribution Projects

Distribution Growth

- Extension of service to new customers
- Capacity improvements to meet normal load growth.



Distribution Sustaining

- Planned rehabilitation
- Urgent and unplanned rebuilds

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Distribution Growth Table 4.1 (Page 78)

Table 4.1
Distribution Projects Expenditures

		Previously Approved	2009 Total	2010 Total
			($000s)	
1	GROWTH			
2	New Connects - System-wide		9,788	10,670
3	Distribution Growth Projects			
4	Glenmore -New Feeder		788	
5	Airport Way Upgrade Feeder			1,551
6	Hollywood Feeder 3- Sexsmith Feeder 4 Tie			365
7	Christina Lake Feeder 1 Upgrade		608	489
8	Beaver Park-Fruitvale Tie			1,227
9	Small Growth Projects			137
10	Unplanned Growth Projects		974	994
11	TOTAL GROWTH		12,158	15,433

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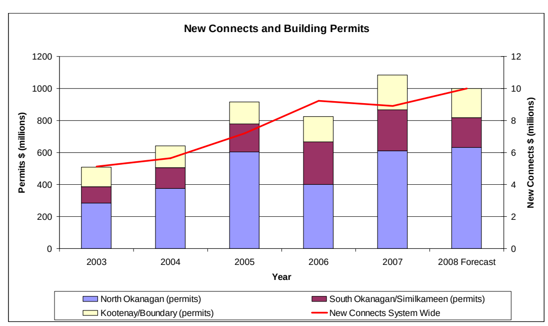
Building Permits and New Connects, System-wide



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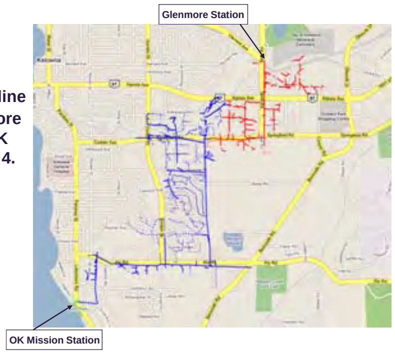
FORTISBC — Glenmore Substation - New Feeder

Issue – Forecast line overload on Glenmore Feeder No. 1 and OK Mission Feeder No. 4.



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FORTISBC — Glenmore Substation - New Feeder

Project - build feeder into the Spall Road-Dickson Avenue Area.

Benefits - splitting load ensures distribution capacity and quality of service to Kelowna customers Springfield-Spall areas

92

FORTISBC — Airport Way Capacity Upgrade

Issue - Insufficient Capacity

Project - Replace No. 2 Copper U/G Cable With No. 750MCM U/G Cable

Benefits - Capacity To accommodate forecast load and future expansion.

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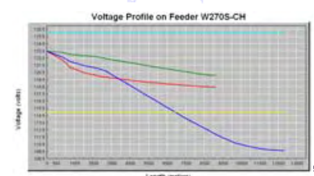
FORTISBC — Christina Lake Feeder 1 Capacity Upgrade

Issue - low voltage, overload, and poor condition



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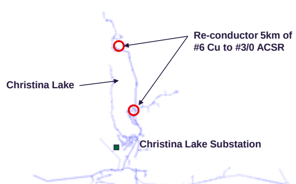
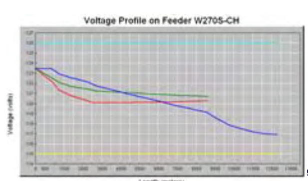
FORTISBC — Christina Lake Feeder 1 Capacity Upgrade

Project - upgrade, re-conductor and phase balance line north of substation and east of Christina Lake

Benefits - quality voltage, safety and reliability for customers along Christina Lake





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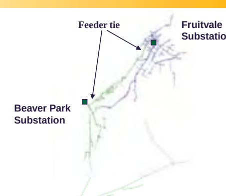
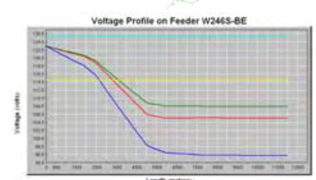
FORTISBC — Beaver Park – Fruitvale Feeder Tie

Issues - Station Load, Transfer Capability, and Reliability



Existing voltage profile with Fruitvale load transferred to Beaver Park.



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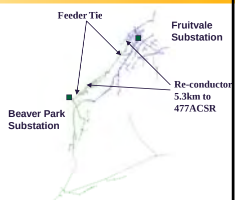
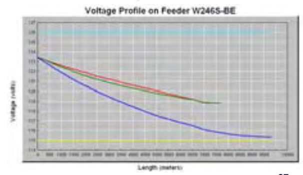
Beaver Park – Fruitvale Feeder Tie

Project - Upgrade 5.3 kilometers of line on Beaver Park Feeder 2 and Fruitvale Feeder 1.



Benefits - Station Load transfer capability and improved reliability for customers in the Fruitvale, Montrose, Trail Area.



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Distribution Sustaining Table 4.1 (Page 78)

Table 4.1
Distribution Sustaining Projects Expenditures

		Previously Approved	2009 Total	2010 Total
13	Distribution Sustaining Programs and Projects			
14	Distribution Line Condition Assessment		599	667
15	Distribution Line Rehabilitation		3,124	3,470
16	Distribution Right-of-Way Reclamation		621	646
18	Distribution Pine Beetle Hazard Allocation		722	551
19	Distribution Line Rebuilds		1,178	1,167
20	Small Planned Capital		668	747
21	Forced Upgrades and Line Moves		1,255	1,461
22	Distribution Urgent Repair		1,911	1,805
23	PCB Program	G-52-05	1,073	1,117
24	Aesthetic and Environment Upgrades	G-58-06	100	100
25	Copper Conductor Replacement Program	CPCN to be filed	4,798	6,586
26	TOTAL SUSTAINING		16,049	18,317

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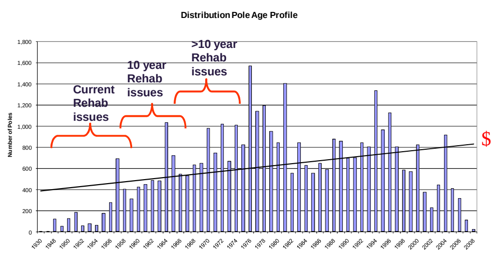
Distribution Sustaining



Distribution Sustaining Capital is forecast to increase over present levels in future years due to the age of the plant.

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Distribution Sustaining

- Condition Assessment
  - Rehabilitation
    - Rebuilds


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Distribution Line Condition Assessment

Distribution Assessment

The program;

- provides a detailed assessment of each feeder
- based on an eight year cycle
- tests and treats poles

Proactively manages;

- risk to employee and public safety
- life extension of distribution plant

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Distribution Line Rehabilitation

Distribution Rehabilitation

Rehabilitation of distribution lines assessed in previous years condition assessment project.

Includes;

- Stubbing poles
- Replacing poles
- Replacing crossarms
- Guy wire repair
- Replace Hot Tap Connectors
- Other defects found during assessments

Benefits to customer

- Employee and public safety
- Service reliability


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Distribution Line Rebuilds

Rebuild

Project to replace <u>sections</u> of deteriorated lines.

- Line sections in general poor condition identified by annual or detailed line patrol or day to day operations.
- Assessed by Engineering and Planning for consistency and priority.
- <u>NOT based</u> on feeder level reliability but rather on localized safety/reliability of the section identified.

Benefits

- Employee and public safety
- Service reliability

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Small Planned Capital

Project captures off-cycle work required to keep the distribution lines safe and reliable.

- Operational and safety concerns on the distribution system related to damage, clearance problems and aging equipment.

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Forced Upgrades and Line Moves

Project captures capital upgrades driven by third party requests.

- Relocation of distribution lines due to highway/road widening initiated by Ministry of Transportation / municipalities.
- Line moves driven by insufficient land rights located on private property.

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Distribution Urgent Repair

Project for repair or replacement of failed equipment.

- Failures on the distribution system due to weather, defective equipment, animals, vandalism, vehicle collisions, and human error.
- Can cause outages or present risk that must be addressed in an expedient manner to ensure employee and public safety and service continuity is maintained.

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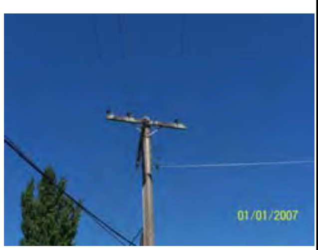
Copper Conductor Replacement Program

- Approximately 500 kilometres of No. 8, No. 6, & No. 90 MCM Copper to be removed
- All in excess of 50 years old
- Approximately 200 failures in the last five years
- Failures have resulted in energized lines on the ground
- This is a ten year program
- A CPCN Application has been filed



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Distribution Projects

Questions / Comments

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General Plant

Tim Swanson
Manager, Information Systems

August 12, 2008
Kelowna, BC

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General Plant
Table 7.1 (Page 116)

	General Plant	CPCN filed	Exp Dec 31\08	2009	2010
			($000s)		
1	Vehicles			1,326	2,868
2	Advanced Metering Infrastructure	Dec. 19, 2007	568	16,492	20,240
3	Metering Changes to Uninstalled Meter Inventory			526	559
4	Information Systems			5,167	4,499
5	Telecommunications			105	106
6	Buildings			3,248	1,981
7	Furniture and Fixtures			347	393
8	Tools and Equipment			572	575
9	TOTAL		568	27,783	31,221

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Vehicles

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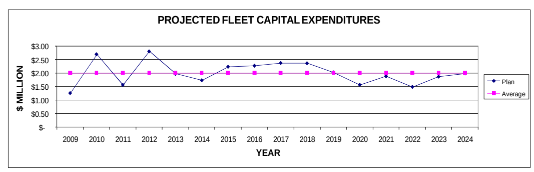
Long Term Planning

- Fifteen year outlook for Vehicles
- The average annual expenditure is $2.01 million



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Hybrid Low Emission Vehicles

- Six passenger vehicles in service by Fall 2008
- One single bucket aerial device to be piloted in 2009 as rental/demonstrator
- One single bucket aerial device budgeted to purchase in 2010
- More Hybrids will be purchased as technology advances and as they can be matched to practical applications in the organization

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Vehicle Purchases
Table 7.3 (Page 118)

	Category	No. of Units 2009	No. of Units 2010
1	Heavy Fleet Vehicles	3	6
2	Service Vehicles	2	5
3	Passenger Vehicles	3	7
4	Off-Road Vehicles\Trailers	1	6
5	Total Units	9	24
6	Total Replacement Cost ($000s)	1,226	2,768
7	Contingency ($000s)	100	100
8	Total Cost ($000s	1,326	2,868

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Information Systems

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Advanced Metering Infrastructure

- Written CPCN process complete June 30, 2008
- Cost benefits
- Customer benefits
- Environmental benefits

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Information Systems Table 7.4 (Page 121)

		2009 Total	2010 Total
		($000s)	
1	Infrastructure Upgrade	789	794
2	Desktop Infrastructure Upgrade	842	847
3	SAP & Operations System Enhancements	947	953
4	AM/FM Enhancements	211	423
5	Customer Service Systems Enhancements	789	794
6	SCADA Enhancements	790	688
7	Distribution Design Software	799	
8	TOTAL	5,167	4,499

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Infrastructure Upgrades

- Maintain up to date productive infrastructure
- Balance value and productivity

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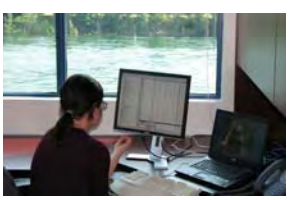
Business System Enhancements

- Enhancing existing systems – SAP, CIS, ESRI, etc.
- Based on business requirements and efficiency



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SCADA Enhancements

- SCADA systems enhancements
- Integral to safety and reliability

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Distribution Design Software

- Integrated
- Efficient

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Basis for IT/Business Capital Requirements

- Reliable and scalable core systems & infrastructure

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Buildings

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Buildings Table 7.5 (Page 130)

	Location	Project	2009	2010
			($000s)	
1	All	Facility Upgrades	2,637	1,368
2	All	Facilities Emergency	88	89
3	All	Construction Projects Requirements	218	219
4	All	Security System upgrades	305	305
5	Total		3,248	1,981

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Major Facility Upgrade Initiatives

- Safety & Security
- Environmental/Energy Conservation

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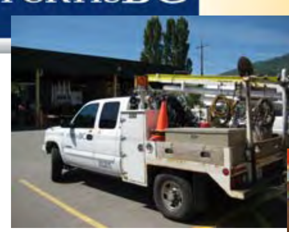
Tools and Equipment

2009 - $0.572 Million

2010 - $0.575 Million



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General Plant

Questions / Comments

FORTISBC

Demand Side Management

Mark Warren
Director, Customer Service

August 12, 2008
Kelowna, BC

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Demand Side Management Environment

BC Energy Plan

Bill 15 Utilities Commission Act Amendments

Customer expectations

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Demand Side Management

Expenditure and GW.h Savings 2008-10

Sector	2008 Approved Plan ($000)	2008 Plan Savings (GW.h)	2009 Plan Expenditure ($000)	2009 Plan Savings (GW.h)	2010 Plan Expenditure ($000)	2010 Plan Savings (GW.h)
Residential	1,023	8.4	1,391	10.7	1,516	12.1
General Service	754	9.1	1,287	11.6	1,380	12.1
Industrial	200	2.0	345	3.0	388	3.4
Plan/Evaluate/educate	378	-	644	-	667	-
Total	2,355	19.5	3,668	25.3	3,952	27.6
Total (Net of Tax)	1,498		2,568		2,806	

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Demand Side Management

2009/10 Activities

- Continuation of existing programs
- New Programs Residential
- New Programs General Service
- New Programs Industrial
- Conservation Education

- DSM Strategic Plan

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Demand Side Management

Questions / Comments

Issue: Separation of RS31 and RS33 customers into separate rate classes

1.0 Reference: Exhibit B-1, Section 12.2, p. 67

"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."

Q1.1 How many large general service ("LGS") customers have currently opted to receive service under Rate Schedule 33? Is Celgar the only current Rate Schedule 33 customer?

A1.1 Zellstoff Celgar is currently the only FortisBC customer receiving service under Rate Schedule 33.

Q1.2 How many LGS customers have currently opted to receive service under Rate Schedule 31?

A1.2 There are currently three customers receiving service under Rate Schedule 31.

Q1.3 The referenced statement suggests a customer in a given rate class can choose amongst available rate schedules for that rate class. Please describe when and why this triggers a change in the customer's rate class.

A1.3 The rate schedules available to a customer depends upon the nature of the related energy use, the maximum demand requirements of the customer and the load factor. In some cases, such as with time-of-use or green rates, customer choice is also a factor. It is possible that a customer in a given class is eligible to be served under more than one rate schedule. In those cases, "… 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." [T&C Section 2.1]

Q1.4 Does FortisBC consider LGS customers that opt for service under Rate Schedule 33 to constitute a separate "Rate Class" from those LGS customers that opt to receive service under Rate Schedule 31? If not, why not?

A1.4 The term "Rate Class" in its common usage is primarily determined by customer eligibility as outlined in FortisBC's Electric Tariff. Thus, there is no distinction made between customers who are eligible to take service under the base rate, or the time-of-use, discounted, or green variant of the rate. However, for the purposes of this COSA, Rate Schedule 33 customers have been identified as a separate class of service for the reasons set out in the response to Zellstoff Celgar IR No. 1 Q2.1.

Q1.5 Please explain why separate rate classes are not proposed for the Residential, Small General Service, General Service Secondary, LGS Primary, and various Wholesale customers based on their choice of Time of Use rates.

A1.5 Please refer to the response to Zellstoff Celgar IR No. 1 Q1.4 above.

2.0 Reference: Exhibit B-1, Appendix A, p. 12

Q2.1 Please describe the characteristics that distinguish Rate 31 customers from Rate 33 customers. What characteristics justify the creation of a separate class of service?

A2.1 A customer that takes service under Rate Schedule 31 is also eligible to take service under Rate Schedule 33 subject to the conditions contained in the Tariff, including the time restrictions and the maintenance of a satisfactory load factor. As discussed in the response to Zellstoff Celgar IR No.1 Q1.4, Rate 31 and Rate 33 are both considered to be Large General Service – Transmission, however for COSA purposes the small number of customers in the class overall, and given that Zellstoff Celgar is the lone Schedule 33 customer, is also a self-generator, and has a significant impact on the class as a whole, a separation for cost allocation is necessary to avoid intra-class subsidization.

3.0 Reference: Exhibit B-1, Appendix A, Schedule 8.2, p. 2 of 3

Q3.1 Please explain why the System Coincidence Factor is the same for the Rate 33 Industrial class as for the Rate 31 Industrial Class.

A3.1 To develop coincidence factors for the industrial transmission customers, hourly load data was used for a three year time period. The data was averaged over all of the customers in the industrial transmission class. In addition, the information for Rate 33 reflected many hours where self-generation occurred, which did not provide accurate data on the use of wires facilities at those time periods.

Q3.2 What studies were performed to establish the System Coincidence Factor for the Rate 33 Industrial class? Please provide a copy of any applicable studies.

A3.2 The studies contain hourly load data for each individual customer within the class. FortisBC does not believe it is appropriate to provide the data requested, as it is potentially sensitive for customers in competitive industries.

4.0 Reference: Exhibit B-1, Appendix A, Schedule 8.3

Q4.1 Please explain why the Primary Line Losses factor is the same for the Rate 33 Industrial class as for the Rate 31 Industrial Class.

A4.1 The primary line loss factor is the same for all customers served at transmission voltage and reflects transmission losses. FortisBC cannot calculate line losses for individual customers since they are served off of an integrated grid.

5.0 Reference: Exhibit B-1, Appendix I, p. 8

Q5.1 FortisBC lists "Call for meeting" as the method of contact for Celgar. Please provide the specifics of when and to whom the call was placed.

A5.1 Blair Weston, FortisBC PowerSense Technical Advisor contacted Brian Merwin, Mercer International Business Analyst by telephone to confirm with whom FortisBC staff should meet. A meeting with Jim McLaren, Zellstoff Celgar Manager, Energy Projects was subsequently set up by email.

Dennis Swanson, FortisBC Director of Regulatory Affairs, Corey Sinclair, FortisBC Manager of Regulatory Affairs and Blair Weston, FortisBC PowerSense Technical Advisor met with Jim McLaren at 2 pm, Tuesday May 26, 2009 at Zellstoff Celgar Pulp Mill in Castlegar.

Q5.2 Please identify when in the consultation process, if at all, Celgar was notified that Rate Schedule 33 customers may be allocated the full burden of reapportionment of costs over the LGS class, to the exclusion of other members of the LGS class through the establishment of a new rate class.

A5.2 Celgar was not notified that the revenue to cost ratios for the Rate Schedule 33 and the Rate Schedule 31 customers would be identified separately during the consultation process. As a result of the consultation process and the analysis that was subsequently done, it was discovered that the revenue to cost ratios of the Rate Schedule 31 customers were being significantly negatively impacted by the Rate Schedule 33 customer. The customers were further separated into Rates 31 and 33 and the Company included this information in the final Application to ensure that there was a more thorough explanation of the issues affecting the revenue to cost ratios of the respective rate classes.

6.0 Reference: Exhibit B-1, Appendix I, p. 30

Q6.1 Please explain why the Rate 33 LGS ratepayers were not identified as a separate rate class in the table on Slide 18 of the presentation dated May 2009, but instead appears to have been included in the "Industrial Transmission" rate class.

A6.1 Please refer to the response to Zellstoff-Celgar IR No. 1 Q5.2.

7.0 Reference: Exhibit B-1, Appendix I, p. 44

Q7.1 Please explain why the Rate 33 LGS ratepayers were not identified as a separate rate class in the table shown on Slide 5 of the referenced presentation, but instead appear to have been included in the "Industrial Transmission" rate class.

A7.1 Please refer to the response to Zellstoff Celgar IR No. 1 Q5.2 above.

Q7.2 When was the referenced presentation prepared?

A7.2 The content of the presentation was prepared during the week of August 9, 2009.

8.0 Reference: Exhibit B-1, Appendix I, p. 63

Q8.1 Please explain why the Rate 33 LGS ratepayers were not identified as a separate rate class in the table shown in the referenced Discussion Guide, but instead appear to have been included in the "Industrial Transmission" rate class.

A8.1 Please see the response to Zellstoff Celgar IR No. 1 Q5.2.

Q8.2 When was the referenced Discussion Guide prepared?

A8.2 The discussion guide was prepared in advance of the July public open houses.

9.0 Reference: Exhibit B-1, Appendix 1, p. 84

Q9.1 Please explain why the Rate 33 LGS ratepayers were not identified as a separate rate class in the table shown in the report "An Assessment of Public Reactions to the Rate Rebalancing and Rate Design Options" dated September 4, 2009, but instead appear to have been included in the "Industrial Transmission" rate class.

A9.1 Please refer to the response to Zellstoff Celgar IR No. 1 Q5.2.

Q9.2 Please provide a copy of the first instance in which FortisBC identified that Rate Schedule 33 customers were proposed to be treated as a stand-alone rate class for the purposes of the proposed rate rebalancing. When did such classification and/or reallocation occur?

A9.2 FortisBC first identified that Rate Schedule 33 was to be separated for COSA purposes in the EES Electric Cost of Service Study, dated September 30, 2009 and filed as Appendix A to the Application (Exhibit B-1).

10.0 Reference: EXCEL Spreadsheet Attachment to Exhibit B-1, "Cover" Worksheet

Q10.1 The "Cover" Worksheet identifies in Row 46 this version of the spreadsheet as the "Revised Final Version". Please provide working copies of the "Final Draft" and "Final Version" identified in Rows 44 and 45, and the dates those versions were prepared or issued.

A10.1 The Cover worksheet is part of the EES COSA model. The various dates for different drafts on the Cover page were never used in the case of FortisBC.

11.0 Reference: 1997 COSA

Q11.1 Please provide the total revenue from Rate Schedule 31 customers (or equivalent) in the 1997 COSA, and identify the percentage and amount of revenue that was assumed to come from the Celgar facility in Castlegar, and also identify the Revenue to Cost Ratio for that rate class.

A11.1 The revenue for the class was $2,668,000. The revenue to cost ratio was 125.3 percent, as shown on page 39 of the COSA Report. The amount of revenue from the Zellstoff Celgar facility was not separately identified in the 1997 COSA.

Q11.2 Please provide the values for the total energy delivered to Rate Schedule 31 customers (or equivalent) in the 1997 COSA, and identify the percentage and amount of energy that was assumed to be delivered to the Celgar facility in Castlegar.

A11.2 The energy for the class was 60,000 MWh. The amount of energy from the Zellstoff Celgar facility was not separately identified in the 1997 COSA.

Q11.3 Please provide the actual values for the total energy delivered to Rate Schedule 31 customers (or equivalent) in the 1997, and identify the percentage and amount of energy that was delivered to the Celgar facility in Castlegar.

A11.3 Energy delivered to the Industrial Transmission customers in 1997 was 107 GWh.

Q11.4 Please provide a table showing the annual amount of energy purchased by the Celgar facility in Castlegar for each year between 1992 and 2008, and if different, please also provide in the table the annual plant load for each year and the difference between the two values. If the value has changed over time, please explain why, and if FortisBC's energy sales to the Celgar facility in Castlegar have not increased along with increases in plant load, please explain why.

A11.4 Annual energy purchased is provided below in Table Zellstoff Celgar A11.4. The data for 2007 and 2008 is energy billed, including manual adjustments.

Data between 1997 and 2006 is extracted from system control interchange estimates. The energy purchases between 1992 and 1996 are not included in the table below because the data was combined with Westar Timber in system control records.

Table Zellstoff Celgar A11.4

Year	MWh
2008	13,772
2007	25,108
2006	62,694
2005	54,427
2004	59,234
2003	71,393
2002	93,833
2001	88,704
2000	30,636
1999	19,824
1998	28,217
1997	5,072

FortisBC does not track the Zellstoff Celgar plant load and therefore cannot provide a summary of the differences between the plant load and energy purchased.

Issue: Design of Rate Schedule 33

12.0 Reference: Exhibit S-1, Section 14.3, p. 73

Q12.1 Please provide a comparison of the charges an LGS customer would pay for service under Rate Schedule 31 as compared to service under Rate Schedule 33 where: maximum monthly demand is 10 MW - during one day in each month electricity is drawn at the 10 MW rate, while the rest of the hours in the month are at a constant load to achieve the specified load factor Provide comparisons for a customer load factor of 90 percent, 75 percent and 55 percent. Please show the monthly charges for winter, summer and shoulder months as well as the annual total. If the calculation methodology is not readily apparent in the hardcopy of the response, please also provide the analysis in electronic spreadsheet format.

A12.1 Please refer to Tables Zellstoff Celgar A12.1a and A12.1b below. A customer with the flat load shape specified by the assumptions in this question would not benefit from Schedule 33 as detailed in Table Zellstoff Celgar A12.1a. Table Zellstoff Celgar A12b provides a scenario with the same base assumptions but provides for a shift of 10 percent of energy use from the on-peak period to the off-peak period. In that case Schedule 33 provides savings at all three load factors. Tables Zellstoff Celgar A12.1a and A12.b below are also provided in electronic Excel format with supporting calculations as Zellstoff Celgar Appendix A12.1.

Table Zellstoff Celgar A12.1a

	Rate 33	Rate 33	Rate 33	Rate 33	Rate 33
	Customer Charge	**Demand Charge**	**On-Peak Charge**	**Off-Peak Charge**	**Total Charges**
90% Load Factor	$24,782	$0	$2,616,931	$1,299,173	$3,940,886
75% Load Factor	$24,782	$0	$2,180,776	$1,082,644	$3,288,202
55% Load Factor	$24,782	$0	$1,599,235	$793,939	$2,417,957
	Rate 31	**Rate 31**	**Rate 31**	**Rate 31**	**Rate 31**
	Customer Charge	**Wires Charge**	**Power Supply Charge**	**Energy Charge**	**Total Charges**
90% Load Factor	$24,782	$420,000	$240,000	$3,104,719	$3,789,501
75% Load Factor	$24,782	$420,000	$240,000	$2,587,266	$3,272,048
55% Load Factor	$24,782	$420,000	$240,000	$1,897,328	$2,582,111

Table Zellstoff Celgar A12.1b

	Rate 33	Rate 33	Rate 33	Rate 33	Rate 33
	Customer Charge	**Demand Charge**	**On-Peak Charge**	**Off-Peak Charge**	**Total Charges**
90% Load Factor	$24,782	$0	$2,106,283	$1,515,175	$3,646,240
75% Load Factor	$24,782	$0	$1,755,236	$1,262,646	$3,042,664
55% Load Factor	$24,782	$0	$1,287,173	$925,940	$2,237,896
	Rate 31	**Rate 31**	**Rate 31**	**Rate 31**	**Rate 31**
	Customer Charge	**Wires Charge**	**Power Demand**	**Energy Charge**	**Total Charges**
90% Load Factor	$24,782	$420,000	$240,000	$3,104,719	$3,789,501
75% Load Factor	$24,782	$420,000	$240,000	$2,587,266	$3,272,048
55% Load Factor	$24,782	$420,000	$240,000	$1,897,328	$2,582,111

Q12.2 In the above scenario, please identify the load factor required to cause the annual totals for the two rate schedules to be equal to one another. For load factors higher than this, what was FortisBC's intent in having the Rate Schedule 33 amounts exceed those of Rate Schedule 31?

A12.2 The load factor at which the two rate schedules produce the same annual total is 73 percent. FortisBC did not have an "intent" from this perspective when considering the creation of these rates, however, it can be seen from the tables above that a modest shift in consumption patterns provides a benefit for a customer on Rate 33.

Q12.3 Please explain if the original design of the energy charges of Rate Schedule 33 included an embedded demand charge, or assumed a particular load profile or load factor of a typical customer that would elect to take service under that rate. Please describe if the original design of the energy charges of Rate Schedule 33 included an adjustment for higher system losses in the on-peak charge, and lower system losses in the off-peak charge. Please provide the details of all the assumptions used in the design of Rate Schedule 33.

A12.3 The design of the existing TOU rates is described in detail in pages 15 to 25 of the 1997 RDA filing, which is attached to these IR Responses as BCMEU Appendix A34.1. Rate 33 was designed under the same principles and using the same methodology as all other time of use rates. There was no explicit adjustment for higher on-peak losses.

Q12.4 Please confirm that Mr. George Isherwood: (i) was instrumental in designing the original Rate Schedule 33; and (ii) is currently contracted to FortisBC. Please advise as to whether Mr. Isherwood has been consulted with regard to questions 12.1 through 12.3, inclusive.

A12.4 Mr. Isherwood was involved in the design of the original Rate Schedule 33. It is confirmed that Mr. Isherwood has been contracted by FortisBC and has been consulted on Zellstoff Celgar IR No. 1 questions 12.1 through 12.3.

13.0 Reference: Exhibit B-1, Section 8.1, Table 8.1a, p. 48

Q13.1 FortisBC identifies an annual "Total Rate % Increase" for Large General Service Transmission 33 of ten percent in each of five years. Please provide numerical values (not percentages) for the components of that rate in each of the five years as well as the assumed monthly energy usage and kVA demand.

A13.1 The values contained in Tables 8.1a and 8.1b were provided for information purposes as an approximation of the rebalancing results. No attempt was made in the development of tables to derive the values using a bottom-up calculation of revenues. No individual billing determinants were used. Costs were assumed to increase at the rate identified by the associated annual rise in the revenue requirement while maintaining a consistent proportion of recovery across the rate groups. Revenues rise as per the assumed annual revenue rate increase added to the rebalancing increase. Assuming a 5 percent annual rate increase and 5 percent rebalancing adjustment the numerical values associated with the tables are shown in Table Zellstoff Celgar A13.1 below:

Table Zellstoff Celgar A13.1
Rate 33 Rebalancing

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Allocated Costs ($)	3,814,638	4,005,370	4,205,638	4,415,920	4,636,716	4,868,552
Revenues at Proposed Rates ($)	897,931	987,724	1,086,496	1,195,146	1,314,660	1,446,126
Revenue to Cost Ratio	23.5%	24.7%	25.8%	27.1%	28.4%	29.7%

14.0 Reference: Exhibit B-1, Section 8.1, Table 8.1b, p. 49

Q14.1 FortisBC shows the revenue to cost ratio for Large General Service Transmission 33 rising from 23.5 percent to 29.7 percent over a period of five years. Please provide the numerical values for the components of the rate, the customer monthly and annual load demand, the customer monthly and annual load energy, and the monthly and annual revenues from the customer in each of the five years. Please calculate and provide the overall average cost per MW.h for each of the five years. Please advise as to how the annual increments reflect the 10 percent annual cap increases contemplated by the rate reapportionment allocated to Celgar.

A14.1 Please refer to the response to Zellstoff Celgar IR No. 1 Q13.1 above.

Q14.2 Can FortisBC confirm that the "all-in" average cost of energy for BC Hydro's pulp and paper customers is approximately $39/MW.h? if not, please provide whatever information FortisBC has regarding this average energy cost.

A14.2 FortisBC cannot confirm current cost information for a utility other than itself.

15.0 Reference: Exhibit B-1, Section 10.1, p. 58

"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."

Q15.1 Was one of the original objectives of Rate Schedule 33 to promote conservation? If so, has Rate Schedule 33 been effective in achieving that objective? If Rate Schedule 33 has been effective in promoting conservation, please advise as to how such objective has been met or promoted and how FortisBC measures the effectiveness and quantifies the benefits of Rate Schedule 33 in doing so.

A15.1 The intent of the implementation of Time-of-Use rate schedules was articulated in the 1997 Cost of Service and Rate Design Application:

> *The time of use rate meets the first and third stated objective of this Application, that is, to provide customers with more choice and to provide customers with price signals that reflect trends in evolving electricity markets.*

The intention at the time was primarily to shift customer usage from on-peak to off-peak periods to reduce power purchase costs and defer system capital expenditures.

Q15.2 Was one of the original objectives of Rate Schedule 33 to reduce peak demand? If so, has Rate Schedule 33 been effective in achieving that objective? If Rate Schedule 33 has been effective in reducing peak demand, please describe how Rate Schedule 33 has achieved or promoted such objective and how FortisBC measures the effectiveness of Rate Schedule 33 in doing so.

A15.2 As stated in the response to Zellstoff Celgar IR No. 1 Q15.1, one of the objectives of Time-of-Use rates is to reduce load during peak hours. With the normal application of the rate to commercial customers, success can be measured by reviewing load data from periods both prior to and during a customers participation in the TOU program to determine if a shifting of peak demand has occurred. The TOU rate was not developed in consideration of a customer with the ability to generate all or a portion of its power requirement. This hinders the ability to determine whether and to what extent peak load has been shifted or simply reduced by self generation, and whether the TOU rate has been responsible for the reduction or has simply made it economic for the self- generating customer to make investments in generation.

Q15.3 Please explain why and how the wires-based demand charge proposed for Rate Schedule 33 is consistent with Principle 3 referenced in Exhibit B-1, Section 10.1, p. 58 and Exhibit B-1, Section 5.0, p.33 and with the additional weight given to conservation, as suggested in Exhibit B-1, Section 5.0, p. 34.

A15.3 FortisBC looked at all of the principles listed on page 33 and tried to balance those principles. While the wires-based demand charge may not promote a lower overall energy use, it does promote the reduction of peak demand, which is a factor in FortisBC's need to build future resources. Even with a contract demand billing determinant, the ratchet provision would deter customers from creating peak demand levels above the contract demand. And although the contract demand is fixed for a period of time, by creating the wires charge the customer will no longer have an incentive to request a high contract demand for reliability reasons without paying for the facilities required to meet that contract demand. As FortisBC is contractually responsible to meet contract demand levels, a lower contract demand level will conserve resources.

Further, conservation of resources typically refers to the power supply and generation side of the business. The wires charge is designed to cover the fixed costs of the wires system and does not reflect any costs associated with power supply.

16.0 Reference: Exhibit B-1, Appendix B - Amended Rate Schedules, Rate Schedule 33, Sheet 12

"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."

Q16.1 Please describe the criteria and characteristics of a satisfactory load factor.

A16.1 Section 5.1.4 of the 1997 Rate Design and New Service Options Application considered the load factor restriction to be necessary as demonstrated below.

> *The proposed restriction (see TOU Tariffs, Applicable, lines 5 - 7) for customers with low load factors provides sufficient flexibility to meet the needs of participating customers while protecting the interests of non-participating customers.*

In determining what constitutes an acceptable load factor the Company will assess each situation individually to determine whether allowing a customer to take or remain on TOU service adversely affects the remaining customers in the class, and whether a poor load factor contributes to the impact.

Q16.2 Please describe the criteria and characteristics of an unsatisfactory load factor.

A16.2 Please refer to the response Zellstoff Celgar IR No. 1 Q16.1 above.

Q16.3 Please describe if the criteria and characteristics described above are the same for Rate Schedules 2A, 22A, 32, 33, 40A, 408, 40C, 40D, 40E, 40F, 43 and 61.

A16.3 Please refer to the response Zellstoff Celgar IR No. 1 Q16.1 above.

Q16.4 Please explain how the phrase "as determined by the Company" is to be applied by FortisBC, without providing criteria upon which the concept "satisfactory Load Factors" is to be assessed. Does FortisBC have an internal list of such criteria upon which they intend to rely? If so, what are they? If not, what assurances do ratepayers have that they will be able to continue to access Rate Schedule 33 and that FortisBC's "determination" will be consistently, and not arbitrarily, applied over time?

A16.4 A customer who had been placed on Rate 33 would continue to be eligible unless it was determined that its load factor had become unsatisfactory in which case it may be placed back on Rate 31. Please also refer to the response to Zellstoff Celgar IR No. 1 Q16.1 above.

Q16.5 Please explain how a customer that is successful in shifting all energy consumption to off-peak hours, as the Time of Use rate incents the customer to do, will be addressed by FortisBC in its interpretation of a satisfactory load factor.

A16.5 The assessment of satisfactory load factor does not change from those considerations discussed in the response to Zellstoff Celgar IR No. 1 Q16.1.

Q16.6 Please describe how FortisBC intends to address a customer with low contract demand during on-peak hours and high contract demand during off-peak hours.

A16.6 Under the proposed rates included in the Application, all customers with a contract demand billing component are charged a wires-based amount of at least 100 percent of their contract demand. Contract demand should not vary throughout the day as it is a single nomination.

Q16.7 Please explain why FortisBC is not proposing the introduction of a wires charge for the Time of Use Rate Schedules 2A and 22A.

A16.7 Wires based demand charges are only contemplated in the Application for Rate Schedules with a Contract Demand based billing component and their associated TOU rates. The Company does not have the ability to collect a demand charge for either residential or small general service customers as they do not have sufficient metering in place.

Q16.8 If a residential customer conserves electricity through shutting off lights and turning electric heat down by 2 degrees does this reduce a customer's load factor? Is this not considered conservation? Please explain how FortisBC will discriminate between conservation and an unsatisfactory load factor when allowing access to Time of Use rates.

A16.8 FortisBC agrees that turning down the heat or turning off lights is conservation, however, this would not affect the assessment of a satisfactory load factor.

Q16.9 Please explain if and how reduced load factors that come about as a result of conservation could require higher per unit energy rates in order to preserve full recovery of costs. Is this not contradictory to achieving conservation?

A16.9 Conservation will not necessarily result in a lower load factor. However, if it did, but the energy use of a customer remained the same, a lower load factor will result in higher peak usage. This may increase demand-related costs and may therefore increase energy and/or infrastructure costs. These increased costs are not contradictory to achieving conservation.

Q16.10 If a residential customer installs a small wind turbine and a solar panel roof, thereby reducing the customer's load factor to 5 percent, would this customer be refused access to the conservation focused Time of Use rate?

A16.10 It is unlikely that a single residential customer would be refused access as the likelihood that the customer could create a situation that would adversely affect the non-participating members of the customer class is negligible.

Q16.11 If a number of residential customers made this shift to distributed generation (wind turbines and solar panel roofs) would Fortis need to create a new rate class as these customers would now have a low cost recovery. Please explain.

A16.11 No. For TOU customers, in order to limit the short-term impacts on non-participating customers, the annual incremental customer participation in each class is limited to 5 percent per annum of the previous year's total load for that customer class. In other words, a customer not on the TOU rate will not be able to utilize the TOU rate if in that year the total load of additional customers utilizing the rate exceeds 5 percent of the previous year's total load for that class. This program restriction was specified in the 1997 Rate Design and New Service Options Application and FortisBC believes that the Commission expressed support for this aspect of the proposal when it commented in its Decision G-15-98, "*Further, the Commission finds that the rules that will govern this program limit the risks for both participants and nonparticipants so that neither group should be exposed to undue risks."* (Order G-15-98, Appendix A, page 6)

Issue: Assignment of costs to Rate Schedule 33

17.0 Reference: Exhibit B-1, Appendix A, Schedule 1.1

Q17.1 Please explain why the Rate 33 Industrial customer should attract any Distribution-Related Costs.

A17.1 The distribution assets flowing through to transmission customers are for accounts 369-371. These accounts contain costs for Services, Meters and Installations on Customer Premises. These items are attributable to all customers, regardless of voltage level.

18.0 Reference: Exhibit B-1, Appendix A, Schedule 1.3

Q18.1 Please explain why the Rate 33 Industrial customer attracts $304,196 for Distribution Customer charges, and what this charge is meant to represent.

A18.1 Please refer to the response to Zellstoff Celgar IR 17.1, above. The $304,196 referenced in the question is the amount of rate base assigned to the class, not the annual cost of service.

Q18.2 Please quantify the number of FortisBC employee-hours that are spent per month reading its Rate Schedule 33 customer's meter.

A18.2 Schedule 33 meter reading cost and time tracking is aggregated with other interval meter customers and is not tracked separately. FortisBC estimates the time spent reading Rate Schedule 33 meters at 51 hours annually based on the COSA allocation.

Q18.3 Please quantify the number of FortisBC employee-hours that are spent per month preparing its Rate Schedule 33 customer's bill for Rate Schedule 33 energy purchases.

A18.3 Schedule 33 billing cost and time tracking is aggregated with other interval meter customers and is not tracked separately. FortisBC estimates the time spent preparing Rate Schedule 33 bills is 11 hours annually based on the COSA allocation.

Q18.4 What is the average cost per hour of an employee who reads Celgar's meter and what is the average hourly cost of an employee who prepares Celgar's monthly bill?

A18.4 The average hourly cost of an employee who reads Celgar’s meter is $60.26 and the average hourly cost of an employee who prepares Celgar’s monthly bill is $56.20.

Q18.5 Please give five examples of advertising directed at Rate Schedule 33 customers, and itemize the cost of this advertising.

A18.5 FortisBC generally does not produce any advertising directed solely to Rate Schedule 33 customers or any other specific customer class.

19.0 Reference: Exhibit B-1, Appendix A, Schedule 2.1

Q19.1 Please explain the basis for the 480,000 Total kVA Contract value for the Rate 33 Industrial customer in Schedule 2.1.

A19.1 The 480,000 Total kVA reflects 40,000 kVA per month, which is based on the contract demand limit contained in the contract.

Q19.2 Please provide all contracts which specify the demand service FortisBC has with the Rate 33 Industrial customer.

A19.2 FortisBC assumes that "demand service" refers to the General Service Power Contract under which Zellstoff Celgar is entitled to receive service on Rate schedule 33.This information is attached as Zellstoff Celgar Appendix A19.2.

Q19.3 Please provide the actual monthly maximum demand amounts for 2007 and 2008 for the Rate 33 Industrial Customer, and reconcile these against the values for Total Demand (kW) and Total kVA Contract in Schedule 2.1.

A19.3 Table Zellstoff Celgar A19.3 below shows the monthly maximum non-coincident demands for the Rate 33 Industrial Customer. The amount of 480,000 kVA in Schedule 2.1 of the COSA (Appendix A of the Application) represents the contract demand of 40 MVA per month times 12 months. This amount reflects the ratchet provisions associated with the demand charge proposed for Rate 33. The Total Demand (kW) of 136,800 represents 12 months of an estimated 12 MVA, adjusted for power factor to reflect MW. This number was developed to be consistent with the coincident peaks of other classes but is not relevant in the case of Rate 33 as there is no demand charge and therefore no comparable billing determinant for demand.

The contract demand was exceeded by 5 MVA in the year 2008. If the

COSA were updated to reflect this exceedance, the 45 MVA would be used for both allocating demand-related costs and for calculating the unit cost of demand for the class.

Table Zellstoff Celgar A19.3

	2007 (MW)	2008 (MW)
January	26	44
February	41	10
March	39	38
April	38	32
May	40	44
June	41	26
July	16	41
August	16	43
September	8	45
October	40	43
November	41	40
December	23	41

Q19.4 Please provide any information FortisBC has regarding the demand rate with was used in BC Hydro's most recent cost-of-service study for industrial customers with self-generation. Please describe whether BC Hydro used the maximum potential load for industrial customers with self-generation when setting the demand rate, or some lower amount.

A19.4 From the Cost of Service Data provided by BC Hydro on page 14 of Appendix C to its 2007 Rate Design Application, it does not appear that industrial customers with self-generation were distinguished from other industrial customers for the purpose of determining the unit cost of demand. FortisBC does not have information on the specific allocation factors used in the 2007 BC Hydro cost-of-service study and cannot confirm how the final demand rate was set in the Industrial rate schedules but notes that Tariff rate ($5.26 /kW for Rate 1823) is below the COSA derived amount ($7.51 / kW per the 2007 FACOS).

20.0 Reference: Exhibit B-1, Appendix A, Schedules 6.3 and 6.4

Q20.1 When did the Rate 33 Industrial customer first access service under Rate Schedule 33?

A20.1 The Rate 33 customer first took service under Rate Schedule 33 for the October 2006 billing period.

Q20.2 Since the Rate 33 Industrial customer first took service under Rate Schedule 33, please provide a history of the number of hours, by month, that the customer had a demand of 40,000 kVA or more, separately for on-peak hours and off-peak hours. Also express this as a percentage of the total hours in the month and per calendar year.

A20.2 Zellstoff Celgar first took service under Rate Schedule 33 in October 2006. Zellstoff Celgar Table A20.2a - Monthly below shows monthly hours and Table A20.2b - Annual shows annual hours as requested. FortisBC does not record MVA demand. For the purposes of the tables below, Zellstoff Celgar Load over 36 MW is equivalent to 40 MVA. On-peak and off-peak hours are as defined in FortisBC's current Rate Schedule 33.

1 **Zellstoff Celgar Table A20.2a - Monthly**

Year	Month	On Peak	Off Peak	Total On Peak	Total Off Peak	On Peak	Off Peak
		Number of Hours				%	
2006	October	2	5	416	328	0.5%	1.5%
2006	November	17	58	231	489	7.4%	11.2%
2006	December	1	8	209	535	0.5%	1.5%
2007	January	0	0	242	502	0.0%	0.0%
2007	February	5	2	220	452	2.3%	0.4%
2007	March	2	0	432	312	0.5%	0.0%
2007	April	1	7	400	320	0.3%	2.2%
2007	May	1	3	432	312	0.2%	1.0%
2007	June	7	3	416	304	1.7%	1.0%
2007	July	0	0	231	513	0.0%	0.0%
2007	August	0	0	242	502	0.0%	0.0%
2007	September	0	0	400	320	0.0%	0.0%
2007	October	4	2	432	312	0.9%	0.6%
2007	November	1	10	231	489	0.4%	2.0%
2007	December	0	0	209	535	0.0%	0.0%
2008	January	0	10	242	502	0.0%	2.0%
2008	February	0	0	231	465	0.0%	0.0%
2008	March	5	0	416	328	1.2%	0.0%
2008	April	0	0	416	304	0.0%	0.0%
2008	May	8	0	432	312	1.9%	0.0%
2008	June	0	0	400	320	0.0%	0.0%
2008	July	0	12	242	502	0.0%	2.4%
2008	August	4	10	220	524	0.9%	2.3%
2008	September	17	15	416	304	4.1%	4.9%
2008	October	1	20	432	312	0.2%	6.4%
2008	November	4	0	209	511	1.9%	0.0%
2008	December	3	7	231	513	1.3%	1.4%
2009	January	7	2	231	513	3.0%	0.4%
2009	February	1	1	220	452	0.5%	0.2%
2009	March	1	0	416	328	0.2%	0.0%
2009	April	0	0	416	304	0.0%	0.0%
2009	May	3	7	416	328	0.7%	2.1%
2009	June	0	0	416	304	0.0%	0.0%
2009	July	0	0	242	502	0.0%	0.0%
2009	August	0	1	220	524	0.0%	0.2%
2009	September	0	0	416	304	0.0%	0.0%
2009	October	0	0	432	312	0.0%	0.0%
2009	November	0	25	220	500	0.0%	5.0%
2009	December	0	0	231	513	0.0%	0.0%

2 Note: Total On Peak and Off Peak hours vary due to the number of week days and week end days in the month.

1 **Zellstoff Celgar Table A20.2a - Annual**

Annual	On Peak	Off Peak	Total On Peak	Total Off Peak	On Peak	Off Peak
	Hours		Hours		Percentage	
2007	21	27	3,887	4,873	0.5%	0.6%
2008	42	74	3,887	4,897	1.0%	1.6%
2009	12	36	3,876	4,884	0.3%	0.7%

Q20.3 Please provide a history of the demand of the Rate 33 Industrial customer since it first took service under Rate Schedule 33 at the time of the FortisBC system peak for the months of January, February, July, August, November and December of each year. In how many instances did the customer's demand meet or exceed 40,000 kVA at the time of the FortisBC system peak in each of those months?

A20.3 Zellstoff Celgar load (MW) at the time of the FortisBC Monthly System Peak is provided in the table below:

Table Zellstoff Celgar A20.3

	January	February	July	August	November	December
2006	XX	XX	XX	XX	0	5
2007	10	0	0	0	0	0
2008	0	0	0	0	37	2
2009	40	0	0	0	42	0 est

If the Zellstoff load is high, a reasonable power factor to assume is 0.9. This means MVA loads will be approximately 11 percent higher than MW loads.

Based on this assumption, the Zellstoff Celgar load exceeded 40,000 kVA at the time of the FortisBC monthly system peak 3 times since October 2006.

21.0 Reference: Exhibit B-1, Appendix A, pp. 17-18

"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."

"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."

Q21.1 Please provide the source information FortisBC used to identify the classification of BC Hydro generation costs.

A21.1 The source of the information was the Cost of Service Schedules from BC Hydro's most recent RDA, as found at the following link:

http://www.bchydro.com/planning_regulatory/regulatory/rate_design_application/regulatory_documents.html

22.0 Reference: Exhibit B-1, Appendix A, p. 31

"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."

Q22.1 As FortisBC is a winter-peaking utility, please provide further justification as to why the summer peak is afforded the same weight as the winter peak for transmission cost allocation.

A22.1 Please refer to the responses to BCUC IR No. 1 Q68.1 thru Q68.8.

Q22.2 Please provide justification as to why the 1 CP approach is not the more appropriate method for transmission cost allocation.

A22.2 Please refer to the responses to BCUC IR No. 1 Q68.1 thru Q68.8.

23.0 Reference: EXCEL Spreadsheet Attachment to Exhibit B-1, "Rate Base" Worksheet, Cells AH51 to AH61

Q23.1 Please describe the substation assets in service between the Celgar facility and the interconnection of the FortisBC and BCTC/BC Hydro transmission system, and please identify the ownership of these substation assets.

A23.1 FortisBC operates a meshed transmission system with multiple interconnections to the BCTC transmission system; thus, it is not possible to define a single path from the Zellstoff Celgar facility to the BCTC system. Energy transfers between Zellstoff Celgar and BCTC can take place over five system interconnection paths in the Kootenays and the Okanagan. There are numerous facilities that make up these paths (lines, transformers and substations) and these are owned/operated by various parties including FortisBC, Teck Metals, Columbia Power Corporation and BCTC.

Q23.2 Please assign a cost to each of the FortisBC substation assets described in the previous question and assign a "percentage utilization" of the substation assets to the Celgar facility.

A23.2 Given the complex network of transmission interconnections described in the response to Zellstoff Celgar IR No. 1 Q23.2, it is not possible to assign a “percentage utilization” value as requested.

Q23.3 Please describe the FortisBC transmission line infrastructure assets between the Celgar facility and the Brilliant Terminal Station, and identify the book value and replacement cost of these assets. Please assign a "percentage utilization" of the transmission line infrastructure assets to the Celgar facility.

A23.3 Between the Zellstoff Celgar facility and the Brilliant Terminal Station there are two 63 kV transmission lines (6L and 26L), a 63 kV switching station and another two 63 kV transmission lines (7L and 8L). This is shown schematically in the following Figure Zellstoff Celgar A23.3. Note that the Zellstoff Celgar facility is represented as “KRA”, the 63 kV switching station as “BSS” and the Brilliant Terminal Station as “BTS”. The requested values can be found in Table Zellstoff Celgar A23.3 following. Note that the replacement costs in the table should be considered +/- 50 percent planning level estimates.

Figure Zellstoff Celgar A23.3 – Castlegar-area Transmission Network

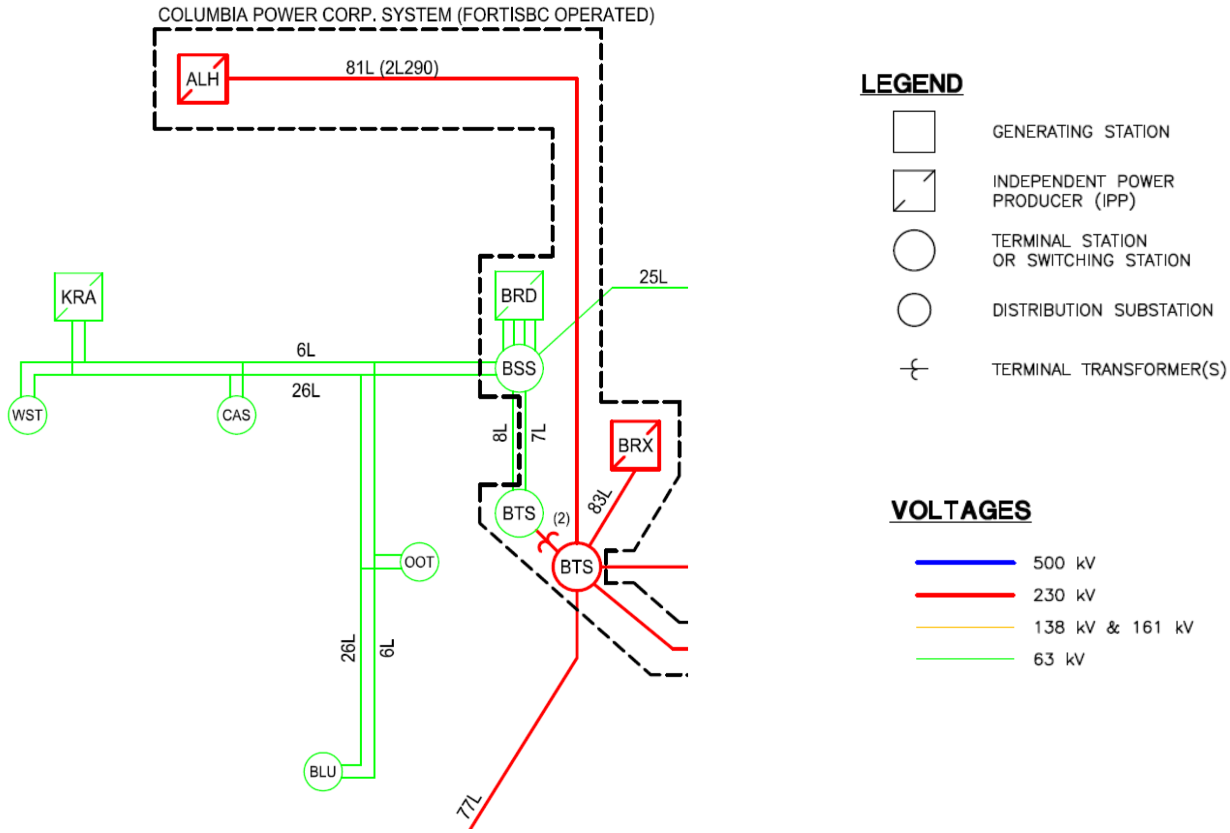

Table Zellstoff Celgar A23.3

Facility	Book Value ($000s)	Replacement Cost ($000s)	Percentage Utilization
6L	288	4,700	n/a[1]
26L	338	4,700	n/a
BSS[2]	n/a	n/a	n/a
7L[3]	n/a	n/a	n/a
8L	742	250	n/a

[1] It is not possible to assign a percent utilization as described in the response to Q23.2.
[2] Asset owned by Brilliant Power Corporation
[3] Asset owned by Brilliant Power Corporation

Q23.4 There are two 63 kV transmission lines between the Celgar facility and the Castlegar substation. Please identify all customers connected to the transmission lines "downstream" of the Castlegar substation.

A23.4 As shown in Figure Zellstoff Celgar A23.3, downstream of the Castlegar substation ("CAS"), the two 63 kV transmission lines (6L and 26L) are used to supply two customers: one is the Zellstoff Celgar facility ("KRA") and the other is a customer-owned substation ("WST") for the Interfor sawmill northwest of Castlegar. While the sawmill site is currently shut down, the substation is still energized.

Q23.5 There are two 63 kV transmission lines between the Celgar facility and the Castlegar substation. If Celgar decided to be served by only one of the transmission lines, please describe the changes to the Transmission Plant Rate Base Cost Allocation assigned to the Rate 33 Industrial customer.

A23.5 The FortisBC transmission system is integrated and as such does not rely on dedicated facilities for each customer. The postage stamp concept is used by FortisBC and approved by the BCUC. Rates are not differentiated by location and the costs of all facilities are spread among all of the customers on the system.

Issue: Impact of potential changes to Rate Schedule 33

24.0 Reference: Exhibit B-1, Section 14.3, p. 73

"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."

Q24.1 Please provide a calculation that shows the blended cost per MW.h for each usage period in the Time of Use Rate Schedule 33 if a wires-based demand charge is incorporated in an amount that brings the revenue to cost ratio to 100 percent as calculated in this Application. In other words, keeping the wires-based demand charge at $0 per kVA, please identify the equivalent energy rates required to achieve a revenue to cost ratio of 100 percent for the Rate Schedule 33 customer. Please provide the calculation in electronic spreadsheet format if the calculation procedure is not readily apparent in printed format.

A24.1 Please see Table Zellstoff Celgar A24.1 below.

Table Zellstoff Celgar A24.1

	Rate as Proposed	Billing Determinants	Revenue	Rate as Requested	Billing Determinants	Revenue
Basic Customer Charge	$2,065.18	12	$24,782	$2,065.18	12	$24,782
Energy Charge ($ / kWh):		**kWh**			**kWh**	
On-Peak Winter	$0.1267	2,511,915	$318,184	$0.3042	2,511,915	$764,174
Off-Peak Winter	$0.0359	4,098,387	$147,091	$0.2134	4,098,387	$874,759
On-Peak Summer	$0.1690	763,813	$129,062	$0.3465	763,813	$264,677
Off-Peak Summer	$0.0279	1,246,222	$34,795	$0.2055	1,246,222	$256,061
On-Peak Shoulder	$0.0405	4,570,205	$185,276	$0.2181	4,570,205	$996,716
Off-Peak Shoulder	$0.0214	3,309,459	$70,657	$0.1989	3,309,459	$658,251
		16,500,000	$885,064		16,500,000	$3,814,638
Cost of Service			$3,814,638			$3,814,638
Revenue to Cost Ratio			23.2%			100.00%

Q24.2 Please identify the total revenue received from the Rate 33 Customer for the question above on a monthly and annual basis, and compare this with the revenue being received at present rates on a monthly and annual basis. Please include your assumptions for energy consumption and demand.

A24.2 The current revenues are equal to the revenues at proposed rates in Table Zellstoff Celgar A24.1. There is no assumption for demand as there are no demand charges in the present or proposed initial rate.

Issue: Transmission Standby Service Rate Schedule

25.0 Reference: Exhibit B-i, Appendix A, p. 33

"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."

Q25.1 Please provide five Canadian Utility references for FortisBC's claim that it is standard utility practice to charge for standby service for customer-owned self-generation.

A25.1 The following table summarizes the standby rates for 7 Canadian utilities with standby rates.

Table Zellstoff Celgar A25.1

From OEB Rate Design Review			
Utility	**Customer Class**	**Standby Rate (per May 1, 2006 Rate Schedule)**	
		Demand Rate	**Customer Rate**
Barrie Hydro Distribution Inc.	GS > 50-Non RIMS	$2.60/kW	$356
Canadian Niagara Power – Port Colborne	Backup / Standby Power	$1.45 service charge plus $1.1432/kW	-
EnWin Powerlines Limited	Large Use >5MW	$0.56/kW	$5,964
	Intermediate (3,000-4,999 kW)	$0.56/kW	$400
Haldimand Couty Hydyro Inc.	GS>50-Non RIMS	N/A	$34
Horizon Utilities Corporation	GS>50-Non RIMS	$1.26/kW	$234
Hydro Ottawa Limited	GS>50-Non RIMS	$1.2678/kW	$247
	GS>50 RIMS	$1.1620/kW	$3,962
	Large Use >5MW	$1.2907/kW	$14,386
Toronto Hydro-Electric System Limited	GS>50	$4.96/kVA	$716
	Intermediate	$4.15/kVA	$2,750
	Large Use >5MW	$3.54/kVA	

Q25.2 Please provide a copy of BC Hydro's applicable electricity tariff rate schedule for standby service provided to industrial transmission-connected customers with self-generation.

A25.2 A copy of the requested BC Hydro rate schedule is provided as Zellstoff Celgar Appendix A25.2.

Q25.3 Please discuss the operation of BC Hydro's applicable electricity tariff rate schedule for standby service provided to industrial transmission-connected customers with self-generation, and what such a similar Rate Schedule would be for FortisBC using the same principles.

A25.3 FortisBC has no further comment to add to the full description of the use of the BC Hydro Schedule 1880 that is attached in response to Zellstoff Celgar IR No. 1 Q25.2 above. FortisBC does not have a comparable rate schedule.

Q25.4 If a charge for standby service is standard utility practice, please explain why FortisBC does not have a rate schedule for standby service.

A25.4 FortisBC may provide standby or back-up service to a customer on an individual basis if requested but has not developed a standard tariff due to the infrequent nature of the requirement.

Issue: Assignment of O&M Costs

26.0 Reference: Exhibit B-1, Appendix A, p. 24

"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."

Q26.1 On what evidence does FortisBC rely in support of the statement that employees are more closely tied to asset value rather than operations and maintenance.

A26.1 Please refer to the response to BCUC IR No. 1 Q54.3.

Q26.2 Please identify the number of employee-hours engaged in operations and maintenance in each of the three functions, and the percentage this represents of total employee-hours in each of the three functions, as well as for the company as a whole, and provide for reference the asset value of each function,

A26.2 Please refer to the response to BCUC IR No. 1 Q54.1.

Issue: Classification of Assets in the Minimum System Study

27.0 Reference: Exhibit B-1, Appendix A, p. 20

"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."

Q27.1 Please explain how the costs for the land, the control building, the grounding system, the security system, and the protection and control equipment are different for a single transformer 5 MVA substation as compared to a single transformer 25 MVA substation.

A27.1 Those costs would differ based on the specific nature of the substation to be built, and they may or may not differ in the simplistic case of a single transformer substation of various sizes.

Q27.2 Please justify the appropriateness of classifying all substation costs as demand related rather than classifying some portion as customer-related that is required independent of the level of demand.

A27.2 The classification of substations 100 percent to demand is standard industry practice.

Q27.3 For each substation in the FortisBC system, please identify the size and cost of substation that would be required if each customer's demand was limited to the PLCC of 1.0 kW per customer.

A27.3 FortisBC has not designed its substations on the basis of a 1.0 kW limit per customer, and therefore does not have the requested information.

Issue: Customer Bypass Opportunities

28.0 Reference: None

Q28.1 Does FortisBC believe that an opportunity for a specific customer to bypass the transmission portion of the FortisBC infrastructure (for which it has been allocated a cost in the COSA) through a customer-funded investment should be addressed in the overall exercise of rate design in order to incent the customer to abandon the customer-funded investment and choose to continue to utilize the FortisBC infrastructure and not implement the customer-funded investment. Please explain.

A28.1 Bypass rates are negotiated outside of the rate design process and as such are not considered in this RDA. In negotiating bypass rates FortisBC would look at the technical feasibility of the bypass, the expected cost of the bypass, the savings on the FortisBC system associated with a bypass and recovery of costs for any stranded assets associated with a bypass.

Issue: Order No. G-48-09

29.0 Reference: Decision Accompanying Order No. G-48-09, pp. 30-31, 34

"The Commission Panel directs BC Hydro, in consultation with FortisBC, to identify and submit to the Commission an agreed methodology to monitor "net of load" energy within 90 days of the date of this Decision."

"For its part, BC Hydro is to provide a report to the Commission that will summarize the terms and conditions of its contractual arrangements with any of its industrial customers with self-generation capacity who may sell power on a basis which is inconsistent with the "net of load" concept as enunciated in this Decision."

"FortisBC is requested to file a written statement within 90 days of the date of this Decision as to its intentions to provide such transparency."

Q29.1 Please provide a copy of BCUC Order No. G-48-09 and the accompanying Decision.

A29.1 The requested Order and Decision are provided as Zellstoff Celgar Appendix A29.1.

Q29.2 Please provide copies of the FortisBC methodology, the BC Hydro report, and the FortisBC statement referenced in the introduction to this Information Request.

A29.2 The requested documents are attached as Zellstoff Celgar Appendix A29.2.

Q29.3 Prior to BCUC Order No. G-48-09, please confirm whether FortisBC agrees that the regulatory environment within the FortisBC service area allowed for a customer with self-generation to purchase all of its required electrical load while allowing its onsite generator to produce electricity for export to third parties.

A29.3 Commission Order G-48-09 amended the Power Purchase Agreement between FortisBC and BC Hydro by replacing the existing Section 2.1 with the following:

> (a) "The Electricity purchased under this Agreement is solely for the purpose of supplementing FortisBC's resources to enable it to meet its service area load requirements and, shall not be exported or stored, provided that nothing contained herein shall prohibit FortisBC from storing its entitlement resources in its entitlement account pursuant to the Canal Plant Agreement; and
>
> (b) shall not be sold to any FortisBC customer that is selling self generated electricity which is not in excess of its load.
>
> For greater certainty, paragraph (b) above is to prevent FortisBC self generating customers from arbitraging between PPA embedded cost electricity and market prices."

Prior to Order G-48-09, FortisBC was not precluded from entering into contractual agreements with its customers such as that described in the question.

Q29.4 Please confirm that FortisBC had signed a contract with Zellstoff-Celgar that was subject to BCUC acceptance that would have resulted in FortisBC supplying all of the electrical power for the load at Celgar's industrial plant in Castlegar.

A29.4 Confirmed. The referenced agreement was submitted to the Commission on August 26, 2008 and subsequently withdrawn on September 29, 2008. Please also refer to the response to Zellstoff-Celgar IR No. 1 Q19.2.

30.0 Reference: None

Q30.1 Please explain the concept of Generator Baseline ("GBL") and how this would apply to an industrial facility with self-generation capability.

A30.1 The concept of Generator Baseline is not present within any of the FortisBC filings related to this Application, and appears neither in the COSA itself nor in any of the rates or tariffs of the Company. GBL is unique to BC Hydro who provided a description in response to a BCUC Information Request during the Bioenergy Call Phase 1 Electricity Purchase Agreements proceeding. An excerpt of the response is below.

6.0 Reference: Generator Baseline ("GBL")
Application, Section 3, p. 19
Net of Load & Arbitrage

1.6.1 Explain Generator Baseline and Net of Load ("NOL") and the differences between GBL and NOL.

RESPONSE:

The GBL for a customer with self-generation represents the amount of electricity supplied by its generation that has historically been used to partially or fully meet the energy demand of the customer's industrial load. The GBL does not vary with an increase or decrease to the customer load. Furthermore the GBL determined for each of the respective EPAs is fixed for the term or duration of the EPA.

If a customer adds new or incremental generation, then electricity supplied from the customer's generation above the GBL is self-generation sold under the EPA and electricity supplied from the customer's generation below the GBL is applied to partially or fully meet the customer's industrial load. Establishing a GBL:

1) allows customers with existing self-generation, who wish to add new or incremental generation, to bid into a BC Hydro call for energy similar to other IPPs, and

2) prevents arbitrage opportunities by ensuring energy currently generated by such customers to serve their respective loads is not being sold to BC Hydro under an EPA.

As such, under the Bioenergy EPAs BC Hydro is ensuring it is purchasing "new" generation from the proponents and is not providing an opportunity for customers to displace their self-generation with embedded cost rates for the purpose of selling their self-generation to BC Hydro at call prices.

The GBL is not calculated from a formula and requires sensitive customer specific information. For all three cases where EPAs were awarded to existing generation, BC Hydro reviewed several years of historic metered generator data, load data, site-specific production data, thermal/steam data as well as any other energy sales or Demand Side Management contracts to develop a GBL.

Q30.2 Please explain if and how, prior to May 2009, FortisBC determined the GBL for customers with self-generation capability such as the Celgar facility in Castlegar. If no such determination was made, please explain why not.

A30.2 FortisBC does not use a Generator Baseline in any interactions with its customers and thus does not have a requirement or a means to determine what any specific customer Generator Baseline would be.

Q30.3 Please confirm that FortisBC had no reason to seek to determine a GBL for a customer with self-generation capability prior to the date upon which BCUC Order No. G-48-09 was issued.

A30.3 Please refer to the response to BCUC IR No. 1 Q30.2 above.

Q30.4 Please confirm if and how BC Hydro establishes a GBL for an industrial customer with self-generation

A30.4 It is FortisBC's understanding that BC Hydro establishes a GBL for certain customers, however, the Company is not privy to the methodology employed.

31.0 Reference: Exhibit B-1, Section 2.2, Table 2.2, p. 13

Q31.1 Please re-calculate the COSA Revenue to Cost Ratios found in Table 2.2 on the basis that the Celgar facility in Castlegar was able to purchase all of its electricity needs from FortisBC with an annual demand of 43,000 kVA at 100 percent power factor and 95 percent load factor. Please provide the requested calculation both for service taken under Rate Schedule 31 and for service taken under Rate Schedule 33.

A31.1 Please see the following table.

Table Zellstoff Celgar A31.1

	Revenue to Cost Ratio Per Q31.1 Load	Revenue to Cost Ratio Per Q31.2 Load	Revenue to Cost Ratio Per Q31.3 Load	Revenue to Cost Ratio Per Q31.4 Load
Residential	96.1%	96.3%	96.6%	97.1%
Small General Service	110.5%	110.7%	111.1%	111.8%
General Service	134.5%	134.8%	135.5%	136.5%
Rate 33 Industrial	122.6%	121.1%	116.4%	105.5%
Industrial Primary	118.4%	118.6%	119.2%	120.2%
Rate 31 Industrial	105.5%	105.8%	106.4%	107.5%
Lighting	81.1%	81.1%	81.2%	81.4%
Irrigation	76.7%	76.8%	77.1%	77.5%
Kelowna Wholesale	87.0%	87.2%	87.7%	88.3%
Penticton Wholesale	75.9%	76.0%	76.3%	76.8%
Summerland Wholesale	93.4%	93.6%	94.1%	94.8%
Grand Forks Wholesale	66.5%	66.6%	66.8%	67.2%
BCH Lardeau Wholesale	99.1%	99.3%	99.7%	100.3%
BCH Yahk Wholesale	100.2%	100.4%	100.9%	101.7%
Nelson Wholesale	77.6%	77.7%	78.1%	78.7%

These calculations follow the load described in the questions. It was assumed that power supply purchase costs would increase by added energy and demand times the market energy and demand rates. It was also assumed that there would be no additional O&M costs as a result of the additional load placed on the FortisBC system. Note that the revenue to cost ratios are much higher for Rate 33 due to the use of a very high load factor for the assumptions.

Q31.2 Please re-calculate the COSA Revenue to Cost Ratios found in Table 2.2 on the basis that the Celgar facility in Castlegar had a GBL of 3 MW, but had a facility load such that it was still necessary to purchase electricity from FortisBC with an annual demand of 40,000 kVA at 100 percent power factor and 95 percent load factor. Please provide the requested calculation both for service taken under Rate Schedule 31 and for service taken under Rate Schedule 33.

A31.2 Please refer to the response to Zellstoff Celgar IR No. 1 Q31.1.

Q31.3 Please re-calculate the COSA Revenue to Cost Ratios found in Table 2.2 on the basis that the Celgar facility in Castlegar had a GBL of 10 MW, but had a facility load such that it was still necessary to purchase electricity from FortisBC with an annual demand of 33,000 kVA at 100 percent power factor and 95 percent load factor. Please provide the requested calculation both for service taken under Rate Schedule 31 and for service taken under Rate Schedule 33.

A31.3 Please refer to the response to Zellstoff Celgar IR No. 1 Q31.1.

Q31.4 Please re-calculate the COSA Revenue to Cost Ratios found in Table 2.2 on the basis that the Celgar facility in Castlegar had a GBL of 20 MW, but had a facility load such that it was still necessary to purchase electricity from FortisBC with an annual demand of 23,000 kVA at 100 percent power factor and 95 percent load factor. Please provide the requested calculation both for service taken under Rate Schedule 31 and for service taken under Rate Schedule 33.

A31.4 Please refer to the response to Zellstoff Celgar IR No. 1 Q31.1.

32.0 Reference: Exhibit B-1, Section 8.1, Tables 8.1a and 8.1b, pp. 48-49

Q32.1 Please re-calculate Tables 8.1a and 8.1b on the basis that the Celgar facility in Castlegar was able to purchase all of its electricity needs from FortisBC with an annual demand of 43,000 kVA at 100 percent power factor and 95 percent load factor. Please provide the requested calculation both for service taken under Rate Schedule 31 and for service taken under Rate Schedule 33.

A32.1 Please see the following tables.

Table Zellstoff Celgar A32.1(a)

Total Rate Increase Assuming Celgar Revenues Under Rate 33

	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	2.1%	2.6%	5.0%	5.0%	5.0%
General Service	2.1%	2.0%	2.5%	2.5%	2.6%
Industrial Transmission 33	2.1%	2.0%	2.5%	2.5%	2.6%
Industrial Primary	2.1%	2.0%	2.5%	2.5%	3.5%
Industrial Transmission 31	2.1%	5.0%	5.0%	5.0%	5.0%
Lighting	10.0%	10.0%	10.0%	7.0%	5.0%
Irrigation	10.0%	10.0%	10.0%	10.0%	8.1%
Kelowna Wholesale	10.0%	9.4%	5.0%	5.0%	5.0%
Penticton Wholesale	10.0%	10.0%	10.0%	10.0%	9.1%
Summerland Wholesale	6.9%	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%	8.3%
Total	5.0%	5.0%	5.0%	5.0%	5.0%

Table Zellstoff Celgar A32.1(b)

Revenue to Cost Ratio Assuming Celgar Revenues Under Rate 33

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio
Residential	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%
Small General Service	110.5%	107.5%	105.0%	105.0%	105.0%	105.0%
General Service	134.5%	130.8%	127.1%	124.0%	121.1%	118.3%
Industrial Transmission 33	122.6%	119.3%	115.9%	113.1%	110.4%	107.9%
Industrial Primary	118.4%	115.1%	111.8%	109.1%	106.5%	105.0%
Industrial Transmission 31	105.5%	102.6%	102.6%	102.6%	102.6%	102.6%
Lighting	81.1%	85.0%	89.0%	93.2%	95.0%	95.0%
Irrigation	76.7%	80.3%	84.1%	88.1%	92.3%	95.0%
Kelowna Wholesale	87.0%	91.2%	95.0%	95.0%	95.0%	95.0%
Penticton Wholesale	75.9%	79.5%	83.3%	87.2%	91.4%	95.0%
Summerland Wholesale	93.4%	95.0%	95.0%	95.0%	95.0%	95.0%
Grand Forks Wholesale	66.5%	69.7%	73.0%	76.5%	80.1%	83.9%
BCH Lardeau Wholesale	99.1%	99.1%	99.1%	99.1%	99.1%	99.1%
BCH Yahk Wholesale	100.2%	100.2%	100.2%	100.2%	100.2%	100.2%
Nelson Wholesale	77.6%	81.3%	85.1%	89.2%	92.2%	95.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table Zellstoff Celgar A32.1(c)

Total Rate Increase Assuming Celgar Revenues Under Rate 31

	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	3.5%	2.6%	3.6%	5.0%	5.0%
General Service	3.5%	2.0%	2.5%	2.4%	2.2%
Industrial Transmission 33	3.5%	2.0%	2.5%	2.4%	5.0%
Industrial Primary	3.5%	2.0%	2.5%	2.4%	2.2%
Industrial Transmission 31	4.5%	5.0%	5.0%	5.0%	5.0%
Lighting	10.0%	10.0%	10.0%	7.0%	5.0%
Irrigation	10.0%	10.0%	10.0%	10.0%	8.1%
Kelowna Wholesale	10.0%	9.4%	5.0%	5.0%	5.0%
Penticton Wholesale	10.0%	10.0%	10.0%	10.0%	9.1%
Summerland Wholesale	6.9%	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%	8.3%
Total	5.0%	5.0%	5.0%	5.0%	5.0%

Table Zellstoff Celgar A32.1(d)

Revenue to Cost Ratio Assuming Celgar Revenues Under Rate 33

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio
Residential	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%
Small General Service	110.5%	108.9%	106.4%	105.0%	105.0%	105.0%
General Service	134.5%	132.6%	128.8%	125.7%	122.6%	119.3%
Industrial Transmission 33	115.2%	113.6%	110.3%	107.7%	105.0%	105.0%
Industrial Primary	118.4%	116.7%	113.3%	110.6%	107.8%	105.0%
Industrial Transmission 31	105.5%	105.0%	105.0%	105.0%	105.0%	105.0%
Lighting	81.1%	85.0%	89.0%	93.2%	95.0%	95.0%
Irrigation	76.7%	80.3%	84.1%	88.1%	92.3%	95.0%
Kelowna Wholesale	87.0%	91.2%	95.0%	95.0%	95.0%	95.0%
Penticton Wholesale	75.9%	79.5%	83.3%	87.2%	91.4%	95.0%
Summerland Wholesale	93.4%	95.0%	95.0%	95.0%	95.0%	95.0%
Grand Forks Wholesale	66.5%	69.7%	73.0%	76.5%	80.1%	83.9%
BCH Lardeau Wholesale	99.1%	99.1%	99.1%	99.1%	99.1%	99.1%
BCH Yahk Wholesale	100.2%	100.2%	100.2%	100.2%	100.2%	100.2%
Nelson Wholesale	77.6%	81.3%	85.1%	89.2%	92.2%	95.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Q32.2 Please re-calculate Tables 8.1a and 8.1b on the basis that the Celgar facility in Castlegar had a GBL of 3 MW, but had a facility load such that it was still necessary to purchase electricity from FortisBC with an annual demand of 40,000 kVA at 100 percent power factor and 95 percent load factor. Please provide the requested calculation both for service taken under Rate Schedule 31 and for service taken under Rate Schedule 33.

A32.2 Please refer to the following tables:

Table Zellstoff Celgar A32.2(a)

Total Rate Increase Assuming Zellstoff Celgar Revenues Under Rate 33

	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	2.0%	2.5%	5.0%	5.0%	5.0%
General Service	2.0%	2.0%	2.5%	2.3%	2.5%
Industrial Transmission 33	2.0%	2.0%	2.5%	2.3%	2.5%
Industrial Primary	2.0%	2.0%	2.5%	2.3%	3.6%
Industrial Transmission 31	4.2%	5.0%	5.0%	5.0%	5.0%
Lighting	10.0%	10.0%	10.0%	7.0%	5.0%
Irrigation	10.0%	10.0%	10.0%	10.0%	7.9%
Kelowna Wholesale	10.0%	9.2%	5.0%	5.0%	5.0%
Penticton Wholesale	10.0%	10.0%	10.0%	10.0%	9.0%
Summerland Wholesale	6.6%	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%	8.1%
Total	5.0%	5.0%	5.0%	5.0%	5.0%

Table Zellstoff Celgar A32.2(b)

Revenue to Cost Ratios Assuming Zellstoff Celgar Revenues Under Rate 33

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio
Residential	96.3%	96.3%	96.3%	96.3%	96.3%	96.3%
Small General Service	110.7%	107.5%	105.0%	105.0%	105.0%	105.0%
General Service	134.8%	130.9%	127.2%	124.2%	121.0%	118.1%
Industrial Transmission 33	121.1%	117.6%	114.3%	111.6%	108.7%	106.1%
Industrial Primary	118.6%	115.2%	111.9%	109.3%	106.5%	105.0%
Industrial Transmission 31	105.8%	105.0%	105.0%	105.0%	105.0%	105.0%
Lighting	81.1%	85.0%	89.0%	93.3%	95.1%	95.1%
Irrigation	76.8%	80.4%	84.3%	88.3%	92.5%	95.0%
Kelowna Wholesale	87.2%	91.4%	95.0%	95.0%	95.0%	95.0%
Penticton Wholesale	76.0%	79.6%	83.4%	87.4%	91.6%	95.0%
Summerland Wholesale	93.6%	95.0%	95.0%	95.0%	95.0%	95.0%
Grand Forks Wholesale	66.6%	69.8%	73.1%	76.6%	80.2%	84.0%
BCH Lardeau Wholesale	99.3%	99.3%	99.3%	99.3%	99.3%	99.3%
BCH Yahk Wholesale	100.4%	100.4%	100.4%	100.4%	100.4%	100.4%
Nelson Wholesale	77.7%	81.4%	85.3%	89.4%	92.4%	95.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table Zellstoff Celgar A32.2(c)

Total Rate Increase Assuming Zellstoff Celgar Revenues Under Rate 31

	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	3.2%	2.2%	4.1%	5.0%	5.0%
General Service	3.2%	2.2%	2.5%	2.0%	2.0%
Industrial Transmission 33	3.2%	2.2%	2.5%	3.7%	5.0%
Industrial Primary	3.2%	2.2%	2.5%	2.0%	2.5%
Industrial Transmission 31	4.2%	5.0%	5.0%	5.0%	5.0%
Lighting	10.0%	10.0%	10.0%	7.0%	5.0%
Irrigation	10.0%	10.0%	10.0%	10.0%	7.9%
Kelowna Wholesale	10.0%	9.2%	5.0%	5.0%	5.0%
Penticton Wholesale	10.0%	10.0%	10.0%	10.0%	9.0%
Summerland Wholesale	6.6%	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%	8.1%
Total	5.0%	5.0%	5.0%	5.0%	5.0%

Table Zellstoff Celgar A32.2(d)

Revenue to Cost Ratio Assuming Zellstoff Celgar Revenues Under Rate 31

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio
Residential	96.3%	96.3%	96.3%	96.3%	96.3%	96.3%
Small General Service	110.7%	108.8%	105.9%	105.0%	105.0%	105.0%
General Service	134.8%	132.5%	128.9%	125.9%	122.3%	118.8%
Industrial Transmission 33	113.8%	111.9%	108.9%	106.3%	105.0%	105.0%
Industrial Primary	118.6%	116.6%	113.5%	110.8%	107.6%	105.0%
Industrial Transmission 31	105.8%	105.0%	105.0%	105.0%	105.0%	105.0%
Lighting	81.1%	85.0%	89.0%	93.3%	95.1%	95.1%
Irrigation	76.8%	80.4%	84.3%	88.3%	92.5%	95.0%
Kelowna Wholesale	87.2%	91.4%	95.0%	95.0%	95.0%	95.0%
Penticton Wholesale	76.0%	79.6%	83.4%	87.4%	91.6%	95.0%
Summerland Wholesale	93.6%	95.0%	95.0%	95.0%	95.0%	95.0%
Grand Forks Wholesale	66.6%	69.8%	73.1%	76.6%	80.2%	84.0%
BCH Lardeau Wholesale	99.3%	99.3%	99.3%	99.3%	99.3%	99.3%
BCH Yahk Wholesale	100.4%	100.4%	100.4%	100.4%	100.4%	100.4%
Nelson Wholesale	77.7%	81.4%	85.3%	89.4%	92.4%	95.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Q32.3 Please re-calculate Tables 8.1a and 8.1b on the basis that the Celgar facility in Castlegar had a GBL of 10 MW, but had a facility load such that it was still necessary to purchase electricity from FortisBC with an annual demand of 33,000 kVA at 100 percent power factor and 95 percent load factor. Please provide the requested calculation both for service taken under Rate Schedule 31 and for service taken under Rate Schedule 33.

A32.3 Please refer to the following tables:

Table Zellstoff Celgar A32.3(a)

Total Rate Increase Assuming Zellstoff Celgar Revenues Under Rate 33

	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	2.0%	2.1%	5.0%	5.0%	5.0%
General Service	2.0%	2.1%	2.2%	2.0%	2.5%
Industrial Transmission 33	2.0%	2.1%	2.2%	3.0%	2.5%
Industrial Primary	2.0%	2.1%	2.2%	2.0%	3.5%
Industrial Transmission 31	3.6%	5.0%	5.0%	5.0%	5.0%
Lighting	10.0%	10.0%	10.0%	7.0%	5.0%
Irrigation	10.0%	10.0%	10.0%	10.0%	7.9%
Kelowna Wholesale	10.0%	9.2%	5.0%	5.0%	5.0%
Penticton Wholesale	10.0%	10.0%	10.0%	10.0%	9.0%
Summerland Wholesale	6.1%	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%	8.1%
Total	5.0%	5.0%	5.0%	5.0%	5.0%

1 **Table Zellstoff Celgar A32.3(b)**

2 **Revenue to Cost Ratio Assuming Zellstoff Celgar Revenues Under Rate 33**

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio
Residential	96.6%	96.6%	96.6%	96.6%	96.6%	96.6%
Small General Service	111.1%	107.9%	105.0%	105.0%	105.0%	105.0%
General Service	135.5%	131.6%	128.0%	124.6%	121.0%	118.1%
Industrial Transmission 33	116.4%	113.1%	109.9%	107.0%	105.0%	102.5%
Industrial Primary	119.2%	115.8%	112.6%	109.6%	106.5%	105.0%
Industrial Transmission 31	106.4%	105.0%	105.0%	105.0%	105.0%	105.0%
Lighting	81.2%	85.1%	89.2%	93.4%	95.2%	95.2%
Irrigation	77.1%	80.7%	84.6%	88.6%	92.8%	95.4%
Kelowna Wholesale	87.7%	91.8%	95.5%	95.5%	95.5%	95.5%
Penticton Wholesale	76.3%	80.0%	83.8%	87.8%	92.0%	95.5%
Summerland Wholesale	94.1%	95.0%	95.0%	95.0%	95.0%	95.0%
Grand Forks Wholesale	66.8%	70.0%	73.4%	76.9%	80.5%	84.3%
BCH Lardeau Wholesale	99.7%	99.7%	99.7%	99.7%	99.7%	99.7%
BCH Yahk Wholesale	100.9%	100.9%	100.9%	100.9%	100.9%	100.9%
Nelson Wholesale	78.1%	81.8%	85.7%	89.8%	92.8%	95.5%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table Zellstoff Celgar A32.3(c)

Total Rate Increase Assuming Zellstoff Celgar Revenues Under Rate 31

	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	2.1%	2.6%	5.0%	5.0%	5.0%
General Service	2.1%	2.0%	2.5%	2.5%	2.6%
Industrial Transmission 33	2.1%	2.0%	2.5%	2.5%	2.6%
Industrial Primary	2.1%	2.0%	2.5%	2.5%	3.5%
Industrial Transmission 31	2.1%	5.0%	5.0%	5.0%	5.0%
Lighting	10.0%	10.0%	10.0%	7.0%	5.0%
Irrigation	10.0%	10.0%	10.0%	10.0%	8.1%
Kelowna Wholesale	10.0%	9.4%	5.0%	5.0%	5.0%
Penticton Wholesale	10.0%	10.0%	10.0%	10.0%	9.1%
Summerland Wholesale	6.9%	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%	8.3%
Total	5.0%	5.0%	5.0%	5.0%	5.0%

Table Zellstoff Celgar A32.3(d)

Revenue to Cost Ratio Assuming Zellstoff Celgar Revenues Under Rate 31

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio
Residential	96.1%	96.1%	96.1%	96.1%	96.1%	96.1%
Small General Service	110.5%	107.5%	105.0%	105.0%	105.0%	105.0%
General Service	134.5%	130.8%	127.1%	124.0%	121.1%	118.3%
Industrial Transmission 33	122.6%	119.3%	115.9%	113.1%	110.4%	107.9%
Industrial Primary	118.4%	115.1%	111.8%	109.1%	106.5%	105.0%
Industrial Transmission 31	105.5%	102.6%	102.6%	102.6%	102.6%	102.6%
Lighting	81.1%	85.0%	89.0%	93.2%	95.0%	95.0%
Irrigation	76.7%	80.3%	84.1%	88.1%	92.3%	95.0%
Kelowna Wholesale	87.0%	91.2%	95.0%	95.0%	95.0%	95.0%
Penticton Wholesale	75.9%	79.5%	83.3%	87.2%	91.4%	95.0%
Summerland Wholesale	93.4%	95.0%	95.0%	95.0%	95.0%	95.0%
Grand Forks Wholesale	66.5%	69.7%	73.0%	76.5%	80.1%	83.9%
BCH Lardeau Wholesale	99.1%	99.1%	99.1%	99.1%	99.1%	99.1%
BCH Yahk Wholesale	100.2%	100.2%	100.2%	100.2%	100.2%	100.2%
Nelson Wholesale	77.6%	81.3%	85.1%	89.2%	92.2%	95.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Q32.4 Please re-calculate Tables 8.1a and 8.1b on the basis that the Celgar facility in Castlegar had a GBL of 20 MW, but had a facility load such that it was still necessary to purchase electricity from FortisBC with an annual demand of 23,000 kVA at 100 percent power factor and 95 percent load factor. Please provide the requested calculation both for service taken under Rate Schedule 31 and for service taken under Rate Schedule 33.

A32.4 Please refer to the following tables:

Table Zellstoff Celgar A32.4(a)

Total Rate Increase Assuming Zellstoff Celgar Revenues Under Rate 33

	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	1.8%	1.8%	5.0%	5.0%	5.0%
General Service	1.8%	1.8%	1.5%	1.2%	2.4%
Industrial Transmission 33	4.5%	5.0%	5.0%	5.0%	5.0%
Industrial Primary	1.8%	1.8%	1.5%	1.2%	4.8%
Industrial Transmission 31	2.6%	5.0%	5.0%	5.0%	5.0%
Lighting	10.0%	10.0%	10.0%	6.7%	5.0%
Irrigation	10.0%	10.0%	10.0%	10.0%	6.9%
Kelowna Wholesale	10.0%	7.8%	5.0%	5.0%	5.0%
Penticton Wholesale	10.0%	10.0%	10.0%	10.0%	7.8%
Summerland Wholesale	5.2%	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%	10.0%	5.3%
Total	5.0%	5.0%	5.0%	5.0%	5.0%

1 **Table Zellstoff Celgar A32.4(b)**

2 **Revenue to Cost Ratio Assuming Zellstoff Celgar Revenues Under Rate 33**

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio
Residential	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%
Small General Service	111.8%	108.4%	105.0%	105.0%	105.0%	105.0%
General Service	136.5%	132.3%	128.2%	124.0%	119.5%	116.5%
Industrial Transmission 33	105.5%	105.0%	105.0%	105.0%	105.0%	105.0%
Industrial Primary	120.2%	116.5%	112.9%	109.1%	105.2%	105.0%
Industrial Transmission 31	107.5%	105.0%	105.0%	105.0%	105.0%	105.0%
Lighting	81.4%	85.3%	89.3%	93.6%	95.0%	95.0%
Irrigation	77.5%	81.2%	85.1%	89.1%	93.4%	95.0%
Kelowna Wholesale	88.3%	92.6%	95.0%	95.0%	95.0%	95.0%
Penticton Wholesale	76.8%	80.5%	84.3%	88.4%	92.6%	95.0%
Summerland Wholesale	94.8%	95.0%	95.0%	95.0%	95.0%	95.0%
Grand Forks Wholesale	67.2%	70.4%	73.8%	77.3%	81.0%	84.8%
BCH Lardeau Wholesale	100.3%	100.3%	100.3%	100.3%	100.3%	100.3%
BCH Yahk Wholesale	101.7%	101.7%	101.7%	101.7%	101.7%	101.7%
Nelson Wholesale	78.7%	82.4%	86.4%	90.5%	94.8%	95.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table Zellstoff Celgar A32.4(c)

Total Rate Increase Assuming Zellstoff Celgar Revenues Under Rate 31

	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	2.6%	1.8%	4.1%	5.0%	5.0%
General Service	2.6%	1.8%	1.5%	1.5%	2.5%
Industrial Transmission 33	5.0%	5.0%	5.0%	5.0%	5.0%
Industrial Primary	2.6%	1.8%	1.5%	1.5%	3.6%
Industrial Transmission 31	2.6%	5.0%	5.0%	5.0%	5.0%
Lighting	10.0%	10.0%	10.0%	6.7%	5.0%
Irrigation	10.0%	10.0%	10.0%	10.0%	6.9%
Kelowna Wholesale	10.0%	7.8%	5.0%	5.0%	5.0%
Penticton Wholesale	10.0%	10.0%	10.0%	10.0%	7.8%
Summerland Wholesale	5.2%	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%	10.0%	5.3%
Total	5.0%	5.0%	5.0%	5.0%	5.0%

Table Zellstoff Celgar A32.4(d)

Revenue to Cost Ratio Assuming Zellstoff Celgar Revenues Under Rate 31

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio	R/C Ratio
Residential	97.1%	97.1%	97.1%	97.1%	97.1%	97.1%
Small General Service	111.8%	109.2%	105.9%	105.0%	105.0%	105.0%
General Service	136.5%	133.4%	129.3%	125.0%	120.8%	118.0%
Industrial Transmission 33	99.3%	99.3%	99.3%	99.3%	99.3%	99.3%
Industrial Primary	120.2%	117.4%	113.8%	110.0%	106.4%	105.0%
Industrial Transmission 31	107.5%	105.0%	105.0%	105.0%	105.0%	105.0%
Lighting	81.4%	85.3%	89.3%	93.6%	95.0%	95.0%
Irrigation	77.5%	81.2%	85.1%	89.1%	93.4%	95.0%
Kelowna Wholesale	88.3%	92.6%	95.0%	95.0%	95.0%	95.0%
Penticton Wholesale	76.8%	80.5%	84.3%	88.4%	92.6%	95.0%
Summerland Wholesale	94.8%	95.0%	95.0%	95.0%	95.0%	95.0%
Grand Forks Wholesale	67.2%	70.4%	73.8%	77.3%	81.0%	84.8%
BCH Lardeau Wholesale	100.3%	100.3%	100.3%	100.3%	100.3%	100.3%
BCH Yahk Wholesale	101.7%	101.7%	101.7%	101.7%	101.7%	101.7%
Nelson Wholesale	78.7%	82.4%	86.4%	90.5%	94.8%	95.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

33.0 Reference: Decision Accompanying Order No. G-48-09, p. 30

"Similarly, Zellstoff Celgar refers to the failure of its 3.5 MW generator in 1993 and its replacement with a 52MW generator in 1994. This was followed in 2008 with an investment decision to purchase a 48 MW generator scheduled for installation in 2009."

"Are these Increases in generation capacity to be considered incremental energy generation or new generation? What portion of the increased generation capacity should be available for export by the owners? The Panel believes that on the basis of the record in this proceeding, it has insufficient evidence on which to base any set numerical answer to the questions."

Q33.1 Please explain the effect that establishing a GBL of 3 MW for the Celgar facility in Castlegar would have on the COSA and on the Revenue to Cost Ratio, if the facility continued to take service under Rate Schedule 33 with an annual demand of 40,000 kVA at 100 percent power factor and 95 percent load factor.

A33.1 Generally, if Zellstoff Celgar were to take load at the levels listed, both the revenues and cost of service would increase. FortisBC would be required to purchase additional power in the marketplace. At a 95 percent load factor and relatively constant load placed on FortisBC, Rate 31 would be a more attractive rate for Celgar, regardless of the GBL level. The revenue to cost ratio would also increase substantially as Zellstoff Celgar would purchase more power from FortisBC, making a greater contribution to the fixed costs of serving Zellstoff Celgar.

While the responses to Zellstoff Celgar IR No. 1 Q31 and Q32 are illustrative of the impacts of establishing various GBL levels, the assumptions about the additional power supply costs are very simplistic and may not be representative of what is available from the market at the time. The differences in the level of the GBL and the resulting amount of power placed on the FortisBC system may have an impact on the price at which FortisBC could purchase additional supplies.

Q33.2 Please explain the effect that establishing a GBL of 10 MW for the Celgar facility in Castlegar would have on the COSA and on the Revenue to Cost Ratio, if the facility continued to take service under Rate Schedule 33 with an annual demand of 33,000 kVA at 100 percent power factor and 95 percent load factor.

A33.2 Please refer to the response to Zellstoff Celgar IR No. 1 Q33.2.

Q33.3 Please explain the effect that establishing a GBL of 20 MW for the Celgar facility in Castlegar would have on the COSA and on the Revenue to Cost Ratio, if the facility continued to take service under Rate Schedule 33 with an annual demand of 23,000 kVA at 100 percent power factor and 95 percent load factor.

A33.3 Please refer to the response to Zellstoff Celgar IR No. 1 Q33.2.

Issue: Comparable BC Hydro Rates

34.0 Reference: None

Q34.1 Please provide a comparison table of all FortisBC rates against the comparable BC Hydro rates, including the costs under each rate.

A34.1 The requested comparison table is provided as Zellstoff Celgar Appendix A34.1.

Q34.2 Please identify those FortisBC or BC Hydro rates for which no comparable rate exists in the other utility, including the costs under each such rate.

A34.2 Please refer to Zellstoff Celgar Appendix A34.1 for a listing of FortisBC and BC Hydro rates for which no comparable rate exists between the utilities.

Issue: Other

35.0 Reference: Exhibit B-1, Appendix 1, p. 84

"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.

Q35.1 Please describe any credible situation or circumstance in which FortisBC would choose to take service under Rate 3808 rather than generate with its own hydro plants.

A35.1 The Company's own hydro plants are fuel (water) constrained. Therefore the Company often takes service under Rate 3808 in order to allow Company generation at a later time with the limited water available.

Q35.2 Is Rate 3808 a market-based rate, and if so, what market does it reflect?

A35.2 The Company does not believe Rate 3808 from BC Hydro to be a market-based rate.

GENERAL SERVICE POWER CONTRACT

Customer No.: 4853368029

This Agreement made October 1, 2006 between Zellstoff Celgar Limited Partnership. ("the Customer") and FortisBC Inc. ("FortisBC") witnesses that, for and in consideration of the mutual covenants and agreements contained herein, the parties agree as follows:

1. AGREEMENT: FortisBC agrees to supply and the Customer agrees to take and pay for electric service to the Customer's premises located at Castlegar, British Columbia in accordance with the terms of this Agreement.

2. THE POINT OF DELIVERY of electricity shall be at the load side of FortisBC's disconnect switch near the Customer's substation located at the Customer's pulp mill. FortisBC's responsibility for supply of electricity shall cease at the Point of Delivery.

3. The TYPE OF SERVICE to be supplied by FortisBC to the Customer shall be nominally 60,000 volt, three phase, 60 hertz service. FortisBC shall make available the firm capacity reservation of 10MVA between 8:00 am and 10:00 pm and 25 MVA between 10:00 pm and 8:00 am. throughout the term of this Agreement. The Customer shall not exceed the DEMAND LIMIT OF 40,000 kVA unless otherwise agreed in writing.

4. Service pursuant to this Agreement shall be deemed to COMMENCE on October 1, 2006. In the event that electricity is not available to the Customer on the above commencement date, service pursuant to this Agreement shall then be deemed to commence on the day that it is made available. The TERM of this Agreement shall be for one year, and shall continue thereafter until terminated by 12 months prior notice in writing by either party to the other. After one year the customer has the option to revert back to Rate Schedule 31 and a contract demand of 16MVA 24 hours per day.

5. The RATE to be paid by the Customer for electric service made available by FortisBC shall be as set out in Rate Schedule 33 as same may be amended, from time to time, commencing from the date set out in clause 4.

6. A REVENUE GUARANTEE of $ nil and a SECURITY DEPOSIT of $ nil will be required from the Customer pursuant to the Terms and Conditions of FortisBC's filed Electric Tariff before FORTISBC provides electric service.

7. A CUSTOMER CONTRIBUTION will be required with respect to the construction and installation of supply facilities and the Customer agrees to pay, in advance, the sum of $ nil pursuant to the provisions of FortisBC's filed Terms and Conditions and Extension Schedule.

8. THE TERMS AND CONDITIONS OF FORTISBC INC. ATTACHED HERETO HAVE BEEN FILED WITH AND APPROVED BY THE BRITISH COLUMBIA UTILITIES COMMISSION, AND FORM PART OF THIS AGREEMENT AND BY THIS REFERENCE ARE INCORPORATED HEREIN. THE TERMS AND CONDITIONS AND SCHEDULES MAY BE AMENDED FROM TIME TO TIME SUBJECT TO APPROVAL BY THE COMMISSION, AND THE CUSTOMER SHALL BE SUBJECT TO ANY SUCH AMENDMENTS AND THE TERMS AND CONDITIONS AS AMENDED SHALL BECOME PART OF THIS AGREEMENT.

9. This Agreement replaces the previous Agreement for electric service between West Kootenay Power Ltd. and KPMG Inc. dated December 20, 2002.

10. The Customer's ADDRESS for purposes of billing and notification shall be: P.O. Box 1000, Castlegar, B.C.

11. SPECIAL PROVISIONS: The terms set out in Schedule A hereto entitled "Electricity Supply Brokerage Agreement" are incorporated by reference herein.

Per: ______________________________
Zellstoff Celgar Limited Partnership

Per: ______________________________
FortisBC Inc.

SCHEDULE A

SPECIAL PROVISIONS

ELECTRICITY SUPPLY BROKERAGE AGREEMENT

Zellstoff Celgar Limited Partnership ("Customer") is a customer of FortisBC Inc. ("FortisBC") supplied under FortisBC's Rate Schedule 33 by a contract (the "Agreement") dated October 1st, 2006. This "Schedule" is incorporated into the Agreement under Section 11 thereof. The Customer operates a pulp mill at Castlegar, B.C. This mill has a total load of 46.5 MVA. Under most circumstances, this load is satisfied by the Customer's 50 MW turbo generator. From time to time, the turbo generator may be unavailable due to maintenance shutdowns or equipment failures. Since the pulp mill can operate independently of the turbo generator, the Customer would like a backup source of power above the firm supply levels of 10 MVA between 8:00 am and 10:00pm and 25 MVA between 10:00 pm and 8:00 am.

If FortisBC was required to provide this backup by contract purchase from B.C. Hydro, the Customer could incur excessive costs for relatively minimal power consumption as a result of capacity charges imposed under the BC Hydro rate of supply for FortisBC. The intent of this electricity supply brokerage agreement is that should the customer's requirements exceed the Firm Capacity reservation, described above, then the customer shall pay the equivalent of Rate Schedule 33 as more fully described below. As a result, FortisBC and the Customer have agreed as follows:

1. FORTISBC shall not be liable for any direct, indirect or consequential damage or loss to the Customer or its agents as a result of any action undertaken as a result of this Agreement.

2. The Customer shall use commercially reasonable efforts to schedule its generator maintenance for the months of April through October as much as possible. In order to minimize power purchase costs, the Customer will use commercially reasonable efforts to notify FORTISBC of any planned shutdowns with at least three months notice.

3. In the event of a failure of the Customer's turbo generator, the Customer will use its best efforts to notify FORTISBC as quickly as reasonably possible as to the amount of backup power necessary. The time of notification is of the essence.

4. The Firm Capacity reservation is as follows:

    - between the hours of 8:00 am and 10:00 pm the reservation will be 10 MVA
    - between the hours of 10:00 pm and 8:00 am the reservation will be 25 MVA

5. The Firm Capacity reservation shall not apply during any hour in which the Customer has Scheduled Exports from the FORTISBC System. "Scheduled Exports" shall be defined in the agreement governing transmission access by the Customer on the FORTISBC system.

6. FORTISBC, upon notification of a requirement by the Customer in excess of the Firm Capacity reservation, will use commercially reasonable efforts to meet that requirement as promptly as possible. FORTISBC will look to its own resources initially and, if FORTISBC has no available surplus, will then look to outside market opportunities including BC Hydro. For the purposes of this Agreement, "own resources" means power that is available to FortisBC, including power available from B.C. Hydro that does not result in incremental capacity charges, and "available surplus" means power available for delivery from FortisBC's own resources. FORTISBC will try to procure power as inexpensively as possible. In the case where FORTISBC is forced to purchase incremental capacity from BC Hydro, the Customer will reimburse FortisBC for any incremental capacity costs incurred by FortisBC in meeting

the Customers load requirements beyond the Firm Capacity reservation. For the purposes of this Agreement, "incremental capacity" means capacity that FortisBC becomes legally obliged to pay for under the B.C. Hydro Tariff, as a result of providing power to the Customer in excess of the Firm Capacity reservation, that it would not otherwise have become liable to pay for, and "incremental capacity charges" means the amount or amounts payable by FortisBC in respect thereof, from time to time.

7. Energy deliveries to the Customer will be purchased by the Customer as set out in Rate Schedule 33 at all times, including when the Customer has a requirement in excess of the applicable capacity reservation amount, except as noted in clause 8.

8. Should the customer exceed the Firm Capacity reservation of 25 MVA during the 10:00 pm to 8:00 am period, energy associated with the capacity in excess of 25 MVA will be billed at an amount per kWh equal to the Off-Peak Winter Rate. This clause will only apply after the Customer has exceeded the 25 MVA threshold for a total of 20 hours in any given month and will not apply for any period that the Customer has notified FortisBC that it was in a forced or maintenance outage situation. Such notification can be in written or e-mail form to the FortisBC System Control Centre located in Warfield, British Columbia and must be sent at least 2 days before or after such outage situation.

9. Each party will allow the other access to their respective metering devices.

10. For hours in which Customer does not have an export schedule and delivers unscheduled energy to FortisBC, the rate paid to the Customer shall be the lower of the BC Hydro 3808 energy rate, effective at January 1 of the current year, or the Mid-C Dow Jones day-ahead Index price, using the heavy load index for the heavy load hours and the light load index for the light load hours, less 2 mills. Delivery of such energy shall be in accordance with the Terms and Conditions of the B.C. Hydro Tariff, particularly Section 10.

SCHEDULE 1880 – TRANSMISSION SERVICE – STANDBY AND MAINTENANCE SUPPLY

Availability: For Customers supplied with Electricity under Schedules 1823, 1825, 1827, and 1852 subject to the Special Conditions below.

Applicable in: Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.

Rate: The Rate per Period of Use shall be:

Administrative Charge:

$150.00 per Period of Use

Energy Charge:

For each hour during the Period of Use the Energy Charge is the Schedule 1880 Energy metered consumption (in kW.h) multiplied by 7.360¢ per kW.

Period of Use: A period of consecutive hours during which Electricity is taken under this Schedule which may extend into subsequent Billing Periods. The Period of Use is as defined by the Customer when making the request to BC Hydro for service under Schedule 1880.

Reference Demand: The HLH Reference Demand is defined as the highest kV.A Demand in the HLH for the current Billing Period prior to the Period of Use excluding any prior Period of Use. If the Period of Use extends over an entire Billing Period, the highest kV.A Demand in the HLH from the prior Billing Period will be used in determining the HLH Reference Demand, excluding any Period of Use in the prior Billing Period.

For the purpose of the Reference Demand, the HLH periods are as defined per Schedule 1823, 1825, 1827 or 1852, whichever is applicable.

Schedule 1880 Energy Determination: During the HLH periods, on an hourly basis, the kW.h consumption which exceeds the HLH High kW.h/hr within the Period of Use, or portion thereof.

The HLH High kW.h/hr is defined as the product of the HLH Reference Demand multiplied by the Power Factor for the half hour when the HLH Reference Demand occurred.

ACCEPTED: MAY 30 2008

ORDER NO. G 41 08

COMMISSION SECRETARY

For the purpose of the Schedule 1880 Energy Determination, the HLH periods are as defined per Schedule 1823, 1825, 1827 or 1852, whichever is applicable.

Special Conditions:

1. BC Hydro agrees to provide Electricity under this Schedule to the extent that it has energy and capacity to do so.

2. BC Hydro may, without notice to the Customer, terminate the supply of Electricity under this Schedule if at any time during the Period of Use BC Hydro does not have sufficient energy or capacity.

3. This Schedule is only for the following purposes:

   To provide Electricity which the Customer would otherwise generate when all or part of the Customer's electrical generating plant is curtailed.

   Electricity used for this purpose may be taken on an instantaneous basis when the impact of the instantaneous pickup of loads normally provided by the Customer's electrical generation units does not occur after BC Hydro has advised the Customer that a period of system constraint or potential system constraint exists.

   During periods of potential system constraints, BC Hydro will require Customers to arm load shedding relays to ensure that the loss of Electricity production from a Customer's electrical generation unit will not result in a demand greater than the Customer's Maximum kV.A Demand on BC Hydro's system. BC Hydro may require the Customer to provide it with control of these load shedding relays. During periods of potential system constraints, upon a Customer's request, BC Hydro will endeavour to provide Electricity normally provided by the Customer's electrical generation unit.

   The Customer is required to advise BC Hydro within 30 minutes of taking energy under this schedule for this purpose. If the Customer fails to advise BC Hydro the subsequent measured demand and energy will be billed under Rate Schedule 1823, 1825, 1827 or 1852, whichever is applicable.

4. Electricity taken under this Schedule shall not displace Electricity otherwise to be taken by this Customer under Schedule 1823, Schedule 1825, Schedule 1827 or Schedule 1852.

   Electricity taken under this Schedule shall not displace Electricity that would normally be generated by the Customer for the purpose of re-sale.

5. In addition to the charges specifically set out in this Schedule, the Customer shall pay for any additional facilities required to deliver Electricity under this Schedule provided that BC Hydro obtains the prior consent of the Customer for construction of the additional facilities.

6. A Customer may be required to allow BC Hydro to install metering and communication equipment to measure the electricity output of the Customer's self-generation unit.

7. BC Hydro will bill for Electricity taken under Schedule 1880 at the same time it bills for Electricity taken under Schedule 1823, 1825, 1827 or 1852, whichever is applicable.

Taxes: The rates contained herein are exclusive of the Goods and Services tax and the Social Services tax.

Note: The terms and conditions under which transmission service is supplied are contained in Electric Tariff Supplements 5 and 6.

Rate Rider: The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Interim Rate: Effective April 1, 2008 the Rate charged under this schedule is on an interim basis as per BCUC Order No. G-41-08.

ACCEPTED: MAY 30 2008

ORDER NO. G 41 08

E Hamilton

COMMISSION SECRETARY

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-48-09

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by British Columbia Hydro and Power Authority
to Amend Section 2.1 of Rate Schedule 3808 ("RS 3808")
Power Purchase Agreement

BEFORE: P.E. Vivian, Commissioner and Panel Chair
A.A. Rhodes, Commissioner
L.A. O'Hara, Commissioner

May 6, 2009

O R D E R

WHEREAS:

A. On June 24, 2008 FortisBC Inc. ("FortisBC") filed its Umbrella Agreement ("UA") for Short-Term Firm Point to Point Transmission Service Agreement dated April 18, 2008 between FortisBC and the Corporation of the City of Nelson ("City of Nelson"), and the Power Coordination Agreement ("PCA") dated May 14, 2008 between FortisBC and the City of Nelson with the British Columbia Utilities Commission ("the Commission"); and

B. On June 25, 2008 the Commission requested comments from British Columbia Hydro and Power Authority ("BC Hydro") on the UA and PCA (the "Nelson Agreements") filed by FortisBC as well as a response to queries posed by the Commission staff to BC Hydro; and

C. On July 16, 2008 BC Hydro submitted its comments and reply, and indicated that at a minimum, a formal hearing process would need to be held to allow all interested parties an opportunity to review and comment on the Nelson Agreements; and

D. On July 18, 2008 the Commission forwarded the BC Hydro comments and reply received on the Nelson Agreements to FortisBC and the City of Nelson for reply; and

E. On September 16, 2008 BC Hydro provided its final comments on the Nelson Agreements wherein it stated that BC Hydro did not purport to represent the interests of FortisBC's ratepayers whose interests may be affected by the Nelson Agreements and that BC Hydro's primary interest was with respect to FortisBC's reliance on RS 3808 Power Purchase Agreement ("PPA") purchases to replace power exported by the City of Nelson; and

F. In addition to the final comments filed by BC Hydro on September 16, 2008 BC Hydro concurrently filed an application under subsections 58 (1) and (2) of the Utilities Commission Act ("the Act") for approval to amend section 2.1 of the PPA to clarify that electricity purchased by FortisBC under the PPA cannot be sold to FortisBC customers to replace electricity to be sold by those customers ("the Application"); and

.../2

G. On September 25, 2008 BC Hydro and FortisBC both filed further submissions to the Commission stating that the only application that had been filed was with regard to BC Hydro's requested amendments to section 2.1 of the PPA, that any Commission review of the Nelson Agreements should not be conducted until after a Commission decision on the Application, and that the review of the Nelson Agreements should be done in a separate process; and

H. On October 2, 2008 the Commission, by Order G-148-09, established a written public hearing process for the review of the Application; and

I. The written hearing process concluded on February 15, 2009; and

J. The Commission has reviewed and considered the Application, the responses to information requests and the submissions of BC Hydro and the participating Interveners.

NOW THEREFORE the Commission orders as follows:

1. Subject to any directives, orders, or qualifications contained in the Decision, the Application is approved.

2. BC Hydro is to comply with all directives and orders as set out in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 6th day of May 2009.

BY ORDER

Original signed by:

A.A. Rhodes
Commissioner

BRITISH COLUMBIA UTILITIES COMMISSION

SPLENDOR SINE OCCASU

IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

AND

APPLICATION TO AMEND SECTION 2.1 OF
RATE SCHEDULE 3808 POWER PURCHASE AGREEMENT

DECISION

May 6, 2009

Before:

Peter E. Vivian, Commissioner and Panel Chair
Liisa A. O'Hara, Commissioner
Alison A. Rhodes, Commissioner

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1.0 INTRODUCTION

This is an Application by British Columbia Hydro and Power Authority to amend its Power Purchase Agreement ("PPA") with FortisBC Inc. to address concerns arising from the potential for arbitrage of power supplied by it to FortisBC and FortisBC's customers under Rate Schedule ("RS") 3808.

The key parties in this proceeding include BC Hydro and FortisBC, as well as the Corporation of the City of Nelson, Zellstoff Celgar Limited Partnership and Northpoint Energy Solutions Inc. The inter-relationships of these companies and their respective contracts in the context of their energy transactions are described in more detail in Section 2.1 of this Decision.

On June 24, 2008, FortisBC filed its Umbrella Agreement for Short-Term Firm or Non-Firm Point-to-Point Transmission Service with the City of Nelson, dated April 18, 2008, as well as its Power Coordination Agreement, dated May 14, 2008, also with the City of Nelson, with the British Columbia Utilities Commission. FortisBC also filed its Power Supply Agreement with Zellstoff Celgar. FortisBC sought to increase its purchases of power under RS 3808 from BC Hydro pursuant to the PPA in response to requests from its self-generating customers, including the City of Nelson and Zellstoff Celgar, to increase their purchases of power. All three agreements were either suspended or withdrawn pending the outcome of this proceeding.

1.1 Issues Arising from the Nelson Agreements

BC Hydro responded to the Commission's request for comments regarding the two Nelson Agreements on July 16, 2008. BC Hydro first addressed the commercial impacts of the Nelson Agreements and introduced a third relevant contract which is the 1993 Power Purchase Agreement ("PPA") between BC Hydro and FortisBC as well as its Rate Schedule 3808 – Transmission Service FortisBC. To highlight its concerns, BC Hydro then described in greater detail arbitrage between embedded-cost utility service and market prices from the perspective of RS 3808 and Tariff Supplement No. 3 and its obligation to serve customers with self-generation capability. BC Hydro also noted some potential technical impacts of the Nelson Agreements in the context of generation system impacts under the Canal Plant Agreement and noted that FortisBC cannot use electricity purchased under the PPA for the provision of ancillary services to the City of Nelson.

By way of summary, BC Hydro stated that it has serious concerns with respect to the Power Coordination Agreement because of the potential financial implications for BC Hydro ratepayers, the potential detrimental impacts to its operating efficiency and “the precedent this agreement could set for other customers with their own generation”. Finally, BC Hydro called for a formal hearing process to allow interested parties an opportunity to review and comment on the Nelson Agreements (Exhibit B-4).

These concerns of BC Hydro and submissions by other parties ultimately resulted in a formal Application by BC Hydro on September 16, 2008. The pre-application activities of the Commission and key parties between June 24, 2008 and September 16, 2008 are chronicled in Appendix 1.

1.2 Application

On September 16, 2008, BC Hydro applied to the Commission pursuant to subsections 58(1) and (2) of the Utilities Commission Act (“UCA”) for approval to amend the PPA to clarify that electricity purchased by FortisBC under the PPA cannot be sold to a FortisBC customer to replace electricity to be sold by that customer (Exhibit B-1). BC Hydro referred to the concerns highlighted in its July 16, 2008 letter and, more specifically, stated that if it is required to provide incremental energy to FortisBC at embedded cost based rates for the purpose of supporting the export activities of FortisBC’s customers, BC Hydro and its ratepayers will incur an estimated loss of $ 16.7 million per annum. This loss is based on BC Hydro’s assertion that provision of the incremental energy to FortisBC would require it to either purchase the energy from the market at a price “that is almost certainly greater than the sale price to FortisBC” or “use its own generation and lose the opportunity to sell that energy in the market or store it for later use”.

BC Hydro seeks approval to add conditions to section 2.1 of the PPA that prohibit FortisBC (formerly West Kootenay Power) from reselling PPA purchases to customers with self-generation who wish to displace their self-generation with utility service for the purpose of selling their self-generation to market. Specifically, BC Hydro seeks approval to replace the existing section 2.1 of the PPA with the following new section 2.1:

> "The Electricity purchased under this Agreement is solely for the purpose of supplementing FortisBC's resources to enable it to meet its service area load requirements and,
>
> (a) shall not be Exported or stored, provided that nothing contained herein shall prohibit FortisBC from storing its entitlement resources in its entitlement account pursuant to the Canal Plant Agreement; and
>
> (b) shall not be sold to any FortisBC customer that is selling self-generated electricity which is not in excess of its load.
>
> For greater certainty, paragraph (b) above is to prevent FortisBC self-generating customers from arbitraging between PPA embedded-cost electricity and market prices."

BC Hydro's Application does not seek any changes to the Agreements between FortisBC and the City of Nelson. The Application is solely to address BC Hydro's concerns about arbitrage of RS 3808 power by FortisBC customers that export their self-generated power (Exhibit B-1).

1.3 Regulatory and Consultation Process

On October 2, 2008, the Commission issued Order G-148-08 which established a Regulatory Timetable for a written public hearing process for the review of the Application (Exhibit A-1).

Order G-148-08 directed BC Hydro to provide a copy of the Commission Order and the Regulatory Timetable to all parties who participated in the FortisBC F07/F08 Revenue Requirements Application and the 2007 Rate Design Application, and to all parties who participated in BC Hydro's

F07/F08 Revenue Requirements Application and the 2007 Rate Design Application as well as those Intervenors participating in its F2009/F2010 Revenue Requirements Application.

Order G-148-08 also directed BC Hydro to arrange for early publication of the Notice of Application and Written Public Hearing Process in provincial and other appropriate local news publications so as to provide adequate notice to the customers in its service area and that of FortisBC.

The regulatory background and process following the filing of the Application are summarized in Appendix 2.

A List of Intervenors and Interested Parties is provided in Appendix 3.

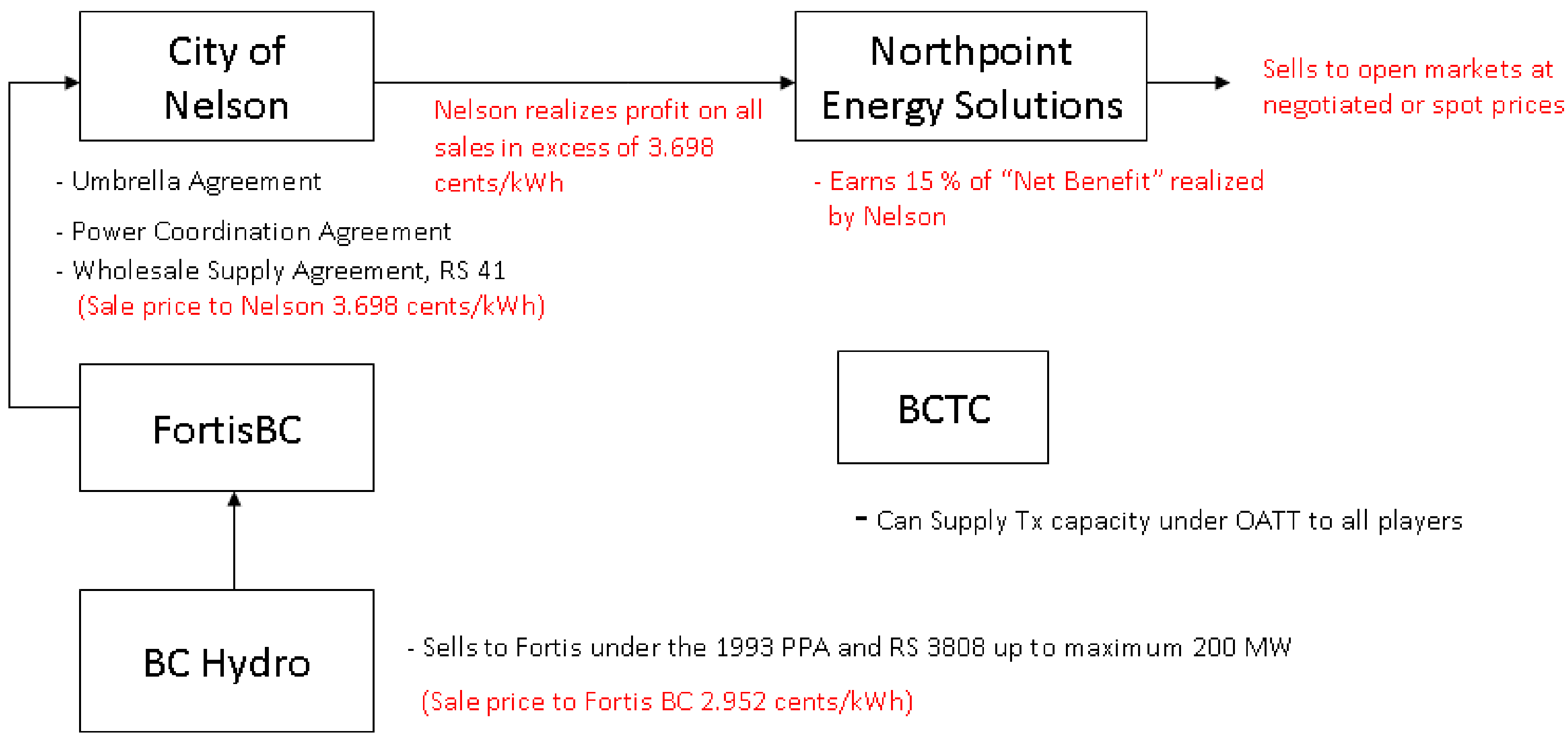
2.0 THE ISSUE BEFORE THE PANEL

2.1 The Inter-relationships of the Companies and their Respective Contracts

In order to understand the public policy issue at stake in this proceeding, it is important to understand the various companies (and the municipality of the City of Nelson), and the role that they play in the circumstances before the Commission. The diagram below is a sketch that illustrates the contractual ties among the various parties to this proceeding. It attempts to track the flow of energy under the various contracts as well as to note, in brief, the financial flows and costs of energy that are purchased/sold under the contracts.

Schematic Diagram of the Energy Transactions

(energy pricing in red)



In order to simplify the analysis that follows, the Panel has characterized each of the parties and the attributes of each that are relevant to this proceeding:

BC Hydro – Is the largest electrical utility in the Province and often acts as the supplier of last resort. In the case before the Commission, BC Hydro is best characterized as the supplier of power to Fortis BC under the Power Purchase Agreement ("PPA") which was executed by BC Hydro and FortisBC on October 1, 1993 and which will expire according to its terms, on September 13, 2013. The sale price of power sold under the PPA is 2.952 cents per kWh. BC Hydro is also an active player in the sale/purchase of power, both within the Province (buying power from IPPs), and buying/selling power on domestic and international markets through its subsidiary, Powerex.

FortisBC – Is a regional electrical utility that supplies a small area of the Province including the City of Nelson. As well as generating its own power, it purchases power from BC Hydro under the PPA discussed above for resale to its customers. The historical relationship between BC Hydro and FortisBC, and the Commission's involvement in regulating that relationship is set out in some detail in BC Hydro's Argument (see Section 1.1 Background, p. 2). FortisBC has entered into two recent contracts with the City of Nelson (the Umbrella Agreement ("UA")) dated April 18, 2008 and the Power Coordination Agreement ("PCA") dated May 14, 2008). There is also a third agreement between FortisBC and Nelson, the Wholesale Supply Agreement dated November 1, 2004 and it is under this agreement (and the associated Rate Schedule 41) that FortisBC supplies power to Nelson when requested. (See FortisBC Argument, p.4, and Exhibit C-4-7, Attachment 3) The price of supply to Nelson under this contract was set at 3.507 cents per kWh and this was recently increased as a result of a general FortisBC rate increase, to 3.698 cents per kWh. (see Order G-193-08)

While FortisBC is a utility, supplying the City of Nelson at regulated rates under the Power Co-ordination Agreement, it is in a position to control the timing and flow of energy as between the City of Nelson and Northpoint.

The City of Nelson – This municipality carries on all the requisite functions of a municipal government but in addition has its own power generating facilities at Bonnington Falls. It is termed a “self-generator” in these proceedings. It is not a public utility under the *Utilities Commission Act* but, because it supplies electricity to customers located outside the boundaries of the City of Nelson, it does come under the jurisdiction of the Commission for certain rate approvals. Its rates are normally approved in an informal way by the Commission and the rates applied are equal to those charged to Nelson residents. In short, Nelson currently has the option to buy power from FortisBC (under Rate Schedule 41) to supplement and replace its own generated power. Under certain conditions, the City of Nelson is also a seller of power to BC Hydro at low rates (incremental cost of supply at 0.7 cents per kWh) that were negotiated between the parties some time ago in the context of the 2006 Water Rights Agreement. Nelson takes the position that this arrangement allows BC Hydro to “arbitrage” between the low rates available from Nelson and the rates charged on a sale by BC Hydro of the power to another customer including customers in the open market. (Nelson Argument, p. 29)

Northpoint Energy Solutions Inc. - Nelson has entered into an agreement (February 29, 2008) with Northpoint Energy Solutions Inc. (a subsidiary of Saskatchewan Power, a provincial Crown corporation) under which Northpoint buys power from the City of Nelson for resale on the open power market at market rates, including the possibility of export sales into Alberta or the US. Northpoint is in nature, a marketer or reseller of power. It earns a 15 percent commission on the “Net Benefit” on sales from the City of Nelson.

Zellstoff Celgar Limited Partnership – Zellstoff Celgar operates a pulp mill in the service territory of FortisBC and is also a “self-generator” in that it operates a sizeable power plant using black liquor (a bi-product of the pulp mill) as a fuel. It generates power in excess of its own requirements and looks to sell such excess in the open market. As a customer of FortisBC, it also has the ability to purchase power to service its mill. FortisBC also filed its Power Supply Agreement with Zellstoff Celgar on August 21, 2008. This Agreement would have enabled Zellstoff Celgar to engage in similar transactions as the City of Nelson. This agreement was withdrawn pending the outcome of this proceeding.

British Columbia Transmission Corporation –BCTC is a provincial Crown corporation created in 2003. It has established an Open Access Transmission Tariff ("OATT") under which it offers transmission service to BC Hydro, FortisBC, Independent Power Producers ("IPPs"), and indeed, any company that seeks to move power about the province. Prior to the establishment of BCTC and the OATT, BC Hydro fulfilled this role under its Wholesale Transmission Services Tariff. While not a party to this proceeding, BCTC plays a role in the issue under study in that it supplies transmission capacity to move power about and among the parties.

2.2 The "Arbitrage" of Power

BC Hydro submits that the arrangement contemplated by the various agreements noted above permits the City of Nelson to buy power under FortisBC's Rate Schedule 41 and to resell it at market rates through Northpoint. BC Hydro argues that the power, for the most part, is supplied in turn from BC Hydro to FortisBC at embedded cost rates that reflect the Heritage Power generated by BC Hydro at its major hydro (water) generation sites. The Ministry of Energy, Mines and Petroleum Resources notes that in 2008, pulp and paper mills served by BC Hydro self-generated some 4,188,625 MWh and that those BC Hydro customers could similarly ask to be supplied at embedded cost regulated rates so that their total generation would be available to sell to market at market prices. (Ministry Argument, p. 4) The disposition of the BC Hydro Application in this proceeding may be seen as having precedential value for all self-generators in the province.

The definition of the term "arbitrage" received a good deal of attention during the proceeding. BC Hydro offered the following:

> "The term "arbitrage" refers to the simultaneous purchase and sale of the same securities, commodities or foreign exchange in different markets to profit from unequal prices." (Exhibit B-7, BC Hydro response to BCSEA IR 1.4.2 and Argument, p. 14)

Zellstoff Celgar stated that it would not be engaging in "arbitrage" as that term is defined by either BC Hydro or Black's Law Dictionary. It stated:

> "As Zellstoff Celgar intends only to service its Mill load from energy acquired from FortisBC and to sell its own self-generation, Zellstoff Celgar will <u>not</u> be engaging in "arbitrage" as such term is defined by either BC Hydro or Black's Law Dictionary. Neither definition contemplates a party producing its own "commodity". In typical arbitrage activities, such does not occur. Both definitions reference the simultaneous purchase and sale of the same item, with a view to taking advantage of different prices in different markets. Zellstoff Celgar will not be engaging in such activities as its intention is to purchase its Mill load from FortisBC and sell only its <u>own</u> self-generation." (Zellstoff Celgar Argument, pp. 29-30)

It should be understood that, in any commercial context, the concept of arbitrage is not illegal nor does it carry any pejorative implication. Rather, it is simply a market mechanism to discipline price variations among separate markets. The result of arbitrage is normally to bring about an equalization of prices in separate markets and generally, it assumes that pricing in the separate markets is variable. That may not be the case in the facts before the Commission Panel in this proceeding. While power prices in open markets (including sales to other provinces or territories as well as US customers) are variable and fluctuate with demand, weather, and a host of other factors, the price of the power supplied by BC Hydro and by FortisBC is at fixed, regulated rates.

The Commission employed the term "arbitrage" in its Order G-38-01 (discussed below) and stated:

> "The Commission directs B.C. Hydro to allow Rate Schedule 1821 customers with idle self-generation capability to sell excess self-generated electricity, provided the self-generating customers do not arbitrage between embedded cost utility service and market prices."

Thus, the Commission used the term "arbitrage" in the context of sales of power involving utilities and self-generators. Indeed, Order G-38-01 addressed the very issue that is before the Panel in this proceeding, but in the context of sales by self-generators who were customers of BC Hydro, not FortisBC, as in this case.

Simply stated, the issue considered by the Commission that led to the promulgation of Order G-38-01 was whether or not self-generators who were customers of BC Hydro ought to be allowed to purchase power from BC Hydro to service their respective "domestic" or base load at embedded cost rates, while at the same time selling their **total** self-generated power into the market at whatever negotiated or spot price could be obtained. The difference between the embedded cost price and the negotiated or spot price would accrue to the self-generator as profit. The Commission Panel is of the view that it is neither important, nor necessary, to qualify such actions under any definition of arbitrage. Nothing turns on any such characterization. The sales mechanisms and the resulting financial flows are well-understood. What the Commission Panel must determine is whether such an arrangement is in the public interest and, if it is not, whether the Commission Panel has the jurisdiction to impose a change in the contract(s) that is (are) before it.

2.3 The Short Term Nature of the Issue

The current Power Purchase Agreement between BC Hydro and FortisBC expires on September 13, 2013. It is unlikely that the parties will agree to its renewal on identical terms, particularly given the filings in this proceeding. BC Hydro notes that the two parties "have been holding discussions during the last two years with respect to the potential renewal and extension of the PPA beyond its 2013 expiry date. Those discussions are on-going and will hopefully result in a comprehensive, renewed PPA." (Exhibit B-1, p. 5) Therefore, the relief sought by BC Hydro is for the remaining term of the PPA.

2.4 The Changing Nature of the Electricity Power Markets in the Province

As noted earlier, the original Power Purchase Agreement as between BC Hydro and West Kootenay Power (now FortisBC) was executed in 1993. Since that time, there have been fundamental changes in the structure of the electricity industry in the province, including the number of players considered as active participants in the markets for power, the transmission of power throughout the Province, the common acceptance of international transmission standards, and the dynamic nature of export markets.

What was then BC Hydro has now been separated into a generation and distribution entity (BC Hydro) and a transmission entity (British Columbia Transmission Corporation ("BCTC")). Previously, both these roles were discharged by BC Hydro. With the establishment of BCTC came the establishment of "open access" to transmission facilities. The Open Access Transmission Tariff ("OATT") for BCTC was approved by the Commission on June 20, 2005 (Order G-58-05). The purpose of the OATT is to adopt international standards of transmission access for BC and it is modeled on the US Federal Energy Regulatory Commission's Order No. 888 and the Orders that build upon it.

The Province has also issued two "Energy Plans", the first in 2002 and the second in 2007 and has passed legislation requiring that the Commission take into consideration, when setting rates, the Energy Plan objectives together with any applicable prescribed requirements, factors and guidelines.

Further, the Energy Plan has led to the private sector establishment and financing of Independent Power Producers ("IPPs") which will supply power to BC Hydro under various power "calls" and the resulting Electricity Purchase Agreements. Also, the IPPs will have the capability of generating power for sale in domestic, interprovincial and international power markets.

Historically, the generation, transmission, storage and marketing of energy in British Columbia was dominated by BC Hydro and its energy trading subsidiary, Powerex. Substantial revenues were (and continue to be) booked by BC Hydro as a result of export sales. These sales raise profit for BC Hydro and benefit the ratepayers of BC Hydro as well as provide general revenues to the Province. Now, however, the number of significant players is increased and there will be a much more dynamic and competitive environment for the sale of power generated in the Province.

3.0 THE COMMISSION'S PREVIOUS DECISIONS OF RELEVANCE

Section 75 of the Act provides that the Commission is not bound by its prior decisions by way of precedent. However, it is prudent to examine relevant past decisions to assess the historical context of such decisions, the degree of congruence with new factual situations addressed, and whether or not there are good reasons to depart from the policy enunciations that led to the past decisions. In general, it is advantageous both for the Commission and those regulated companies that fall within its jurisdiction, to have a consistent and predictable body of decisions that will support informed decision-making in the future.

3.1 Orders G-38-01 (April 5, 2001) and G-17-02 (March 14, 2002)

Order G-38-01 addressed facts very similar to those under examination in this proceeding. In brief, BC Hydro sought the guidance of the Commission in defining the scope and ambit of its obligation to serve customers with self-generating capability, under what was then Rate Schedule 1821 when Howe Sound Pulp and Paper ("HSPP"), an RS 1821 customer, sought an Order from the Commission requiring BC Hydro to permit and facilitate sales of incremental [excess] power from HSPP. At that time, in 2001, export market pricing made it economic for a power generator to use natural gas to generate power for the export market, even though it might have been uneconomic to run the self-generating capacity to service its own base load. Definitional problems as to what constituted "idle" or "excess" capacity or "customer baseline" were addressed. The Commission, in recital F of the Order, concluded:

> "That it [the Commission] must act to meet the complementary objectives of creating conditions which allow B.C. Hydro to safeguard its own supply to British Columbians at lowest cost, assisting British Columbia industries with idle self-generation capability to capitalize on current market opportunities, and helping to mitigate the potential energy shortages in the Pacific Northwest and California."

It might be questioned whether the objectives as set out by the Commission were "complementary" or mutually exclusive. In the Order, the Commission permitted the sale of self-generated power. It stated:

> "The Commission directs B.C. Hydro to allow Rate Schedule 1821 customers with idle self-generation capability to sell excess self-generated electricity, provided the self-generating customers do not arbitrage between embedded cost utility service and market prices. This means that B.C. Hydro is not required to supply any increased embedded cost of service [beyond normal historical levels] to a RS 1821 customer selling its self-generation output to market."

The regime was established on a short-term basis and was subsequently extended by Order G-17-02 "until such time as future circumstances warrant further review." Thus, the Orders remain in place notwithstanding the Commission's reference in Section 4 of Order G-38-01 to "this short term program of purchases and sales."

The situation addressed in the HSPP case which led to the promulgation of Order G-38-01 is similar, but not identical, to this proceeding. FortisBC points out that BC Hydro had made substantial subsidies to the financing of the HSPP generators whereas neither BC Hydro nor FortisBC have made any monetary contributions to the construction of the City of Nelson's self-generating capability. (Exhibit C4-4) FortisBC argues that this fact distinguishes this proceeding from the Howe Sound Pulp and Paper case and that therefore the principles enunciated in Order G-38-01 are not necessarily applicable as a result.

Similarly, Zellstoff Celgar points out that, as it is not a BC Hydro customer, "Zellstoff Celgar is not eligible for loans or subsidies from BC Hydro, or contractual arrangements that have a similar effect" and therefore should not be bound by the principles set out in Order G-38-01. (Zellstoff Celgar Argument, p. 21, Paragraphs 53 and 61, and Exhibit C-10, pp. 4-5). Zellstoff Celgar argues that in BC Hydro's territory, of the seven biomass/black liquor turbines having capacity greater than 17 MW, which have been installed since 1990, "two of the seven turbines were installed by BC Hydro customers , whereby BC Hydro granted these customers the status of "Independent

Power Producers" and entered into power purchase agreements with them while continuing to supply their adjacent industrial facilities with embedded cost power. Both such facilities receive fuel from the adjacent facility and the generating station cogenerates steam from the adjacent industrial complex while BC Hydro absolves these facilities from self-supplying electricity." (Zellstoff Celgar Argument, p. 26, paragraph 61(v); Exhibit C-2-11, BC Hydro IR 1.1)

The potential characterization of industrial self-generators as IPPs highlights the changing nature of the power market in the province and the possible requirement for more general guidelines and rules as discussed in Section 4.2 below. Should self-generators with a base load acquire the status of IPPs and, if so, what results?

For its part, BC Hydro rejects the argument that its subsidization of its own self-generating customers in any way distinguishes the facts in this proceeding from those that gave rise to Order G-38-01. BC Hydro seems to take the position that, notwithstanding contrary arrangements that may form part of the contracts with self-generators, Order G-38-01 is of general applicability. "The Orders apply in relation to all BC Hydro transmission voltage customers with self-generation capability. The Orders are clearly not restricted to circumstances where BC Hydro has provided a demand side management (DSM) incentive to a customer as has been suggested by Fortis BC." (BC Hydro Argument, para. 44) This begs the question as to the treatment to be afforded a BC Hydro self-generator if the provisions of the DSM arrangement with the self-generator are inconsistent with the provisions of Order G-38-01.

The Commission Panel must then examine whether past arrangements between BC Hydro and its customers (particularly self-generating industrial customers operating pulp mills in BC Hydro's territory), condition the background of the principles enunciated in Order G-38-01 in such a way as to make it unfair to apply the same principles to self-generating industrial customers of FortisBC. This, in turn, raises questions as to whether the Commission ought to try to establish a "level playing field" for all BC customers in a particular industry segment, by setting electricity "rates" (including contractual amendments) that would reflect all past negotiated subsidies as between utilities and their industrial customers. The Commission Panel is of the view on this latter point that it cannot do so. The record of this proceeding is inadequate for such a general purpose and would involve setting industrial policy for the province that goes well beyond the jurisdiction of the Commission.

3.2 Order G-113-01 (October 25, 2001), Riverside Forest Products Ltd. ("Riverside")

This matter involved an exemption application to the Commission by Riverside which resulted in a Lieutenant Governor in Council approval. The factual situation was similar to the arrangement before the Commission in this proceeding in that it involved the possibility of the sale by Riverside of self-generated power to export markets.

The approved exemption was from "certain provisions of the Act" although the specific sections were not identified in the Order. In the result, Riverside was permitted to sell "Incremental Power" for export out of the Province and, importantly, was permitted to sell its historical initial 2 MW of generation, not required for use at the mill (i.e. excess energy), to the City of Kelowna. In the Order, there did not appear to be any restraint imposed upon the City of Kelowna as to the options open to the City, including the possible subsequent sale by the City into the export market.

Again, the Commission was aware of the possibility of arbitrage and stated " …the exclusion of the first 2 MW of generation each hour from the definition of Incremental Power and the relatively constant production level associated with the generators will protect WKP [West Kootenay Power, now FORTISBC] and its customers from arbitrage with respect to the initial 2 MW or other impacts."

Zellstoff Celgar refers to the arrangements that BC Hydro has made with its customers that, under certain circumstances, permit a self-generation customer to sell "incremental energy" into the market. In specific, Zellstoff Celgar refers to the arrangements between BC Hydro and another pulp mill, Tembec. It argues that approval of the Application "would impose a double standard, limiting FortisBC's ability to enter into agreements and arrangements with <u>its</u> customers, where BC

Hydro is not so limited." (Zellstoff Celgar Argument, p. 31) Again, this begs the question as to what general guidelines and rules ought to be developed and applied to all self-generators (and perhaps IPPs) as discussed below in Section 4.2.

4.0 THE JURISDICTION OF THE COMMISSION

4.1 Application under Section 58 of the Utilities Commission Act

BC Hydro applied to the Commission for an amendment to Section 2.1 of the Power Purchase Agreement between BC Hydro and FortisBC. (Exhibit B-1) The Application is made pursuant to subsections 58(1) and (2) of the Utilities Commission Act and BC Hydro characterizes the relief sought as a "clarification" of the existing terms of the PPA. (Exhibit B-1, p. 5) BC Hydro, then, asks the Commission for contractual interpretation of the PPA. For its part, Zellstoff Celgar argues that the Commission does not have jurisdiction to interpret agreements and that the preferred forum to carry out "contractual interpretation", is before the courts. (Zellstoff Celgar Argument, paras. 12, 16, and 75) Similarly, the City of Nelson sees the Application as a request to the Commission to "engage in the interpretation of a contract, but in doing so, to ignore basic and well-established principles of law governing contract interpretation." (Nelson Argument, p. 18)

Section 58 and the following relevant sections, read as follow:

Commission may order amendment of schedules

58 (1) The commission may,

(a) on its own motion, or

(b) on complaint by a public utility or other interested person that the existing rates in effect and collected or any rates charged or attempted to be charged for service by a public utility are unjust, unreasonable, insufficient, unduly discriminatory or in contravention of this Act, the regulations or any other law,

after a hearing, determine the just, reasonable and sufficient rates to be observed and in force.

(2) If the commission makes a determination under subsection (1), it must, by order, set the rates.

(2.1) The commission must set rates for the authority in accordance with

(a) the prescribed requirements, if any, and

(b) the prescribed factors and guidelines, if any.

(2.2) A requirement prescribed for the purposes of subsection (2.1) (a) applies despite

(a) any other provision of

(i) this Act, including, for greater certainty, section 58.1, or

(ii) the regulations, except a regulation under section 3, or

(b) any previous decision of the commission.

(2.3) Subsections (2.1) (a) and (2.2) are repealed on March 31, 2010.

(2.4) Despite subsection (2.3), a requirement prescribed for the purposes of subsection (2.1) (a) that is in effect immediately before March 31, 2010, continues to apply after that date as though subsection (2.2) were still in force, unless the prescribed requirement is amended or repealed after that date.

(3) The public utility affected by an order under this section must

(a) amend its schedules in conformity with the order, and

(b) file amended schedules with the commission.

Discrimination in rates

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.

(2) A public utility must not

(a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or

(b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

(3) The commission may, by regulation, declare the circumstances and conditions that are substantially similar for the purpose of subsection (2) (b).

(4) It is a question of fact, of which the commission is the sole judge,

(a) whether a rate is unjust or unreasonable,

(b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or

(c) whether a service is offered or provided under substantially similar circumstances and conditions.

(5) In this section, a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason.

Setting of rates

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,

(b.1) the commission may use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period, and

(c) if the public utility provides more than one class of service, the commission must

(i) segregate the various kinds of service into distinct classes of service,

(ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self contained unit, and

(iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates fixed for any other unit.

(2) In setting a rate under this Act, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area.

(3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.

(4) For this section, the commission must exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

Orders respecting contracts

64 (1) If the commission, after a hearing, finds that under a contract entered into by a public utility a person receives a regulated service at rates that are unduly preferential or discriminatory, the commission may

(a) declare the contract unenforceable, either wholly or to the extent the commission considers proper, and the contract is then unenforceable to the extent specified, or

(b) make any other order it considers advisable in the circumstances.

(2) If a contract is declared unenforceable either wholly or in part, the commission may order that rights accrued before the date of the order be preserved, and those rights may then be enforced as fully as if no proceedings had been taken under this section.

In order to determine the Commission's jurisdiction, it is necessary to consider the meaning of the term "rate", as it is defined in the Act. Section 1 of the Act states:

"rate" includes

(a) a general, individual or joint rate, fare, toll, charge, rental or other compensation of a public utility,

(b) a rule, practice, measurement, classification or **contract** of a public utility or corporation relating to a rate, and

(c) a **schedule or tariff** respecting a rate; (emphasis added);

As shown above, the definition of "rate" refers specifically to a "contract" as a rate, and to a "schedule or tariff" as comprising a rate for definitional purposes. It therefore appears to the Commission Panel that the legislature intended to give the Commission jurisdiction over all rate-related matters that are common in the industry.

Commission Determination

Based on the above, the Commission Panel determines that it has jurisdiction to consider the Application. Further, it finds that the provisions of the PPA do not specifically address the kinds of transactions now before it. Therefore, in the view of the Commission Panel, the Application does not involve "contractual interpretation" or "clarification" as was suggested by BC Hydro, but involves the setting of a "rate" within the meaning of the Act.

Also, the Commission Panel agrees with the City of Nelson, that there is no suggestion "that FortisBC and BC Hydro simply made a mistake in the words that they chose." (Nelson Argument, p. 18) However, given the industry practices, regulation and transmission capabilities that were present in 1993 when the PPA was executed, the Commission Panel is of the view that the parties to the PPA could not reasonably be expected to have addressed the possible sale of power, not in excess of load, by self-generating customers of FortisBC. Had the issue been posed by one of the parties at that time, the response probably would have been: "But that's impossible!" As noted by the BCOAPO, "the PPA became effective prior to market access of transmission services when export activities of FortisBC customers with their own generation was not possible." (BCOAPO Argument p. 2-3) As noted above, the same issue did not come up as between BC Hydro and its self-generating customers until the Commission considered the matter in 2001 and issued Order G-38-01.

And so a further question is: Does the Commission have the jurisdiction to amend the provisions of a contract, given the finding that the contract (or "rate" as per the definition in Section 1 of the Act) is deficient for some reason?

Section 59(4) of the Act states:

> "It is a question of fact, of which the commission is the sole judge,
>
> (a) whether a rate is unjust or unreasonable,
>
> (b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or…

Section 59(5) (c) also provides that a rate is "unjust" or "unreasonable " if the rate is "unjust and unreasonable for any other reason."

It is the view of the Commission Panel that the PPA, in its current form, reflects a rate which is unjust and/or unreasonable within the meaning of subsection 59(5)(c) in that it allows for a particular customer or class of customers (self-generators) to profit by purchasing power from BC Hydro at regulated rates in order to sell its own generation into the open market at market prices, to the potential detriment of ratepayers and other British Columbians.

Section 60(1) requires that the Commission, in setting a rate under the Act, have "due regard to the setting of a rate that (i) is not unjust or unreasonable within the meanin of section 59…"

The Commission Panel finds that the provisions of subsections 59(4)(a) and (b), and 59(5)(c) do provide sufficient flexibility to found the Commission's jurisdiction to order an amendment to a contract in the fact situation of this proceeding. The Commission Panel further finds that the current arrangement results in a rate which could result in undue discrimination or preference within the meaning of subsection 59(4)(b) and that the contract is therefore is unjust or unreasonable within the meaning of the Act.

4.2 Other Provisions of the Utilities Commission Act Considered

The relief sought by BC Hydro in this proceeding is specific and relates to a simple change in the bilateral PPA agreement between BC Hydro and FortisBC. In analyzing the issue to be addressed, the Commission Panel also reviewed other sections of the Act. The Commission Panel did so with a view to assessing the options that might be available to provide general rules, regulations or guidelines in respect of the sale by self-generators of power not in excess of their own load. The objective in assessing other options for relief was to ascertain if there was some more suitable methodology for treating the perceived unfairness.

The Commission Panel reviewed Section 31 that provides:

31. The Commission may make **rules** governing conditions to be contained in agreements entered into by public utilities for their regulated services or for a class of regulated service.

Section 59(3) refers to the possibility of Commission regulations:

> 59(3) The Commission may, by regulation, declare the circumstances and conditions that are substantially similar for the purpose of subsection (2) (b) [which deals with discrimination by a public utility in supplying services under substantially similar circumstances].

The Commission Panel is of the view that a more global solution to the issue of reselling or "arbitrage" of power would be preferable and that a Commission "rule" or "regulation" might have been a viable way to proceed. However, in the end, the Commission Panel decided that the record in this proceeding and the limited number of parties participating, did not permit or support a more general solution or remedy. As the power export market for BC generators and their agents (BC Hydro, Powerex, FortisBC, IPPs, resellers and marketers etc.) matures, the Commission or the Government may choose to establish guidelines, rules or regulations to deal with the markets and to spell out the permitted roles and operational rules that will be open to the various players province-wide.

5.0 IS THE CONTRACTUAL ARRANGEMENT CONTRARY TO THE PUBLIC INTEREST?

The Commission Panel is persuaded that a rate allowing for the sale of power by self-generators, not in excess of their historical loads, is unjust and unreasonable and therefore contrary to the public interest for the reasons that follow. The Panel is of the view that the general principles enunciated in Order G-38-01 ought to be extended to customers of FortisBC.

We agree with BC Hydro as to the characterization of the issue at hand as: "…whether the new use of PPA power by FortisBC renders the current PPA, and specifically section 2.1 of it, unjust or unreasonable because it allows certain [Fortis BC] customers to unfairly profit from embedded cost utility service to the detriment of all other customers." (BC Hydro Reply Argument, p. 14, para. 43)

5.1 The Intent of the Energy Plan

5.1.1 Government Policy Context - The Energy Plan, The Heritage Contract Scheme

The Ministry of Energy, Mines and Petroleum Resources supports the Application on the basis that it would be unfair to allow one set of BC Hydro's customers to benefit from the heritage assets to the detriment of its customers as a whole. (MEMPR Argument, pp. 1-2)

The Ministry submits that it is necessary to look at the policy and legislative foundations of the Heritage Contract (which "was enacted to ensure that BC Hydro's ratepayers collectively receive the benefits of the heritage assets…"). (MEMPR Argument, pp. 1-2)

5.1.2 BC Energy Plan 2002

As noted in the MEMPR Argument, one of the cornerstones of the 2002 BC Energy Plan "Energy For Our Future: A Plan for BC" ("2002 Energy Plan") was "low electricity rates and public ownership of BC Hydro". The 2002 Energy Plan stated: "BC Hydro ratepayers will benefit from a legislated heritage contract that locks in the value of existing low-cost generation (heritage energy), and from the continued use of trading revenues to supplement domestic revenues. The BC Utilities Commission will conduct an inquiry and recommend the terms and conditions of the heritage contract legislation. To benefit ratepayers and taxpayers alike, public ownership of BC Hydro generation, transmission and distribution assets will continue." (2002 Energy Plan, p. 7)

The Commission conducted a public review process and made recommendations to the Provincial Government, most of which were implemented by way of Special Directions, including the establishment of the "Heritage Contract" between BC Hydro's generation line of business and its distribution line of business under Special Direction No. HC2 to BCUC ("HC2"). HC2 was made pursuant to the BC Hydro Public Power Legacy and Heritage Contract Act, which was enacted in November 20, 2003.

The BC Hydro Public Power Legacy and Heritage Contract Act identifies "protected [generation and storage] assets" and prohibits their sale, unless under certain specified circumstances.

The Heritage Contract states at the outset:

> "Whereas on November 25, 2002 the Province of British Columbia released Energy for Our Future, A plan for B.C. (the "Energy Plan");
>
> And Whereas the Energy Plan outlines certain policy actions designed to ensure *British Columbians* have continued access to sufficient supplies of dependable low-cost electricity…" (emphasis added),

arguably confirming the intention of the government to give the policy outlined in the 2002 Energy Plan legislative force. Of note, however, is the use of the term "British Columbians" to describe the class of persons assured access to "sufficient supplies of dependable low-cost electricity" in the legislation, as opposed to "BC Hydro's ratepayers collectively".

The original term of the Heritage Contract was 10 years, commencing April 01, 2004 (HC2 Appendix A). The Heritage Contract also provided that the Agreement could "be terminated by government, with 5 years notice, any time after April 1, 2009…" (HC2 Appendix A, s. 11(2). However, that provision was repealed by BC Reg. 335/2008 in November, 2008, as envisioned in The BC Energy Plan A Vision for Clean Leadership (the "2007 Energy Plan") as described below.

In the 2007 Energy Plan the government confirmed its commitment to the public ownership of BC Hydro and the British Columbia Transmission Corporation ("BCTC") stating:

> "BC Hydro and the BC Transmission Corporation are publicly-owned crown corporations and will remain that way now and into the future….BC Hydro owns the heritage assets, which include historic electricity facilities such as those on the Peace and Columbia Rivers that provide a secure, reliable supply of low-cost power for British Columbians….
>
> Under the 2002 Energy Plan, a legislated heritage contract was established for an initial term of 10 years to ensure BC Hydro customers benefit from its existing low-cost resources. With [the 2007 Energy Plan], government confirms the heritage contract in perpetuity to ensure ratepayers will continue to receive the benefits of this low-cost electricity for generations to come." (2007 Energy Plan, p. 12)

The 2007 Energy Plan also states:

> "British Columbians require a secure, reliable supply of competitively priced electricity now and in the future. Competitively priced power is also an incentive for investors to locate in British Columbia. It provides an advantage over other jurisdictions and helps sustain economic growth. We are fortunate that historic investments in hydroelectric assets provide electricity that is readily available, reliable, clean and inexpensive. By ensuring public ownership of BC Hydro, the heritage assets and the BC Transmission Corporation and confirming the heritage contract in perpetuity, we will ensure that ratepayers continue to receive the benefits of this low cost generation….Profits from electricity trade also contribute to keeping our electricity rates competitive. BC Hydro, through its subsidiary, Powerex, buys and sells electricity when it is advantageous to British Columbia's ratepayers. Government will continue to support capitalizing on electricity trading opportunities and will continue to allocate trade revenue to BC Hydro ratepayers to keep electricity rates low for all British Columbians." (2007 Energy Plan, pp. 14, 15)

This contextual background confirms the public nature of the heritage assets. The Commission Panel is of the view that Nelson residents, as British Columbians, do share in the overall benefits of the Heritage Power framework but should not be permitted to benefit unduly at the expense of other customers of BC Hydro.

5.2 Winners and Losers - Tracking the Money Flow

If the proposed power sales by self-generators were to be permitted, then there would be prospective "Winners" and "Losers". In brief, the Winners would be FortisBC, City of Nelson, and Northpoint Energy Solutions; Zellstoff Celgar would also be a winner were it to participate in a similar manner. Their respective gross profits on the sales are easily calculated by simply subtracting acquisition costs from sale price and, in the case of the City of Nelson, deducting the commission costs of sales payable to Northpoint. This may be overly simplistic in that administrative overheads and other internal costs are ignored. Also, there is no way to factor in the business decision-making that self-generators may use in retaining some self-generated power for base or domestic loads.

The costs to BC Hydro to replace the increased sale of power under RS 3808 to FortisBC have been addressed above. We noted that some unknown but sizeable cost to BC Hydro will accrue; but the ultimate cost will be born in the end, by either the BC Hydro ratepayers or BC Hydro's owner, the provincial government and hence the general taxpayers of the province. The benefit to BC Hydro ratepayers of export sales by Powerex is capped at $200 million and gross profits beyond that cap accrue to the province as owner. The City of Nelson noted that the total impact incurred by BC Hydro will eventually accrue to the provincial government in any year where export sales are in excess of $200 million. (City of Nelson Argument, p. 14) As well, the City of Nelson was of the view that, given reasonable assumptions as to sales and foreign exchange rates, the impact of the proposed sales would most likely fall upon the owner, not the BC Hydro ratepayer. The Commission Panel agrees that this is a possible outcome, if the proposed transactions were permitted. Regardless of which parties "lose," as between the Province and BC Hydro, in each case the loss will be borne by either taxpayers or ratepayers, respectively.

5.3 The Cost to be Incurred by BC Hydro

BC Hydro expends considerable effort to dimension the possible financial impact upon itself and its ratepayers that would accrue as a result of increased sales under the PPA to support the market sales by FortisBC's self-generating customers. BC Hydro estimated the potential cost to BC Hydro ratepayers as "… roughly $16.7 million per year, assuming annual sales by the City of Nelson of 28 GWh and Zellstoff Celgar of 350 GWh (and therefore 378 GWh of increased purchases by FortisBC under the PPA"). (BC Hydro Argument, p. 19, paragraph 50) The background assumptions for this calculation were set out in Exhibit B-5, BCUC IR 1.8.1.1. BCUC staff had suggested an alternative method of calculation that would have led to an estimated cost to BC Hydro of $12.3 million per year. (Exhibit C4-8, BCUC IR 3.1.8.1)

There were differences expressed as to the appropriate assumptions to be chosen in calculating the estimated cost of the additional power that BC Hydro would have to purchase to replace the increased power usage under the PPA to support sales by the self-generators. All parties to the proceeding, including BC Hydro, have noted the imprecision of any estimate of dollar cost to BC Hydro. For instance, BC Hydro states, "The potential cost to BC Hydro and its ratepayers could be much greater, or lower, than that estimate depending on the actual amount of incremental purchases under the PPA to replace exported electricity and the actual cost to BC Hydro of acquiring that incremental electricity." (BC Hydro Argument, p. 19, paragraph 50) The City of Nelson notes that changing foreign exchange rates might also affect the estimates for lost trade income for sales to the US. (City of Nelson Argument, p. 14)

The Commission Panel is persuaded that if the City of Nelson and Zellstoff Celgar are permitted to sell all of their respective **total** generation capacity into the available markets, there would be some fairly large negative impact on BC Hydro. It seems to the Commission Panel that the exact dollar amount of that impact is not important because it is the policy principles surrounding the treatment of self-generating customers of BC Hydro spelled out in Order G-38-01 that are in issue. Once there is some material anticipated loss, then the principles come into play and the

Commission Panel must decide if the principles should be applied to the self-generating customers of FortisBC, namely the City of Nelson and Zellstoff Celgar.

6.0 FUTURE OPERATIONS OF SELF-GENERATORS AND PRESCRIBED RELIEF

6.1 Self-Generators Can Still Sell "Excess" Power

The phrase "excess self-generated power" was used by the Commission in Order G-38-01. The principle stated in Order G-38-01 did not preclude **any** power sales by self-generators, only sales of power that would increase the consumption by the customer of embedded cost power as a result. In other words, BC Hydro was not required to provide increased supply of embedded cost power to supply base load requirements and hence support additional export sales by the customer. So it is clear, self-generators were permitted to sell self-generated power in excess of their base load.

While this is a simple concept, it does require some definition of the "customer baseline", which would be based "either on the historical energy consumption of the customer or the historical output of the generator." (Order G-38-01, Section 1)

Generally, the Commission Panel believes that self-generators should be able to sell any self-generated power that is not required by their base loads, and we would prefer to use the term "excess generated power" to mean any power generated **net of load on a dynamic basis**.

It is also not possible to judge the possibility that domestic load would be reduced (by a reduction in plant operations, say or total plant shutdown) if management of the self-generator came to a business decision that there were better commercial prospects selling power than selling whatever product the industrial self-generator produces (e.g. pulp vs. power). This possibility was recognized by the Commission when it released Order G-38-01. Making reference to the proposal of the self-generator in that proceeding, the Commission stated the " proposal could create incentives that, in time, may lead to a reduction in employment and economic activity as customers with self-generation may seek to reduce production in order to provide electricity sales to the market." (Order G-38-01, Recital D)

In the end, the Commission Panel has decided that there must be a simple definition of what constitutes "excess power" and we define that term to mean power "net of load on a dynamic basis." The Commission Panel determines that any self-generators, as owners of the generation facilities, should have the flexibility to reduce domestic load as they see fit in the commercial circumstances at hand in order to optimize the export of self-generated power. What will not be permitted is the supply of embedded cost power to service the domestic load, at any time when the self-generator is selling power into the market.

6.2 Definition of Customer "Baseline" and "Net of Load"

Both "baseline" and "historical" are used in Order G-38-01. The Commission Panel believes that in any short term resolution of the policy issue addressed in this proceeding, there must be some definition for each self-generator of the historical baseline load served, or, in the alternative, some means of monitoring, on a dynamic basis, excess self-generation net of load. As the Commission stated in Order G-38-01:

> "The Commission recognizes that considerable debate may ensue over whether a self-generator has met the principle, but the Commission expects BC Hydro to make every effort to agree on a customer baseline, based either on the historical energy consumption of the customer or the historical output of the generator."

In the course of these proceedings, there has also been reference to "idle generation", "incremental energy generation" and "new generation". There has also been reference to the development, over time, of the generation capabilities of the self-generators. The City of Nelson refers to the investment in the G5 facility in 1995, two years after the PPA came into force:

> "The G5 installation provided incremental capacity, increased efficiency, and replacement of old generation capacity all of which is consistent with the objectives of Order G-38-01. The financial incentive to Nelson for G5 was marginal, being derived principally based on the avoided cost of purchased power. The export of power provides an important opportunity for Nelson to achieve more than marginal returns from its investment in G5." (City of Nelson Argument, p. 23)

Similarly, Zellstoff Celgar refers to the failure of its 3.5 MW generator in 1993 and its replacement with a 52MW generator in 1994. This was followed in 2008 with an investment decision to purchase a 48 MW generator scheduled for installation in 2009. (Zellstoff Celgar Argument, p. 1)

Are these increases in generation capacity to be considered incremental energy generation or new generation? What portion of the increased generation capacity should be available for export by the owners? The Panel believes that on the basis of the record in this proceeding, it has insufficient evidence on which to base any set numerical answer to the questions.

The Commission Panel has determined that self-generators should be permitted to sell any self-generated power that is in excess of the self-generator's own "domestic" load and to do so on a dynamic basis. This will require a technical means of monitoring both the purchase of embedded cost power from the utility and the export of excess self-generated power by the self-generator. Such a monitoring system will be required to discipline the sale of excess self-generated power and to ensure that power purchased from the utility by the self-generator is not being sold into the open market.

The Commission Panel directs BC Hydro, in consultation with FortisBC, to identify and submit to the Commission an agreed methodology to monitor "net of load" energy within 90 days of the date of this Decision.

As to the treatment of any new or incremental generation capacity added by a self-generator, the Commission Panel makes no determination. This issue can be dealt with in the future on a case by case basis.

For its part, BC Hydro is to provide a report to the Commission that will summarize the terms and conditions of its contractual arrangements with any of its industrial customers with self-generation capacity who may sell power on a basis which is inconsistent with the "net of load" concept as enunciated in this Decision.

6.3 Specific Relief and Contractual Amendment

For all the reasons enunciated above, the Commission Panel Orders that section 2.1 of the PPA be amended to read as follows:

> **"(a) The electricity purchased under this agreement is solely for the purpose of supplementing FortisBC's resources to enable it to meet its service area load requirements and, shall not be exported or stored, provided that nothing contained herein shall prohibit FortisBC from storing its entitlement resources in its entitlement account pursuant to the Canal Plant Agreeement; and**
>
> **(b) shall not be sold to any FortisBC customer when such customer is selling self generated electricity which is not in excess of its load.**
>
> **For greater certainty, paragraph (b) above is to prevent FortisBC self-generating customers from purchasing power at regulated embedded cost rates and simultaneously selling an equivalent amount of power into available domestic and export markets."**

For clarity, this amendment is to be effective as of the date of this Decision.

7.0 EXTRANEOUS OR ANCILLARY ISSUES ARISING IN THE PROCEEDING

7.1 The City of Nelson's Sales to BC Hydro

The existing power sales from the City of Nelson to BC Hydro under the provisions of the 2006 Water Rights Agreement was raised by the City of Nelson in the IRs as an example of where BC Hydro could earn a profit by using "arbitrage" between the low rates specified in the agreement and available market rates. BC Hydro responded that the rates in the Agreement were beyond the jurisdiction of the Commission and in any event were justified given the totality of the Agreement. (BC Hydro Argument, p. 11) Nelson argues that the rates ought to be open to renegotiation (just as BC Hydro has sought amendment to RS 3808) and that the Agreement "…is part of BC Hydro's Tariff Supplement as filed with the Commission and was filed by BC Hydro as an Energy Supply Contract subject to the jurisdiction of the Commission." (City of Nelson Argument, p. 32) The rates to BC Hydro appear to be low given today's markets but might well have been reasonable in the context of the agreement and the negotiations in 2006. If the City of Nelson feels that there are now changed circumstances and that it is unjust for BC Hydro to be in a position to purchase at such low rates, and that there are material and significant amounts of money at stake, then it can attempt to renegotiate such rates with BC Hydro and in the absence of agreement, file an application with the Commission to seek a change in the rates. No decision is made as part of this proceeding, as to the Commission's jurisdiction to entertain such an application. Jurisdiction will be determined if, as and when an application is made.

7.2 Allegations of Abuse of Dominance by BC Hydro

The City of Nelson made the allegation that certain acts by BC Hydro constituted anti-competitive acts and if the Commission granted the relief sought by BC Hydro, it would be endorsing such anti-competitive behaviour. (City of Nelson Argument, pp. 24-25) In any event, the City of Nelson argued that evidence of such anti-competitive acts should weigh in the decision-making by the Commission Panel in this proceeding. The Commission Panel dismisses this argument and finds no *prima facie* evidence of any anti-competitive behaviour on the part of BC Hydro. Should the City of Nelson wish to pursue this matter, an application under the *Competition Act* could be brought.

7.3 Possible Sale of Self-Generating Assets to a Third Party

BCOAPO notes in its Argument (p. 3) that BC Hydro has acknowledged "…that if the City of Nelson was to sell its Bonnington Falls generating facility to an arm's length third party, it [Nelson] would be able to buy all of its supply from FortisBC which BC Hydro would be obligated to supply even under the amended PPA (up to 200 MW). (See BCSEA.BCH 1.6.1 and Celgar/BCH 1.7.8) The matter of a possible sale of self-generating assets to either a related or arm's length party is hypothetical in the context of this proceeding. No such sale is anticipated.

7.4 Further Issues Raised by BC Hydro in Argument (pp. 31-32)

This section contains the Commission Panel's findings and comments regarding four other issues raised by BC Hydro.

(a) BC Hydro notes that the negotiations with FortisBC with respect to the potential renewal and extension of the PPA are on-going but that the BC Hydro Application in this proceeding, seeks no relief or order associated with such renewal.

The Commission Panel has therefore made no such order.

(b) BC Hydro raises the possibility of the provisions of the Power Coordination Agreement (between FortisBC and the City of Nelson) and the Power Supply Agreement (between FortisBC and Zellstoff Celgar) as constituting "rates" which are subject to Commission approval.

Both agreements have either been held in abeyance or withdrawn pending the outcome in this proceeding and therefore this issue is academic.

(c) BC Hydro suggests that the sales by the City of Nelson to NorthPoint Energy Solutions are subject to Commission review. The relevant contract is the Energy Portfolio Optimization Agreement.

Again, given the outcome in this proceeding, the question is academic.

(d) BC Hydro asks whether FortisBC ought to be required to provide, on its website or on an open access same-time information system (OASIS), its transmission transactions.

FortisBC is requested to file a written statement within 90 days of the date of this Decision as to its intentions to provide such transparency.

DATED at the City of Vancouver, in the Province of British Columbia, this 6th day of May 2009.

Original signed by:

L.A. O'HARA
Panel Chair and Commissioner

Original signed by:

A.A. RHODES
Commissioner

Original signed by:

P.E. VIVIAN
Commissioner

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-48-09

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by British Columbia Hydro and Power Authority
to Amend Section 2.1 of Rate Schedule 3808 ("RS 3808")
Power Purchase Agreement

BEFORE: P.E. Vivian, Commissioner and Panel Chair
A.A. Rhodes, Commissioner
L.A. O'Hara, Commissioner

May 6, 2009

O R D E R

WHEREAS:

A. On June 24, 2008 FortisBC Inc. ("FortisBC") filed its Umbrella Agreement ("UA") for Short-Term Firm Point to Point Transmission Service Agreement dated April 18, 2008 between FortisBC and the Corporation of the City of Nelson ("City of Nelson"), and the Power Coordination Agreement ("PCA") dated May 14, 2008 between FortisBC and the City of Nelson with the British Columbia Utilities Commission ("the Commission"); and

B. On June 25, 2008 the Commission requested comments from British Columbia Hydro and Power Authority ("BC Hydro") on the UA and PCA (the "Nelson Agreements") filed by FortisBC as well as a response to queries posed by the Commission staff to BC Hydro; and

C. On July 16, 2008 BC Hydro submitted its comments and reply, and indicated that at a minimum, a formal hearing process would need to be held to allow all interested parties an opportunity to review and comment on the Nelson Agreements; and

D. On July 18, 2008 the Commission forwarded the BC Hydro comments and reply received on the Nelson Agreements to FortisBC and the City of Nelson for reply; and

E. On September 16, 2008 BC Hydro provided its final comments on the Nelson Agreements wherein it stated that BC Hydro did not purport to represent the interests of FortisBC's ratepayers whose interests may be affected by the Nelson Agreements and that BC Hydro's primary interest was with respect to FortisBC's reliance on RS 3808 Power Purchase Agreement ("PPA") purchases to replace power exported by the City of Nelson; and

F. In addition to the final comments filed by BC Hydro on September 16, 2008 BC Hydro concurrently filed an application under subsections 58 (1) and (2) of the Utilities Commission Act ("the Act") for approval to amend section 2.1 of the PPA to clarify that electricity purchased by FortisBC under the PPA cannot be sold to FortisBC customers to replace electricity to be sold by those customers ("the Application"); and

.../2

G. On September 25, 2008 BC Hydro and FortisBC both filed further submissions to the Commission stating that the only application that had been filed was with regard to BC Hydro's requested amendments to section 2.1 of the PPA, that any Commission review of the Nelson Agreements should not be conducted until after a Commission decision on the Application, and that the review of the Nelson Agreements should be done in a separate process; and

H. On October 2, 2008 the Commission, by Order G-148-09, established a written public hearing process for the review of the Application; and

I. The written hearing process concluded on February 15, 2009; and

J. The Commission has reviewed and considered the Application, the responses to information requests and the submissions of BC Hydro and the participating Interveners.

NOW THEREFORE the Commission orders as follows:

1. Subject to any directives, orders, or qualifications contained in the Decision, the Application is approved.

2. BC Hydro is to comply with all directives and orders as set out in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 6th day of May 2009.

BY ORDER

Original signed by:

A.A. Rhodes
Commissioner

SUMMARY OF PRE-APPLICATION ACTIVITIES

On June 24, 2008 FortisBC Inc (“FortisBC”) filed its Umbrella Agreement (“UA”) for Short-Term Firm Point to Point Transmission Service dated April 18, 2008 between FortisBC and the Corporation of the City of Nelson (“Nelson”) and the Power Coordination Agreement (“PCA”) dated May 14, 2008 between FortisBC and Nelson (Exhibit C4-3).

On June 25,2008 the Commission requested comment from BC Hydro on the UA and PCA (the “Nelson Agreements”) filed by FortisBC, as well as a response to queries posed by the Commission staff to BC Hydro, and that BC Hydro file its comments by July 15, 2008. Also, the Commission advised BC Hydro that its comments would be forwarded to FortisBC for its reply (Exhibit A-2).

On July 11, 2008, Nelson Hydro requested to receive copies of material on the matter of Nelson Agreements (Exhibit C1-3).

On July 11, 2008, the Commission responded to Mercer International Inc.’s (“Zellstoff Celgar”) request to provide comment on the matter of Nelson Agreements (Exhibit A-4).

On July 14, 2008, the Commission responded to Nelson Hydro’s request to provide comment on the matter of Nelson Agreements (Exhibit A-3).

On July 16, 2008 BC Hydro submitted its comments and reply, and indicated that at a minimum a formal hearing process needed to be held to allow all interested parties an opportunity to review and comment on the Nelson Agreements (Exhibit B-4).

On July 18, 2008 the Commission forwarded the BC Hydro comments and reply received on the Nelson Agreements to FortisBC and Nelson for reply by August 5, 2008 (Exhibit A-5).

On July 23, 2008, Nelson Hydro requested an extension of the deadline for response from August 5, 2008 to August 14, 2008 (Exhibit C1-4).

On July 29, 2008, the Commission accepted a request by Nelson Hydro to extend the deadline for response from August 5, 2008 to August 14, 2008 (Exhibit A-6).

On August 14, 2008 FortisBC and Nelson Hydro provided their comments on the BC Hydro's submission dated July 16, 2008 (Exhibits C4-4 & C1-5).

On August 20, 2008 the Commission requested that BC Hydro provide its final reply by September 16, 2008 with regard to the submissions of FortisBC and Nelson on the Nelson Agreements (Exhibit A-7).

On September 16, 2008 BC Hydro provided its final comments on the Nelson Agreements wherein it stated that BC Hydro did not purport to represent the interests of FortisBC's ratepayers whose interests may be affected by the Nelson Agreements and that BC Hydro's primary interest was with respect to FortisBC's reliance on RS 3808 Power Purchase Agreement (PPA) purchases to replace power exported by the City of Nelson. In addition to the final comments filed by BC Hydro on September 16, 2008, BC Hydro concurrently filed an application under subsections 58 (1) and (2) of the Act for approval to amend section 2.1 of the PPA to clarify that electricity purchased by FortisBC under the PPA cannot be sold to FortisBC customers to replace electricity to be sold by those customers (Exhibit B-1).

REGULATORY BACKGROUND AND PROCESS

On September 25, 2008 BC Hydro and FortisBC both filed further submissions to the Commission stating that the only application that had been filed was with regard to BC Hydro's requested amendments to section 2.1 of the PPA, that any Commission review of the Nelson Agreements should be dealt with after a Commission decision had been reached on BC Hydro's application of September 16, 2008, and that the review of the Nelson Agreements should be in a separate process from BC Hydro's application (Exhibit B-2).

On September 30, 2008, BC Hydro stated that the Nelson Agreements are relevant to the approval BC Hydro is seeking in its Application, and BC Hydro requested that the following documents should be made part of the evidentiary record of the written proceeding to review BC Hydro's Application: the Nelson Agreements, the previous submissions and comments filed by FortisBC, the City of Nelson and BC Hydro with regard to the Nelson Agreements; and BC Hydro's September 16, 2008 letter to the Commission, in its entirety, with regard to the Nelson Agreements and BC Hydro's application to amend section 2.1 of the PPA (Exhibit B-3).

On October 2, 2008 the Commission Order G-148-08 established a Regulatory Timetable and a Written Hearing Process (Exhibit A-1).

On October 16, 2008, FortisBC stated that it has no objection to the inclusion of all written documents related to the Nelson Agreements as requested in Order G-148-08, Recital J (Exhibit C4-2).

On October 16, 2008, Nelson Hydro agreed to the inclusion of all written documents related to the Nelson Agreements as requested in Order G-148-08, Recital J (Exhibit C1-2).

On October 21, 2008, the Commission Order G-154-08 established an amended Regulatory Timetable (Exhibit A-8).

On November 4, 2008, (Exhibit C2-3), Zellstoff Celgar requested that the Commission extend the entire regulatory schedule by two business days, or more. The Commission amended the Regulatory Timetable (Exhibit A-10).

On November 7, 2008, and at the second request by the City of Nelson, the Commission Letter L-52-08, amended the Regulatory Timetable (Exhibit A-11).

On December 8, 2008, Sangra Moller LLP and Lang Michener LLP (representing Celgar and Nelson respectively) filed letters, Exhibits C2-7 and C8-4 respectively, with the Commission requesting an extension to the Commission's Regulatory Timetable. The Commission Letter, L-57-08, established a revised regulatory timetable (Exhibit A-15).

On December 19, 2008 and after considering the submissions of the parties, the Commission denied the request to invite further submissions on the request to compel BC Hydro to respond to certain information requests and denied Zellstoff Celgar's request to compel BC Hydro to provide the additional information sought. Also, the Commission declined to further amend the Amended Regulatory Timetable established in its December 10, 2008 letter (L-57-08) (Exhibit A-16).

On January 5, 2009, further to the Commission's December 10, 2008 letter (Exhibit A-15) approving an extension to the Regulatory Timetable, the Commission amended BC Hydro's Final Submissions to Friday, January 16 rather than January 19 (Exhibit A-20).

On January 13, 2009, FortisBC filed a letter with the Commission stating that it "does not have any issues with holding these agreements [the Nelson Agreements] in abeyance pending the decision on the above noted BC Hydro Application". On January 14, 2009, Commission Letter L-4-09, suspended the review of the Nelson Agreements, until such time as a Commission Decision has been made in the on-going hearing on the Application to Amend Section 2.1 of the PPA (Exhibit A-21).

On January 16, 2009, BC Hydro submitted its Final Argument. On January 21, 2009, Joint Industry Electricity Steering Committee ("JIESC"), FortisBC, Zellstoff Celgar, Commercial Energy Consumers Association ("CEC"), BC Old Age Pensioners Organization et al. ("BCOAPO"), City of Nelson, Ministry of Energy, Mines and Petroleum Resources, and BC Sustainable Energy Association submitted their Final Arguments. On January 30, 2009, BC Hydro submitted its Reply Argument.

On February 5, 2009, Zellstoff Celgar submitted its Reply Submission. On February 5, 2009, BC Hydro submitted its reply to Zellstoff Celgar's Reply Submission. On February 6, 2009, Zellstoff Celgar submitted its response to BC Hydro's Reply.

On March 2, 2009, the Commission Panel reviewed and considered the submissions of Zellstoff Celgar and BC Hydro, and determined to allow these additional submissions to be added to the record of this proceeding (Exhibit A-21).

LIST OF APPEARANCES, INTERESTED PARTIES AND LETTERS OF COMMENT

The Intervenors, who registered for written public hearing process for the review of the Application, were:

WILLIAM J. ANDREWS	BCSEA and the Sierra Club of Canada, BC Chapter ("SCCBC") (Exhibit C7-1)
R.E. CARLE	City of New Westminster, Electric Utility Commission (Exhibit C5-1)
KEVIN CORMACK ALEXANDER LOVE	The Corporation of the City of Nelson (Exhibit C1-1)
THOMAS HACKNEY	BC Sustainable Energy Association (Exhibit C7-1)
LUDO BERTSCH	Okanagan Environmental Industry Alliance (Exhibit C10-1)
JENNIFER CHAMPION	Ministry of Energy, Mines and Petroleum Resources (Exhibit C11-1)
KARL E. GUSTAFSON	City of Nelson (Exhibit C8-1)
JIM QUAIL EUGENE KUNG BILL HARPER	The BC Old Age Pensioners Organization *et al*. (Exhibit C3-1)
PIERRE LAMARCHE DAN POTTS	Joint Industry Electricity Steering Committee (Exhibit C9-1)
KIM C. MOLLER BRIAN MERWIN	Zellstoff Celgar Limited Partnership (Exhibit C2-1, C2-4)
CHRIS WEAFER	Commercial Energy Consumers Association (Exhibit C6-1)
DENNIS SWANSON DEAN O'LEARY	FortisBC Inc. (Exhibit C4-1)

The Interested Parties, who registered for written public hearing process for the review of the Application, were:

Mountain FM – Castlegar, B.C. (Exhibit D-1)
James Campbell – Sidney, B.C. (Exhibit D-2)
Mr. Chris Shepard, Express Newspaper – Nelson, B.C. (Exhibit D-3)

No Letters of Comment were received.

LIST OF ACRONYMNS

BC Hydro	British Columbia Hydro and Power Authority
BCOAPO	The BC Old Age Pensioners Organization *et al*.
BCSEA	BC Sustainable Energy Association and the Sierra Club of Canada (BC Chapter)
CEC	Commercial Energy Consumers Association
FortisBC	FortisBC Inc.
HSP	Howe Sound Pulp and Paper
IPPs	Independent Power Producers
JIESC	Joint Industry Electricity Steering Committee
MEMPR	Ministry of Energy, Mines and Petroleum Resources
Nelson	City of Nelson
Nelson Agreements	Umbrella Agreement and Power Coordination Agreement
OATT	Open Access Transmission Tariff
PCA	Power Coordination Agreement
PPA	Power Purchase Agreement
Riverside	Riverside Forest Products Ltd.
TCE	TransCanada Energy Ltd.
UA	Umbrella Agreement
Zellstoff Celgar	Mercer International Inc.

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

British Columbia Hydro & Power Authority
Amend Section 2.1 of Rate Schedule 3808 Power Purchase Agreement Application

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated October 2, 2008 issuing Order No. G-148-08 establishing a regulatory timetable to review the Application to Amend Section 2.1 of Rate Schedule 3808 Power Purchase Agreement
A-2	Letter dated June 25, 2008 to BC Hydro requesting comment on the CON Agreements
A-3	Letter dated July 14, 2008 to Nelson Hydro granting the request to participate
A-4	Letter dated July 14, 2008 to Mercer International (Celgar) refusing a request to participate in the process
A-5	Letter dated July 18, 2008 to FortisBC requesting comments on BC Hydro letter dated July 16, 2008
A-6	Letter dated July 29, 2008 to Nelson Hydro and FortisBC extending the deadline for responses to August 14, 2008
A-7	Letter dated August 20, 2008 to BC Hydro requesting a response to the FortisBC and Nelson Hydro submissions
A-8	Letter dated October 22, 2008 and Order G-154-08 amending the Regulatory Timetable and updating the Evidentiary Record
A-9	Letter dated October 22, 2008 issuing Commission Information Request No. 1 to BC Hydro
A-10	Letter dated November 4, 2008 amending the Regulatory Timetable in response to a request from Zellstoff-Celgar (Exhibit C2-3)

Exhibit No.	Description
A-11	Letter dated November 7, 2008 issuing response to request for filing extension (Exhibit C8-2)
A-12	Letter dated November 13, 2008, issuing a request to BC Hydro to confirm the context of the spirit of the Power Purchase Agreement with attachments
A-13	Letter dated November 14, 2008 granting BC Hydro filing extension request
A-14	Letter dated November 27, 2008 issuing Commission Information Request No. 2 to BC Hydro
A-15	Letter dated December 10, 2008 amending the Regulatory Timetable in response to Exhibits C2-7 and C8-4
A-16	Letter dated December 19, 2008 denying applications from Zellstoff-Celgar and the City of Nelson for an Order compelling BC Hydro to respond to certain Information Requests
A-17	Letter dated December 22, 2008 and Commission Information Request No. 3 to FortisBC Inc. with respect to its Intervenor Evidence
A-18	Letter dated December 22, 2008 and Commission Information Request No. 4 to Zellstoff Celgar with respect to its Intervenor Evidence
A-19	Letter dated December 22, 2008 and Commission Information Request No. 5 to Nelson Hydro with respect to its Intervenor Evidence
A-20	Letter dated January 5, 2009 amending the date for BC Hydro Final Submissions and reissuing the Regulatory Timetable
A-21	Letter L-4-09 dated January 14, 2009 to FortisBC Inc. suspending the review of the City of Nelson Umbrella Agreement pending the Commission's Decision on the BC Hydro Amend Section 2.1 of Rate Schedule 3808 Power Purchase Agreement Application
A-22	Letter L-11-09 dated February 16, 2009 allowing the following documents to be added to the record: February 5, 2009 Reply from Zellstoff-Celgar to BC Hydro's Reply Argument; February 5, 2008 BC Hydro Reply to Zellstoff-Celgar; February 6, 2009 Reply to BC Hydro's February 5, 2009 letter

Exhibit No.	Description
APPLICANT DOCUMENTS	
B-1	Letter dated September 16, 2008, filing further comments and an amendment to the Rate Schedule 3808 Power Purchase Agreement
B-2	Letter dated September 25, 2008 filing comments on the procedural process
B-3	Letter dated September 30, 2008 filing further comments on the procedural process
B-4	BC Hydro’s July 16, 2008 response to the Commission’s letter of June 25, 2008
B-5	Letter dated October 30, 2008 filing responses to Commission Information Request No. 1
B-6	Letter dated November 5, 2008 filing comments on the request for a further amendment to the Regulatory Timetable (Exhibit C8-2 & Exhibit C2-3)
B-7	Letter dated November 21, 2008 filing responses to Intervenor Information Request No. 1
B-8	Letter dated November 25, 2008 filing response to the term spirit (Exhibit A-12)
B-9	Letter dated December 5, 2008 filing response to the Commissions’ and to the Intervenors’ Information Request No. 2
B-10	Letter dated December 10, 2008 providing comments in response to applications filed by the City of Nelson (Exhibit C8-4) and Zellstoff Celgar (Exhibit C2-7), dated December 8, 2008 and application of Zellstoff Celgar dated December 10, 2008
B-11	Letter dated December 22, 2008 filing Information Request No. 1 to FortisBC
B-12	Letter dated December 22, 2008 filing Information Request No. 1 to the City of Nelson
B-13	Letter dated December 22, 2008 filing Information Request No. 1 to Zellstoff Celgar

Exhibit No.	Description
INTERVENOR DOCUMENTS	
C1-1	**NELSON HYDRO –** Letter dated October 1, 2008 filing request for participation and comments on procedural process
C1-2	Letter dated October 16, 2008 filing comments on procedural process and evidentiary record
C1-3	Letter dated July 11, 2008 to the Commission from Nelson Hydro requesting to participate
C1-4	Letter dated July 23, 2008 to the Commission requesting an extension until August 14, 2008
C1-5	Nelson Hydro August 14, 2008 response to Commission letter dated July 18, 2008 including Attachments A and B
C1-6	**REMOVED** – See Exhibit C8-8
C2-1	**ZELLSTOFF CELGAR LIMITED PARTNERSHIP -** Letter dated October 8, 2008 from Brian Merwin, Director, filing request for Intervenor status and comments
C2-2	Letter dated July 11, 2008 to the Commission from Celgar requesting to participate
C2-3	Letter dated November 3, 2008 requesting an extension to the Regulatory Timetable due to the late filing of BC Hydro responses to Commission Information Request No. 1
C2-4	Email dated November 6, 2008 filing Notice of Counsel and request to be added to the distribution lists
C2-5	Letter dated November 7, 2008 filing Information Request No. 1 to BC Hydro from K.C. Moller, Sangra Moller, Counsel for Zellstoff Celgar
C2-6	Letter dated November 28, 2008 from K.C. Moller, Sangra Moller, legal counsel filing Information Request No. 2 to BC Hydro
C2-7	Letter dated December 8, 2008 from K.C. Moller, Sangra Moller, legal counsel requesting the Commission to extend the time for Intervenor Evidence submissions

Exhibit No.	Description
C2-8	Letter dated December 10, 2008 applying for an order pursuant to section 34(3)(b) of the Administrative Tribunals Act compelling BC Hydro to produce responses to Information Requests identified in Schedule A
C2-9	Letter dated December 11, 2008 issuing further response to BC Hydro letter Exhibit B-10
C2-10	Letter dated December 15, 2008 filing Evidence
C2-11	Email dated January 2, 2009 filing responses to Commission Information Request No. 4 (Exhibit A-18)
C3-1	**BRITISH COLUMBIA OLD AGE PENSIONER'S ORGANIZATION (BCOAPO) –** Letter dated October 9, 2008, filing request for Registered Intervenor status for Jim Quail and on behalf of Bill Harper of Econalysis Consulting
C3-2	Letter dated November 26, 2008 filing Information Request No. 2 to BC Hydro
C3-3	Letter dated December 15, 2008 filing notification of Eugene Kung, BC Public Interest Advocacy Centre as additional counsel
C3-4	Letter dated December 19, 2008 filing Information Request No. 3 to FortisBC
C3-5	Letter dated December 19, 2008 filing Information Request No. 3 to the City of Nelson
C4-1	**FORTISBC INC.** – Letter dated October 14, 2008 opposing BC Hydro's Application and requesting Intervenor status
C4-2	Letter dated October 16, 2008 filing comments on Order G-148-08 regarding the evidentiary record
C4-3	FortisBC June 24, 2008 filing of Short-Term Firm or Short Term Non-Firm Service and the Power Coordination Agreement with the City of Nelson
C4-4	FortisBC August 14, 2008 response to Commission letter dated July 18, 2008
C4-5	Letter dated November 7, 2008 filing Information Request No. 1
C4-6	Letter dated November 28, 2008 filing Information Request No. 2 to BC Hydro

Exhibit No.	**Description**
C4-7	Letter dated December 15, 2008 filing Evidence of Dan Egolf on behalf of FortisBC Inc.
C4-8	Letter dated December 31, 2008 filing responses to Commission Information Request No. 3
C5-1	**CITY OF NEW WESTMINSTER** – Letter dated October 17, 2008 from R.E. Carle, General Manager, requesting Intervenor status
C6-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BC (CEC)** – Letter dated October 16, 2008 from Christopher P. Weafer, Owen Bird, legal counsel, requesting Intervenor status
C6-2	Letter dated November 28, 2008 from Christopher P. Weafer, Owen Bird, legal counsel, filing Information Request No. 2 to BC Hydro
C6-3	Letter dated December 22, 2008 filing response to City of Nelson Information Request No. 1
C6-4	Letter dated December 22, 2008 filing response to FortisBC Information Request No. 1
C6-5	Letter dated December 22, 2008 filing response to Zellstoff Celgar Information Request No. 1
C7-1	**BC SUSTAINABLE ENERGY ASSOCIATION & SIERRA CLUB OF CANADA BC CHAPTER (BCSEA ET AL) –** Letter dated October 17, 2008, from William J. Andrews, legal counsel, filing request for Registered Intervenor status
C7-2	Letter dated November 5, 2008 from William J. Andrews, filing Information Request No. 1 to BC Hydro
C8-1	**CITY OF NELSON –** Letter dated October 20, 2008 from Karl E. Gustafson, Lang Michener, legal counsel, filing request for Intervenor status
C8-2	Letter dated November 4, 2008 requesting an extension to the Regulatory Timetable and filing comments
C8-3	Letter dated November 7, 2008 filing Information Request No. 1

Exhibit No.	Description
C8-4	Letter dated October 8, 2008 from K.E. Gustafson, Lang Michener, legal counsel, requesting the Commission to dismiss the Application, or to direct BC Hydro to file responses to those Information Requests which the Utility declined to respond to and extend the deadline for filing Intervenor Evidence
C8-5	Letter dated December 11, 2008 from K.E. Gustafson, Lang Michener, legal counsel, requesting Commission reconsider Letter No. L-57-08 Exhibit A-15
C8-6	Letter dated December 12, 2008 from K.E. Gustafson, Lang Michener, legal counsel, issuing support of Zellstoff Celgar request
C8-7	Letter dated December 15, 2008 filing Evidence
C8-8	Letter dated November 28, 2008 from Karl Gustafson, Lang Michener, legal counsel, filing Information Request No. 2 to BC Hydro
C8-9	Letter dated January 2, 2009 from Karl Gustafson, Lang Michener, legal counsel, filing responses to Information Requests
C9-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC) –** Letter dated October 28, 2008 from Dan Potts, filing request for Intervenor status
C9-2	Letter dated December 12, 2008 filing concern about Zellstoff Celgar's request for information relating to various pulp and paper operations in British Columbia
C10-1	**OKANAGAN ENVIRONMENTAL INDUSTRY ALLIANCE –** Online web registration received October 31, 2008 from Ludo Bertsch, filing request for Intervenor status
C11-1	**MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES (MEMPR) –** Letter dated October 31, 2008 from Jennifer Champion, Policy Analyst, filing request for Intervenor status

Exhibit No.	Description
INTERESTED PARTY DOCUMENTS	
D-1	**MOUNTAIN FM** – Email dated October 17, 2008 filing request for Interested Party status
D-2	**CAMPBELL, Jim** – Facsimile dated October 31, 2008 requesting Interested Party status
D-3	**EXPRESS NEWSPAPER –** Email dated December 4, 2008 from Chris Shepherd requesting Interested Party status

BC hydro

FOR GENERATIONS

Joanna Sofield
Chief Regulatory Officer
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bchydroregulatorygroup@bchydro.com

October 5, 2009

Ms. Erica M. Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: Project No. 3698531
British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
Application to Amend Section 2.1 of Rate Schedule 3808 (RS 3808)
Power Purchase Agreement (the Application) - BCUC Order No. G-48-09

BC Hydro is writing to the BCUC in compliance with BCUC Order No. G-48-09 and specifically the Directive contained in section 6.2 of the Decision accompanying that Order which states that:

> "BC Hydro is to provide a report to the Commission that will summarize the terms and conditions of its contractual arrangements with any of its industrial customers with self-generation capacity who may sell power on a basis which is inconsistent with the "net of load" concept as enunciated in this Decision. *(page 31)"*

There are currently four BC Hydro industrial customers with self-generation capacity who may sell, or who have sold, power on a basis which may be considered as inconsistent with the "net of load" concept enunciated in the BCUC's Decision. These customers were listed in BC Hydro's response to BCUC IR 1.10.11.2 (Exhibit B-5) in the proceeding to review the Application and are as follows:

1. Domtar (formerly known as Weyerhaeuser), Kamloops

2. Canfor, Prince George

3. Tembec, Skookumchuck

4. Howe Sound Pulp and Paper (HSPP), Port Mellon

BC Hydro provides below a general summary of the contractual arrangements which apply to each of these industrial customers' load and/or generation. Supplementary information for each customer, containing site-specific details related to each customer's load and generation, is in the attached document (Attachment 1). BC Hydro requests that the attached document remain confidential on the basis that it contains sensitive third-party information which could reasonably be expected to result in significant harm or prejudice to these customers' competitive or commercial negotiating position.

Agreements Related to Electrical Service

Electrical service to BC Hydro's industrial customers is subject to the terms and conditions of Tariff Supplement No. 5, the Electricity Supply Agreement (ESA). Each of the industrial customers noted above is a Rate Schedule 1823 – Transmission Service – Stepped Rate (RS 1823) customer and has an ESA with BC Hydro that stipulates the customer's point of delivery and contract demand. As set out in Clause 6 of the ESA, a customer cannot exceed the contract demand without prior approval from BC Hydro. This clause ensures that BC Hydro is aware of a customer's load.

The issue of selling power is addressed in Clause 2.4 of the ESA which states that:

> "[t]he Customer shall not sell, or otherwise dispose of for compensation, all or part of the Electricity supplied pursuant to this Agreement to any other person directly or indirectly without prior authorization from the British Columbia Utilities Commission and notice to BC Hydro."

Although the ESA addresses the issue of resale of electricity provided by BC Hydro, it does not cover the issue of the sale of a customer's self-generation. The ESA only addresses the circumstance of self-generation with respect to technical issues, as provided in Clause 20 of the ESA, and there is no language in the ESA that prevents industrial customers with self-generation from selling their generation so long as they are complying with the terms and conditions of the ESA. Consequently, BC Hydro's obligation to serve such industrial customers who wish to take their self-generation output to market has been prescribed by BCUC Order Nos. G-38-01 and G-17-02 and confirmed more recently in the BCUC's decision regarding the RS 3808 Application (BCUC Order No. G-48-09).

In addition to a customer's ESA, some industrial customers may also participate in other programs or rates related to their electrical service agreements. Specifically, RS 1823 customers may be eligible for Rate Schedule 1852 Transmission Service – Modified Demand (RS 1852) or may be eligible for a Load Curtailment Agreement (LCA). Customers who subscribe to RS 1852 are required to have in place a Modified Demand Agreement (Tariff Supplement No. 54). The Modified Demand Agreement (MDA) provides that BC Hydro may from time to time, in its sole discretion, make an offer to the customer for the customer to reduce its electricity demand and the customer either accepts or rejects BC Hydro's offer in accordance with the terms and conditions of the MDA. Compensation is as set forth in the MDA and RS 1852.

A LCA is akin to an MDA, but unlike a RS 1852 customer, the LCA customer is compensated for being available for curtailment and is considered to be a contingency resource for capacity. With respect to the above-noted customers, only HSPP has an MDA and a LCA with BC Hydro, and HSPP's LCA does take into account that demand reductions may occur under the MDA.

Load Displacement Agreements

A load displacement agreement is an agreement whereby BC Hydro provides a financial incentive for a customer to construct a new project, such as generation, to serve the electricity requirements of its plant operations which would then displace a certain amount of electricity purchases from BC Hydro on a long-term basis. In the more recent past, load displacement agreements were offered via a generic Power Smart Incentive Program Agreement. A template of such an agreement was attached to the response to Zellstoff Celgar IR 1.8.2 (Exhibit B-7) in the proceeding to review the Application, and of those customers listed above only Canfor currently has a Power Smart Incentive Program Agreement with BC Hydro which is in effect.[1]

HSPP also has a form of a "load displacement" agreement with BC Hydro, which pre-dates the Power Smart Incentive Program Agreement by approximately ten years, but the financial incentive and terms of the agreement are different than the Power Smart Incentive Program Agreements.

Both the HSPP agreement and the Power Smart Incentive Program agreements contain terms and conditions to support the underlying principle that the contractually agreed output of a customer's new or incremental generation is to be applied towards the customer's load as defined in the agreement. However, no matter what the form of the load displacement agreement, the modifications made to an ESA as s result of a load displacement agreement only relate to resetting the customer's demand and load requirements and with respect to technical metering details to be addressed for the customer's specific site. Output in excess of the contractual obligations in the load displacement agreement may be sold by the customer.

Electricity Purchase Agreements (EPA)

Consistent with the approach suggested by the BCUC on page 30 of the Decision issued for the Application, BC Hydro determines a case by case generator baseline (GBL) for each customer with self-generation who sells power. The GBL is determined by BC Hydro using data provided by the customer, as well as BC Hydro's billing meter data, regarding historical self-generation at the customer's industrial facility.

With respect to BC Hydro's recent calls for power (i.e., Bioenergy Call Phase I Request for Proposals (RFP), Standing Offer Program and Clean Power Call), BC Hydro has used the GBL methodology for determining the historical generator output used to serve

1 Domtar did have a Power Smart Incentive Program Agreement which has been terminated.

the customer's load, and the new or incremental generation available for sale, for the following reasons:

1. When dealing directly with a party who is bidding into one of BC Hydro's calls, BC Hydro has the ability and means of determining historical generator output and load for a self generating customer.

2. Once the GBL is determined it is not adjusted during the term of the EPA to reflect fluctuations in the customer's energy consumption or energy generation.

3. The GBL sets a steady state condition that gives both the customer and BC Hydro certainty with respect to what energy is available from the generator for the purposes of the EPA.

BC Hydro believes that the GBL methodology it has used in its calls for power prevents arbitrage opportunities by:

(a) ensuring energy currently generated by customers with self-generation to serve their respective loads continues to be used by such customers for their load and is not sold to BC Hydro under an EPA;

(b) requiring such customers to install additional metering on their generators giving BC Hydro the ability to ensure the customer is using the energy output of their generators up to their GBL to serve their load; and

(c) preventing the customers from purchasing additional power from BC Hydro and then selling back that energy through the EPA.

As such, establishing a GBL for each customer on a case by case basis is consistent with the approach defined in BCUC Order No. G-48-09 in that BC Hydro reviews the historical generating profile and historical customer load in order to determine what excess power would be available on a "net of load" basis. This approach is also consistent with the principle established under Directive 1 of BCUC Order No. G-38-01 whereby the "Commission expects BC Hydro to make every effort to agree on a customer baseline, based either on the historical energy consumption of the customer or the historical output of the generator."

For generation above the GBL there is no arbitrage of embedded cost of energy because there is no increased take from BC Hydro under the ESA compared to the customer's historical consumption. For generation below the GBL, the exclusivity clauses of the EPAs prevent the customers from selling the generation to third party energy buyers

For the customers noted above, Domtar and Canfor have EPAs pursuant to BC Hydro's Bioenergy Call Phase I RFP, and such EPAs were accepted by the BCUC per its Order No. E-8-09. Tembec has an existing 1997 EPA which, unlike the GBL approach, does not require Tembec to serve part of its mill load with self generation. This existing EPA pre-dates BCUC Order No. G-38-01 and has been replaced by a new EPA (2009 EPA) that requires the establishment of a GBL. The 2009 EPA was filed with the BCUC for acceptance on September 24, 2009.

With respect to HSPP and its electricity sales, it is noted that since 2001, and the issuance of BCUC Order No. G-38-01, HSPP has at times sold surplus idle generation to Powerex Corp. via an enabling agreement. The determination of HSPP's available idle generation is agreed to by BC Hydro via a consent agreement which is renewed on a yearly basis.

For further information, please contact Fred James at 604 623-4317.

Yours sincerely,

JSofield

Joanna Sofield
Chief Regulatory Officer

Enclosure (1)

c. BCUC Project No. 3698531 Registered Intervenor Distribution List.

FortisBC Inc.
Attention: Mr. Dennis Swanson

FORTISBC

Dennis Swanson
Director, Regulatory Affairs

FortisBC Inc.
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Kelowna, BC V1Y 7V7
Ph: (250) 717-0890
Fax: 1-866-335-6295
regulatory@fortisbc.com
www.fortisbc.com

August 4, 2009

Via Email
Original via mail

Ms. Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: *British Columbia Hydro and Power Authority ("BC Hydro") Application to Amend Section 2.1 of Rate Schedule 3808 – Order G-48-09*

In its Reasons for Decision issued concurrently with Order G-48-09, the British Columbia Utilities Commission ("Commission") noted at page 34 that:

> "BC Hydro asks whether FortisBC ought to be required to provide, on its website or on an open access same-time information system (OASIS), its transmission transactions"

and directed FortisBC Inc. ("FortisBC" or the "Company") to file a response as to its intentions in this regard.

FortisBC hereby advises that, for the reasons explained below, it does not believe there to be a need to do so, and unless directed by the Commission, the Company does not intend to provide the information on an OASIS or on its website at this time. If, as discussed below, BC Hydro or any other parties require such information, it will be made available to them individually.

BC Hydro's comment in Final Argument in the proceeding named above is found at page 31:

> "There is a lack of transparency with respect to transmission transactions on the FortisBC system because FortisBC does not post information about such transactions on its website or on an open access information system (OASIS)[72] Now that FortisBC has customers purchasing transmission wheeling services, the Commission may wish to review whether FortisBC should be required to develop an OASIS."
>
> [72] *Exhibit B-9, BC Hydro response to BCUC IR 2.14.7*

It is FortisBC's belief that the purpose of an OASIS is for the management of potential transmission congestion. FortisBC has no constrained transmission paths and therefore neither it, nor its potential transmission customers, would benefit from the development of an OASIS at this time, or from posting the transactions on FortisBC's public website.

In response to BCUC IR 2.14.7, BC Hydro expressed its concern with the lack of transparency of FortisBC's transmission transactions as they relate to the source of ancillary services. FortisBC agrees that if such information is relevant to BC Hydro under the Canal Plant Agreement ("CPA"), it is then an administrative matter under the CPA, easily resolved through the existing Operating Committee. FortisBC does not object to providing, in that forum, relevant ETAGS to BC Hydro upon request, as suggested in BC Hydro's response to IR 2.14.7.

In summary, FortisBC believes that the administrative burden or expense of developing an OASIS is unnecessary at this time, and that the administrative issues BC Hydro raises in relation to the CPA can be resolved through the existing Operating Committee.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

cc: Registered Intervenors

BC hydro

FOR GENERATIONS

Joanna Sofield
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August 5, 2009

Ms. Erica M. Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: Project No. 3698531
British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
Application to Amend Section 2.1 of Rate Schedule 3808 (RS 3808)
Power Purchase Agreement - BCUC Order No. G-48-09

BC Hydro is writing to the BCUC in compliance with BCUC Order No. G-48-09 and specifically the Directive contained in Section 6.2 of the Decision accompanying that Order which states that:

"The Commission Panel directs BC Hydro, in consultation with FortisBC, to identify and submit to the Commission an agreed methodology to monitor "net of load" energy within 90 days of the date of this Decision." ***(page 30)***

BC Hydro's submission, which follows, has been reviewed by FortisBC and they are in agreement with its contents. Please note that this submission only discusses the issue of the methodology to be used by a utility to monitor "net of load" energy situations for customers with self-generation. This submission does not address the issues of the treatment of any new or incremental generation added by a self-generator nor does it provide a methodology for determining a self-generator's historical baseline generation or a customer's baseline load.

Introduction

This directive relates to customers of BC Hydro and FortisBC that have their own self-generation capability ("self-generators"). A self-generator purchases electricity from BC Hydro or FortisBC at embedded cost-of-service rates pursuant to an Electricity Supply Agreement ("ESA") approved by the BCUC. Subject to BCUC and other regulatory requirements, a self-generator may sell its excess self-generated power at open market prices to BC Hydro or FortisBC, or to a third party buyer (e.g., a power marketer or a transmission-connected industrial site in British Columbia, or a buyer in markets outside British Columbia).

The BCUC has confirmed that BC Hydro and FortisBC need some technical means of monitoring both the self-generator's purchase of embedded cost power from the utility and its sales of excess self-generated power. Such monitoring allows the respective utility to ensure any customer with self-generation capability is not inappropriately arbitraging between the utility's embedded cost-of-service and market prices.

Before selling excess self-generated power off-site, a self-generator would have to consult with the utility because any flow of electricity from the customer's system to the utility's system would have to be in accordance with the utility's technical interconnection requirements. Interconnection requirements are different for load customers as compared to customers who are able to sell excess generation. For example, a self-generator's substation will have reverse power relays that prevent electricity flow from the customer's system to the utility's system. Breakers in the substation will trip open to prevent such flow off-site. The reverse power relays would have to be removed prior to the self-generator selling excess power off-site and the utility would be required to modify the self-generator's interconnection facilities before such sales could occur. Thus, the utility would be aware of the self-generator's intention to sell self-generated power off-site.

The key requirements to enable the utility to monitor a self-generator's electricity purchases and sales are (i) metering equipment to measure the self-generator's hourly purchases and sales of electricity, and (ii) telemetering equipment to enable the utility to access and monitor the self-generator's metering data.

Metering Equipment

If a self-generator wishes to sell self-generated electricity off-site, then the utility can require as a condition in its ESA with the self-generator that the self-generator install, operate and maintain metering equipment as required by the utility. Also, if the utility agrees to purchase excess electricity from the self-generator, the utility can also include provisions in the Electricity Purchase Agreement ("EPA") that require the self-generator to install certain metering equipment.

In most situations, a self-generator must have revenue quality metering equipment that measures the output of its generation facility independent of its load. Separate metering of generation and load allows a determination of how much of the self-generator's load is served by its generator, how much is served by the utility, and how much self-generation capability is transmitted through the transmission system for a sale in the open market.

Self-generators will have separate metering equipment installed on their load and generation facilities for power management purposes. If a self-generator uses its self-generation capability solely to serve its own load, then the self-generator may not necessarily be required to have separate revenue quality metering equipment for its generation facilities. Furthermore, if the self-generator's load and generation facilities are interconnected to the transmission system through a single point of interconnection and the self-generator only sells generation in excess of its load (i.e., the customer's generator does not have an accepted historical generation baseline), then the self-generator may only be required to have revenue quality net metering at the site's point of interconnection to measure the net electricity purchased from the utility or sold in the market on at least an hourly basis.

If a self-generator has separate interconnections for its load and generation facilities, or is able to sell electricity in excess of an accepted historical generation baseline, the self-generator would be required to have separate and independent revenue metering equipment for generation and load.

In addition, non-revenue quality telemetering of the generator will still be required by the respective transmission provider in most circumstances.

Access to Revenue Metering Data

The utility can require as a condition in its ESA and/or its EPA with the self-generator that the self-generator install, operate and maintain telemetering equipment that allows the utility to remotely interrogate the load and generator metering data.

In addition to requirements to install, operate and maintain revenue metering and telemetering equipment, the ESA or EPA can also provide that the self-generator must allow the utility's representatives to inspect and test the revenue metering and telemetering equipment; and to inspect the self-generator's records, operating and maintenance logs, etc. for the generating facilities.

Thus, by the terms of its ESA and/or EPA with the self-generator, the utility can obtain various rights to monitor and audit the self-generator's purchases and sales to ensure there is no inappropriate arbitrage.

Conclusion

If a self-generator wishes to sell excess self-generated electricity off-site, then it must:

1. install, operate and maintain such metering equipment as required by the utility, such as:

    - separate and independent revenue metering equipment for the self-generator's generation and load facilities in circumstances where the self-generator has separate interconnections for generation and load or a historical generation baseline for the generator; or

    - net metering equipment in circumstances where the self-generator has a single interconnection for generation and load facilities;

2. install, operate and maintain telemetering equipment with respect to such metering equipment; and

3. allow the utility to remotely interrogate the metering data.

The above rights and obligations can be set out in the ESA and/or EPA between the utility and the self-generator. The ESA or EPA can also include provisions that permit the utility to inspect and test the equipment, and audit the self-generator's records of electricity purchases and sales.

Thus, systems are either in place or are readily available that allow the utility to monitor a self-generator's electricity purchases and sales to ensure that there is no inappropriate arbitrage between utility embedded cost-of-service and market prices.

For further information, please contact Fred James at 604 623-4317.

Yours sincerely,

A. James

for Joanna Sofield
Chief Regulatory Officer

c. BCUC Project No. 3698531 Registered Intervenor Distribution List.
Mr. Dennis Swanson – FortisBC Inc.

Current FortisBC Rates (Jan 1/10)							Current BC Hydro Comparative Rates[1]					
Name	**Rate**	**Criteria**	**Basic Charge**	**Energy Rate (¢ / kWh)**		**Demand (/ kVA)**	**Equivalent BCH Rate**	**Basic Charge**	**Energy Rate (¢ / kWh)**		**Demand (/ kVA)**	
Residential	RS01	Residential Service	$25.72 bi-monthly	8.085		N/A	**1101 / 1121 Residential Service**	$3.79 / month *	675 kwh / month @ 5.91		N/A	
									Balance @ 8.27			
							1151/1161 Exempt Residential Service	$4.05 / month**	6.84		N/A	
Residential – Time of Use	RS02A	Residential Service	$25.72 bi-monthly	On-peak	13.564	N/A	**No comparable rate**					
				Off-peak	4.394							
Small General Service	GS20	Less than 40 kW	$30.99 bi-monthly	Tier 1	9.216	N/A	**1220 General Service (Under 35kW)**	$4.85 / month***	7.69		N/A	
				Tier 2	6.997							
				Tier 3	5.194							
General Service	GS21	40 kW – 500kW	$15.49	Tier 1	9.216	$7.64 /kW	**1200, 1201, 1210, 1211 General Service (35kW and over)**	$4.85 / month ***	14800 kWh	7.69	<35 kW	$0.00 / kW
				Tier 2	6.997				>14800 kWh	3.70	>35 kW	$3.94 / kW
				Tier 3	5.194						>150 kW	$7.56 / kW
General Service – Time of Use	GS22A	Less than 500 kW	15.49	On-peak	14.210	N/A	**No comparable rate**					
				Off-peak	4.605							
General Service Primary – Time of Use	GS23	Less than 500 kW	34.88	Winter On-peak	20.521	Nf/A	**No comparable rate**					
				Winter Off-peak	5.142							
				Summer On-peak	19.748							
				Summer Off-peak	4.268							
				Shoulder On-peak	5.652							
				Shoulder Off-peak	3.549							
Large General Service Primary	ID30	Above 500 kVa	$793.65	4.811		7.20	**As above. No distinction between GS and LGS (Subject of LGS Application)**					
Large General Service Transmission	ID31	Above 5,000 kVa 60,000+ volts	$2,380.99	4.233		5.82	**1823 Transmission Service - Stepped Rate**	Minimum applies	90% CBL	2.608	$5.26	
									> 90% CBL	7.360		
Large General Service Primary Time of Use	ID32	Above 500 kVa	$1.875.43	Winter On-peak	19.044	N/A	**No comparable rate**					
				Winter Off-peak	3.883							
				Summer On-peak	18.282							
				Summer Off-peak	3.021							
				Shoulder On-peak	4.386							
				Shoulder Off-peak	2.311							

Current FortisBC Rates (Jan 1/10)							Current BC Hydro Comparative Rates[1]				
Name	**Rate**	**Criteria**	**Basic Charge**	**Energy Rate (¢ / kWh)**		**Demand (/ kVA)**	**Equivalent BCH Rate**	**Basic Charge**	**Energy Rate (¢ / kWh)**		**Demand (/ kVA)**
Large General Service Transmission – Time of Use	ID33	Above 5,000 kVa 60,000+ volts	$2,189.09	Winter On-peak	13.427	N/A	**1825 Transmission Service – TOU**	Minimum applies	Winter HLH < 90% of CBL	2.608	$5.26
									Winter HLH > 90% of CBL	8.213	
				Winter Off-peak	3.804				Winter LLH < 90% of CBL	2.608	
				Summer On-peak	17.911				Winter LLH > 90% of CBL	7.443	
				Summer Off-peak	2.960				Spring < 90% of CBL	2.608	
				Shoulder On-peak	4.297				Spring > 90% of CBL	6.629	
				Shoulder Off-peak	2.263				Remaining period < 90% of CBL	2.608	
Irrigation	IR60	Irrigation Service	$15.50	5.369		N/A	**1401 Irrigation**	Minimum applies	3.70		N/A
Irrigation – Time of Use	IR61	Irrigation Service	38.15	Winter On-peak	14.228	N/A	**No comparable rate**				
				Winter Off-peak	3.567						
				Summer On-peak	13.692						
				Summer Off-peak	2.958						
				Shoulder On-peak	3.918						
				Should Off-peak	2.458						
Wholesale	WH40	Primary Service	$1,832.82 per POD per month	4.068		$7.93	**No comparable rate**				
Wholesale Transmission	WH41	60,000+ volts	$4,189.36	4.006		4.71	**1827 Transmission Service - New Westminster & UBC**	Minimum applies	3.083		$5.26
							3808 – Transmission Service – FortisBC	N/A	3.083		$5.26
Wholesale – Time of Use	WH42	Primary Service	$1,832.82 per POD per month	Winter On-peak	16.926	N/A	**No comparable rate**				
				Winter Off-peak	3.451						
				Summer On-peak	16.250						
				Summer Off-peak	2.686						
				Shoulder On-peak	3.899						
				Shoulder Off-peak	2.052						

<table>
<tr><th colspan="7"><u>Current FortisBC Rates (Jan 1/10)</u></th><th colspan="6"><u>Current BC Hydro Comparative Rates</u>[1]</th></tr>
<tr><th>Name</th><th>Rate</th><th>Criteria</th><th>Basic Charge</th><th colspan="2">Energy Rate
(¢ / kWh)</th><th>Demand
(/ kVA)</th><th>Equivalent BCH Rate</th><th>Basic Charge</th><th colspan="3">Energy Rate
(¢ / kWh)</th><th>Demand
(/ kVA)</th></tr>
<tr><td rowspan="6">Wholesale – Time of Use</td><td rowspan="6">WH43</td><td rowspan="6">60,000+ volts</td><td rowspan="6">$628.13 per month</td><td>Winter Off-peak</td><td>11.719</td><td rowspan="6">N/A</td><td colspan="6" rowspan="6">See Rate 1825 above</td></tr>
<tr><td>Winter Off-peak</td><td>3.321</td></tr>
<tr><td>Summer On-peak</td><td>15.633</td></tr>
<tr><td>Summer Off-peak</td><td>2.581</td></tr>
<tr><td>Shoulder On-peak</td><td>3.750</td></tr>
<tr><td>Shoulder Off-peak</td><td>1.976</td></tr>
<tr><td colspan="7" rowspan="8">No comparable rate</td><td>1852
Transmission Service – Modified Demand</td><td>N/A</td><td colspan="3">N/A</td><td>Contingency resource – BC Hydro permitted to request demand modifications</td></tr>
<tr><td>1853
Transmission Service – IPP Station Service</td><td>29.64</td><td colspan="3">Dow Jones Mid-C Firm Electricity Price Index for HLH and LLH corresponding to time when consumption occurred</td><td>N/A</td></tr>
<tr><td>1880
Transmission Service – Standby and Maintenance</td><td>$150 per use</td><td colspan="3">7.360</td><td>N/A</td></tr>
<tr><td rowspan="5">1890
Transmission Service – Energy Imbalance</td><td rowspan="5">N/A</td><td>Period</td><td>Tier 1</td><td>Tier 2</td><td rowspan="5">N/A</td></tr>
<tr><td>Mar to Apr</td><td>2.608</td><td>7.269</td></tr>
<tr><td>May to Jun</td><td>2.608</td><td>6.629</td></tr>
<tr><td>Jul to Oct</td><td>2.608</td><td>7.269</td></tr>
<tr><td>Nov to Feb</td><td>2.608</td><td>8.213 (HLH)
7.443 (LLH)</td></tr>
</table>

[1] All BCH Rates are standard Zone I
* 12.64 cents per day
** 13.49 cents per day
*** 16.17 cents per day

Current FortisBC Lighting Rates (Jan 1/10)					Current BC Hydro Comparative Lighting Rates[1]		
Name	**Rate**	**Criteria**	**Light Type**	**Rate ($ per month)**	**Equivalent BCH Rate**	**Light Type**	**Rate ($ per month)**
Lighting	RS50	Lighting – Company owned	70W HPS	13.03	**1701 Overhead Street Lighting Company owned**	100W HPS	11.86
			100W HPS	14.85			
			150W HPS	17.85			
			200W HPS	20.59			
			250W HPS	23.18		150W HPS	14.14
			400W HPS	31.28			
Lighting	RS50	Lighting – customer owned	70W HPS	4..34			
			100W HPS	6.11			
			150W HPS	9.09		200W HPS	16.32
			200W HPS	11.84			
			250W HPS	14.47			
			400W HPS	22.54			
No comparable rate					**1702 Ornamental Street Lighting Customer owned**	All fixtures	2.28 cents per watt per month
					1703 Street Lighting Service Customer owned	All fixtures	2.28 cents per watt per month 68.79 cents per contact per month
					1704 Street Lighting Service Customer owned	Traffic signals, signs, warning devices Customer owned	6.84 cents per kWh

[1] All BCH Rates are standard Zone I

1. Interfor-Fortis-1

Preamble: In April 2007, Fortis implemented a policy to require security deposits for customers with a demand in excess of 200 kVa as a condition of continuing service (the "Policy").

Requests:

Q1(a) Produce a copy of the Policy and any subsequent amendments.

A1(a) FortisBC's written security deposit policy does not detail the treatment of customers above 200 kVA, but as of April 2007, the Company has required a security deposit from new customers with a demand above 200 kVA as a condition of continuing service, as well as existing customers that request an increase in their demand limit or exhibit poor payment history. Please also refer to page 11 of Interfor Appendix A4b.

Q1(b) Produce copies of all documents relating to the development of the Policy. Include all internal and external email and written correspondence, notes, meeting minutes, drafts, revisions, records of phone conversations.

A1(b) As noted in the response to Interfor IR No.1 Q1(a), there is no written Policy. In the Company's view the other requested documents are not relevant to this proceeding and in any event should not be subject to production within it.

Q1(c) Was the selection of 200 kVa an arbitrary decision? If not, explain the reasoning behind choosing 200 kVa as the cut off.

A1(c) The 200 kVA threshold exists because any loss of revenues from a single customer with this level of demand or higher represents a significant bad debt risk for ratepayers, due to their high energy use and the requirement for written notification of termination as per Section 2.2 of FortisBC's Tariff.

Q1(d) As of the date of implementation of the Policy how many of Fortis' existing customers had demands in excess of 200 kVa?

A1(d) As of April 2007, there were 129 accounts with demands in excess of 200 kVA.

Q1(d)(i) Who were they and how many kVa did they demand?

A1(d)(i) The Company does not believe it is appropriate to disclose the names and usage levels of individual customers.

Q1(d)(ii) Which of these customers were required to pay a security deposit and what was the amount of those deposits?

A1(d)(ii) At the time of the implementation of the policy one of these customers had been required to pay a deposit.

Q1(e) How many new customers since the implementation of the Policy have had demands in excess of 200 kVa?

A1(e) Since April 1st, 2007, there are 16 new customers with demand above 200 kVA.

Q1(e)(i) Who are they?

A1(e)(i) The Company does not believe it is appropriate to disclose the names and usage levels of individual customers.

Q1(e)(ii) Which of them have been required to pay a security deposit and what is the amount of the deposit?

A1(e)(ii) FortisBC can confirm that 10 of these customers have been required to pay security deposits in the amounts below. During 2008, FortisBC discovered 6 accounts that required a deposit which, due to oversight were not collected. FortisBC has reviewed its processes to mitigate the likelihood of such errors in the future.

Customer	Deposit Amount	
1	$	3,610.00
2	$	8,100.00
3	$	10,000.00
4	$	11,680.00
5	$	12,064.00
6	$	13,200.00
7	$	14,650.00
8	$	19,230.00
9	$	25,835.00
10	$	438,654.87

Q1(f) As of the date of implementation of the Policy how many of Fortis' existing customers had demands of between 175-199 kVa? Who were they?

A1(f) FortisBC can confirm that at the date of the implementation of the Policy, there were 24 customers with demands between 175 and 199 kVA. Due to confidentiality concerns, the names of those customers cannot be released.

Q1(g) As of the date of implementation of the Policy how many of Fortis' existing customers had demands of between 150-174 kVa? Who were they?

A1(g) FortisBC can confirm that at the date of the implementation of the Policy, there were 35 customers with demands between 150 and 174 kVA. Due to confidentiality concerns, the names of those customers cannot be released.

Q1(h) As of the date of implementation of the Policy how many of Fortis' existing customers had demands of between 100-149 kVa? Who were they?

A1(h) FortisBC can confirm that at the date of the implementation of the Policy, there were 94 customers with demands between 100 and 149 kVA. Due to confidentiality concerns, the names of those customers cannot be released.

Q1(i) Since implementation of the Policy how many customers have had to pay a security deposit as a result of their demand increasing or having a poor payment history? For each provide the names and amount of the security deposits and an explanation of how those security deposits were calculated.

A1(i) FortisBC can confirm that since the date of implementation of the Policy, there have been three customers who have had to pay a security deposit as a result of their demand increasing or having a poor payment history. Due to confidentiality concerns, the names of these customers cannot be released.

In the case of the one customer who paid a security deposit as a result of their increased demand, the deposit was calculated based on three months average billing plus 6 months minimum bill for the incremental increase in load.

In the case of the two customers who had to pay a security deposit as a result of having poor payment history, individual negotiations occurred with each customer. In these discussions, FortisBC seeks to find a balance between protecting the ratepayer in the event of default by the customer and the need of the customer to continue operating its business.

Q1(j) Were these security deposits less than what a new customer would be required to pay?

A1(j) Yes, the amount of deposit paid by these customers was less than it would have been if these same customers were applying for a new service with FortisBC.

2. Interfor-Fortis - 2

Reference: October 14, 2008 letter from Fortis to the Commission

Preamble: In a October 14, 2008 letter to the Commission, Fortis states that *"the company does not believe it is necessary at this time to retroactively require all customers over 200 kVa to pay this deposit, but will continue to monitor their payment history and charge such deposits if their payment history warrants it."*

Requests:

Q2(a) Who were Fortis' customers on October 14, 2008 that had demands in excess of 200 kVa but were not required to pay a security deposit?

A2(a) FortisBC can confirm that as of October 14, 2008 there were approximately 139 accounts with demands in excess of 200 KVA that had not been required to pay a security deposit at that time. However, due to confidentiality, the names of these customers cannot be released.

Q2(b) In the 10 years prior to the implementation of the Policy, how many of Fortis' customers with demands in excess of 200 kVa were: (i) delinquent on payment of invoices or (ii) defaulted on accounts? For each, provide particulars including the amounts, timeframe for which they were delinquent and the outcome if they defaulted.

A2(b) FortisBC has access to nine years of historical data within its billing system. Therefore, this question has been answered with data beginning in the year 2000. Between 2000 and the implementation of the Policy, there have been:

(i) 234 customers that had at least one overdue balance; and

(ii) Four customers with demands in excess of 200 kVA that had defaulted on their accounts prior to the implementation of the policy.

For these four customers, three were referred to 3rd party collections while one was written-off internally due to bankruptcy. Due to confidentiality concerns, the names and particulars of these customers cannot be released.

Q2(c) Since the implementation of the Policy how many of Fortis' customers with demands in excess of 200 kVa have been: (i) delinquent on payment of invoices or (ii) defaulted on accounts? For each, provide particulars including the amounts, timeframe for which they were delinquent and the outcome if they defaulted.

A2(c) Since the implementation of the Policy there has been:

(i) 86 customers that have had at least one overdue balance. Due to confidentiality concerns, the names and particulars of these customers cannot be released; and

(ii) Three customers with demands in excess of 200 kVA that have defaulted on their account. Two of these customers were sent to third party collections while one was written-off due to bankruptcy documentation that was received.

Q2(d) Of these:

Q2(d)(i) how many were new customers and subject to the Policy?

A2(d)(i) Of the 86 customers that had at least one overdue balance, there were no new customers since the implementation of the Policy in April 2007.

Q2(d)(ii) how many were existing customers prior to the implementation of the Policy and how many since have been required to pay security deposits?

A2(d)(ii) All of the 86 customers that had at least one overdue balance were existing customers as of the implementation of the Policy in April 2007. Three of these customers have been required to pay security deposits since the implementation of the new Policy.

Q2(e) To the extent it is not addressed above, in the past 10 years how many times has a Fortis customer with demands in excess of 200 kVa defaulted on payment of account(s) where Fortis was ultimately unable to collect on the debt? Who were they and what was the amount? For each, indicate whether they had paid a security deposit and, if so, what was the amount of the deposit?

A2(e) Seven customers (representing 13 accounts) defaulted on payment of account(s) where Fortis was ultimately unable to collect on the debt. Of the seven customers, three had paid a deposit. Due to confidentiality, the names of these customers, bad debt amounts and security deposit amounts cannot be released.

Q2(f) What is Fortis' loss experience ratio (i.e. the value of defaulted payments) by rate class as a percentage of revenue?

A2(f) Please see Table Interfor A2f below for the years 2007 – 2009..

Table Interfor A2f

	Revenue	Write Offs	WO % Revenue
General Service	$158,309,461	$309,921	0.196%
Industrial	$46,761,361	$873,240	1.867%
Irrigation	$7,729,936	$6,318	0.082%
Lighting	$5,435,933	$2,747	0.051%
Residential	$303,174,604	$2,349,795	0.775%
Wholesale	$138,346,059	$ -	0.000%
	$659,757,354	**$3,542,021**	

3. Interfor-Fortis-3

Reference: Fortis Rate Design Application October 30, 2009; Appendix H -Terms & Conditions

Preamble: Fortis has proposed a number of revisions to Clause 2.3 (Security Deposit) of its general Terms & Conditions, including making the security deposit mandatory for all customers with a demand in excess of 200 kVa.

Request:

Q3(a) Explain why Fortis considers the amendments to clause 2.3 necessary.

A3(a) As stated in the Application in Section 22.2, page 85, lines 27-29, "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." (Exhibit B-1)

Q3(b) Produce copies of all documents relating to the formulation of the proposed revisions to Clause 2.3 and the requirement for security deposits, generally. Include all internal and external email and written correspondence, notes, meeting minutes, drafts, revisions, records of phone conversations.

A3(b) The present version of Clause 2.3 and the proposed revision of Clause 2.3 on which FortisBC relies have been provided. In FortisBC's view the other requested documents are not relevant to this proceeding and in any event should not be subject to production within it.

Q3(c) As of December 18, 2009 who are Fortis' customers with demands in excess of 200 kVa and what are their respective demands?

A3(c) FortisBC can confirm that as of December 18th, 2009 there were approximately 162 accounts with demand in excess of 200 kVA. The names of those customers and their respective demands are confidential.

Q3(c)(i) Which of them have been required to pay a security deposit and what is the amount of the deposit?

A3(c)(i) Of the accounts referenced in the answer to Interfor IR No. 1 Q3(c), 10 have been required to pay a security deposit. Please also see the response to Interfor IR No. 1 Q1(e)(ii).

Q3(d) As of December 18, 2009 how many of Fortis' existing customers had demands of between 175-199 kVa? Who are they?

A3(d) As of December 18th, 2009 there were approximately 24 customers with demands between 175 and 199 kVA. The names of those customers and their respective demands are confidential.

Q3(e) As of December 18, 2009 how many of Fortis' existing customers had demands of between 150-174 kVa? Who are they?

A3(e) As of December 18th, 2009 there were approximately 38 customers with demands between 150 and 174 kVA. The names of those customers and their respective demands are confidential.

Q3(f) As of December 18, 2009 how many of Fortis' existing customers had demands of between 100-149 kVa? Who are they?

A3(f) As of December 18th, 2009 there were approximately 102 customers with demands between 100 and 149 kVA. The names of those customers and their respective demands are confidential.

Q3(g) Why should a customer with a demand in excess of 200 kVa be required to pay a security deposit if they have good credit?

A3(g) All customers over 200 kVA are required to pay a deposit regardless of credit standing or payment history for the reasons stated in the response to Interfor IR No. 1 Q1(c).

Q3(h) Why should a customer with a demand in excess of 200 kVa be required to pay a security deposit if they have 2 years of continuous service over which they have paid each and every account by the due date?

A3(h) All customers over 200 kVA are required to pay a deposit regardless of credit standing or payment history for the reasons stated in the response to Interfor IR No. 1 Q1(c).

Q3(i) What is the rational for not requiring customers with demands of 175 to 199 kVa to pay a security deposit?

A3(i) Security deposits are not mandatory for these customers per the current or proposed tariff, but are currently required for new general service customers with demand below 200 kVA. Security deposits are not mandatory per the tariff for smaller customers since the potential loss of revenue from a single customer may not represent a significant bad debt risk for ratepayers.

Q3(j) What is the rational for not requiring customers with demands of 150 to 174 kVa to pay a security deposit?

A3(j) Please refer to the response to Interfor IR No. 1 Q3(i), above.

Q3(k) Is the mandatory requirement to pay a security deposit to be applied retroactively? In other words will all customers with demands in excess of 200 kVa be required to pay or is it intended to only apply to new customers?

A3(k) The Company does not intend at this time to retroactively require all customers over 200 kVA to pay this deposit (unless they request an increase in their contract demand or exhibit poor payment history), but will continue to monitor their payment history and charge such a deposit if their payment history warrants it. New customers above 200 kVA will be required to pay the deposit.

Q3(l) If it will only apply to new customers:

Q3(l)(i) What is the effective date for determining if a customer is a "new" customer?

A3(l)(i) The effective date for determining new customers is April 1, 2007.

Q3(l)(ii) What is the explanation for requiring only "new" customers to pay a security deposit?

A3(l)(ii) Existing customers with demand in excess of 200 kVA have not been requested to provide a security deposit under FortisBC's security deposit policy, with the exception of existing customers that have exhibited poor payment history and those that are requesting an increase in their contract demand. Like any policy or tariff change, existing customers are not retroactively charged as a result of the change. The new tariff or policy is applied on a go-forward basis. In regards to customers with demand in excess of 200 kVA, FortisBC has requested security deposits as a condition of continuing service from new customers, customers that have exhibited poor payment history, and for existing customers that have requested increases to their demand limit.

Q3(m) Confirm the total amount of security deposits paid by Interfor to Fortis as of December 18, 2009. Provide a breakdown by the Grand Forks and Castlegar mills.

A3(m) Interfor has provided FortisBC with a Letter of Credit in the amount of $143,693.65 for the Castlegar mill and in the amount of $294,961.22 for the Grand Forks mill.

Q3(n) What was the amount of the security deposits paid by the prior owner of the Grand Forks and Castlegar mills?

A3(n) That information is confidential.

Q3(o) Will any additional security deposit be required from Interfor as a result of the proposed changes to the Terms and Conditions or otherwise?

A3(o) No change to the security deposit required from Interfor is anticipated as a result of the proposed changes to the Terms and Conditions. Changes to the security deposit may result from other factors, such as a request from a customer for a reduced deposit as a result of a reduced load or contract demand.

Q3(p) Confirm the amount of Interfor's bills for both the Grand Forks and Castlegar operations since service was first provided to Interfor. Provide a breakdown by month.

A3(p) Please see the following table:

Table Interfor A3(p)

Data as of: 12/30/2009			Data as of: 12/30/2009		
International Forest Products - Grand Forks			**International Forest Products - Castlegar**		
Account ID	Read Date	Amount	Account ID	Read Date	Amount
1963588280	11/30/2009	$107,343.25	969268116	12/29/2009	$26,065.95
	10/31/2009	$69,970.70		11/25/2009	$22,560.31
	09/30/2009	$40,502.49		10/26/2009	$23,143.69
	08/31/2009	$39,453.37		09/23/2009	$19,768.38
	07/31/2009	$39,740.90		08/26/2009	$21,813.94
	06/30/2009	$41,162.53		07/24/2009	$20,200.07
	05/31/2009	$45,587.16		06/25/2009	$21,943.43
	04/30/2009	$46,928.93		05/26/2009	$23,376.29
	03/31/2009	$45,107.95		04/28/2009	$27,249.57
	02/28/2009	$51,465.36		03/24/2009	$25,589.60
	01/31/2009	$103,437.42		02/25/2009	$30,246.75
	12/31/2008	$111,093.39		01/26/2009	$31,164.27
	11/30/2008	$100,182.32		12/23/2008	$26,970.67
	10/31/2008	$103,931.85		11/24/2008	$27,367.35
	09/30/2008	$86,683.10		10/24/2008	$25,428.00
	08/31/2008	$42,893.47		09/23/2008	$24,414.24
	07/31/2008	$20,507.42		08/26/2008	$29,086.34
	06/30/2008	$20,537.98		07/23/2008	$33,604.00
	05/31/2008	$26,368.18		06/24/2008	$42,224.65
Total		**$ 1,142,897.77**		05/23/2008	$34,045.32
			Total		**$ 536,262.82**

Q3(q) Confirm the total demand by kVa for both the Grand Forks and Castlegar operations since service was first provided. Provide a breakdown by month.

A3(q) Please see the following table

Table Interfor A3(q)

Data as of: 12/30/2009				Data as of: 12/30/2009			
International Forest Products - Grand Forks				**International Forest Products - Castlegar**			
Account ID	Read Date	Billed Demand	UOM	Account ID	Read Date	Billed Demand	UOM
1963588280	11/30/2009	4,326	kVA	969268116	12/29/2009	676	KVA
	10/31/2009	3,913	kVA		11/25/2009	635	KVA
	09/30/2009	3,913	kVA		10/26/2009	684	KVA
	08/31/2009	3,913	kVA		09/23/2009	684	KVA
	07/31/2009	3,913	kVA		08/26/2009	684	KVA
	06/30/2009	3,913	kVA		07/24/2009	684	KVA
	05/31/2009	3,913	kVA		06/25/2009	904	KVA
	04/30/2009	3,913	kVA		05/26/2009	1,011	KVA
	03/31/2009	3,913	kVA		04/28/2009	1,011	KVA
	02/28/2009	3,913	kVA		03/24/2009	1,011	KVA
	01/31/2009	4,754	kVA		02/25/2009	1,011	KVA
	12/31/2008	4,881	kVA		01/26/2009	1,011	KVA
	11/30/2008	5,218	kVA		12/23/2008	1,011	KVA
	10/31/2008	5,005	kVA		11/24/2008	1,011	KVA
	09/30/2008	4,756	kVA		10/24/2008	1,011	KVA
	08/31/2008	2,784	kVA		09/23/2008	1,011	KVA
	07/31/2008	679	kVA		08/26/2008	1,011	KVA
	06/30/2008	679	kVA		07/23/2008	1,130	KVA
	05/31/2008	905	kVA		06/24/2008	1,264	KVA
Total		**69,205**	**kVA**		05/23/2008	1,237	KVA
				Total		**18,695**	**KVA**

4. Interfor- Fortis- 4

Reference: Fortis Rate Design Application October 30, 2009: Appendix H -Terms & Conditions

Preamble: The revised clause 2.3 specifically provides, in part, that *"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"*

Request:

Q(4a) What does Fortis mean by "to the satisfaction of the Company"? What is the test that will be applied.? What are the criteria that will be considered relevant?

A4(a) The revised clause referenced in this question is not relevant to customers with demand in excess of 200 kVA for whom a deposit is mandatory under the revised tariff.

The test and the criteria for new and existing customers under 200 kVA that is to be applied is set out in Interfor Appendix A4b.

Q4(b) Produce any written record of the criteria used by Fortis to determine the credit of customers.

A4(b) Please refer to Interfor Appendix A4b.

Q4(c) Does BC Hydro require a security deposit from its customers? If so, what is the criteria BC Hydro applies to determine who is required to pay a security deposit? Produce a copy of BC Hydro's Terms and Conditions that related to the security deposit.

A4(c) The portion of BC Hydro's tariff terms and conditions relating to security deposits is provided as Interfor Attachment A4c. FortisBC does not have knowledge of how BC Hydro interprets and implements its policies regarding security deposits.

2.3. Refusal to Provide Service and Discontinuance of Service

BC Hydro may refuse to provide service or may discontinue without notice service to any Customer who:

1. failed to pay for service at any or all Premises, or
2. breached the terms and conditions upon which service is provided by BC Hydro, or
3. refused to provide reference information and identification acceptable to BC Hydro, when applying for service or at any subsequent time on request by BC Hydro, or
4. occupies the Premises with another occupant who has an outstanding account incurred for service while occupying any Premises at the same time as the Customer, or
5. refuses to provide reasonable access for meter servicing or to read the meters for billing purposes.

For the purpose of this paragraph the term "Customer" shall have its ordinary meaning and shall not be restricted by its definition in these Terms and Conditions.

BC Hydro shall not be liable for any loss, injury or damage suffered by any Customer by reason of the discontinuation of or refusal to provide service as aforesaid.

2.4. Security Deposits

2.4.1. Pay As You Go Billing

With Pay As You Go Billing, BC Hydro will bill a Customer for the required amount at the beginning of the consumption period based on either the estimated monthly bill or one-twelfth of the estimated annual bill for electricity. The amount of the monthly instalment will be amended by BC Hydro from time to time. Such bills are deemed to have the same force and effect as bills which are based on actual meter readings.

The due date for payment of bills for Customers billed under Pay As You Go Billing is the first business day after the twenty-first (21st) calendar day following the billing date or, where applicable, under the terms set out under the heading “Pre-Authorized Payment with Discount”.

2.4.2. Security Deposits for Applicants

A Residential Service or General Service applicant who has not established credit satisfactory to BC Hydro shall be required to select one of the following options:

1. provide a security deposit equal to two times the Customer's estimated average monthly bill if the account is on monthly billing based on actual consumption, or

2. provide a security deposit equal to three times the Customer's estimated average monthly bill if the account is on bi-monthly billing based on actual consumption, or

3. participate in Pay As You Go Billing, with no security deposit.

2.4.3. Security Deposits for Existing Customers

Any Residential Service or General Service Customer who has not maintained a credit history satisfactory to BC Hydro shall be required to select one of the following options:

1. provide a security deposit equal to two times the Customer's estimated average monthly bill if the account is on monthly billing based on actual consumption, or

2. provide a security deposit equal to three times the Customer's estimated average monthly bill if the account is on bi-monthly billing based on actual consumption, or

3. participate in Pay As You Go Billing and provide a security deposit equal to the Customer's estimated a average monthly bill.

Any such Residential Service or General Service Customer billed under Pay As You Go Billing who has paid the amount due within terms of payment set out on every bill rendered during the immediately preceding one year, may elect to terminate payment under Pay As You Go Billing and may elect any other billing option then available to that Customer.

2.4.4. Form of Security Deposits

Security deposits shall be in the form of cash or an equivalent form of security acceptable to BC Hydro.

1. A security deposit may be returned, at any time, to the Customer by whom the deposit was made and when, according to the records of BC Hydro, the Customer has maintained an account with BC Hydro for the immediately preceding one year and has paid every amount due within one month of the billing date on every bill rendered during such period.

2. If the Customer's bill is not paid when due, BC Hydro may apply the whole or any part of the Customer's security deposit and earned interest, if any, towards payment of the amount due. The Customer shall promptly replenish the security deposit upon being requested by BC Hydro to do so. Nothing in this clause shall restrict BC Hydro's right to discontinue service on the failure of a Customer to pay for service.

ACCEPTED: MAY 30 2008
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E Hamilton
COMMISSION SECRETARY

3. A cash security deposit and interest, if any, may be applied by BC Hydro in whole or in part toward payment of the final accounts of the Customer by whom the deposit was made, at the time the final accounts are billed.

4. A security deposit in a form other than cash may be applied by BC Hydro in whole or in part toward payment of the final accounts of the Customer by whom the deposit was made, if the final accounts are not paid when due.

5. Any part of a security deposit, including interest, if any, on a cash security deposit, which has not been applied in accordance with this section, shall be refunded or returned to the Customer.

6. BC Hydro will pay interest on cash security deposits at a rate equal to BC Hydro's weighted average cost of debt, calculated for BC Hydro's most recent fiscal year.

7. Payment of interest on a cash security deposit held by BC Hydro will be made in the form of a credit to the Customer's account each time the account is billed or added to the amount of the cash deposit when a refund is made as provided in paragraph 1 preceding.

8. BC Hydro will not pay interest on security deposits held by it in a form other than cash.

9. No interest shall accrue on any security deposit after the date of the final bill for the account secured by the deposit.

2.5. Termination of Service

The Customer must give BC Hydro at least 24 hours notice of termination of service. If the Customer fails to give the required notice, or vacates the Premises before expiry of the notice period, the Customer will be held responsible for all Electricity used on the Premises and all damage to and loss of wires, meters or other apparatus of BC Hydro until 24 hours after BC Hydro receives the required notice.

2.6. Re-Application for Service

If service is terminated by a Customer, whether or not there is an actual disconnection by BC Hydro, and if the prior Customer or spouse, servant or agent of that person re-applies for service on the same Rate Schedule within 12 months of the most recent termination date for the same Premises, then the applicant shall pay the greater of:

(a) the costs that BC Hydro estimates that it will incur in making the restoration or reconnection of the service, or

(b) the sum of the minimum charges which a Customer would have paid between the time of termination and the time of application for a new service agreement on the applicable Rate Schedule.

5. Interfor- Fortis- 5

Reference: Fortis Rate Design Application October 30, 2009: Appendix H -Terms & Conditions

Preamble: Clause 2.3 provides that the security deposit will be in *"an amount equal to the customer's bill for 3 months as estimated by the Company", and for customers with demands in excess of 200 kVa the security deposit "shall be increased by an amount equivalent to the estimated minimum charge under the applicable rate schedule for six months."*

Request:

Q5(a) Will the revised clause 2.3 have any effect on the current security deposits paid by Interfor? If so, in what way?

A5(a) Please refer to the response to Interfor IR No. 1 Q3(o).

Q5(b) Why should a customer with a demand in excess of 200 kVa be required to pay a higher security deposit if they have a good credit?

A5(b) All customers over 200 kVA are required to pay a deposit regardless of credit standing or payment history for the reasons stated in the response to Interfor IR No. 1 Q1(c).

Q5(c) Why should a customer with a demand in excess of 200 kVa be required to pay a higher security deposit if they have 2 years of continuous service over which they have paid each and very account by the due date?

A5(c) All customers over 200 kVA are required to pay a deposit regardless of credit standing or payment history for the reasons stated in the response to Interfor IR No. 1 Q1(c).

Q5(d) How did Fortis determine the formula that would be used to calculate the security deposit?

A5(d) The formula is representative of the potential bad debt from a customer that defaults on their bill payments and does not provide the required written notice of termination.

Q5(e) What is the formula BC Hydro uses to calculate a security deposit?

A5(e) As per Sections 2.4.2 and 2.4.3 of BC Hydro's tariff, security deposits for new applicants and existing customers are calculated as being equal to two times the Customer's estimated average monthly bill (monthly billing based on actual consumption), or equal to three times the Customer's estimated average monthly bill (bi-monthly billing based on actual consumption).

Q5(f) Explain why the security deposit is increased for customers with demands in excess of 200 kVa?

A5(f) Customers with demand over 200 kVA are required to provide more notice before termination of their account (as per Sections 2.2(c) and 8.3 of FortisBC's Electric Tariff, Terms and Conditions). They represent a significant bad debt risk for other customers and for this reason must also pay a larger deposit.

Q5(g) What is the rational for not requiring customers with demands of 175 to 199 kVa to pay a higher security deposit?

A5(g) Please refer to the response to Interfor IR No. 1 Q3(i).

Q5(h) What is the rational for not requiring customers with demands of 150 to 174 kVa to pay a higher security deposit?

A5(h) Please refer to the response to Interfor IR No. 1 Q3(i).

6. Interfor- Fortis- 6

Reference: Fortis Rate Design Application October 30, 2009: Appendix H Terms & Conditions & Public Consultation

Request:

Q6(a) Did Fortis discuss security deposits, the Policy and the proposed changes to Clause 2.3 in any consultation sessions for the Rate Design Application? If so, provide a summary of those consultations, including the parties involved, the issues/concerns raised and the respective positions of Fortis and the other parties.

A6(a) The subject of the public consultation sessions held by the Company was COSA and rate design. Proposed changes to the Terms and Conditions portion of the tariff were not discussed. FortisBC made two attempts to contact Interfor representatives by telephone, leaving voice mail messages both times, during the consultation phase of the Rate Design Application but was unable to establish dialog with the customer.

7. Interfor- Fortis- 7

Reference: Fortis Rate Design Application October 30, 2009: Rate Classes

Requests:

Q7(a) Explain why there are seven separate Large General Service rate classes (30 to 36).

A7(a) In the current Tariff, the Large General Service rates are differentiated by service size and delivery voltage with Time-of-Use and/or Green options. Thus, the basic choices for a Large General Service customer are:

Rate 30 – minimum 500 kVA service sized taking service at primary voltage: and

Rate 31 – minimum 5,000 kVA service sized taking service at transmission voltage.

Time-of-Use and Green (eliminated in favour of Rate 110 in the proposed rate design) options are variations on the basic rates.

It is conventional practice to differentiate based on service size and voltage as these factors influence cost-to-serve, drive cost-based rates and are thus separated in the cost-of-service study.

Q7(b) Provide a list of Fortis' customers for each of the seven Large General Service rate classes (30 to 36 inclusive)

A7(b) The names of these customers are considered confidential and therefore cannot be released. Please see Table Interfor A7b below.

Table Interfor A7b

Rate Class	Number of Customers
Schedule 30	24
Schedule 31	3
Schedule 32	0
Schedule 33	1

Q7(c) Explain the differences between Large General Service - Primary 30; Large General Service - Transmission 31; and Large General Service - Transmission- Time of Use 33.

A7(c) Rate Schedule 30 is for customers served at primary or transmission voltage, generally between 500 and 5,000 kVA in demand. Rate Schedule 31 applies to customers served at transmission voltage and with demand generally over 5,000 kVA. Rate Schedule 33 is a time-of-use rate optionally available to customers eligible for Rate Schedule 31. (There is also time-of-use Rate Schedule 32 optionally available to customers eligible for Rate Schedule 30).

Q7(d) Confirm that the rate applied to Interior's Grand Forks mill is according to Rate Schedule 30 (Large General Service - Primary).

A7(d) Confirmed.

Q7(e) Confirm that the rate applied to Interfor's Castlegar mill is according to Rate Schedule 31 (Large General Service - Transmission).

A7(e) Confirmed.

Q7(f) Explain the reason for the different rate classes for Interfor's Castlegar and Grand Forks mills.

A7(f) The Grand Forks mill is served on Rate Schedule 30 since it is generally below 5,000 kVA and is served at primary voltage. The Castlegar mill is currently served on Rate Schedule 31 since it is served at transmission voltage and was historically generally above 5,000 kVA. The Castlegar mill has however been operating below 5,000 kVA for some time and FortisBC has proposed a change to Rate Schedule 30 to Interfor.

8. Interfor- Fortis- 8

Reference: Fortis Rate Design Application October 30, 2009: Large General Service Rates

Requests:

Q8(a) Provide a comparison of basic charges, energy rates and demand charges by rate class between Fortis and BC Hydro.

A8(a) Please refer to Zellstoff Celgar Appendix A34.1 for the requested comparison.

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 FortisBC Inc.

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.

Failure to pay a security deposit or to provide an equivalent form of security acceptable to the Company may, in FortisBC Inc.'s discretion, result in termination or refusal of service .

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 FortisBC Inc. 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 Inc.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.

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.

If the Company is unable to locate the Customer to whom a security deposit is payable, FortisBC Inc. will take reasonable steps to trace the Customer; but if the security deposit remains unclaimed 10 years after the date on which it first became refundable, the deposit, together with any interest accrued thereon, will be remitted to the British Columbia Unclaimed Property Society.

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 FortisBC Inc.

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 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 FortisBC Inc.'s discretion, result in termination or refusal of service.

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 FortisBC Inc. will reconnect or continue service to the Customer.

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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 contract demand in excess of 200 kVA will only be eligible for return of a security deposit upon discontinuation of service, 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.

If the Company is unable to locate the Customer to whom a security deposit is payable, FortisBC Inc. will take reasonable steps to trace the Customer; but if the security deposit remains unclaimed 10 years after the date on which it first became refundable, the deposit, together with any interest accrued thereon, will be remitted to the British Columbia Unclaimed Property Society.

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 FortisBC Inc.

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 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 FortisBC Inc.'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 any time.

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 FortisBC Inc. 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 Inc.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 contract demand in excess of 200 kVA will only be eligible for return of a security deposit upon discontinuation of service, 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.

If the Company is unable to locate the Customer to whom a security deposit is payable, FortisBC Inc. 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 remitted to the British Columbia Unclaimed Property Society less any costs incurred by the Company in attempting to locate the Customer.

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.

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.

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.¶

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.

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.

Issued
FORTISBC INC.

By:

Accepted for filing
BRITISH COLUMBIA UTILITIES COMMISSION

By: ____________________________
Commission Secretary

EFFECTIVE (applicable to consumption on and after)

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.

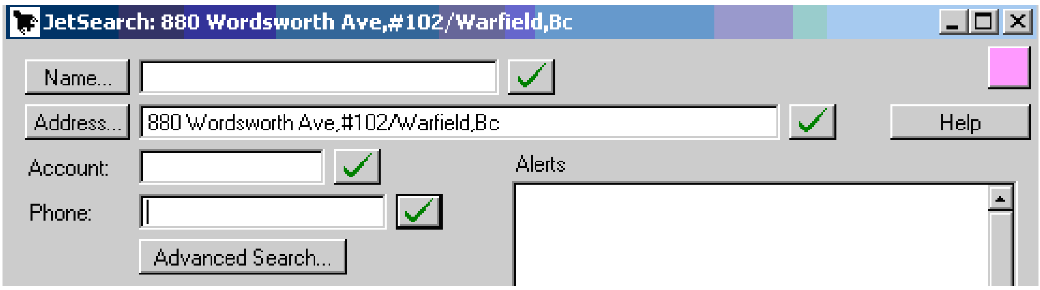
Deposits

In order to ensure adequate security in accordance with FortisBC's tariff for residential and commercial accounts, we must assess both new and existing residential and commercial accounts for security requirements.

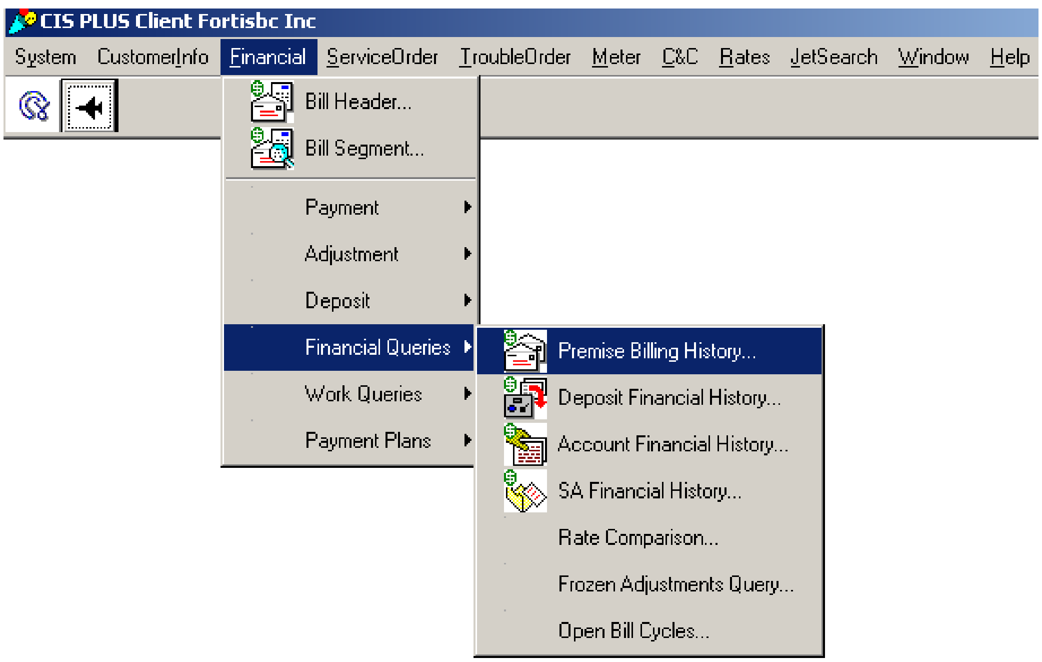
Contents

Calculating the Deposit

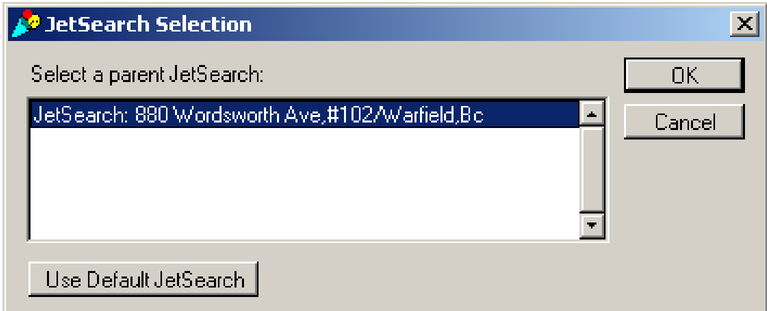
To determine what the deposit amount should be, bring up the address that the customer is **moving into**.



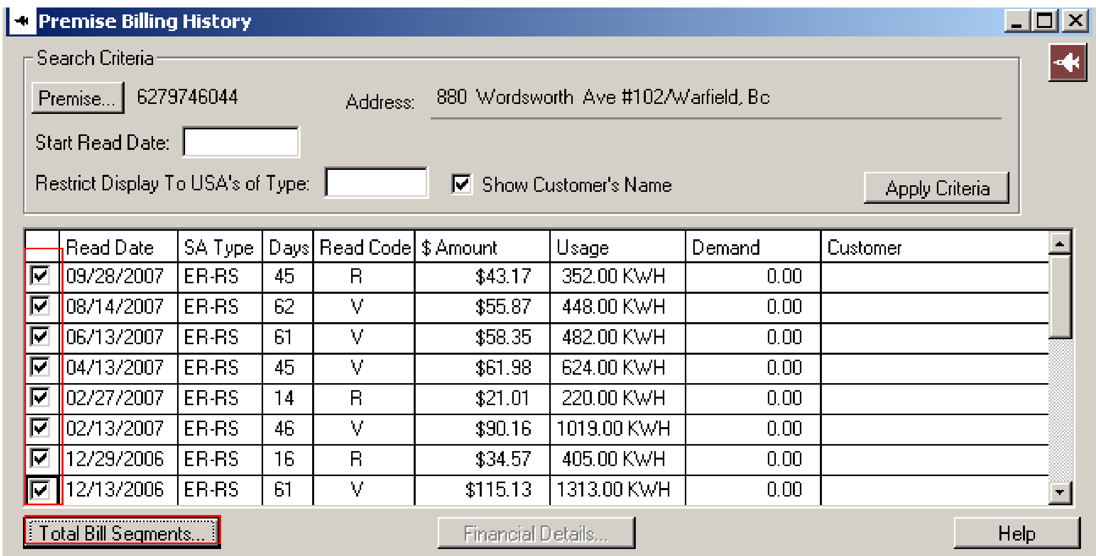
Go to the main menu bar of CIS, click on Financial, then go down to Financial Queries and click on Premise Billing History.



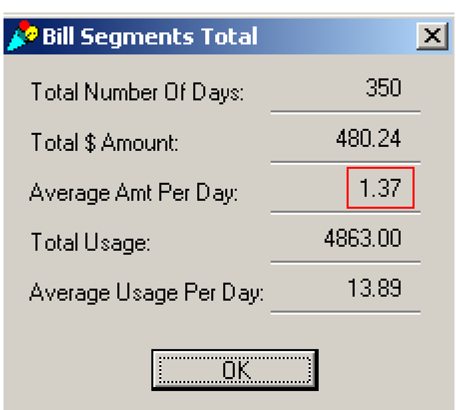
This will bring up a new window. Ensure that the correct address or name of the current account holder is in the window and click on OK.



This will bring up the Premise Billing History. Select at least the previous 12 months of billing history (**do not include any cancelled bills**) and click on Total Bill Segments on the bottom left.



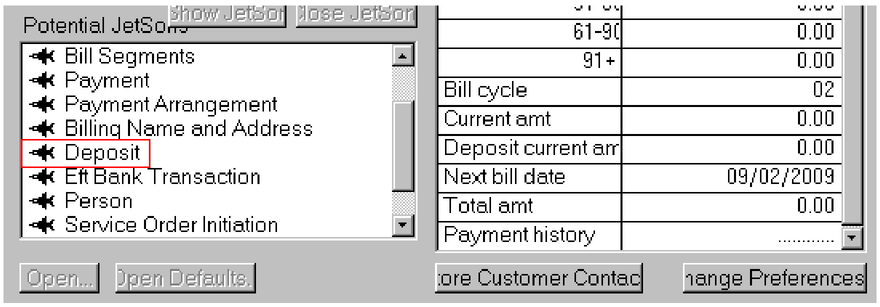
This will bring up the Bill Segment Totals in the middle of the screen. Take the average amount per day, $1.37 in this case, and multiple it by 90 days (3 months). This will give us a total equaling $123.30. By rounding down to the nearest $5.00 we come up with a total deposit amount of $120.00. We can now add this calculated deposit amount to the customer's account.



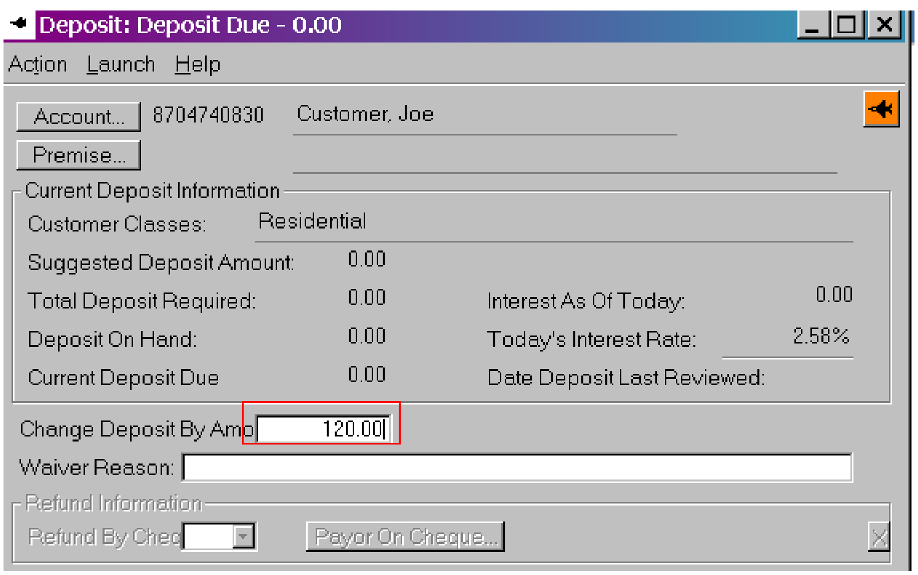
For an existing premise, the minimum deposit is always $100. For a new premise or a premise with insufficient history (less than a year), the minimum deposit is $200.

Adding the Deposit to the Account

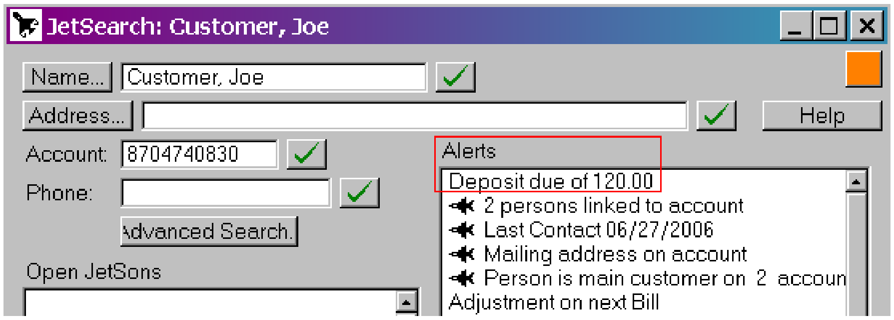
Once we have calculated the deposit we can then add the deposit to the new customer's account. Go down to the Deposit jetson in the bottom left window and double click.



You should now have the Deposit Screen up. Enter the amount of the deposit in the Change Deposit By Amount field.

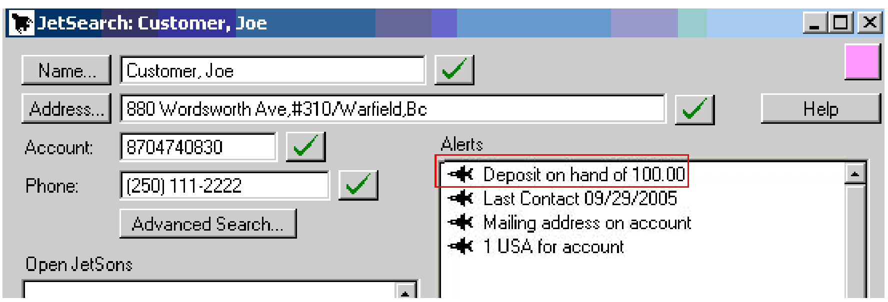


Go up to Action and click Request/Change Deposit Amount. A confirmation that the deposit will be added to the account should appear. Close the Deposit window and in the top right window of the customer's account you will see deposit due of $120.00 (in this case).

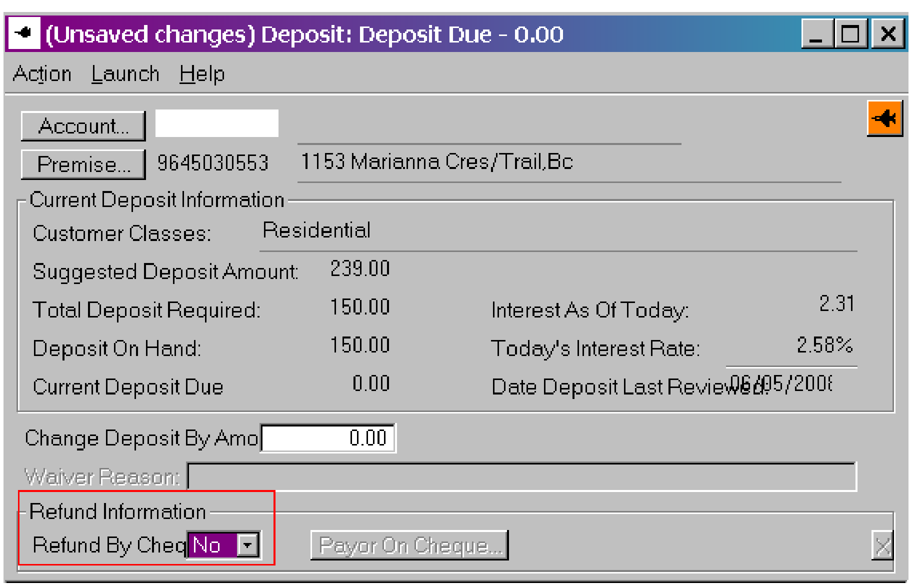


Applying the Deposit to the Account

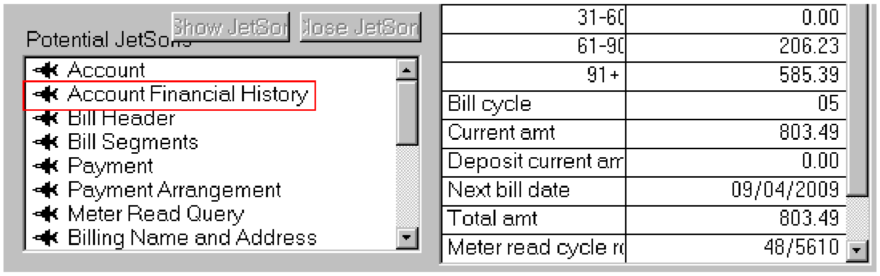
Generally, a deposit may be applied back to the customer's account if they have had 2 years of good credit history or if they are leaving FortisBC's service area. To apply the deposit, bring up the customer's account and double click on the 'Deposit on hand' alert at the top right.



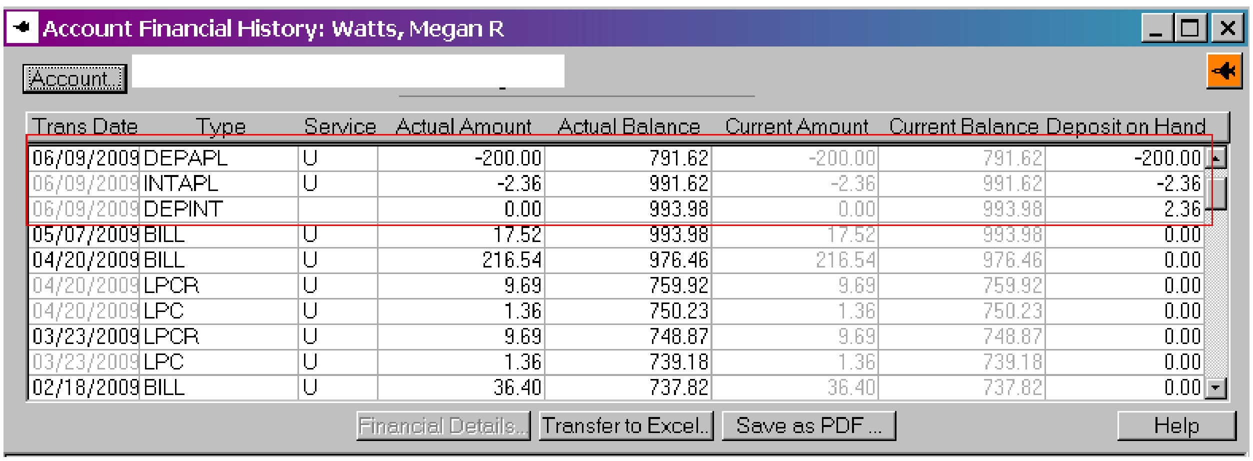
The Deposit screen will appear. From the 'Refund by Cheque' drop down choose the option NO. Then go up to Action and click Apply Deposit and Interest.



A confirmation window will appear confirming the amount to be applied back to the customer's account. Click OK. Close the Deposit window. To confirm that the deposit was applied back to the balance, double click the Account Financial History jetson.

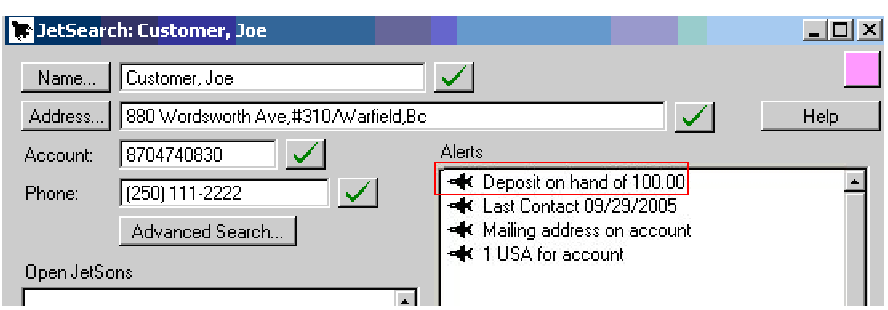


The deposit and interest adjustments should appear towards the top (most recent transactions are always at the top):

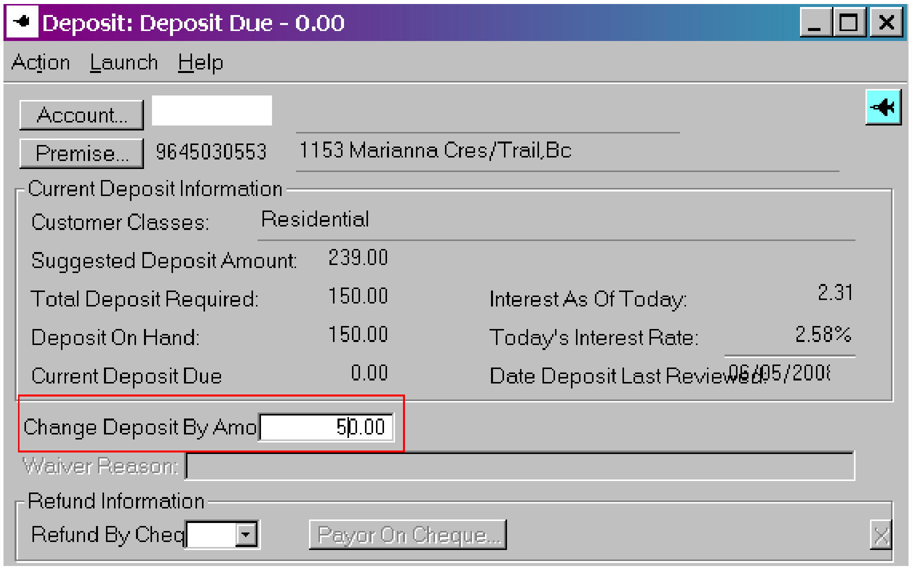


Increasing the Deposit

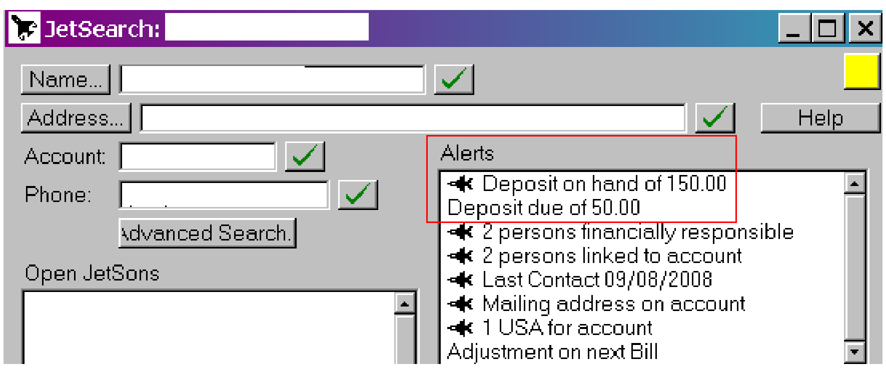
If the customer already has a deposit on hand and, during their move to a new location, you determine that an additional deposit amount is required, you will need to add this additional amount. Bring up the customer's account and double click the 'Deposit on hand' jetson.



Type in the additional amount in the Change Deposit by Amount field (in this example, 50.00) and then go up to Action and click Request/Change Deposit Amount.



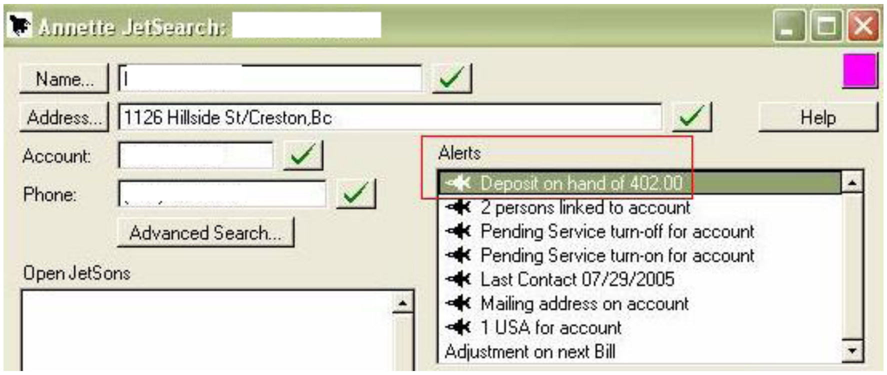
Close the deposit window and you will now see both a deposit on hand and a deposit due alert on the customer's main account screen:



Decreasing the Deposit

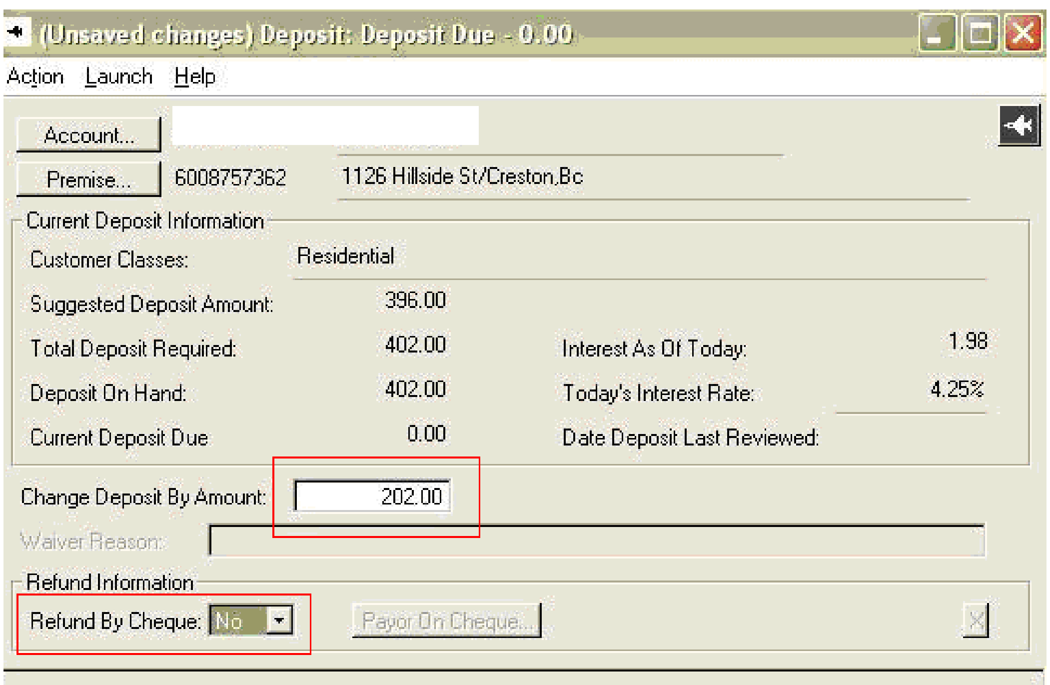
During a customer move, if you determine that you can lower the deposit on hand for the customer (based on the consumption at the **NEW** location) the following process should be observed.

Bring up the customer's account in CIS and verify what the current Deposit on Hand amount is:



In this example, the customer has a deposit of $402 on hand. Based on the consumption of his new address, we have determined that the deposit should be only $200.

From the main customer screen, double click the Deposit on Hand jetson. Enter in the amount that's needed to correct the deposit amount (in this case the difference is $202), and change the Refund by Cheque drop down to NO. Then go to Action and click Apply Deposit And Interest.



CIS will apply that difference amount ($202) and ALL of the interest as of today to the account. The Deposit Due on the main screen will now say $200.

Residential Accounts

Any time a customer moves into a location, their account financial history should be reviewed to determine if a deposit can be added, changed or removed.

New Residential Meter Installation

When a customer requests a new service installation the customer should be charged a minimum security deposit of **$200**. This is in all situations where we do not have any consumption history for the new premise. The security deposit should be added to the customer's account at the same time as the OID is created.

In this situation, Equifax or credit reference letter from another energy utility may be offered to waive the security deposit.

New Residential Customer

Any customer who has not previously held an account with FortisBC should be charged a security deposit. If the **address already exists** in CIS, the deposit should be calculated based on three months consumption (**minimum $100**). If it is a **new address with no or insufficient premise billing history**, a **minimum deposit of $200** should be charged.

In this situation, Equifax or credit reference letter from another energy utility may be offered to waive the security deposit.

Existing Residential Customer

A security deposit audit should be performed each time a residential customer moves from one location to another. To do this, you must review the customer's account financial history and then do one of the following:

- **Charge a new deposit** based on the premise billing history of the new premise.
- **Increase or decrease an existing deposit** based on the premise billing history of the new premise.
- **Refund an existing deposit** provided that the customer's credit history with FortisBC has been satisfactory.

Commercial Accounts

All new and existing commercial accounts are subject to a security deposit. The deposit will be dependent on whether it is an existing premise or new installation and the customer's financial history with FortisBC. Please read the below thoroughly for further instruction.

New Installation – Drop Service or Construction Required

Anytime a new Commercial service is requested, an account should be set up for the customer in CIS. All Commercial accounts are subject to a security deposit. To determine what deposit should be charged, please use the following chart:

Service Details	Deposit to be Charged	Action
200 amp or less, 120/240V	$500	Add deposit to account in CIS
200 amp or less, 120/208V, 5 jaw	$500	Add deposit to account in CIS
Over 200 amp and either 120/240v or 120/208v, 7 jaw	Dependent on connected load information	Fax customer connected load form. Resource Team will charge deposit.

Existing Premise – New Commercial Customer

A security deposit audit should be done each time a customer requests service at an existing commercial premise.

For a new commercial account, a deposit must be charged. The deposit is calculated using the Premise Billing History and averaging over a period of three months.

For an existing commercial account, you will need to review the account financial history and determine whether you need to apply a new deposit or increase/decrease an existing deposit. The deposit calculation is made using the Premise Billing History for the new premise and averaging over a period of three months.

If there is insufficient premise billing history, we may require a connected load form.

Waiving Security Deposits

Please be advised that the below methods for waiving security deposits do not apply to locations whose demand exceeds 200 kVA. Security deposits will not be waived for these locations.

Residential Accounts

All residential customers or sole proprietorship and partnership customers should be offered Equifax as their primary means of having their security deposit waived. Again, this applies to the main account holder only. **A secondary person's credit history cannot be used to waive a security deposit.**

We may accept a credit reference letter from another energy utility in the event the customer:

- Is not a resident of Canada or has not been a resident very long and, as a result, will not have a file with Equifax,
- Declines using Equifax to check their credit, or
- Their Equifax comes back as 'Deposit Required'

The credit reference must:

- Be from another **energy utility** company – gas and electric only,
- Be in the **exact same subscriber name**,
- **Be recent** – if they closed their account it must be no more than 60 days old,
- Have **no more than 2 payments that were past due**, and
- For **residential/personal** accounts – must be a period of **2 years** or more of good payment history, or
- For **commercial/business** accounts – must be a period of **4 years** or more of good payment history.

If this option is given to the customer, it **must** be made clear that:

- The **deposit will be added to the account** and is considered due and payable until the reference letter is received,
- The reference letter **must come directly** from the energy utility to FortisBC,
- It is the **customer's responsibility** to ensure that the reference letter gets to FortisBC – due to privacy reasons we are unable to request these letters and, therefore, unable to follow up on them.

Commercial Accounts

Security deposits will only be waived for Commercial accounts **whose demand is less than 200 kVA** if the customer can provide to the Company a satisfactory credit history. This is defined as:

- A 2 year history of prompt payment with FortisBC for the exact same subscriber,

- A satisfactory credit reference letter from another **energy** utility as defined above,

OR

- **Corporations/Limited Partnerships:** FortisBC will also accept an irrevocable letter of credit to waive a deposit for these types of businesses. An irrevocable letter of credit is a letter from the customer's bank stating that the bank will pay a specified amount upon demand of the person or company who is named on the letter. We must receive an original copy of the letter which should be signed by the bank manager and should have a specified end date. Once we have received the letter, this should be given to Marc, Christine or Del. (CIS Business types: CP, IN, LP, LT, OT and PL)
- **Partnerships:** Members of partnerships are jointly liable for any amounts owed. Each and every partner may be subjected to individual Equifax credit checks (or credit reference letters as detailed above). All credit checks must qualify for the deposit to be waived. (CIS Business types: PT)
- **Sole Proprietorships:** A credit check through Equifax may be performed or they may submit a credit reference from another energy utility. As Sole Proprietorship accounts must be set up in the customer's personal name, you may also waive the deposit provided the customer has a personal account with FortisBC that is in good standing. (CIS Business types: ST)

Notes detailing the reasons for waiving a commercial deposit should always be included on all applicable accounts.

Refunding Security Deposits

Security deposits may be refunded to the customer under the following circumstances:

- 2 year prompt payment history with FortisBC by the same subscriber,
- Closure of the customer's account

It is important to note that a cheque is not actually issued in the amount of the security deposit. The deposit plus interest is applied back to the customer's account. The credit will either go towards any outstanding balances or typically future billings. If the amount is substantial, a refund request can be sent through for the remaining credit on the account.

Please be advised that on accounts whose demand exceeds 200 kVA, FortisBC reserves the right to hold security as long as service is provided.

Equifax

If a customer has agreed to allow FortisBC to perform a credit check via Equifax they must be the main account holder for their FortisBC account. **Adding a second person to the account and doing an Equifax check is not sufficient to waive a security deposit.**

The following process should be observed when performing an Equifax credit check.

Signing On

The following internet link will be the website used to obtain Credit Bureau Reports from Equifax. https://www.equifax.ca/credit

On the initial page you will need to sign on by filling out the following fields:

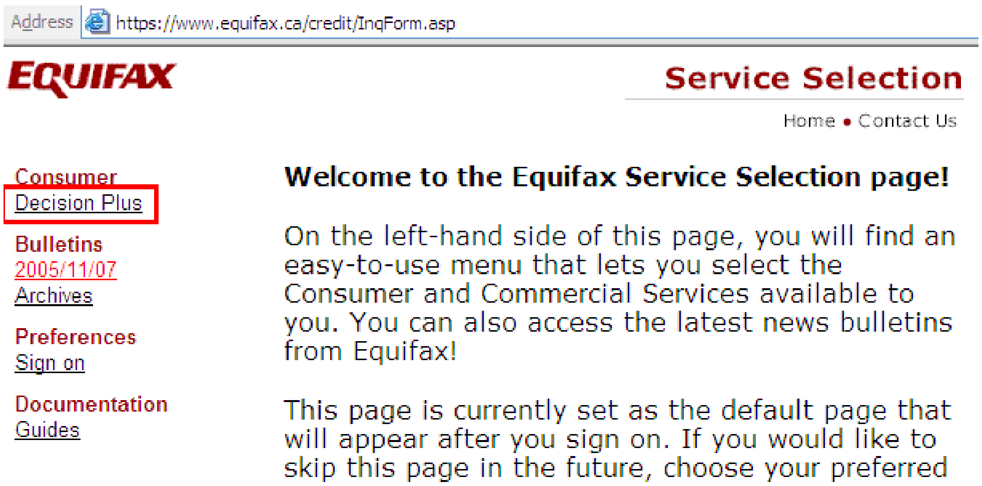
- Client ID:
- User ID: first initial and last name (up to eight characters)
- Password: as assigned (if your password has expired or does not work, please email a Supervisor or Manager)

Then click Sign-On as shown below:

If this is your first login, you will be automatically prompted to change your password.

Using Equifax

Once you are signed on to the Equifax Service you will see the Service Selection Screen. Select the Decision Plus link on the top left corner of the screen, highlighted in red below:


Address https://www.equifax.ca/credit/InqForm.asp

EQUIFAX

Service Selection

Home • Contact Us

Consumer
Decision Plus

Bulletins
2005/11/07
Archives

Preferences
Sign on

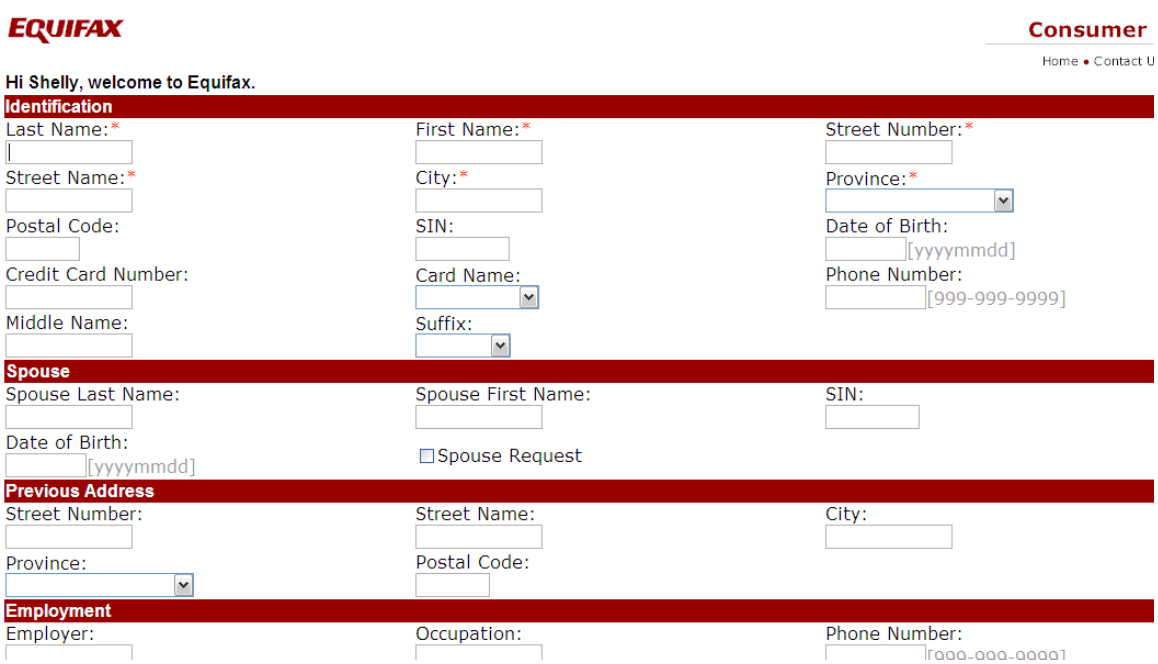
Documentation
Guides

Welcome to the Equifax Service Selection page!

On the left-hand side of this page, you will find an easy-to-use menu that lets you select the Consumer and Commercial Services available to you. You can also access the latest news bulletins from Equifax!

This page is currently set as the default page that will appear after you sign on. If you would like to skip this page in the future, choose your preferred

The Decision Plus link will bring you to the Consumer Report screen as shown below. This page is where we enter the customer's information:


EQUIFAX

Consumer

Home • Contact U

Hi Shelly, welcome to Equifax.

Identification

Last Name:* First Name:* Street Number:*

Street Name:* City:* Province:*

Postal Code: SIN: Date of Birth: [yyyymmdd]

Credit Card Number: Card Name: Phone Number: [999-999-9999]

Middle Name: Suffix:

Spouse

Spouse Last Name: Spouse First Name: SIN:

Date of Birth: [yyyymmdd] Spouse Request

Previous Address

Street Number: Street Name: City:

Province: Postal Code:

Employment

Employer: Occupation: Phone Number: [999-999-9999]

All the required fields have a red asterisks (*) beside it and are as follows:

- First Name
- Last Name
- Street Number (where they are moving from)
- Street Name (where they are moving from)
- City (where they are moving from)
- Province (where they are moving from)

Other information we should try to obtain:

- Postal Code (where they are moving from)
- Date of Birth
- Middle Name
- Employer
- Occupation

The more information we can get the better. A SIN may be requested but do not record this information on the customer's account. Due to the high cost of each request submitted to Equifax please limit the number of requests.

Below is an example of a filled out Equifax Consumer report form:

Identification

Last Name:* Customer
First Name:* Joe
Street Number:* 1074
Street Name:* Spokane
City:* Trail
Province:* British Columbia
Postal Code: V1R 3W9
SIN:
Date of Birth: 19850824 [yyyymmdd]
Credit Card Number:
Card Name:
Phone Number: [999-999-9999]
Middle Name: Ann
Suffix:

Spouse

Spouse Last Name:
Spouse First Name:
SIN:
Date of Birth: [yyyymmdd]
Spouse Request

Previous Address

Street Number:
Street Name:
City:
Province:
Postal Code:

Employment

Employer: Fortis
Occupation: Cotnact Centre Age
Phone Number: [999-999-9999]

Insurance

CPLS Policy Type:

Billing

Billing: Standard
Reference: sproudfo
French Report

* Required field.
Submit Reset

Once the form is filled out click the submit button, on the bottom right corner of the form.

Reading the Results

Once you press submit on the Consumer Report sheet the results will appear as shown below:

EQUIFAX
1 877 227-8800

Consumer Report
12/15/2005

File Requested by: SPROUDFO

Identification

Name:	CUSTOMER, JOE, ANN
Current Address:	1074, SPOKANE, TRAIL, BC, V1R 3W9
Date of Birth, SIN:	1985/08/24
Reference:	

Employment

Employer, Occupation:	FORTIS CONTACT CENTRE AGENT

Subject 1: File Requested, Decision, Score, Identification, Employment.

Decision (Subject 1)

Accept

Product Score (Subject 1)

Beacon **741**
Date of last inquiry too recent or unknown
Too many inquiries last 12 months
Length of time accounts have been established
Lack of recent retail account information

Identification (Subject 1)

Unique Number	3488630165	**File Number**	00-0008095-00-009
Date File Opened:	09/10/2003	**Date of Last Activity:**	12/15/2005
DOB/Age:	08/24/1985	**SIN:**	

Name:	CUSTOMER, JOE, ANN
Current Address:	166, HEATHER PL, PENTICTON, BC, V2A 8B3
Since, R/O/B:	09/2003
Reported:	STS Reported
Former Address:	1074, SPOKANE ST, TRAIL, BC, V1R 3W9
Since, R/O/B:	10/2005
Reported:	STS Reported

Employment (Subject 1)

Employment Information:

Current Employer:	FORTIS BC

End Of Report

The decision where you will take your direction from is indicated in the highlighted red area, as above. In this situation Joe Customer has an acceptable credit reference so a deposit does not need to be charged.

Below is a list of possible responses:

- Accept
- Deposit required on the first bill
- Deposit required prior to connection
- Deposit required; no file
- Deposit required; death notice on file
- Deposit required; bankruptcy in the last 12 months
- Deposit required; file request rejected

NOTE: For the last five responses, we have to obtain the deposit prior to connection because either credit is reported poor; or there is no file; or there is some other anomaly that makes us "suspect" the credit.

Impact to Credit Score

Prior to performing a credit check, should the customer ask you what impact the check will have on their credit score, you will need to advise them that the 'hit' will depend on a number of variables:

- Their balance to credit ratio
- How many recent hits they've had
- Their debt to worth ratio
- Their overall score
- They payment history with credit card companies, banks, 3rd party lenders (Leon's, The Brick, Ikea), etc
- Other factors

If a customer has excellent credit history, our credit check may have no effect on the customer's credit score at all. If the customer has poor credit history it could have more of a significant impact. If the customer wishes to find out what impact an inquiry to their credit might have on their credit rating, they should contact the Equifax Consumer Department at 1-800-465-7166.

Fraud Warnings

Effective Jan 1, 2008, for customers that are moving from other provinces to BC, the following alert may appear on their Equifax report:

```
**** WARNING ****ALERT TO VERIFY CONSUMER'S IDENTITY - PLEASE CONTACT
CONSUMER AT (000) - 000- 0000 BEFORE EXTENDING CREDIT
```

Due to Bill 152 (a bill passed to allow Ontario residents to help prevent identity theft), should the above alert appear on a customer's report, we will need to contact the customer at the phone number provided on the alert before proceeding with the Equifax check. **This means you will not be able to complete the customer's account set up.** The following scripting may be used:

"Due to a privacy alert that has been set up on your Equifax file, I will not be able to complete your application until I have called you back at the number you specified on your report."

The following Q & A may assist you in these types of situations:

Can we give the customer the phone number they provided to Equifax?

No.

What if the customer claims the phone number is incorrect?

They must contact Equifax to correct the contact number. Advise the customer you will not be able to complete their application.

What if the customer is calling from the number listed on Equifax?

You must still end the call and call the customer back.

What if we are unable to reach the customer at the phone number provided to Equifax?

You will not be able to complete the customer's application until you have reached them at the phone number that was provided to Equifax.

NOTE: The customer cannot choose to continue with the application by having a deposit added to their account.

Obtaining Deposits Prior to Connection

When the Equifax Credit Report indicates that a deposit is required prior to connection, follow the process below.

- Create the customer's account and a Service Order Initiation for the premise they want to move into.
- Advise the customer that they are required to pay a deposit upfront. They can make this payment via credit card or may call in a reference number if payment is made at the bank.
- After you have completed the move in and added the deposit, and should they choose to pay by credit card, warm transfer the customer to extension 0698 (Resource desk) to process the payment.

Fraud: If the Equifax Credit Bureau Report comes back as Deposit required; death notice on file, the customer must come into the Trail office or Kelowna office (Springfield) to present picture identification before we will connect them.

When waiving or charging a deposit you must add comments in the customer's CIS account(s) specifying the reason for waiving or not waiving the deposit.

In order to reduce costs and increase efficiency of the BCUC proceedings, Okanagan Environmental Industry Alliance, Natural Resource Industries and Hedley Improvement District have contributed together and are supportive of this Information Request.

1.0) Conservation reduction in costs

FortisBC notes in its 2009 Rates Design Application ("*2009 RDA*"):

"Finding ways to encourage conservation is a benefit to all customers through reductions in power purchase and infrastructure costs."[1]

Q1.1 Please describe the ways in FortisBC encouraged conservation resulting in reductions in power purchase and infrastructure costs.

A1.1 Please refer to the response to BCOAPO IR No. 1 Q1.2. All conservation initiatives are assumed to be aimed at reducing power purchase costs and deferring the need for infrastructure additions.

[1] **Exhibit B-1, Section 1.2, Page 5, Lines 13-15**

2.0) Meaningful stakeholder engagement

FortisBC notes in the 2009 RDA documents:

"FortisBC will engage in meaningful stakeholder engagement before the Rate Design Application (RDA), Cost of Service, Advanced Meter Infrastructure . . . applications are submitted to the BCUC." [2]

Q2.1 Please describe how FortisBC interprets *"meaningful stakeholder engagement".*

A2.1 FortisBC does not hold to a single definition of "meaningful stakeholder engagement" as the requirement for consultation activities will vary with the nature of the application to be put before the Commission. Generally speaking, the Company will make all reasonable efforts to consult with those parties or representative groups affected by the application in question. Ultimately, the Commission will determine whether consultation activities have been adequate. FortisBC believes that with respect to the 2009 COSA and RDA Application the activities described in Section 4 of the Application are meaningful (Exhibit B-1).

Q2.2 Explain how FortisBC met the requirements of *"meaningful stakeholder engagement"* for the RDA, Cost of Service Analysis (COSA) and Advanced Meter Infrastructure (AMI) as described in item 2.1.

A2.2 A description of the public consultation activities completed with respect to the COSA and RDA Application can be found in Section 4 of the Application (Exhibit B-1). Consultation activities pertaining to AMI have not been completed as that process has not been concluded.

[2] **Exhibit B-1, Section 1.3, Page 7, Line 2**

3.0) RDA Contribution to Energy Conservation and Efficiency

FortisBC notes in the 2009 RDA document:

"This RDA is a key component of FortisBC's energy conservation and efficiency strategy."[3]

Q3.1 Please explain in detail how the RDA is a key component of FortisBC's energy conservation and efficiency strategy.

A3.1 Please refer to the response to BCOAPO IR No. 1 Q1.2. The RDA will provide appropriate price signals to drive customers' energy conservation behaviours, and also incent customers to increase participation in DSM programs.

Q3.2 Please explain how the RDA is integrated with FortisBC's DSM plan.

A3.2 The RDA will be an important consideration in determining the achievable potential in the 2010 Conservation Potential Review (currently under development), and the CPR in turn will be the primary reference document for the 2011 DSM plan.

Q3.3 Please indicated the extent to which the conservation due to rates is expected to contribute to FortisBC's energy conservation targets.

A3.3 The Company has not quantified the incremental conservation due to the proposed rate changes, but has commissioned a study on the effect of time-based rates as described on page 24 of the Application (Exhibit B-1).

[3] **Exhibit B-1, Section 2.1, Page 11, Lines 25-26**

4.0) AMI and interim rates

FortisBC notes in the 2009 RDA document:

"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."[4]

Q4.1 Please indicate the date that FortisBC is projecting for the decision of the RDA application.

A4.1 Based on the BCUC Practice Directive, FortisBC expects that a decision in the RDA Application will be rendered within three to six months after the conclusion of the regulatory process.

Q4.2 Please indicate the date that FortisBC is projecting for the proposed implementation of AMI.

A4.2 Please refer to the response to BCUC IR No. 1 Q6.1.

Q4.2.1 Please indicate what is meant by the *"implementation of AMI"* in item 4.2 - for example, does implementation mean full scale implementation or the initial installations?

A4.2.1 By "implementation of AMI" FortisBC is referring to a full-scale implementation.

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[4] Exhibit B-1, Section 2.1, Page 11, Lines 25-26

Q4.3 Please specify the maximum time limit for the *"relatively short time period"* for the statement above.

A4.3 The phrase above was used precisely because the dates involved cannot be determined with any certainty. The implementation of the rates contemplated by this application is proposed to come into effect in 2011 which is after the expected filing date of the AMI CPCN Application. The intent of the statement is to convey FortisBC's concern that the rapid introduction and subsequent change of conservation rate types is not in the interest of either the customers or the Company.

Q4.4 Please list all interim rates that FortisBC considered and describe in detail why each was not recommended.

A4.4 All of the rate options considered by FortisBC are detailed in Section 10.1 of the Application (Exhibit B-1).

5.0) AMI and time-based rates

FortisBC notes in the 2009 RDA document:

"FortisBC intends to file an AMI application in 2010 with the intention of making interval data readily available, and thereby permitting the introduction of timebased 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."[5]

Q5.1 Please indicate the timing of the stages above as follows:

Q5.1.1 the expected start and finish date of the study noted in stage 1 above,

A5.1.1 The AMI Future Program study was initiated in December 2009 and is expected to be complete by the end of March 2010.

[5] Exhibit B-1, Section 3.1, Page 24, Lines 13-28

Q5.1.2 the expected filing date for the AMI application,

A5.1.2 The AMI CPCN application is expected to be filed in the 4th quarter of 2010. However, this is dependent on several factors including the issuance of Smart Meter Regulations made pursuant to the Utilities Commission Act.

Q5.1.3 the expected start and finish date of the study noted in stage 3 above, and

A5.1.2 The use of AMI data to model and study time based rates would begin once a statistically significant number of meters were installed in the field. Currently, this is expected to be during 2013. It is unknown at this time how long this study would take to complete, but it is unlikely to be shorter than six months. This project will be further detailed in the AMI CPCN Application.

Q5.1.4 the expected date of stage 4.

A5.1.4 It is likely that information could be consolidated for the purposes of filing time-based rates within six months after “Stage 3” is complete. However, the filing of any Rate Design Application would depend not only on the completion of “Stage 3” but other factors as well.

Q5.2 Please indicate if FortisBC is planning any time-based rate pilots of its own:

A5.2 At this time, FortisBC is not planning to conduct any time-based rate pilots since the Company is of the opinion that the numerous published rate studies and pilots can be used to extrapolate probable FortisBC benefits from AMI-related future initiatives, including the implementation of time-based rates. The results of the AMI future program study expected within the first quarter next year and will draw comparisons between FortisBC and other utilities that have implemented pilots and programs over the past several years.

Q5.2.1 if so, please list the expected volume of units for the pilots, the goals of the pilots, and timing of the pilots,

A5.2.1 Please refer to the response to OEIA IR No. 1 Q5.2 above.

Q5.2.2 if not, please explain why such pilots are not required and how the specifics of the rate will be finalized.

A5.2.2 Please refer to the response to OEIA IR No. 1 Q5.2 above.

Q5.3 Please indicate the expected timing when the wide scale time-based rate will be introduced for the FortisBC customers.

A5.3 The implementation of wide-scale time-based rates could occur after the Rate Design Application contemplated in Exhibit B-1, Section 3.1, Page 24, Lines 13-28 is approved.

6.0) FortisBC AMI and Ontario

FortisBC notes in the 2009 RDA document:

"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 reached similar conclusions, summarized in the following table:"[6]

Q6.1 Please confirm that the document in the attached Appendix A[7] is the report noted in FortisBC's Footnote #1 and also references the Ontario pricing pilot noted by FortisBC.

A6.1 Confirmed.

Q6.2 Please indicate the source of the information (plus, include the document) for the overall 6% reduction and 25% peak demand reduction figures noted in the statement above.

A6.2 The 6 percent and 25 percent estimates were taken from the Ontario Pricing pilot document included as Appendix A to OEIA's submitted IR No. 1, and the Brattle Group document included as Appendix B with OEIA's submitted IR No. 1.

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[6] **Exhibit B-1, Section 3.1, Page 22, Line 27 to Page 23, Line 2**
[7] **Attached Appendix A**

Q6.3 Please discuss the differences and similarities of FortisBC to the Ontario situation, and discuss the relevancy of using the data from Ontario for FortisBC.

A6.3 The Company intends to conduct a review of all available material related to conservation based rates in order to provide an accurate estimate of both costs and benefits of AMI future programs. For this reason, it has commissioned a study of available rate pilots and programs (the AMI Future Program Study) which will not only identify those that closely align with FortisBC but will also discuss the relevancy of the pilots and provide information on both costs and benefits for these programs. This study will be complete in the first quarter of 2010 and will require additional time in order to examine the findings and incorporate into the AMI program planning.

Q6.4 Does FortisBC expect to have similar results as shown in Table 3.1[8]?

A6.4 Please refer to the response to OEIA IR No. 1 Q6.3.

[8] **Exhibit B-1, Section 3.1, Page 23, Line 3**

7.0) FortisBC AMI and Brattle Group

FortisBC notes in the 2009 RDA document:

"A 2008 Brattle Group study 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%.'"[9]

Q7.1 Please confirm that the document in the attached Appendix B10 is the report noted in FortisBC's Footnote #2 and also references the Brattle Group study noted by FortisBC.

A7.1 Confirmed

Q7.2 Does FortisBC expect to have similar results as noted in the above statement?

A7.2 Please refer to the response to OEIA IR No. 1 Q6.3.

Q7.3 The Brattle Group study notes *"fourteen recent pricing experiments"*[11]. Please identify the experiments which most closely aligns with FortisBC and provide reasons.

A7.3 Please refer to the response to OEIA IR No. 1 Q6.3.

[9] Exhibit B-1, Section 3.1, Page 23, Lines 10 to 12
[10] Attached Appendix B
[11] Attached Appendix B, Cover Page

Q7.4 The Brattle Group study also notes that the drop in peak usage is expected for *"those with enabling technologies in 25-45% range"*[12]. Does FortisBC expect to include enabling technologies with its AMI implementations?

A7.4 FortisBC intends to provide customers choices in how and when they receive usage data provided by AMI. These choices are likely to include information via the internet and In Home Display. The Company also expects to provide a gateway device which will provide usage data and pricing signals to other technologies within the home that can further support customer conservation and home automation. However, a final decision on the inclusion of these items within the AMI application will be dependent on several factors including the results of the Company's consultation and the Smart Meter regulations made pursuant to the Utilities Commission Act.

[12] **Attached Appendix B, Cover Page**

8.0) Electric Usage Interval Data meters

FortisBC notes in the 2009 RDA document:

"The majority of meters installed throughout the FortisBC service territory do not collect electric usage interval data."[13]

Q8.1 Please indicate the number of meters throughout the FortisBC service territory that do collect electric usage interval data.

A8.1 There are currently 49 meters installed that collect interval data. These 49 meters are used to bill 30 individual accounts and 22 distinct customers.

Q8.1.1 Please indicate the model numbers, specification sheets of these meters and communication capabilities.

A8.1.1 Table OEIA A8.1.1 below details the make and model numbers for the installed interval meters, as well as specification sheets from the vendors provided as OEIA Appendix A8.1.1.

Table OEIA A8.1.1

Make	Model	Count	Communication	Capabilities	Vendor Data Sheet
Elster	A1K+	2	Optical Port	KW	ALPHA Plus Meter Data Sheet
Elster	A1R+	2	Optical Port	KW+KVA	ALPHA Plus Meter Data Sheet
Elster	A1RL+	4	RS232/Optical Port	Load Profile	ALPHA Plus Meter Data Sheet
Elster	A3RAL	39	RS232/Optical Port	Load Profile	A3 Alphas Meter Data Sheet
Elster	A3RALC	2	RS232/Optical Port	Transformer loss compensation available	A3 Alpha Meter Data Sheet
Total		**49**			

[13] **Exhibit B-1, Section 3.1, Page 24, Lines 4 to 5**

Q8.1.2 Please provide a historical context (including related company acquisitions - e.g. Aquila Networks) for the meters.

A8.1.2 FortisBC is not aware of any relationship between meters and company acquisitions (the meters were not exchanged when Company ownership changed).

Q8.2 Please breakdown the number of meters (that collect electric usage interval data) into a table showing the number of meters per region and the tariff rate class.

A8.2 The breakdown is as follows:

Table OEIA A8.2

	10 - Trail	20 - Castlegar	30 - Grand Forks	40 - Creston	50 - Kelowna	60 - Oliver	70 - Penticton	80 - Princeton	Total
GS21	2	-	1	-	6	2	-	-	11
ID30	1	2	1	3	1	1	1	1	11
ID31	-	1	-	-	-	-	1	-	2
ID33	-	1	-	-	-	-	-	-	1
IR60A	-	-	-	-	-	3	-	-	3
WH40	-	-	3	-	6	-	9	-	18
WH41	-	3	-	-	-	-	-	-	3
Total	**3**	**7**	**5**	**3**	**13**	**6**	**11**	**1**	**49**

Q8.3 Please breakdown this number into a table showing the number of meters per customer type and the tariff rate class.

A8.3 The breakdown is as follows:

Table OEIA A8.3

	General Service	Industrial	Irrigation	Wholesale	Total
GS21	11				11
ID30		11			11
ID31		2			2
ID33		1			1
IR60A			3		3
WH40				18	18
WH41				3	3
Total	11	14	3	21	49

Q8.4 Please discuss the advantages and disadvantages of running a pilot on the existing meters that collect electric usage interval data.

A8.4 Due to the statistically insignificant number of meters in the field and the absence of residential and small commercial meters capable of reporting interval data, a pilot using existing meters would not produce any meaningful results.

9.0) Hedley Improvement District Project

OEIA noted in its September 22, 2008 Final Submission of the 2009-2010 Capital Expenditure Plan (see attached Appendix C) a number of observations regarding *"FortisBC Time of Use Rates"*[14].

Q9.1 Please confirm that the discussion presented in Section 6.2 of OEIA's Final Submission (Pages 22 to 26)[15] is an accurate reflection of activities. Please correct as necessary.

A9.1 The referenced discussion contains a number of stated assumptions and opinions, in addition to references to a number of dates, events and references to filed regulatory documents. FortisBC cannot verify the accuracy of the entire discussion, and will instead defer to the regulatory record.

Q9.2 Please provide all the supporting documentation referenced (e.g. DSM Advisory Committee notes), plus subsequent DSM Advisory Committee notes and all other relevant documentation.

A9.2 The requested documentation is provided as OEIA Attachment A9.2.

[14] Attached Appendix C, Sections 6.2, 6.3, 6.3.1, 6.3.2, Pages 22 to 28
[15] Attached Appendix C, Section 6.2, Pages 22 to 26

Meeting Attendees

Attending:
Sarah Khan, Public Interest Advocacy Centre
Richard Tarnoff, NRI, Hedley Improvement District
Buryl Goodman, South Okanagan
Katherine Muncaster, Ministry of Energy, Mines and Petroleum Resources (MEMPR)
Tony Roberts, BCUC Sr. Economist
Alison Richter, BCUC
Keith Veerman, PowerSense, FortisBC
Mark Warren, Customer Service, FortisBC

Preview of Semi-Annual Report to June 30, 2009 – Keith Veerman

- It was noted that the report will be filed by the end of the week.
- General thought was that the report was done well in terms of savings and cost.
- We have reached 120% of the YTD plan, for the first 6 months of the year.
- Residential savings was at 114% (end of June) of plan savings. It was noted that although the results were down slightly due to a drop in the Heat Pump program, it was still a strong program. planning is based on the kWh as opposed to the units sold
- General Service was at 135% (end of June) of its anticipated savings, which is largely attributed to the bigger projects that were recorded from the first half of the year.
- Industrial Services were at 88% (end of June) of its anticipated savings. They have some catching up to do, but they are doing well.
- Tony Roberts noted that Kelowna results were so much better than any of the other area's results. This is partly due to the presence of FortisBC and PowerSense, and is mostly due to a number of buildings going up; it's a bigger market and wealth of activity.
- It was noted that the PowerSense program and offers are available to all direct and indirect customers in our service area.
- The Program Costs were slightly under budget – 96% of the YTD plan. We have so far spent $1.75 million of the projected $1.8 million.
- Residential costs were overspent due to honoring prior commitments made to customers, i.e. carry over projects (i.e.: window rebates), and the delayed effective date of the provincial EnergyStar window regulation from January 2009 to April 2009.
- Industrial costs were under spent, which was largely attributed to certain fixed costs, the lumpy nature of industrial projects and 2 yr payback limitation on rebates
- Mark noted that the same effort is being made by the DSM reps in all regions. To some extent the under budget can be attributed to the recession - mills shut down or curtailing. The outlook for the companies and mills at this point is still not looking good.
- Summary Financial Results showed that we have strong numbers, and that we are paying for a number of audits through livesmart, etc. Even with the number of audits being done there is up to 18-month lag time between the initial audit and the retrofit work completion
- We have collaborated with Livesmart to continue to provide incentives to customers, which has resulted in more audits being done. There is typically a 75% completion rate i.e. of the recommended efficiency upgrades. In addition, the federal home renovation tax continues to motivate people to fix their homes.

- The financial results were presented in BCUC format – with a question as to why there were negative numbers in two of the programs re: customer incurred cost.
    - A large component of the New Home Program is the CFL packages we send to participants, which results in the customer not having to purchase lamps for the first 5+ yrs. The windows also contribute to this as we pay 100% of the incremental cost, if Energy Star qualified
- it was noted that the BC cabinet is scheduled to meet Nov 18th re: LiveSmart, and will likely extend their audit rebate until the end of March 2010. FortisBC will continue to match this until the end of the 2010 DSM budget year.
- The clothesline program, as spoken about in the May 20th meeting, brought up the need to discuss the opposition from the Stratas on hanging clothes outside. Fortis may approach the government to change this ruling, as Ontario has already done, through the provincial collaborative committee on which Mark participates
- We help promote a conservation culture to the general public to increase adoption of conservation behaviors. Social marketing approaches are more effective than either educational or paid commercial (advertising) approaches.

Summary of the Rate Design Application and Schedule 90 DSM Tariff – Mark Warren

- This application is to be filed by the end of the week. It is an overhaul of the tariff and the Company's rate schedules.
- The application meets the government directives, energy efficiency strategies. It is linked to a longer term Rate Design program and Power Sense programs.
- In order to fully understand the customer base, Mark spent time talking with customers, in the format of 2 large focus groups of 50 people each (in the Kootenays and Okanagan) and 7 public meetings.
- The revisions to the Power Sense Tariff allow for more flexibility to change the programs over the years. The current tariff is too specific focused to allow flexibility.
- An up-to-date listing of all programs, on the website, will allow customers see the different incentives they can look into
- The Rate Design Application deals with future time based rates. The rates change due to the time of the day or the time of the year which helps to make it more effective of a program than the tier rate program. It allows a customer to be more conscious of the energy they use at peak times.
- We are not currently in a position to promote time of use heavily or to make it mandatory. These meters require you to preprogram them ahead for all holidays and time changes, etc. To implement this program would require too much manual labor as we physically need to pull each meter, e.g. when the Daylight time schedule was changed
- We believe Time of Use is the future for this company and when we reapply for advanced metering, which enables this type of rate, we will discuss this more
- Residential Rates are going to be kept at a flat rate for now – we listened to our customers and this is what they were looking for.
- Inclined Block rates only have about a 1-2% difference in energy savings, and are punitive to customers who have electric heat, etc.

- Commercial Rates – Small General Service rates will stay at a flat rate to promote conservation, while Large General Service rates will move from a 3 tier to a 2 tier schedule. This will also be accommodated with an increase in the demand charges by 5% to promote demand changes for peak energy usage reduction.
- Industrial Rates: Primary customers will see an increase in the demand rates; Transmission/Wholesaler customers will see an intro of separate demand charges to cover costs of the transmission capacity available to them.
- The Tariff will go through approval process and any comments on this will be incorporated prior to a decision.
- One option with Rates is to cut customer charges, and raise the energy rate to stay revenue neutral regardless of how much power they are using.

DSM Study – Keith Veerman

- The 2011 plan will include a 10yr plan for DSM for 2011-2020.
- We have commissioned and created some residential and commercial surveys which customers have completed. From the survey's some details we noted were:
  - 38% use electric as their primary source of heating
    - Ongoing opportunity for heat pumps
  - Almost half have electric hot water tanks
    - possible a load control on Hot Water tanks
  - 18% have single pane windows
    - we can look at targeting this with a window program.
- We have commissioned a Conservation Potential Review (CPR), as BC Hydro did in 2007. We need this to determine the remaining DSM opportunities in our service area. The final report is due at the end of February
- There will be two foundations for the 2011 DSM plan – it will focus on both demand and conservation potential.
- The CPR consultants will put together different scenarios to look at the different DSM activity ramp-ups for the 2011 plan period, and beyond
- we will continue the residential CFL program, for specialty bulbs (3-way, dimmable etc.) until government regulations are put into place to mandate them
- we plan to consult on the 2011 DSM plan in the New Year to get public & stakeholder feedback on the various DSM scenarios

Co-Present at Annual Review

- Keith Veerman and David Mayes will co-present at the Annual Review.

Q9.3 OEIA suggested that a *"public report"* be produced on the *"Hedley Improvement District Project"*, and provide suggestions for details of that proposed report[16].

Q9.3.1 Please indicate whether or not such a *"public report"* has been produced. If so, please attach. If not, is one expected and what is the timeframe for release? If no report is expected, please explain why not?

A9.3.1 At this time, FortisBC has no plans to produce a public report due to the issues outlined in the response to OEIA IR No. 1 Q9.4.1.

Q9.4 At the 2009 BC Water & Waste Association (BCWWA) conference in Penticton April 25-29, 2009), Richard Tarnoff (Water System Operator) and Perry Fraser (FortisBC) reported that: "*it appears that Hedley can save up to 30% on its pumping power costs by going onto a TOU rate*"[17].

Q9.4.1 Please confirm the 30% savings in costs.

A9.4.1 The 30 percent theoretical savings have unfortunately not been achieved to date. FortisBC understands that the cost savings have not materialized as expected since the controls for the Hedley Improvement District Project have been twice been rendered inoperative by lightning strikes.

Q9.4.2 Please indicate the energy savings or shifting.

A9.4.2 Please refer to the response to OEIA IR No. 1 Q9.4.1.

Q9.4.3 Please provide slides and/or report presented at that conference.

A9.4.3 The requested slides are provided as OEIA Appendix A9.4.3.

[16] Attached Appendix C, Section 6.3, Pages 26 to 27
[17] Attached Appendix D, 11:00 – 11:35am, Hedley Load Shifting Pilot Project

Q9.5 Does FortisBC intend to continue the Hedley Improvement District Project?

A9.5 Unfortunately due to the high cost of repairing the pump controls after the lighting strikes, the HID has indicated they will withdraw from the TOU rate.

Q9.6 Does FortisBC intend to expand the program to include other districts? If so, please expand. If not, why not?

A9.6 The Company intends to promote the adoption of similar conservation measures to other water and improvement districts within the service area.

Q9.7 Does FortisBC intend to develop a time of use rate to accommodate such operations? If so, please explain. If not, why not?

A9.7 The existing General Service TOU rates will continue to be offered.

10.0) DSM Rates Project

OEIA suggested that a *"DSM Rates Project"* be initiated to *"support the DSM targets by conserving, shifting and reducing demand through rate structures"*[18].

Q10.1 Please indicate whether or not a *"DSM Rates Project"* or a similar project has been initiated. If so, please provide details. If not, please explain why such a project has not been initiated.

A10.1 As discussed in the response to OEIA IR No. 1 Q5.2.1, FortisBC has commissioned a study of AMI Future Programs that will include the predicted effect of time based rates. The Company believes that this study is the first step in achieving the objectives outlined by OEIA in the request for a "DSM Rates Project".

Q10.2 It is noted in the August 16, 2007 DSM Advisory Committee meeting that *"BC Hydro plans to meet their DSM targets with 1/3 from rates . . . "*[19].

Q10.2.1 Similarly, please indicate the percentage of DSM goals that FortisBC is planning to achieve from rates.

A10.2.1 Please refer to the response to OEIA IR No. 1 Q3.3.

Q10.2.2 Please identify for each year of the next 10 years the DSM targets from rates for FortisBC.

A10.2.1 Please refer to the response to OEIA IR No. 1 Q3.3.

[18] Attached Appendix C, Section 6.3.2, Pages 27 to 28
[19] Attached Appendix C, Section 6.2, Page 25

11.0) Basic Charge

FortisBC in its discussion in the RDA document decided not to change the Basic Charge for the Residential Rate[20].

Q11.1 In evaluating the possibility of lowering of the Basic Charge, FortisBC stated: *"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."*[21]

Q11.1.1 Please discuss the ramifications if a minimum bi-monthly bill is not implemented.

A11.1.1 If a minimum bill is not implemented the under-recovery of revenue required from low usage accounts will increase (in other words, the non-energy costs identified in the COSA will not be fully recovered). The under-recovery from these customers will be recovered through higher charges to other customers.

Q11.1.2 FortisBC suggests that the minimum bi-monthly amount be $32[22]. Please discuss how this number was arrived at, and the ramifications if the number is higher or lower.

A11.1.2 As stated in the Application (Exhibit B-1) $32 equates to approximately 250 kWh over two months. This low level of consumption is characteristic of an unoccupied building without electric heat and is more representative of the COSA-derived basic charge for residential rate.

[20] Exhibit B-1, Section 10.0, Pages 55 to 60
[21] Exhibit B-1, Section 10.1, Page 57, Lines 22 to 24
[22] Exhibit B-1, Section 10.1, Page 57, Line 25

Q11.2 A table is shown with varying Basic Charges and consequent kWh charges to maintain revenue neutrality[23].

Q11.2.1 Please add a column to the table showing the expected corresponding conservation in energy consumption for each row in the table (compared to the current Basic Charge).

A11.2.1 Assuming a price elasticity ratio of -0.1, and using the current bi-monthly charge as a baseline, the resulting change in consumption is shown in the table below.

Table OEIA A11.2.1

Basic Charge	kWh Charge	Consumption Impact
$0.00	$0.08692	-1.4%
$12.00	$0.08123	-0.7%
$24.26	$0.07627	0.0%
$32.00	$0.07177	0.6%
$50.00	$0.06325	1.7%
$59.31	$0.05884	2.3%

[23] **Exhibit B-1, Section 10.1, Table 10.1, Page 57, Line 17**

Q11.3 A chart shows comparisons of the monthly customer charge for utilities across Canada[24].

Q11.3.1 Please provide the numerical values for the chart.

A11.3.1 Please see Table OEIA A11.3.1 below.

Table OEIA A11.3.1

Customer Charge Comparison	
Utility	**Basic Monthly**
NS Power	$10.83
NF Power	$15.56
NB Power (urban)	$19.73
NB Power (rural)	$21.63
Hydro Quebec	$12.19
Manitoba (<= 200A)	$6.85
Manitoba (> 200A)	$13.70
Saskpower (urban)	$17.35
Saskpower (rural)	$24.60
BC Hydro	$3.79
FortisBC	$11.87

[24] **Exhibit B-1, Section 10.1, Figure 10.1b, Page 58, Line 5**

Q11.3.2 Please explain why there is such a difference between the FortisBC and BC Hydro basic charge.

A11.3.2 Ideally, the Basic or Customer Charge levied by any utility should be cost-based and designed to adequately recover the appropriate costs identified by a fully allocated cost of service study. In the cases of both FortisBC and BC Hydro, the residential basic charges do not fully recover the allocated cost on a per-customer basis.

As BC Hydro and FortisBC are distinct in their cost structure, the make-up and density of their customer base, and the geography of their service areas, as well as in the evolution of the basic charges as they exist today, it is reasonable to conclude that there would be variation in the amount of the respective basic charges.

Q11.4 Please provide any technical papers which discusses the impact of reduction of Basic Charges to the encouragement of conservation.

A11.4 FortisBC does not have any technical papers which discuss the impact of Basic Charges on conservation.

Q11.5 Please provide any technical papers or information which discusses customer attitudes toward reducing Basic Charges and increasing electric usage charges.

A11.5 FortisBC does not have any technical papers which discuss customer attitudes toward reducing Basic Charges and increasing electric usage charges.

Q11.6 FortisBC states in regards to the Basic Charge: *“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).”*[25]

Q11.6.1 Please confirm that the statistics supporting the statement above came from the chart in Appendix I, Page 87[26] in reaction to: *“It seems reasonable to recover more of the fixed costs by raising the basic customer charge”*

48% = 12% (strongly agree) + 36% (somewhat agree)

48% = 25% (somewhat disagree) + 23% (strongly disagree)

If not, please provide the underlying statistics to support the above statement.

A11.6.1 Confirmed.

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[25] Exhibit B-1, Section 10.1, Page 57, Lines 14 to 16
[26] Exhibit B-1, Appendix I, Page 87

Q11.6.1.1 Please confirm that the above statement in item 11.6 was based upon raising the basic customer charge and did not suggest lowering. If not, please indicate where the suggestion of lowering was used.

A11.6.1.1 This is not confirmed. The statement in Q11.6 was based on discussion of four rate design options with Super Group participants and included increasing, decreasing or maintaining the basic customer charge. The four rate design options were outlined in the PowerPoint presentation for the Super Group, as well as the Backgrounder and Discussion Guide provided to participants.

Copies of the PowerPoint slides, Backgrounder and Discussion Guide were provided in Appendix I (Exhibit B-1). Option 1 proposed a lower basic bi-monthly charge with higher energy rates (flat rate) and a minimum bill. Option 2 proposed inclining block rate with existing bi-monthly basic charge and higher energy rates. Option 3 proposed inclining block rate with higher basic bi-monthly charge and lower energy rates. Option 4 proposed maintaining existing rate with same basic bi-monthly approximately same energy rates (flat rate.).

Q11.6.1.2 Please confirm that the above statement in item 11.6 was based upon recovering more of the fixed cost, and did not include the encouragement of conservation.

A11.6.1.2 This is not confirmed. The statement in Q11.6 was based on evaluating four rate design options which included discussion of both fixed cost recovery and conservation goals. See Appendix I, page 50 and 51 (Exhibit B-1) for PowerPoint slides which identify both inclining block rate and reducing bi-monthly basic charge as rate designs which encourage conservation.

Q11.6.1.3 Please confirm that instead of the statement as indicated in item 11.6 it would be more accurate to state:

"In fact, there was an even split between those who thought the charge should be raised <u>to recover more of the fixed costs</u> and those who thought it should <u>not be raised</u> (48 percent each with 4 percent undecided)." **[changes highlighted]**

A11.6.1.3 Given the wording in the questionnaire, FortisBC believes that the restatement in the Information request above is reasonable.

Q11.6.1.4 Please comment on the accuracy of the data based upon the sample size.

A11.6.1.4 The margin of error for the sample sizes are shown in the table below.

Table OEIA A11.6.1.4

Kelowna and Castlegar	n=114	+/- 9.2%
Kelowna	n=56	+/- 13.1%
Castlegar	n=58	+/- 12.9%

These margins of error apply with 95 percent confidence (i.e. 19 times in 20).

Q11.6.1.5 Please confirm that all the comments noted on Page 87 in Appendix I support not raising the Basic Charge.

A11.6.1.5 For a full listing of comments, please see the response to OEIA IR No. 1 Q11.6.1.7 below. Reaction to the question was mixed in both the answer to the questions seen in the table in Appendix I, page 87 (Exhibit B-1) and in the comments provided in response to OEIA IR No.1 Q11.6.1.7. Comments ranged from non-support for raising the basic charge (“Fixed cost shouldn't change”) to mixed feelings (“To a degree, as long as reasonable”) to agreement (“Fixed cost recovery ensures continuity of services and helps stabilize rates”).

Q11.6.1.6 Please confirm that all the comments noted on Page 87 in Appendix I, were primarily addressing conservation, even though conservation was not prompted in the question.

A11.6.1.6 These comments address conservation. The four rate design options provided to participants for discussion included components of both conservation and fixed cost recovery. For a full listing of comments, please see the response to OEIA IT No. 1 Q11.6.1.7 below.

Q11.6.1.7 Please provide a complete listing of all comments received in response to this item.

A11.6.1.7 Provided in Table OEIA A11.6.1.7 below is the full listing of comments as provided to FortisBC by Environics on January 4, 2010.

Table OEIA A11.6.1.7

Fixed costs need fixed revenue but in this case attempts to conserve energy needs to be rewarded.
Only if the overall cost to FortisBC increases.
But lowering costs of gas.
Fixed cost shouldn't change.
Costs of the plant should be recovered from the product.
This might not be the answer.
Why?
If cost goes up percentage of use should be considered.
Basic rate should have no effect, you use, you pay.
Charging more should come from usage of power.
Don’t understand this question.
Rebalance to ensure users pay 100%.
This would keep bills down.
I just don't like having to pay more.
This seems fair.
Fixed /low income people try to conserve to lower their bills. Raise the customer charge makes it more difficult to pay bills.
Fixed costs are directly analogous to a basic charge so it seems 'fair'.
To a degree, as long as reasonable.
Basic customer charge does not encourage conservation.
No. Usage is more reasonable than higher charges.
Those who are higher users should cover costs.
The fixed cost should remain the same and incentives for lower usage should be rewarded.
A fairer policy is necessary.
Everyone share the initial cost of power to your home.
I like to have food to put on the table.
People won't like it, but all costs go up.
Should be done by consumption use.
Seems fair.
Fixed costs, everyone should pay.
Make the second block more expensive.
Not sure if you are talking about all customers or those involved in rebalancing.
Better to reward efficient energy use.
Nope-because my house would barely reach the minimum!!
I don't have enough information to answer these questions.
Makes sense.
Bills are already too high, but if fixed costs increase will lower power rate, then it's ok.
Fixed cost recovery ensures continuity of services and helps stabilize rates.
This would not allow customers the control to regulate their cost.

Table OEIA A11.6.1.7 cont'd

The charges should be more for how much you use.
Raising fixed costs does nothing to promote energy conservation = less power usage.
We are all responsible to help cover costs.
The statement is correct but it needs to be recovered over time so people can adjust.
Customers are always picking up the costs.
Fortis BC should demonstrate to the public and make known all their efforts to minimize fixed costs (ie incentive to use electronic bill instead of paper).
Why raise prices, low basic charge higher electricity costs.
Seems reasonable.
That will spread the costs on a more equitable base.
I think Fortis can be more efficient.
I don't want to pay more.
Only if really needed.
Not sure of difference between raising basic chg or changing rates of use as to which helps meet costs more.
This places the onus on the user to support it's supplier more directly.
I'm not sure how else you would do it.
As long as it is deducted from the bill.
You have investors and they are making money. Therefore I see this as a way for you to make a more money for them. Hydro is basic need, not luxury.
Even at the current base charge, fixed cost recovery is inevitable.
Fixed cost/fixed rates.
Raise fixed costs for higher users.
Providing kwh cost are reduced.
Because it will bring down the cost of the power used.
Until AMI is implemented so that customers would know when high rates would apply.
A slight increase would be acceptable.
Hit the people that have not been paying their share first.
Should depend on the amount of kwh used; residential should be a flat rate.
Better to charge more for usage to encourage energy saving.
I'm lukewarm on this issue. I basically think the user should pay in relation to consumption.
Does not promote conservation.
Perhaps we should be looking at ways to conserve energy which lower costs=lower revenue for a service that should be reduced to conserve energy.
The power co must be as stable as possible, so we can keep on taking it for granted :)
Logical.

Q11.7 Please discuss the 8 Bonbright principles[27] if the Basic Charges were reduced and electric usage charges increased.

A11.7 In its Rate Design, FortisBC used the paraphrasing of all the Bonbright Principles in the Application (at page 33) to provide balance when looking at available options. With respect to the Basic Charge, Principles 3 (concerning efficient use) and 8 (concerning revenue stability) are most relevant.

FortisBC recognizes that a reduction in the basic charge with a corresponding increase in consumption charges would reduce the revenue stability for the utility and may provide a conservation incentive to customers.

[27] **Exhibit B-1, Section 5.0, Pages 33 to 35**

12.0) Information supporting schedules

In the FortisBC 2009 RRA proceedings, Richard Tarnoff stated:

"By letter dated August 21, 2007, FortisBC applied to the Commission for approval for two new Time-of-Use rate schedules, 2A for residential customers and 22A for general service customers. By order no. G-115-07 the Commission approved the new rates on September 21, 2007. Please provide all studies used to develop the new schedules, including hourly demand tables and explain how the company determines what are 'peak periods'."[28]

FortisBC replied: *"FortisBC respectively declines to respond to this information request as it is out of the context of this proceeding."[29]*

Q12.1 Please provide all studies, including hourly demand tables used to develop the new schedules.

A12.1 The referenced rate schedules were not developed using technical studies, but are a blend of the FortisBC and Princeton Light and Power Time-of-Use rate schedules in effect at the time.

Q12.2 Please explain how FortisBC determines the peak periods (e.g. TOU periods).

A12.2 The original FortisBC peak periods were developed as detailed in the 1997 Rate Design and New Services Options Application attached as BCMEU Appendix A34.1 starting at page 15. FortisBC derived Schedule 2A and 22A peak periods based on the Princeton Light and Power Time of Use rates after confirming the on-peak periods were consistent with the existing FortisBC TOU rates and the system peak loads. Please also refer to the response to OEIA IR No. 1 Q12.1.

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[28] FortisBC 2009 RRA, Exhibit B-4, Richard Tarnoff IR#1, Item 2.0, Q2.1
[29] FortisBC 2009 RRA, Exhibit B-4, Richard Tarnoff IR#1, Item A2.1

Q12.3 Please discuss the effectiveness of the TOU rates and customer acceptance levels by varying the peak periods.

A12.3 All else being equal (including the ratio between on-peak and off-peak rates), shorter peak periods would generally be expected to increase customer acceptance since there is less exposure to on-peak rates. FortisBC does not have any information on the relationship between "effectiveness" of TOU rates and peak periods, but would expect its study, currently underway, and referenced in Exhibit B-1, Section 3.1, Page 24, Lines 13-28 to provide some insight into some aspects of "effectiveness".

13.0) Order directing TOU rates

In the 2009 RDA document, FortisBC reiterated Order G-115-07, which states, in part: "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."[30]

Q13.1 Please discuss how FortisBC meets or will meet the Order G-115-07 in which it is to implement Time-of-Use rates that apply to all customers.

A13.1 As discussed in the Application (Exhibit B-1, Section 14.1 page 72), FortisBC proposes that time-of-use rates will continue to be optionally available to all rate classes except lighting. Lighting customers are excluded since they are not metered.

[30] Exhibit B-1, Section 1.3, Page 6, Lines 7 to 9

14.0) Time-of-Use Schedules

In the 2009 RDA document, FortisBC discusses its Time-of-Use Schedules.

Q14.1 FortisBC states that: "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."[31]

Q14.1.1 Please estimate the costs to promote the time-based rates. Please include a range of promotional approaches - e.g. from basic information to full-blown intensive campaigns.

A14.1.1 FortisBC's wide-scale time based rate implementation strategy is based upon the implementation of AMI. As part of the AMI Application the Company anticipates it would include a summary of proposed promotional activities. As a point of clarification, FortisBC has not widely promoted its current time-based rates because of the costs related to maintaining the existing time-of-use metering technology.

Q14.1.2 Given that FortisBC is planning to implement time-based rates in the future, please discuss how promoting these existing rates may provide a foundation to build upon for the future time-of-use rates.

A14.1.2 Greater promotion of time-of-use rates using existing metering technology could be confusing to customers as there will likely be differences between current time-based rates and future time-based rates.

[31] Exhibit B-1, Section 14.1, Page 72, Lines 5 to 8

Q14.2 FortisBC states: *"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."*[32]**

Q14.2.1 Please explain why there is a scarcity of interval data?

A14.2.1 The meters deployed through the FortisBC service territory (aside from approximately 49 meters) are not capable of recording interval data.

Q14.2.2 Please explain how maintaining the current on-peak and off-peak differential ratios relates to a "points toward a greater on-peak off-peak differential" (e.g. the two items seem contradictory).

A14.2.2 The second point referenced in above in OEIA IR No. 1 Q14.2 would have been more complete had it been written as "The need to encourage the efficient use of electricity and reduction of demand points toward a greater on-peak off-peak differential than the COSA results indicated"

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[32] Exhibit B-1, Section 14.1, Page 72, Lines 10 to 20

Q14.2.3 Given that FortisBC is planning to implement time-based rates in the future, please discuss how promoting these existing TOU rates may provide a foundation to build upon for the future time-of-use rates.

A14.2.3 Please refer to the response to OEIA IR No. 1 Q14.1.2.

Q14.2.4 Please provide information indicating the satisfaction levels of the existing customers with the TOU rates.

A14.2.4 FortisBC has no information directly indicating the satisfaction levels of existing customers with the TOU rates.

Q14.2.5 Please discuss in detail the consultation process used to canvas and gather feedback from the existing TOU customers.

A14.2.5 TOU customers were involved in the consultation process in the same manner as other customers in the same rate category (Residential, General Service and Large General Service).

Q14.2.5.1 How many of the 150 TOU customers have been approached by FortisBC?

A14.2.5.1 The 10 customers affected by the proposed removal of rate schedules 2 and 22 were directly contacted.

Q14.3 FortisBC states the TOU rates *"have been adopted by approximately 150 residential, general service and Large General Service customers."*[33]

Q14.3.1 Why are there only 150 customers on TOU rates?

A14.3.1 FortisBC cannot speculate as to why approximately 150 customers have opted to take service under TOU rates, and not a higher or lower number.

Q14.3.2 What could be done to encourage a higher penetration rates of TOU rates?

A14.3.2 A variety of measures could encourage higher penetration of TOU rates, including:

- Providing real-time consumption information that would allow customers to take advantage of TOU rates; and
- Making TOU rates mandatory after the implementation of an Advanced Metering Infrastructure

Q14.3.3 Please describe in detail how the rate structures could be changed (e.g. in pricing or time periods) to encourage a higher penetration rate?

A14.3.3 FortisBC believes the best way to encourage a higher penetration rate is to make the rate mandatory. FortisBC intends to implement mandatory time based rates after the implementation of AMI.

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[33] Exhibit B-1, Section 14.1, Page 72, Lines 4 to 5

Q14.4 Please discuss the relevancy for FortisBC to maintain its time-of-use schedules (on-peak and off-peak hours) as in previous schedules, yet there have been *"significant changes"* since 1997. Has FortisBC re-evaluated the various aspects of the rate structures? If so, please discuss.

A14.4 The reasons for maintaining the existing time-of-use schedules are described in the Application in Section 14.1, p. 72, lines 10-20 (Exhibit B-1). FortisBC did not re-evaluate the various aspects of the rate structures, other than comparing them to the COSA-recommended levels (which is the second of the three reasons articulated in that section of the Application, as clarified in the response to OEIA IR No. 1 Q14.2.2).

15.0) RDA commitments from 2009 RRA

In the 2009 RDA document, FortisBC listed one of the resolutions of the 2009 RRA NSA (G-193-08) which states that *"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."*[34]

Q15.1 Please discuss how the RDA Application addresses the 2007 BC Energy Plan policy #4.

A15.1 Policy Action No. 4 from the 2007 BC Energy Plan states, "Explore with BC utilities new rate structures that encourage energy efficiency and conservation."

Please see the responses to OEIA IR No. 1 Q16.1 thru Q16.4.

Q15.2 Please discuss how the RDA Application has included general tariffs for customers to sell power back to FortisBC.

A15.2 Please refer to the response to BCUC IR No. 1 Q1.1.

[34] Exhibit B-1, Section 1.3, Page 7, Line 2

16.0) Rate Structures that encourage energy efficiency and conservation

In the RDA document, FortisBC provide a table summary of the proposed rate changes[35].

Q16.1 Please discuss how the drop in Energy Rate for all wholesale customers (e.g. Grand Forks 3.838 cents/kwh to 1.728 cents/kwh) supports the claim that *"the Company has proposed rate structures that encourage energy efficiency and conservation"*[36].

16.1 One of the challenges the Company faces in encouraging energy efficiency and conservation is that 26 percent of its load is being provided to wholesale utilities that are not regulated by the Commission and that make incremental profit on the sale of additional electricity. From that perspective, the wholesale utilities have an incentive to sell additional electricity, rather than to conserve energy. The first step in encouraging energy efficiency and conservation in this context is the acceptance of contract demand and rebalancing rates so that the wholesale utilities are paying their cost of service. The second step in encouraging energy efficiency and conservation would be to implement mandatory time based rates which will send appropriate price signals to the wholesale utilities that encourage conservation and reduce demand.

Table 2.3 in the Application provides a comparison of existing rates with those proposed as a result of the COSA and rate design summarized in Exhibit B-1. As noted in the Application, there are a number of factors to be considered which generally are captured by the Principles discussed in Section 5 of Exhibit B-1. While FortisBC has endeavored to balance these considerations in the design of rates, it is not possible in all cases that each will be fully

[35] Exhibit B-1, Section 2.3, Table 2.3, Page 15
[36] Exhibit B-1, Section 2.3, Page 14, Lines 9 to 10

reflected in the resulting individual billing components. In addition, the billing determinants must all be examined for their overall customer impact versus singling out only one component.

Q16.2 Please discuss how having Tier 2 (6.333 cents/kwh) lower than Tier 1 (8.571 cents/kwh) for General Service supports the claim that *"the Company has proposed rate structures that encourage energy efficiency and conservation"*[37].

A16.2 Table 2.3 in the Application provides a comparison of existing rates with those proposed as a result of the COSA and rate design summarized in Exhibit B-1. As noted in the Application, there are a number of factors to be considered which generally are captured by the Principles discussed in Section 5 of the Application (Exhibit B-1). While FortisBC has endeavored to balance these considerations in the design of rates, it is not possible in all cases that each will be fully reflected in the resulting billing components.

With respect to General Service rates, the reasons for maintaining a two step declining block are articulated in Section 11, page 64 and 65 of the Application (Exhibit B-1).

[37] **Exhibit B-1, Section 2.3, Page 14, Lines 9 to 10**

Q16.3 Please discuss how reducing the Energy Rate for Large General Service (Primary: from 4.539 cents/kwh to 4.383 cents/kwh; Transmission: from 3.993 cents/kwh to 3.938 cents/kwh) supports the claim that *"the Company has proposed rate structures that encourage energy efficiency and conservation"*[38].

A16.3 Table 2.3 in the Application provides a comparison of existing rates with those proposed as a result of the COSA and rate design summarized in Exhibit B-1. As noted in the Application, there are a number of factors to be considered which generally are captured by the Principles discussed in Section 5 of Exhibit B-1. While FortisBC has endeavored to balance these considerations in the design of rates, it is not possible in all cases that each will be fully reflected in the resulting billing components.

The Energy Rate applicable to the Large General Service – Primary is set in consideration of the Demand Charge which reflects an amount closer to its COSA derived level and a small increase over the previous amount in recognition of FortisBC's desire to reduce peak demand.

[38] Exhibit B-1, Section 2.3, Page 14, Lines 9 to 10

Q16.4 Please discuss how maintaining the Energy Charge at 7.627 cents/kwh for Residential and with no other changes supports the claim that *"the Company has proposed rate structures that encourage energy efficiency and conservation"*[39].

A16.4 Table 2.3 in the Application provides a comparison of existing rates with those proposed as a result of the COSA and rate design summarized in Exhibit B-1. As noted in the Application, there are a number of factors to be considered which generally are captured by the principles discussed in Section 5 of Exhibit B-1. While FortisBC has endeavored to balance these considerations in the design of rates, it is not possible in all cases that each will be fully reflected in the resulting billing components.

The COSA-derived amount for the residential Basic Charge is more than double what the proposed rate has been set at in the Application. Were the Principle of cost causation strictly adhered to in the rate design, the Basic Charge would have been considerably higher and the Energy Rate considerably lower; both arguably disincentives to conservation. In recognition of this fact, and of the opinions expressed during consultation, FortisBC chose to leave the residential rate structure unchanged. It is anticipated that a more fully developed conservation strategy with respect to residential rates will emerge when the ability to provide wide-scale time-based rates is practicable.

[39] **Exhibit B-1, Section 2.3, Page 14, Lines 9 to 10**

17.0) Cost of Service Analysis

In the RDA document, FortisBC provided a Cost of Service Analysis (COSA)[40].

Q17.1 Please discuss why the Transmission Demand charge of Schedule 2.2 is so large for Wholesale customers - for example, $105.06/kw for Grand Forks[41]. Please identify all the costs that add up to the $105.06.

A17.1 Schedule 2.2 provides the rate base per customer class rather than the revenue requirements or demand charge per customer class. This reflects the installed capital cost for transmission rather than the annual operating costs for the facilities. The results of Schedule 2.2 are not used for setting rates and are for comparison purposes only.

Q17.2 Please discuss how the Customer Demand values in Schedule 8.2 are used for Wholesale customers in the subsequent calculations - for example, show how for Grand Forks, the 85,072 kW for Coincident Peak[42], 273,240 kW for Contract Demand Limit[43], and 273,240 kW for Max Demand[44] values are then used in subsequent calculations (to the final results).

A17.2 The Coincident Peak value for each month is used to develop the allocation factor for power supply costs that occur in each month, as shown in Schedule 6.3. The higher of the Contract Demand Limit and the Coincident Peak results in the Max Demand Value. The data from the Max Demand Value is then used to generate the 2CP allocator used for transmission costs, as shown in Schedule 6.4 (Exhibit B-1).

[40] Exhibit B-1, Appendix A
[41] Exhibit B-1, Appendix A, Schedule 2.2, Page 1 of 1
[42] Exhibit B-1, Appendix A, Schedule 8.2, Page 3
[43] Exhibit B-1, Appendix A, Schedule 8.2, Page 3
[44] Exhibit B-1, Appendix A, Schedule 8.2, Page 3

Q17.3 Please identify the differences between pages 3 and 4 of Schedule 8.2; or are they unintentional duplicates?

A17.3 Page 4 of 4 of Schedule 8.2 is an unintentional duplicate. Please also refer to Errata No. 2.

Q17.4 FortisBC states in the COSA in regards to transmission and distribution systems for Wholesale and large General Service:

> ***"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."***[45]

> ***"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."***[46]

Q17.4.1 Please explain how allocation on contractual demand promotes efficiency and conservation.

A17.4.1 Please refer to the response to BCMEU IR No. 1 Q49.1.

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[45] **Exhibit B-1, Appendix A, Page 32**
[46] **Exhibit B-1, Appendix A, Page 32**

Q17.4.2 Do FortisBC customers have a choice on the level contractual demand is provided?

A17.4.2 Contractual demand levels form part of the terms of the agreements negotiated by the Company and certain customers. Historically, in most cases, contract demand levels have reflected installed capacity, which has been implemented after customer consultation. All but one of the contracts between the municipal wholesale utilities and FortisBC are expiring shortly and FortisBC has made efforts to enter into renegotiations and allow all of the wholesale utilities to restate their contract demand nominations prior to filing the COSA, the results of which would have been incorporated into the final filed COSA. FortisBC is willing to renegotiate the contracts with the wholesale utilities and industrial transmission, incorporating their desired contractual demands with appropriate terms.

Q17.4.3 Does FortisBC decide on the level of surplus? If so, what mechanisms are in place to limit the level of surpluses. If not, how is the level of surplus decided?

A17.4.3 The mechanisms that are in place to limit the level of surpluses are the Company's prudent utility planning practice, the BC Utilities Commission Approval process and the proposed cost allocation methodology using contract demand which will encourage the wholesale and industrial transmission customers to only nominate the capacity reservations that they require.

Q17.4.4 Please clarify if FortisBC believes that the promotion of efficiency and conservation is accomplished through reflecting the true costs of facilities to serve them? Please explain.

A17.4.4 Please see the response to OEIA IR No. 1 Q17.4.1. If costs are not allocated in consideration of the principle of cost-causation and reasonably foreseeable conditions, there is no incentive for customers to demand only reasonable levels of service. FortisBC believes that this could lead to the inefficient use of resources.

Q17.4.5 Please describe how a Wholesale customer will be encouraged to conserve if it is charged to the level of contract demand.

A17.4.5 Please refer to the responses to OEIA IR No. 1 Q17.4.1 and Q17.4.4.

Q17.4.6 Please re-run the COSA calculations using actual demand versus contractual demand.

A17.4.6 Please see the response to BCUC IR No. 1 Q79.1.

A3 ALPHA® Meter

The A3 ALPHA Meter

Elster's A3 ALPHA meter builds upon the strengths of existing ALPHA meter designs. Like its predecessors, the A3 ALPHA meter uses Elster's patented digital measurement techniques that offer high accuracy, repeatability, and low ownership costs. In support of open architecture standards, the A3 ALPHA meter is the first Elster meter with full ANSI C12.18, C12.19 and C12.21 communication protocol support. Other features include advanced four quadrant metering, transformer and line loss compensation, and interval data recording of instrumentation values.

Interval Data Recording and Self Reads

The main circuit board in the A3 ALPHA meter has more than 40 KB of nonvolatile memory for storing profile, data logs, and self read data. Recording options include interval profiles of instrumentation data and up to 15 self reads. Additionally, an extended memory option board can be easily added to increase total memory by 1 MB.

When the optional instrumentation profiling is enabled, the A3 ALPHA meter stores two separate sets of instrumentation data. Each data set has an independent interval length and up to 16 channels (32 total). With instrumentation profiling, each meter becomes a powerful data collection tool to monitor data and diagnose problems without installing expensive temporary monitoring equipment. One of over 50 instrumentation quantities can be assigned to each channel, and the storage algorithm for each channel can be independently selected. Four storage algorithms are available:

- minimum value per interval
- maximum value per interval
- average value per interval
- end of interval snapshot

Instrumentation

Each A3 ALPHA meter, including the most basic demand version, can display over 50 different instrumentation quantities. With this highly integrated capability, the A3 ALPHA meter can provide the equivalent function of all of the following devices:

- voltmeter
- wattmeter
- VA meter
- distortion indicator
- ammeter
- VAR meter
- phase angle meter
- phase rotation indicator

Revenue Metering

The A3 ALPHA meter is a very accurate revenue meter (0.2 accuracy Class). Existing ALPHA meter users will find the basic A3 ALPHA meter types familiar. The A3 ALPHA meter provides advanced four quadrant revenue functions, transformer and line loss compensation, and increased data profiling without adding hardware option boards.

Meter type	No. of measured quantities
A3D	1 (Watthours only)
A3T	1 (Watthours only)
A3Q, A3K, A3R	2 (user configurable selections)
A3QA, A3KA, A3RA	6 (user configurable selections)

Each measured quantity is stored in nonvolatile memory and includes energy, demand, and TOU data. Note. TOU data is not available for A3D.

Power Quality Monitoring

Power quality monitoring (PQM) provides continuous service condition monitoring 24 hours a day. PQM looks for exceptions to user-defined thresholds for items such as voltage, current, and total harmonic distortion. Each of the 12 PQM tests can be configured to control relay activation, LCD warning, date/time stamp log entry, and even an automatic telephone call to report the condition.

ANSI Communications Protocols

As the industry moves to the ANSI communications protocols, more system/communications options will become available, enabling A3 ALPHA meter users to benefit from a more competitive environment for data collection and analysis. The A3 ALPHA meter provides full support for ANSI C12.18, C12.19 and C12.21 communications protocols and data structures to prepare you for the future.

A Communication Enabler

Data can be retrieved using the standard optical communications port. Additional communications interfaces are available for A3 ALPHA meters as a simple add-on option board:

- 2400 bps internal telephone modem with outage reporting capabilities
- RS-232
- RS-485
- external serial interface
- 20 mA current loop
- internal LAN controller (ILC1)
- internal LAN node (ILN1)
- Itron 50ESS ERT®

Communications interfaces can be combined with alarming options in the A3 ALPHA meter to permit immediate notification of critical events.

The relay option boards of all existing ALPHA meters are compatible with the A3 ALPHA meter. When relay option boards are used with the A3 ALPHA meter, the relay functions are fully programmable.

Optional AnyPhase™ Power Supply

With the optional AnyPhase power supply installed, the A3 ALPHA meter is powered from all wires of the electrical service. If one or more service wires are disconnected, the meter is automatically powered from any two service wires including line-to-line or line-to-neutral.

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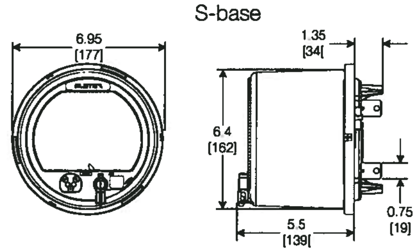
A3 ALPHA Specifications and Technical Data

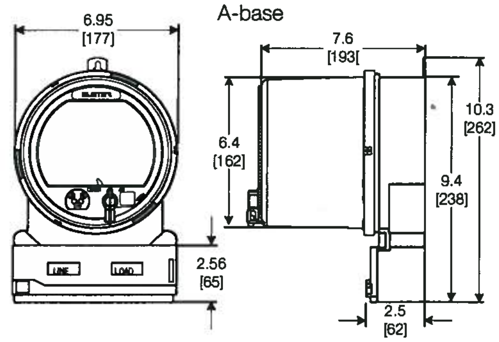
OEIA Appendix A8.1.1

Absolute Maximums		
Voltage	Continuous 528 VAC (AnyPhase option: L-L or L-N)	
Surge voltage withstand	*ANSI C37.90.1 Oscillatory*	2.5 kV, 2500 strikes
	Fast transient	5 kV, 2500 strikes
	ANSI C62.41	6 kV at 1.2/50 µs, 10 strikes
	IEC 61000-4-4	4 kV, 2.5 kHz repetitive burst for 1 minute
	ANSI C12.1 insulation	2.5 kV, 60 Hz for 1 minute
Current	Continuous at Class amperes Temporary (1 second) at 200 % of meter max. current	
Operating Ranges		
Voltage	*Nameplate nominal range*	120 V to 480 V
	Operating range	96 V to 528 V
Current	0 to Class amperes	
Frequency	Nominal 50 Hz or 60 Hz ±5 %	
Temperature range	-40 °C to +85 °C inside meter cover	
Humidity range	0 % to 100 % noncondensing	
Operating Characteristics		
Power supply burden	Less than 4 W	
Per phase current burden	0.1 milliohms typical at 25 °C	
Per phase voltage burden	*120 V*	0.008 W
	240 V	0.03 W
	480 V	0.04 W
Accuracy	Meets ANSI C12.20 accuracy for accuracy class 0.2 %	
General Performance Characteristics		
Starting current	*Form 1S and Form 3S*	10 mA for Class 20 100 mA for Class 200 160 mA for Class 320
	All other forms	5 mA for Class 20 50 mA for Class 200 80 mA for Class 320
Creep 0.000A (no current)	No more than one pulse measured per quantity, conforming to ANSI C12.1 requirements	
Primary time base	Power line frequency (50 Hz or 60 Hz), with selectable crystal oscillator	
Secondary time base	Meets the ANSI limit of 0.02 % using the 32.768 kHz crystal. Initial performance is expected to be equal to or better than ±55 seconds per month at room temperature	
Outage carryover capacity	6 hours at 25 °C. Supercapacitor rated at 0.1 Farads, 5.5 V	
Battery (optional)	$LiSOCl_2$ battery rated 1000 mAhr, 3.6 V and shelf life of 20+ years. 5 years continuous duty at 25 °C	
Communications rate	*Optical port*	300 to 28,800 bps
	Remote port	1200 to 19,200 bps
ANSI Standards	C12.1; C12.10; C12.18; C12.19; C12.20; C12.21	
Shipping Weights *All values are approximate*		
S-base	*Single*	5.06 lbs [2.30 kg]
	4-pack	13.46 lbs [6.11 kg]
A-base	*Single*	7.38 lbs [3.35 kg]
	4-pack	26.02 lbs [11.82 kg]

S-base



A-base



Dimensions in inches [millimeters]. For reference only. Do not use in construction.

ALPHA Plus® meter

As a 240 volt, single phase meter or a reactive meter with service validation, PQM, load profile, and communications– ALPHA Plus means powerful metering.

Elster's ALPHA Plus meter is a powerful meter that builds on the patented ALPHA® metering technology. The ALPHA Plus meter can be a single phase, 240 volt, one-rate demand meter or a polyphase, wide voltage supply, multi-rate, real/reactive meter that validates meter service connections automatically, performs power quality monitoring, and provides load profile reading with remote communication.

Load profile and event logs

The main circuit board has 28 KB of memory available to record load profile and data logs. A sample of the quantity of load profile with 15-minute intervals:

Channels	Max. days stored
1 channel	141 days*
4 channels	36 days*

*Number of days may be fewer depending on the number of event log entries.

Load profile data is stored in nonvolatile memory. Whe load profile is enabled, the ALPHA Plus meter records date and time stamps for power failures, test mode entries, time changes, and demand resets. With power quality monitoring enabled, the meter also includes date and time stamps of PQM events (including voltage sags).

Power quality monitoring

With PQM enabled, the meter searches for exceptions to user-defined thresholds for voltage, current, power factor, total harmonic distortion, and other items. The meter performs PQM tests 24 hours a day.

System service tests

System service tests are performed to check the validity of the electrical service as wired to the meter. The ALPHA Plus meter verifies the service type, phase rotation, and validity of phase voltages. The ALPHA Plus meter also determines if phase currents are within a user-defined threshold.

Revenue metering

A1K+ and A1R+ meters measure, store, and display a full set of energy and demand values for both real/apparent and real/reactive quantities, respectively. These meters provide two complete blocks of TOU data. The TOU rate is supported by separate fractional energy registers.

The A1R+ meter offers vectorial kVA values as a metered quantity choice. Average PF can be displayed when kW and kVA are selected as metered quantities.

Technology to empower utilities

Instrumentation

Instrumentation values provide near instantaneous analysis of the electrical service. All quantities can be programmed to display on the LCD in the normal or alternate display sequence:

- per phase values for:
  - voltage and current
  - voltage and current phase angles (compared to phase A)
  - current phase angle as measured to same-phase voltage
  - power factor and power factor angle
  - kW, kVAR, and kVA
  - THD for voltage and current
- system frequency
- system kW, kVAR, kVA, power factor, and power factor angle

Maximum voltage	Continuous at maximum of operating range	
Maximum current	Continuous at Class amperes; temporary (1 second) at 200 % of meter maximum current	
Surge voltage withstand	ANSI C37.90.1 oscillatory	2.5 kV, 2500 strikes
	ANSI C37.90.1 fast transient	5 kV, 2500 strikes
	ANSI C62.41	6 kV at 1.2/50 µs, 10 strikes
	IEC 61000-4-4	4 kV, 2.5 kHz repetitive burst for 1 minute
	ANSI C12.1 Insulation	2.5 kV, 60 Hz for 1 minute
Voltage range	Nameplate nominal range	Operating range
	120 V to 480 V	96 V to 528 V
	63 V to 240 V*	54 V to 264 V*
	Dedicated 240 V	192 V to 264 V
Current range	0 to Class amperes	
Frequency range	Nominal 50 Hz or 60 Hz ± 5 %	
Temperature range	-40 °C to +85 °C inside the meter cover	
Humidity range	0 % to 100 % noncondensing	
Power supply burden	Less than 3 W	
Per phase current burden	0.1 milliohms typical at 25 °C	
Per phase voltage burden	0.008 W at 120 V; 0.03 W at 240 V; 0.04 W at 480 V	
Accuracy	Power supply 120 V to 480 V 120 V to 240 V Dedicated 240 V	ANSI C12.20 accuracy Meets accuracy Class 0.2 %
	63 V to 240 V*	Meets accuracy Class 0.5 %
Starting current	Forms 1S and 3S	10 mA for Class 20 100 mA for Class 200 160 mA for Class 320
	All other forms	5 mA for Class 20 50 mA for Class 200 80 mA for Class 320
Primary time base	Power line frequency (50 Hz or 60 Hz) with selectable crystal oscillator	
Secondary time base	Meets the ANSI limit of 0.02 % using the 32.768 kHz crystal. Initial performance is expected to be equal to or better than ±55 seconds per month at room temperature.	
Outage carryover capacity	6 hours at 25 °C. Super capacitor rated at 0.1 Farads, 5.5 V.	
Communication rates	Optical port: 9600 bps (nominal); Remote port: 1200 to 19,200 bps	
S-base shipping weights	Single	5.5 lbs (2.5 kg), approximate
	4 pack	15.5 lbs (7 kg), approximate
A-base shipping weights	Single	7.5 lbs (3.4 kg), approximate
	4 pack	26 lbs (11.8 kg), approximate

*Not available on meters with CPS power supply

See the ALPHA Plus Meter Technical Manual for complete specifications

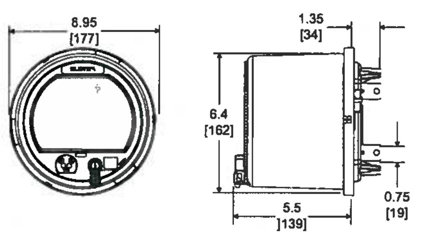
Communications

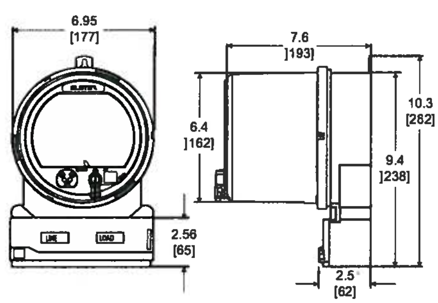
Data can be retrieved using the standard optical port. By adding an option board, other communication interfaces are available, including the following:

- 2400 bps internal telephone modem with outage callback
- RS-232 serial interface
- RS-485 serial interface
- 20 mA current loop
- external serial interface

About Elster Group

A world leader in advanced metering infrastructure, integrated metering, and utilization solutions to the gas, electricity and water industries, Elster's systems and solutions reflect over 170 years of knowledge and experience in measuring precious resources and energy. Elster provides solutions and advanced technologies to help utilities more easily, efficiently, and reliably obtain and use advanced metering intelligence to improve customer service, enhance operational efficiency, and increase revenues. Elster's AMI solutions enable utilities to cost-effectively generate, deliver, manage and conserve the life-essential resources of gas, electricity and water. Elster has 7500 staff and operations in 38 countries in North and South America, Europe, and Asia.





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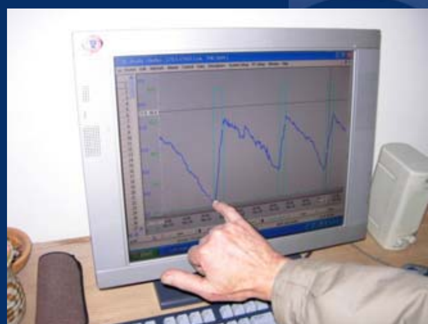
20080201

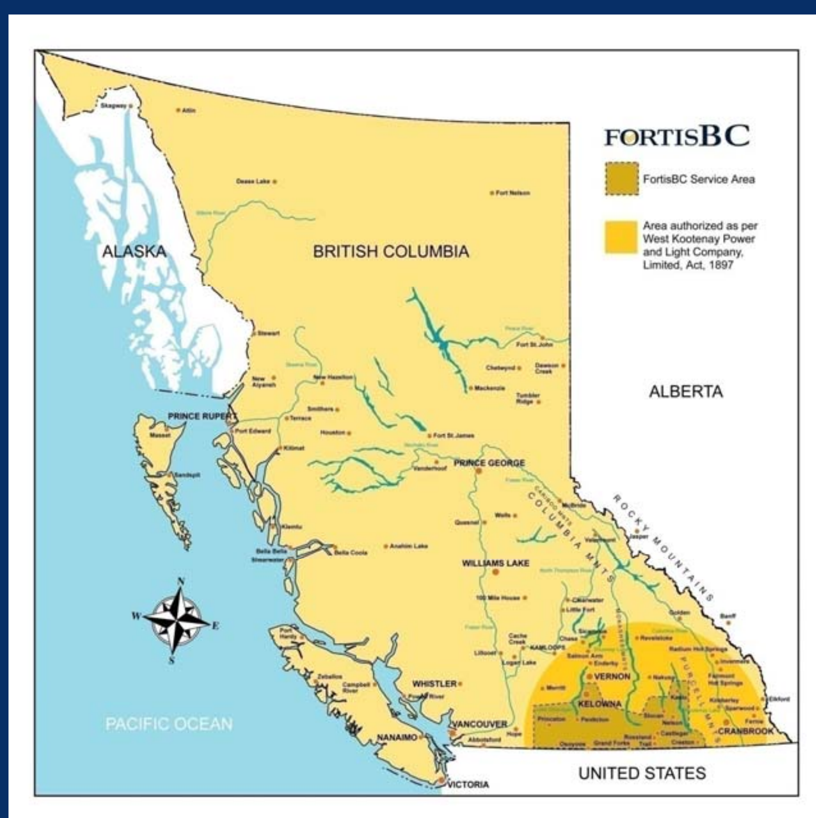
Hedley Load Shifting Project



Perry Feser, FortisBC
perry.feser@fortisbc.com

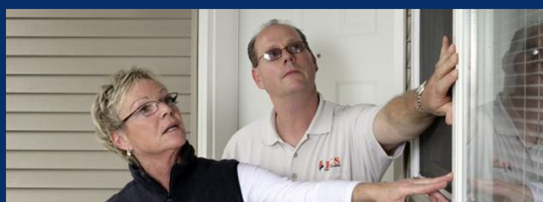
Richard Tarnoff, Hedley Improvement District
otootski@gmail.com

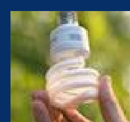
FortisBC Service Area

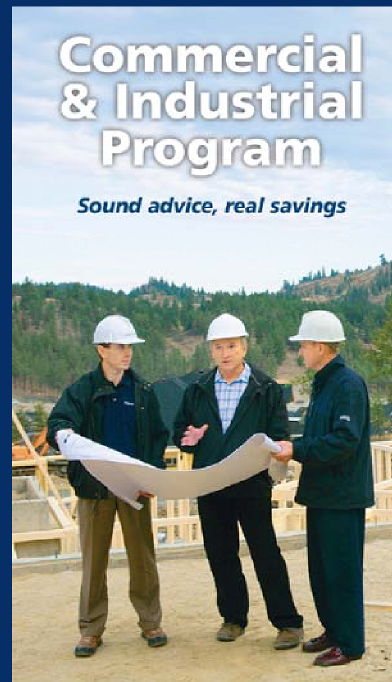


FortisBC Energy Efficiency Programs

- **Advice and financial incentives to carry out energy efficiency upgrades**







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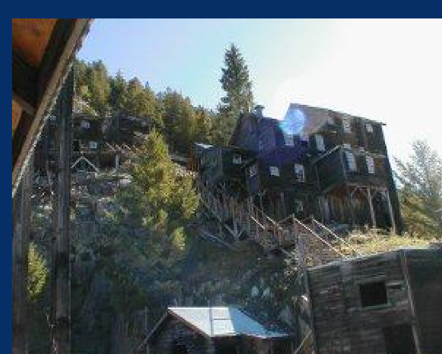
Hedley Improvement District



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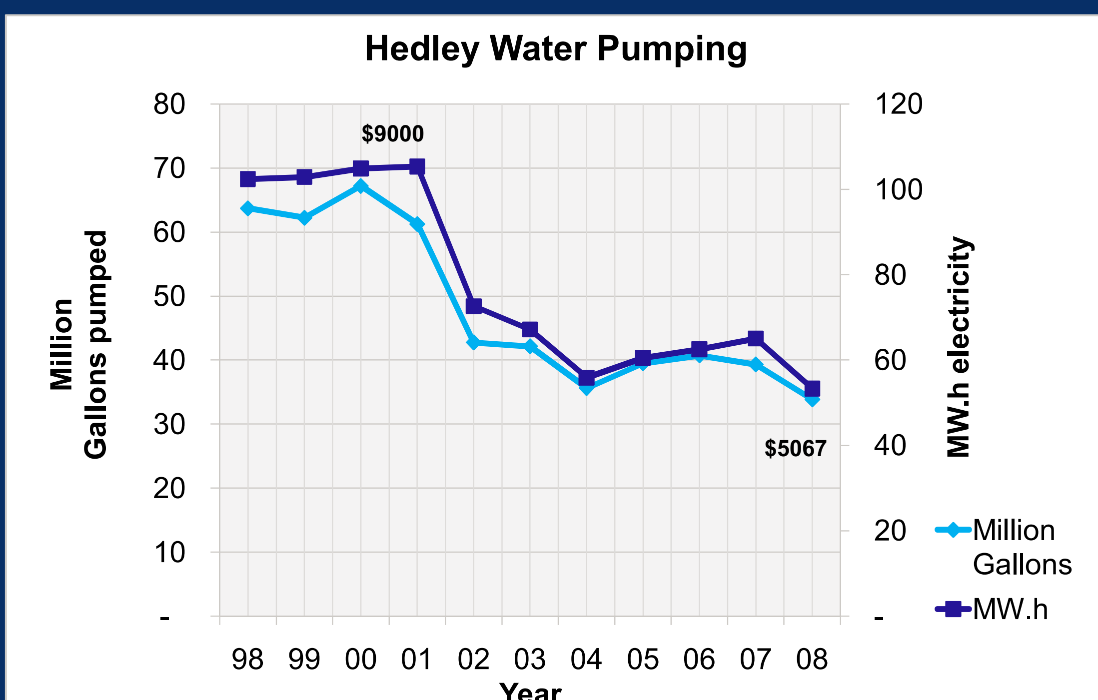
Energy and Water Efficiency Upgrades

- Energy audit
- Pumping study and upgrade
- Water leakage survey and repairs
- Building improvements
- Street lighting

5

Results



6

Electrical Demand Peaks

- **Daily**
- **Weekly**
- **Seasonal**

7

FortisBC GS21 TOU Rate

SCHEDULE 22 A – GENERAL 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 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
Summer (July, August)	On-Peak Hours: 9:00 am - 11:00 am Monday-Friday 3:00 pm – 11:00 pm Monday-Friday	13.117
	Off-Peak Hours: 11:00 pm - 9:00 am Monday-Friday 11:00 am – 3:00pm Monday-Friday All hours on Saturday and Sunday	4.250
All other months	On-Peak Hours: 8:00 am - 1:00 pm Monday-Friday 5:00 pm - 10:00 pm Monday-Friday	13.117
	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	4.250

A

plus:

CUSTOMER CHARGE: $14.30 per month A

8

FortisBC GS21 Rate

SCHEDULE 21 - GENERAL 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:

$7.05 per kW of "Billing Demand" above 40 kW A

plus

An Energy Charge of:

First	8000 kW.h	8.507¢ per kW.h	A
Next	92000 kW.h	6.459¢ per kW.h	
Balance		4.795¢ per kW.h	

plus

BASIC CHARGE: $14.30 per month A

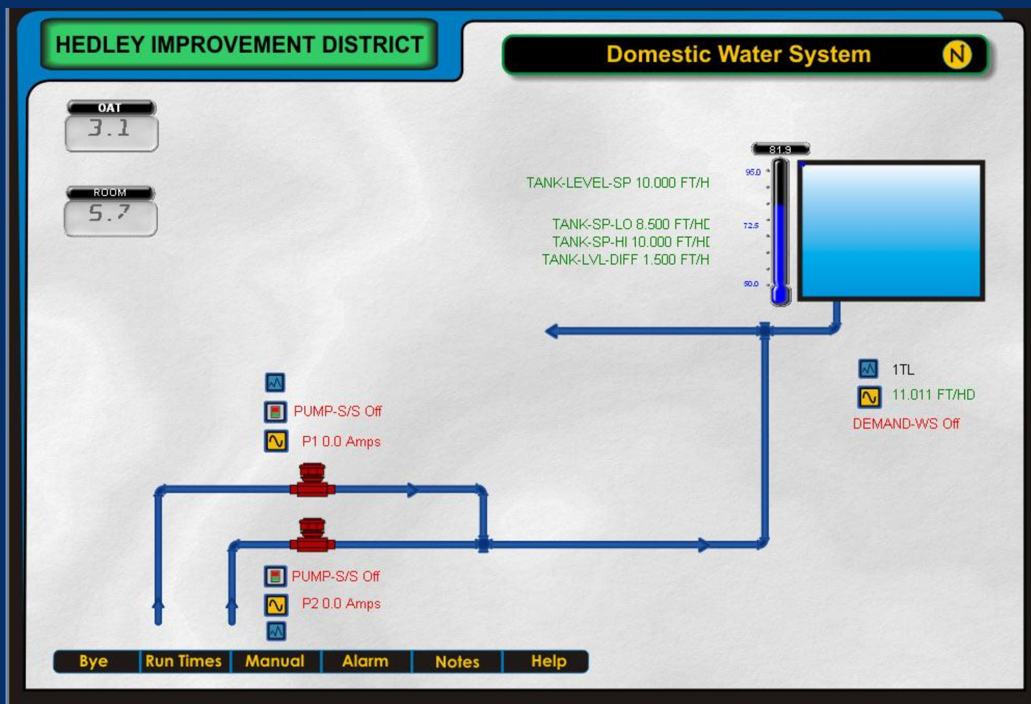
9

Hedley Pumping System TOU Pilot Project

- Opportunity to further reduce pumping cost

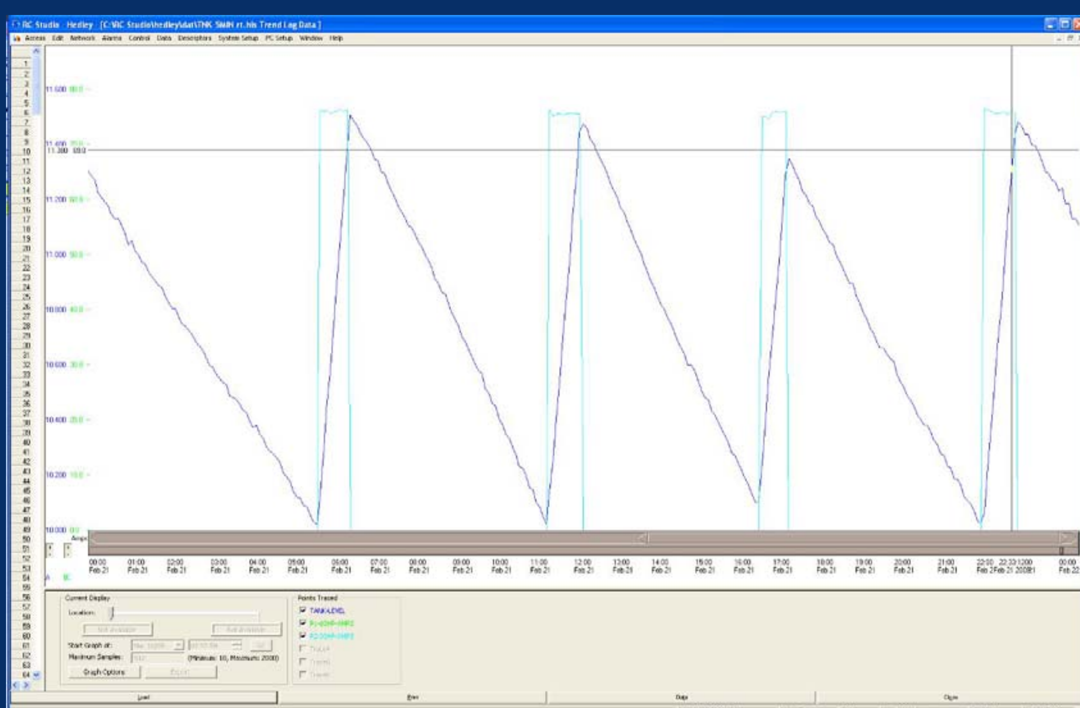
10

Pumping Controls Upgrade



11

Winter Operation



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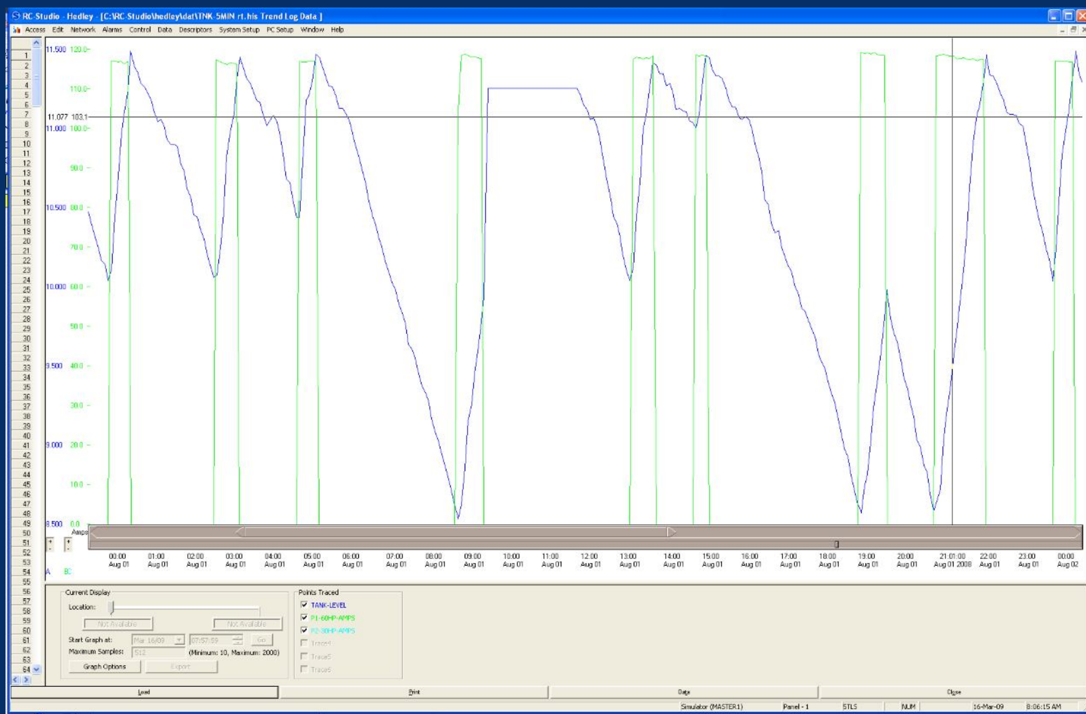
Summer Operation



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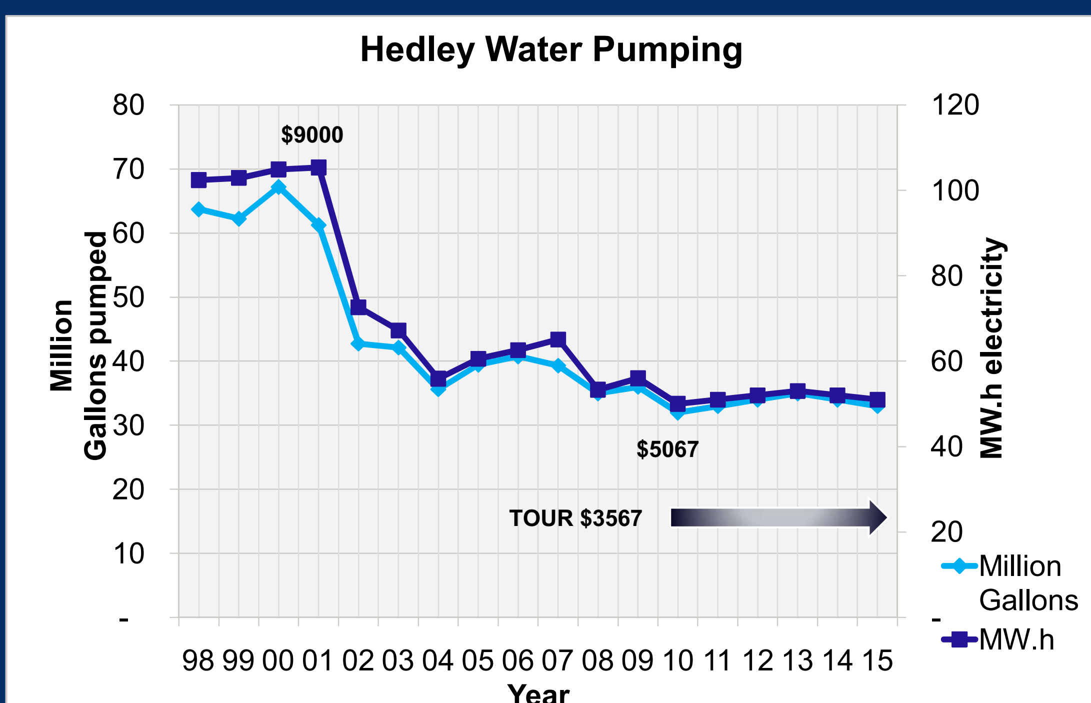
Results



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FORTISBC
Hedley
Questions?

Q1. In respect of each of the rate classes listed in Table 7.0 - 2009 Revenue to Costs Ratios contained in the erratum filed December 14, 2004, please advise as follows:

Q1(a) What is the total demand and consumption for each of the rate classes for the year that was analysed for the cost of service analysis contained in the 2009 FortisBC Rate Design Application;

A1(a) The demand and energy by class used for the 2009 COSA can be found in Schedules 8.1 and 8.2 of Appendix A of the EES Study which is attached as Appendix A to the Application (Exhibit B-1).

Q1(b) Please explain the various variables at play (and their interplay and significance) that have resulted in the Large General Service Transmission (31) rate class having a revenue to cost ratio of 109.9%;

A1(b) The Rate 31 class shows a revenue to cost ratio above 100 percent. In the 1997 COSA the class had a revenue to cost ratio of 125.3 percent, which was adjusted to 112.8 percent after rate rebalancing. Since that time, FortisBC has applied across the board rate increases to all of its customer classes to reflect increases in its revenue requirements. In 1997 Rate 31 and Rate 33 were both in the same rate class, but the 2009 COSA separates Rate 33 from Rate 31. As a result of separating the two rate classes, the COSA shows the revenue to cost ratio for Rate 33 to be significantly below 100 percent while for Rate 31 it is above 100 percent.

Q1(c) Please explain the various variables at play (and their interplay and significance) that have resulted in the Large General Service Transmission TOU (33) rate class having a revenue to cost ratio of 23.5%;

A1(c) The revenue to cost ratio for Rate 33 is significantly below 100 percent because the current rate has no demand charge and the wires costs are only charged in the on-peak periods. This allows customers on this rate to avoid the majority of wires costs by generating power during the on-peak periods, while at the same time FortisBC must be ready and able to meet the full load of the customer in all hours, with facilities in place to serve that load if called upon.

(d) Please explain the various variables at play (and their interplay and significance) that have resulted in the Kelowna Wholesale, Penticton Wholesale, Summerland Wholesale and Grand Forks Wholesale rate classes having revenue to cost ratio of 89.9%, 78%, 96.6% and 68.1% respectively;

A1(d) The most significant variable in the 2009 COSA is the contractual demand methodology that uses contract demands contained in industrial and wholesale contracts as a means to allocate costs of the wires system to various customer classes, which is a change from the 1997 COSA study. Because the wholesale utilities listed have contract demand levels above their current loads, they have been assigned higher costs in this COSA than in the past. This change to contract demands reflects that FortisBC has build facilities to serve the contract loads and must consider these contract amounts in system planning.

Q2. Please provide us with the total demand and consumption for Roxul Inc. (Grand Forks) for the previous five years; and

A2. Roxul Inc. (Grand Forks) demand and consumption for the previous 5 years is shown in Table A2 below:

Table Roxul A2

Read Date	Amount	Usage (KWH)	Billed Demand (kVA)
12/14/2009	253,977.55	4,448,850	8,392
11/16/2009	285,397.25	5,149,200	8,390
10/14/2009	263,023.35	4,668,300	8,261
09/14/2009	246,972.50	4,405,800	8,049
08/14/2009	204,798.11	3,469,200	8,280
07/15/2009	195,222.81	3,290,700	7,993
06/15/2009	149,347.54	2,244,900	8,001
05/14/2009	232,142.59	4,149,600	7,860
04/16/2009	273,627.99	5,086,200	7,919
03/13/2009	238,986.90	4,259,850	8,192
02/13/2009	241,687.03	4,516,050	6,775
01/15/2009	269,081.62	5,111,400	8,138
	2009 Total	**50,800,050**	**96,250**
12/11/2008	228,081.60	4,277,700	8,003
11/13/2008	258,304.63	5,027,400	7,787
10/14/2008	136,268.12	2,137,800	7,659
09/12/2008	219,842.98	4,121,250	7,713
08/14/2008	228,609.38	4,319,700	7,789
07/14/2008	235,506.10	4,481,400	7,808
06/12/2008	59,611.61	1,117,200	7,858
06/04/2008	169,414.90	2,845,500	8,255
04/30/2008	251,086.53	4,853,100	8,152
03/31/2008	232,736.95	4,387,950	8,331
02/28/2008	250,976.75	4,806,900	8,469
01/31/2008	250,318.87	4,797,450	8,423
	2008 Total	**47,173,350**	**96,247**

1 **Table Roxul A2 cont'd**

Read Date	Amount	Usage (KWH)	Billed Demand (kVA)
12/31/2007	217,476.89	4,168,500	8,354
11/30/2007	247,738.48	4,860,450	8,366
10/31/2007	240,101.18	4,689,300	8,251
09/30/2007	184,997.74	3,347,400	8,196
08/31/2007	248,363.65	4,933,950	8,100
07/31/2007	207,940.47	3,918,600	8,259
06/30/2007	248,145.51	4,906,650	8,259
05/31/2007	258,985.60	5,127,150	8,593
04/30/2007	150,893.30	2,553,600	7,991
03/31/2007	234,101.48	4,686,150	8,228
02/28/2007	247,859.64	5,152,350	7,348
01/31/2007	219,749.75	4,331,250	8,190
	2007 Total	**52,675,350**	**98,135**
12/31/2006	188,948.49	3,643,500	7,991
11/30/2006	169,653.38	3,129,000	8,169
10/31/2006	253,381.25	5,271,000	8,054
09/30/2006	159,735.32	2,919,000	7,865
08/31/2006	127,953.02	2,110,500	7,875
07/31/2006	245,168.18	5,061,000	8,064
06/30/2006	184,311.88	3,507,000	8,127
05/31/2006	253,141.39	5,197,500	8,138
04/30/2006	218,376.18	4,347,000	7,959
03/31/2006	254,056.22	5,271,000	7,770
02/28/2006	216,430.01	4,273,500	8,138
01/31/2006	202,154.89	3,937,500	8,033
	2006 Total	**48,667,500**	**96,180**
12/30/2005	201,521.53	4,210,500	8,043
11/30/2005	199,883.19	4,200,000	7,802
10/31/2005	224,778.75	4,840,500	7,970
09/30/2005	193,024.02	4,021,500	7,770
08/31/2005	210,835.50	4,515,000	7,634
07/29/2005	184,504.61	3,780,000	7,875
06/30/2005	182,504.55	3,706,500	8,022
05/31/2005	196,316.58	4,074,000	7,917
04/30/2005	190,266.16	3,906,000	7,970
03/31/2005	179,598.40	3,622,500	7,970
02/28/2005	142,458.79	2,635,500	7,970
01/31/2005	167,304.06	3,265,500	8,190
	2005 Total	**46,777,500**	**95,130**

Q3. Please provide us with the total demand and consumption for Grand Forks Wholesale for the previous five years.

A3. Grand Forks Wholesale demand and consumption for the previous 5 years is shown in Table A3 below:

Table Roxul A3

Read Date	Amount	Usage (KWH)	Billed Demand (kVA)
11/30/2009	199,567.00	3,588,800	6,764
10/31/2009	190,540.02	3,364,800	6,764
09/30/2009	175,913.27	2,865,600	7,001
08/31/2009	183,350.56	3,126,400	7,124
07/31/2009	184,581.50	3,158,400	7,120
06/30/2009	168,410.31	2,817,600	6,764
05/31/2009	170,365.91	2,867,200	6,764
04/30/2009	175,728.05	3,003,200	6,764
03/31/2009	208,117.33	3,737,600	7,211
02/28/2009	211,064.01	3,817,600	7,184
01/31/2009	248,833.39	4,580,800	8,183
	2009 Total	**36,928,000**	**77,644**
12/31/2008	247,779.19	4,680,000	9,019
11/30/2008	191,955.25	3,601,600	6,954
10/31/2008	176,544.85	3,284,800	6,482
09/30/2008	155,334.73	2,792,000	6,124
08/31/2008	175,504.95	3,076,800	7,408
07/31/2008	174,468.14	3,136,000	6,963
06/30/2008	156,216.89	2,798,400	6,211
05/31/2008	159,858.76	2,912,000	6,124
04/30/2008	170,390.37	3,192,000	6,306
03/31/2008	189,291.04	3,635,200	6,625
02/28/2008	202,363.02	3,830,400	7,417
01/31/2008	234,742.42	4,550,400	8,165
	2008 Total	**41,489,600**	**83,798**

1 **Table Roxul A3 cont'd**

Read Date	Amount	Usage (KWH)	Billed Demand (kVA)
12/31/2007	221,238.49	4,428,800	7,819
11/30/2007	195,914.60	3,825,600	7,339
10/31/2007	171,176.45	3,281,600	6,410
09/30/2007	155,264.55	2,848,000	6,410
08/31/2007	163,073.72	3,060,800	6,410
07/31/2007	178,220.72	3,358,400	7,001
06/30/2007	151,389.33	2,742,400	6,410
05/31/2007	154,198.74	2,864,000	6,410
04/30/2007	156,840.94	2,936,000	6,410
03/31/2007	169,219.23	3,352,000	6,503
02/28/2007	192,472.32	3,800,000	7,525
01/31/2007	227,423.99	4,619,200	8,312
	2007 Total	**41,116,800**	**82,956**
12/31/2006	217,357.20	4,464,000	8,044
11/30/2006	197,411.44	3,804,800	8,546
10/31/2006	161,760.56	3,185,600	6,570
09/30/2006	149,314.13	2,835,200	6,570
08/31/2006	157,782.25	3,073,600	6,570
07/31/2006	170,990.77	3,332,800	7,149
06/30/2006	150,433.82	2,849,600	6,658
05/31/2006	153,375.84	2,908,800	6,570
04/30/2006	155,096.75	2,956,800	6,570
03/31/2006	177,640.63	3,585,600	6,570
02/28/2006	183,613.42	3,664,000	7,023
01/31/2006	192,865.66	3,955,200	6,901
	2006 Total	**40,616,000**	**83,741**
12/30/2005	218,091.66	4,646,400	8,760
11/30/2005	174,823.30	3,681,600	7,151
10/31/2005	148,928.04	3,104,000	6,189
09/30/2005	138,365.34	2,792,000	6,189
08/31/2005	149,256.40	3,088,000	6,321
07/29/2005	145,786.31	3,011,200	6,189
06/30/2005	148,494.70	3,091,200	6,189
05/31/2005	139,600.41	2,816,000	6,189
04/30/2005	143,022.91	2,916,800	6,189
03/31/2005	159,836.66	3,412,000	6,189
02/28/2005	167,413.52	3,566,400	6,542
01/31/2005	206,699.66	4,390,400	8,252
	2005 Total	**40,516,000**	**80,349**

2

1. Residential customers in the BC Hydro Lardeau Wholesale service area paid 12.93 cents per day as a Basic Charge between July 3 and September 3, 2008, and 12.64 cents between September 1 and October 30 in 2009. In contrast, using the same calculation as applied by BC Hydro, I, as a residential customer of FortisBC, paid 36.4 cents per day between December 8, 2008 and February 10, 2009 and 39.1 cents between October 8 and December 9, 2009 as a Basic Customer Charge.

This represents a 2.2% decline in BC Hydro's residential Basic Charge, and 8.1% and 6.8% of the total bill respectively, whereas FortisBC's Basic Customer Charge increased by 7.4% and represents 31.3% and 30% respectively of my total bill. Thus FortisBC's residential Basic Customer Charge is now 309% higher than BC Hydro's residential Basic Charge in Area D of the Regional District Central Kootenay.

Q1. What was the basic differential between BC Hydro's residential Basic Charge and the then West Kootenay Power Basic Customer Charge when I first moved to Kaslo in 1987?

A1. The FortisBC bi-monthly customer charge as at May 1, 1987 was $11.09. FortisBC has been unable to confirm the equivalent BC Hydro amount in effect in 1987.

2. Figure 10.1b: "Basic Charges at select Canadian Utilities", page 58, 2009 Fortis BC Rate Design Application, illustrates the basic charge differential described above, except that there is no mention that BC Hydro's Basic Charge is declining. Further I note, for example, that no Alberta or Ontario electrical power utilities are listed in Figure 10.1b.

Q2. Can FortisBC please provide a list of Canadian electrical power utilities who have lowered or eliminated their basic charge over the last 22 years?

A2. FortisBC could find no published source of the requested information.

Q3. Can FortisBC please show what a 10.1b chart would look like if they chose these electrical power utilities, who have either lowered or eliminated their basic charge, rather than the ones originally chosen to present on page 58?

A3. Please refer to the response to Shadrack IR No. 1 Q2.

2. At a November 5, 2009 General Affairs Committee meeting of the Regional District Central Kootenay, in Nelson, Fortis BC made a presentation of their May 29, 2009 Resource Plan in which they state at 1.6 Transmission, page 6, lines 20 to 24:

From a transmission planning perspective, FortisBC's service territory consists of two distinct regions: the Okanagan region and the West Kootenay region. The West Kootenay region can be considered as a "generation-surplus" region with no requirement for reliability or capacity driven reinforcement within the planning period of this 2009 Resource Plan. By contrast, the Okanagan region faces both reliability and capacity constraints within the planning period of this 2009 Resource Plan.

Earlier at 1.2 "Capacity and Supply/Demand Gaps" page 2, lines 9 to 15, and page 3, lines 1 to 7, FortisBC describes how 74% of the winter peak is met from its four hydroelectric generating plants and long term power purchase agreements with BC Hydro and the Brilliant Power Corporation (Columbia Power Corporation and Columbia Basin Trust). It also notes that the current 18 GWh annual shortfall will grow to 131 GWh by 2028.

Q4. Given that FortisBC has previously reported that it is able to generate power along the Kootenay River cheaper than it can purchase it under various contracts and on the spot market, what is the cost differential of supplying residential power in the West Kootenay versus supplying residential power in the Okanagan?

A4 Any analysis on the relative costs of serving customers based on location should be based on sound cost causation principles, and as this analysis was not completed as part of the filed COSA study, FortisBC believes that any conclusions drawn in this regard would be speculative. From a principle perspective, FortisBC is not proposing or supportive of moving away from postage stamp rates to regional rates at this time.

Q5. What is the cost differential of supplying power to Nelson Wholesale versus the four Boundary and Okanagan municipal "Wholesales"?

A5. The cost to serve each of the municipalities is determined for the COSA and is summarized from Appendix A to the Application, Schedule 1.1 as follows:

Allocated Revenue Requirement (Forecast Year 2009)				
Kelowna	Penticton	Summerland	Grand Forks	Nelson
$18,272,621	$24,781,094	$5,761,237	$3,396,442	$7,093,496

Q6. What would happen to FortisBC's cost profit ratio if it dropped one or more of the five municipal "Wholesale" contracts and/or its contract with Celgar?

A6 There would be no impact to FortisBC's profit from the loss of any or all of the wholesale customers. FortisBC's profit is based on the allowed return on the equity component of rate base. However, the exit of any municipal utility would in some scenarios result in a general rate decrease for the rest of FortisBC's customers.

4. At Appendix I - Public Consultation Report, page 13, FortisBC states: *"Kelowna participants were more likely to have larger homes than those from Castlegar"* and on page 14 continues on to state: *"Castlegar participants were more likely to use wood to heat their homes while Kelowna participants were more likely to have central air."*

Q7. If FortisBC were to divide its service area into two "distinct regions" as described in the 2009 Resource Plan (above), and further subdivide those "distinct regions" into summer and winter consumption patterns, what would the respective quintiles look like, in terms of consumption patterns, for the Okanagan and West Kootenay?

A7 As a percent of 2009 forecast monthly loads by distinct region, the Okanagan and West Kootenay region winter loads are forecast to be in higher quintiles than summer.

Table Shadrack A7a

Region	Season	Month	Quintile
Okanagan	Winter	January	1
	Winter	December	2
Okanagan	Summer	July	4
	Summer	August	4
West Kootenay	Winter	January	1
	Winter	December	2
West Kootenay	Summer	July	4
	Summer	August	5

Table Shadrack A7b – Percent of 2009 Region Forecast

Okanagan			West Kootenay			Winter & Summer Forecast % of Load		
Month	%	Quintile Frequency	Month	%	Quintile Frequency		Okanagan	West Kootenay
1	10.4%	10.4%	1	11.0%	11.0%			
12	9.6%	9.6%	12	10.4%	9.7%	Winter	8.0%	8.8%
2	9.1%	8.8%	2	9.9%	8.4%		7.9%	8.6%
3	8.8%	7.9%	3	9.6%	7.1%	Summer	9.6%	6.5%
11	8.7%	7.1%	11	8.8%	5.8%		10.4%	5.8%
8	8.1%		4	8.6%				
10	8.0%		5	8.6%				
7	7.9%		10	7.1%				
4	7.6%		9	7.0%				
9	7.5%		6	6.8%				
6	7.3%		7	6.5%				
5	7.1%		8	5.8%				

Q8. Is the emerging, so called, double peak of winter and summer more noticeable in the Okanagan than in the West Kootenay?

A8 The emerging double peak is equally noticeable in both the Okanagan and Kootenay Regions.

Also at page 14 in Appendix I FortisBC further states:

"Participants in Castlegar had a greater propensity to report that their electricity bill has a noticeable impact on their household finances"

Q9. In relation to question 7 above, and the observation directly above, which "distinct region" has the higher average residential per household electrical consumption, the Okanagan or the West Kootenay?

A9 The average residential customer in the West Kootenays used 13,525 kWh in 2009, compared to the Okanagan residential average of 13,506 kWh, a difference of 0.1 percent.

Project No. 3698564: Rate Design and Cost of Service
Requestor Name: Alan Wait
Information Request No: 1
To: FortisBC
Request Date: December 18, 2009
Response Date: January 18, 2010

Q1. Is FortisBC maintaining the postage stamp principle for charging customers throughout its system with this COSA? Is this postage stamp principle mandated by the BCUC?

A1. The Rate Design Application that is filed in conjunction with the COSA does not propose any deviation from the current postage stamp system of rates. The postage stamp system has not been mandated by the BCUC.

Q2. Please provide copies of the current large commercial and municipal wholesale rate schedules.

A2. The requested rate schedules are provided as Wait Appendix A2.

Q3. Please explain any differences between large commercial customers and municipal wholesale customers in the way they require services from FortisBC.

A3. The municipal utilities operate equipment and facilities that produce and generate, in the case of City of Nelson, and deliver and sell electricity, in the case of all, to the public. These activities would fall within the definition of "public utility" in the Utilities Commission Act and would be regulated but for a specific exemption for municipalities. Therefore municipal wholesale utilities fundamentally differ from all end-use customers, including large commercial customers.

Wholesale municipal utilities have the following characteristics that further differentiate them from all other customer classes, including large commercial customers:

- The ability to resell electricity in a monopoly environment and recover their revenue requirements (and can set their own rate of return);
- Access to multiple points of supply with totalized demand billing;
- Availability of DSM services to indirect customers;
- Higher degree of supply certainty; and
- Growth related upgrade costs entirely borne (subsidized) by all customers in general;

Q4. What are the reasons for changing the Demand Charge from 75% to 100% for the largest customers in Schedules 31 and 40?

A4. The minimum charge as applied to demand in the current and proposed schedules are not directly comparable. The rate applied to the 75 percent Contract Demand in FortisBC's current Electric Tariff is billed at the combined wires and power supply rate, whereas the 100 percent Contract Demand in the proposed Tariff is billed at the wires charge rate only.

Q5. Please explain the parameters and provide the calculations that show the Grand Forks Wholesale 2009 Revenue to Cost Ratio is 68.1%.

A5. The derivation of the 68.1% Revenue to Cost Ratio is found in Appendix A to the Application, Schedule 1.1 (Exhibit B-1). The ratio is comprised of the total expected revenues from the customer at current rates, divided by the total allocated cost to serve as determined by the cost of service study. A further breakdown of the costs can be found at Schedule 3.3 of the Appendix, while total revenues are found in Schedule 7.1. The calculations show:

Revenues / Costs $2,311,992 / $3,396,442 = 68.1%

Q6. Why are the Time of Use rates set with such high cost power during peak times and so low at off peak hours rather than a more moderate difference?

A6. The intent of the differential is to incent conservation, it is not necessarily cost based. The differential is intended to discourage consumption during peak periods.

Q7. Has FortisBC studied the residential 'time of use patterns' to design a tariff that would start out relatively revenue neutral?

A7. The FortisBC residential Time of Use rate was originally designed to be revenue neutral. The Company did not study residential Time of Use patterns as part of this Application.

Q8. What would be the cost difference expected if a residential customer changed from Schedule 1 to Schedule 2A with no change of use pattern?

A8. As indicated in the response to Wait IR No. 1 Q7, the Schedule 2A rates were designed to be revenue neutral to Schedule 1. Therefore, the “average” customer switching from Schedule 1 to Schedule 2A would expect no change in their bill over the course of a year if they did not change their consumption in response to the higher marginal cost during the on-peak hours. A customer using 10 percent more than average on-peak and 10 percent less off-peak would see an increase of approximately 4.2 percent over the Schedule 1 cost. For a customer with the approximate average bi-monthly consumption of 2,000 kWh, this would mean an increase of $6.41 per bill. A customer using 10 percent less on-peak and 10 percent more off-peak would see a decrease of approximately 4.8 percent over the Schedule 1 cost, a reduction of $7.32 per bill.

Q9. What would be the equivalent cost per kwh for electric base board heaters compared to an 80% efficient natural gas furnace operating on $9.75 per qiqajoule gas (present cost to residential customers)?

A9. The fuel cost equivalent of $9.75 per gigajoule at 80 percent efficiency is equivalent to $0.044 per kWh, compared to electric heat at $0.076 per kWh assuming 100 percent conversion.

The above comparison omits the cost of the monthly natural gas customer charge of $11.84 which if included would increase the equivalent cost to $0.054 per kWh.

Q10. Please provide a graph showing the hourly consumption for each the summer and the winter peak days and two days each side of the peak day.

A10. The requested information is provided below as Figure Wait A10a (summer peak load) and Figure Wait A10b (winter peak load).

Figure Wait A10a – 2009 Summer Peak Load

Summer Peak (July 22, 2009)

Hour	MW
1	300
2	282
3	270
4	265
5	257
6	264
7	310
8	367
9	415
10	450
11	477
12	496
13	513
14	527
15	541
16	556
17	560
18	561
19	547
20	531
21	499
22	484
23	436
24	380

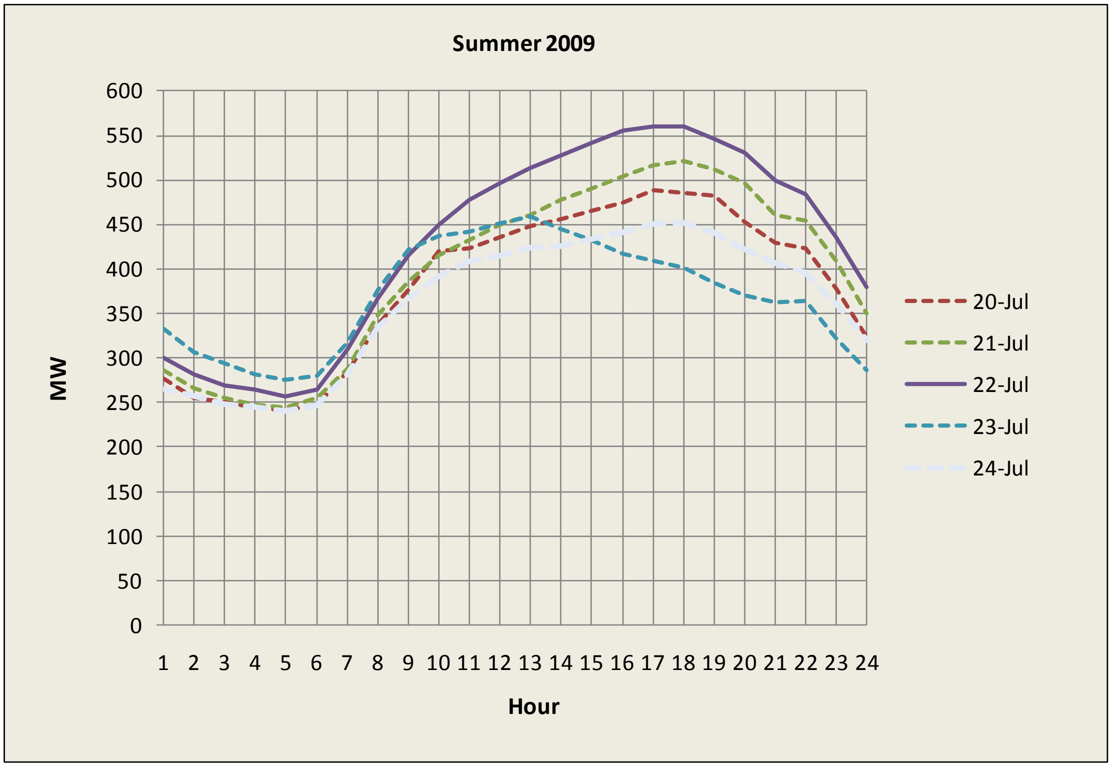
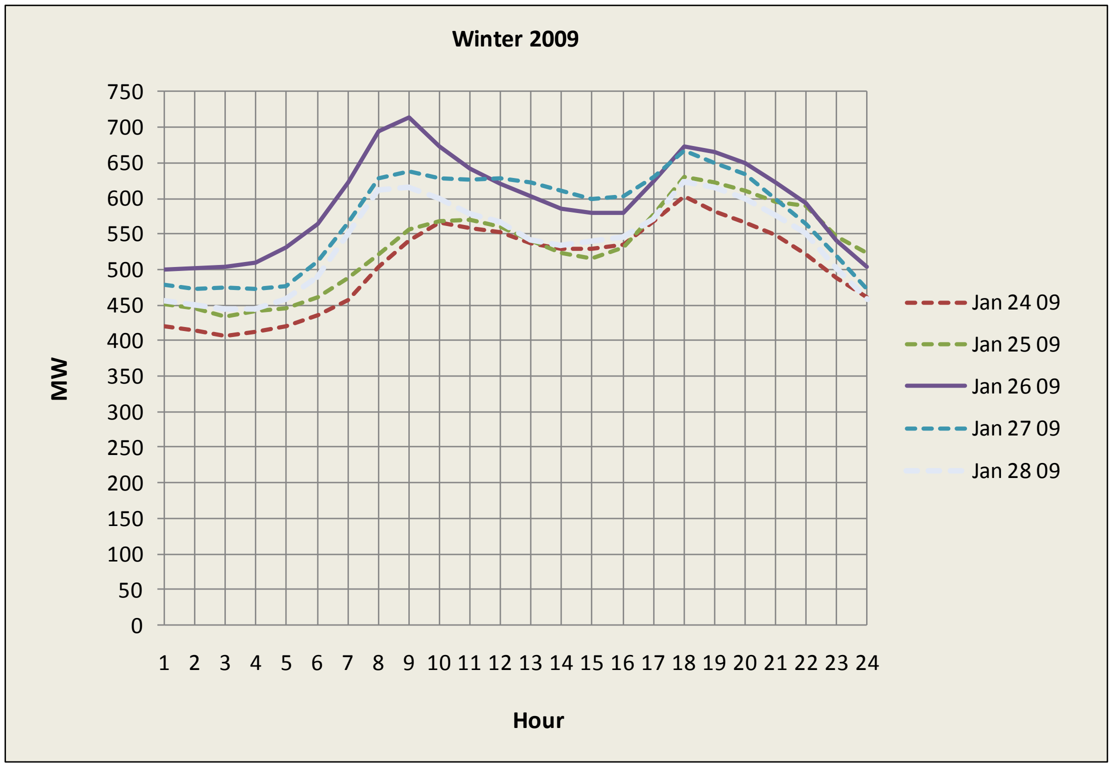


Figure Wait A10b – 2009 Winter Peak Load

Winter Peak (January 26, 2009)

Hour	MW
1	500
2	501
3	503
4	510
5	531
6	565
7	623
8	695
9	714
10	673
11	642
12	621
13	603
14	586
15	580
16	580
17	625
18	674
19	665
20	649
21	622
22	593
23	540
24	504



Q11. At what point does each of the Municipal Electrics receive power, transmission voltage? or distribution voltage at the transformer or off distribution lines?

A11. Please refer to response to BCMEU IR No. 1 Q4.1.

SCHEDULE 30 - LARGE GENERAL SERVICE - PRIMARY

APPLICABLE: To power service to Customers for a contract demand of 500 kVA or more, subject to written agreement.

MONTHLY RATE: A Customer Charge of $793.65

plus: A Demand Charge of $7.20 per kVA of Billing Demand A

plus: An Energy Charge of 4.811¢ per kW.h

plus

"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.

Issued December 23, 2009
FORTISBC INC.

By: David Bennett
Vice President, Regulatory & General Counsel

Accepted for filing
BRITISH COLUMBIA UTILITIES COMMISSION

By:
Commission Secretary

EFFECTIVE (applicable to consumption on and after) January 1, 2010 Orders G-158-09 & G-162-09

SCHEDULE 30 - LARGE GENERAL 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 68.3¢ 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. A

(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.

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FORTISBC INC.

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Vice President, Regulatory & General Counsel

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SCHEDULE 31 - LARGE GENERAL 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 Customer Charge of $2,380.99

plus: A Demand Charge of $5.82 per kVA of Billing Demand A

plus: An Energy Charge of 4.233¢ per kW.h

"Billing Demand"

The greatest of:

(a) 80% of the Contract Demand, or
(b) The maximum demand in kVA for the current billing month; or
(c) 80% 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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FORTISBC INC.

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SCHEDULE 32 - LARGE GENERAL 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 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	19.044
	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	3.883
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	18.282
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	3.021
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	4.386
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	2.311

A

plus:

CUSTOMER CHARGE: $1,875.43 per month A

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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FORTISBC INC. BRITISH COLUMBIA UTILITIES COMMISSION

By: David Bennett By: ____________
Vice President, Regulatory & General Counsel Commission Secretary

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SCHEDULE 33 - LARGE GENERAL 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 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	13.427	
	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	3.804	
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	17.911	A
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	2.960	
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	4.297	
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	2.263	

plus:

CUSTOMER CHARGE: $2,189.09 per month A

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 - WHOLESALE SERVICE - PRIMARY

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

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

MONTHLY RATE: A Customer Charge of $1,832.82 per Point of Delivery

plus: A Demand Charge of $7.93 per kVA of Billing Demand A

plus: An Energy Charge of 4.068¢ 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.

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 Customer Charge of $4,189.36

plus: A Demand Charge of $4.71 per kVA of Billing Demand A

plus: An Energy Charge of 4.006¢ 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.

SCHEDULE 42 - WHOLESALE SERVICE - PRIMARY -TIME OF USE

APPLICABLE: To power service to Grand Forks, Kelowna, Penticton, Princeton, Summerland, Lardeau and Yahk. To service 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 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	16.926
	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	3.451
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	16.250
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	2.686
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	3.899
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	2.052

A

plus:

CUSTOMER CHARGE: $1,832.82 per month per Point of Delivery A

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.

Issued December 23, 2009
FORTISBC INC.

By: David Bennett
Vice President, Regulatory & General Counsel

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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 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	11.719
	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	3.321
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	15.633
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	2.581
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	3.750
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	1.976

A

plus:

CUSTOMER CHARGE: $628.13 per month A

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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