Introduction

The attached Draft Cost of Service Analysis ("COSA") report is being submitted to the British Columbia Utilities Commission in order to provide background information and context for the Rate Design Application ("RDA") that will be filed by FortisBC Inc ("FortisBC" or "the Company")on September 30, 2009. Both the COSA and RDA are required pursuant to BCUC Order G-115-07 with filing dates as amended by Orders G-83-08, G-147-08, and G-164-08. Note that the commonly used terms, *Fully Allocated Cost of Service* ("FACOS"), and *Cost of Service Analysis* ("COSA") are interchangeable and FortisBC has chosen to use COSA in this and future submissions.

The attached draft report, ELECTRIC COST OF SERVICE STUDY, prepared by EES Consulting, can be read as a standalone document. Doing so will afford the reader a good understanding of the background, methodology, key assumptions and results of the FortisBC COSA without delving further into the data tables or model employed. These supporting documents are appended to the report and are also available on the FortisBC website (www.fortisbc.com).

A COSA provides for the fair and equitable distribution of costs compared to the collection of revenue from each of the Company's customer rate classes. The distribution of costs to individual customer rate classes is based upon the extent to which the various rate classes contribute to the overall cost of operating the utility. The output of the study results in a Revenue to Cost Ratio for each rate class, which is used as a basic input for rate design. As the outcome of the COSA and ultimately the Rate Design process is revenue neutral to FortisBC, in that the total cost or revenue requirement does not change as a result of the outcome, the primary concern for the Company is that the principals of cost-causation and equitable treatment are held as key considerations within the cost allocation methodologies and assumptions.

The attached Draft COSA results are part of a commitment to foster open and informed discussion with its stakeholders. This commitment is also reflected in the public consultation activities that preceded the submission of the attached report (which are more fully explained later in this document). In these activities the Company has attempted to educate its stakeholders in the COSA procedure itself with the intention of promoting a meaningful and inclusive regulatory process.

A Draft COSA Study That Presents Fair and Accurate Results

The enclosed COSA report is the culmination of a lengthy and complex process involving all functional areas of the Company, fully reviewed and endorsed at the Executive level. Every effort has been made to scrutinize the methods employed, however, the Company still considers the COSA Report to be in draft form until opportunities for public input have been fully exhausted prior to the filing of the Rate Design Application.

This introduction provides context for your review of the COSA report by outlining:

1.0 ***The Methodology Used To Product The Draft COSA Study.*** This section will describe the involvement of EES Consulting in producing this COSA report; how the methodology used within the COSA is consistent with common practices of utilities; what relevant data were included, and; how the methodology in the current draft COSA is substantially consistent with that used in the 1997 study.

2.0 ***How The COSA Reflects current Regulatory and Industry Trends.*** This section will outline how changing regulatory expectations, a growing “capacity gap”, the emergence of dual peaking load and significant system investment all must be accounted for and reflected in the COSA; how the COSA methodology used by EES has been updated to incorporate current realities; and how the results produced by the study strongly suggest rates must be rebalanced to ensure the fair and equitable distribution of costs.

3.0 ***This Draft COSA Reflects A Commitment To Meaningful Public Consultation.*** This section will describe FortisBC’s ongoing efforts to promote education of and dialogue with its stakeholders, through public presentations, individual meetings and the dissemination of relevant information; it will also outline the next steps around consultation.

1.0 Methodology

Though this COSA study is still in draft form, FortisBC believes the process and methodology used to derive its results is fundamentally sound.

1.1 Prepared By EES Consulting

To assist in completing its draft Cost of Service Study (and the development of its Rate Design Application), FortisBC engaged EES Consulting Inc. ("EES"). EES provided technical expertise and input in the completion of the study and provided the model used to gather and analyze the various data, while FortisBC provided the necessary information and policy level guidance.

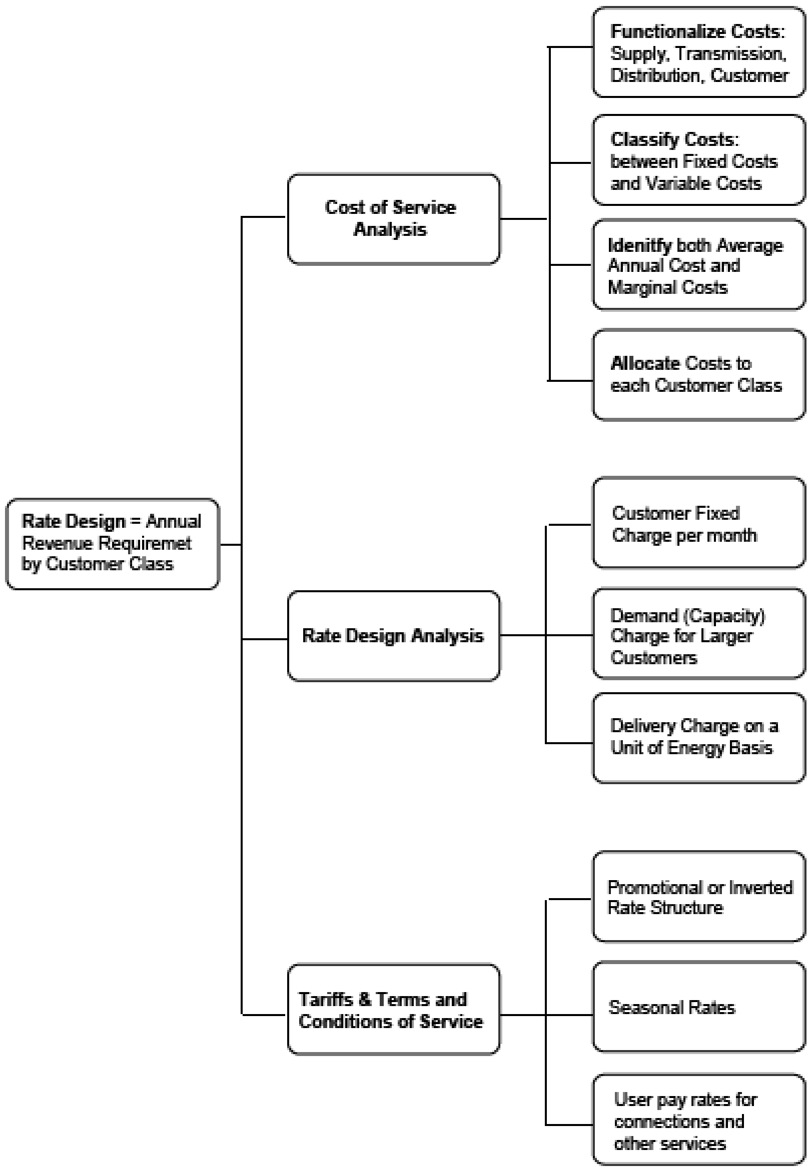
FortisBC's last COSA, completed in 1997, also utilized the expertise of EES. The familiarity of the consultant with Company's operating structure and environment contributed to the quality of the result and the linkage to past practice and relevant history. As there were a number of updates in methodology and assumptions made as the current study was completed, this institutional knowledge was of considerable value.

1.2 Consistent Methodology

The basic methodology employed in the COSA process follows a generally accepted sequence of steps common to the majority of such studies. The process employed by FortisBC and EES follows the sequence of steps outlined beginning on page 44 of the British Columbia Utilities Commission document, *A Participants' Guide to the B.C. Utilities Commission,* which can be found on the Commission website (http://www.bcuc.com), including Figure 5.2 that appears on page 47 and is reproduced below.

The COSA, subject of the EES Report, is concerned with only the Cost of Service Analysis and the associated Revenue Requirement. FortisBC has not deviated from these steps and thus the methodologies employed are comparable to other major provincial utilities such as BC Hydro and Terasen Gas.

Figure 5-2
KEY COMPONENTS OF RATE DESIGN



1.3 Prepared Using Relevant Data

In order to proceed with the study, there are several pieces of key information that were required as inputs. In the order that they are discussed in the Report, they are:

- The Revenue Requirement;
- Rate Base details;
- Load Forecasts;
- Projected Revenues; and
- System Cost data.

The Revenue Requirement used in the COSA is derived from the most recently submitted FortisBC Revenue Requirement Application ("RRA") and approved by Commission Order G-193-08. The Revenue Requirement figure of $233.1 million was adjusted by $2.3 million to reflect the impact on FortisBC of the recent BC Hydro Rate 3808 increase. In addition, as the calculated revenues per rate class using existing rates provided a smaller revenue requirement than anticipated, and as the calculated number is seen as appropriate for the basis of the COSA, the approved Revenue Requirement was grossed-up in order that allocated costs and revenues were equal. The full description of these adjustments is found on pages 7 to 10 of the Report. Any changes to the Revenue Requirement as approved by Order G-193-08 will be the subject of a separate regulatory process.

Rate Base, Load Forecasts, and Projected Revenues used in the COSA were all provided by FortisBC and are based either in the case of Rate Base on previously filed information (2009 RRA), or on the most recent projections available.

System Cost data, as required to perform the Minimum System Study used for the allocation of distribution costs as described in the Report on pages 19-22, and Appendix B, was provided by FortisBC Planning Engineers using the most current cost information available.

1.4 Broadly Consistent With The 1997 Cost of Service Study

As noted in the Report, the 1997 COSA served as the starting point for the 2009 Study. In most cases, basic assumptions remain consistent with those used at that time. The bulk of the Report therefore is devoted to explaining those assumptions in greater detail, and importantly, pointing out the areas of deviation from previous practice, along with the rationale, and impact of the changes. It is to be expected that differences in the electric utility industry, the operating environment and the characteristics of FortisBC itself would contribute to the need to re-evaluate the underlying assumptions incorporated into the model. These considerations are fully explored in the Report.

FortisBC last filed with the Commission a full COSA and Rate Design Application in September of 1997. The 1997 Study was filed as a matter of normal utility practice which deems the periodic examination of cost allocations to be prudent, and in response to changing industry conditions developing at the time, namely, the potential for the unbundling of utility services with the advent of deregulation.

The COSA was conducted using the same series of steps, (determination of Revenue Requirement, Functionalization, Classification, and Allocation) as previously mentioned, with the classification or allocation of the key COSA cost components being:

Item	Basic Method
Generation Plant	Classified as energy/demand related (100% energy)
Transmission Plan	Allocated on a 2 Coincident Peak (CP) methodology
Distribution Plant	Classified per a Minimum System Study
General Plant	Allocated on the basis of Labour Ratios
DSM	Functionalized on a generation/transmission split

Generally speaking, the methodologies used in the 1997 study were the same as those employed in the completion of the 2009 version. Within each basic methodology, there lay assumptions that must be made based upon the circumstances that exist at the time of the study. Where these specific assumptions differ between the two studies, it has been noted in the Report and will be discussed in this summary in a later section.

As a cost of service study is concerned with the equitable allocation of the revenue requirements to the various customer classes of service, the revenue to cost ratios that are developed from the study are important indicators of the degree to which this equitable treatment exists. In the 1997 Study, these ratios were:

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%

Note that any revenue to cost ratio in excess of 100% indicates a situation where a customer class is providing revenue in excess of its allocated costs and is, in effect subsidizing those classes that are below 100%.

Pursuant to the 1997 Rate Design Application, FortisBC (West Kootenay Power at the time), was directed to increase the residential rate by 1% per year for three years and to apply the additional revenue to the other classes.

2.0 Changes from the 1997 Study

As previously outlined, the methodologies used in the 1997 study are very similar to those used in the study that is attached. Notwithstanding this, FortisBC's business – and the environment in which it operates – has evolved since the 1997 study. Changes include:

2.1 Regulatory Environment

The environment in which FortisBC operates has seen significant change since the last COSA was filed in 1997.

As a starting point for rate design, the COSA must portray as accurately as possible the cost responsibility for the customer groups such that any rate adjustments can best meet the goals of the 2007 BC Energy Plan: A Vision for Clean Energy Leadership ("2007 Energy Plan") and the requirements for rate setting found in Utilities Commission Act, particularly

Section 60 (1): In setting a rate under this Act

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

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

> (i) is not unjust or unreasonable within the meaning of section 59,
>
> (ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and
>
> (iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,

The Provincial Government has released comprehensive energy plans in 2002 and more recently with the 2007 Energy Plan: A, and made changes to the Utilities Commission Act that have shifted industry focus towards a greater consideration of objectives related to conservation, efficiency, adequate capacity availability and self sufficiency. While many of the Policy Actions can be seen as having a greater relevance to issues encountered during Rate Design, such as the 2007 Energy Plan Policy Action #4, "Explore with BC utilities new rate structures that encourage energy efficiency and conservation", one can conclude from the tone of the Plans that there is a general call for more focus on the part of both the operating utilities and the individual customers in the manner in which they utilize electricity and energy in general. Where a discussion of adequate energy supply and capacity constraints was not evident in the 1997 COSA, today, the situation at FortisBC in many respects mirrors that of the Province which has focused attention on these issues through such 2007 Energy Plan Policy Actions as #13, which focus on the adequacy of transmission system capacity.

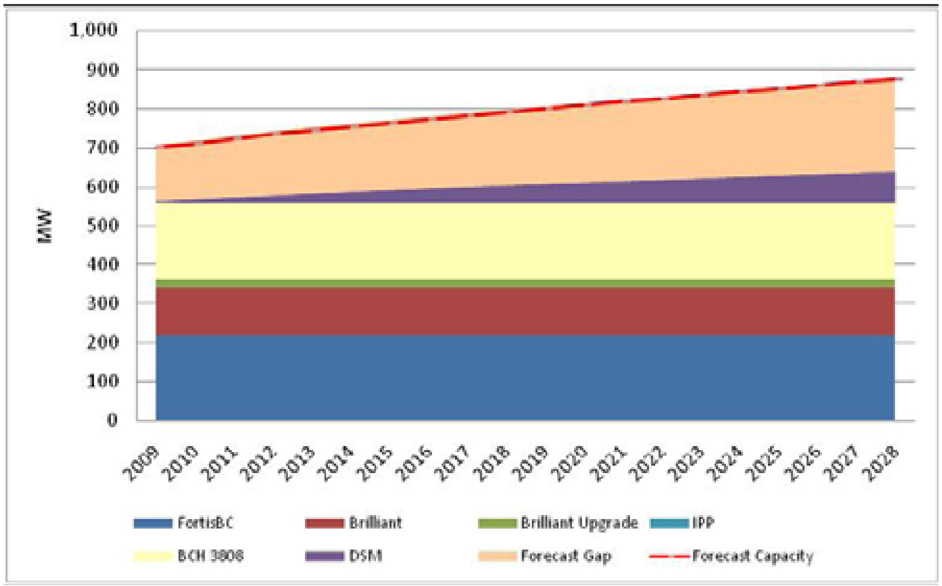
Some assumptions on the 2009 COSA have been made to reflect the inherent value of system capacity and the responsibility of each customer class for the costs that it imposes upon the system as a whole. The need for these assumptions is discussed more below and in greater detail in the EES Report.

2.2 Growing Capacity Constraints

FortisBC is forecasting that it will face an ever-widening gap between capacity and demand. In its 2009 Resource Plan, filed with the Commission on May 29, 2009 the Company stated,

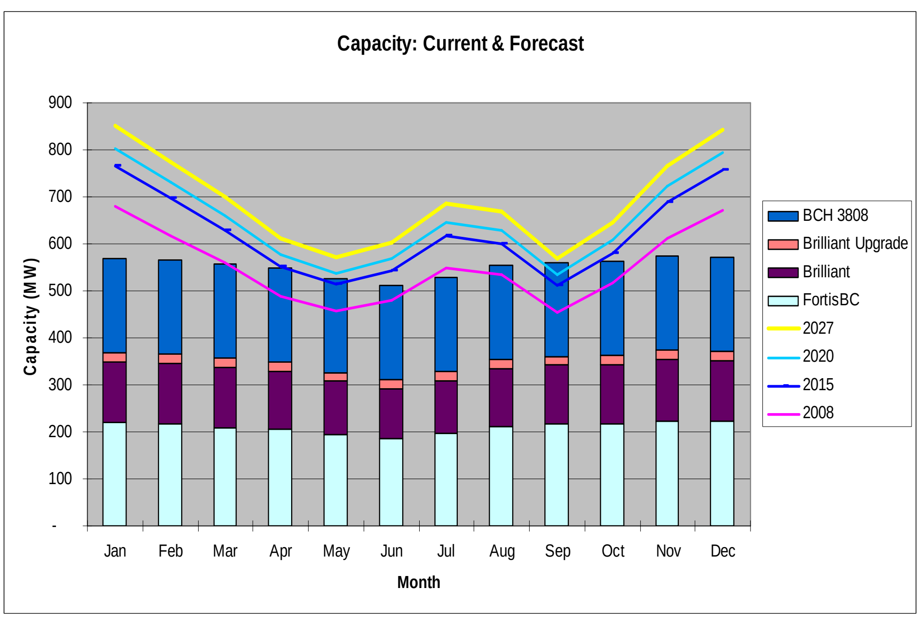
"The FortisBC Plants and the power purchase agreements with BC Hydro and Brilliant Power Corporation together constitute the bulk of the Company's existing power supply resources, providing a total winter peak capacity of approximately 551MW. In 2008 these resources served about 74% of FortisBC's December 2008 winter peak of 746 MW, resulting in a shortfall of 195 MW which was met through short term, market based contracts. In 2009, FortisBC's load forecast predicts a capacity shortfall of about 145 MW."

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



2.3 *Emergence of Dual Peaking Load*

Also related to capacity concerns is the emerging trend within the FortisBC system to a dual-peak system demand resulting in the convergence of the summer and winter peak. The pink line in the chart below shows the pronounced summer peak which FortisBC believes is primarily due to the large air conditioning load developing in the FortisBC service area.



2.4 Required Reinvestment In System Infrastructure Has Taken Place

There has been significant investment in system infrastructure during the period between the 1997 and 2009 studies. These investments were made both in consideration of age-related replacements and customer growth. When examined collectively they indicate that the composition of costs has likely changed.

As noted in the Report on page 12, FortisBC's Rate Base has increased by over 200% since the 1997 COSA Study. Much of the investment has been required to accommodate ongoing capacity constraints on the transmission and distribution systems. Capital Expenditures in 2007 and 2008 were approximately $130 million $110 million respectively. These levels of investment exemplify the recent investment required in order to respond to the need for system expansion and replacement. The $119 million Kootenay 230 kV Transmission Project, completed in 2003 is an example of one such project required to keep pace with the growth and deal with the age of existing plant.

The allocation of costs related to transmission and distribution plant tends to affect certain classes of customers to a greater extent than others. Transmission plant accounted for 24% of the rate base in 1997 versus 29% today, while production was 9% of the rate base in 1997 and makes up 12% of the total in the 2009 study. The result of the shift in investment towards generation and transmission shows up as widening gaps in the revenue-to-cost ratios between the customer classes.

2.5 COSA Assumptions Updated

Several key assumptions used in the 2009 study have been made to reflect the facts discussed above. With the exception of the use of Contract Demand as an allocation factor (discussed below), these revisions to the 1997 methodology have a small impact on the study results.

- **Demand Component of Generation.** In consideration of the capacity constrained nature of the FortisBC system the allocation of generation rate base was changed from an assumption that 100% of the cost amount was energy related, as was done in the 1997 study, to an 80% energy, 20% demand split in the 2009 version. The derivation of the split is discussed in detail on page 18 of the EES Report. The recognition that the FortisBC plants provide both energy and capacity is consistent with acknowledging the value of capacity in the system. The effect on the revenue to cost ratios from this change alone is small, causing a drop in the ratio for the Industrial Transmission class of less than 3 points, and a smaller rise in the ratios for the General Service and Industrial Primary classes.

- **Use of Contractual Demand.** FortisBC is contractually obligated to have available a predetermined level of supply for certain customers connected to its system. The use of the greater of this "contractual demand" or actual demand for Rate 31 and 33 industrial and wholesale customers as an allocation factor for transmission and distribution costs in the 2009 study is discussed in detail beginning on page 31 of the EES Report. In the 1997 study, only the actual demands were considered. This update is required to better reflect the fact that FortisBC is contractually obligated to have sufficient capacity to supply to the limits specified in the contracts, even if at levels above historical demand.

  There is a significant cost attributable to the planning and constructing of infrastructure that is required to satisfy the contractual arrangements. The approach better reflects both the value of firm capacity reservations and the cost associated with requiring that capacity on the system. As noted in the report, the directive of the BC Energy Plan is for all utilities to promote efficiency and conservation, and it is imperative that customers which are not directly regulated by the BCUC are provided price signals that reflect the true cost of the facilities used to serve them. This change is the most significant of the updates to the 1997 COSA in terms of the effect on individual customer groups.

- **Use of Two Coincident Peak Method.** The emerging dual peaking nature of the FortisBC system load is reflected in the decision to use the sum of two winter and two summer peaks for the 2 Critical Peak ("2 CP") method for allocating demand related transmission costs. The 2 CP method was also employed in the 1997 COSA and the incorporation of the additional peak data has a minor effect on the outcome of the study. A full discussion on the selection of the 2 CP method is contained in the Reports beginning at page 26.

- **Relative Weightings Within Total Rate Base.** Investment in the system that has occurred since the 1997 COSA changes the distribution of the relative weightings of the generation, transmission, and distribution values within the total rate base. The effects on the COSA are manifested in every result that relies on this distribution in its calculation.

For the classification of distribution plant, a minimum system study was performed in order to determine the split between customer and demand related costs. A similar approach was taken in the 1997 COSA; however, the study in the 2009 COSA incorporates cost information updated for 2008 costs as provided by FortisBC Staff. Hence, the customer/demand split is different than that in the previous study.

- **Minimum System Study.** Along with the minimum system results, an offset to account for the peak load carrying capability ("PLCC") of a minimum system was incorporated into the analysis. The minimum system study is discussed in Appendix B to the Report.

2.6 Study Results Indicate Rate Rebalancing Required

The revenue to cost ratios for each customer class summarize the COSA results in terms of the extent to that FortisBC is collecting the appropriate amount of revenue given the costs allocated to each group. For the 2009 COSA these results are reproduced below. Note that in the table, Kelowna Wholesale through BC Hydro Yahk Wholesale belong to the same Rate class (40) and are broken out for information purposes as discussed on page 13 of the Report. These customers, as a single class have a revenue/cost ratio of 81.8%.

Rate Class	Cost Ratio
Residential	98.5%
Small General Service (20)	113.4%
General Service (21)	139.8%
Industrial Primary (30)	123.6%
Industrial Transmission (31/33)	61.9%
Lighting	84.2%
Irrigation	79.6%
Kelowna Wholesale	87.9%
Penticton Wholesale	77.1%
Summerland Wholesale	95.6%
Grand Forks Wholesale	68.1%
BC Hydro Lardeau Wholesale	101.2%
BC Hydro Yahk Wholesale	103.1%
Nelson Wholesale	80.2%
Total	100.0%

The extent to which adjustments are made to the rates applicable to each class in order to achieve more equitable treatment of the customer groups, and the manner that this is accomplished is a matter for the Rate Design Application that FortisBC will be filing in September of 2009. However, FortisBC does intend to address some proposed rebalancing mechanisms in the September 2009 RDA.

3.0 Public Consultation Process

FortisBC recognizes the complex nature of the cost of service study process, and so is committed to public consultation. Actions being taken as a reflection of that commitment are outlined below.

3.1 To Date: Extensive Public Consultation

FortisBC focused its initial stages of public consultation on awareness and education in an effort to improve the breadth and quality of the input and comment that would be received during the development of both the COSA Report and the Rate Design Application.

A series of face-to-face meetings and public open houses were conducted where a high level overview of the COSA process, changes in COSA assumptions and initial results were discussed.

In an effort to reach as many stakeholders as possible, and to capture the attention of a wide range of customers, the Public Sessions were advertised in local media and over 230 notifications were sent directly to intervenors in previous FortisBC regulatory processes, all local governments, Provincial and Federal elected officials, representatives of all major customers, stakeholder groups, Chambers of Commerce and First Nations. The presentation was also reviewed with the FortisBC DSM Committee in advance of the open houses.

The public open houses were held during the week of May 26, 2009 in Castlegar, Kelowna, and Osoyoos.

In addition to the public sessions, representatives of FortisBC met in person with each customer taking service under Rates 31 and 33, as well as the wholesale municipalities of Nelson, Grand Forks, Kelowna, Penticton and Summerland to review the study results.

Individual meetings were also held with non-wholesale municipalities throughout the service area to inform representative bodies of the 2009 COSA assumptions, the initial draft COSA results, the upcoming consultation activities and the September 2009 COSA/RDA Application process.

3.2 Creating Opportunities For Input

A key message at each meeting was the potential for the COSA results to be reflected in the Rate Design process and an explanation of how each stakeholder could remain involved in the process if desired.

The draft Report was posted to the FortisBC website on June 12th, 2009 along with copies of all open house materials. Each stakeholder and open house attendee was notified of the posting and invited to submit comment by June 19th, 2009 for inclusion in the draft report.

3.2 Summary of Comments

During the initial meetings and open houses, customers were generally appreciative of being provided with the information and indicated a better understanding of the process. The majority of the customers were also generally supportive of the COSA assumptions, including those assumptions that had changed compared to the 1997 COSA. From an educational perspective, the May and June meetings were successful.

Without a full copy of the COSA report to review, the wholesale customers generally reserved comment until such a time as the detail could be examined. At the time of filing, FortisBC has not received any comment for its Wholesale Customers

The British Columbia Municipal Electrical Utilities ("BCMEU") and the British Columbia Public Interest Advocacy Centre ("BCPIAC") responded in writing to FortisBC by the June 19 deadline. The BCMEU wished to confirm its interest in the process while the BCPIAC sought clarification on a number of points in the draft Report.

FortisBC has made a number of changes in the Report in response to the BCPIAC letter, and will deal with the remaining questions during future regulatory processes.

3.4. Ongoing Commitment To Consultation

Consultation activities related to both the COSA and the RDA will continue throughout the period between the filing of this report and the September 30, 2009 RDA filing. FortisBC is committed to meaningful consultation on these matters as agreed to during the 2008 Revenue Requirements negotiated settlement process and outlined in Appendix A of Commission Order G-193-08 in that matter.

Summary and Next Steps

As previously mentioned this COSA report is an important foundational component of the RDA and provides important background information and context for the RDA. And while still in draft format, FortisBC believes the contents of the Draft COSA Report represent an accurate and fair set of results. However, should information arise during the additional consultation, the Company reserves the right to make further changes prior to filing the COSA along with the Rate Design Application in final form on or before September 30, 2009.

The attached Draft COSA is being filed with the Commission not for approval, but as supporting documentation in advance of the Rate Design Application that will be filed on or before September 30, 2009. FortisBC expects that the COSA will be examined as part of the Rate Design Application. The suggested regulatory process for the RDA will be included with the September filing.

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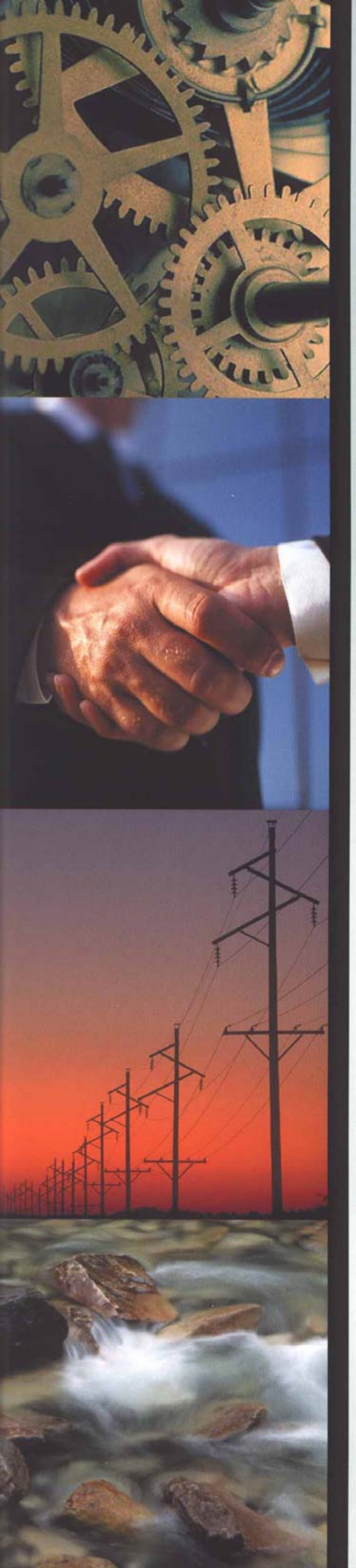


FortisBC

EES Consulting

Draft Report
ELECTRIC COST OF SERVICE STUDY

June 30, 2009

June 30, 2009

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

SUBJECT: Electric Cost of Service Study

Gentlemen:

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

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

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

Very truly yours,

Gary Saleba
President

570 Kirkland Way, Suite 200
Kirkland, Washington 98033

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

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

Contents

Executive Summary

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

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

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

Overview of the COSA

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

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

- Functionalization
- Classification
- Allocation

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

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

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

FortisBC Revenue Requirement and Rate Base

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

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

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

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

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

Major Assumptions of the COSA

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

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

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

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

Key assumptions include:

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

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

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

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

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

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

These assumptions are discussed in greater detail throughout this report.

Summary of Results

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

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

	Millions
Residential	$428.9
Other Retail	$249.5
Wholesale	$229.6
Total System	$908.0

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

	Millions
Residential	$ 108.9
Other Retail	$ 66.4
Wholesale	$ 60.2
Total System	$235.4

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

	Millions
Residential	$106.0
Other Retail	$ 77.6
Wholesale	$ 48.9
Total Revenues	$232.5

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

	Revenue to Cost Ratio	Adjusted Revenue to Cost Ratio
Residential	97.3%	98.5%
Small General Service (20)	112.0%	113.4%
General Service (21)	138.1%	139.8%
Industrial Primary (30)	122.1%	123.6%
Industrial Transmission (31/33)	61.1%	61.9%
Lighting	83.1%	84.2%
Irrigation	78.7%	79.6%
Kelowna Wholesale	86.8%	87.9%
Penticton Wholesale	76.2%	77.1%
Summerland Wholesale	94.4%	95.6%
Grand Forks Wholesale	67.2%	68.1%
BC Hydro Lardeau Wholesale	99.9%	101.2%
BC Hydro Yahk Wholesale	101.9%	103.1%
Nelson Wholesale	79.2%	80.2%
Total	98.8%	100.0%

Given a number of assumptions, the results show that when using present rates FortisBC is collecting insufficient revenues to meet current costs for 2009. The amount is roughly 1.2% less than projected revenue requirements due to two adjustments from the approved 2009 filing. First, the revenue requirement increased by $2.3 million due to a change in rate 3808 from BC Hydro. Secondly, the revenues associated with street lighting were reduced by $542,000 to better match actual revenues per kWh received in 2008. Revenue to Cost Ratios were adjusted to reflect the case where revenue match revenue requirements. This adjustment better reflects the deviations from 100 percent that occur between the various customer classes. The Adjusted Revenue to Cost Ratios will be used to determine the need for interclass adjustments.

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

Based on these results, FortisBC will need to make adjustments between classes to better achieve rates that are based on an equitable cost allocation. Any adjustments will be incorporated in the rate design application, to be filed later in the year.

Overview and Basis for the COSA

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

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

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

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

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

Overview of the COSA

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

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

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

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

FortisBC Revenue Requirement

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

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

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

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

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

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

Rate Base

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

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

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

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

Projected Load Forecast

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

	GWh
Residential	1222
Other Retail	964
Wholesale	921
Total System	3,107

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

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

Projected Revenues

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

	Millions
Residential	$106.0
Other Retail	$ 77.6
Wholesale	$ 48.9
Total Revenues	$232.5

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 0.2% higher 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.

Using the updated calculations, total revenues resulted in an amount of $232.5 million, which is roughly $600,000 less than the approved revenue requirement, reflecting a percent difference of less than 1 percent. This difference can be attributed to the lighting class. The updated revenue for lighting reflects the 2008 actual average rate per kWh for lighting sales.

Cost of Service Analysis

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

COSA Overview and General Principles

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

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

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

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

- Functionalization
- Classification
- Allocation

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

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

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

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

Major Assumptions of the Cost of Service Analysis

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

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

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

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

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

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

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

Key assumptions include:

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

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

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

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

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

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

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

Functionalization of Costs

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

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

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

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

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

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

Functionalization of Rate Base

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

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

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

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

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

Working capital for FortisBC was set at $7.1 million, which was added to rate base along with an adjustment for capital additions of $10.8 million. Each of these items was functionalized on the same basis as all O&M costs. Working capital is set aside to cover the time lag between when costs are incurred and when revenue is received from customers. Because O&M and purchased power costs are the primary bills paid by the utility, O&M costs was considered to be a reasonable method for functionalizing and allocating working capital costs. The adjustment for capital additions is similar to working capital was therefore treated in the same manner as working capital.

The rate base was reduced by $87.4 million in customer contributions. All of these contributions were for items at the distribution level and were assigned to functions on the basis of poles, conductors and transformers.

Other rate base items totaled $36.1 million and were separated out by function. The largest item in this category is $22.6 million of plant acquisition adjustment and deferred costs, which were treated on the same basis of Gross Plant prior to General Plant. Also included is $6.9 million of construction work in progress (CWIP) that does not earn an allowance for funds used during construction (AFUDC). This amount was broken out by function according to total CWIP by function, and was treated in the same manner as the rate base for each of the functions. Another $6.6 million is related to demand-side management (DSM) spending. This DSM amount was functionalized and classified as 64% power supply energy, 21% power supply demand and 15% transmission and distribution. This split is consistent to that used by FortisBC in the cost/benefit analyses performed for DSM spending.

Functionalization of Revenue Requirement

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

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

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

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

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

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

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

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

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

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

Classification of Costs

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

The three primary classifiers are:

- Demand
- Energy
- Customer

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

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

Classification of Generation and Transmission Rate Base

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

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

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

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

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

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

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

The transmission rate base includes the utility's own transmission assets associated with providing power to FortisBC's distribution system. In addition, FortisBC purchases wheeling from the British Columbia Transmission Corporation (BCTC) in the Okanagan and Creston areas to supplement its own transmission. The cost of providing transmission service to a customer is considered to be directly proportional to the contribution to system peak demand that customer imposes on the system. All transmission rate base accounts are classified 100 percent demand-related, as was the case for the 1997 COSA.

Classification of Distribution Rate Base

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Peak Load Carrying Capability Adjustment (PLCC)

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

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

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

Other Rate Base Items

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

The $22.7 million of plant acquisition adjustment and deferred costs was classified on the same basis of Gross Plant prior to General Plant. The CWIP not earning AFUDC assigned to each function was classified in the same manner as the rate base for each function. DSM was classified as 71.6% power supply energy, 16.6% power supply demand and 11.8% transmission and distribution demand. This split is consistent to that used by FortisBC in the cost/benefit analyses performed for DSM spending.

Classification of Production/Power Supply Expenses

Classifying power supply costs to demand and energy components depends on the use of the generation and the pricing for power supply purchases. When a utility has numerous generating facilities the use of the various units to supply baseload versus peaking power should be considered. In the case of FortisBC, the power supply resources include FortisBC-owned generation, long term power purchase contracts including a tariff-based purchase from BC Hydro, and a small amount of market purchases. All of the resources used by FortisBC have both an energy and peaking component to them.

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

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

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

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

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

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

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

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

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

Classification of Other Expenses

The transmission function includes FortisBC's own transmission assets associated with providing power to FortisBC's distribution system. In addition, FortisBC purchases wheeling services from BCTC in the Okanagan and Creston areas to supplement its own transmission. The cost of providing transmission service to a customer is considered to be directly proportional to the demand that customer imposes on the system. All transmission expense accounts are classified on the same basis as transmission rate base.

Many of the distribution expense accounts correspond to a rate base account and follow the treatment of the rate base item. For example, account 583.10 is for distribution line maintenance, corresponding to rate base account 365-conductors and devices. Since the distribution rate base uses a minimum system approach, the expenses will also follow the splits resulting from that analysis. Street lighting expenses are directly assigned to the lighting class. Account 598 – other distribution plant is classified on the basis of total distribution rate base.

Customer Service expenses are all classified as customer-related.

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

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

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

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

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

Allocation of Costs

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

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

Demand Allocation Factors

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

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

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

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

Demand Allocation Alternatives

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

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

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

These tests are:

<u>FERC Test #1</u>

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

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

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

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

FERC Test #2

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

FERC Test #3

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

FERC Test #4

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

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

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

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

OEB Test #1

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

OEB Test #2

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

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

Selection of 2 CP Method

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

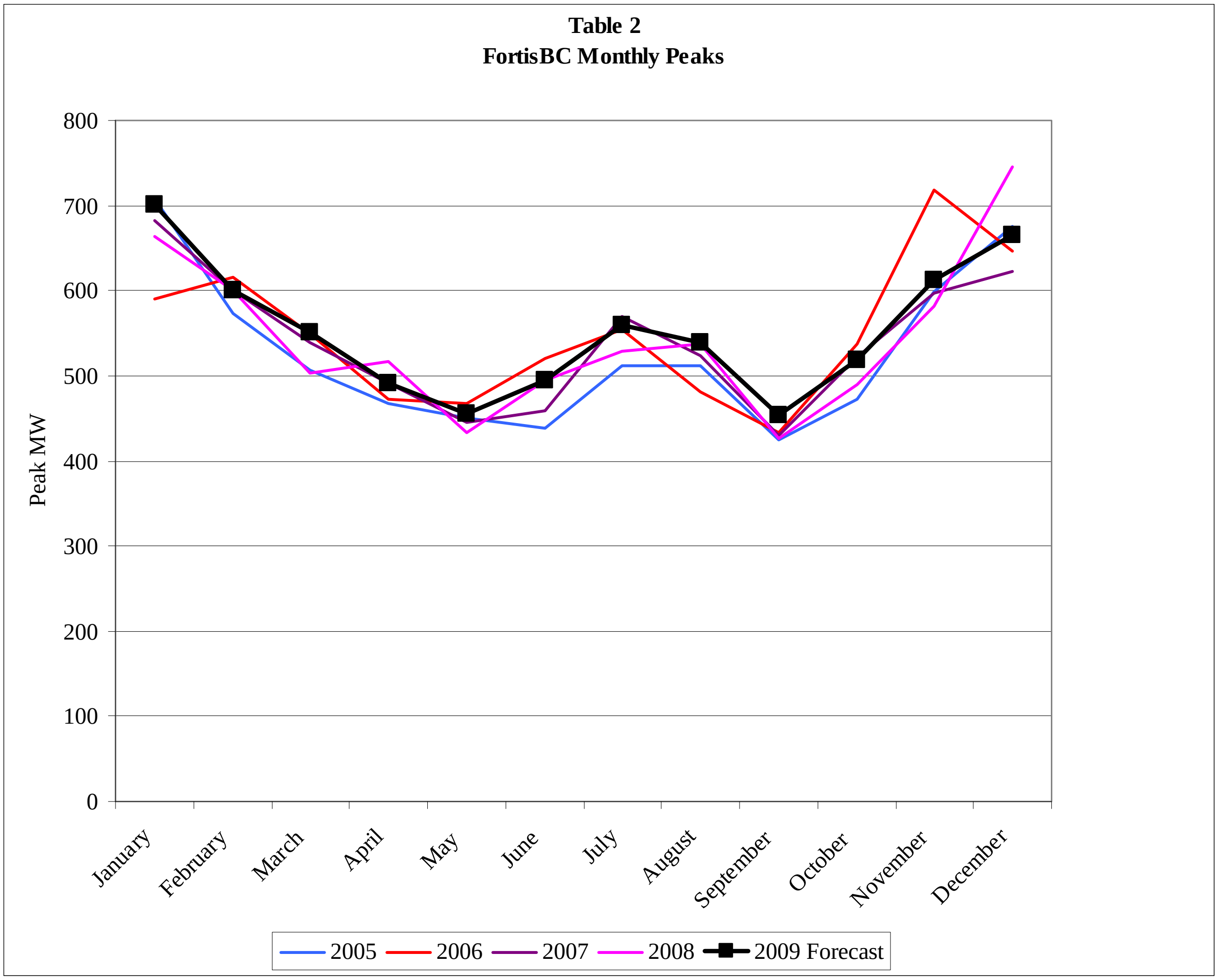
Table 1
FERC and OEB Tests for Demand Allocator

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

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

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

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



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

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

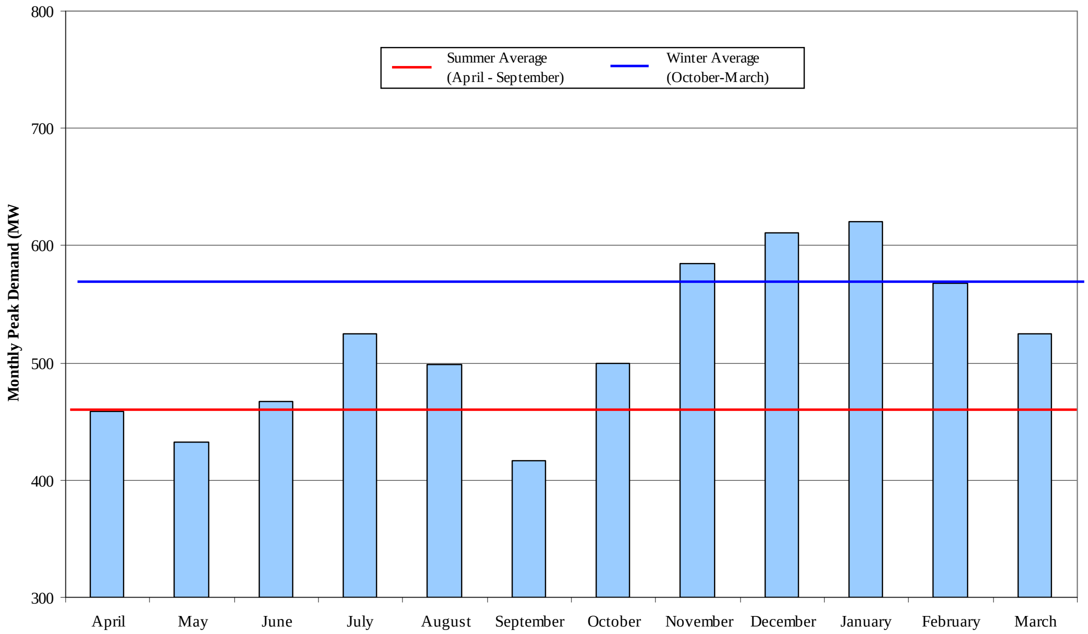
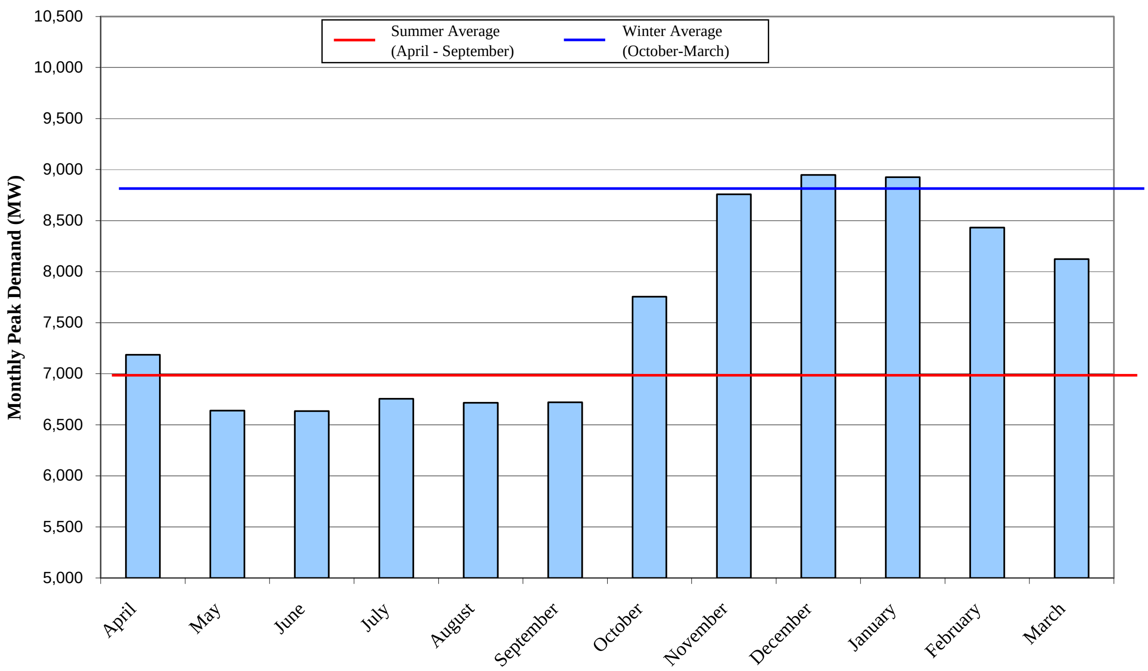


Table 4
BC Hydro Domestic System Monthly Peak Demand
(2001 - 2007 Average)



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

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

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

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

Use of Contractual Demand

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

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

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

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

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

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

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

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

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

Energy Allocation Factors

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

Customer Allocation Factors

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

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

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

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

Other Allocation Factors

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

Allocation of Rate Base

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

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

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

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

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

Allocation of Revenue Requirements

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

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

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

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

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

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

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

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

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

Summary and Conclusions

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

Rate Base

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

	Millions
Residential	$428.9
Other Retail	$249.5
Wholesale	$229.6
Total System	$908.0

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

Revenue Requirement

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

	Millions
Residential	$ 108.9
Other Retail	$ 66.4
Wholesale	$ 60.2
Total System	$235.4

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

	Millions
Residential	$106.0
Other Retail	$ 77.6
Wholesale	$ 48.9
Total Revenues	$232.5

Revenue to Cost Ratios

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

	Revenue to Cost Ratio	Adjusted Revenue to Cost Ratio
Residential	97.3%	98.5%
Small General Service (20)	112.0%	113.4%
General Service (21)	138.1%	139.8%
Industrial Primary (30)	122.1%	123.6%
Industrial Transmission (31/33)	61.1%	61.9%
Lighting	83.1%	84.2%
Irrigation	78.7%	79.6%
Kelowna Wholesale	86.8%	87.9%
Penticton Wholesale	76.2%	77.1%
Summerland Wholesale	94.4%	95.6%
Grand Forks Wholesale	67.2%	68.1%
BC Hydro Lardeau Wholesale	99.9%	101.2%
BC Hydro Yahk Wholesale	101.9%	103.1%
Nelson Wholesale	79.2%	80.2%
Total	98.8%	100.0%

Given a number of assumptions, the results show that when using present rates FortisBC is collecting insufficient revenues to meet current costs for 2009. The amount is roughly 1.2% less than projected revenue requirements due to two adjustments from the approved 2009 filing. First, the revenue requirement increased by $2.3 million due to a change in rate 3808 from BC Hydro. Secondly, the revenues associated with street lighting were reduced by $542,000 to better match actual revenues per kWh received in 2008. Revenue to Cost Ratios were adjusted to reflect the case where revenue match revenue requirements. This adjustment better reflects the deviations from 100 percent that occur between the various customer classes. The Adjusted Revenue to Cost Ratios will be used to determine the need for interclass adjustments.

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

Unit Costs

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

	Cents per kWh
Residential	8.91
Other Retail	6.89
Wholesale	6.53
Total System	7.57

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

As discussed above, since no rate design application accompanies this COSA, the resulting unit costs do not yet have an impact on FortisBC rates. It is expected that unit cost calculations will be used for adjusting rate design components when FortisBC files its upcoming rate design application in December of 2009.

Comparison to 1997 COSA Methodology and Results

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

Table 5
1997 vs 2009 COSA Methodology

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

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

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

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

Industrial at primary (Rate 30) revenues are still more than 20% above their cost of service, while the industrial customers served at transmission voltage are now collecting just over 60% of their assigned costs. This change comes in part because of the use of contract demand in the COSA, but also because the industrial TOU rate (Rate 33) was set very low in comparison to Rate 31. This low rate led to lower than expected revenues for this class compared to the 1997 COSA revenues. Wholesale rates after the rebalancing were set equal to 100%, however, they are now primarily undercollecting their costs, with the exception of BC Hydro Lardeau and BC Hydro Yahk. As a group, these customers billed under Rate Schedule 40 have a Revenue-to-Cost Ratio of 81.8%. Individually, the Revenue-to-Cost Ratios vary from 68.1% to 103.1%. Nelson in particular is only collecting about 80% of its costs due to the fact that current rates do not account for the back-up service provided and the need to build transmission facilities to meet loads in the event Nelson's generating unit is off-line.

Conclusions

Because this COSA is not accompanied by a rate design application, the revenue to cost ratios resulting from the COSA are not used to support a rate rebalancing at this time. It is expected that the results from this COSA will be used to develop proposed rates for FortisBC later this year.

It is clear from the results, however, that FortisBC will need to make adjustments between classes to better achieve rates that are based on an equitable cost allocation.

Appendix A—COSA Schedules

EES Consulting, Inc.

Fortis BC 2009 COSA

Cost of Service Schedules

June 30, 2009

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A registered professional engineering corporation with offices in the Seattle, Portland, Bellingham, and southern California areas

TABLE OF CONTENTS

TABLE OF CONTENTS

COST OF SERVICE SUMMARY
BY CUSTOMER CLASS
Schedule 1.1

Forecast Year: 2009	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Revenues:															
Customer Charge Revenues	$16,781,898	$13,870,451	$1,543,005	$423,237	$290,114	$103,372		$180,478	$81,209	$101,512	$40,605	$60,907	$20,302	$20,302	$46,406
Energy Revenues	$187,277,138	$92,085,331	$16,297,213	$30,129,853	$6,262,625	$3,471,222	$1,974,565	$2,522,827	$11,286,794	$13,336,001	$3,704,361	$1,592,612	$346,520	$105,780	$4,161,435
Demand Revenues	$28,513,910			$10,732,074	$3,175,819	$588,079			$4,523,458	$5,489,171	$1,662,398	$636,377	$222,273	$65,836	$1,418,425
Total Revenues at Existing Rates	**$232,572,947**	**$105,955,782**	**$17,840,218**	**$41,285,164**	**$9,728,558**	**$4,162,673**	**$1,974,565**	**$2,703,305**	**$15,891,461**	**$18,926,683**	**$5,407,364**	**$2,289,896**	**$589,095**	**$191,918**	**$5,626,265**
															15%
Production-Related Costs	108,315,364	43,518,698	6,920,467	16,909,077	4,755,721	2,952,434	447,263	1,630,866	10,126,269	12,036,824	3,318,341	1,418,124	339,104	100,401	3,841,775
Transmission-Related Costs	56,672,801	17,840,700	2,757,807	6,719,897	1,761,527	3,616,919	83,708	716,445	6,490,078	9,974,540	1,837,549	1,485,244	162,781	41,346	3,184,259
Distribution-Related Costs	70,438,592	47,499,347	6,247,622	6,263,819	1,450,884	239,675	1,844,182	1,089,748	1,686,262	2,832,059	572,713	501,965	87,636	46,624	76,056
Total Allocated Revenue Requirements	**$235,426,757**	**$108,858,745**	**$15,925,895**	**$29,892,793**	**$7,968,133**	**$6,809,029**	**$2,375,153**	**$3,437,059**	**$18,302,608**	**$24,843,424**	**$5,728,603**	**$3,405,332**	**$589,521**	**$188,371**	**$7,102,091**
Difference	-$2,853,811	-$2,902,963	$1,914,322	$11,392,372	$1,760,425	-$2,646,356	-$400,589	-$733,754	-$2,411,147	-$5,916,741	-$321,239	-$1,115,437	-$426	$3,547	-$1,475,825
% Increase to Equal Allocated Cost	1.2%	2.7%	-10.7%	-27.6%	-18.1%	63.6%	20.3%	27.1%	15.2%	31.3%	5.9%	49%	0%	-2%	26%
Revenue To Cost Ratio	**98.8%**	**97.3%**	**112.0%**	**138.1%**	**122.1%**	**61.1%**	**83.1%**	**78.7%**	**86.8%**	**76.2%**	**94.4%**	**67.2%**	**99.9%**	**101.9%**	**79.2%**
Adjusted Revenues at Existing Rates	$235,426,757	$107,255,924	$18,059,128	$41,791,758	$9,847,933	$4,213,752	$1,998,794	$2,736,476	$16,086,459	$19,158,925	$5,473,715	$2,317,994	$596,324	$194,273	$5,695,303
Adjusted Revenue to Cost Ratio	**100.0%**	**98.5%**	**113.4%**	**139.8%**	**123.6%**	**61.9%**	**84.2%**	**79.6%**	**87.9%**	**77.1%**	**95.6%**	**68.1%**	**101.2%**	**103.1%**	**80.2%**
Average Unit Costs:															
Customer Charge $ / Per Customer / Month	$31.91	$29.65	$35.70	$59.80	$1,063.93	$5,002.48	$29.96	$36.95	$13,586.34	$19,188.47	$6,179.88	$8,462.18	$2,606.67	$2,500.09	$6,695.88
Average Energy + Demand Charge $ / kWh	$0.02617	$0.02645	$0.02627	$0.02641	$0.02493	$0.02498	$0.08909	$0.02566	$0.02503	$0.02508	$0.02499	$0.02497	$0.02557	$0.02551	$0.02486
Average Energy Charge $ / kWh	$0.06210	$0.06102	$0.05935	$0.05924	$0.05352	$0.07897	$0.11995	$0.06215	$0.06035	$0.06930	$0.05732	$0.07790	$0.06049	$0.05622	$0.06240
Demand Charge $ / kW	$13.50	$13.12	$10.55	$9.06	$9.37	$18.65	$31.86	$12.06	$17.65	$21.79	$15.77	$26.99	$13.03	$12.58	$16.35
Combined Average Rate $ / kWh	**$0.0758**	**$0.0891**	**$0.0783**	**$0.0630**	**$0.0565**	**$0.0819**	**$0.1713**	**$0.0719**	**$0.0609**	**$0.0700**	**$0.0581**	**$0.0803**	**$0.0639**	**$0.0669**	**$0.0631**

FUNCTIONALIZATION AND CLASSIFICATION OF REVENUE REQUIREMENT SUMMARY BY CUSTOMER CLASS

Schedule 1.2

Forecast Year: 2009	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Production															
Demand (PD)	$27,935,341	$11,235,097	$1,580,229	$4,375,812	$1,241,749	$874,437	$97,551	$404,970	$2,604,160	$3,131,543	$853,878	$359,480	$103,221	$28,559	$1,044,657
Energy (PE)	$80,380,022	$32,283,601	$5,340,238	$12,533,265	$3,513,973	$2,077,998	$349,712	$1,225,896	$7,522,109	$8,905,282	$2,464,463	$1,058,644	$235,883	$71,843	$2,797,117
Direct Assignment (PDA)															
Transmission															
Demand (TD)	$56,672,801	$17,840,700	$2,757,807	$6,719,897	$1,761,527	$3,616,919	$83,708	$716,445	$6,490,078	$9,974,540	$1,837,549	$1,485,244	$162,781	$41,346	$3,184,259
Energy (TE)															
Direct Assignment (TDA)															
Distribution															
Demand (DD)	$27,026,122	$13,157,728	$2,392,468	$4,489,181	$1,028,646	-$431	$246,642	$622,959	$1,522,132	$2,599,833	$498,175	$400,068	$56,297	$16,592	-$4,167
Energy (DE)															
Customer (DC)	$42,477,874	$34,307,650	$3,850,534	$1,769,826	$421,314	$240,119	$711,831	$465,965	$163,036	$230,262	$74,159	$101,546	$31,280	$30,001	$80,351
Direct Assignment (DDA)	$934,596	$33,969	$4,620	$4,813	$924	-$13	$885,708	$823	$1,094	$1,965	$380	$351	$59	$30	-$128
Total	**$235,426,757**	**$108,858,745**	**$15,925,895**	**$29,892,793**	**$7,968,133**	**$6,809,029**	**$2,375,153**	**$3,437,059**	**$18,302,608**	**$24,843,424**	**$5,728,603**	**$3,405,332**	**$589,521**	**$188,371**	**$7,102,091**
Total Cost / Function															
Production	$108,315,364	$43,518,698	$6,920,467	$16,909,077	$4,755,721	$2,952,434	$447,263	$1,630,866	$10,126,269	$12,036,824	$3,318,341	$1,418,124	$339,104	$100,401	$3,841,775
Transmission	$56,672,801	$17,840,700	$2,757,807	$6,719,897	$1,761,527	$3,616,919	$83,708	$716,445	$6,490,078	$9,974,540	$1,837,549	$1,485,244	$162,781	$41,346	$3,184,259
Distribution	$70,438,592	$47,499,347	$6,247,622	$6,263,819	$1,450,884	$239,675	$1,844,182	$1,089,748	$1,686,262	$2,832,059	$572,713	$501,965	$87,636	$46,624	$76,056
Total Cost / Function	**$235,426,757**	**$108,858,745**	**$15,925,895**	**$29,892,793**	**$7,968,133**	**$6,809,029**	**$2,375,153**	**$3,437,059**	**$18,302,608**	**$24,843,424**	**$5,728,603**	**$3,405,332**	**$589,521**	**$188,371**	**$7,102,091**
Total Cost / Classifier															
Demand	$111,634,265	$42,233,525	$6,730,504	$15,584,890	$4,031,922	$4,490,925	$427,902	$1,744,374	$10,616,369	$15,705,915	$3,189,601	$2,244,792	$322,299	$86,497	$4,224,750
Energy	$80,380,022	$32,283,601	$5,340,238	$12,533,265	$3,513,973	$2,077,998	$349,712	$1,225,896	$7,522,109	$8,905,282	$2,464,463	$1,058,644	$235,883	$71,843	$2,797,117
Customer	$42,477,874	$34,307,650	$3,850,534	$1,769,826	$421,314	$240,119	$711,831	$465,965	$163,036	$230,262	$74,159	$101,546	$31,280	$30,001	$80,351
Direct Assignment	$934,596	$33,969	$4,620	$4,813	$924	-$13	$885,708	$823	$1,094	$1,965	$380	$351	$59	$30	-$128
Total Cost / Classifier	**$235,426,757**	**$108,858,745**	**$15,925,895**	**$29,892,793**	**$7,968,133**	**$6,809,029**	**$2,375,153**	**$3,437,059**	**$18,302,608**	**$24,843,424**	**$5,728,603**	**$3,405,332**	**$589,521**	**$188,371**	**$7,102,091**

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

Mid-Year	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Production															
Demand (PD)	$40,116,642	$16,182,975	$2,590,875	$6,248,029	$1,743,633	$1,087,740	$157,981	$608,019	$3,730,779	$4,450,713	$1,217,251	$522,885	$125,803	$37,690	$1,412,269
Energy (PE)	$155,012,394	$62,484,998	$10,205,605	$24,132,603	$6,733,295	$4,091,200	$634,685	$2,371,427	$14,430,904	$17,170,130	$4,711,084	$2,028,127	$469,546	$142,527	$5,406,264
Direct Assignment (PDA)															
Transmission															
Demand (TD)	$335,237,528	$105,912,722	$16,361,370	$39,751,815	$10,415,998	$21,316,342	$519,486	$4,242,842	$38,294,329	$58,838,945	$10,845,888	$8,760,141	$961,402	$244,518	$18,771,730
Energy (TE)															
Direct Assignment (TDA)															
Distribution															
Demand (DD)	$171,148,062	$80,647,850	$14,998,731	$28,972,695	$6,704,675	$451	$1,334,532	$3,986,949	$10,326,196	$17,615,186	$3,374,608	$2,699,754	$377,774	$108,516	$147
Energy (DE)															
Customer (DC)	$200,447,837	$163,675,583	$18,661,991	$8,390,148	$817,070	$1,216,782	$3,046,210	$2,119,300	$532,051	$667,162	$265,228	$396,788	$132,030	$131,910	$395,584
Direct Assignment (DDA)	$6,016,036	$4,003	$548	$605	$121	$19	$6,010,065	$99	$169	$285	$57	$48	$8	$4	$6
Total	**$907,978,500**	**$428,908,131**	**$62,819,120**	**$107,495,896**	**$26,414,791**	**$27,712,535**	**$11,702,959**	**$13,328,636**	**$67,314,428**	**$98,742,421**	**$20,414,115**	**$14,407,743**	**$2,066,562**	**$665,164**	**$25,986,000**
Total Cost / Function															
Production	$195,129,036	$78,667,973	$12,796,480	$30,380,633	$8,476,928	$5,178,940	$792,666	$2,979,446	$18,161,683	$21,620,842	$5,928,335	$2,551,011	$595,349	$180,217	$6,818,533
Transmission	$335,237,528	$105,912,722	$16,361,370	$39,751,815	$10,415,998	$21,316,342	$519,486	$4,242,842	$38,294,329	$58,838,945	$10,845,888	$8,760,141	$961,402	$244,518	$18,771,730
Distribution	$377,611,936	$244,327,436	$33,661,270	$37,363,448	$7,521,866	$1,217,253	$10,390,806	$6,106,349	$10,858,415	$18,282,633	$3,639,892	$3,096,591	$509,811	$240,430	$395,737
Total Cost / Function	**$907,978,500**	**$428,908,131**	**$62,819,120**	**$107,495,896**	**$26,414,791**	**$27,712,535**	**$11,702,959**	**$13,328,636**	**$67,314,428**	**$98,742,421**	**$20,414,115**	**$14,407,743**	**$2,066,562**	**$665,164**	**$25,986,000**
Total Cost / Classifier															
Demand	$546,502,233	$202,743,547	$33,950,976	$74,972,539	$18,864,305	$22,404,534	$2,011,999	$8,837,810	$52,351,304	$80,904,843	$15,437,747	$11,982,780	$1,464,978	$390,724	$20,184,146
Energy	$155,012,394	$62,484,998	$10,205,605	$24,132,603	$6,733,295	$4,091,200	$634,685	$2,371,427	$14,430,904	$17,170,130	$4,711,084	$2,028,127	$469,546	$142,527	$5,406,264
Customer	$200,447,837	$163,675,583	$18,661,991	$8,390,148	$817,070	$1,216,782	$3,046,210	$2,119,300	$532,051	$667,162	$265,228	$396,788	$132,030	$131,910	$395,584
Direct Assignment	$6,016,036	$4,003	$548	$605	$121	$19	$6,010,065	$99	$169	$285	$57	$48	$8	$4	$6
Total Cost / Classifier	**$907,978,500**	**$428,908,131**	**$62,819,120**	**$107,495,896**	**$26,414,791**	**$27,712,535**	**$11,702,959**	**$13,328,636**	**$67,314,428**	**$98,742,421**	**$20,414,115**	**$14,407,743**	**$2,066,562**	**$665,164**	**$25,986,000**

SUMMARY OF REVENUE REQUIREMENT COST ALLOCATION
Schedule 1.4

Forecast Year: 2009	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Hydraulic Power Generation	$9,679,000	$3,903,270	$636,366	$1,506,678	$420,067	$256,198	$39,220	$147,990	$900,541	$1,072,181	$293,840	$126,514	$29,458	$8,937	$337,738
Purchased Power Supply/Other	$73,237,757	$29,405,205	$4,618,594	$11,435,801	$3,227,822	$2,022,984	$308,072	$1,094,700	$6,853,934	$8,146,844	$2,249,965	$959,994	$231,945	$67,939	$2,613,959
Total Production	$82,916,757	$33,308,475	$5,254,960	$12,942,479	$3,647,889	$2,279,183	$347,292	$1,242,690	$7,754,475	$9,219,025	$2,543,805	$1,086,509	$261,403	$76,876	$2,951,697
Total Transmission	$12,219,000	$3,860,390	$596,352	$1,448,905	$379,650	$776,955	$18,935	$154,646	$1,395,782	$2,144,608	$395,319	$319,296	$35,042	$8,912	$684,207
Total Distribution	$7,743,000	$5,580,385	$714,235	$502,333	$82,490	$51,126	$191,634	$95,982	$147,742	$241,941	$52,115	$49,438	$10,128	$6,852	$16,599
Total Operation & Maintenance	**$102,878,757**	**$42,749,250**	**$6,565,547**	**$14,893,717**	**$4,110,029**	**$3,107,263**	**$557,861**	**$1,493,319**	**$9,297,999**	**$11,605,574**	**$2,991,239**	**$1,455,243**	**$306,572**	**$92,640**	**$3,652,502**
Total O&M w/o Purchased Power Supply & A&G	**$36,389,000**	**$18,811,029**	**$2,458,395**	**$3,606,536**	**$1,128,097**	**$1,115,431**	**$390,564**	**$474,153**	**$2,472,865**	**$3,494,560**	**$754,689**	**$513,477**	**$80,608**	**$30,556**	**$1,058,041**
Total Customer Service, Accounts & Sales	$6,748,000	$5,466,984	$511,442	$148,619	$245,890	$31,152	$140,775	$75,534	$28,800	$35,830	$13,414	$18,228	$5,980	$5,854	$19,497
Total Administrative & General	$11,721,000	$5,579,708	$825,537	$1,461,374	$366,988	$314,841	$142,441	$175,450	$861,080	$1,201,578	$267,639	$168,280	$27,365	$8,855	$319,864
Total O&M plus A&G	**$121,347,757**	**$53,795,942**	**$7,902,527**	**$16,503,710**	**$4,722,907**	**$3,453,256**	**$841,078**	**$1,744,303**	**$10,187,879**	**$12,842,982**	**$3,272,293**	**$1,641,751**	**$339,917**	**$107,350**	**$3,991,863**
Total Depreciation	$37,504,000	$19,499,159	$2,739,541	$4,194,764	$984,351	$959,993	$545,439	$559,189	$2,335,319	$3,488,637	$706,608	$517,554	$72,486	$23,954	$877,006
Total Property Taxes	$11,561,000	$5,809,318	$824,602	$1,324,521	$317,127	$320,487	$153,650	$171,178	$771,823	$1,138,559	$233,505	$166,878	$23,627	$7,619	$298,106
Total Return and Income Taxes	$69,929,000	$33,032,849	$4,838,086	$8,278,919	$2,034,365	$2,134,312	$901,317	$1,026,520	$5,184,297	$7,604,760	$1,572,216	$1,109,629	$159,159	$51,228	$2,001,341
Revenue Requirement Before Other Revenues	**$240,341,757**	**$112,137,268**	**$16,304,756**	**$30,301,913**	**$8,058,750**	**$6,868,048**	**$2,441,483**	**$3,501,190**	**$18,479,319**	**$25,074,938**	**$5,784,622**	**$3,435,812**	**$595,189**	**$190,151**	**$7,168,317**
Total Other Revenues	$4,915,000	$3,278,523	$378,861	$409,120	$90,617	$59,019	$66,330	$64,131	$176,711	$231,515	$56,019	$30,479	$5,668	$1,780	$66,227
REVENUE REQUIREMENT for COST ALLOCATION	**$235,426,757**	**$108,858,745**	**$15,925,895**	**$29,892,793**	**$7,968,133**	**$6,809,029**	**$2,375,153**	**$3,437,059**	**$18,302,608**	**$24,843,424**	**$5,728,603**	**$3,405,332**	**$589,521**	**$188,371**	**$7,102,091**

SUMMARY OF RATE BASE COST ALLOCATIONS
Schedule 1.5

Mid-Year	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Total Production Plant	$162,227,500	$65,421,817	$10,665,985	$25,253,091	$7,040,644	$4,294,083	$657,358	$2,480,430	$15,093,757	$17,970,586	$4,924,987	$2,120,480	$493,734	$149,794	$5,660,753
Total Transmission Plant	$351,704,000	$111,115,030	$17,165,021	$41,704,377	$10,927,619	$22,363,376	$545,003	$4,451,245	$40,175,302	$61,729,045	$11,378,626	$9,190,428	$1,008,625	$256,528	$19,693,775
Total Distribution Plant	$571,086,500	$384,056,568	$51,097,618	$55,082,720	$10,796,739	$1,475,090	$14,333,640	$9,229,995	$13,203,200	$22,232,006	$4,425,368	$3,763,784	$619,250	$291,618	$478,905
Total Transmission & Distribution	$922,790,500	$495,171,599	$68,262,639	$96,787,097	$21,724,358	$23,838,465	$14,878,643	$13,681,240	$53,378,501	$83,961,051	$15,803,994	$12,954,212	$1,627,875	$548,146	$20,172,681
Total General Plant	$147,970,500	$71,579,930	$10,436,066	$18,332,419	$4,588,519	$3,946,623	$1,690,452	$2,214,070	$10,619,554	$14,746,453	$3,294,637	$2,052,866	$333,686	$106,247	$4,028,976
Total Plant Before General Plant & Intangible	**$1,085,018,000**	**$560,593,416**	**$78,928,624**	**$122,040,188**	**$28,765,001**	**$28,132,548**	**$15,536,001**	**$16,161,670**	**$68,472,259**	**$101,931,637**	**$20,728,981**	**$15,074,692**	**$2,121,608**	**$697,940**	**$25,833,434**
Total Gross Plant in Service	**$1,232,988,500**	**$632,173,346**	**$89,364,690**	**$140,372,608**	**$33,353,521**	**$32,079,171**	**$17,226,453**	**$18,375,740**	**$79,091,813**	**$116,678,090**	**$24,023,618**	**$17,127,559**	**$2,455,294**	**$804,187**	**$29,862,410**
Total Accumulated Depreciation	$289,697,500	$158,176,417	$22,083,379	$32,301,663	$7,478,331	$5,929,776	$4,689,822	$4,408,934	$16,116,864	$23,780,157	$4,971,380	$3,511,593	$527,472	$182,557	$5,539,155
Total Net Plant	**$943,291,000**	**$473,996,929**	**$67,281,311**	**$108,070,945**	**$25,875,189**	**$26,149,395**	**$12,536,631**	**$13,966,806**	**$62,974,948**	**$92,897,933**	**$19,052,238**	**$13,615,966**	**$1,927,823**	**$621,630**	**$24,323,255**
Total Working Capital	$17,875,000	$7,442,605	$1,132,775	$2,579,217	$728,962	$537,196	$98,992	$260,386	$1,611,543	$2,010,219	$518,263	$251,731	$53,046	$15,999	$634,067
Total Contributions	-$92,438,500	-$71,865,085	-$8,391,412	-$7,923,931	-$1,368,975		-$1,402,628	-$1,486,469							
SUB-TOTAL RATE BASE	**$868,727,500**	**$409,574,450**	**$60,022,674**	**$102,726,231**	**$25,235,176**	**$26,686,591**	**$11,232,995**	**$12,740,723**	**$64,586,492**	**$94,908,152**	**$19,570,500**	**$13,867,697**	**$1,980,869**	**$637,629**	**$24,957,322**
Total Other Rate Base Items	$39,251,000	$19,333,681	$2,796,446	$4,769,665	$1,179,615	$1,025,944	$469,964	$587,914	$2,727,936	$3,834,269	$843,615	$540,046	$85,693	$27,535	$1,028,678
TOTAL RATE BASE	**$907,978,500**	**$428,908,131**	**$62,819,120**	**$107,495,896**	**$26,414,791**	**$27,712,535**	**$11,702,959**	**$13,328,636**	**$67,314,428**	**$98,742,421**	**$20,414,115**	**$14,407,743**	**$2,066,562**	**$665,164**	**$25,986,000**

SUMMARY OF REVENUE REQUIREMENT UNIT COSTS
BY CUSTOMER CLASS
Schedule 2.1

Forecast Year: 2009	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Billing Determinants															
Total kVA (with ratchet)	4,404,617			1,720,080	478,286	109,512			617,959	749,887	227,104	86,937	30,365	8,994	375,494
Total Demand (kW)	8,336,121	3,222,578	638,546	1,720,080	430,457	240,836	41,225	144,719	601,397	720,794	202,239	83,197	24,736	6,878	258,440
Total kVA Contract									1,101,600	1,692,600	312,000	252,000	30,365	5,400	540,000
Total Energy (kWh)	3,107,070,981	1,221,674,870	203,446,005	474,707,344	141,018,352	83,180,240	13,866,327	47,802,478	300,580,396	355,153,151	98,651,430	42,413,094	9,228,226	2,817,036	112,532,033
Average Monthly Customers	110,944	96,413	8,989	2,466	33	4	1,980	1,051	1	1	1	1	1	1	1
Average PODs									4	5	2	3	1	1	3
Functional Cost															
Production															
Demand (PD)	$27,935,341	$11,235,097	$1,580,229	$4,375,812	$1,241,749	$874,437	$97,551	$404,970	$2,604,160	$3,131,543	$853,878	$359,480	$103,221	$28,559	$1,044,657
$/kW	$3.35	$3.49	$2.47	$2.54	$2.88	$3.63	$2.37	$2.80	$4.33	$4.34	$4.22	$4.32	$4.17	$4.15	$4.04
or $/kVa				$2.54	$2.60	$7.98			$4.21	$4.18	$3.76	$4.13	$3.40	$3.18	$2.78
Energy (PE)	$80,380,022	$32,283,601	$5,340,238	$12,533,265	$3,513,973	$2,077,998	$349,712	$1,225,896	$7,522,109	$8,905,282	$2,464,463	$1,058,644	$235,883	$71,843	$2,797,117
$/kWh	$0.026	$0.026	$0.026	$0.026	$0.025	$0.025	$0.025	$0.026	$0.025	$0.025	$0.025	$0.025	$0.026	$0.026	$0.025
Transmission															
Demand (TD)	$56,672,801	$17,840,700	$2,757,807	$6,719,897	$1,761,527	$3,616,919	$83,708	$716,445	$6,490,078	$9,974,540	$1,837,549	$1,485,244	$162,781	$41,346	$3,184,259
$/kW	$6.80	$5.54	$4.32	$3.91	$4.09	$15.02	$2.03	$4.95	$10.79	$13.84	$9.09	$17.85	$6.58	$6.01	$12.32
or $/kVa				$3.91	$3.68	$33.03			$10.50	$13.30	$8.09	$17.08	$5.36	$4.60	$8.48
or $/kVa Contract									$5.89	$5.89	$5.89	$5.89	$5.36	$7.66	$5.90
Distribution															
Demand (DD)	$27,026,122	$13,157,728	$2,392,468	$4,489,181	$1,028,646	-$431	$246,642	$622,959	$1,522,132	$2,599,833	$498,175	$400,068	$56,297	$16,592	-$4,167
$/kW	$3.24	$4.08	$3.75	$2.61	$2.39	$0.00	$5.98	$4.30	$2.53	$3.61	$2.46	$4.81	$2.28	$2.41	-$0.02
or $/kVa				$2.61	$2.15	$0.00			$2.46	$3.47	$2.19	$4.60	$1.85	$1.84	-$0.01
Customer (DC)	$42,477,874	$34,307,650	$3,850,534	$1,769,826	$421,314	$240,119	$711,831	$465,965	$163,036	$230,262	$74,159	$101,546	$31,280	$30,001	$80,351
$/Customer/Month	$31.91	$29.65	$35.70	$59.80	$1,063.93	$5,002.48	$29.96	$36.95	$13,586.34	$19,188.47	$6,179.88	$8,462.18	$2,606.67	$2,500.09	$6,695.88
Direct Assignment (DDA)	$934,596	$33,969	$4,620	$4,813	$924	-$13	$885,708	$823	$1,094	$1,965	$380	$351	$59	$30	-$128
$/kW	$0.11	$0.01	$0.01	$0.00	$0.00	$0.00	$21.48	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$/kVa				$0.00	$0.00	$0.00			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$/kWh	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.064	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Total	**$235,426,757**	**$108,858,745**	**$15,925,895**	**$29,892,793**	**$7,968,133**	**$6,809,029**	**$2,375,153**	**$3,437,059**	**$18,302,608**	**$24,843,424**	**$5,728,603**	**$3,405,332**	**$589,521**	**$188,371**	**$7,102,091**
Total															
$/kW	**$13.50**	**$13.12**	**$10.55**	**$9.06**	**$9.37**	**$18.65**	**$31.86**	**$12.06**	**$17.65**	**$21.79**	**$15.77**	**$26.99**	**$13.03**	**$12.58**	**$16.35**
$/kVa				**$9.06**	**$8.43**	**$41.01**			**$17.18**	**$20.95**	**$14.05**	**$25.83**	**$10.62**	**$9.62**	**$11.25**
$/kWh	**$0.0262**	**$0.0265**	**$0.0263**	**$0.0264**	**$0.0249**	**$0.0250**	**$0.0891**	**$0.0257**	**$0.0250**	**$0.0251**	**$0.0250**	**$0.0250**	**$0.0256**	**$0.0255**	**$0.0249**
$/kWh (energy only)	**$0.0621**	**$0.0610**	**$0.0594**	**$0.0592**	**$0.0535**	**$0.0790**	**$0.1200**	**$0.0622**	**$0.0603**	**$0.0693**	**$0.0573**	**$0.0779**	**$0.0605**	**$0.0562**	**$0.0624**
$/Customer/Month	**$31.91**	**$29.65**	**$35.70**	**$59.80**	**$1,063.93**	**$5,002.48**	**$29.96**	**$36.95**	**$13,586.34**	**$19,188.47**	**$6,179.88**	**$8,462.18**	**$2,606.67**	**$2,500.09**	**$6,695.88**
$/POD/Month									**$3,396.59**	**$3,837.69**	**$3,089.94**	**$2,820.73**	**$2,606.67**	**$2,500.09**	**$2,231.96**
Total Average Cost per kWh	**$0.0758**	**$0.0891**	**$0.0783**	**$0.0630**	**$0.0565**	**$0.0819**	**$0.1713**	**$0.0719**	**$0.0609**	**$0.0700**	**$0.0581**	**$0.0803**	**$0.0639**	**$0.0669**	**$0.0631**

SUMMARY OF RATE BASE UNIT COST
BY CUSTOMER CLASS
Schedule 2.2

Forecast Year: 2009	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Billing Determinants															
Total kVa	4,404,617			1,720,080	478,286	109,512			617,959	749,887	227,104	86,937	30,365	8,994	375,494
Total Demand (kW)	8,336,121	3,222,578	638,546	1,720,080	430,457	240,836	41,225	144,719	601,397	720,794	202,239	83,197	24,736	6,878	258,440
Total Energy (kWh)	3,107,070,981	1,221,674,870	203,446,005	474,707,344	141,018,352	83,180,240	13,866,327	47,802,478	300,580,396	355,153,151	98,651,430	42,413,094	9,228,226	2,817,036	112,532,033
Average Monthly Customers	110,944	96,413	8,989	2,466	33	4	1,980	1,051	1	1	1	1	1	1	1
Functional Cost															
Production															
Demand (PD)	$40,116,642	$16,182,975	$2,590,875	$6,248,029	$1,743,633	$1,087,740	$157,981	$608,019	$3,730,779	$4,450,713	$1,217,251	$522,885	$125,803	$37,690	$1,412,269
$/kW		$5.02	$4.06	$3.63	$4.05	$4.52	$3.83	$4.20	$6.20	$6.17	$6.02	$6.28	$5.09	$5.48	$5.46
or $/kVa				$3.63	$3.65	$9.93			$6.04	$5.94	$5.36	$6.01	$4.14	$4.19	$3.76
Energy (PE)	$155,012,394	$62,484,998	$10,205,605	$24,132,603	$6,733,295	$4,091,200	$634,685	$2,371,427	$14,430,904	$17,170,130	$4,711,084	$2,028,127	$469,546	$142,527	$5,406,264
$/kWh	$0.050	$0.051	$0.050	$0.051	$0.048	$0.049	$0.046	$0.050	$0.048	$0.048	$0.048	$0.048	$0.051	$0.051	$0.048
Transmission															
Demand (TD)	$335,237,528	$105,912,722	$16,361,370	$39,751,815	$10,415,998	$21,316,342	$519,486	$4,242,842	$38,294,329	$58,838,945	$10,845,888	$8,760,141	$961,402	$244,518	$18,771,730
$/kW		$32.87	$25.62	$23.11	$24.20	$88.51	$12.60	$29.32	$63.68	$81.63	$53.63	$105.29	$38.87	$35.55	$72.63
or $/kVa				$23.11	$21.78	$194.65			$61.97	$78.46	$47.76	$100.76	$31.66	$27.19	$49.99
Distribution															
Demand (DD)	$171,148,062	$80,647,850	$14,998,731	$28,972,695	$6,704,675	$451	$1,334,532	$3,986,949	$10,326,196	$17,615,186	$3,374,608	$2,699,754	$377,774	$108,516	$147
$/kW		$25.03	$23.49	$16.84	$15.58	$0.00	$32.37	$27.55	$17.17	$24.44	$16.69	$32.45	$15.27	$15.78	$0.00
or $/kVa				$16.84	$14.02	$0.00			$16.71	$23.49	$14.86	$31.05	$12.44	$12.07	$0.00
Customer (DC)	$200,447,837	$163,675,583	$18,661,991	$8,390,148	$817,070	$1,216,782	$3,046,210	$2,119,300	$532,051	$667,162	$265,228	$396,788	$132,030	$131,910	$395,584
$/Customer/Month		$141	$173	$283	$2,063	$25,350	$128	$168	$44,338	$55,597	$22,102	$33,066	$11,002	$10,992	$32,965
Direct Assignment (DDA)	$6,016,036	$4,003	$548	$605	$121	$19	$6,010,065	$99	$169	$285	$57	$48	$8	$4	$6
$/kW		$0.00	$0.00	$0.00	$0.00	$0.00	$145.79	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$/kVa				$0.00	$0.00	$0.00			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$/kWh		$0.000	$0.000	$0.000	$0.000	$0.000	$0.433	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Total	**$907,978,500**	**$428,908,131**	**$62,819,120**	**$107,495,896**	**$26,414,791**	**$27,712,535**	**$11,702,959**	**$13,328,636**	**$67,314,428**	**$98,742,421**	**$20,414,115**	**$14,407,743**	**$2,066,562**	**$665,164**	**$25,986,000**

INPUT REVENUE REQUIREMENT
Schedule 3.1

FERC Account		2009 Cost, $	Function	Classification Factor	Classification Method
	Operation & Maintenance Expense				
535.00	Op. Supervision & Engineering	-$207,000	P	RBG	On the Basis of Generation Rate Base
536.00	Water for Power	$8,286,000	P	RBG	On the Basis of Generation Rate Base
542.00	Structures	$627,000	P	RBG	On the Basis of Generation Rate Base
543.00	Dams & Waterways	$176,000	P	RBG	On the Basis of Generation Rate Base
544.00	Electric Plant	$530,000	P	RBG	On the Basis of Generation Rate Base
545.00	Other Plant	$267,000	P	RBG	On the Basis of Generation Rate Base
	Purchased Power Supply/Other				
555.00	Purchased Power - Energy Charges	$52,400,770	P	PURCHkWh	On the Basis of Energy Purchases Weighted by Month
555.00	Purchased Power - Demand Charges	$19,393,988	P	PURCHkW	On the Basis of Demand Purchases Weighted by Month
556.00	System Control	$1,443,000	P	CP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
	Total Purchased Power	$71,794,757			
	Total Production	$82,916,757			
	Transmission				
560.10	Op. Supervision & Engineering	$648,000	T	RBT	On the Basis of Transmission Rate Base
560.20	System Planning	$1,390,000	T	RBT	On the Basis of Transmission Rate Base
561.00	Load Dispatching	$1,157,000	T	RBT	On the Basis of Transmission Rate Base
562.00	Transmission Station Expense	$750,000	T	RBT	On the Basis of Transmission Rate Base
563.10	Transmission Line Maintenance	$310,000	T	RBT	On the Basis of Transmission Rate Base
563.20	Transmission TROW Maintenance	$556,000	T	RBT	On the Basis of Transmission Rate Base
565.00	Wheeling	$4,010,000	T	RBT	On the Basis of Transmission Rate Base
567.00	Rents	$3,398,000	T	RBT	On the Basis of Transmission Rate Base
	Total Transmission	$12,219,000			
	Distribution				
583.10	Distribution Line Maintenance	$3,467,000	D		On the Basis of RBD Poles, Towers & Fixtures
583.20	Distribution ROW Maintenance	$1,714,000	D		On the Basis of RBD Poles, Towers & Fixtures
586.00	Meter Expenses	$971,000	D		On the Basis of RBD Meters
592.00	Distribution Station Expense	$1,214,000	D		On the Basis of RBD Station Equipment
596.00	Street Lighting	$89,000	D	DA1	On the Basis of RBD Street Lights and Signal Systems
598.00	Other Plant	$288,000	D	RBD	On the Basis of Distribution Rate Base
	Total Distribution	$7,743,000			
	Total Operation & Maintenance	$102,878,757			
	Customer Service, Accounts, & Sales				
901.00	Supervision & Administration	$753,000	D		As All Other Customer Service Expense
902.00	Meter Reading	$1,855,000	D	CUSTW	Customers Weighted for Accounting/Metering
903.00	Customer Billing	$381,000	D	CUSTW	Customers Weighted for Accounting/Metering
904.00	Credit & Collections	$1,983,000	D	CUSTR	Retail Customers
910.00	Customer Assistance	$1,720,000	D	CUSTW	Customers Weighted for Accounting/Metering
911.00	Energy Management Promotion	$56,000	SS	DSM	Classified 64% Energy, 21% Demand & 16% T&D
	Total Customer Service, Accounts & Sales	$6,748,000			
	Total O&M w/o Purchased Power Supply & A&G	$37,832,000			

INPUT REVENUE REQUIREMENT
Schedule 3.1

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

Prepared By EES Consulting, Inc.

Fortis BC 2009 COSA

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.2

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

Fortis BC 2009 COSA

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.2

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

Fortis BC 2009 COSA

REVENUE REQUIREMENT COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 3.3

	2009 Total Expenses	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Operation & Maintenance Expense															
Op. Supervision & Engineering	-$207,000	-$83,477	-$13,610	-$32,223	-$8,984	-$5,479	-$839	-$3,165	-$19,259	-$22,930	-$6,284	-$2,706	-$630	-$191	-$7,223
Water for Power	$8,286,000	$3,341,512	$544,780	$1,289,837	$359,611	$219,326	$33,576	$126,692	$770,935	$917,873	$251,551	$108,307	$25,218	$7,651	$289,131
Structures	$627,000	$252,852	$41,223	$97,602	$27,212	$16,596	$2,541	$9,587	$58,337	$69,455	$19,035	$8,196	$1,908	$579	$21,878
Dams & Waterways	$176,000	$70,976	$11,571	$27,397	$7,638	$4,659	$713	$2,691	$16,375	$19,496	$5,343	$2,301	$536	$163	$6,141
Electric Plant	$530,000	$213,734	$34,846	$82,502	$23,002	$14,029	$2,148	$8,104	$49,312	$58,710	$16,090	$6,928	$1,613	$489	$18,494
Other Plant	$267,000	$107,674	$17,554	$41,562	$11,588	$7,067	$1,082	$4,082	$24,842	$29,577	$8,106	$3,490	$813	$247	$9,317
Purchased Power Supply/Other															
Purchased Power - Energy Charges	$52,400,770	$21,028,381	$3,500,390	$8,167,576	$2,294,982	$1,338,980	$237,974	$797,608	$4,911,354	$5,803,050	$1,611,922	$693,012	$150,785	$46,029	$1,818,726
Purchased Power - Demand Charges	$19,393,988	$7,782,422	$1,029,367	$3,044,708	$873,117	$640,893	$67,131	$277,358	$1,811,436	$2,182,786	$596,280	$248,891	$75,788	$20,310	$743,502
System Control	$1,443,000	$594,402	$88,837	$223,517	$59,723	$43,111	$2,966	$19,734	$131,144	$161,008	$41,763	$18,092	$5,372	$1,599	$51,731
Total Purchased Power	$52,400,770	$21,028,381	$3,500,390	$8,167,576	$2,294,982	$1,338,980	$237,974	$797,608	$4,911,354	$5,803,050	$1,611,922	$693,012	$150,785	$46,029	$1,818,726
Total Production	$82,916,757	$33,308,475	$5,254,960	$12,942,479	$3,647,889	$2,279,183	$347,292	$1,242,690	$7,754,475	$9,219,025	$2,543,805	$1,086,509	$261,403	$76,876	$2,951,697
Transmission															
Op. Supervision & Engineering	$648,000	$204,725	$31,626	$76,839	$20,134	$41,204	$1,004	$8,201	$74,021	$113,733	$20,965	$16,933	$1,858	$473	$36,285
System Planning	$1,390,000	$439,147	$67,839	$164,824	$43,188	$88,384	$2,154	$17,592	$158,780	$243,965	$44,970	$36,322	$3,986	$1,014	$77,833
Load Dispatching	$1,157,000	$365,535	$56,468	$137,195	$35,949	$73,569	$1,793	$14,643	$132,165	$203,070	$37,432	$30,234	$3,318	$844	$64,787
Transmission Station Expense	$750,000	$236,950	$36,604	$88,934	$23,303	$47,689	$1,162	$9,492	$85,673	$131,636	$24,265	$19,598	$2,151	$547	$41,996
Transmission Line Maintenance	$310,000	$97,939	$15,130	$36,759	$9,632	$19,712	$480	$3,923	$35,411	$54,409	$10,029	$8,101	$889	$226	$17,359
Transmission TROW Maintenance	$556,000	$175,659	$27,136	$65,929	$17,275	$35,354	$862	$7,037	$63,512	$97,586	$17,988	$14,529	$1,595	$406	$31,133
Wheeling	$4,010,000	$1,266,893	$195,709	$475,498	$124,593	$254,979	$6,214	$50,751	$458,064	$703,812	$129,735	$104,786	$11,500	$2,925	$224,541
Rents	$3,398,000	$1,073,542	$165,840	$402,928	$105,578	$216,065	$5,266	$43,006	$388,155	$596,397	$109,935	$88,794	$9,745	$2,478	$190,272
Total Transmission	$12,219,000	$3,860,390	$596,352	$1,448,905	$379,650	$776,955	$18,935	$154,646	$1,395,782	$2,144,608	$395,319	$319,296	$35,042	$8,912	$684,207
Distribution															
Distribution Line Maintenance	$3,467,000	$2,899,096	$293,064	$156,120	$19,098		$58,551	$41,072							
Distribution ROW Maintenance	$1,714,000	$1,433,242	$144,884	$77,182	$9,441		$28,946	$20,305							
Meter Expenses	$971,000	$575,597	$161,450	$69,137	$4,565	$50,382		$6,275	$21,810	$27,262	$10,905	$16,357	$5,452	$5,452	$16,357
Distribution Station Expense	$1,214,000	$478,770	$89,069	$172,116	$43,941		$7,908	$23,677	$119,274	$203,468	$38,978	$31,183	$4,363	$1,253	
Street Lighting	$89,000						$89,000								
Other Plant	$288,000	$193,680	$25,769	$27,778	$5,445	$744	$7,228	$4,655	$6,658	$11,212	$2,232	$1,898	$312	$147	$242
Total Distribution	$7,743,000	$5,580,385	$714,235	$502,333	$82,490	$51,126	$191,634	$95,982	$147,742	$241,941	$52,115	$49,438	$10,128	$6,852	$16,599
Total Operation & Maintenance	$102,878,757	$42,749,250	$6,565,547	$14,893,717	$4,110,029	$3,107,263	$557,861	$1,493,319	$9,297,999	$11,605,574	$2,991,239	$1,455,243	$306,572	$92,640	$3,652,502
Customer Service, Accounts, & Sales															
Supervision & Administration	$753,000	$610,053	$57,071	$16,584	$27,439	$3,476	$15,709	$8,429	$3,214	$3,998	$1,497	$2,034	$667	$653	$2,176
Meter Reading	$1,855,000	$1,458,323	$135,961	$37,306	$101,078	$12,252	$41,929	$22,256	$9,662	$12,078	$4,831	$7,247	$2,416	$2,416	$7,247
Customer Billing	$381,000	$299,526	$27,925	$7,662	$20,760	$2,516	$8,612	$4,571	$1,985	$2,481	$992	$1,488	$496	$496	$1,488
Credit & Collections	$1,983,000	$1,723,398	$160,674	$44,087	$590	$72	$35,393	$18,787							
Customer Assistance	$1,720,000	$1,352,191	$126,066	$34,591	$93,722	$11,360	$38,877	$20,636	$8,959	$11,199	$4,480	$6,719	$2,240	$2,240	$6,719
Energy Management Promotion	$56,000	$23,493	$3,744	$8,387	$2,302	$1,476	$256	$855	$4,981	$6,074	$1,614	$739	$162	$49	$1,867
Total Customer Service, Accounts & Sales	$6,748,000	$5,466,984	$511,442	$148,619	$245,890	$31,152	$140,775	$75,534	$28,800	$35,830	$13,414	$18,228	$5,980	$5,854	$19,497
Total O&M w/o Purchased Power Supply & A&G	$36,389,000	$18,811,029	$2,458,395	$3,606,536	$1,128,097	$1,115,431	$390,564	$474,153	$2,472,865	$3,494,560	$754,689	$513,477	$80,608	$30,556	$1,058,041

Fortis BC 2009 COSA

REVENUE REQUIREMENT COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 3.3

	2009 Total Expenses	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Administrative & General															
Executive & Senior Management	$1,768,000	$841,645	$124,524	$220,434	$55,357	$47,491	$21,486	$26,465	$129,886	$181,246	$40,371	$25,383	$4,128	$1,336	$48,248
Legal	$658,000	$313,237	$46,344	$82,039	$20,602	$17,675	$7,996	$9,850	$48,340	$67,455	$15,025	$9,447	$1,536	$497	$17,957
Human Resources	$1,034,000	$492,229	$72,827	$128,919	$32,375	$27,775	$12,566	$15,478	$75,963	$106,000	$23,611	$14,845	$2,414	$781	$28,218
Finance & Accounting	$720,000	$342,751	$50,711	$89,770	$22,543	$19,340	$8,750	$10,778	$52,895	$73,811	$16,441	$10,337	$1,681	$544	$19,649
Information Services	$1,792,000	$853,070	$126,215	$223,426	$56,108	$48,135	$21,778	$26,824	$131,649	$183,707	$40,919	$25,728	$4,184	$1,354	$48,903
Materials Management	$284,000	$135,196	$20,003	$35,409	$8,892	$7,629	$3,451	$4,251	$20,864	$29,114	$6,485	$4,077	$663	$215	$7,750
Other	$705,000	$335,611	$49,655	$87,899	$22,074	$18,937	$8,568	$10,553	$51,793	$72,273	$16,098	$10,122	$1,646	$533	$19,239
Special Services	$1,536,000	$731,203	$108,184	$191,508	$48,093	$41,259	$18,666	$22,992	$112,842	$157,463	$35,073	$22,053	$3,586	$1,160	$41,917
Insurance	$615,000	$292,767	$43,316	$76,678	$19,256	$16,520	$7,474	$9,206	$45,181	$63,047	$14,043	$8,830	$1,436	$465	$16,783
Maintenance & General Plant	$1,578,000	$751,197	$111,142	$196,745	$49,408	$42,387	$19,177	$23,621	$115,927	$161,769	$36,032	$22,656	$3,684	$1,192	$43,063
Transportation Equipment Expenses	$1,031,000	$490,801	$72,616	$128,545	$32,281	$27,694	$12,529	$15,433	$75,742	$105,693	$23,542	$14,802	$2,407	$779	$28,136
Total Administrative & General	$11,721,000	$5,579,708	$825,537	$1,461,374	$366,988	$314,841	$142,441	$175,450	$861,080	$1,201,578	$267,639	$168,280	$27,365	$8,855	$319,864
Total O&M plus A&G	$121,347,757	$53,795,942	$7,902,527	$16,503,710	$4,722,907	$3,453,256	$841,078	$1,744,303	$10,187,879	$12,842,982	$3,272,293	$1,641,751	$339,917	$107,350	$3,991,863
Depreciation															
Generation Plant	$3,231,000	$1,302,972	$212,429	$502,953	$140,225	$85,523	$13,092	$49,401	$300,614	$357,911	$98,088	$42,232	$9,833	$2,983	$112,742
Transmission Plant	$9,518,000	$3,007,054	$464,529	$1,128,626	$295,729	$605,210	$14,749	$120,462	$1,087,245	$1,670,544	$307,934	$248,716	$27,296	$6,942	$532,963
Distribution Plant	$15,977,000	$10,744,558	$1,429,532	$1,541,022	$302,055	$41,268	$401,005	$258,223	$369,379	$621,974	$123,806	$105,297	$17,324	$8,158	$13,398
General Plant And Deferred Charges	$7,844,000	$4,052,739	$570,604	$882,274	$207,953	$203,381	$112,316	$116,839	$495,012	$736,902	$149,858	$108,981	$15,338	$5,046	$186,760
DSM Amortization	$934,000	$391,837	$62,447	$139,889	$38,389	$24,612	$4,277	$14,264	$83,069	$101,306	$26,921	$12,327	$2,694	$824	$31,143
Total Depreciation	$37,504,000	$19,499,159	$2,739,541	$4,194,764	$984,351	$959,993	$545,439	$559,189	$2,335,319	$3,488,637	$706,608	$517,554	$72,486	$23,954	$877,006
Taxes															
Property	$11,561,000	$5,809,318	$824,602	$1,324,521	$317,127	$320,487	$153,650	$171,178	$771,823	$1,138,559	$233,505	$166,878	$23,627	$7,619	$298,106
Total Property Taxes	$11,561,000	$5,809,318	$824,602	$1,324,521	$317,127	$320,487	$153,650	$171,178	$771,823	$1,138,559	$233,505	$166,878	$23,627	$7,619	$298,106
Return and Income Taxes															
Incentive Adjustments	-$1,443,000	-$681,640	-$99,835	-$170,837	-$41,980	-$44,042	-$18,599	-$21,182	-$106,979	-$156,926	-$32,443	-$22,897	-$3,284	-$1,057	-$41,298
Income Tax	$4,354,000	$2,056,729	$301,234	$515,472	$126,666	$132,889	$56,119	$63,914	$322,791	$473,496	$97,891	$69,089	$9,910	$3,190	$124,610
Return on Rate Base	$67,018,000	$31,657,760	$4,636,687	$7,934,285	$1,949,679	$2,045,465	$863,797	$983,788	$4,968,486	$7,288,190	$1,506,768	$1,063,437	$152,533	$49,096	$1,918,030
Interest on Non Rate Base Deferral Account															
Total Return and Income Taxes	$69,929,000	$33,032,849	$4,838,086	$8,278,919	$2,034,365	$2,134,312	$901,317	$1,026,520	$5,184,297	$7,604,760	$1,572,216	$1,109,629	$159,159	$51,228	$2,001,341
Revenue Requirement Before Other Revenues	$240,341,757	$112,137,268	$16,304,756	$30,301,913	$8,058,750	$6,868,048	$2,441,483	$3,501,190	$18,479,319	$25,074,938	$5,784,622	$3,435,812	$595,189	$190,151	$7,168,317
Revenue Req. Before Taxes and Other Revenues	$228,780,757	$106,327,951	$15,480,154	$28,977,392	$7,741,623	$6,547,561	$2,287,833	$3,330,013	$17,707,496	$23,936,379	$5,551,117	$3,268,934	$571,562	$182,532	$6,870,211
Other Revenues															
Electric Apparatus Rental	$2,133,000	$1,783,609	$180,302	$96,050	$11,749		$36,022	$25,268							
Lease Revenue	$171,000	$82,720	$12,060	$21,186	$5,303	$4,561	$1,954	$2,559	$12,272	$17,042	$3,807	$2,372	$386	$123	$4,656
Waneta Contract Revenue	$470,000	$189,538	$30,901	$73,162	$20,398	$12,441	$1,904	$7,186	$43,729	$52,064	$14,269	$6,143	$1,430	$434	$16,400
Brilliant Management Fees	$465,000	$187,522	$30,572	$72,384	$20,181	$12,308	$1,884	$7,110	$43,264	$51,510	$14,117	$6,078	$1,415	$429	$16,226
Fortis Pacific Holdings	$641,000	$305,144	$45,147	$79,920	$20,070	$17,218	$7,790	$9,595	$47,091	$65,712	$14,637	$9,203	$1,497	$484	$17,493
Connection Charges	$545,000	$473,652	$44,159	$12,117	$162	$20	$9,727	$5,163							
NSF Cheque Charges	$9,000	$7,822	$729	$200	$3	$0	$161	$85							
Sundry Revenue	$150,000	$77,500	$10,912	$16,872	$3,977	$3,889	$2,148	$2,234	$9,466	$14,092	$2,866	$2,084	$293	$96	$3,571
Investment Income	$331,000	$171,017	$24,078	$37,230	$8,775	$8,582	$4,739	$4,930	$20,888	$31,096	$6,324	$4,599	$647	$213	$7,881
Total Other Revenues	$4,915,000	$3,278,523	$378,861	$409,120	$90,617	$59,019	$66,330	$64,131	$176,711	$231,515	$56,019	$30,479	$5,668	$1,780	$66,227
REVENUE REQUIREMENT for COST ALLOC/	$235,426,757	$108,858,745	$15,925,895	$29,892,793	$7,968,133	$6,809,029	$2,375,153	$3,437,059	$18,302,608	$24,843,424	$5,728,603	$3,405,332	$589,521	$188,371	$7,102,091

REVENUE REQUIREMENT COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.4

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

REVENUE REQUIREMENT COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.4

	2009 Total Expenses	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Operation & Maintenance Expense															
Administrative & General															
Executive & Senior Management	$8,609	$5,615	$768	$848	$170	$27	$233	$139	$237	$400	$80	$68	$11	$5	$9
Legal	$3,204	$2,090	$286	$316	$63	$10	$87	$52	$88	$149	$30	$25	$4	$2	$3
Human Resources	$5,035	$3,284	$449	$496	$99	$16	$136	$81	$139	$234	$47	$40	$7	$3	$5
Finance & Accounting	$3,506	$2,287	$313	$345	$69	$11	$95	$57	$97	$163	$32	$28	$5	$2	$4
Information Services	$8,726	$5,691	$779	$860	$172	$27	$236	$141	$241	$405	$81	$69	$11	$5	$9
Materials Management	$1,383	$902	$123	$136	$27	$4	$37	$22	$38	$64	$13	$11	$2	$1	$1
Other	$3,433	$2,239	$306	$338	$68	$11	$93	$56	$95	$159	$32	$27	$4	$2	$3
Special Services	$7,479	$4,878	$667	$737	$147	$23	$202	$121	$206	$347	$69	$59	$10	$5	$7
Insurance	$2,995	$1,953	$267	$295	$59	$9	$81	$48	$83	$139	$28	$24	$4	$2	$3
Maintenance & General Plant	$7,684	$5,012	$686	$757	$151	$24	$208	$124	$212	$357	$71	$60	$10	$5	$8
Transportation Equipment Expenses	$5,020	$3,274	$448	$495	$99	$15	$136	$81	$138	$233	$46	$39	$6	$3	$5
Total Administrative & General	$57,074	$37,226	$5,092	$5,623	$1,124	$176	$1,542	$923	$1,574	$2,651	$528	$449	$74	$35	$57
Total O&M plus A&G	$149,765	$37,226	$5,092	$5,623	$1,124	$176	$94,232	$923	$1,574	$2,651	$528	$449	$74	$35	$57
Depreciation															
Generation Plant															
Transmission Plant															
Distribution Plant	$204,732						$204,732								
General Plant And Deferred Charges	$52,905						$52,905								
DSM Amortization															
Total Depreciation	$257,637						$257,637								
Taxes															
Property	$71,061						$71,061								
Total Property Taxes	$71,061						$71,061								
Return and Income Taxes															
Incentive Adjustments	-$9,561	-$6	-$1	-$1	$0	$0	-$9,551	$0	$0	$0	$0	$0	$0	$0	$0
Income Tax	$28,849	$19	$3	$3	$1	$0	$28,820	$0	$1	$1	$0	$0	$0	$0	$0
Return on Rate Base	$444,044	$295	$40	$45	$9	$1	$443,604	$7	$12	$21	$4	$4	$1	$0	$0
Interest on Non Rate Base Deferral Account															
Total Return and Income Taxes	$463,332	$308	$42	$47	$9	$1	$462,872	$8	$13	$22	$4	$4	$1	$0	$0
Revenue Requirement Before Other Revenues	$941,794	$37,534	$5,134	$5,670	$1,133	$177	$885,802	$931	$1,587	$2,673	$532	$453	$74	$35	$58
Revenue Req. Before Taxes and Other Revenues	$870,733	$37,534	$5,134	$5,670	$1,133	$177	$814,741	$931	$1,587	$2,673	$532	$453	$74	$35	$58
Other Revenues															
Electric Apparatus Rental															
Lease Revenue	$833	$403	$59	$103	$26	$22	$10	$12	$60	$83	$19	$12	$2	$1	$23
Waneta Contract Revenue															
Brilliant Management Fees															
Fortis Pacific Holdings	$3,121	$1,486	$220	$389	$98	$84	$38	$47	$229	$320	$71	$45	$7	$2	$85
Connection Charges															
NSF Cheque Charges															
Sundry Revenue	$1,012	$523	$74	$114	$27	$26	$14	$15	$64	$95	$19	$14	$2	$1	$24
Investment Income	$2,232	$1,153	$162	$251	$59	$58	$32	$33	$141	$210	$43	$31	$4	$1	$53
Total Other Revenues	$7,198	$3,565	$515	$857	$210	$190	$94	$108	$494	$708	$152	$101	$16	$5	$185
REVENUE REQUIREMENT for COST ALLOCATION	$934,596	$33,969	$4,620	$4,813	$924	-$13	$885,708	$823	$1,094	$1,965	$380	$351	$59	$30	-$128

INPUT RATE BASE
Schedule 4.1

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

INPUT RATE BASE
Schedule 4.1

FERC Account		2008 Cost, $	2009 Cost, $	Mid-Year Cost, $	Function	Classification Factor	Classification Method
	General Plant						
389.00	Land & Rights	$5,800,000	$5,800,000	$5,800,000	SS	LABOR	On the Basis of Labor Ratios
390.00	Structures - Frame & Iron	$337,000	$337,000	$337,000	SS	LABOR	On the Basis of Labor Ratios
390.10	Structures - Masonry	$24,674,000	$26,680,000	$25,677,000	SS	LABOR	On the Basis of Labor Ratios
391.00	Office Furniture & Equipment	$5,767,000	$7,586,000	$6,676,500	SS	LABOR	On the Basis of Labor Ratios
391.10	Computer Equipment	$51,652,000	$57,188,000	$54,420,000	SS	LABOR	On the Basis of Labor Ratios
392.00	Transportation Equipment	$19,180,000	$21,180,000	$20,180,000	SS	LABOR	On the Basis of Labor Ratios
394.00	Tool and Work Environment	$10,664,000	$11,282,000	$10,973,000	SS	LABOR	On the Basis of Labor Ratios
397.00	Communication Structures & Equipment	$23,031,000	$24,783,000	$23,907,000	SS	LABOR	On the Basis of Labor Ratios
	Total General Plant	$141,105,000	$154,836,000	$147,970,500	12%		
	Total Plant Before General Plant & Intangible	$1,032,010,000	$1,138,026,000	$1,085,018,000			
	Total Gross Plant in Service	$1,173,115,000	$1,292,862,000	$1,232,988,500			
	Less: Accumulated Depreciation						
	Hydraulic Production Plant	$25,802,000	$27,273,000	$26,537,500	P		On the Basis of Hydraulic Production Plant
	Transmission Plant	$49,770,000	$50,897,000	$50,333,500	T	RBT	On the Basis of Transmission Rate Base
	Distribution Plant	$143,586,000	$159,226,000	$151,406,000	D	RBD	On the Basis of Distribution Rate Base
	General Plant	$52,671,000	$61,113,000	$56,892,000	SS	RBGP	On the Basis of General Plant Rate Base
	CWIP	$4,104,000	$4,953,000	$4,528,500	SS		On the Basis of CWIP
	Total Accumulated Depreciation	$275,933,000	$303,462,000	$289,697,500			
	Total Net Plant	$897,182,000	$989,400,000	$943,291,000			
	Working Capital						
	Allowance for Working Capital		$7,018,000	$7,018,000	SS	OM	On the Basis of All O&M
	Adjustment for Capital Additions		$10,857,000	$10,857,000	SS	OM	On the Basis of All O&M
	Total Working Capital		$17,875,000	$17,875,000			
	Distribution Plant CIAC	-$87,388,000	-$97,489,000	-$92,438,500	D		On the Basis of Poles, Conductors and Transformers
	Total Contributions	-$87,388,000	-$97,489,000	-$92,438,500			
	SUB-TOTAL RATE BASE	$809,794,000	$909,786,000	$868,727,500			
	Other Rate Base Items						
	Production Plant CWIP not subject to AFUDC				P	RBG	On the Basis of Generation Rate Base
	Transmission Plant CWIP not subject to AFUDC				T	RBT	On the Basis of Transmission Rate Base
	Distribution Plant CWIP not subject to AFUDC				D	RBD	On the Basis of Distribution Rate Base
	General Plant CWIP not subject to AFUDC	$6,865,000	$6,865,000	$6,865,000	D	RBGP	On the Basis of General Plant Rate Base
	Deferred DSM	$6,595,000	$8,229,000	$7,412,000	SS	DSM	Classified 64% Energy, 21% Demand & 16% T&D
	Plant Acquisition Adjustment & Deferred	$22,654,000	$27,294,000	$24,974,000	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Total Other Rate Base Items	$36,114,000	$42,388,000	$39,251,000			
	TOTAL RATE BASE	$845,908,000	$952,174,000	$907,978,500			

Fortis BC 2009 COSA

RATE BASE FOR COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 4.2

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

Fortis BC 2009 COSA

RATE BASE FOR COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 4.2

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

RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3

Account Description	Total Rate Base	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Hydraulic Production															
Land & Rights	$847,000	$341,571	$55,688	$131,848	$36,760	$22,420	$3,432	$12,950	$78,805	$93,826	$25,714	$11,071	$2,578	$782	$29,555
Structures & Improvements	$11,770,500	$4,746,714	$773,876	$1,832,251	$510,838	$311,559	$47,695	$179,969	$1,095,135	$1,303,865	$357,335	$153,853	$35,823	$10,868	$410,719
Reservoirs, Dams, & Waterways	$22,146,000	$8,930,863	$1,456,035	$3,447,350	$961,132	$586,194	$89,737	$338,609	$2,060,479	$2,453,201	$672,320	$289,471	$67,401	$20,449	$772,761
Water Wheels, Turbines, & Generators	$63,405,500	$25,569,666	$4,168,727	$9,869,996	$2,751,787	$1,678,313	$256,924	$969,459	$5,899,291	$7,023,680	$1,924,897	$828,775	$192,972	$58,546	$2,212,466
Accessory Electric Equipment	$23,865,000	$9,624,088	$1,569,054	$3,714,937	$1,035,737	$631,695	$96,703	$364,892	$2,220,416	$2,643,621	$724,506	$311,940	$72,632	$22,036	$832,743
Misc. Power Plant Equipment	$39,140,500	$15,784,270	$2,573,374	$6,092,793	$1,698,690	$1,036,030	$158,600	$598,451	$3,641,659	$4,335,749	$1,188,248	$511,607	$119,123	$36,141	$1,365,765
Roads, RR, & Bridges	$1,053,000	$424,645	$69,232	$163,915	$45,700	$27,872	$4,267	$16,100	$97,972	$116,645	$31,968	$13,764	$3,205	$972	$36,743
Total Hydraulic Production	$162,227,500	$65,421,817	$10,665,985	$25,253,091	$7,040,644	$4,294,083	$657,358	$2,480,430	$15,093,757	$17,970,586	$4,924,987	$2,120,480	$493,734	$149,794	$5,660,753
Total Production Plant	$162,227,500	$65,421,817	$10,665,985	$25,253,091	$7,040,644	$4,294,083	$657,358	$2,480,430	$15,093,757	$17,970,586	$4,924,987	$2,120,480	$493,734	$149,794	$5,660,753
Transmission Plant															
Land & Rights - R/W	$7,478,000	$2,362,550	$364,966	$886,727	$232,345	$475,495	$11,588	$94,643	$854,215	$1,312,495	$241,935	$195,409	$21,446	$5,454	$418,733
Land & Rights - Clearing	$4,895,000	$1,546,494	$238,902	$580,440	$152,090	$311,252	$7,585	$61,952	$559,158	$859,142	$158,367	$127,912	$14,038	$3,570	$274,097
Station Equipment	$183,076,500	$57,839,976	$8,935,104	$21,708,856	$5,688,278	$11,641,063	$283,697	$2,317,057	$20,912,909	$32,132,525	$5,923,046	$4,783,999	$525,031	$133,534	$10,251,426
Poles Towers & Fixtures	$79,265,500	$25,042,617	$3,868,577	$9,399,149	$2,462,819	$5,040,159	$122,830	$1,003,202	$9,054,533	$13,912,220	$2,564,465	$2,071,298	$227,319	$57,815	$4,438,496
Conductors & Devices	$75,972,500	$24,002,248	$3,707,861	$9,008,672	$2,360,504	$4,830,771	$117,727	$961,525	$8,678,372	$13,334,252	$2,457,927	$1,985,248	$217,876	$55,413	$4,254,104
Roads, Railroads & Bridges	$1,016,500	$321,146	$49,611	$120,535	$31,583	$64,635	$1,575	$12,865	$116,115	$178,410	$32,887	$26,562	$2,915	$741	$56,919
Total Transmission Plant	$351,704,000	$111,115,030	$17,165,021	$41,704,377	$10,927,619	$22,363,376	$545,003	$4,451,245	$40,175,302	$61,729,045	$11,378,626	$9,190,428	$1,008,625	$256,528	$19,693,775
Distribution Plant															
Land & Rights - R/W	$3,321,500	$1,309,913	$243,691	$470,909	$120,223		$21,637	$64,780	$326,334	$556,687	$106,645	$85,316	$11,937	$3,428	
Land & Rights - Clearing	$7,441,500	$2,934,733	$545,967	$1,055,026	$269,348		$48,476	$145,133	$731,119	$1,247,203	$238,928	$191,142	$26,744	$7,680	
Station Equipment	$117,123,000	$46,190,253	$8,593,068	$16,605,229	$4,239,307		$762,977	$2,284,266	$11,507,207	$19,629,941	$3,760,525	$3,008,420	$420,933	$120,875	
Poles, Towers, & Fixtures	$121,450,000	$103,919,411	$10,014,804	$3,832,397	$294,915		$2,120,021	$1,268,453							
Conductors & Devices	$192,810,000	$140,321,805	$18,521,280	$23,158,982	$4,371,181		$2,646,226	$3,790,526							
Line Transformers	$93,193,500	$72,528,099	$8,451,863	$7,935,987	$1,368,119		$1,416,303	$1,493,130							
Services	$7,292,000	$4,322,606	$1,212,455	$519,202	$34,280	$378,358		$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	$65,211	$719,748		$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	$34,156	$376,983		$46,949	$163,190	$203,987	$81,595	$122,392	$40,797	$40,797	$122,392
Street Lights and Signal Systems	$7,318,000						$7,318,000								
Total Distribution Plant	$571,086,500	$384,056,568	$51,097,618	$55,082,720	$10,796,739	$1,475,090	$14,333,640	$9,229,995	$13,203,200	$22,232,006	$4,425,368	$3,763,784	$619,250	$291,618	$478,905
Total Transmission & Distribution	$922,790,500	$495,171,599	$68,262,639	$96,787,097	$21,724,358	$23,838,465	$14,878,643	$13,681,240	$53,378,501	$83,961,051	$15,803,994	$12,954,212	$1,627,875	$548,146	$20,172,681

RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3

Account Description	Total Rate Base	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
General Plant															
Land & Rights	$5,800,000	$2,805,719	$409,063	$718,576	$179,856	$154,696	$66,261	$86,785	$416,255	$578,017	$129,140	$80,466	$13,079	$4,165	$157,924
Structures - Frame & Iron	$337,000	$163,022	$23,768	$41,752	$10,450	$8,988	$3,850	$5,043	$24,186	$33,585	$7,503	$4,675	$760	$242	$9,176
Structures - Masonry	$25,677,000	$12,421,110	$1,810,948	$3,181,185	$796,236	$684,849	$293,340	$384,203	$1,842,788	$2,558,920	$571,711	$356,229	$57,904	$18,437	$699,140
Office Furniture & Equipment	$6,676,500	$3,229,721	$470,880	$827,168	$207,036	$178,074	$76,274	$99,900	$479,159	$665,367	$148,656	$92,626	$15,056	$4,794	$181,789
Computer Equipment	$54,420,000	$26,325,381	$3,838,135	$6,742,224	$1,687,547	$1,451,473	$621,708	$814,282	$3,905,617	$5,423,392	$1,211,688	$754,995	$122,722	$39,075	$1,481,761
Transportation Equipment	$20,180,000	$9,761,966	$1,423,255	$2,500,148	$625,776	$538,235	$230,541	$301,952	$1,448,279	$2,011,100	$449,318	$279,967	$45,508	$14,490	$549,466
Tool and Work Environment	$10,973,000	$5,308,129	$773,904	$1,359,471	$340,269	$292,668	$125,358	$164,188	$787,511	$1,093,548	$244,319	$152,234	$24,745	$7,879	$298,775
Communication Structures & Equipment	$23,907,000	$11,564,882	$1,686,113	$2,961,895	$741,349	$637,640	$273,120	$357,718	$1,715,759	$2,382,525	$532,301	$331,673	$53,912	$17,166	$650,946
Total General Plant	$147,970,500	$71,579,930	$10,436,066	$18,332,419	$4,588,519	$3,946,623	$1,690,452	$2,214,070	$10,619,554	$14,746,453	$3,294,637	$2,052,866	$333,686	$106,247	$4,028,976
Total Plant Before General Plant & Intangible	$1,085,018,000	$560,593,416	$78,928,624	$122,040,188	$28,765,001	$28,132,548	$15,536,001	$16,161,670	$68,472,259	$101,931,637	$20,728,981	$15,074,692	$2,121,608	$697,940	$25,833,434
Total Gross Plant in Service	$1,232,988,500	$632,173,346	$89,364,690	$140,372,608	$33,353,521	$32,079,171	$17,226,453	$18,375,740	$79,091,813	$116,678,090	$24,023,618	$17,127,559	$2,455,294	$804,187	$29,862,410
Less: Accumulated Depreciation															
Hydraulic Production Plant	$26,537,500	$10,701,832	$1,744,763	$4,130,951	$1,151,723	$702,435	$107,532	$405,754	$2,469,067	$2,939,665	$805,639	$346,872	$80,766	$24,504	$925,997
Transmission Plant	$50,333,500	$15,902,032	$2,456,542	$5,968,449	$1,563,887	$3,200,495	$77,997	$637,032	$5,749,618	$8,834,244	$1,628,432	$1,315,272	$144,348	$36,713	$2,818,440
Distribution Plant	$151,406,000	$101,820,773	$13,546,960	$14,603,487	$2,862,423	$391,075	$3,800,123	$2,447,049	$3,500,422	$5,894,132	$1,173,250	$997,851	$164,175	$77,313	$126,967
General Plant	$56,892,000	$27,521,198	$4,012,480	$7,048,486	$1,764,203	$1,517,406	$649,948	$851,270	$4,083,028	$5,669,746	$1,266,729	$789,290	$128,296	$40,850	$1,549,069
CWIP	$4,528,500	$2,230,582	$322,634	$550,290	$136,096	$118,366	$54,221	$67,829	$314,730	$442,371	$97,330	$62,307	$9,887	$3,177	$118,682
Total Accumulated Depreciation	$289,697,500	$158,176,417	$22,083,379	$32,301,663	$7,478,331	$5,929,776	$4,689,822	$4,408,934	$16,116,864	$23,780,157	$4,971,380	$3,511,593	$527,472	$182,557	$5,539,155
Total Net Plant	$943,291,000	$473,996,929	$67,281,311	$108,070,945	$25,875,189	$26,149,395	$12,536,631	$13,966,806	$62,974,948	$92,897,933	$19,052,238	$13,615,966	$1,927,823	$621,630	$24,323,255
Working Capital															
Allowance for Working Capital	$7,018,000	$2,922,081	$444,745	$1,012,640	$286,202	$210,911	$38,866	$102,232	$632,717	$789,243	$203,478	$98,834	$20,827	$6,282	$248,944
Adjustment for Capital Additions	$10,857,000	$4,520,524	$688,030	$1,566,577	$442,760	$326,285	$60,126	$158,155	$978,827	$1,220,976	$314,785	$152,898	$32,219	$9,718	$385,122
Total Working Capital	$17,875,000	$7,442,605	$1,132,775	$2,579,217	$728,962	$537,196	$98,992	$260,386	$1,611,543	$2,010,219	$518,263	$251,731	$53,046	$15,999	$634,067
Distribution Plant CIAC	-$92,438,500	-$71,865,085	-$8,391,412	-$7,923,931	-$1,368,975		-$1,402,628	-$1,486,469							
Total Contributions	-$92,438,500	-$71,865,085	-$8,391,412	-$7,923,931	-$1,368,975		-$1,402,628	-$1,486,469							
SUB-TOTAL RATE BASE	$868,727,500	$409,574,450	$60,022,674	$102,726,231	$25,235,176	$26,686,591	$11,232,995	$12,740,723	$64,586,492	$94,908,152	$19,570,500	$13,867,697	$1,980,869	$637,629	$24,957,322
Other Rate Base Items															
Production Plant CWIP not subject to AFUDC															
Transmission Plant CWIP not subject to AFUDC															
Distribution Plant CWIP not subject to AFUDC															
General Plant CWIP not subject to AFUDC	$6,865,000	$3,320,907	$484,175	$850,521	$212,882	$183,101	$78,427	$102,720	$492,688	$684,153	$152,853	$95,241	$15,481	$4,929	$186,922
Deferred DSM	$7,412,000	$3,109,523	$495,561	$1,110,129	$304,646	$195,312	$33,942	$113,198	$659,213	$803,943	$213,641	$97,828	$21,379	$6,541	$247,145
Plant Acquisition Adjustment & Deferred	$24,974,000	$12,903,251	$1,816,710	$2,809,015	$662,088	$647,531	$357,594	$371,995	$1,576,035	$2,346,174	$477,122	$346,976	$48,833	$16,065	$594,611
Total Other Rate Base Items	$39,251,000	$19,333,681	$2,796,446	$4,769,665	$1,179,615	$1,025,944	$469,964	$587,914	$2,727,936	$3,834,269	$843,615	$540,046	$85,693	$27,535	$1,028,678
TOTAL RATE BASE	$907,978,500	$428,908,131	$62,819,120	$107,495,896	$26,414,791	$27,712,535	$11,702,959	$13,328,636	$67,314,428	$98,742,421	$20,414,115	$14,407,743	$2,066,562	$665,164	$25,986,000

A-24

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

Purchased Power Supply Summary	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	Totals
Energy Charges	$5,711,582	$4,663,080	$4,749,462	$4,166,801	$3,414,723	$3,171,778	$4,075,928	$3,582,288	$3,603,323	$4,416,048	$5,337,105	$5,508,652	$52,400,770
Total System kWh	361,624,888	319,102,862	310,114,993	270,884,123	258,896,213	244,989,642	255,898,311	254,588,796	251,457,025	265,349,496	297,889,762	335,436,486	3,426,232,597
	$0.0158	$0.0146	$0.0153	$0.0154	$0.0132	$0.0129	$0.0159	$0.0141	$0.0143	$0.0166	$0.0179	$0.0164	$0.0153
Capacity Charges	$2,867,106	$2,704,435	$2,101,202	$956,739	$1,205,871	$1,642,359	$824,263	$793,155	$902,662	$921,980	$1,617,900	$2,856,315	$19,393,988
Total System CP kW	700,994	599,529	549,574	491,637	454,044	494,231	561,282	538,237	454,371	519,098	612,218	666,561	6,641,776
	$4.09	$4.51	$3.82	$1.95	$2.66	$3.32	$1.47	$1.47	$1.99	$1.78	$2.64	$4.29	$2.92

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

ENERGY GW.h	JAN Forecast	FEB Forecast	MAR Forecast	APR Forecast	MAY Forecast	JUNE Forecast	JULY Forecast	AUG Forecast	SEPT Forecast	OCT Forecast	NOV Forecast	DEC Forecast	TOTAL
FortisBC	156	151	140	119	128	128	136	118	123	111	118	152	1581
Brilliant Base Plant	82	63	57	82	79	72	79	86	66	62	63	65	857
Brilliant Upgrade	1	-1	0	10	14	13	14	13	1	1	0	0	65
Brilliant Regulated													
Cominco													
Small Misc IPP Resource	1	0	1	1	3	2	3	1	1	1	1	1	13
Turbine Upgrades													
CPC Loss, Wheeling & PPA Adjustments													
DSM	2	2	2	2	2	2	2	2	2	2	2	2	25
City of Nelson Special Adjustment													
Market Capacity - ENERGY	1		4				3	0			0		8
Market Energy Purchase													
BCH Purchase	126	108	107	56	30	30	42	32	56	86	115	119	908
SUBTOTAL	368	324	311	270	256	247	279	251	249	263	299	340	3457
Gross Load	368	324	311	270	256	242	253	251	249	263	299	340	3426
Surplus						4	27						31
RATE (Mills/kW.h)													
Surplus Rate	58.08	53.70	48.11	25.69	20.63	17.41	33.60	39.26	41.15	57.82	61.07	73.02	
Brilliant Base Plant	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	
Brilliant Upgrade	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	25.90	
Brilliant Regulated	28.49	28.49	28.49	31.13	31.13	31.13	31.13	31.13	31.13	31.13	31.13	31.13	
Market Capacity - ENERGY	80.32	74.49	61.69	56.30	45.65	47.77	94.80	115.57	84.12	73.68	84.44	100.38	
Market Energy Purchase	58.08	53.70	48.11	25.69	20.63	17.41	33.60	39.26	41.15	57.82	61.07	73.02	
BCH : Purchase	28.49	28.49	28.49	31.13	31.13	31.13	31.13	31.13	31.13	31.13	31.13	31.13	
IPP Rate	28.49	28.49	28.49	28.49	28.49	28.49	28.49	28.49	28.49	28.49	28.49	28.49	
ENERGY EXPENSE ($000)													
Surplus Revenue						($76)	($893)						($969)
Brilliant Base Plant	$2,789	$2,146	$2,007	$2,784.85	$2,699	$2,459	$2,700	$2,931	$2,250	$2,120	$2,144	$2,215	$29,245
Brilliant Upgrade	$18	($17)	($11)	$253.61	$360	$335	$360	$330	$25	$16	$8	$9	$1,686
Brilliant Regulated													
IPP Costs	$14	$11	$20	$17.09	$71	$63	$77	$17	$20	$14	$23	$23	$370
BCH Purchase	$3,577	$3,081	$3,054	$1,750.06	$947	$921	$1,318	$1,000	$1,756	$2,685	$3,578	$3,697	$27,365
Market Capacity - ENERGY	$55		$251				$283	$1			$6		$596
Market Energy Purchase													
TOTAL	$6,453	$5,222	$5,321	$4,805.61	$4,077	$3,702	$3,845	$4,279	$4,051	$4,835	$5,758	$5,944	$58,293
CAPACITY (MW)													

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

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

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

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

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

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

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

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

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

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

Resulting Classification Factor	
Energy Component	80%
Demand Component	20%

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

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

CLASSIFICATION and ALLOCATION BY FUNCTION
Schedule 6.1

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

CLASSIFICATION AND ALLOCATION BY CUSTOMER
Schedule 6.2

Classification Factors	Total Allocated	Residential	General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
CP1	100%	44.683%	5.258%	15.059%	3.823%	3.165%	0.373%	0.567%	8.759%	10.254%	2.929%	1.150%	0.479%	0.097%	3.403%
CP2	100%	41.192%	6.156%	15.490%	4.139%	2.988%	0.206%	1.368%	9.088%	11.158%	2.894%	1.254%	0.372%	0.111%	3.585%
CP4	100%	42.594%	5.123%	14.545%	3.905%	3.087%	0.422%	1.138%	9.352%	11.195%	3.022%	1.274%	0.398%	0.098%	3.846%
CP12	100%	38.919%	5.623%	16.229%	4.648%	3.273%	0.318%	1.748%	9.299%	11.250%	3.094%	1.281%	0.382%	0.106%	3.829%
TCP1	100%	35.132%	4.134%	11.840%	3.006%	5.731%	0.294%	0.446%	10.296%	17.564%	3.365%	2.692%	0.377%	0.077%	5.047%
TCP2	100%	31.593%	4.881%	11.858%	3.107%	6.359%	0.155%	1.266%	11.423%	17.551%	3.235%	2.613%	0.287%	0.073%	5.600%
TCP4	100%	32.759%	3.940%	11.187%	3.003%	6.095%	0.324%	0.875%	10.949%	18.678%	3.578%	2.863%	0.306%	0.075%	5.367%
TCP12	100%	28.638%	4.138%	11.942%	3.420%	6.794%	0.234%	1.286%	12.205%	18.752%	3.457%	2.792%	0.281%	0.078%	5.983%
NCP	100%	36.598%	6.809%	13.157%	3.359%	4.777%	0.605%	1.810%	8.581%	14.638%	2.804%	2.243%	0.319%	0.095%	4.206%
NCPP	100%	39.437%	7.337%	14.178%	3.620%		0.651%	1.950%	9.825%	16.760%	3.211%	2.569%	0.359%	0.103%	
NCPS	100%	62.049%	11.543%	22.306%			1.025%	3.077%							
kWh	100%	40.110%	6.680%	15.586%	4.390%	2.562%	0.455%	1.569%	9.358%	11.057%	3.071%	1.32%	0.29%	0.09%	3.47%
CUST	100%	86.894%	8.101%	2.223%	0.030%	0.004%	1.784%	0.947%	0.004%	0.005%	0.002%	0.003%	0.001%	0.001%	0.003%
CUSTW	100%	78.616%	7.329%	2.011%	5.449%	0.660%	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%	0.470%	5.189%		0.646%	2.246%	2.808%	1.123%	1.68%	0.56%	0.56%	1.68%
CUSTR	100%	86.909%	8.103%	2.223%	0.030%	0.004%	1.785%	0.947%							
MINSYSP	100%	85.176%	8.104%	2.766%	0.144%	0.003%	1.742%	0.996%	0.318%	0.541%	0.104%	0.08%	0.01%	0.00%	0.00%
MINSYSC	100%	68.861%	8.133%	7.927%	1.233%	0.002%	1.340%	1.463%	3.303%	5.634%	1.080%	0.86%	0.12%	0.04%	0.00%
MINSYST	100%	80.186%	9.031%	7.645%	0.022%	0.003%	1.579%	1.522%	0.003%	0.003%	0.001%	0.00%	0.00%	0.00%	0.00%
20D/80E	100%	40.327%	6.575%	15.566%	4.340%	2.647%	0.405%	1.529%	9.304%	11.077%	3.036%	1.307%	0.304%	0.092%	3.489%
DA1	100%						100.000%								
REV	100%	46.476%	6.766%	12.666%	3.384%	2.862%	1.000%	1.456%	7.740%	10.463%	2.426%	1.43%	0.25%	0.08%	3.00%
RB	100%	47.238%	6.919%	11.839%	2.909%	3.052%	1.289%	1.468%	7.414%	10.875%	2.248%	1.59%	0.23%	0.07%	2.86%
RBG	100%	40.327%	6.575%	15.566%	4.340%	2.647%	0.405%	1.529%	9.304%	11.077%	3.036%	1.307%	0.304%	0.092%	3.489%
RBT	100%	31.593%	4.881%	11.858%	3.107%	6.359%	0.155%	1.266%	11.423%	17.551%	3.235%	2.61%	0.29%	0.07%	5.60%
RBT-D	100%	31.593%	4.881%	11.858%	3.107%	6.359%	0.155%	1.266%	11.423%	17.551%	3.235%	2.613%	0.287%	0.073%	5.600%
RBT-E															
RBT-DA															
RBD	100%	65.224%	8.922%	9.852%	1.970%	0.308%	2.702%	1.618%	2.758%	4.645%	0.925%	0.786%	0.129%	0.061%	0.100%
RBGP	100%	48.374%	7.053%	12.389%	3.101%	2.667%	1.142%	1.496%	7.177%	9.966%	2.227%	1.39%	0.23%	0.07%	2.72%
OM	100%	41.553%	6.382%	14.477%	3.995%	3.020%	0.542%	1.452%	9.038%	11.281%	2.908%	1.41%	0.30%	0.09%	3.55%
OMAG	100%	51.694%	6.756%	9.911%	3.100%	3.065%	1.073%	1.303%	6.796%	9.603%	2.074%	1.41%	0.22%	0.08%	2.91%
GPLT	100%	51.667%	7.274%	11.248%	2.651%	2.593%	1.432%	1.490%	6.311%	9.394%	1.910%	1.39%	0.20%	0.06%	2.38%
NETPLT	100%	50.249%	7.133%	11.457%	2.743%	2.772%	1.329%	1.481%	6.676%	9.848%	2.020%	1.44%	0.20%	0.07%	2.58%
LABOR	100%	47.60%	7.04%	12.47%	3.13%	2.69%	1.22%	1.50%	7.35%	10.25%	2.28%	1.44%	0.23%	0.08%	2.73%
PURCHkWh	100%	40.13%	6.68%	15.59%	4.38%	2.56%	0.45%	1.52%	9.37%	11.07%	3.08%	1.32%	0.29%	0.09%	3.47%
PURCHkW	100%	40.13%	5.31%	15.70%	4.50%	3.30%	0.35%	1.43%	9.34%	11.25%	3.07%	1.28%	0.39%	0.10%	3.83%
DSM															

COINCIDENT PEAK DEMAND ALLOCATION - PRODUCTION
Schedule 6.3

Calculation of 1 CP Allocation - Production

	Total Allocated	Residential	General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	700,994	313,226	36,855	105,566	26,797	22,189	2,617	3,972	61,401	71,883	20,529	8,062	3,358	683	23,855
Feb-09															
Mar-09															
Apr-09															
May-09															
Jun-09															
Jul-09															
Aug-09															
Sep-09															
Oct-09															
Nov-09															
Dec-09															
Total Annual 1CP	700,994	313,226	36,855	105,566	26,797	22,189	2,617	3,972	61,401	71,883	20,529	8,062	3,358	683	23,855
% of Total	100%	44.68%	5.26%	15.06%	3.82%	3.17%	0.37%	0.57%	8.76%	10.25%	2.93%	1.15%	0.48%	0.10%	3.40%

Calculation of 2 CP & 4 CP Allocation - Production

	Total Allocated	Residential	General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
2 CP - Production															
Jan-09	700,994	313,226	36,855	105,566	26,797	22,189	2,617	3,972	61,401	71,883	20,529	8,062	3,358	683	23,855
Feb-09															
Mar-09															
Apr-09															
May-09															
Jun-09	494,231	180,644	27,699	77,683	25,787	17,663		8,866	50,500	61,262	16,049	6,866	1,655	812	18,747
Jul-09	561,282	201,547	50,988	104,809	25,439	14,733		14,032	45,859	61,151	15,590	6,607	1,849	504	18,173
Aug-09															
Sep-09															
Oct-09															
Nov-09															
Dec-09	666,561	302,697	33,633	87,268	22,263	17,807	2,364	6,267	62,455	76,066	17,959	8,845	2,158	686	26,092
2 Winter + 2 Summer	2,423,069	998,113	149,174	375,327	100,287	72,392	4,981	33,136	220,216	270,363	70,128	30,380	9,021	2,685	86,866
% of Total	100%	41.19%	6.16%	15.49%	4.14%	2.99%	0.21%	1.37%	9.09%	11.16%	2.89%	1.25%	0.37%	0.11%	3.58%

	Total Allocated	Residential	General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
4 CP - Production															
Jan-09	700,994	313,226	36,855	105,566	26,797	22,189	2,617	3,972	61,401	71,883	20,529	8,062	3,358	683	23,855
Feb-09	599,529	255,130	23,056	77,894	26,859	22,022	2,792	4,642	59,575	71,184	19,953	8,126	2,864	540	24,893
Mar-09															
Apr-09															
May-09															
Jun-09															
Jul-09															
Aug-09															
Sep-09															
Oct-09															
Nov-09	612,218	227,577	38,586	104,440	24,804	17,613	3,109	14,479	57,778	69,624	19,518	7,833	1,881	622	24,354
Dec-09	666,561	302,697	33,633	87,268	22,263	17,807	2,364	6,267	62,455	76,066	17,959	8,845	2,158	686	26,092
4 Winter	2,579,303	1,098,630	132,129	375,168	100,723	79,631	10,882	29,360	241,209	288,758	77,959	32,866	10,262	2,531	99,194
% of Total	100%	42.59%	5.12%	14.55%	3.91%	3.09%	0.42%	1.14%	9.35%	11.20%	3.02%	1.27%	0.40%	0.10%	3.85%

COINCIDENT PEAK DEMAND ALLOCATION - PRODUCTION
Schedule 6.3

Calculation of 12 CP Allocation - Production

	Total Allocated	Residential	General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Power Supply															
Winter	2,579,303	1,098,630	132,129	375,168	100,723	79,631	10,882	29,360	241,209	288,758	77,959	32,866	10,262	2,531	99,194
% of Total	100%	42.59%	5.12%	14.55%	3.91%	3.09%	0.42%	1.14%	9.35%	11.20%	3.02%	1.27%	0.40%	0.10%	3.85%
Summer	4,062,474	1,486,303	241,349	702,747	208,007	137,740	10,264	86,723	376,396	458,415	127,527	52,206	15,134	4,515	155,146
% of Total	100%	36.59%	5.94%	17.30%	5.12%	3.39%	0.25%	2.13%	9.27%	11.28%	3.14%	1.29%	0.37%	0.11%	3.82%
Annual	6,641,776	2,584,934	373,478	1,077,915	308,730	217,371	21,146	116,084	617,606	747,173	205,486	85,072	25,396	7,046	254,340
% of Total	100%	38.92%	5.62%	16.23%	4.65%	3.27%	0.32%	1.75%	9.30%	11.25%	3.09%	1.28%	0.38%	0.11%	3.83%
Utility Owned Transmission															
Annual	6,641,776	2,584,934	373,478	1,077,915	308,730	217,371	21,146	116,084	617,606	747,173	205,486	85,072	25,396	7,046	254,340
% of Total	100%	38.92%	5.62%	16.23%	4.65%	3.27%	0.32%	1.75%	9.30%	11.25%	3.09%	1.28%	0.38%	0.11%	3.83%

COINCIDENT PEAK DEMAND ALLOCATION - TRANSMISSION
Schedule 6.4

Calculation of 1 CP Allocation - Transmission

	Total Allocated	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	891,576	313,226	36,855	105,566	26,797	51,100	2,617	3,972	91,800	156,600	30,000	24,000	3,358	683	45,000
Feb-09															
Mar-09															
Apr-09															
May-09															
Jun-09															
Jul-09															
Aug-09															
Sep-09															
Oct-09															
Nov-09															
Dec-09															
Total Annual 1CP	891,576	313,226	36,855	105,566	26,797	51,100	2,617	3,972	91,800	156,600	30,000	24,000	3,358	683	45,000
% of Total	100%	35.13%	4.13%	11.84%	3.01%	5.73%	0.29%	0.45%	10.30%	17.56%	3.36%	2.69%	0.38%	0.08%	5.05%

Calculation of 2 CP & 4 CP Allocation - Transmission

	Total Allocated	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
2 CP - Transmission															
Jan-09	891,576	313,226	36,855	105,566	26,797	51,100	2,617	3,972	91,800	156,600	30,000	24,000	3,358	683	45,000
Feb-09															
Mar-09															
Apr-09															
May-09															
Jun-09															
Jul-09	752,568	201,547	50,988	104,809	25,439	51,100		14,032	91,800	125,500	22,000	18,000	1,849	504	45,000
Aug-09	714,575	198,115	35,412	83,532	25,378	51,100		16,414	91,800	125,500	22,000	18,000	1,853	472	45,000
Sep-09															
Oct-09															
Nov-09															
Dec-09	855,836	302,697	33,633	87,268	22,263	51,100	2,364	6,267	91,800	156,600	30,000	24,000	2,158	686	45,000
2 Winter + 2 Summer	3,214,555	1,015,585	156,887	381,176	99,878	204,400	4,981	40,684	367,200	564,200	104,000	84,000	9,219	2,345	180,000
% of Total	100%	31.59%	4.88%	11.86%	3.11%	6.36%	0.15%	1.27%	11.42%	17.55%	3.24%	2.61%	0.29%	0.07%	5.60%
4 CP - Transmission															
Jan-09	891,576	313,226	36,855	105,566	26,797	51,100	2,617	3,972	91,800	156,600	30,000	24,000	3,358	683	45,000
Feb-09	792,276	255,130	23,056	77,894	26,859	51,100	2,792	4,642	91,800	156,600	30,000	24,000	2,864	540	45,000
Mar-09															
Apr-09															
May-09															
Jun-09															
Jul-09															
Aug-09															
Sep-09															
Oct-09															
Nov-09	813,998	227,577	38,586	104,440	24,804	51,100	3,109	14,479	91,800	156,600	30,000	24,000	1,881	622	45,000
Dec-09	855,836	302,697	33,633	87,268	22,263	51,100	2,364	6,267	91,800	156,600	30,000	24,000	2,158	686	45,000
4 Winter	3,353,686	1,098,630	132,129	375,168	100,723	204,400	10,882	29,360	367,200	626,400	120,000	96,000	10,262	2,531	180,000
% of Total	100%	32.76%	3.94%	11.19%	3.00%	6.09%	0.32%	0.88%	10.95%	18.68%	3.58%	2.86%	0.31%	0.08%	5.37%

Calculation of 12 CP Allocation - Transmission

Utility Owned Transmission

	Total Allocated	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Annual	9,026,148	2,584,934	373,478	1,077,915	308,730	613,200	21,146	116,084	1,101,600	1,692,600	312,000	252,000	25,396	7,065	540,000
% of Total	100%	28.64%	4.14%	11.94%	3.42%	6.79%	0.23%	1.29%	12.20%	18.75%	3.46%	2.79%	0.28%	0.08%	5.98%

NON-COINCIDENT PEAK DEMAND ALLOCATION
Schedule 6.5

NCP Distribution Allocation

	Total	Residential	General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Winter															
NCP at Input (NCP)	1,047,170	391,533	55,122	140,755	35,812	51,100	3,642	17,426	91,800	156,600	30,000	24,000	3,415	964	45,000
% of Total	100%	37.39%	5.26%	13.44%	3.42%	4.88%	0.35%	1.66%	8.77%	14.95%	2.86%	2.29%	0.33%	0.09%	4.30%
NCP Primary (NCPP)	914,331	368,488	51,878	132,470	33,704		3,642	17,426	91,800	156,600	30,000	24,000	3,358	964	
% of Total	100%	40.30%	5.67%	14.49%	3.69%		0.40%	1.91%	10.04%	17.13%	3.28%	2.62%	0.37%	0.11%	
NCP Secondary (NCPS)	548,332	351,443	49,478	126,342			3,642	17,426							
% of Total	100%	64.09%	9.02%	23.04%			0.66%	3.18%							
Summer															
NCP at Input (NCP)	904,629	273,402	72,839	139,746	35,935	51,100	6,467	19,363	91,800	125,500	22,000	18,000	2,463	1,014	45,000
% of Total	100%	30.22%	8.05%	15.45%	3.97%	5.65%	0.71%	2.14%	10.15%	13.87%	2.43%	1.99%	0.27%	0.11%	4.97%
NCP Primary (NCPP)	776,124	257,310	68,552	131,520	33,820		6,087	18,223	91,800	125,500	22,000	18,000	2,357	954	
% of Total	100%	33.15%	8.83%	16.95%	4.36%		0.78%	2.35%	11.83%	16.17%	2.83%	2.32%	0.30%	0.12%	
NCP Secondary (NCPS)	459,411	245,408	65,381	125,437			5,805	17,380							
% of Total	100%	53.42%	14.23%	27.30%			1.26%	3.78%							
Annual															
NCP at Input (NCP)	1,069,820	391,533	72,839	140,755	35,935	51,100	6,467	19,363	91,800	156,600	30,000	24,000	3,415	1,014	45,000
% of Total	100%	36.60%	6.81%	13.16%	3.36%	4.78%	0.60%	1.81%	8.58%	14.64%	2.80%	2.24%	0.32%	0.09%	4.21%
NCP Primary (NCPP)	934,362	368,488	68,552	132,470	33,820		6,087	18,223	91,800	156,600	30,000	24,000	3,358	964	
% of Total	100%	39.44%	7.34%	14.18%	3.62%		0.65%	1.95%	9.82%	16.76%	3.21%	2.57%	0.36%	0.10%	
NCP Secondary (NCPS)	566,398	351,443	65,381	126,342			5,805	17,426							
% of Total	100%	62.05%	11.54%	22.31%			1.02%	3.08%							

POWER SUPPLY COST ALLOCATION
Schedule 6.6

		Residential	General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Monthly Power Costs-kWh															
Jan-06	$5,711,582	44.74%	6.20%	14.46%	3.45%	2.02%	0.36%	0.17%	9.34%	11.04%	3.07%	1.32%	0.29%	0.09%	3.46%
Feb-06	$4,663,080	47.09%	5.18%	12.09%	3.78%	2.21%	0.36%	0.21%	9.50%	11.22%	3.12%	1.34%	0.29%	0.09%	3.52%
Mar-06	$4,749,462	44.52%	6.39%	14.90%	4.06%	2.37%	0.41%	0.13%	8.89%	10.50%	2.92%	1.25%	0.27%	0.08%	3.29%
Apr-06	$4,166,801	45.03%	5.79%	13.51%	4.63%	2.70%	0.42%	0.26%	9.04%	10.68%	2.97%	1.28%	0.28%	0.08%	3.35%
May-06	$3,414,723	40.46%	7.18%	16.75%	5.14%	3.00%	0.50%	1.51%	8.32%	9.83%	2.73%	1.17%	0.26%	0.08%	3.08%
Jun-06	$3,171,778	37.23%	6.73%	15.71%	5.28%	3.08%	0.57%	2.56%	9.42%	11.13%	3.09%	1.33%	0.29%	0.09%	3.49%
Jul-06	$4,075,928	30.82%	8.70%	20.29%	5.04%	2.94%	0.54%	4.00%	9.04%	10.68%	2.97%	1.28%	0.28%	0.08%	3.35%
Aug-06	$3,582,288	34.10%	6.97%	16.25%	4.49%	2.62%	0.48%	4.71%	9.92%	11.73%	3.26%	1.40%	0.30%	0.09%	3.68%
Sep-06	$3,603,323	33.65%	8.13%	18.98%	4.05%	2.36%	0.49%	3.75%	9.34%	11.03%	3.06%	1.32%	0.29%	0.09%	3.46%
Oct-06	$4,416,048	37.98%	6.86%	16.01%	4.73%	2.76%	0.55%	2.40%	9.38%	11.08%	3.08%	1.32%	0.29%	0.09%	3.47%
Nov-06	$5,337,105	37.41%	7.44%	17.37%	4.73%	2.76%	0.50%	0.74%	9.49%	11.21%	3.11%	1.34%	0.29%	0.09%	3.51%
Dec-06	$5,508,652	42.84%	5.52%	12.89%	3.97%	2.32%	0.37%	0.29%	10.39%	12.27%	3.41%	1.47%	0.32%	0.10%	3.85%
Total	$52,400,770	40.11%	6.68%	15.59%	4.39%	2.56%	0.46%	1.57%	9.36%	11.06%	3.07%	1.32%	0.29%	0.09%	3.47%
Weighted % Allocation	100.00%	40.13%	6.68%	15.59%	4.38%	2.56%	0.45%	1.52%	9.37%	11.07%	3.08%	1.32%	0.29%	0.09%	3.47%
Monthly Power Costs-kW															
Jan-06	$2,867,106	44.7%	5.3%	15.1%	3.8%	3.2%	0.4%	0.6%	8.8%	10.3%	2.9%	1.2%	0.5%	0.1%	3.4%
Feb-06	$2,704,435	42.6%	3.8%	13.0%	4.5%	3.7%	0.5%	0.8%	9.9%	11.9%	3.3%	1.4%	0.5%	0.1%	4.2%
Mar-06	$2,101,202	39.8%	4.7%	17.0%	4.9%	4.0%	0.6%	0.5%	9.0%	11.0%	3.1%	1.3%	0.4%	0.1%	3.8%
Apr-06	$956,739	39.0%	4.1%	15.0%	5.4%	4.2%	0.7%	0.9%	9.2%	11.4%	3.8%	1.3%	0.3%	0.1%	4.4%
May-06	$1,205,871	36.2%	5.3%	19.3%	5.6%	3.4%		1.8%	9.3%	10.6%	2.8%	1.2%	0.5%	0.1%	3.7%
Jun-06	$1,642,359	36.6%	5.6%	15.7%	5.2%	3.6%		1.8%	10.2%	12.4%	3.2%	1.4%	0.3%	0.2%	3.8%
Jul-06	$824,263	35.9%	9.1%	18.7%	4.5%	2.6%		2.5%	8.2%	10.9%	2.8%	1.2%	0.3%	0.1%	3.2%
Aug-06	$793,155	36.8%	6.6%	15.5%	4.7%	2.9%		3.0%	10.2%	11.7%	3.1%	1.3%	0.3%	0.1%	3.7%
Sep-06	$902,662	30.7%	6.1%	21.2%	5.6%	3.2%		3.2%	9.6%	11.7%	3.1%	1.4%	0.5%	0.1%	3.6%
Oct-06	$921,980	36.8%	5.6%	16.5%	5.2%	3.3%	0.7%	3.4%	8.6%	10.7%	3.2%	1.2%	0.3%	0.2%	4.4%
Nov-06	$1,617,900	37.2%	6.3%	17.1%	4.1%	2.9%	0.5%	2.4%	9.4%	11.4%	3.2%	1.3%	0.3%	0.1%	4.0%
Dec-06	$2,856,315	45.4%	5.0%	13.1%	3.3%	2.7%	0.4%	0.9%	9.4%	11.4%	2.7%	1.3%	0.3%	0.1%	3.9%
Total	$19,393,988	38.92%	5.62%	16.23%	4.65%	3.27%	0.32%	1.75%	9.30%	11.25%	3.09%	1.28%	0.38%	0.11%	3.83%
Weighted % Allocation	100.00%	40.13%	5.31%	15.70%	4.50%	3.30%	0.35%	1.43%	9.34%	11.25%	3.07%	1.28%	0.39%	0.10%	3.83%

FORECAST OF REVENUES FROM CURRENT RATES
Schedule 7.1

	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Customer Charge Revenues															
Jan-09	$1,389,707	$1,148,992	$127,085	$34,863	$24,176	$8,614		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692	$3,867
Feb-09	$1,390,661	$1,149,652	$127,321	$34,921	$24,176	$8,614		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692	$3,867
Mar-09	$1,393,047	$1,151,816	$127,500	$34,964	$24,176	$8,614		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692	$3,867
Apr-09	$1,391,011	$1,149,689	$127,563	$34,992	$24,176	$8,614		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692	$3,867
May-09	$1,394,471	$1,152,708	$127,918	$35,078	$24,176	$8,614		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692	$3,867
Jun-09	$1,399,567	$1,156,865	$128,643	$35,292	$24,176	$8,614		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692	$3,867
Jul-09	$1,400,394	$1,157,208	$129,027	$35,393	$24,176	$8,614		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692	$3,867
Aug-09	$1,399,277	$1,155,912	$129,163	$35,435	$24,176	$8,614		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692	$3,867
Sep-09	$1,401,489	$1,157,873	$129,370	$35,478	$24,176	$8,614		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692	$3,867
Oct-09	$1,404,471	$1,160,502	$129,638	$35,564	$24,176	$8,614		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692	$3,867
Nov-09	$1,407,390	$1,163,274	$129,756	$35,593	$24,176	$8,614		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692	$3,867
Dec-09	$1,410,413	$1,165,960	$130,022	$35,664	$24,176	$8,614		$15,040	$6,767	$8,459	$3,384	$5,076	$1,692	$1,692	$3,867
Total	$16,781,898	$13,870,451	$1,543,005	$423,237	$290,114	$103,372		$180,478	$81,209	$101,512	$40,605	$60,907	$20,302	$20,302	$46,406
Energy Revenues															
Jan-09	$20,087,257	$10,839,896	$1,593,593	$2,961,851	$520,117	$319,282	$166,946	$47,012	$1,189,213	$1,405,124	$390,303	$167,803	$36,510	$11,145	$438,462
Feb-09	$17,666,751	$10,069,313	$1,152,033	$2,175,056	$502,093	$308,135	$145,472	$49,629	$1,067,126	$1,260,872	$350,234	$150,576	$32,762	$10,001	$393,449
Mar-09	$17,237,895	$9,251,442	$1,416,796	$2,620,003	$524,520	$263,082	$161,308	$31,644	$970,409	$1,146,594	$318,491	$136,929	$29,793	$9,095	$357,789
Apr-09	$14,997,210	$8,172,835	$1,136,291	$2,093,790	$522,130	$260,409	$144,414	$30,909	$861,681	$1,018,126	$282,807	$121,587	$26,455	$8,076	$317,701
May-09	$14,305,983	$7,019,237	$1,344,604	$2,456,275	$554,438	$276,050	$164,180	$171,664	$758,108	$895,749	$248,814	$106,972	$23,275	$7,105	$279,514
Jun-09	$13,222,541	$6,111,020	$1,206,522	$2,155,659	$538,508	$271,410	$177,144	$276,080	$812,579	$960,109	$266,691	$114,658	$24,947	$7,615	$299,597
Jul-09	$13,697,675	$5,284,078	$1,568,038	$2,871,917	$537,427	$318,269	$176,011	$451,513	$813,960	$961,741	$267,144	$114,853	$24,990	$7,628	$300,107
Aug-09	$13,492,135	$5,817,404	$1,228,415	$2,276,021	$475,374	$289,098	$156,222	$528,151	$889,468	$1,050,958	$291,926	$125,507	$27,308	$8,336	$327,946
Sep-09	$13,567,475	$5,670,487	$1,437,118	$2,722,325	$423,560	$213,951	$155,037	$415,838	$826,621	$976,700	$271,299	$116,639	$25,378	$7,747	$304,775
Oct-09	$14,388,512	$6,752,840	$1,301,276	$2,406,366	$522,258	$258,783	$185,705	$280,371	$876,219	$1,035,303	$287,578	$123,638	$26,901	$8,212	$323,061
Nov-09	$16,342,960	$7,467,793	$1,591,734	$2,944,714	$587,093	$354,676	$186,736	$165,844	$995,010	$1,175,662	$326,565	$140,400	$30,548	$9,325	$366,860
Dec-09	$18,270,745	$9,628,988	$1,320,794	$2,445,877	$555,107	$338,078	$155,390	$74,171	$1,226,400	$1,449,063	$402,508	$173,050	$37,652	$11,494	$452,173
Total	$187,277,138	$92,085,331	$16,297,213	$30,129,853	$6,262,625	$3,471,222	$1,974,565	$2,522,827	$11,286,794	$13,336,001	$3,704,361	$1,592,612	$346,520	$105,780	$4,161,435
Demand Revenues															
Jan-09	$2,620,529			$985,202	$275,657	$63,073			$424,653	$510,974	$139,903	$57,752	$23,763	$5,292	$134,261
Feb-09	$2,446,937			$911,904	$276,292	$63,076			$386,473	$451,476	$132,450	$52,670	$20,285	$5,292	$147,020
Mar-09	$2,366,135			$867,901	$277,237	$67,004			$378,507	$440,213	$132,450	$51,687	$17,822	$5,292	$128,023
Apr-09	$2,249,986			$839,366	$274,012	$58,493			$347,654	$415,781	$132,450	$48,851	$17,822	$5,292	$110,265
May-09	$2,316,418			$872,074	$263,280	$58,800			$347,654	$415,781	$176,600	$48,851	$17,822	$5,292	$110,265
Jun-09	$2,289,156			$897,285	$265,264	$47,918			$347,654	$415,781	$132,450	$48,851	$17,822	$5,866	$110,265
Jul-09	$2,374,926			$929,852	$261,687	$31,355			$373,296	$463,214	$132,450	$49,693	$17,822	$5,292	$110,265
Aug-09	$2,383,757			$940,825	$261,057	$31,110			$375,103	$455,508	$132,450	$54,324	$17,822	$5,292	$110,265
Sep-09	$2,397,611			$898,530	$261,687	$36,653			$373,810	$506,357	$132,450	$54,745	$17,822	$5,292	$110,265
Oct-09	$2,285,024			$886,445	$275,483	$42,259			$347,654	$415,781	$132,450	$49,810	$17,822	$7,055	$110,265
Nov-09	$2,261,665			$841,796	$255,148	$43,489			$357,462	$443,933	$132,450	$54,009	$17,822	$5,292	$110,265
Dec-09	$2,521,766			$860,894	$229,014	$44,850			$463,539	$554,374	$153,842	$65,135	$17,822	$5,292	$127,004
Total	$28,513,910			$10,732,074	$3,175,819	$588,079			$4,523,458	$5,489,171	$1,662,398	$636,377	$222,273	$65,836	$1,418,425

FORECAST OF REVENUES FROM CURRENT RATES
Schedule 7.1

	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Total Revenues at Existing Rates															
Jan-09	$24,097,493	$11,988,888	$1,720,678	$3,981,916	$819,949	$390,970	$166,946	$62,052	$1,620,633	$1,924,557	$533,590	$230,630	$61,966	$18,129	$576,590
Feb-09	$21,504,349	$11,218,965	$1,279,354	$3,121,881	$802,561	$379,825	$145,472	$64,669	$1,460,366	$1,720,807	$486,068	$208,321	$54,739	$16,984	$544,336
Mar-09	$20,997,077	$10,403,258	$1,544,296	$3,522,868	$825,933	$338,700	$161,308	$46,684	$1,355,684	$1,595,266	$454,325	$193,691	$49,307	$16,078	$489,679
Apr-09	$18,638,206	$9,322,524	$1,263,853	$2,968,148	$820,318	$327,516	$144,414	$45,949	$1,216,103	$1,442,366	$418,640	$175,513	$45,969	$15,059	$431,833
May-09	$18,016,872	$8,171,945	$1,472,522	$3,363,426	$841,894	$343,464	$164,180	$186,703	$1,112,530	$1,319,989	$428,798	$160,899	$42,789	$14,088	$393,646
Jun-09	$16,911,265	$7,267,885	$1,335,165	$3,088,237	$827,949	$327,942	$177,144	$291,120	$1,167,000	$1,384,349	$402,525	$168,585	$44,462	$15,173	$413,729
Jul-09	$17,472,994	$6,441,285	$1,697,065	$3,837,161	$823,290	$358,237	$176,011	$466,553	$1,194,024	$1,433,415	$402,978	$169,622	$44,504	$14,612	$414,238
Aug-09	$17,275,169	$6,973,316	$1,357,578	$3,252,281	$760,608	$328,823	$156,222	$543,191	$1,271,339	$1,514,925	$427,760	$184,907	$46,822	$15,319	$442,078
Sep-09	$17,366,575	$6,828,360	$1,566,488	$3,656,333	$709,423	$259,218	$155,037	$430,878	$1,207,198	$1,491,516	$407,133	$176,461	$44,893	$14,730	$418,906
Oct-09	$18,078,007	$7,913,342	$1,430,913	$3,328,376	$821,917	$309,656	$185,705	$295,411	$1,230,640	$1,459,543	$423,412	$178,523	$46,415	$16,959	$437,193
Nov-09	$20,012,015	$8,631,067	$1,721,490	$3,822,103	$866,418	$406,779	$186,736	$180,884	$1,359,239	$1,628,054	$462,399	$199,485	$50,062	$16,309	$480,991
Dec-09	$22,202,924	$10,794,947	$1,450,816	$3,342,435	$808,297	$391,542	$155,390	$89,211	$1,696,706	$2,011,896	$559,734	$243,260	$57,166	$18,477	$583,044
Total	**$232,572,947**	$105,955,782	$17,840,218	$41,285,164	$9,728,558	$4,162,673	$1,974,565	$2,703,305	$15,891,461	$18,926,683	$5,407,364	$2,289,896	$589,095	$191,918	$5,626,265

2009 BASELINE REVENUES AT EXISTING RATES
Schedule 7.2

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

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

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

2009 BASELINE REVENUES AT EXISTING RATES
Schedule 7.2

INDUSTRIAL ID30		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		396	33	33	33	33	33	33	33	33	33	33	33	33
Consumption	*kWh*	**141,018,352**	11,711,699	11,305,845	11,810,860	11,757,036	12,484,524	12,125,836	12,101,478	10,704,218	9,537,494	11,759,915	13,219,843	12,499,603
	MVA	478.3	41.5	41.6	41.8	41.3	39.7	39.9	39.4	39.3	39.4	41.5	38.4	34.5
Account Fixed Charge	*Monthly* $	732.61												
Unit Energy Charge	*$/kWh* $	0.04441												
Unit Demand Charge	*$/KVA* $	6.64												
Fixed Charge Revenue	*$,000*	$290	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24
Energy Charge Revenue	*$,000*	$6,263	$520	$502	$525	$522	$554	$539	$537	$475	$424	$522	$587	$555
Demand Charge Revenue	*$,001*	$3,176	$276	$276	$277	$274	$263	$265	$262	$261	$262	$275	$255	$229
Total Billed Revenue (000's)	*$,000*	**$9,729**	$820	$803	$826	$820	$842	$828	$823	$761	$709	$822	$866	$808

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

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

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

2009 BASELINE REVENUES AT EXISTING RATES
Schedule 7.2

WHOLESALE WH40 - Kelowna		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		48	4	4	4	4	4	4	4	4	4	4	4	4
Consumption	*KWh*	**300,580,396**	31,670,124	28,418,812	25,843,110	22,947,572	20,189,302	21,639,922	21,676,701	23,687,558	22,013,863	23,334,721	26,498,260	32,660,451
	MVA	596.0	58.0	52.8	51.7	43.2	38.6	42.4	51.0	51.2	51.1	43.8	48.8	63.3
	MVA with ratchet	618.0	58.0	52.8	51.7	47.5	47.5	47.5	51.0	51.2	51.1	47.5	48.8	63.3
Account Fixed Charge	*Monthly* $	1,691.86												
Unit Energy Charge	*$/kWh* $	0.03755												
Unit Demand Charge	*$/KVA* $	7.32000												
Fixed Charge Revenue	*$,000*	$81	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7
Energy Charge Revenue	*$,000*	$11,287	$1,189	$1,067	$970	$862	$758	$813	$814	$889	$827	$876	$995	$1,226
Demand Charge Revenue	*$,001*	$4,523	$425	$386	$379	$348	$348	$348	$373	$375	$374	$348	$357	$464
Total Billed Revenue (000's)	*$,000*	**$15,891**	$1,621	$1,460	$1,356	$1,216	$1,113	$1,167	$1,194	$1,271	$1,207	$1,231	$1,359	$1,697

WHOLESALE WH40 - Penticton		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		60	5	5	5	5	5	5	5	5	5	5	5	5
Consumption	*KWh*	**355,153,151**	37,420,086	33,578,473	30,535,132	27,113,885	23,854,830	25,568,822	25,612,278	27,988,222	26,010,654	27,571,325	31,309,230	38,590,215
	MVA	723.2	69.8	61.7	60.1	50.4	49.5	47.3	63.3	62.2	69.2	53.3	60.6	75.7
	MVA with ratchet	749.9	69.8	61.7	60.1	56.8	56.8	56.8	63.3	62.2	69.2	56.8	60.6	75.7
Account Fixed Charge	*Monthly* $	1,691.86												
Unit Energy Charge	*$/kWh* $	0.03755												
Unit Demand Charge	*$/KVA* $	7.32000												
Fixed Charge Revenue	*$,000*	$102	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8
Energy Charge Revenue	*$,000*	$13,336	$1,405	$1,261	$1,147	$1,018	$896	$960	$962	$1,051	$977	$1,035	$1,176	$1,449
Demand Charge Revenue	*$,001*	$5,489	$511	$451	$440	$416	$416	$416	$463	$456	$506	$416	$444	$554
Total Billed Revenue (000's)	*$,000*	**$18,927**	$1,925	$1,721	$1,595	$1,442	$1,320	$1,384	$1,433	$1,515	$1,492	$1,460	$1,628	$2,012

WHOLESALE WH40 - Summerland		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		24	2	2	2	2	2	2	2	2	2	2	2	2
Consumption	*KWh*	**98,651,430**	10,394,234	9,327,143	8,481,790	7,531,465	6,626,192	7,102,290	7,114,361	7,774,331	7,225,019	7,658,529	8,696,812	10,719,263
	MVA	210.5	19.1	17.6	17.1	14.4	24.1	13.7	17.9	17.1	16.9	14.1	17.4	21.0
	MVA with ratchet	227.1	19.1	18.1	18.1	18.1	24.1	18.1	18.1	18.1	18.1	18.1	18.1	21.0
Account Fixed Charge	*Monthly* $	1,691.86												
Unit Energy Charge	*$/kWh* $	0.03755												
Unit Demand Charge	*$/KVA* $	7.32000												
Fixed Charge Revenue	*$,000*	$41	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
Energy Charge Revenue	*$,000*	$3,704	$390	$350	$318	$283	$249	$267	$267	$292	$271	$288	$327	$403
Demand Charge Revenue	*$,001*	$1,662	$140	$132	$132	$132	$177	$132	$132	$132	$132	$132	$132	$154
Total Billed Revenue (000's)	*$,000*	**$5,407**	$534	$486	$454	$419	$429	$403	$403	$428	$407	$423	$462	$560

WHOLESALE WH40 - Grand Forks		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		36	3	3	3	3	3	3	3	3	3	3	3	3
Consumption	*KWh*	**42,413,094**	4,468,781	4,010,008	3,646,566	3,237,994	2,848,791	3,053,479	3,058,669	3,342,409	3,106,244	3,292,622	3,739,010	4,608,520
	MVA	84.4	7.9	7.2	7.1	5.9	5.6	6.0	6.8	7.4	7.5	6.8	7.4	8.9
	MVA with ratchet	86.9	7.9	7.2	7.1	6.7	6.7	6.7	6.8	7.4	7.5	6.8	7.4	8.9
Account Fixed Charge	*Monthly* $	1,691.86												
Unit Energy Charge	*$/kWh* $	0.03755												
Unit Demand Charge	*$/KVA* $	7.32000												
Fixed Charge Revenue	*$,000*	$61	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
Energy Charge Revenue	*$,000*	$1,593	$168	$151	$137	$122	$107	$115	$115	$126	$117	$124	$140	$173
Demand Charge Revenue	*$,001*	$636	$58	$53	$52	$49	$49	$49	$50	$54	$55	$50	$54	$65
Total Billed Revenue (000's)	*$,000*	**$2,290**	$231	$208	$194	$176	$161	$169	$170	$185	$176	$179	$199	$243

2009 BASELINE REVENUES AT EXISTING RATES
Schedule 7.2

WHOLESALE WH40 - Lardeau		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		12	1	1	1	1	1	1	1	1	1	1	1	1
Consumption	*KWh*	**9,228,226**	972,316	872,496	793,419	704,522	619,839	664,375	665,504	727,240	675,855	716,408	813,533	1,002,720
	MVA	25.0	3.2	2.8	1.9	1.5	2.1	1.6	1.8	1.8	2.3	1.8	1.8	2.2
	MVA with ratchet	30.4	3.2	2.8	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Account Fixed Charge	*Monthly* $	1,691.86												
Unit Energy Charge	*$/kWh* $	0.03755												
Unit Demand Charge	*$/KVA* $	7.32000												
Fixed Charge Revenue	*$,000*	$20	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Energy Charge Revenue	*$,000*	$347	$37	$33	$30	$26	$23	$25	$25	$27	$25	$27	$31	$38
Demand Charge Revenue	*$,001*	$222	$24	$20	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18
Total Billed Revenue (000's)	*$,000*	**$589**	$62	$55	$49	$46	$43	$44	$45	$47	$45	$46	$50	$57

WHOLESALE WH40 - Yahk		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		12	1	1	1	1	1	1	1	1	1	1	1	1
Consumption	*KWh*	**2,817,036**	296,812	266,341	242,201	215,064	189,214	202,809	203,154	222,000	206,314	218,693	248,341	306,093
	MVA	6.9	0.7	0.5	0.5	0.4	0.4	0.8	0.5	0.5	0.5	1.0	0.6	0.7
	MVA with ratchet	9.0	0.7	0.7	0.7	0.7	0.7	0.8	0.7	0.7	0.7	1.0	0.7	0.7
Account Fixed Charge	*Monthly* $	1,691.86												
Unit Energy Charge	*$/kWh* $	0.03755												
Unit Demand Charge	*$/KVA* $	7.32000												
Fixed Charge Revenue	*$,000*	$20	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Energy Charge Revenue	*$,000*	$106	$11	$10	$9	$8	$7	$8	$8	$8	$8	$8	$9	$11
Demand Charge Revenue	*$,001*	$66	$5	$5	$5	$5	$5	$6	$5	$5	$5	$7	$5	$5
Total Billed Revenue (000's)	*$,000*	**$192**	$18	$17	$16	$15	$14	$15	$15	$15	$15	$17	$16	$18

WHOLESALE WH40 - Combined		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Accounts Billed		192	16	16	16	16	16	16	16	16	16	16	16	16
Consumption	*kWh*	**808,843,332**	85,222,352	76,473,274	69,542,218	61,750,502	54,328,167	58,231,698	58,330,668	63,741,759	59,237,948	62,792,298	71,305,187	87,887,262
	MVA	1,646.0	158.7	142.6	138.3	115.8	120.4	111.8	141.3	140.3	147.5	120.8	136.7	171.9
	MVA with ratchet	1,721.2	158.8	143.3	140.2	132.2	138.3	132.3	142.3	142.1	149.0	132.6	138.1	172.1
Account Fixed Charge	*Monthly* $	1,691.86												
Unit Energy Charge	*$/kWh* $	0.03755												
Unit Demand Charge	*$/KVA* $	7.32												
Fixed Charge Revenue	*$,000*	$325	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27
Energy Charge Revenue	*$,000*	$30,372	$3,200	$2,872	$2,611	$2,319	$2,040	$2,187	$2,190	$2,394	$2,224	$2,358	$2,678	$3,300
Demand Charge Revenue	*$,001*	$12,600	$1,162	$1,049	$1,026	$968	$1,012	$968	$1,042	$1,040	$1,090	$971	$1,011	$1,260
Total Billed Revenue (000's)	*$,000*	**$43,296**	$4,390	$3,947	$3,664	$3,314	$3,079	$3,182	$3,259	$3,461	$3,342	$3,355	$3,716	$4,587

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

FORECAST CUSTOMERS AND ENERGY SALES
Schedule 8.1

Number of Customers / Services		Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
	Jan-09	110,237	95,840	8,884	2,438	33	4	1,980	1,051	1	1	1	1	1	1	1
	Feb-09	110,312	95,895	8,900	2,442	33	4	1,980	1,051	1	1	1	1	1	1	1
	Mar-09	110,508	96,075	8,913	2,445	33	4	1,980	1,051	1	1	1	1	1	1	1
	Apr-09	110,337	95,898	8,917	2,447	33	4	1,980	1,051	1	1	1	1	1	1	1
	May-09	110,620	96,150	8,942	2,453	33	4	1,980	1,051	1	1	1	1	1	1	1
	Jun-09	111,032	96,496	8,993	2,468	33	4	1,980	1,051	1	1	1	1	1	1	1
	Jul-09	111,095	96,525	9,020	2,475	33	4	1,980	1,051	1	1	1	1	1	1	1
	Aug-09	110,999	96,417	9,029	2,478	33	4	1,980	1,051	1	1	1	1	1	1	1
	Sep-09	111,180	96,580	9,044	2,481	33	4	1,980	1,051	1	1	1	1	1	1	1
	Oct-09	111,424	96,800	9,062	2,487	33	4	1,980	1,051	1	1	1	1	1	1	1
	Nov-09	111,666	97,031	9,071	2,489	33	4	1,980	1,051	1	1	1	1	1	1	1
	Dec-09	111,913	97,255	9,089	2,494	33	4	1,980	1,051	1	1	1	1	1	1	1
Total Average		110,944	96,413	8,989	2,466	33	4	1,980	1,051	1	1	1	1	1	1	1

Historic Energy, Demand And Customer Count
Historic Year

	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Input Recorded Data															
Energy Sales (kWh)	3,107,070,981	1,221,674,870	203,446,005	474,707,344	141,018,352	83,180,240	13,866,327	47,802,478	300,580,396	355,153,151	98,651,430	42,413,094	9,228,226	2,817,036	112,532,033
Total Billing Capacity (kVa)	4,329,408			1,720,080	478,286	109,512			595,975	723,176	210,513	84,439	24,986	6,947	375,494
Avg. Monthly Billing Capacity (kVa)	360,784			143,340	39,857	9,126			49,665	60,265	17,543	7,037	2,082	579	31,291
Number of Customers	110,944	96,413	8,989	2,466	33	4	1,980	1,051	1	1	1	1	1	1	1
Ratio of NCP to Avg. Billing Capacity				88%	85%	255%			121%	120%	127%	119%	154%	165%	85%
Rate Classes NCP Demand at Meter	817,222	351,443	65,381	126,342	33,820	23,254	5,805	17,380	60,152	72,326	22,217	8,403	3,214	954	26,531
Estimated Based on Recorded Data															
Annual NCP Load Factor	43%	40%	36%	43%	48%	41%	27%	31%	57%	56%	51%	58%	33%	34%	48%
Rate Classes CP Demand at Input Voltage	700,994	313,226	36,855	105,566	26,797	22,189	2,617	3,972	61,401	71,883	20,529	8,062	3,358	683	23,855
Annual CP Load Factor	51%	45%	63%	51%	60%	43%	60%	137%	56%	56%	55%	60%	31%	47%	54%

Customer Information	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Weighting Factors for:															
Points of Delivery per Customer		1.0	1.0	1.0	1.0	1.0	1.0	1.0	4.0	5.0	2.0	3.0	1.0	1.0	3.0
Customers Meters & Services		$ 45.55	$ 137.04	$ 213.87	$ 1,055.38	$ 96,100.00	$ -	$ 45.55	$ 41,600.00	$ 41,600.00	$ 41,600.00	$ 41,600.00	$ 41,600.00	$41,600.00	$ 41,600.00
Customer Retail		1.000	1.000	1.000	1.000	1.000	1.000	1.000							
Customer Accounting/Metering		1.000	1.000	1.000	202.500	202.500	1.400	1.400	159.700	159.700	159.700	159.700	159.700	159.700	159.700
Weighted Number of Customers															
Customers (PODs)	110,956	96,413	8,989	2,466	33	4	1,980	1,051	4	5	2	3	1	1	3
Customers Meters & Services	7,408,437	4,391,629	1,231,815	527,493	34,828	384,400	-	47,873	166,400	208,000	83,200	124,800	41,600	41,600	124,800
Customer Retail	110,937	96,413	8,989	2,466	33	4	1,980	1,051	-	-	-	-	-	-	-
Customer Accounting/Metering	122,639	96,413	8,989	2,466	6,683	810	2,772	1,471	639	799	319	479	160	160	479
Provided Services															
Power Purchased from Utility*		1	1	1	1	1	1	1	1	1	1	1	1	1	1
Reg & Shaping from Utility*		1	1	1	1	1	1	1	1	1	1	1	1	1	1
Uses Utility Transmission*		1	1	1	1	1	1	1	1	1	1	1	1	1	1
Uses Primary Distribution*		1	1	1	1		1	1	1	1	1	1	1	1	
Uses Secondary Distribution*		1	1	1			1	1							

* (yes=1,no=0)

FORECAST CUSTOMERS AND ENERGY SALES
Schedule 8.1

Load Data And Customer Sales by Rate Class

kWh Sales at the Meter		Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
	Jan-09	327,649,540	143,810,401	19,924,547	46,490,610	11,711,699	6,908,193	1,172,370	552,628	31,670,124	37,420,086	10,394,234	4,468,781	972,316	296,812	11,856,739
	Feb-09	289,285,119	133,587,255	14,701,642	34,303,832	11,305,845	6,668,798	1,021,572	583,394	28,418,812	33,578,473	9,327,143	4,010,008	872,496	266,341	10,639,505
	Mar-09	280,921,453	122,736,750	17,605,493	41,079,484	11,810,860	6,966,683	1,132,778	371,980	25,843,110	30,535,132	8,481,790	3,646,566	793,419	242,201	9,675,208
	Apr-09	245,571,631	108,427,119	13,941,916	32,531,137	11,757,036	6,934,935	1,014,144	623,673	22,947,572	27,113,885	7,531,465	3,237,994	704,522	215,064	8,591,169
	May-09	234,531,042	93,122,593	16,516,947	38,539,543	12,484,524	7,364,046	1,152,947	3,463,753	20,189,302	23,854,830	6,626,192	2,848,791	619,839	189,214	7,558,521
	Jun-09	222,372,614	81,073,492	14,661,868	34,211,026	12,125,836	7,152,473	1,243,991	5,570,622	21,639,922	25,568,822	7,102,290	3,053,479	664,375	202,809	8,101,608
	Jul-09	232,073,813	70,102,639	19,781,723	46,157,354	12,101,478	7,138,105	1,236,031	9,110,437	21,676,701	25,612,278	7,114,361	3,058,669	665,504	203,154	8,115,377
	Aug-09	231,112,936	77,178,162	15,765,838	36,786,955	10,704,218	6,313,926	1,097,065	10,656,806	23,687,558	27,988,222	7,774,331	3,342,409	727,240	222,000	8,868,206
	Sep-09	227,953,964	75,229,040	18,180,843	42,421,967	9,537,494	5,625,729	1,088,745	8,390,595	22,013,863	26,010,654	7,225,019	3,106,244	675,855	206,314	8,241,604
	Oct-09	240,714,712	89,588,369	16,182,021	37,758,050	11,759,915	6,936,633	1,304,110	5,657,206	23,334,721	27,571,325	7,658,529	3,292,622	716,408	218,693	8,736,111
	Nov-09	270,284,596	99,073,490	19,712,090	45,994,876	13,219,843	7,797,777	1,311,349	1,949,500	26,498,260	31,309,230	8,696,812	3,739,010	813,533	248,341	9,920,484
	Dec-09	304,599,561	127,745,562	16,471,076	38,432,510	12,499,603	7,372,941	1,091,224	871,883	32,660,451	38,590,215	10,719,263	4,608,520	1,002,720	306,093	12,227,500
Total Sales		3,107,070,981	1,221,674,870	203,446,005	474,707,344	141,018,352	83,180,240	13,866,327	47,802,478	300,580,396	355,153,151	98,651,430	42,413,094	9,228,226	2,817,036	112,532,033

FORECAST CUSTOMER DEMAND
Schedule 8.2

Billing Demand - kVa	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
				All kVA					kVA	kVA	kVA	kVA	kVA	kVA	kVA
Jan-09	404,189			168,457	41,515	11,745			58,013	69,805	19,112	7,890	3,246	661	23,746
Feb-09	341,470			124,298	41,610	11,746			52,797	61,677	17,608	7,195	2,771	523	21,244
Mar-09	365,552			148,850	41,753	12,477			51,709	60,138	17,055	7,061	1,876	474	24,159
Apr-09	303,661			117,875	41,267	10,893			43,182	50,371	14,406	5,901	1,544	389	17,833
May-09	328,489			139,646	39,651	10,950			38,617	49,479	24,126	5,628	2,119	393	17,880
Jun-09	309,140			123,962	39,949	8,923			42,426	47,309	13,668	5,994	1,634	801	24,474
Jul-09	413,511			167,249	39,411	5,839			50,997	63,281	17,912	6,789	1,822	496	59,716
Aug-09	359,748			133,296	39,316	5,793			51,244	62,228	17,135	7,421	1,822	464	41,030
Sep-09	379,327			153,714	39,411	6,826			51,067	69,174	16,922	7,479	2,341	480	31,913
Oct-09	346,497			136,815	41,488	7,869			43,766	53,333	14,110	6,805	1,785	964	39,561
Nov-09	386,035			166,660	38,426	8,098			48,834	60,647	17,442	7,378	1,817	600	36,132
Dec-09	391,788			139,258	34,490	8,352			63,325	75,734	21,017	8,898	2,207	702	37,805
Total	4,329,408			1,720,080	478,286	109,512			595,975	723,176	210,513	84,439	24,986	6,947	375,494

Individual Load Factor	Peak Balance	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	0.00%	49.5%	42.5%	37.1%	42.1%	41.2%	67.1%	15.0%	73.0%	73.4%	72.3%	75.6%	73.6%	73.6%	67.5%
Feb-09	0.06%	62.5%	55.5%	41.1%	44.9%	44.0%	60.7%	15.0%	73.5%	73.9%	73.3%	76.0%	74.2%	74.2%	65.9%
Mar-09	0.17%	60.5%	53.5%	37.1%	42.2%	40.3%	52.3%	15.0%	74.4%	70.9%	68.9%	73.8%	72.0%	72.0%	64.3%
Apr-09	0.09%	63.0%	56.0%	38.3%	44.0%	44.3%	43.1%	15.0%	71.5%	69.4%	58.2%	71.6%	67.7%	67.7%	57.5%
May-09	0.30%	61.0%	54.0%	37.1%	47.0%	45.4%	34.5%	45.0%	66.7%	67.7%	69.7%	68.4%	68.1%	68.1%	60.0%
Jun-09	0.09%	50.0%	43.0%	38.3%	46.8%	50.0%	29.8%	70.0%	61.8%	58.1%	62.5%	64.0%	61.6%	61.6%	60.0%
Jul-09	-0.26%	37.5%	30.5%	37.1%	45.9%	56.6%	32.2%	70.0%	60.8%	59.6%	64.2%	64.5%	62.3%	62.3%	60.0%
Aug-09	0.16%	42.0%	35.0%	37.1%	40.7%	50.2%	39.9%	70.0%	60.3%	61.5%	63.7%	63.9%	62.4%	62.4%	60.0%
Sep-09	-0.13%	60.0%	53.0%	38.3%	37.3%	43.7%	49.0%	65.0%	69.9%	70.3%	74.9%	67.0%	70.5%	70.5%	60.0%
Oct-09	0.02%	50.5%	43.5%	37.1%	42.3%	49.4%	57.8%	35.0%	70.6%	67.3%	66.3%	68.2%	68.1%	68.1%	44.3%
Nov-09	0.05%	48.5%	41.5%	38.3%	53.1%	56.7%	65.3%	15.0%	65.9%	65.5%	65.5%	69.0%	66.5%	66.5%	57.3%
Dec-09	-0.13%	45.5%	38.5%	37.1%	54.1%	51.3%	69.1%	15.0%	73.0%	71.7%	64.8%	73.7%	70.8%	70.8%	62.0%
	0.03%	52.5%	46%	38%	45%	48%	50%								

FORECAST CUSTOMER DEMAND
Schedule 8.2

Individual NCP (kW)	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
	Power Factor:		100%	100%	90%	95%	100%	100%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
Jan-09		390,492	63,012	168,457	37,363	22,558	2,349	4,952	58,329	68,490	19,321	7,945	3,214	654	23,596
Feb-09		318,065	39,419	124,298	37,449	22,559	2,506	5,788	57,549	67,651	18,943	7,851	2,743	517	24,009
Mar-09		272,676	44,230	148,850	37,577	23,254	2,910	3,333	46,709	57,874	16,546	6,642	1,857	470	20,214
Apr-09		239,037	34,578	117,875	37,140	21,748	3,269	5,775	44,591	54,263	17,983	6,283	1,528	385	20,760
May-09		205,188	41,111	139,646	35,686	21,802	4,488	10,346	40,705	47,336	12,784	5,595	2,098	390	16,932
Jun-09		225,204	47,357	123,962	35,955	19,877	5,805	11,053	48,632	61,116	15,789	6,628	1,617	793	18,754
Jul-09		251,264	87,175	167,249	35,470	16,947	5,166	17,493	47,919	57,724	14,894	6,370	1,804	491	18,180
Aug-09		246,986	60,545	133,296	35,384	16,904	3,696	20,462	52,789	61,159	16,394	7,028	1,804	459	19,866
Sep-09		174,141	47,644	153,714	35,470	17,884	3,088	17,929	43,733	51,403	13,402	6,435	2,318	475	19,078
Oct-09		238,445	50,000	136,815	37,340	18,876	3,033	21,725	44,435	55,066	15,534	6,487	1,768	954	26,531
Nov-09		283,716	65,971	166,660	34,583	19,094	2,791	18,051	55,854	66,387	18,431	7,529	1,799	594	24,034
Dec-09		377,365	57,503	139,258	31,041	19,334	2,122	7,813	60,152	72,326	22,217	8,403	2,185	695	26,487
Maximum		390,492	87,175	168,457	37,577	23,254	5,805	21,725	60,152	72,326	22,217	8,403	3,214	954	26,531
									601,397	720,794	202,239	83,197	24,736	6,878	258,440

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

Rate Class NCP @ Meter (kW)	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	351,443	47,259	126,342	33,627	22,558	2,349	3,961	58,329	68,490	19,321	7,945	3,214	654	23,596
Feb-09	286,258	29,564	93,224	33,704	22,559	2,506	4,630	57,549	67,651	18,943	7,851	2,743	517	24,009
Mar-09	245,408	33,173	111,637	33,820	23,254	2,910	2,667	46,709	57,874	16,546	6,642	1,857	470	20,214
Apr-09	215,133	25,934	88,406	33,426	21,748	3,269	4,620	44,591	54,263	17,983	6,283	1,528	385	20,760
May-09	184,669	30,834	104,735	32,117	21,802	4,488	8,277	40,705	47,336	12,784	5,595	2,098	390	16,932
Jun-09	202,684	35,518	92,972	32,359	19,877	5,805	8,842	48,632	61,116	15,789	6,628	1,617	793	18,754
Jul-09	226,138	65,381	125,437	31,923	16,947	5,166	13,995	47,919	57,724	14,894	6,370	1,804	491	18,180
Aug-09	222,287	45,409	99,972	31,846	16,904	3,696	16,370	52,789	61,159	16,394	7,028	1,804	459	19,866
Sep-09	156,727	35,733	115,286	31,923	17,884	3,088	14,343	43,733	51,403	13,402	6,435	2,318	475	19,078
Oct-09	214,600	37,500	102,611	33,606	18,876	3,033	17,380	44,435	55,066	15,534	6,487	1,768	954	26,531
Nov-09	255,344	49,478	124,995	31,125	19,094	2,791	14,441	55,854	66,387	18,431	7,529	1,799	594	24,034
Dec-09	339,628	43,127	104,444	27,937	19,334	2,122	6,250	60,152	72,326	22,217	8,403	2,185	695	26,487
Maximum	351,443	65,381	126,342	33,820	23,254	5,805	17,380	60,152	72,326	22,217	8,403	3,214	954	26,531
Winter Peak Month	351,443	49,478	126,342	33,704	22,559	2,791	14,441	60,152	72,326	22,217	8,403	3,214	695	26,487
Summer Peak Month	245,408	65,381	125,437	33,820	23,254	5,805	17,380	52,789	61,159	17,983	7,028	2,318	954	26,531

FORECAST CUSTOMER DEMAND
Schedule 8.2

Rate Class NCP @ Primary Voltage (kW)	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Line Losses:	4.85%	4.85%	4.85%			4.85%	4.85%							
Jan-09	368,488	49,551	132,470	33,627	22,558	2,463	4,154	58,329	68,490	19,321	7,945	3,214	654	23,596
Feb-09	300,142	30,998	97,745	33,704	22,559	2,627	4,855	57,549	67,651	18,943	7,851	2,743	517	24,009
Mar-09	257,310	34,782	117,052	33,820	23,254	3,052	2,796	46,709	57,874	16,546	6,642	1,857	470	20,214
Apr-09	225,567	27,191	92,694	33,426	21,748	3,428	4,844	44,591	54,263	17,983	6,283	1,528	385	20,760
May-09	193,626	32,329	109,814	32,117	21,802	4,705	8,678	40,705	47,336	12,784	5,595	2,098	390	16,932
Jun-09	212,514	37,241	97,481	32,359	19,877	6,087	9,271	48,632	61,116	15,789	6,628	1,617	793	18,754
Jul-09	237,105	68,552	131,520	31,923	16,947	5,417	14,673	47,919	57,724	14,894	6,370	1,804	491	18,180
Aug-09	233,068	47,611	104,821	31,846	16,904	3,876	17,164	52,789	61,159	16,394	7,028	1,804	459	19,866
Sep-09	164,328	37,466	120,877	31,923	17,884	3,238	15,039	43,733	51,403	13,402	6,435	2,318	475	19,078
Oct-09	225,008	39,319	107,588	33,606	18,876	3,181	18,223	44,435	55,066	15,534	6,487	1,768	954	26,531
Nov-09	267,728	51,878	131,057	31,125	19,094	2,926	15,141	55,854	66,387	18,431	7,529	1,799	594	24,034
Dec-09	356,100	45,219	109,509	27,937	19,334	2,225	6,553	60,152	72,326	22,217	8,403	2,185	695	26,487
Maximum	368,488	68,552	132,470	33,820	23,254	6,087	18,223	60,152	72,326	22,217	8,403	3,214	954	26,531
Winter Peak Month	368,488	51,878	132,470	33,704	22,559	2,926	15,141	60,152	72,326	22,217	8,403	3,214	695	26,487
Summer Peak Month	257,310	68,552	131,520	33,820	23,254	6,087	18,223	52,789	61,159	17,983	7,028	2,318	954	26,531

Rate Class NCP @ Input Voltage (kW)	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Line Losses:	6.25%	6.25%	6.25%	6.25%	5.22%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	5.22%
Jan-09	391,533	52,650	140,755	35,730	23,736	2,617	4,413	61,977	72,774	20,529	8,442	3,415	695	24,828
Feb-09	318,913	32,937	103,858	35,812	23,737	2,792	5,158	61,148	71,881	20,128	8,342	2,915	550	25,263
Mar-09	273,402	36,957	124,372	35,935	24,468	3,242	2,971	49,630	61,493	17,581	7,057	1,974	499	21,270
Apr-09	239,674	28,892	98,491	35,517	22,884	3,642	5,147	47,380	57,657	19,107	6,676	1,624	409	21,844
May-09	205,735	34,351	116,682	34,126	22,941	5,000	9,221	43,250	50,296	13,584	5,945	2,229	414	17,817
Jun-09	225,804	39,570	103,577	34,383	20,915	6,467	9,851	51,673	64,938	16,777	7,043	1,719	843	19,733
Jul-09	251,934	72,839	139,746	33,919	17,832	5,755	15,591	50,916	61,334	15,826	6,769	1,917	522	19,129
Aug-09	247,644	50,588	111,376	33,837	17,787	4,118	18,237	56,091	64,984	17,419	7,468	1,916	488	20,904
Sep-09	174,605	39,809	128,436	33,919	18,818	3,440	15,979	46,468	54,618	14,240	6,838	2,463	505	20,074
Oct-09	239,080	41,778	114,316	35,707	19,862	3,379	19,363	47,214	58,510	16,506	6,893	1,878	1,014	27,917
Nov-09	284,472	55,122	139,254	33,072	20,091	3,109	16,088	59,347	70,539	19,584	7,999	1,912	632	25,289
Dec-09	378,371	48,047	116,358	29,684	20,344	2,364	6,963	63,914	76,849	23,607	8,928	2,322	738	27,870
Maximum	391,533	72,839	140,755	35,935	24,468	6,467	19,363	63,914	76,849	23,607	8,928	3,415	1,014	27,917
Winter Peak Month	391,533	55,122	140,755	35,812	23,737	3,109	16,088	63,914	76,849	23,607	8,928	3,415	738	27,870
Summer Peak Month	273,402	72,839	139,746	35,935	24,468	6,467	19,363	56,091	64,984	19,107	7,468	2,463	1,014	27,917

System Coincidence Factor	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	80.00%	70.00%	75.00%	75.00%	93.48%	100.00%	90.00%	99.07%	98.78%	100.00%	95.49%	98.34%	98.34%	96.08%
Feb-09	80.00%	70.00%	75.00%	75.00%	92.78%	100.00%	90.00%	97.43%	99.03%	99.13%	97.41%	98.25%	98.25%	98.54%
Mar-09	80.00%	70.00%	75.00%	75.00%	89.53%	100.00%	90.00%	99.55%	98.02%	97.70%	97.68%	98.24%	98.24%	97.56%
Apr-09	80.00%	70.00%	75.00%	75.00%	90.88%	100.00%	90.00%	95.52%	97.31%	98.37%	95.55%	96.69%	96.69%	98.84%
May-09	80.00%	70.00%	75.00%	75.00%	68.22%		90.00%	98.07%	96.03%	92.60%	94.50%	95.30%	95.30%	95.00%
Jun-09	80.00%	70.00%	75.00%	75.00%	84.45%		90.00%	97.73%	94.34%	95.66%	97.48%	96.30%	96.30%	95.00%
Jul-09	80.00%	70.00%	75.00%	75.00%	82.62%		90.00%	90.07%	99.70%	98.51%	97.62%	96.48%	96.48%	95.00%
Aug-09	80.00%	70.00%	75.00%	75.00%	86.84%		90.00%	97.89%	96.66%	97.29%	94.91%	96.69%	96.69%	95.00%
Sep-09	80.00%	70.00%	75.00%	75.00%	76.69%		90.00%	93.67%	96.97%	98.19%	94.01%	95.71%	95.71%	82.19%
Oct-09	80.00%	70.00%	75.00%	75.00%	86.16%	100.00%	90.00%	94.30%	94.93%	99.40%	91.80%	95.11%	95.11%	80.96%
Nov-09	80.00%	70.00%	75.00%	75.00%	87.67%	100.00%	90.00%	97.36%	98.70%	99.66%	97.92%	98.41%	98.41%	96.30%
Dec-09	80.00%	70.00%	75.00%	75.00%	87.53%	100.00%	90.00%	97.72%	98.98%	76.08%	99.07%	92.96%	92.96%	93.62%

FORECAST CUSTOMER DEMAND
Schedule 8.2

Coincident Peak (CP) @ Input (kW)	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	700,994	313,226	36,855	105,566	26,797	22,189	2,617	3,972	61,401	71,883	20,529	8,062	3,358	683	23,855
Feb-09	599,529	255,130	23,056	77,894	26,859	22,022	2,792	4,642	59,575	71,184	19,953	8,126	2,864	540	24,893
Mar-09	549,574	218,722	25,870	93,279	26,951	21,906	3,242	2,674	49,408	60,272	17,176	6,893	1,939	490	20,751
Apr-09	491,637	191,739	20,224	73,868	26,637	20,797	3,642	4,632	45,257	56,106	18,796	6,379	1,570	396	21,592
May-09	454,044	164,588	24,046	87,512	25,594	15,650		8,299	42,415	48,300	12,579	5,618	2,124	394	16,926
Jun-09	494,231	180,644	27,699	77,683	25,787	17,663		8,866	50,500	61,262	16,049	6,866	1,655	812	18,747
Jul-09	561,282	201,547	50,988	104,809	25,439	14,733		14,032	45,859	61,151	15,590	6,607	1,849	504	18,173
Aug-09	538,237	198,115	35,412	83,532	25,378	15,446		16,414	54,909	62,813	16,948	7,087	1,853	472	19,858
Sep-09	454,371	139,684	27,866	96,327	25,439	14,432		14,381	43,527	52,965	13,982	6,428	2,357	483	16,498
Oct-09	519,098	191,264	29,244	85,737	26,780	17,113	3,379	17,426	44,520	55,546	16,407	6,328	1,786	964	22,601
Nov-09	612,218	227,577	38,586	104,440	24,804	17,613	3,109	14,479	57,778	69,624	19,518	7,833	1,881	622	24,354
Dec-09	666,561	302,697	33,633	87,268	22,263	17,807	2,364	6,267	62,455	76,066	17,959	8,845	2,158	686	26,092
Total	6,641,776	2,584,934	373,478	1,077,915	308,730	217,371	21,146	116,084	617,606	747,173	205,486	85,072	25,396	7,046	254,340
Peak Month	700,994	313,226	36,855	105,566	26,797	22,189	2,617	3,972	61,401	71,883	20,529	8,062	3,358	683	23,855
Winter Peak Month		2,584,934	373,478	1,077,915	308,730	217,371	21,146	116,084	617,606	747,173	205,486	85,072	25,396	7,046	254,340
Summer Peak Month		201,547	50,988	104,809	26,780	20,797	3,642	17,426	54,909	62,813	18,796	7,087	2,357	964	22,601
Use Contract Demand (1=Yes)						1			1	1	1	1	1	1	1

Contract Demand Limit (kW)	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09						51,100			91,800	156,600	30,000	24,000		500	45,000
Feb-09						51,100			91,800	156,600	30,000	24,000		500	45,000
Mar-09						51,100			91,800	156,600	30,000	24,000		500	45,000
Apr-09						51,100			91,800	125,500	22,000	18,000		400	45,000
May-09						51,100			91,800	125,500	22,000	18,000		400	45,000
Jun-09						51,100			91,800	125,500	22,000	18,000		400	45,000
Jul-09						51,100			91,800	125,500	22,000	18,000		400	45,000
Aug-09						51,100			91,800	125,500	22,000	18,000		400	45,000
Sep-09						51,100			91,800	125,500	22,000	18,000		400	45,000
Oct-09						51,100			91,800	156,600	30,000	24,000		500	45,000
Nov-09						51,100			91,800	156,600	30,000	24,000		500	45,000
Dec-09						51,100			91,800	156,600	30,000	24,000		500	45,000
Total						613,200			1,101,600	1,692,600	312,000	252,000		5,400	540,000

Max Demand @ Input (kW)	Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
Jan-09	891,576	313,226	36,855	105,566	26,797	51,100	2,617	3,972	91,800	156,600	30,000	24,000	3,358	683	45,000
Feb-09	792,276	255,130	23,056	77,894	26,859	51,100	2,792	4,642	91,800	156,600	30,000	24,000	2,864	540	45,000
Mar-09	771,677	218,722	25,870	93,279	26,951	51,100	3,242	2,674	91,800	156,600	30,000	24,000	1,939	500	45,000
Apr-09	676,114	191,739	20,224	73,868	26,637	51,100	3,642	4,632	91,800	125,500	22,000	18,000	1,570	400	45,000
May-09	665,962	164,588	24,046	87,512	25,594	51,100		8,299	91,800	125,500	22,000	18,000	2,124	400	45,000
Jun-09	676,545	180,644	27,699	77,683	25,787	51,100		8,866	91,800	125,500	22,000	18,000	1,655	812	45,000
Jul-09	752,568	201,547	50,988	104,809	25,439	51,100		14,032	91,800	125,500	22,000	18,000	1,849	504	45,000
Aug-09	714,575	198,115	35,412	83,532	25,378	51,100		16,414	91,800	125,500	22,000	18,000	1,853	472	45,000
Sep-09	659,939	139,684	27,866	96,327	25,439	51,100		14,381	91,800	125,500	22,000	18,000	2,357	483	45,000
Oct-09	755,082	191,264	29,244	85,737	26,780	51,100	3,379	17,426	91,800	156,600	30,000	24,000	1,786	964	45,000
Nov-09	813,998	227,577	38,586	104,440	24,804	51,100	3,109	14,479	91,800	156,600	30,000	24,000	1,881	622	45,000
Dec-09	855,836	302,697	33,633	87,268	22,263	51,100	2,364	6,267	91,800	156,600	30,000	24,000	2,158	686	45,000
Total	9,026,148	2,584,934	373,478	1,077,915	308,730	613,200	21,146	116,084	1,101,600	1,692,600	312,000	252,000	25,396	7,065	540,000
Peak Month	891,576	313,226	50,988	105,566	26,951	51,100	3,642	17,426	91,800	156,600	30,000	24,000	3,358	964	45,000
Winter Peak Month	891,576	313,226	38,586	105,566	26,951	51,100	3,642	17,426	91,800	156,600	30,000	24,000	3,358	964	45,000
Summer Peak Month	752,568	201,547	50,988	104,809	25,787	51,100		16,414	91,800	125,500	22,000	18,000	2,357	812	45,000

FORECAST kWh AT INPUT
Schedule 8.3

kWh @ Input Voltage		Total	Residential	Small General Service	General Service	Industrial Primary	Industrial Transmission	Lighting	Irrigation	Kelowna Wholesale	Penticton Wholesale	Summerland Wholesale	Grand Forks Wholesale	BCH Lardeau Wholesale	BCH Yahk Wholesale	Nelson Wholesale
	Jan-09	361,624,888	161,773,663	22,413,309	52,297,722	12,493,005	7,288,898	1,318,810	621,657	33,782,888	39,916,439	11,087,650	4,766,900	1,037,180	316,613	12,510,154
	Feb-09	319,102,862	150,273,551	16,538,015	38,588,702	12,060,076	7,036,310	1,149,176	656,265	30,314,676	35,818,546	9,949,372	4,277,522	930,702	284,109	11,225,840
	Mar-09	310,114,993	138,067,717	19,804,584	46,210,695	12,598,781	7,350,611	1,274,273	418,444	27,567,145	32,572,179	9,047,624	3,889,834	846,349	258,359	10,208,400
	Apr-09	270,884,123	121,970,679	15,683,391	36,594,580	12,541,367	7,317,113	1,140,821	701,576	24,478,441	28,922,696	8,033,901	3,454,006	751,521	229,412	9,064,621
	May-09	258,896,213	104,754,475	18,580,068	43,353,492	13,317,386	7,769,873	1,296,961	3,896,409	21,536,162	25,446,223	7,068,236	3,038,838	661,189	201,837	7,975,064
	Jun-09	244,989,642	91,200,328	16,493,273	38,484,303	12,934,769	7,546,640	1,399,377	6,266,445	23,083,556	27,274,558	7,576,095	3,257,182	708,696	216,339	8,548,081
	Jul-09	255,898,311	78,859,113	22,252,645	51,922,839	12,908,787	7,531,480	1,390,423	10,248,416	23,122,788	27,320,914	7,588,972	3,262,718	709,901	216,707	8,562,609
	Aug-09	254,588,796	86,818,435	17,735,138	41,381,990	11,418,314	6,661,881	1,234,099	11,987,941	25,267,792	29,855,360	8,292,969	3,565,386	775,756	236,809	9,356,926
	Sep-09	251,457,025	84,625,849	20,451,800	47,720,867	10,173,755	5,935,758	1,224,739	9,438,658	23,482,442	27,745,866	7,707,011	3,313,466	720,943	220,077	8,695,792
	Oct-09	265,349,496	100,778,793	18,203,307	42,474,383	12,544,438	7,318,905	1,467,006	6,363,844	24,891,417	29,410,652	8,169,441	3,512,278	764,200	233,282	9,217,550
	Nov-09	297,889,762	111,448,694	22,174,314	51,740,066	14,101,760	8,227,506	1,475,148	2,193,010	28,266,001	33,397,918	9,276,990	3,988,446	867,805	264,909	10,467,194
	Dec-09	335,436,486	143,702,176	18,528,467	43,233,089	13,333,472	7,779,258	1,227,528	980,789	34,839,281	41,164,629	11,434,361	4,915,962	1,069,613	326,513	12,901,348
Total Purchases - Bottom Up		3,426,232,597	1,374,273,473	228,858,311	534,002,726	150,425,909	87,764,233	15,598,361	53,773,454	320,632,590	378,845,979	105,232,622	45,242,539	9,843,856	3,004,965	118,733,579

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

Appendix B—Minimum System Analysis

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

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

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

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

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

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

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

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

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

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

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

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

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

Poles

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

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

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

FortisBC
Minimum System Analysis
Power Poles – As built

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

FortisBC
Minimum System Analysis
Power Poles – Minimum

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

Customer-Related	81%
Demand-Related	19%

Assumptions 2008

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

Power Pole Costs (from 2007 Study)

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

Cost per pole calculations (from 2007 Study)

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

Other Material:

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

Conductors

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

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

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

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

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

Assumptions in 2007 Study

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

Conductor Costs per Kilometer (from 2007 Study)

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

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

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

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

Transformers

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

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

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

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

Assumptions 2008

Actual transformer cost derived from FortisBC purchase price contract.
Any transformers that weren't available were replaced by the next larger size.
A 15 kVA transformer is assumed to be the minimum size used for this analysis.

Transformer Costs (from 2007 Study)

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

Cost per transformer calculations (from 2007 Study)

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

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

Peak Load Carrying Capability Adjustment (PLCC)

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

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

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

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

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

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

W302S-GLE2	13	9.44	26.89	36.34	451.00	Urban	1576.17
W302S-GLE5	13	37.64	69.00	106.64	1642.00	Urban	1576.17
W302S-GLE7	13	38.18	86.22	124.40	903.00	Urban	1576.17
W304S-HOL1	13	87.76	144.65	232.42	1843.00	Urban/Rural	234.72
W304S-HOL2	13	25.22	50.12	75.34	1673.00	Urban	1576.17
W304S-HOL3	13	22.51	45.14	67.65	1974.00	Urban	1576.17
W304S-HOL4	13	22.11	45.48	67.59	2165.00	Urban	1576.17
W304S-HOL5	13	53.25	85.36	138.61	2158.00	Urban	1576.17
W304S-HOL7	13	10.53	26.45	36.98	859.00	Urban	1576.17
W305S-COKOKM1	13	9.99	20.95	30.94	464.00	Urban	1576.17
W305S-OKM1	13	50.12	93.86	143.98	2617.00	Urban	1576.17
W305S-OKM2	13	11.47	26.18	37.64	1017.00	Urban	1576.17
W305S-OKM3	13	27.27	55.63	82.90	1089.00	Urban	1576.17
W305S-OKM4	13	32.15	61.99	94.14	3245.00	Urban	1576.17
W308S-SEX1	13	77.20	173.03	250.23	1395.00	Urban	1576.17
W308S-SEX2	13	47.01	85.20	132.21	2114.00	Urban	1576.17
W308S-SEX3	13	53.27	90.73	144.00	971.00	Urban	1576.17
W308S-SEX4	13	5.34	15.49	20.83	121.00	Urban	1576.17
W316S-DUC1	13	72.03	133.72	205.75	983.00	Urban/Rural	234.72
W316S-DUC2	13	22.43	41.97	64.40	439.00	Urban/Rural	234.72
W321S-KAL1	13	136.29	229.77	366.06	775.00	Urban/Rural	234.72
W322S-NAR1	13	34.05	53.50	87.55	515.00	Urban/Rural	234.72
W322S-NAR2	13	46.33	74.16	120.49	325.00	Urban/Rural	234.72
W323S-OKF1	13	33.22	67.16	100.38	729.00	Urban	1576.17
W323S-OKF2	13	10.92	19.97	30.89	183.00	Rural	93.89
W323S-OKF3	13	44.58	84.04	128.63	932.00	Rural	93.89
W333S-PIN1	13	32.77	64.14	96.91	1040.00	Urban	1576.17
W333S-PIN2	13	126.23	222.86	349.09	905.00	Rural	93.89
W333S-PIN3	13	32.23	63.08	95.32	1282.00	Urban	1576.17
W338S-OSO1	13	24.64	57.13	81.77	1314.00	Urban	1576.17
W338S-OSO2	13	68.05	114.78	182.83	1075.00	Urban	1576.17
W338S-OSO3	13	94.43	196.54	290.96	1464.00	Urban	1576.17
W345S-KER1	13	99.41	210.12	309.53	739.00	Rural	93.89
W345S-KER2	13	137.53	317.53	455.06	1466.00	Rural	93.89
W347S-HED2	13	51.30	124.58	175.88	409.00	Rural	93.89
W347S-HED3	13	11.19	30.56	41.75	23.00	Rural	93.89
W371S-DGB1	13	31.37	50.11	81.47	1333.00	Urban	1576.17
W371S-DGB2	13	92.43	151.95	244.38	1416.00	Urban	1576.17
W371S-DGB3	13	50.79	83.44	134.23	717.00	Urban	1576.17
W372S-LEE1	13	72.09	125.88	197.97	2998.00	Urban	1576.17
W372S-LEE2	13	79.02	137.96	216.98	896.00	Urban/Rural	234.72
W386S-OLI1	13	80.24	135.63	215.87	611.00	Rural	93.89
W386S-OLI2	13	46.99	98.04	145.04	742.00	Rural	93.89
W390S-BUR1	13	14.28	33.56	47.83	372.00	Urban	1576.17
W390S-EAS1	13	50.07	125.26	175.33	363.00	Urban	1576.17
W390S-LIM1	13	27.32	55.44	82.76	1125.00	Urban	1576.17
W390S-NOR1	13	197.56	406.64	604.20	951.00	Rural	93.89
W102S-KAS1	25	16.36	27.24	43.60	398.00	Rural	347.22
W102S-KAS2	25	36.71	60.59	97.30	428.00	Rural	347.22

W103S-COF1	25	40.88	88.43	129.30	200.00	Rural	347.22
W258S-CSC1	25	21.61	51.86	73.47	79.00	Rural	347.22
W258S-CSC2	25	19.30	35.65	54.95	1161.00	Urban	3031.09
W258S-CSC3	25	51.18	91.64	142.81	558.00	Urban	3031.09
W292S-ROC1	25	182.30	349.28	531.57	374.00	Rural	347.22
W292S-ROC2	25	116.48	174.63	291.11	311.00	Rural	347.22
W315S-JOR1	25	74.31	158.80	233.10	1102.00	Rural	347.22
W315S-JOR2	25	77.84	182.00	259.84	537.00	Rural	347.22
W320S-HUT2	8.66	0.04	0.12	0.16		Urban	1049.97
W326S-WEB1	8.66	34.72	73.12	107.85	912.00	Urban	1049.97
W326S-WEB2	8.66	31.62	62.68	94.30	502.00	Urban	1049.97
W327S-SPL	5	7.09	7.09	14.19	16.00	Rural	13.89
W329S-TRC1	8.66	3.77	11.30	15.07		Rural	41.66
W347S-HED4	25	23.90	64.60	88.49	434.00	Urban	3031.09
W380S-RGA1	8.66	19.52	26.49	46.01	75.00	Rural	41.66

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

Zero-Intercept Approach

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

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

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

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

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

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

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

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

Zero-Intercept Poles

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

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

Minimum System Results	
Percent Customer	81%
Percent Demand	19%

SUMMARY OUTPUT

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

ANOVA

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

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

Zero-Intercept Conductor

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

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

SUMMARY OUTPUT

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

ANOVA

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

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

X Variable 1	4.254896492	1.0932923	3.8918197	0.0045974

Zero-Intercept Transformers

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

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

SUMMARY OUTPUT (First 8 Data Points)

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

ANOVA

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

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

Appendix C—Load Analysis

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

Energy

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

Billing Demand

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

Individual Load Factor

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

Group Coincident Factor

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

Rate Class Non-Coincident Peak (NCP)

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

System Coincident Factor

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

For the wholesale and industrial customers, FortisBC has hourly meters allowing for the collection of data on a detailed basis. System coincident factors for these classes were based on actual hourly load data. Wholesale customers generally have system coincident factors in the range of 90% to 100%. 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. Industrial transmission customers have factors in the 62% to 72% range. Assumptions were made for the other classes, including 75% for industrial primary and large general service customers, 70% for small general service and 80% for residential customers.

Rate Class Coincident Peak (CP)

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