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October 21, 2011

Via Email

Ms. Alanna Gillis
Acting Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: FortisBC Inc. (FortisBC) Application for 2012 -2013 Revenue Requirements and Review of 2012 Integrated System Plan Responses to Intervener Information Requests No. 2

Please find attached FortisBC's responses to Information Requests No. 2 from the British Columbia Old Age Pensioners' Association et al., British Columbia Municipal Electrical Utilities, British Columbia Sustainable Energy Association, Zellstoff Celgar Limited Partnership, and Mr. Norman Gabana.

If further information is required, please contact the undersigned at (250) 717- 0890.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

1.0 Reference: Exhibit B-4, BCUC IR #1.15.1

1.1 Please update Table 4.1-1 (Exhibit B-1, RRA) from the original Application to reflect the updated market prices provided in the response to BCUC 1.15.1.

Response:

Please refer to the response to BCUC IR2 Q2.1

2.0 Reference: Exhibit B-4, BCUC IR #1.94.2

2.1 The responses to various Round #1 information requests have updated FortisBC's 2011 forecast costs and revenues. Please update Table 1.2 from the original application and the calculation of the 2011 ROE sharing mechanism (per BCUC 1.94.2) to reflect these changes. Please also provide a schedule setting out the IR responses that discuss the changes that have been incorporated in the 2011 update.

Response:

This information will be filed no later than November 2, 2011, as part of the Evidentiary Update to the 2012-13 RRA, which is discussed in the response to BCUR IR2 Q1.1. Included in that response is a schedule identifying the IR responses for each component of the update.

3.0 Reference: Exhibit B-4, BCUC IR #1.25.1 and 1.25.5

3.1 It is not clear from the responses which services from FEI are totally new services and which ones were provided to FortisBC in some other manner in the past. Please clarify.

Response:

None of the services FEI plans on providing to the Power Supply group are new to FortisBC. In the past these services have all been provided by Power Supply, using primarily its own resources. These resources however are too limited to continue to provide both these services and to successfully manage the increasingly complex environment faced by the Company's Power Supply operations. The integration of FortisBC's and FEI's Energy Supply groups offers a means to address both the need for an improved range of back-office and support services and freeing management resources so that they can be better focused on the management of power supply costs.

This re-alignment of responsibilities within the integrated Energy Supply team will help to better respond to a general increase in the levels of activity faced by Power Supply, which were described in the 2012-13 RRA in Tab 4 on pages 13-15 and in the responses to BCUC IR1 Q25.1 and BCUC IR1 Q25.4 and BCUC IR2 Q8.2. It was determined that greater focus and attention is needed in this area because of the significant changes that are expected to arise from the negotiation and renewal of key power purchase contracts, the need to address the rise of intermittent renewable generation, and the continued tightening of transmission resources.

This re-alignment of responsibilities is also important so that the group is better positioned to manage employee development and succession planning. Managing employee development to ensure the appropriate level of market expertise and experience on an on-going basis is an important means to support the successful completion of daily activities in light of employee changes and transfers, competitive challenges, and the potential for retirements.

These changes, including the additional cost for the services FEI will be providing, are required and prudent in order to be able to continue to manage the reliability and costs of power resources, and are in the best interests of customers.

4.0 Reference: Exhibit B-4, BCUC IR #1.62.5 and 1.62.6

4.1 The response to BCUC 1.62.5 suggests that current insurance market conditions are contributing to a decrease in insurance expense whereas the response to BCUC 1.62.6 suggests that current market conditions are causing an increase in insurance premiums. Please reconcile.

Response:

The response to BCUC IR1 Q62.5 is referring to historical market conditions causing a decrease in insurance expense for 2007 through to 2010. This was explained on page 92 of Tab 4 of the 2012-13 RRA, where the decrease in insurance expense resulting from market conditions was explained as follows:

> "Favourable insurance market conditions in 2008 resulted in the stabilization or reduction of insurance premiums through to 2010."

The response to BCUC IR1 Q62.6 is referring to current and future market conditions causing an increase in 2011 through 2013 insurance expense. This concept was explained in the response to BCUC IR1 Q62.6 with the following statements:

> "The 5 percent increase in insurance premiums for each of 2012 and 2013 was based primarily on qualitative factors. This would include the expectation that after several years of experiencing more favourable insurance market conditions, the market would eventually harden resulting in an increase in insurance premiums……..The appropriateness of using a 5 percent forecast of insurance premiums for each of 2012 and 2013 has been further corroborated as a reasonable forecast due to the Company's payment of its July 2011 through to June 2012 insurance premiums at an increase of 7 percent over the July 2010 through June 2011 insurance premiums."

5.0 Reference: Exhibit B-4, BCUC IR #1.75.1 and 1.75.2

5.1 Has FortisBC filed its 2010 Corporate Tax Return? If so, is there any over/under provision and how is it treated in the current Application?

Response:

The Company filed its 2010 Corporate Tax Return at the end of June 2011 which resulted in an under-provision of $0.127 million for 2010. Since both the tax return and the current 2012-13 RRA were filed around the same time, the 2010 under-provision was not included in the 2012-13 RRA filed on June 30, 2011. The Company's 2011 Income Tax Expense will be reforecast in the Evidentiary Update to be filed on or before November 2, 2011, and will include the 2010 under-provision.

6.0 Reference: Exhibit B-4, BCUC IR #1.100.1 and 1.101.2

6.1 If the allocation is to be based on actual expenditures over the 2012 to 2016 period then won't the "transfer" have to wait until the end of this period when all of the actual expenditures are known? Similarly, how can the annual allocation (per BCUC 1.101.2) be known at this time?

Response:

As indicated in the responses to BCUC IR1 Q100.1 and Q101.2 (as referenced above), the yearly allocation of the ISP cost is forecast to be $677,000 per year during the five year period of 2012 to 2016. The allocation to individual projects during the year will be on a percentage basis to be calculated on year end forecasts. This "allocation percentage" will be reviewed periodically during the year (and adjusted if required) to achieve the yearly ISP allocation at year end.

The allocation percentage for any particular year will be calculated as follows:

ISP Allocation Percentage = **ISP Allocation Forecast for the Year ($677,000)** / **Total Capital Project Year End Forecast (without the Forecast ISP Allocation Component of $677,000)**

7.0 Reference: Exhibit B-4, BCUC IR #102.4

Exhibit B-5, BCOAPO IR #102.1

7.1 Please describe more fully what FortisBC considers to be an "extraordinary event" outside of management's control, particularly in view of the fact that there is no proposed materiality limit.

<u>Response:</u>

Examples of extraordinary events outside of management's control would include Force Majeure events (such as an earthquake, ice storm or other acts of God), or changes to government legislation. FortisBC has previously defined its view of what is an "extraordinary event" outside of management's control and has provided examples such as:

Tab 5, Section 5.4.3 Non-Controllable Items Variances page 16 of the 2012-13 RRA, the Company describes extraordinary events or costs as:

> "outside of "steady state" operations, excluding those deferral accounts already requested for approval above. Such circumstances for inclusion in this deferral account would include directives and decisions made by the Commission or other competent regulatory agencies, including the decisions related to capital plan approval processes, acts of legislation or regulation of government, changes due to GAAP, Force Majeure events or other extraordinary events."

The response to BCUC IR1 Q102.4 elaborated with the following description of extraordinary costs:

> "Prudently incurred costs, which were unforeseen at the time of forecasting and may result from factors beyond the Company's control. This variance deferral account has been proposed to capture the impacts on rates as a result of directives and decisions made by the Commission or other competent regulatory agencies, including acts of legislation or regulation of government, changes due to GAAP, Force Majeure events or other extraordinary events. All of these potential factors have a common theme in that the Z-factors require the Company to implement changes that differ from forecast and the drivers are out of the Company's control for forecast purposes. Costs to be recovered or refunded as a result of government or regulatory decisions would undergo the same level of scrutiny for reasonableness and prudency as other rate base accounts."

8.0 Reference: Exhibit B-4, BCUC IR #1.150.2

8.1 If a new large (distribution) customer triggers the need for upgrades to FortisBC's transmission system, is the customer responsible for the cost of these upgrades?

Response:

In a situation where the customer is supplied from a distribution voltage and its individual load requirements require a transmission line upgrade, the distribution substation would also require an upgrade. FortisBC's Electric Tariff provides that commercial and industrial applicants for service may be required to make a contribution in situations where installation and/or upgrading of substation and transmission facilities are necessary. Depending on the magnitude of the upgrade required, an application to the Commission for approval may be required, and would include any detail on applicable Contributions in Aid of Construction for which the prospective customer would be responsible.

In a situation where the new customer requested service at a transmission voltage (63kV and higher) and its individual load requirements result in issues with either capacity or voltage on the transmission line, that customer is responsible for all upgrade costs to ensure that the standard of service to other customers is not impacted.

Please refer also to the response to BCUC IR1 Q150.2.

9.0 Reference: Exhibit B-4, BCUC IR #1.192.4 and 1.192.5

9.1 Please confirm that the costs of removal do not affect either rate base or depreciation expense until after they have actually been incurred. If this is not the case, please explain.

Response:

Rate Base for the purpose of rate setting is affected by the forecast values of Cost of Removals (COR).

The COR is reflected in forecast Rate Base through Accumulated Depreciation and Amortization:

1. 2012-13 RRA (Exhibit B-1), Tab 5, Table 5.3, Page 8, Lines 31 to 36 shows COR as a component of Accumulated Depreciation and Amortization; and

2. 2012-13 RRA (Exhibit B-1), Tab 5, Table 5.1.1, Page 2, Line 13 shows Accumulated Depreciation and Amortization as a component of Rate Base.

The actual Rate Base in any specific year is affected by COR only when such costs are actually incurred.

Depreciation expense is calculated on Gross Book Value (GBV) of an asset and is not affected by COR since COR is not a part of the GBV of any asset.

10.0 Reference: Exhibit B-4, BCUC IR #1.222.1

10.1 Based on FortisBC's current plans, when does it anticipate dispensation from Measurement Canada will be applied for and when might such dispensation be received?

<u>Response:</u>

FortisBC expects to make application to Measurement Canada for dispensation following the approval of the FortisBC Advanced Metering Infrastructure CPCN application. It is expected that Measurement Canada may take up to six months to approve and grant the dispensation.

11.0 Reference: Exhibit B-4, BCUC IR #1.231.3

11.1 Please confirm that the RIB impact calculation assumes that <u>all</u> residential customers are on the RIB. Please reconcile this with FortisBC's plan to introduce TOU rates on an optional basis after the implementation of AMI.

<u>Response:</u>

The RIB impact calculation assumes that all residential customers are on the RIB rate. FortisBC assumes that any inaccuracy resulting from this assumption is negligible as the RIB energy savings are already uncertain since they are based on a proposed (rather than approved) RIB rate structure and assumed price elasticities, and since time-based rates are also expected to provide energy savings.

12.0 Reference: Exhibit B-4, BCUC IR #1.242.1 and 1.242.2

12.1 The response to BCUC 1.242.2 indicates that the $124.30/MWh BCH LRMC quoted in BCUC 1.242.1 is in 2009$. Are all of the rest of the values quoted in Table BCUC IR1.242.1 also in 2009$? If not, what is the reference year for each?

Response:

The $38.04/MWh Marginal Cost is actually the annual marginal cost for 2012, and is in nominal dollars (i.e. 2012 dollars).

The $84.94/MWh levelized LRMC from market purchases is in nominal dollars. The levelized cost was determined by discounting the forecast of annual BC New Resource Market Energy costs using an 8% nominal discount rate to obtain an equivalent flat nominal price over the 30 year term, 2011-2040. Adjusting for inflation and using a real discount rate of 6% would result in a levelized price in 2011 dollars of $69.97/MWh that then escalates annually with inflation. (Note that the table in the response to BCUC IR1 Q242.1 incorrectly says that the levelized rate was determined using a 6% real discount rate. This should say that it was determined using an 8% nominal discount rate. Please refer to Errata 3.)

The $97/MWh LRMC New Construction – Similkameen UEC is in 2010 dollars which would then escalate with inflation.

As with the levelized LRMC from market purchases, the $111.96/MWh levelized BC New Resources Market Energy is in nominal dollars, and is the equivalent flat price for a 30 year term starting in 2011. Adjusting for inflation and using a real discount rate of 6% would result in a levelized price of $92.23/MWh in 2011 dollars that then escalates annually with inflation.

The $124.30/MWh BCH levelized LRMC (Clean Power Call, Delivered to LML) is in 2009 dollars and would escalate with inflation.

The $111.3/MWh BC Hydro levelized LRMC (Clean Power Call, Plantgate) is in 2009 dollars and would escalate with inflation.

13.0 Reference: Exhibit B-4, BCUC IR #1.242.1 and 1.270.1

13.1 Please confirm that the value quoted for BC New Resources Market Energy ($124.30) is based on an 8% nominal discount rate (per BCUC 1.242.1) whereas the calculation of the BC New Resource Market Capacity values is based on an 8% real discount rate (per BCUC 1.270.1). Should a consistent rate be used in the calculation of these values and, if so, what is FortisBC's view as to the appropriate discount rate?

Response:

Note: This response assumes that the question refers to the levelized BC New Resources Market Energy Curve price of $111.96/MWh (as opposed to $124.30/MWh – BC Hydro's LRMC calculated from the most recent clean call).

The BC New Resources Market Energy Curve was levelized using an 8% nominal discount rate (resulting in a nominal levelized price of $111.96/MWh, flat for the 30 year term). The 8% nominal discount rate was used here so that the levelized cost numbers could be compared to the BC Hydro LRMC numbers (see response to BCOAPO IR2 Q12.1).

The BC New Resource Capacity curve is in nominal dollars, and an 8% nominal dollar discount rate was used in the calculation of the levelized price. As noted in BCUC IR1 Q270.1, the BC new resources capacity curve is derived from a SSGT UCC calculation that uses an 8% real discount rate. The new resource capacity curve was created by escalating the UCC starting point value at CPI.

While it is correct that one would typically not mix discount rates, in this case, there is not a material impact to using a different discount rate to levelize the capacity curve (than what was used in deriving the underlying new resource capacity curve). The levelized cost of capacity number is not being utilized for decision-making purposes in the 2012 Resource Plan. All capacity related analysis was based on the UCC of the projects and the nominal dollar capacity cost curves.

In addition, as long as the cost stream from which the UCC is derived is a constant value on a real dollar basis (i.e. on a nominal basis it escalates with inflation), using a different discount rate in levelizing the new resources capacity curve is acceptable. If the cost stream varies each year, using a different discount rate could produce a different levelized price, and this difference would be magnified as the difference in discount rates increases.

14.0 Reference: Exhibit B-4, BCUC IR #1.270.1 and BCUC IR #1.277.2

14.1 When assessing a buy versus build strategy for capacity, is it more appropriate to use the cost comparison shown in Figure 6.3.2-A (per BCUC 1.270) or that shown in Figure 3.3.3-A (per BCUC 1.277.2)? Please explain why.

Response:

Figure 3.3.3-A is a forecast of annual unit capacity costs expressed in MW-Months. Figure 6.3.2-A shows the annual unit capacity costs from Figure 3.3.3-A multiplied by annual capacity gaps to come up with an estimate of the annual cost of obtaining capacity expressed in millions of dollars. Both measures have their advantages and disadvantages.

Annual unit capacity costs are good for a simple high level cost comparison of capacity options. However, as demonstrated in Figure 6.3.2-A, if the resource gap changes significantly, such as with the addition of a new supply resource such as the WAX CAPA, the annual cost comparison in Figure 6.3.2-A clearly shows the least cost solution in the short to medium term.

Neither option is good at presenting the New Resource capacity cost if the generation unit is initially larger than the capacity gap. Additional work would need to be done to demonstrate the impact of offsetting surplus capacity sales, or the temporary stranding of the surplus capacity, until the load grows into it.

15.0 Reference: Exhibit B-4, BCUC IR #1.280.1, 1.280.2 and 1.280.5

15.1 BCUC 1.280.1 states that Figure 3.2.4 sets out FortisBC's "target savings" which differ from acquired savings due to timing issues. In IR #1.280.2, BCUC asked for the data underlying Figure 3.2.4. In the response, the data provided is labeled "Acquired DSM Savings". Please confirm that the column should be labeled "Target DSM Savings". If not, please explain.

Response:

The title on the table is correct, "Acquired DSM Savings". Savings shown in Figure 3.2.4 are acquired savings, not the annual savings targets (please see the response to BCUC IR1 Q280.5.1 regarding the relationship between incremental acquired savings and annual savings targets). Acquired savings are used for load forecasting purposes and thus are more relevant than using program targets when comparing to incremental load growth.

15.2 The response to BCUC 1.280.1 states that the revised target for 2011 is 32 GWh of savings as opposed to the 28 GWh shown in response to BCUC 1.280.2. Please clarify the following:

- Is 2011 the only year for which the target DSM savings have been revised from those set out in response to BCUC 1.280.2? If not, please provide an updated response to BCUC 1.280.2 based on the revised targets.
- What DSM savings targets were incorporated in the Load Forecast used in the Application, those in BCUC 1.280.2 or the revised targets.

Response:

In the response to BCUC IR1 Q280.1, the acquired DSM savings in 2011 are 28 GWh, while the 2011 target is 32 GWh. The annual targets have not been revised except for 2011 which was reduced from 39 GWh (approved) to 32 GWh due to the removal of the Zellstoff Celgar DSM project.

15.3 In determining cumulative DSM savings (as set out in BCUC 1.280.5) does FortisBC assume 100% persistence for savings achieved in preceding years (i.e. back to 2011)? If yes, how valid is this assumption given that DSM measures will have a limited persistence based on the life of the new higher efficiency equipment.

Response:

Yes, 100% persistence of savings is assumed in the cumulative DSM savings. This is because the majority of DSM measures incented are hard-wired and thus cannot be readily removed or reversed to the prior state during their useful lifetime. Persistence of savings is considered to remain after measure life of equipment as it is assumed that equipment of similar or better efficiency will replace the incented measure. For example replacement products available at the end of an EnergyStar appliance life will have the same or lower kWh/year EnerGuide consumption ratings.

In some cases codes and standards savings lock in measure/program savings after measure life has ended. For example, when a CFL light-bulb, with a life of approximately 5 years, burns out the bulb will be replaced by another CFL due to recent and planned CFL regulations by government.

In either case the energy savings are not lost and the persistence is 100%.

16.0 Reference: Exhibit B-4, BCUC IR #1.281.1

16.1 Has FortisBC undertaken any analysis as to the persistence of the savings it has achieved over the period 1991-2010? For example, what is the continuing effect of these program savings in 2011?

<u>Response:</u>

Monitoring and Evaluation (M&E) reports are periodically undertaken to verify energy savings attributed to the various DSM programs offered by the Company, and often include random site visits to verify that the incented measure(s) were still in place. Billing records are normally examined as part of an M&E impact study, thereby factoring into the overall NTGR (net to gross ratio) which is used to adjust the recorded energy savings.

A minority of DSM measures can be reversed, e.g. a low-flow showerhead replaced with a higher flow model, or the clothes dryer is used instead of the clothesline measure provided. The persistence of such measures is determined through statistical survey methods, and the deemed savings of such measures are adjusted appropriately before they are entered into the EM database.

17.0 Reference: Exhibit B-5, BCOAPO IR #1.4.1

17.1 The response suggests that the implementation plan for developing an Asset Management approach/solution will not be available until the next Capital Expenditure Plan filing in 2013. When does FortisBC anticipate that an Asset Management Strategy will actually be implemented and used for one or more of its core businesses and be a key influencer in the development of its capital (and OM&A) expenditure plans.

<u>Response:</u>

The proposed project is intended to develop a business case with a recommended asset management strategy along with the implementation plan, timelines and associated costs. As a result, a detailed implementation timeline is not currently available as this will be one of the deliverables of the project. As identified in Section 1.1.2, page 5 of the 2012 Integrated System Plan (Exhibit B-1-2), FortisBC is proposing a measured implementation timeline in the range of five years. The Company will initially focus on transmission/distribution and generation assets. General Plant assets will not be included in the initial implementation plan. The Asset Management strategy may be extended to include other business areas once it is well established.

18.0 Reference: Exhibit B-5, BCOAPO IR #1.7.1 and 1.7.2

18.1 In forecasting capital expenditures (and associated removal costs), please clarify whether:

a) The total cost of the work (including removal activities) is forecast and then the percentages are used to allocate the costs as between the cost of new facilities and the cost of removal, or

b) The cost of the new structures is forecast and then the percentages are used to estimate the cost of removal.

Response:

In forecasting capital expenditures, the total cost of work including removals is forecast and then the salvage percentage for the project is used to allocate the costs between the new facilities and the cost of removal.

19.0 Reference: Exhibit B-5, BCOAPO IR #1.10.2

19.1 Page 50 referenced in the original question also referred to "the notable increase in construction costs". It was this comment that the question sought to reconcile with the 2%/annum inflation assumption. Please reconcile.

Response:

The estimated construction costs for the All Plants Concrete and Structural Rehabilitation Program were based on 2011 construction dollars escalated by 2% per annum in accordance with pp.13 of the 2012 Long Term Capital Plan.

20.0 Reference: Exhibit B-5, BCOAPO IR #1.27.2 and 1.28.1

20.1 Do the "Revenue Guarantee" provisions apply in this instance for either Summerland or Penticton?

Response:

No. The revenue guarantee provision is contingent upon a scenario where "...FortisBC's facilities must be upgraded significantly to meet a proposed increase in Summerland's load in excess of 5,000 kVA resulting from either a new Summerland customer or the increased load of an existing Summerland customer." The Summerland transformer upgrade is necessitated by incremental load growth of all City of Summerland customers, not a single point load. The same is true for the Penticton upgrade project.

21.0 Reference: Exhibit B-5, BCOAPO IR #1.18.1 and 1.29.1 & 1.29.2

21.1 The response to BCOAPO 1.18.1 suggests that it is projects proposed for 2017 and beyond that will be subject to further reviews. However, BCOAPO 1.29.1 suggests that any project after 2013 will be subject to review based on new information. Please reconcile.

Response:

For all projects beyond 2012-13, each project will be subject to annual or biennial reviews during the development of future capital expenditure plans. During those reviews FortisBC will consider both the need (timing) and solution options. The currently proposed projects have been based on the information available at this time. As new data (e.g. changes in load growth, changes in technology, changes in public policy, etc.) becomes available this information will be used to update project proposals.

The response to BCOAPO IR1 Q18.1 was intended to convey that projects beyond the five year timeframe have more timing uncertainty as many are load-driven and thus may be advanced or deferred if load growth deviates from the current forecast. The timing for projects within the 5 year time frame is much less likely to be affected by changes in the load forecast unless unforeseen major new load additions occur.

The response to BCOAPO IR1 Q29.1 and Q29.2 was intended to convey that the solution options for all future projects will also be reviewed and updated prior to submitting an application for construction to the Commission (either through a Capital Expenditure Plan or CPCN application filing).

22.0 Reference: Exhibit B-5, BCOAPO IR #1.32.2

22.1 It is noted that even with the inclusion of the DC Supply Upgrade spending the annual forecast spending for 2012 and 2013 is virtually double that experienced 2009-2011. Please explain this increase.

Response:

The apparent increase in Station Assessment/Minor Planned spending is due to the unusually low program expenditures in the years 2009 and 2010. 2009 and 2010 were unusually busy years with a number of substation projects underway to meet customer growth. The Company directed its internal resources to support the critical components of the various projects and as a result expenditures were lower than would otherwise be expected. The proposed annual expenditures for this program are consistent with historical expenditure levels for the 2005 to 2008 period.

Table BCOAPO IR2 22.1 Station Assessment and Minor Planned Projects Expenditures

2005	2006	2007	2008	2009	2010	2011	2012	2013
Actual			Budget			Requested		
($000s)								
871	1,132	2,148	1,509	286	286	623	1,343	1,354

23.0 Reference: Exhibit B-5, BCOAPO IR #1.44.1

23.1 The response addresses the role of reserves in covering uncertainty regarding future supply. However, the original question was with respect to the fact that the uncertainty regarding future load (and the load forecast) is reflective of the total load expected to be served. For example, if firm purchases were equal to the forecast load, then the Load Responsibility value would be zero and there would be no reserves to address load forecast uncertainty. Please respond to the original question as posed.

Response:

The example provided above is correct, under the proposed PRM formula if firm purchases were equal to the forecast load, then the Load Responsibility value would be zero and there would be no reserves to address load forecast uncertainty.

PRM principles are specific to the utility and the resources available to it. If the Company were in the situation described, the proposed PRM calculation methodology would not address the

Company's needs and a different proposal would be required. Please see the response to BCUC IR2 Q6.1 for more discussion on PRM resources.

24.0 Reference: Exhibit B-5, BCOAPO IR #1.55.1

24.1 The response states that opportunities for generation options to offset the need for additional transmission/transformation "will be considered when evaluating new generation options". Will the opportunity for new generation based solutions to offset the need transmission/transformation also be evaluated when FortisBC is considering how to address transmission and transformation deficiencies?

Response:

Yes. FortisBC will look at a variety of alternatives when evaluating major facility requirements. Any capacity or reliability transmission/transformation projects that are load-driven will include the consideration of local generation as a project alternative. Additionally, any generation project will include consideration of transmission upgrades as a project alternative.

A cost/benefit analysis will be used to determine if the most cost effective solution is to add generation capacity as opposed to adding new transmission infrastructure.

25.0 Reference: Exhibit B-5, BCOAPO IR #1.64.1 and 1.64.2

25.1 Please confirm that the values presented in Table 5.1.3.3-A of the Midgard Report are in nominal \$ (i.e. \$ of year) and indicate whether the 8% discount rate used is 8% real or 8% nominal.

Response:

The values in Table 5.1.3.3-A of the Midgard 2011 Electricity Market Assessment are in nominal dollars. Section 5.1.3.1 of the report describes how these energy numbers were derived. No discount rate was used in their derivation.

With regards to the \$84.94/MWh referred to in BCOAPO IR1 Q64.1, the 8% discount rate used to calculate the levelized price is a nominal discount rate. Please refer to the response to BCOAPO IR2 Q12.1.

26.0 Reference: Exhibit B-5, BCOAPO IR #1.62.1

Exhibit B-4, BCUC IR #1.296.1

Exhibit B-5, BCOAPO IR #1.64.1 – 1.64.8

Exhibit B-4, BCUC IR #1.242.1

Exhibit B-1-2, Table 3.2.2

26.1 The response to BCUC 1.242.1 states that BC Hydro's avoided energy cost is $124.30/MWh. The response to BCOAPO 1.64.3 states that BC Hydro's avoided cost of energy is $143.53/MWh (2011$). Please reconcile these two responses and in doing so clarify what year's dollars the $124.30 value is expressed in.

<u>Response:</u>

The $124.30 figure in Table BCUC IR1 242.1 is sourced from the BCH Clean Power Call RFP, and is shown in 2009 dollars. The $143.53 figure originated in the BCH 2007 Conservation Potential Review and was escalated into 2011 dollars.

26.2 The response to BCUC 1.242.1 concludes that $111.96 is the appropriate LRMC value for FortisBC. It is noted that this value is based on the BC New Resources Market Energy curve developed by Midgard. However, in response to BCOAPO 1.64.3 and 1.64.8 FortisBC indicates that its LRMC should be based on the market price of power (and not the cost of new construction), yielding a value of $101.34. Please reconcile these two responses and confirm what the appropriate LRMC for FortisBC is for purposes of resource options evaluation, including DSM evaluation. In doing so, please clarify what year's dollars the $101.34 value is expressed in.

<u>Response:</u>

The response to BCUC IR1 Q242.1 does not conclude that the $111.96 is the appropriate LRMC value for FortisBC. It is responding specifically to the question in BCUC IR1 Q242.1 which is *"...Please indicate what is FortisBC's LRMC from <u>New Supply</u> for 2012 (as opposed to the marginal cost of energy in the near to medium term)*". The Company interprets "New Supply" to mean new generation resources. As described in BCUC IR1 Q242.1, the $111.96 is FortisBC's proxy for the LRMC from new generation resources.

As discussed in BCOAPO IR1 Q64.8.1, it is appropriate for FortisBC to use the levelized price from the market price of power as a proxy for LRMC. The $84.94/MWh is derived from the BC Wholesale Energy Market Energy Curve (Table 5.1.3.3-A in Appendix B of the 2012 Long-Term Resource Plan). Note that the table in the response to BCUC IR1 Q242.1 incorrectly says that the levelized rate for the $84.94/MWh was determined using a 6% real discount rate. This should say that it was determined using an 8% nominal discount rate. (Please refer to Errata 3.)

The $101.34 is the blended avoided cost used for TRC "test" purposes to determine the cost effectiveness of DSM measures and programs. It was blended using the $84.94/MWh proxy for FortisBC's LRMC and $143.53/MWh derived from the BC Hydro 2007 CPR. (see response to BCOAPO IR1 Q64.3). It is not FortisBC's LRMC. It is in 2011 dollars.

For the purpose of resource evaluation the FortisBC LRMC from wholesale market energy is appropriate for the reasons described in BCOAPO IR1 Q64.8.1.

For the purpose of DSM evaluation the blended avoided cost is used as required under the Provincial DSM Regulations 326/2008 Section 4 to determine measure, program or portfolio cost-effectiveness.

26.3 Please provide a revised version of Table 3.2.2 from FortisBC's 2012 Long Term Demand Side Management Plan (Exhibit B-1-2) assuming an avoided cost of $84.94/MWh.

Response:

Please see the table provided below.

Table BCOAPO IR2 Q26.3

Sector	TRC B/C
Programs	**B/C Ratio**
Residential	1.4
Commercial	1.4
Industrial	3.2
Subtotal Programs	1.5
Total (including Portfolio spend)	1.3

27.0 Reference: Exhibit B-5, BCOAPO IR #1.72.1.1

27.1 Please explain how a one year delay for Distribution Station Automation accounts for most of the 39% increase in costs. Even allowing for increased inflation and AFUDC, one would not expect this significant an impact.

Response:

Glenmerry, Salmo and Osoyoos substations were initially planned to be completed and transferred into Plant in Service in 2010. However, these three jobs were carried over into 2011 to complete, shifting the expenditures to be transferred into Plant in Service into 2011, which accounts for the majority of the increase in the 2011 Plant in Service amount identified in the response to BCOAPO IR1 Q72.1.1.

The Distribution Substation Automation Project remains on schedule for completion in 2011. Expenditures for the Program remain within approximately one percent of the approved budget as provided in Order C-11-07.

28.0 Reference: Exhibit B-4, BCUC IR #1.41.1

28.1 Please confirm that the FTEs shown for 2012 and 2013 throughout the application assume full staff compliment with no vacancies.

Response:

Yes, the FTE count shown for 2012 and 2013 assumes a full staff compliment with no vacancies. Please also see the response to BCUC IR1 Q28.2.

28.2 Please also confirm whether, throughout the application, the OM&A costs were developed assuming a level of staff vacancy. If so, what level of staff vacancy was assumed for 2012 and 2013 and how does this compare with historical vacancy levels.

Response:

The O&M costs for the application are developed from a bottom up budget approach. The process for each specific year is reviewed to determine the needs and associated costs to operate safely and efficiently. There is no assumed level of vacancy applied to the budget process. In some departments planned changes required addition / reduction in staffing levels while in others status quo has been maintained during the test period of 2012-2013. Typically, the Company fills short term vacancies with contract labour, therefore there is no O&M savings associated with short term vacancies.

29.0 Reference: Exhibit B-5, BCSEA IR #1.6.2 and 1.6.3

Exhibit B-1-6, Errata #2 at p. 3

29.1 Please confirm the avoided cost value used to determine the Benefit/Cost ratio revisions to Tables 7.0, 7.1, 7.2 and 7.3 in Errata #2 was $101.34/MWh. If not, please update accordingly.

Response:

Confirmed.

29.2 Please identify those programs proposed for 2012-2013 that have a TRC of less than one based on the revised avoided cost of $101.34/MWh.

Response:

Residential appliances at 0.9 and Industrial EMIS at 0.8 both have a TRC B/C ratio less than one.

30.0 Reference: Exhibit B-5, Celgar IR #1.4.8 and 1.6.5

30.1 Please confirm that reference to Q64.1 should read Q6.14.

Response:

Confirmed. Please refer to Errata 3.

31.0 Reference: Exhibit B-5, Celgar IR #1.8.2

31.1 What avoided cost value was used to calculate the TRC Benefit/Cost ratios in this response?

Response:

The blended cost of $101.34 in Table 3.2.1, as revised in Errata 2, was used to calculate the TRC B/C ratios in the response to Celgar IR1 Q8.2.

32.0 Reference: Exhibit B-5, BCOAPO IR #2.1 and 2.3

Exhibit B-1-1, ISP page 30 and Appendix K, Attachment 1

32.1 In response to BCOAPO IR #2.1, FortisBC indicated that the ISP summary document was provided to three First Nations. Why was the document not provided to the other First Nations listed at Appendix K?

Response:

At the beginning of the consultation process the Company contacted all the potentially impacted bands; their direction was to deal directly with the respective Nation representing the groups of bands rather than the independent bands.

32.2 Which First Nations were offered capacity funding and why were other First Nations not offered capacity funding?

Response:

The Okanagan Nation Alliance, the Ktunaxa Nation, and the Shuswap Band, have requested and will receive capacity funding. The other First Nations provided specific instruction as noted in the response to BCOAPO IR2 Q32.1 above.

32.3 For what specific purposes was the capacity funding offered?

Response:

The capacity funding will cover First Nation internal resource allocation, external consultants' expenses, traditional land use studies, interviews of Elders, travel expense, and other associated expenses.

32.4 Did any First Nations accept the capacity funding?

Response:

Yes, to date all three First Nations involved in the document review will receive capacity funding.

32.5 Is the capacity funding still available to First Nations who wish to provide feedback and participate in consultations?

Response:

Should other bands provide feedback outside of the process identified by their initial input (described in the response to BCOAPO IR2 Q32.1 above), and the overarching Nation was in agreement, FortisBC would provide capacity funding subject to acceptable deliverables and budgets.

1.0 Reference: BCUC IR 126.0

1.1 The questions dealt with whether the Power Purchases Management expenses would remain an O&M expense if they are not approved as PPME costs. Would one of the differences be if the costs remain in O&M but there are variances to the costs they would not flow through to rate payers in the same manners as if they were in Power Purchase Management Expenses, assuming a return to a PBR approach to regulating FortisBC?

<u>Response:</u>

If the Power Purchase Management Expenses (PPME) remain in O&M it is expected that any variances would be treated in the same manner as any other O&M Expense which in this application would be to the account of the shareholders. In this application, however, the Company has proposed that the PPME costs be classified as Power Purchase Expenses, and in turn that any variances in the Power Purchase Expense be subject to the proposed Power Purchase Expense Variance Deferral Account and flowed back to customers. This will ensure that the costs to manage and actively mitigate the power purchase costs while providing safe and reliable supply to customers is linked directly to the overall Power Purchase Expense.

However, if as suggested in the question there should be a return to the existing PBR approach to regulating FortisBC and the PPME costs stay within O&M, then they will be subject to the same rules as any other O&M Expense. However, if they are classified as part of Power Purchase Expense <u>and</u> the Power Purchase Expense Deferral Account as proposed by the Company is accepted, then variances in Power Purchase Expense, including the PPME, will flow back to customers rather than being subject to whatever PBR mechanism applies elsewhere.

2.0 Reference: BCUC IR 1.34.8

2.1 Please explain the jump in the balance in the SERP account which doubled between the years 2007 and 2010 (2007 = *$620,004/2010* = $1,293,258.00).

<u>Response:</u>

Please see the response to BCUC IR2 Q11.1.

2.2 The BCMEU understands that executives are now shared between FortisBC Inc. and Fortis Energy Utilities. Is the Supplemental Executive Retirement Plan payment shared between the two companies?

Response:

Executives' employment compensation arrangements remain with the company they were originally hired by. Both companies retain independent Supplemental Executive Retirement Plan (SERP) arrangements for executives that they hired. Shared service costs/charges occur where executive members have responsibilities in both companies. The FBC shared service charge includes a fully loaded wage. The loadings include SERP costs.

2.3 Please provide a table of all forecast salaries and benefits including post employment benefits, club memberships, incentives, travel allowances, stock options for the five top executives of FortisBC Inc. and indicated the forecast shared allocation of these costs for the test period amongst the FortisBC affiliates.

Response:

The tables below provide the forecast 2012-2013 annual salaries for the top 5 executives of FortisBC Inc. (Electric), the forecast benefits loadings for each year, and the forecast shared allocation of these costs to other FortisBC affiliates. FortisBC does not forecast individual benefits attributable for each executive, such as post-employment benefits, incentives, etc., but rather applies general benefit loadings to each salary to incorporate all such benefits (referred to below as "Benefit Loaded Salary"). Stock options are not included in the benefit loaded salary or any other forecasted regulated expenses.

Executive Compensation and Allocations			
2012 Forecast			
	2012 Salary ($)	**2012 Benefit Loaded Salary ($)**	**% Allocation to Affiliates**
Walker, John	515,000	760,543	70%
Mulcahy, Michael	289,430	427,358	70%
Leeners, Michele	242,050	357,457	5%
Sam, Doyle	258,530	381,799	0%
Bennett, David	237,724	350,806	65%
Executive Compensation and Allocations			
2013 Forecast			
	2013 Salary ($)	**2013 Benefit Loaded Salary ($)**	**% Allocation to Affiliates**
Walker, John	530,450	773,878	70%
Mulcahy, Michael	298,113	434,926	70%
Leeners, Michele	249,312	363,722	5%
Sam, Doyle	266,286	388,492	0%
Bennett, David	244,856	357,231	65%

As indicated in Table 4.3.4.18-7 on page 99 of Tab 4 of the 2012-13 RRA, the allocation to and from the FEU has resulted in a forecasted net reduction of $0.740 million to FortisBC total executive costs in each of 2012 and 2013.

3.0 Reference: BCUC IR 1.68.1

3.1 The response states in part: "The settlement also facilitates additional revenue opportunities for fibre leasing to other third parties to the benefit of customers." Please describe what capacity remains on the fibre link for lease to third parties.

Response:

At this time, FortisBC has not allocated a specific number of fibres for its own use, nor for the use of third parties. However, in general, FortisBC reserves approximately one-third to one-half of the strands in a fibre cable for its own use (both current and future). This leaves approximately one-half to two-thirds of the cable available for leasing to third parties. Since the incremental cost of procuring fibre cable with additional fibre strands is minor compared to the overall fibre installation cost, installing cable with excess capacity is in the interests of FortisBC's customers (due to the potential lease revenue opportunities).

3.2 Approximately what portion of the fibre link is dedicated specifically to FortisBC customers use as opposed to available for third party lease?

Response:

Please refer to the response to BCMEU IR2 Q3.1.

4.0 Reference: BCUC IR 1.87.2

4.1 To what extent has the agreed upon depreciation rates utilized by FortisBC during the period 2011, as opposed to the proposed depreciation rates of FortisBC prior to that test period, contributed to the variance between the forecast ROE and approved ROE for 2011?

Response:

The depreciation rates used in 2011 (3.2% composite) were the same as those that were approved by the 2011 RR NSA. Hence, the deprecation rates used in 2011 did not contribute to the variance between forecast and the approved ROE in 2011.

4.2 FortisBC has indicated that at a later date it may seek to have its depreciation rates amended and will seek negative salvage value on assets. Does FortisBC intend to recover negative salvage value based on the difference between the agreed upon depreciation rates utilized in the 2011 period and the depreciation rates sought at that future date?

<u>Response:</u>

The Company's position and intention regarding the recovery of negative salvage is clarified in Tab 4, Section 4.7.3.7 Negative Net Salvage, Page 137 of the 2012-2013 RRA which states the following:

> "Despite the Company's acknowledgement that including a provision for negative salvage is the most appropriate method of collecting removal costs, implementing the recommended salvage accrual rate would result in a significant increase to customer rates. As a result, in order to manage rate increases for the term of this application, FortisBC is not proposing to incorporate the recommended salvage accrual rates at this time and is proposing to reconsider for inclusion in a subsequent revenue requirements application."

The depreciation rates to be proposed in a revenue requirements application subsequent to the 2012-13 test period, will consider depreciation rates approved and utilized during the PBR period through to 2011, as well as the proposed depreciation rates in the 2012-2013 RRA. When FortisBC puts forward depreciation rates at a future date, those proposed rates will likely consider not only the depreciation and negative salvage that is required to be collected on a prospective basis, but also those depreciation and negative salvage amounts that have been undercollected or excluded in prior approved depreciation rates.

Depreciation to be collected is the cost of the capital expenditures already incurred over their useful life. The negative salvage amounts to be collected are independent of the depreciation amounts. Negative salvage to be collected builds up a provision for which actual costs of removal are drawn down. A depreciation study can put forth the proposed rates that combine the collection for both depreciation and negative salvage. While the negative net salvage rate is separate from the depreciation rate, they can both be combined to be presented as one single rate.

5.0 Reference: BCUC IR 1.91.2

5.1 Part of the response states:

> Rationale for difference: implementing a provision for negative salvage will result in a significant increase to the electricity rates of FortisBC customers. In light of adverse customer rate impacts, FortisBC has proposed to maintain its current method of accounting for and collecting future costs of removal....
>
> FortisBC supports the principle of collecting negative salvage and depreciation rates and will propose consistent accounting treatment at a time when there is less pressure on customer rates.

Is it FortisBC's view that there is less pressure on rates for FortisBC then there is on the FortisBC Energy Utilities at this time?

Response:

Both FortisBC and the FEU are sensitive to the impacts of rate increases on customers, and both utilities face rate pressure; the adoption of the “traditional method” of recovering negative salvage contributes to rate pressure for both utilities. Two factors have determined the different approaches for the utilities over the two year revenue requirement period.

1. For the FEU, the impact of moving to the method of recovering negative salvage from ratepayers over the lives of the associated assets has a smaller rate impact than what would be experienced by FortisBC. Since the FEU are already collecting from customers the actual removal costs in the year incurred, the adoption of the FEU proposed method does not impact rates as significantly.

2. The large capital renewal and system reinforcement program that has been undertaken by FortisBC in the last five or six years has resulted in FortisBC being at the front end of an asset base with a long life ahead of it over which to collect the removal costs; the FEU are not in the same situation, but instead are facing a wave of asset retirements as their system infrastructure ages. FortisBC is therefore able in the near term to have some flexibility in terms of how quickly it ramps up its recovery of removal costs over time.

5.2 At what level of proposed rate increase do we move from an environment of "less pressure"? Please elaborate.

Response:

The terms “less rate pressure” and “more rate pressure” are relative terms. There is no definitive threshold of less pressure. Nor is it clear cut that customers will require that rates have to be declining or flat to entertain the introduction of recovery of legitimate costs whose recoveries have been deferred.

There is historical precedent in British Columbia where intervenors in gas utility rate proceedings have promoted changes to accounting treatment in order to better match the cost recovery to the term over which benefits are derived by the customers in spite of the fact that the change had a negative near term impact on rates. A case in point was the five year rolling program of pipeline inspections/re-inspections which were being capitalized and which were converted to O&M in 2004.

When the Company eventually proposes the change to the method for accounting and collection of negative salvage, the interveners will have an opportunity to fully explore the issue and formulate their own opinions of whether or not it is the best time to make such a change. It will be the related Commission decision that will in fact determine the timing of implementing the negative salvage change.

6.0 Reference: BCUC IR 1.94.1

6.1 FortisBC indentifies the ROE incentive adjustment at $2,630,000. Does FortisBC believe it appropriate that the variance be paid to shareholders when there may be an adjustment to depreciation and negative salvage values at a future date affecting this period of time which may be charged to ratepayers?

<u>Response:</u>

Yes, the Company does believe that it is appropriate for the Company to receive its share of the ROE variance. The ROE incentive adjustment is being shared pursuant to the BCUC approved PBR agreement in place from 2007 through 2011. During this time, the depreciation was recorded pursuant to the approved depreciation rates.

The decision of whether negative salvage is paid for, by customers, as part of depreciation or as they are actually incurred is only a timing difference. In either situation, the costs associated with negative salvage would be included in Revenue Requirements and incurred on the same basis. Adjustments to depreciation and negative salvage rates at a future date affecting this period of time would be proposed on a prospective basis as part of a future revenue requirements application and therefore would be unrelated to the determination of the 2011 ROE incentive adjustment referred to in BCUC IR 1.94.1.

7.0 Reference: BCUC IR 1.108.1

7.1 Please provide examples of an asset management strategy similar to that proposed by FortisBC utilized by other regulated utility companies which have been approved by regulatory bodies.

Response:

The proposed project is to provide a business case with a recommended asset management strategy and is intended to include a review of approved asset management models and strategies used by other regulated utilities. As a result, FortisBC does not currently have the information requested. At the conclusion of the project, it will recommend an asset management implementation strategy and and identify the associated costs.

8.0 Reference: BCUC IR 1.1, System Losses and Peak (IR Filed in the Load Forecast Technical Committee Process)

In response FortisBC states in part:

> The Company is unable to measure exact system loss rates. Lost numbers present to represent an estimate based on engineering principles and gross load data combined with multi year as billed lost studies.

8.1 Please describe the impacts on ratepayers in the PBR incentive period 2011 where loss rates are:

8.1.1 lower than forecasted by FortisBC; and

Response:

If it is assumed that the Company's actual sales volumes is as forecast but actual losses are lower than forecast, then the Company's actual power purchase requirements would be reduced. This would result in savings in the overall power purchase expense, that in turn would contribute to the incentive sharing mechanism under the current PBR and, all else being equal, would result in lower rates to ratepayers in the following period.

Conversely, if the Company's sales volumes are as forecast, but actual losses are higher than forecast, then, the Company's actual power purchase requirements would be increased resulting in additional costs. All else being equal, this would result in higher rates to ratepayers in the following period as a result of lower benefits received through the incentive sharing program.

8.1.2 higher than forecasted by FortisBC.

Response:

Please refer to the response to BCMEU IR2 Q8.1.1.

8.2 What protection exists to ensure ratepayers are not overcharged for power given the inexact nature of FortisBC's estimate of losses?

Response:

FortisBC has estimated its losses based on the best information it has available to it as determined by comparing the gross load data combined with multi-year as-billed loss studies. In addition, in this Application the Company has proposed a deferral account mechanism (the “Power Purchase Expense Variance Deferral Account” described in Section 4.1.5) which would capture variances between forecast and actual Power Purchase Expenses. This would include the impact to power purchase expense due to variances in losses. Any variances (surplus or deficit) would then be flowed back to ratepayers through rates in 2014 after the test period. In this way ratepayers are protected from variances between actual and forecast losses.

There is no current method for FortisBC to exactly measure the existing losses (though in the future AMI will allow a closer measure than can be done now), and even if actual losses could be perfectly measured, there is no current method to exactly forecast future losses as they are a function of many factors, including, for example, weather.

9.0 Reference: BCMEU IR 1.2.1

9.1 Please add to table BCMEU IR 1.2.0 the amount originally applied for by FortisBC for each of the years 2008 to 2011.

Response:

The response assumes that *"amount originally applied"*, are the amounts included in the "Preliminary Revenue Requirements Application" for each of the years 2008 to 2011.

The necessary data has been provided in the table below in the shaded columns:

1

TABLE BCMEU IR2 9.0
Revenue Requirements Overview

		Prelim Filing 2008	G-147-07 (*) Approved 2008	Actual 2008	Prelim Filing 2009	G-193-08 (*) Approved 2009	Actual 2009	Prelim Filing 2010	G-162-09 (**) Approved 2010	Actual 2010	Prelim Filing 2011	Forecast 2011	Approved 2011	Increase (Decrease)	Forecast 2012	Increase (Decrease)	Forecast 2013
			($000s)														
1	Sales Volume (GWh)	3,197	3,087	3,087	3,125	3,107	3,157	3,174	3,199	3,046	3,187	3,187	3,162	31	3,193	39	3,233
2	Rate Base	833,035	822,847	802,566	914,044	907,977	867,683	975,827	975,113	945,637	1,098,903	1,071,197	1,093,241	52,012	1,145,253	66,928	1,212,181
3	Return on Rate Base	7.53%	7.47%	7.62%	7.39%	7.38%	7.83%	7.28%	7.73%	7.77%	7.71%	7.96%	7.67%	-0.10%	7.57%	-0.01%	7.55%
4																	
5	**REVENUE DEFICIENCY**																
6																	
7	**POWER SUPPLY**																
8	Power Purchases	72,063	68,538	66,010	72,027	70,944	70,776	77,224	80,408	71,964	81,245	75,956	81,212	9,772	90,984	7,837	98,821
9	Water Fees	8,010	7,858	7,878	8,748	8,480	8,656	9,064	9,068	9,256	9,600	8,977	9,381	300	9,681	172	9,853
10		80,073	76,396	73,888	80,775	79,424	79,432	86,288	89,476	81,220	90,845	84,933	90,593	10,072	100,665	8,009	108,674
11	**OPERATING**																
12	O&M Expense	45,374	45,310	44,725	46,708	46,573	46,017	47,883	47,645	46,148	49,362	53,885	53,885	287	54,172	1,622	55,794
13	Capitalized Overhead	(9,075)	(9,062)	(9,062)	(9,342)	(9,315)	(9,315)	(9,577)	(9,529)	(9,529)	(9,872)	(10,777)	(10,777)	(57)	(10,834)	(324)	(11,159)
14	Wheeling	3,691	3,622	3,655	3,944	4,010	4,003	4,149	4,019	4,050	3,338	4,243	3,338	1,387	4,725	508	5,233
15	Other Income	(5,030)	(5,030)	(5,035)	(5,003)	(4,915)	(5,187)	(4,855)	(5,025)	(6,452)	(5,258)	(7,402)	(5,455)	(2,026)	(7,481)	316	(7,165)
16		34,960	34,840	34,283	36,308	36,353	35,518	37,601	37,109	34,217	37,569	39,949	40,991	(409)	40,582	2,122	42,704
17	**TAXES**																
18	Property Taxes	10,976	11,176	11,036	11,561	11,561	11,573	12,548	12,548	12,238	13,633	13,917	13,940	592	14,532	553	15,085
19	Income Taxes	4,719	3,989	5,869	3,849	4,354	4,749	3,758	5,407	4,544	6,121	9,440	6,733	(681)	6,052	1,811	7,862
20		15,695	15,165	16,905	15,411	15,915	16,322	16,306	17,955	16,782	19,754	23,357	20,673	(89)	20,584	2,364	22,947
21	**FINANCING**																
22	Cost of Debt	32,129	31,762	30,163	34,985	34,803	33,411	36,784	36,765	35,138	41,208	39,364	40,505	814	41,319	2,234	43,553
23	Cost of Equity	30,622	29,688	31,001	32,577	32,215	34,499	34,271	38,614	38,293	43,517	45,922	43,292	2,060	45,352	2,650	48,002
24	Depreciation and Amortization	34,953	34,356	34,016	37,622	37,504	37,376	41,978	42,028	41,771	45,366	45,350	45,498	5,900	51,399	1,829	53,228
25		97,704	95,806	95,180	105,184	104,522	105,286	113,034	117,407	115,201	130,090	130,636	129,296	8,774	138,070	6,714	144,784
26																	
27	Prior Year Incentive True Up	22	22	(1,284)	173	173	(1,443)	(322)	(322)	(2,690)	(1,089)	(2,770)	(1,089)	709	(380)	380	-
28	Flow Through Adjustments	27	(42)	624	(307)	(435)	1,172	(933)	(1,068)	2,385	(1,870)	2,406	(2,129)	(276)	(2,406)	2,406	-
	AFUDC / CWIP shortfall	895	895	-	-	-	-	-	-		-	-	-	-	-	-	-
29	ROE Sharing Incentives	(2,265)	(2,159)	1,314	(1,200)	(1,181)	2,285	(1,095)	(1,300)	(325)	898	2,630	448	(3,079)	(2,630)	2,630	-
30		(1,321)	(1,284)	654	(1,334)	(1,443)	2,014	(2,349)	(2,690)	(630)	(2,061)	2,266	(2,770)	(2,646)	(5,416)	5,416	-
31																	
32	**TOTAL REVENUE REQUIREMENT**	**227,111**	**220,923**	**220,909**	**236,344**	**234,771**	**238,572**	**250,879**	**259,258**	**246,791**	**276,199**	**281,141**	**278,783**	**15,701**	**294,484**	**24,625**	**319,109**
33																	
34	Carrying Cost on Rate Base Deferral Account	-	27		-	(8)		-	17		-		-		-		-
34	ADJUSTED REVENUE REQUIREMENT	**227,111**	**220,950**		**236,344**	**234,763**		**250,879**	**259,274**		**276,199**				**294,484**		**319,109**
35	**LESS: REVENUE AT APPROVED RATES**														283,289		298,618
36	**REVENUE DEFICIENCY for Rate Setting**														**11,195**		**20,490**
37																	
38	**RATE INCREASE 2012-13**														**4.00%**		**6.90%**
39	**RATE INCREASE 2014-16 (1)**									**Year 2014:**		**5.8%**					
										Year 2015:		**11.4%**					
										Year 2016:		**5.1%**					

Note (*): BCUC approved annual Revenue Requirement adjusted by BCUC approved BC Hydro rate increase

2 Note (**): BCUC approved annual Revenue Requirement adjusted by BCUC approved BC Hydro rate increase - Order No.: G-127-10

10.0 Reference: BCMEU IR 1.4.1

10.1 Please update table BCMEU IR 1.4 with the applied for amounts in each of the years 2008 to 2011.

<u>Response:</u>

The response assumes that *"<u>applied for amounts</u>"* are the amounts included in the "Preliminary Revenue Requirements Application" for each of the years 2008 to 2011. The necessary data has been provided in the table below in the shaded columns:

TABLE BCMEU IR2 10

	Prelim 2008	Approved 2008	Actual 2008	Prelim 2009	Approved 2009	Actual 2009	Prelim 2010	Approved 2010	Actual 2010
					(GWh)				
1 FortisBC	1,572	1,572	1,607	1,581	1,581	1,585	1,593	1,596	1,529
2 DSM	11	11	-	25	25	-	30	30	-
3 Power Purchases (net of surplus sales)	1,955	1,824	1,791	1,847	1,820	1,893	1,889	1,913	1,795
4 Total System Load (before DSM savings)	3,538	3,407	3,398	3,453	3,426	3,478	3,512	3,539	3,324
5 Less DSM	(11)	(11)	-	(25)	(25)	-	(30)	(30)	-
6 Total System Load (including DSM savings)	3,527	3,396	3,398	3,428	3,401	3,478	3,482	3,509	3,324
					($000s)				
7 Expense - Energy	59,793	57,312	55,813	58,630	59,377	59,921	63,467	67,128	61,557
8 Expense - Capacity	12,671	12,531	12,624	13,700	13,962	11,969	13,881	14,876	12,394
9 Capital Projects, Accounting & Other Adjustments	(401)	(1,304)	(2,428)	(303)	(2,395)	(1,115)	(125)	(1,596)	(1,986)
10 Management Expense	-	-	-	-	-	-	-	-	-
11 Total Power Purchase Expense	72,063	68,538	66,010	72,027	70,944	70,776	77,224	80,408	71,964

16.0 Reference: Exhibit B-1-2, 2012 Integrated System Plan, Resource / Load Balance Analysis, p.52

Fortis states, "The actual resource / load gap will depend upon load growth, DSM effectiveness and the availability of existing contracts, in particular the renewal terms of the BC Hydro PPA.

Load growth: FortisBC's load is expected to grow over time. The primary factor influencing the pace of residential load growth is customer count. However, other factors such as widespread adoption of new electric technologies (e.g. electric vehicles) and societal changes (e.g. a move to smaller residences) may have significant impacts. …

DSM Contribution: … As DSM is a non-firm resource with results subject to voluntary customer participation, it is prudent to consider a possible range of DSM impacts on resourcing needs rather than as a single pre-determined percentage of load growth avoidance."

16.1 Does Fortis believe that the future performance of energy-efficiency resource portfolios is subject to greater uncertainty than future load growth?

Response:

Yes. Load growth and DSM program uptake are considerably different from each other. The Company has an obligation to serve load growth, whereas DSM program performance depends on voluntary customer participation. Therefore, while the Company is not able to quantify the difference in uncertainty, the Company believe DSM measures are subject to greater uncertainty than future load growth.

16.2 If yes, please explain the basis for this conclusion.

Response:

Please refer to the response to BCSEA IR2 Q16.1.

17.0 Reference: Exhibit B-1-2, 2012 Integrated System Plan, Load Forecast, p.41

"FortisBC's load forecast is prepared annually and is composed of individual forecasts for each of the residential, wholesale, industrial, commercial and irrigation and lighting classes and well as system losses and DSM savings. The methodology is primarily econometric in nature with survey data also employed. Forecasts of provincial housing starts and provincial Gross Domestic Product (GDP) by sector are primary drivers of sales. GDP and housing starts forecasts are provided by the Conference Board of Canada (CBoC).

Residential load growth is driven by the increase in customer count, which itself is determined econometrically as a function of provincial housing starts. This is then combined with forecast use per customer. Based on recent trends and the results of residential end use surveys, it is assumed that residential use per customer before DSM will remain constant over the forecast period. [underline added]

The commercial class is comprised of many diverse sectors including commercial enterprises, school, hospitals, other public buildings as well as small industrial sites. As such the energy use in this class has been found to be well correlated with provincial real gross domestic product growth and has been forecast on that basis.

FortisBC's wholesale load is served to the communities of Penticton, Kelowna, Grand Forks, Summerland, Nelson, and two communities in the BC Hydro service territory. These loads are primarily residential and commercial in nature. Wholesale energy use is forecast based on an econometrically derived relationship with provincial real GDP.

Industrial loads are forecast based partly on survey data supplied by customers, and where customer information is not available, by forecast GDP growth rates in each industrial sector. In the long term, composite GDP growth rates of industrial sectors are used to escalate the entire industrial load. Out of 24 listed sectors by CBOC, only 12 sectors contribute to the FBC's industrial load growth rates, with 95 percent of growth determined by five sectors: agriculture, forestry, manufacturing, utilities, and commercial service.

The final two customer classes are irrigation and lighting which combined are less than two percent of gross system load. Irrigation loads are forecast to be constant on a before DSM basis while lighting loads grow based on a trend analysis.

17.1 Please explain the basis for assuming the residential use per customer across all end uses will remain constant for the next 30 years, providing any reports, analysis, data or other support for this assumption in light of impending increases in Canadian efficiency standards, particularly lighting.

<u>Response:</u>

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural Order (Order G-111-11), the Load Forecast is not subject to the initial Information Request process.

17.2 Does Fortis agree that its econometric electric load forecasts for each customer class described above predict uninterrupted continuation of correlations observed in the past between electricity use, customer counts and GDP? If not, please explain why not.

<u>Response:</u>

This question is referred to the Load Forecast Technical Committee. In accordance with the procedural Order (Order G-111-11), the Load Forecast is not subject to the initial Information Request process.

18.0 Reference: B-1-2, 2012 Integrated System Plan, 2.4.3.3 Demand Side Management as a Source of Capacity, p.22

Fortis states that "‥, the widespread adoption of DSM programs and energy efficiency targets as substitutes for firm generation resources has injected a large amount of uncertainty into future load forecasts. Should load growth exceed forecasts, reliance on DSM and energy efficiency programs may lead to both energy and capacity deficits. Overall failure to meet these DSM and efficiency targets could make system operations more challenging."

18.1 Please provide evidence that supports the conclusion that DSM savings are more likely to fall below targets than exceed them.

<u>Response:</u>

The reference speaks to the use of DSM savings as a direct substitute for firm energy. It does not presume that DSM results will not be achieved, but does contemplate the potential impact if the forecast DSM results were not achieved.

18.2 Has Fortis conducted any research to determine how often and to what extent efficiency portfolios have exceeded annual savings acquisition targets?

Response:

Yes, the Company tracks the long term results of its DSM initiatives.

Please see the response to BCSEA IR2 Q18.2.1 below.

18.2.1 If so, please provide the results of this research and supporting documentation.

Response:

The following table illustrates the FortisBC DSM record of plan vs. actual savings:

Table BCSEA IR2 18.2.1

	Plan	Actual	% of Plan
	(GWh)		
1991	13.3	7.9	59%
1992	15.6	16.3	104%
1993	26.1	24.1	92%
1994	14.2	12.9	91%
1995	18.3	15.6	85%
1996	16.3	17.0	104%
1997	14.4	14.2	99%
1998	13.6	13.1	96%
1999	11.6	13.5	116%
2000	12.0	17.5	146%
2001	12.5	16.9	135%
2002	14.1	16.3	116%
2003	15.6	18.5	119%
2004	14.7	21.3	145%
2005	19.0	23.9	126%
2006	20.4	23.1	113%
2007	21.8	27.9	128%
2008	19.5	27.3	140%
2009	25.3	28.4	112%
2010	27.5	29.3	106%

18.2.2 If not, why not?

Response:

No response required.

18.3 Does Fortis agree that the primary risks of underperformance by an efficiency utility are that

(i) not enough customers will participate in the portfolio's programs;

(ii) the customers who do participate do not install enough of the high-efficiency measures the portfolio promotes; and/or

(iii) the high-efficiency technologies customers do install might not save as much as electricity as predicted?

Response:

FortisBC agrees that the risks identified can lead to DSM programs not achieving forecast energy savings. Among other additional risks, measure persistence may differ from plan, whether due to measure failure or early removal.

18.3.1 If not, please indicate why not, identifying and explaining any other drivers omitted from this list.

Response:

Please see the response to BCSEA IR2 Q18.3

18.3.2 Does Fortis agree that one effective way to correct the first two problems (described in Q2.18.3(i) and (ii)) is by raising financial incentives as high as 100 percent of the high-efficiency incremental or installed costs?

Response:

FortisBC agrees that increasing incentives can improve program participation, provided there is sufficient product and service availability.

19.0 Reference: Exhibit B-1-2, 2012 Long-Term Demand-Side Management Plan, s.1.3 BCUC Directives, p.6

Quoting the previous BCUC decision on Fortis's 2010 DSM Plan: "The Panel … encourages FortisBC to incorporate additional best practices, empirical research, and evaluations and lessons learned from pilot programs and program models in other jurisdictions in the preparation of its long-term plan".

19.1 Is Fortis aware that utilities in California, Connecticut, and Vermont have achieved annual energy savings exceeding 1.5 percent of sales during the last three years (2008-2010)?

Response:

Yes. There are likely different drivers in those markets which support a higher level of DSM activities.

19.2 Is Fortis aware that utilities in Hawaii, Massachusetts, Nevada, the Pacific Northwest, and Rhode Island reported annual energy savings of between 1.0 and 1.5% of annual sales during the last three years?

Response:

Yes, FortisBC is aware of this. Although this is not a metric that governs DSM program targets, FortisBC forecasts the 2011 DSM annualized savings will equal approximately 1.0 per cent of energy sales.

19.3 Is Fortis aware that energy efficiency portfolio administrators in Nova Scotia, Rhode Island, and Vermont are planning to save 2 percent or more of annual sales in two or more of the next 5 years?

Response:

FortisBC is aware of these results. It is difficult to comment on why higher levels of DSM are claimed to be achieved in other jurisdictions; there may be different regulatory requirements or economic drivers in other jurisdictions. The reasons for differences are complex and varying.

20.0 Reference: Exhibit B-1-2, 2012 Integrated System Plan, s.5.2.1.1 Application of Planning Reserve Margin, p.54

In justifying the need for maintaining its planning reserve margin, Fortis explains the need to protect against the following risks:

"**Unexpectedly high loads, typically due to extreme weather events:** In such circumstances it may not be prudent to rely on market energy to meet supply shortfalls because the market energy is likely to come from geographically proximate areas that may be experiencing the same weather, with the result that prices may be very high or excess supply may simply be unavailable at the time of greatest need.

A period of accelerated load growth that outpaces the installation of new power supply resources: Given the long lead time associated with most electricity generation projects, it is inadvisable for utilities to function reactively and wait until unforeseen load spikes occur to plan more resources. Carrying a PRM provides a buffer which allows a utility adequate time to react to unforeseen load changes and acquire new assets before load becomes unmanageable."

20.1 Does Fortis agree that energy efficiency investment can help mitigate the risk of unexpectedly high loads due to extreme weather events, for example, high-efficiency air-conditioners save more electricity the hotter the weather?

Response:

About 10% to 15% of current DSM measures are related to building envelope measures that reduce space heating (electric heat) and respond in the manner suggested (the more extreme the weather, the more the DSM measure will save).

However, the majority of the Company's DSM measures either save a constant amount regardless of the weather or the savings actually disappear completely during extreme cold weather events. Air source heat pumps would be an example of the latter.

20.1.1 If not, please explain why not, providing supporting documentation for the answer.

Response:

Please refer to the response to BCSEA IR2 Q20.1.

20.2 Does Fortis agree that energy efficiency investment can help mitigate the risk of accelerated load growth caused by unexpectedly high economic growth, since efficiency programs can reach a larger eligible population of new construction and business expansion?

Response:

To the extent new load growth employs DSM measures, the resulting load will be lower than if no DSM measures were utilized. The Company agrees that in time periods of accelerated load growth the Company could attempt to reduce load growth impacts by targeting these new loads with DSM programs. However, the degree of success is not certain since incentive program participation is voluntary.

20.2.1 If not, please explain why not, providing supporting documentation for the answer.

Response:

Please refer to the response to BCSEA IR2 Q20.2.

20.3 Does Fortis agree that discretionary retrofit programs targeting the early retirement of existing inefficient electrical equipment such as lighting and HVAC can be scaled up if load growth accelerates unexpectedly?

Response:

FortisBC agrees that participation in discretionary retrofit programs can generally be "scaled-up".

Further to the response BCSEA IR2 Q16.1, the response to DSM programs is not immediate, i.e. it cannot be dispatched like the PRM. The response takes place over an extended time frame. The DSM response cycle includes: program awareness, product availability, trades capacity, financial considerations such as customer payback and financial capacity, and willingness to participate.

20.3.1 If not, please explain why not, providing supporting documentation for the answer.

Response:

Please see the response to BCSEA IR2 Q20.3.

20.4 Does Fortis agree that it has not accounted for any of the risk-mitigating advantages of energy-efficiency resources described in the previous three IRs in its resource planning, implicitly assigning them zero value?

Response:

The Company believes that the current DSM plan is reasonable and achievable. The DSM plan is reflected in the load forecast and therefore the benefits referred to are accounted for appropriately.

20.4.1 If not, please explain why not, providing supporting documentation for the answer.

Response:

Please refer to the response to BCSEA IR2 Q20.4.

21.0 Reference: Exhibit B-1-2, 2012 Integrated System Plan, s.5.2.1.2 Capacity Resource / Load Gap, p.58

21.1 Does Fortis agree that each MW of load reduction from energy-efficiency resources lowers the amount planning reserve capacity needed by an additional 12-15 percent, i.e., each 1 MW of DSM displaces the need for 1.12 – 1.15 MW of installed generating capacity?

Response:

The Company agrees that in as much as DSM measures reduce the Company's expected peak load, that other resources will not have to be obtained to meet this load. However, the Company does not agree that in addition to this that there will be an additional 12-15 percent reduction in install generating capacity. The PRM itself will only be lowered by a much smaller amount of approximately 0.05 MW for every MW of DSM savings. The approximately 12% to 15% industry utility reserve margins the question appears to refer to is not the formula to determine required PRM, but the end result of applying a PRM methodology. For further information on PRM calculations, please refer to the Midgard Planning Reserve Margin report attached as Appendix D of the 2012 Long Term Resource Plan.

Additionally, DSM resources, i.e. conservation measures, are not well suited to the role of PRM resources since they are inherently not dispatchable. Demand Response (DR) measures are considered dispatchable, but such measures were found to have limited potential in the 2010 CDPR filed as Appendix C of the 2012 Long Term Demand-Side Management Plan.

21.2 If not, please explain why not, providing supporting documentation for the answer.

Response:

No response required.

22.0 Reference: Exhibit B-1-2, 2012 Integrated System Plan, s.5.2.1.2 Capacity Resource / Load Gap, p.59-60

22.1 Does Fortis agree that it anticipates capacity shortfall in 2030 in June, and in 2040 in June and July?

Response:

Recognizing the assumptions and the uncertainties in long-term load forecasting, the forecasts predict monthly capacity shortfalls in January, June, July and December in 2030 and January, February, March, May, June, July, November and December in 2040. See Tables 5.2.1.2-B and 5.2.1.2-C in the 2012 Long Term Resource Plan for the forecast capacity gap amounts.

22.1.1 If not, please explain why not, providing supporting documentation for the answer.

Response:

No response required.

22.2 Does Fortis agree that this expectation indicates that summer peak demand savings from energy efficiency resources would avoid some avoided generating capacity costs by reducing the need for peak reserve capacity?

Response:

FortisBC's peak capacity demand is based on a winter peak and FortisBC plans for capacity acquisitions based on meeting winter peak. As demonstrated in Figures 5.2.1.2-B and 5.2.1.2-C, December and January have the largest forecast capacity loads, and the largest forecast capacity gaps. It is expected that any measures that are taken to address the winter forecast capacity gap will likely also close the summer capacity gap. Therefore reducing summer peak demand through energy efficiency resources would not likely avoid generating capacity costs.

22.2.1 If not, please explain why not, providing supporting documentation for the answer.

Response:

Please see the response to BCSEA IR2 Q22.2.

23.0 Reference: Exhibit B-1-2, 2012 Integrated System Plan, s.5.2.2 FortisBC Energy Resource/Load Balance, p.65

23.1 Is it correct to conclude that the energy gap first appears in 2017 and increases thereafter?

Response:

No. Based on the forecasts presented in the 2012 Long Term Resource plan and the assumptions contained within, the expected energy gap is 5 GWh in 2011, growing to 35 GWh in 2020, 167 GWh in 2030 and 310 GWh in 2040.

Please see Table 5.2.2.3-A in the 2012 Long Term Resource Plan for the annual forecast of the energy gap.

23.2 Does Fortis agree that accelerating energy-efficiency resource acquisition in the next five years to meet 100% of growth forecast over the next five years would postpone the arrival of the energy gap?

Response:

FortisBC has no additional energy storage opportunities to shift saved energy into the winter period. Since these existing storage opportunities are already fully utilized, if DSM projects do not eliminate the growing winter energy gap, the Company's energy gap will continue to grow regardless of what DSM measures are undertaken outside the winter period.

Therefore, any DSM effort to eliminate the Company's energy gap over the next five years by accelerating energy-efficiency resources would have to concentrate on residential building envelope measures for example. Since these measures currently make up less than 15% of the Company's total DSM as stated in the response to BCSEA IR2 Q20.1, it is not likely that these programs could be ramped up sufficiently to totally meet the Company's winter energy gap. Therefore, other general DSM programs would have to be significantly overdriven by several multiples of current DSM performance to meet the Company's energy gap over the next five years. A dramatic increase in DSM funding for this purpose is not considered prudent at this time since 1) the current level of DSM expenditures is already inflationary on rates and 2) the effect of roughly doubling DSM expenditures in 2011 - 2013 needs to be evaluated for program performance before more increases are considered.

23.2.1 If so, by how long would this level of savings postpone it? Please provide supporting calculations for the answer.

Response:

Assuming the increased level of DSM is achievable, not taking into account the timing of the DSM issue and recognizing that there may still be a small amount of energy shortfall due to capacity shortages before WAX comes online, increasing DSM in the next five years will delay energy gaps by four years (2015-2018) as shown below.

It is assumed that once the accelerated DSM program concludes that there will be a reduction in DSM performance since the overall DSM potential is not impacted.

Table BCSEA IR2 23.2.1

	Current DSM		Updated DSM		Updated vs. Current	
Year	DSM (GWh)	Energy Gaps (GWh)	DSM (GWh)	Energy Gaps (GWh)	DSM (GWh)	Energy Gaps (GWh)
2011	17.5	4.7	17.5	4.7	0.0	0.0
2012	49.6	9.2	70.2	8.3	20.7	-0.9
2013	80.5	9.3	140.3	6.0	59.8	-3.3
2014	112.4	12.3	210.3	6.1	97.9	-6.1
2015	146.9	4.9	280.4	0.0	133.5	-4.9
2016	183.3	6.4	350.4	0.0	167.2	-6.4
2017	214.7	9.4	392.2	0.0	177.6	-9.4
2018	241.9	14.4	411.7	0.0	169.8	-14.4
2019	269.2	24.6	431.2	2.5	162.0	-22.1
2020	296.5	35.1	450.7	6.4	154.2	-28.7
2021	323.8	46.3	470.2	13.2	146.4	-33.2
2022	351.0	57.7	489.7	20.4	138.6	-37.3
2023	378.3	69.5	509.1	29.8	130.8	-39.7
2024	405.6	82.2	528.6	40.9	123.0	-41.3
2025	432.9	94.8	548.1	55.3	115.2	-39.5
2026	460.2	107.3	567.6	70.5	107.4	-36.8
2027	487.4	120.2	587.1	86.0	99.6	-34.2
2028	514.7	135.0	606.6	101.4	91.8	-33.6
2029	542.0	150.9	626.0	117.2	84.0	-33.7
2030	569.3	166.6	645.5	133.9	76.3	-32.8
2031	596.6	180.1	665.0	150.7	68.5	-29.5
2032	623.8	194.9	684.5	168.8	60.7	-26.1
2033	651.1	209.6	704.0	186.8	52.9	-22.8
2034	678.4	224.3	723.5	204.8	45.1	-19.5
2035	705.7	238.8	743.0	222.6	37.3	-16.2
2036	732.9	253.3	762.4	240.4	29.5	-12.8
2037	760.2	267.7	781.9	258.2	21.7	-9.5
2038	787.5	282.0	801.4	275.9	13.9	-6.2
2039	814.8	296.3	820.9	293.5	6.1	-2.8
2040	842.1	310.5	840.4	312.2	-1.7	1.7
Note:	Increasing DSM energy savings will aslo increase DSM capacity savings, which will decrease energy shortfalls associated with capacity shortages.					

23.2.2 If not, please explain why not, providing supporting documentation for the answer.

Response:

Please see the response to BCSEA IR2 Q23.2.1.

23.2.3 Does Fortis agree that such acceleration over the next five years would reduce the amount of uncertainty about long-term DSM performance risk?

Response:

FortisBC does not agree since the risks associated with implementing such a high level of DSM in a short period of time are significant. Such an accelerated program also creates a significant risk in what DSM program performance will be able to achieve in the years immediately after the accelerated program concludes.

However, FortisBC can agree that if such a program were implemented and completed successfully, then from that point in time forward, the overall risks of meeting ongoing DSM targets may be lower since a lower level of DSM from that time onward would be needed in general.

23.2.4 If not, please explain why not, providing supporting documentation for the answer.

Response:

Please see the response to BCSEA IR2 Q23.2.3.

23.3 By how long would the energy resource gap be postponed assuming achieved 2 percent annual savings over the next five years? Please provide supporting calculations for the answer.

Response:

DSM savings will be increased in this case. Increasing DSM in the next five years will increase flow-through cumulative DSM savings and hence delay energy gaps by approximately five years as shown below.

Table BCSEA IR2 23.3

	Current DSM		Updated DSM		Updated vs. Current	
Year	DSM (GWh)	Energy Gaps (GWh)	DSM (GWh)	Energy Gaps (GWh)	DSM (GWh)	Energy Gaps (GWh)
2011	17.5	4.7	17.5	4.7	0.0	0.0
2012	49.6	9.2	88.6	7.6	39.0	-1.6
2013	80.5	9.3	161.2	5.0	80.7	-4.3
2014	112.4	12.3	235.3	5.2	122.9	-7.1
2015	146.9	4.9	310.7	0.0	163.8	-4.9
2016	183.3	6.4	387.0	0.0	203.7	-6.4
2017	214.7	9.4	437.9	0.0	223.3	-9.4
2018	241.9	14.4	455.4	0.0	213.5	-14.4
2019	269.2	24.6	473.0	0.0	203.8	-24.6
2020	296.5	35.1	490.5	3.0	194.0	-32.0
2021	323.8	46.3	508.1	7.4	184.3	-39.0
2022	351.0	57.7	525.6	14.3	174.5	-43.5
2023	378.3	69.5	543.1	21.9	164.8	-47.5
2024	405.6	82.2	560.7	32.8	155.1	-49.4
2025	432.9	94.8	578.2	45.0	145.3	-49.8
2026	460.2	107.3	595.7	60.8	135.6	-46.5
2027	487.4	120.2	613.3	77.0	125.8	-43.2
2028	514.7	135.0	630.8	93.0	116.1	-41.9
2029	542.0	150.9	648.3	109.6	106.3	-41.4
2030	569.3	166.6	665.9	125.9	96.6	-40.7
2031	596.6	180.1	683.4	142.8	86.9	-37.4
2032	623.8	194.9	701.0	161.7	77.1	-33.2
2033	651.1	209.6	718.5	180.6	67.4	-29.1
2034	678.4	224.3	736.0	199.4	57.6	-24.9
2035	705.7	238.8	753.6	218.0	47.9	-20.8
2036	732.9	253.3	771.1	236.7	38.2	-16.6
2037	760.2	267.7	788.6	255.2	28.4	-12.5
2038	787.5	282.0	806.2	273.8	18.7	-8.3
2039	814.8	296.3	823.7	292.2	8.9	-4.1
2040	842.1	310.5	841.2	311.5	-0.8	0.9
Note:	Increasing DSM energy savings will aslo increase DSM capacity savings, which will decrease energy shortfalls associated with capacity shortages.					

24.0 Reference: Exhibit B-1-2, 2012 Integrated System Plan, s.6 Resource Options and Strategies

24.1 Please explain why Fortis did not consider alternative DSM savings alternatives in its comparison of resource options and strategies, that is, considering side-by-side three competing choices consisting of "save, buy, and/or build"?

Response:

DSM is an important part of the 2012 Resource Plan, fulfilling the 2007 BC Energy Plan target of meeting 50% of long-term load growth by DSM means.

The high DSM option, priced at $20 million per annum and conceptually achieving a 90% load growth offset, was considered and rejected in favour of the medium DSM option which was approved in the 2011 CEP filing and which the Company continues to pursue.

Please also see the response to BCSEA IR2 Q23.2.

25.0 Reference: Exhibit B-1-2, 2012 Integrated System Plan, Table 6.1.2-B New Clean Energy Resources Rating Table (Sorted by Rating)

Fortis applied the following criteria in ranking competing supply options:

- Appropriate size
- Environmental impact and adherence to the Clean Energy Act
- Appropriate energy shape
- Comparative economics test – least cost

25.1 How would Fortis rank the High DSM option rejected in the DSM Plan (meeting 90 percent of load growth) according the these criteria relative to the supply options evaluated?

Response:

At this time FortisBC does not have enough project specific information on the incremental DSM projects proposed to meet the High DSM case to do such a ranking using these and other criteria.

In addition, FortisBC is looking at market purchases in the short to medium term to address the energy and capacity gaps, while new resource additions will be contemplated in the long term as power prices (amongst other conditions) favour building new resources. So for the short to medium terms the incremental high DSM projects are more appropriately compared to the marginal cost of wholesale market purchases. In the long-term when market prices are near or higher than new resource prices, it may appropriate to compare the incremental high DSM projects with new generation resources.

As described in response to BCSEA IR2 Q23.2 and Q24.1, the high DSM option was considered and rejected in favour of the medium DSM option. However, in future resource plans the Company will continue look at all options, including high DSM, to meet energy and capacity gaps.

26.0 Reference: Exhibit B-1-2, 2012 Integrated System Plan, Appendix F, *Clean Energy Act* Objectives, p. 1

26.1 Please explain why the following British Columbia Energy Objectives are described as "not applicable" to the ISP and DSM Plan, providing any supporting documentation for the answer:

(b) to take demand side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66 percent;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(k) to encourage economic development and the creation and retention of jobs.

<u>Response:</u>

Please see the response to BCUC IR1 Q278.1 and Q276.1

27.0 Reference: Exhibit B-1-2, 2012 Long-Term Demand-Side Management Plan, s.3.5 Collaborative Programs, p.25; Exhibit B-5, FBC Response to BCSEA IR1 Q2.1

The DSM Plan states: "During 2012, FortisBC will explore, initiate or continue partnerships in the following collaborative programs which directly support Policy Action 2 of the *BC Energy Plan*:

- LiveSmart BC: partnership with BC Hydro, FortisBC Energy Inc. and the BC Ministry of Energy and Mines. LiveSmart BC is a residential retrofit program that encourages customers to upgrade building envelopes (insulation, windows, doors, draft proofing) and upgrade home space and water heating systems;"

FBC's Response to BCSEA IR1 Q2.1 provides examples of collaborative programs.

27.1 Please explain the nature and extent of the coordination, if any, between FortisBC's electric DSM program and FortisBC Energy Utilities gas DSM program and portfolio design, development, assessment, planning, implementation, management, tracking, and evaluation.

Response:

Current examples of coordination include:

- End-Use Studies;
- Co-funding the LiveSmart Residential M&E study with BC Hydro;
- Rossland Energy Diet community campaign;
- Fall Scratch & Win billing insert; and
- TLC furnace, heat pump tune-up promotion.

28.0 Reference: Exhibit B-1-2, 2012 Long-Term Demand-Side Management Plan, CDPR Ramp Rates, p.10

28.1 In addition to factors listed, does FortisBC agree that it can control program ramp rates through its program design and implementation choices by adjusting financial incentives and marketing strategies, especially in discretionary retrofit markets promoting early replacement of functioning inefficient equipment?

Response:

There is no way to completely "control" ramp rates. Program design (including financial incentives and marketing strategies) can and does influence ramp rates, but there are many other factors (as listed) that also have a role in measure adoption.

28.2 If not, please explain why not, providing supporting documentation for the answer.

Response:

Please refer to the response to BCSEA IR2 Q28.1 above.

29.0 Reference: Exhibit B-1-2, 2012 Long-Term Demand-Side Management Plan, s.1 Overview, p.1

"The overall DSM savings target is to offset 50 percent of load growth over the planning period."

29.1 Is Fortis aware that leading utilities achieving the highest percentage savings do not cap incentives at 50% as Fortis does in its high case?

Response:

The 50% referenced in the quoted statement in the preamble above applies to the overall energy savings target for DSM planning, not an incentive cap.

The 50% referenced in "high case" option referred to in the question (which FortisBC assumes comes from Table 2.5 in Exhibit B-1-2) is the incentive average, not the maximum.

FortisBC is not aware of whether other utilities cap incentives at 50% of TRC value.

30.0 Reference: Exhibit B-1-2, 2012 Long-Term Demand-Side Management Plan, p. 5, Prohibition on Use of RIM test; p. 12: Choice of Moderate over High DSM Scenario

At p. 12, Fortis states: "The High option also received support, but escalating the 2012 DSM Plan to the High option, is not considered prudent because it contains more uneconomic measures (B/C ratio 10 < 1.0), increases spending by paying a larger portion of the TRC cost, and hence <u>increases the magnitude of rate increases due to the decreased load</u>. [underline added

At pp.4-5, FortisBC states: "The DSM Regulation also provides in section 4 that the Commission, in determining the cost-effectiveness of a DSM measure proposed in a long-term resource plan or an expenditure schedule: …

> (6) may not determine that a proposed measure is not cost effective on the basis of a 8 rate-impact measure (RIM) test."

30.1 Please reconcile the third justification (underlined) with s.4(6) of the DSM Regulation.

<u>Response:</u>

The third "justification" is simply stating a fact, and does not impact the requirement that the Commission comply with section 4(6) of the DSM Regulation.

31.0 Reference: FortisBC Energy Utilities 2012-2013 Revenue Requirements Application and Rates Application

31.1 Please confirm that FortisBC Energy Utilities (FEU, natural gas) propose to increase DSM spending by at least 50% year over year, including $10 million annually on early retirement of inefficient furnaces with a TRC B/C ratio well below 1.0.

Response:

FortisBC is aware that FEU filed for approval of a $4.2 million or 12% increase to their existing programs (over the 2011 approved funding level of $35.3 million). FEU has also filed for an additional $25 million for new EEC initiatives, including an initiative to support the retirement of standard and mid-efficiency furnaces program that has a B/C ratio below 1.0.

31.2 Does FortisBC believe the FEU 2012-13 DSM plan to be imprudent?

Response:

FortisBC believes the FEU 2012-13 DSM plan to be prudent.

31.3 If not, please explain why this is prudent for FEU gas but would be imprudent for FEU electric.

Response:

FortisBC does not understand this question – a gas DSM program is inappropriate for an electric utility to implement. If the question is referring to the increase in DSM expenditures proposed by FEU, it should be noted that FortisBC roughly doubled DSM expenditures in 2011 and proposes to maintain that level in 2012-2013.

32.0 Reference: Exhibit B-1-2, 2012 Long-Term Demand-Side Management Plan, Exhibit B-1-6, Errata, Figure 3.2.4, Acquired DSM vs. Load Growth Forecast

32.1 Please explain why FortisBC has chosen DSM ramp rates that decline from 2016 precisely when the load growth starts expanding?

Response:

The DSM target proxy is a constant 28 GWh beginning in 2017 and does not decline. Please also see the response to BCUC IR1 Q280.4.

32.2 Did FortisBC develop, examine, and compare any scenarios accelerating DSM ramp rates more rapidly to full 85% achievable of economic potential?

Response:

The “high” DSM option model explored by FortisBC incorporated lower admin costs, higher incentives, a lower TRC B/C ratio threshold, and a higher achievability factor - but did not accelerate the DSM measure ramp rates, for the reasons stated in the response to BCSEA IR2 Q28.1.

32.3 Did FortisBC analyze buy vs. build options using energy and peak demand forecasts net of the high DSM case? Why not?

Response:

Figure 5.2.2.1-A on page 64 of the 2012 Long Term Resource Plan presents the expected, low and high energy forecasts. Table 5.2.2.3-A on page 66 of the 2012 Long Term Resource Plan presents the expected, low and high forecasts of energy gaps. The impact of higher than anticipated DSM performance is included in the low energy forecast.

There is no direct high DSM case since the Monte Carlo simulation modeled all the factors at the same time to produce one combined expected, low and high forecast. For a further description of the Monte Carlo simulation, please refer to the response to BCUC IR1 281.3.

No direct analysis of the low and high energy cases was undertaken since the Company is not bringing forward any specific request for new resources at this time and the high and low case only influence the timing of the Company's requirements by a few years in the short to medium term. For example, referring to Table 5.2.2.1-A referenced above, a gap of 35 GWh is reached in 2020 for the expected case while in the low scenario (the one with high DSM factored in) it takes till 2023.

32.3.1 If not, please explain why not.

Response:

Please refer to the response to BCSEA IR2 Q32.3.

33.0 Reference: Exhibit B-1-2, 2012 Long-Term Demand-Side Management Plan, 3.4.2 Commercial Sector Programs, Building Improvement Program (BIP), p.21; 3.4.3 Industrial Programs, Industrial Efficiency, p.23; Appendix C, Conservation and Demand Potential Review

The DSM Plan (p.21) states the Company's financial incentive design: "FortisBC also will provide rebates towards the incremental cost of efficiency measures compared to standard "baseline" construction. The rebate entitlement is based on estimated annual kWh savings, with the <u>maximum rebate calculated to achieve a two-year payback on incremental cost</u>." [underline added]

FortisBC indicates that the same design applies to industrial efficiency measures. (p. 23)

The CDPR provides the following information on financial incentive structure for General Service customers:

"Rebate structure – General Service rebates are the lesser of:

"Five cents per annual kWh saved; 50% of installed retrofit cost;

100% of incremental cost for new construction; or amount necessary to achieve a two-year payback."

33.1 Does Fortis agree that the third criterion (underlined) will dominate the other two, i.e., that the 2-year payback requirement will serve as a cap since it will usually be the most stringent of the three?

Response:

The two-year payback is not the dominate criterion in most cases. The commercial industrial programs have the paybacks as indicated in the following table. All five of the commercial programs listed have paybacks well above the 2 year cut-off whether using the 5 cent/kWh incentive referred to in the CDPR, or the 10 cent/kWh nominal incentive level that was approved in the current 2011 budget.

The Industrial Efficiency and Irrigation programs do have paybacks under one year as a portfolio of measures, however they represent less than 10% of the DSM 2012-2013 plan total savings. The 2-year payback does come into effect for some individual measures within programs and for individual projects, depending on the specifics involved. Customers are encouraged to bundle fast payback measures with other longer payback measures to maximize their rebate entitlement.

Table BCSEA IR2 Q33.1

	Energy Savings (per cent of total DSM plan)	**Payback before DSM Rebate (years)**	Payback after 5 cents/kWh rebate (years)	Payback after 10 cents/kWh rebate (years)
Residential (for comparison)	46%	**6.9**	6.4	5.8
Commercial – Lighting	23%	**5.5**	4.8	4.1
Commercial – BIP	11%	**6.8**	6.0	5.3
Commercial – Computers	1%	**6.8**	6.1	5.4
Commercial – Municipal	6%	**4.8**	8.6	7.9
Commercial – Irrigation	2%	**1.8**	0.8	0.1
Industrial – EMIS	1%	**17.8**	10.6	9.9
Industrial – Industrial Efficiency	7%	**1.8**	0.5	0.2

33.2 Does Fortis agree that 5 cents/kWh saved annually translates roughly to 0.6 cents/kWh for measures with 15-year life expectancy at a 10% discount rate?

Response:

Agreed, however this is an obsolete reference since the nominal incentive rate was doubled to 10 cents/kWh saved in the 2011 approved DSM Plan. This is equivalent to 1.3 cents per kWh over 15 years using a 10% discount rate.

33.2.1 Does Fortis acknowledge that this criterion could limit incentives to less than the incremental cost of non-residential efficiency savings?

Response:

Yes, the limiting criterion is intended to ensure that the Company is not the sole payer for a DSM project that benefits the participant.

33.2.2 Does Fortis agree that a measure could cost ten times more than this amount and still cost far less than the long-run avoided costs of electricity supply?

Response:

FortisBC acknowledges that this could be true in select cases, but levelized costs are the usual way of comparing demand-side measures to supply-side costs, assuming they have passed the TRC test.

33.2.3 Does Fortis agree that applying these two criteria runs the risk of forfeiting opportunities for one-time opportunities to improve efficiency in new construction and equipment replacement?

Response:

Any restriction on a rebate amount may result in lost opportunities in specific DSM projects. The regulated TRC cost-effectiveness test does not restrict the amount of incentive that can be paid up to the full incremental cost of the measure. However, the Company remains mindful of its obligation to provide an effective DSM program at a reasonable cost to ratepayers.

34.0 Reference: Exhibit B-4, FBC Response to BCUC IR1 Q296.2, Avoided Power Purchase Costs

34.1 When FortisBC calculates its blended avoided cost of energy based in part on the BC Hydro long-run marginal cost of new supply does FortisBC weight the BC Hydro power according to its actual or forecast receipts of power from BC Hydro or according to the maximum receipts of power from BC Hydro available under FortisBC's power purchase agreement with BC Hydro?

<u>Response:</u>

The 28% BC Hydro portion used in the blended cost is based on the forecast energy supply to be obtained from BC Hydro in the 2012/13 test period.

34.2 Given that BC Hydro has to bear its long-run marginal cost of planning to have enough power to meet its maximum commitment under the power purchase agreement with FortisBC, does it make sense that FortisBC should use the maximum amount of power it is entitled to purchase from BC Hydro for weighting purposes in calculating FBC's blended avoided cost of power?

<u>Response:</u>

The Company does not believe that BC Hydro plans to supply the maximum amount of power the Company can contractually take at this time on an annual basis. The Company regularly provides BC Hydro with forward looking forecasts of expected energy purchases and the Company believes it is these forecasts that BC Hydro employs in its long term planning.

The 28% portion is the best estimate of how much energy the Company would obtain under 3808, and thus is representative of that portion of the long term avoided cost. Theoretically FortisBC could take 200 MW x 8760 hrs/yr, however various constraints limit the actual energy that can be obtained under RS 3808 over the normal course of a year. Escalating the BC Hydro energy portion to a 100% load factor would artificially distort the economic price signal used to value DSM programs.

35.0 Reference: Exhibit B-5, FBC Response to BCSEA IR1 Q1.4.1

FortisBC confirms that the Fortis Energy Utilities in their 2012-2013 Revenue Requirements Application are proposing to use a Societal Test rather than the Total Resource Cost (TRC) test as the primary benefit- cost test for demand-side management programs.

FortisBC states: "The FortisBC (electric) DSM program portfolio is sufficiently robust without the use of the Societal Cost Test due to the use of the long-term marginal supply cost in the TRC calculation as mandated in the DSM Regulation. The long-term marginal supply cost, which incorporates the cost of the BC Hydro call for clean power, is currently about twice the current FortisBC marginal supply cost. This creates a larger avoided power purchase benefit and therefore increases the TRC."

35.1 Does FortisBC agree that its use of a long-term marginal supply cost incorporating the BC Hydro LRMC for power purchased at embedded cost rates from BC Hydro creates a more economically efficient price signal than using FBC's own (unblended) marginal supply cost?

<u>**Response:**</u>

No, FortisBC believes that the most efficient price signal is the FortisBC forecast marginal supply costs in the years included in the analysis. From an economic perspective, it does not make sense to use the marginal supply costs of another utility.

35.2 Does FortisBC agree that screening its electricity DSM programs without using a Societal Cost Test, e.g., omitting the non-energy benefits adder, and using a higher discount rate would distort resource allocation between gas and electric efficiency resources and between their respective supply alternatives?

<u>**Response:**</u>

One of the primary intents of the FEU proposal to use a Societal Test is to recognize the "green" attributes of the EEC portfolio, and to level the playing field with electric DSM programs.

FortisBC does agree with using Non-Economic Benefits where they can be readily quantified, e.g. water and laundry soap cost savings for front-loading clothes washers. FortisBC uses a standard discount rate of 8% to ensure that all capital projects (supply-side & DSM) are treated equitably.

35.3 If not, please explain why not, providing supporting documentation for the answer.

Response:

No response required.

36.0 Reference: Exhibit B-1-2, 2012 Long-Term Demand-Side Management Plan, Appendix A, 2009 Customer End-Use Study

At p. 25 of Appendix A, Fortis indicates that 52% of homes heat with gas. At p. 55, the survey results indicate that 50% have central air-conditioning.

36.1 Why has Fortis not accounted for or targeted high-efficiency central air-conditioning in homes that heat with gas?

Response:

Neither the 2007 BC Hydro CDPR nor the NWPCC database included central air conditioning measures. The OPA data set does include central AC measure information, however the OPA measures are not cost effective. The incremental savings for high-efficiency air conditioning upgrades are relatively low compared with the incremental cost relative to baseline air-conditioning.

37.0 Reference: Exhibit B-1-2, 2012 Long-Term Demand-Side Management Plan, Appendix C, CDPR

37.1 In the LiveSmart, Home Improvement Program summarized at pp 12-13, please explain why Fortis is not planning to promote whole-house retrofit of homes with gas heat and central air-conditioning?

Response:

Whole house retrofits (building envelope measures including insulation upgrades, draft proofing and window replacements) are actively promoted through the LiveSmart BC collaboration and available to FortisBC customers with gas heat. Space heating fuel is the primary determinant, under the LiveSmart BC protocol, of which utility pays for the measures undertaken and thus is entitled to those energy savings. For example, a draft-proofing measure incentive is paid by FortisBC Energy if the dwelling is gas heated, or by FortisBC if electric heat and within the FortisBC service area.

In the BC southern interior region the space heating load exceeds the air conditioning load by an order of magnitude. Changes in air conditioning load are not considered in the LiveSmartBC Residential program and thus not factored into the 2012/13 DSM Plan.

37.2 Does FortisBC agree that instrumented air sealing and insulation would save both cooling electricity and heating gas, and that savings from both have the potential to be cost-effective whereas savings from either alone may not?

Response:

FortisBC does not agree. Air sealing and wall/ceiling insulation decrease space heating but generally increase cooling energy slightly. The increase in cooling is more than offset by the reduction in heating energy. Therefore, the inclusion of cooling will diminish the business case for insulation and air sealing.

37.3 Please explain why FortisBC has not targeted central AC early retirement, when FortisBC Energy Utilities propose the Furnace Scrap-It program?

Response:

Please see response to BCSEA IR2 Q36.1 above.

38.0 Reference: Exhibit B-1-2, 2012 Long-Term Demand-Side Management Plan, Appendix C, CDPR

At p. 62, the Conservation and Demand Potential Review considers fuel switching from electricity to natural gas for several end uses.

38.1 For the record, please indicate why the CDPR did not consider fuel-switching to high-efficiency gas space heat for the 33% of homes the Fortis territory with electric heat?

Response:

The Clean Energy Act of 2010 prohibits DSM programs that encourage switching to a more carbon intensive fuel through the definition of what a "demand-side measure" does not include,

> (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia.

39.0 Reference: Exhibit B-1-2, 2012 Long-Term Demand-Side Management Plan, Appendix A, 2009 Customer End-Use Study

At p 42, the report indicates that homes in FBC territory average 11 CFLs per home, with 18 incandescents and 15 halogen/other.

39.1 Why does Fortis not offer incentives for the direct installation of all cost-effective high-efficiency lamps, including CFLs and LEDs, at the time of the home energy assessment conducted as part of the LiveSmart Home Improvement Program?

Response:

The home energy auditors who provide assessments for the LiveSmart program work for service providers under contract to NRCan. The contract forbids them from undertaking any third-party (e.g. FortisBC) work in conjunction with the audit. However, they are authorized to convey partners' literature and FortisBC endeavours to keep them supplied with the current PowerSense programs including efficient lighting offers.

40.0 Reference: Exhibit B-5, FBC Response to BCSEA IR 1.4.2

40.1 For the record, please confirm the response should read "Please see the response to BCSEA IR1 Q4.1."

Response:

Confirmed. Please refer to Errata No. 3.

1.0 References

"The measure incentives, which were based on 40 per cent of TRC for the Medium option, were modified to either an incentive rate (cents/kWh) or to a unit incentive ($/measure) to make the program offers simpler for customers to understand." (Exhibit B-1-2, 2012 Long Term DSM Plan, p. 12, lines 20-23)

FortisBC 2011 Capital Expenditure Plan, BCUC IR2, A41.1 and Commission Decision, p. 54, Table 5.10.

"A change in the avoided supply cost does not directly impact the DSM incentives paid to customers, …" (Exhibit B-5, Celgar IR 1, 4.8)

"Since the utility and its ratepayers are considered together by this method [TRC method], transfer payments between the two are ignored." (Exhibit B-1, Appendix C, 2010 CDPR, Appendix C, p. C-2)

"…40% equals $20 but the 2012-13 incentive is set at $50 to match BC Hydro's offer." (Exhibit B-5, BCUC IR1, 294)

1.1 Please explain the phrase "40% of the TRC" found in the first quote above?

Response:

40% of the TRC means 40% of the Total Resource Cost of the measure.

1.2 Please match "TRC" in this phrase to one of the symbols found in the "Glossary of Symbols" found in the 2010 CDPR, Appendix C, p. C-4?

Response:

It refers to C_{TRC} term (Costs of the program [total resource cost test]) in the glossary. The equation for C_{TRC} is shown near the bottom of page C-2 of the 2010 CDPR.

1.3 Please confirm that the "avoided supply cost" referred to in Exhibit B-5, Celgar IR 1, 4.8 is an input into the calculation of the TRC test?

Response:

Yes, it is an input to the Benefits numerator in the TRC Benefit/Cost test.

1.4 Please explain why a change to the "avoided supply cost" does not directly impact the measure incentives?

Response:

The incentives are determined as a subset of the measure incremental cost, as they are considered a key motivator to encourage a customer to adopt a DSM measure. Other motivators may come from non-energy benefits (NEB) of the measure, such as productivity improvements that may occur from a more efficient industrial process.

A change to the avoided supply cost will only affect the Benefits term of the TRC test, but since such benefits occur on the utilities ledger they are not directly linked to the incentive amount. Incentives are considered a transfer payment, thus do not impact the TRC Benefit/Cost ratio.

1.5 Please confirm that the TRC test as set forth in Appendix C of the 2010 CDPR is used to calculate the measure incentives, and provide an illustrative example of how "40 per cent of the TRC" is used to calculate the measure incentives?

Response:

Not confirmed. The TRC "test" refers to the Benefit/Cost ratio which is the primary determinant of whether a program or DSM measure is cost-effective. The "40 percent of the TRC" or Total Resource Cost, as explained in the response to Celgar IR2 Q1.1 above, is the starting point for determining the incentive offer for a DSM measure or program.

For example, the TRC of a residential ductless heat pump was determined to be $4,766 in the CDPR, of which 40% of that TRC equals $1,906. The incentive for this measure was set at $600 based on market conditions and previous DSM offerings.

1.6 Does FortisBC determine the incentive level for mass-market programs based on 40% of the incremental measure cost as opposed to 40% of the TRC benefits? If so, why does FortisBC state that incentives are based on 40% of the TRC?

Response:

Please refer to the response to Celgar IR2 Q1.4 above.

1.7 Please provide the "modification" calculation of the measure incentives for the residential new home program and the "modification" calculation of the measure incentive for the industrial efficiency program, and provide the corresponding TRC ratio?

Response:

The 2010 CDPR identified the incremental cost of an EnerGuide 80 rated detached home as $3,200, times 40% equals $1,280. The DSM incentive was increased to $1,500 to match the equivalent BC Hydro New Home program offer. The New Home program has a plan 1.2 Benefit/Cost ratio under the TRC test.

The industrial efficiency cost was set at $189,000, which at 40% of TRC yields $75,600 or 3.3 cents per kWh. The DSM plan incentive was subsequently reset to 10 cents per kWh, which increases the incentive to $229,000 and therefore is subject to a cap of $189,000. The Industrial Efficiency program has a B/C ratio of 5.5 under the TRC test.

1.8 Please explain why the measure incentive for the residential new home program was 46.7 cents/kwh with a TRC ratio of 1.4 and the measure incentive for the industrial efficiency program was 5 cents/kWh with a TRC ratio of 5.2 in the FortisBC 2011 Capital Expenditure Plan evidence noted above?

Response:

The New Home market is characterized as a "lost opportunity" since the incremental cost of adding DSM measures at the time of construction is much lower than retrofitting at a later date. New Home measure incentives (with the exception of those related to owner-built homes) are considered a "split" incentive as the builder incurs the incremental costs of the DSM measure(s) – without the certainty of passing on those additional costs - and the homeowner enjoys the benefits in terms of reduced utility billing costs. For these two disparate reasons the DSM incentive is increased.

In contrast the Industrial Efficiency program is primarily a retrofit DSM opportunity, and the DSM incentive is typically only one component of the internal business case the industrial customer prepares in order to justify the DSM project expenditure. Other non-energy benefits or project justifications may include productivity/quality improvements, reduced downtime, saleable by-products etc. All monetary benefits, including the utility bill savings, are used in a payback calculation to meet internal financial hurdles. Even though the nominal incentive rate is 10 cents per kWh saved, it is not atypical for the DSM incentive to be capped by the 2-year payback limit.

1.9 Please explain why it is necessary to modify the 40 per cent of TRC for the Medium option to either an incentive rate or a unit incentive in the industrial sector? That is, why is the 40 percent of TRC benefits for each measure not used to calculate a measure incentive for each measure?

Response:

The typical industrial efficiency cost provided in the response to Celgar IR2 Q1.7 is a planning figure and the actual cost of Industrial Efficiency projects are not known until they are brought forward. Providing the nominal incentive offer of 10 cents per kWh saved gives would-be participants a clear price signal for DSM savings. The 40% of TRC incentive level is a portfolio-level goal of the FortisBC DSM program, and can be used as a starting point for incentive calculations, but it is generally modified to ensure consistency between projects and for market conditions. .

1.10 Please explain why the incentive should not be based on the TRC benefits instead of an amount roughly equal to the avoided supply cost for the utility?

Response:

Please see the response to Celgar IR2 Q1.9.

1.11 Does the DSM Regulation require the incentive to be based on the TRC ratio and not on the avoided supply cost even though the avoided supply cost is an input into the TRC test?

Response:

No, the DSM Regulation is silent on the matter of determining the DSM incentive. Standard practice is that the utility determines an appropriate incentive rate as part of the DSM planning process, and submits the DSM Plan to the Regulator for approval.

2.0 References

"BC Hydro does not file rate sheets on any of its DSM programs? The FortisBC Schedule 90 DSM Tariff is a framework under which its DSM programs operate."

2.1 Does FortisBC file rate sheets on any of its DSM programs? If not, please explain whether or not FortisBC receives Commission approval of individual DSM programs and if so, by what means does it receive Commission approval?

Response:

Schedule 90 of the FortisBC Electric Tariff is the only "rate" sheet applicable, and was approved by BCUC Order G-156-10. There are no individual DSM program rate sheets.

2.2 Please also comment on whether or not FortisBC obtains Commission approval for changes to DSM programs between the filing of capital plans? If not, please explain the regulatory or legislative parameters or provisions that FortisBC relies upon for making available DSM programs or changes to DSM programs that have not been approved by the Commission?

Response:

FortisBC reports on DSM programs to the Commission at a portfolio level, and has managed DSM expenditures and savings on the same basis. FortisBC makes changes to individual programs as and if necessary to respond to markets and optimize DSM resource acquisition.

The Company would seek Commission approval if a proposed DSM program either: (i) did not comply with Schedule 90, or (ii) would be likely to cause spending to materially exceed the approved budget.

2.3 Please explain whether or not FortisBC believes that the Commission has the authority to determine the measure incentive for an energy efficiency measure? If so, is FortisBC willing to seek Commission approval for a measure incentive in the "customized assistance" program for industrial efficiency when the Customer and FortisBC dispute the appropriate measure incentive?

Response:

Please see the response to Celgar IR2 Q2.2.

3.0 Reference

"In order to be considered as conservation, any DSM related activity must result in reduced load on the utility." (Exhibit B-5, Celgar IR 1, 4.2)

"In British Columbia, economic potential is defined using a total resource cost (TRC) test to screen measures for cost effectiveness. A total resource cost perspective considers all costs and benefits for each energy efficiency measure regardless of to whom they occur." (emphasis added) (Exhibit B -1-2, Appendix C, 2010 CDPR, p. 8)

"There are no DSM activities underway in the current year, nor planned in the test period." (Exhibit B-5, Celgar IR 1, p. 5.1)

3.1 Please comment on whether or not the DSM Regulation requires cost-effectiveness of DSM programs to be determined solely by the TRC test?

Response:

Section 4 of the 2008 DSM Regulation sets out what the Commission should consider when determining the cost effectiveness of different types of demand-side measures. Although section 4(1) speaks generally of the cost-effectiveness of demand-side measure(s), the TRC test is only specifically referred to in 4(2) with reference to the demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption.

The Company believes that the TRC test currently is the primary test for determining cost-effectiveness of demand-side measures, and has measured its programs and portfolios using the TRC test as presented in section 7 of the 2012 – 2013 Capital Expenditure Plan.

3.2 Please comment on whether or not the TRC test formula provided in the 2010 CDPR, Appendix C, p. C-2 is the same TRC test referred to in the DSM Regulation?

Response:

The 2008 DSM Regulation under the UCA does not explicitly define the TRC test, but the principles are well understood and are adhered to by FortisBC.

3.3 Please confirm that the TRC test formula provided in the 2010 CDPR includes both utility and customer costs and benefits, including benefits arising from both utility and customer load reductions, for each energy efficiency measure?

Response:

Confirmed. The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

Benefits and Costs: This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (except for the differences in net and gross savings).

The benefits calculated in the Total Resource Cost Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program.

The costs in this test are the program costs paid by both the utility and the participants. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test.

3.4 Please comment on whether or not the DSM Regulation in any way qualifies or restricts conservation and energy measures to those activities that result in “reduced load on the utility” as claimed by FortisBC in the response to Celgar IR 1, 4.2 quoted above?

Response:

A DSM measure is defined by the DSM Regulation:

> **"demand-side measure"** means a rate, measure, action or program undertaken
> (a) to conserve energy or promote energy efficiency,
> (b) to reduce the energy demand a public utility must serve, or
> (c) to shift the use of energy to periods of lower demand,

3.5 Please reconcile the answer to Exhibit B-5, Celgar IR 1, 4.2 with the DSM Regulation and the quote above from the 2010 CDPR, p. 8?

Response:

The response to Celgar IR1 Q4.2 states the FortisBC position on DSM related activities. FortisBC would only consider paying a DSM measure incentive if it expected to receive a benefit for its ratepayers.

FortisBC does not believe there is any inconsistency with this position and the DSM Regulation or the quote from the CDPR.

3.6 Please confirm that the fundamental premise behind the DSM Regulation is that FortisBC will implement all DSM measures that are cost effective as defined by the TRC test?

Response:

The Company cannot comment on the "fundamental premise behind the DSM Regulation" as the Regulation is an instrument of the provincial government. However, as indicated in section 7 of the 2012-13 Capital Plan, the Company has assessed its DSM programs on a Total Resource Cost basis.

4.0 Reference

"The load shapes were used in the 2010 CDPR to calculate peak demand savings from the energy efficiency measures." (Exhibit B-5, Celgar IR 1, 3.1)

Exhibit B-5, Celgar IR 1, 4.3, Table 4.3A

Exhibit B-5, Celgar IR 1, 4.6

"FortisBC would need the total project cost and an estimate of the portion of the project cost strictly related to energy in order to determine whether the project met the TRC cost-effectiveness test prescribe in the DSM regulation." (Exhibit B-5, Celgar IR 1, 6.10.1)

4.1 Please comment on whether or not peak demand savings are included in the calculation of the measure incentives for the industrial efficiency programs? If not, please explain why not?

Response:

The blended avoided power purchase costs developed in section 3.2.1 of the 2012 Long Term DSM Plan, and subsequently modified per Errata 2, represent firm energy prices that are inclusive of capacity benefits. Therefore, separate calculations of demand savings are not required for the cost-effectiveness or incentive calculations of the FortisBC DSM programs.

If the Company were to develop DSM programs designed primarily to achieve capacity savings (e.g. thermal storage systems), then a capacity savings rate might have to be calculated for that program.

4.2 Please comment on whether or not the TRC test distinguishes energy and demand costs and benefits? Does the TRC test formula include demand costs and benefits?

Response:

The TRC test, as outlined on page C-2 of the 2010 CDPR, does not specifically mention energy or demand costs and benefits. It speaks more generally to the participants' costs (investment), avoided costs (bill savings) and to the utilities' program costs and avoided supply costs. The TRC test includes any demand costs and benefits if they form part of the avoided supply cost or participant benefits.

5.0 Reference

"FortisBC supports the use of the blended avoided supply cost prescribed by regulation since it more accurately reflects the economic circumstances of the bulk electricity purchaser than simply using the same avoided supply cost for all bulk electricity purchasers." (Exhibit B-5, Celgar IR 1, 2.6)

"Using the projections contained in the Midgard Report, and a nominal discount rate of 8%, FortisBC has calculated a levelized value for its LRMC, for use in its Application, of $111.96 per MWh." (Exhibit B-5, BCUC IR1, 242.1)

Exhibit B-5, BCOAPO IR1, 64.3

5.1 Please explain why FortisBC uses $84.94(6% real) instead of $111.96(8% nominal) per MWh to calculate the long-term avoided power purchase cost of FortisBC in Revised Table 3.2.1?

Response:

The $84.94/MWh is derived from the BC Wholesale Energy Market Energy Curve (Table 5.1.3.3-A in Appendix B of the 2012 Long-Term Resource Plan). The $111.96 was derived from the BC New Resources Market Energy Curve (Table 5.2-A in Appendix B of the 2012 Long-Term Resource Plan). Note that the table in the response to BCUC IR1 Q242.1 incorrectly says that the levelized rate for the $84.94/MWh was determined using a 6% real discount rate. This should say that it was determined using an 8% nominal discount rate. (Please see Errata 3.)

In order to understand why the $84.94/MWh was used as a proxy for LRMC, please see the response to BCOAPO IR1 Q64.8.1.

5.2 From an economic perspective, please comment on whether or not "avoided supply cost" referenced in the DSM Regulation can be assumed to have the same meaning as "long run marginal cost"?

Response:

Section 4(3) of the DSM Regulation says that the avoided supply cost is "… the authority's long-term marginal cost of acquiring new electricity to replace the electricity sold to the bulk electricity purchaser …"

5.3 Please comment on whether or not it is reasonable to assume that the "avoided supply cost" of all suppliers, assuming the avoided supply cost is determined by market purchases for each supplier, purchasing from the same market should be the same subject only to differences in the cost of transmission?

Response:

Even if it assumed that the marginal cost of supply is the market for different utilities, it is not reasonable to assume that the marginal cost of the different utilities will be the same. There are many different electricity products that can be purchased on the market that would affect the costs.

5.4 If the "avoided supply cost" of BC Hydro and FortisBC was the same, would it be reasonable to assume that measure incentives to BC Hydro and FortisBC industrial customers would be the same?

Response:

Please refer to the response to Celgar IR2 Q1.4.

5.5 If the "avoided supply cost" of BC Hydro and FortisBC was the same, would FortisBC be willing to provide the same level of measure incentives to its customers as BC Hydro provides to its customers? If not, please provide a detailed explanation of reasons why the measure incentives might not be the same?

Response:

FortisBC would not necessarily have the same programs or measure incentives as BC Hydro, even if their avoided cost was the same.

Programs and measure incentives are customized to the specific markets each utility serves. The DSM Regulation respects these market differences and does not prescribe measure incentives or the programs to be offered (aside from those required for adequacy).

6.0 Reference

"The 2010 CDPR study by EES used the blended avoided cost of $154.15 to determine DSM benefits." (Exihibit B-5, Celgar IR 1, 2.10)

Exhibit B-5, BCOAPO IR1, 64.3

6.1 If EES was to revise the 2010 CDPR would it prefer to use the blended avoided cost of $154.15 or the blended avoided supply cost of $101.34? Please explain why or why not?

Response:

The avoided cost used in the 2010 CDPR was an input from FortisBC, and $154.15 was the correct value based on the information available at the time.

FortisBC revisited the avoided cost as part of preparing the 2012 Long Term DSM Plan and filed the updated value of $101.34 (as revised in Errata 2) as part of the 2012-13 Capital Plan.

When FortisBC prepares a new CDPR, it will again revisit the avoided cost.

6.2 Please comment on whether or not the blended avoided cost used in the 2010 CDPR ought to be the same blended avoided supply cost used to determine measure incentives?

Response:

No, the avoided cost is used to calculate the TRC benefits and is not directly related to measure incentives.

7.0 Reference

Exhibit B-5, Celgar IR1, 4.6

Exhibit B-5, Celgar IR 1, 6.5

"If FortisBC pays more than $1,500 for consulting or study services, any incentive amount that may be payable to that Customer will be reduced by the FortisBC contribution for these services." (Exhibit B-5, Celgar IR 1, 6.7)

7.1 Please comment on whether or not the general algorithm provided in response to Celgar IR 1, 4.6 is relevant to the determination of study costs? If so, how is it relevant?

Response:

The general algorithm provided does not take into account specific factors such as study costs or a number of other factors that may affect measure incentives such as those described in the response to the same IR (Celgar IR1 Q4.6) or Schedule 90 of the FortisBC Electric Tariff.

7.2 Please provide the source documents for the comment that an incentive payment will be reduced by the study costs funded by FortisBC?

Response:

Please see Celgar IR2 Appendix 7.2 which provides Schedule 90 from the FortisBC Electric Tariff No. 2 (refer to item 5 under Financial Incentives).

7.3 Please also provide references to any Commission orders or decisions that approved the reduction to an incentive payment by the amount of study costs funded by FortisBC?

Response:

Schedule 90 is approved under BCUC Order G-156-10.

7.4 Should the general algorithm provided in response to Celgar IR 1, 4.6 be amended to account for the recovery of study costs?

Response:

No, the response in Celgar IR1 Q4.6 was intended to be a general description of incentive calculation. The response also referenced the Tariff, under which the study cost recovery is authorized.

8.0 Reference

"The total cost of the measure in this theoretical example is not known, so the TRC B/C ratio cannot be calculated." (Exhibit B-5, Celgar IR1, 6.10.2)

"The 2012-13 plan costs and savings are considerable less than 2011 due to an extraordinary project in the current fiscal year." (Exhibit B-1, 2012-13 Capital Plan, p. 124)

"The Celgar project savings and incentive commitment were based on discussions held in 2010 when the prevailing DSM incentive level was 5 cents per kWh, or $50/MWh." (Exhibit B-5, Celgar IR1, 6.13)

"…two DSM projects were being considered by Celgar in the spring of 2010: new generation screens in pulp cyclones, and systematic replacement of pump stations with more efficient pumps with variable speed drives." (Exhibit B-5, Celgar IR1, 6.23)

"Industrial efficiency – no discrete measure or TRC was provided in the CDPR, but the nominal incentive rate was raised from five to ten cents per annual kWh saved, subject to the caps in Schedule 90." (Exhibit B-5, BCUC IR1, 294.1)

8.1 Please provide the TRC ratio calculation for the "extraordinary project" referred to in the above quote, including all energy and demand benefits and costs?

Response:

<u>Assumptions</u>

- 8% discount rate;
- Avoided power purchase costs $154/MWh;

- Energy savings 7.4[1] GWh 0.9 MW @8,000 load hours;
- Project cost $1.5 million; and
- Effective Measure Life: 10 years.

Calculations

- Benefits = Present Value (8%, 10 yr, 7,440 MWh x $154) = $7,688,143
- Costs: $1.5 million project cost + $0.1 million admin proxy = $ 1,639,717
- TRC "test": Benefit/Cost ratio = 7,688,143 ÷ 1,639,717 = 4.7

8.2 Please calculate the measure incentive for the "extraordinary project" based on "40% of the TRC" without a modification to an incentive/kwh or a unit measure?

Response:

Based on the assumed extraordinary project cost of $1.5 million, then 40% = $0.6 million.

8.3 Please identify the measure incentive that FortisBC was proposing for this project, with the full calculation of such amount? Please explain why FortisBC no longer plans to proceed with this project?

Response:

Energy Savings of 7,440,000 kWh @ 5 cents/kWh = $372,000. The incentive was calculated based on the nominal incentive rate available at the time.

Please also see the response to Celgar IR1 Q6.23.

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[1] Approximately half of the estimated total project savings of 15 GWh. Schedule 90 Terms & Conditions requires larger projects be split, with 50% of incentive paid at project completion and the balance the following year – with sufficient evidence that project energy savings have materialized.

8.4 Please provide the rationale for the increase of the nominal incentive rates from five to ten cents per annual kWh, including all working documents, calculations, and excerpts of relevant filings with the Commission? Please identify the Commission decision that approved the increase of the nominal incentive rate from five to ten cents per annual kWh?

Response:

The nominal doubling of the incentive rate incorporated into the 2011 DSM Capital Expenditure Plan, was approved under Commission Order G-195-10.

8.5 Please comment on whether or not FortisBC is willing, and if so in what circumstances, to provide an incentive rate greater than the nominal incentive rate for industrial efficiency programs?

Response:

FortisBC would consider paying an incentive greater than that which would be based on the nominal incentive subject in either case to the Schedule 90 incentive caps, provided that:

1. The project was demonstrably uneconomic for the customer with a nominal incentive; and
2. The project was demonstrably economic for ratepayers with a higher incentive.

8.6 If so, please provide a detailed description with illustrative examples of the characteristics of a measure that would attract an incentive exceeding the nominal incentive?

Response:

Please see the response to Celgar IR2 Q1.8 for an example of a measure that would attract an incentive exceeding the nominal incentive.

9.0 Reference

"The DSM incentive caps cited above are necessary to ensure that FortisBC customers as a whole are receiving value for DSM investments by placing reasonable limits on the amount of the incentive paid." (Exhibit B-5, Celgar IR1, 6.18

"The approach allows FortisBC to take variables such as measure life and persistence into consideration so that customers will be motivated to implement a project while at the same time acquiring the savings at the least cost to other ratepayers." (Exhibit B-5, Celgar IR 1, 6.12)

9.1 Please comment on whether or not a test to determine the cost to other customers is the ratepayer impact measure test?

Response:

Confirmed, the Ratepayer Impact Measure (RIM) test is a ratio that indicates the relative cost of DSM programs to non-participants by factoring in the lost revenue to the utility.

9.2 Please confirm that the DSM Regulation, section 4(6), does not permit the use of a ratepayer impact test to assess a demand-side measure?

Response:

Section 4(6) of the 2008 DSM Regulation states, "The commission may not determine that a proposed demand-side measure is not cost effective on the basis of the result obtained by using a ratepayer impact measure test to assess the demand-side measure."

9.3 Please comment on whether or not "acquiring the savings at the least cost to other ratepayers" is considered by FortisBC to be relevant to the determination of a measure incentive? If so, please explain how it is relevant and how it might affect the calculation of the measure incentive?

Response:

FortisBC believes that acquiring DSM savings at the least cost to ratepayers is relevant to its DSM programs and therefore to the determination of a DSM measure incentive. The relevance is underscored by the limit on monetary measure incentives described in the response to Celgar IR1 Q6.14.

10.0 Reference

"The Ministry of Energy and Mines (MEM) determines a broad provincial DSM policy framework, including the creation of DSM legislation that public utilities and the BCUC must follow." (Exhibit B-5, Celgar IR1, 10.13)

"FortisBC does not formally benchmark its DSM programs with BC Hydro or any other utility." (Exhibit B-5, Celgar IR1, 2.9)

"As stated in response to Celgar IR1, Q2.8, it is reasonable for utilities to offer DSM incentives based on their specific business circumstances." (Exhibit B-5, Celgar IR1, 2.14)

10.1 Please confirm that BC Hydro and FortisBC are required by the DSM Regulation to apply the same cost-effectiveness test for their respective DSM programs?

Response:

The Commission is required to use the TRC test (and any other analysis the Commission considers appropriate) to evaluate the cost-effectiveness of DSM programs of public utilities.

10.2 Please comment on whether or not FortisBC believes that one of the policy objectives of this "broad provincial DSM policy framework of the MEM" is regulatory and legislative parameters that apply to all DSM programs in the province?

Response:

FortisBC believes that the "broad provincial DSM policy framework" applies to all DSM programs implemented by public utilities in the province.

10.3 Please comment on whether or not FortisBC believes a reasonable policy objective, subject to "specific business circumstances", is that DSM programs offered by public utilities in BC are the same or similar?

Response:

Please see the response to Celgar IR2 Q5.5 above.

10.4 Does FortisBC endeavour to provide the same measure incentives to its residential customers as does BC Hydro to its residential customers?

Response:

Please see the response to Celgar IR2 Q5.5.

10.5 Please identify all "specific business circumstances" of FortisBC, other than the "avoided supply cost", relevant to the design of industrial DSM programs that might result in BC Hydro industrial DSM programs that are either not being made available by FortisBC or are being available with a much lower measure incentive?

Response:

Please see the response to Celgar IR2 Q5.5 above.

11.0 Reference

"The BC Hydro on-line project calculator shows an estimated incentive of $7.5 million, compared to the FortisBC estimated nominal incentive of $4.2 million (a difference of $3.3 million), subject in both cases to the fact that the actual DSM incentive offered would be based on a business case analysis and considerable due diligence (including those considerations listed in the responses to Celgar IR1 Q6.14, Celgar IR1 Q11.1.2 and Celgar IR1 Q6.20).

"Given that the estimates are dependent on a number of situational factors, FortisBC believes no significant conclusion can be drawn from this simple example." (Exhibit B-5, Celgar IR1, 11.1.4)

11.1 Assuming that there is a $3.3 million difference in the industrial incentives, please comment on whether or not the $3.3 million difference in the nominal incentives of FortisBC and BC Hydro is a significant difference?

Response:

Yes, it is a significant difference in this example.

11.2 Please comment on whether or not FortisBC believes that FortisBC industrial customers could ever under any "situational factors" be reasonably expected to receive an incentive close to or the same as incentives available to BC Hydro industrial customers?

Response:

Please see response to Celgar IR2 Q5.5 above.

11.3 If so, please identify the "situational factors" necessary for an incentive at FortisBC to be close to or the same as the incentives available to BC Hydro industrial customers?

Response:

Please see response to Celgar IR2 Q5.5 above.

11.4 Please assume that the factors identified in Exhibit B-5, Celgar IR1 6.20 and Exhibit B-5 Celgar IR 1 6.14 do not apply, please comment on whether or not FortisBC believes that FortisBC industrial customers could ever under any other "situational factors" be reasonably expected to receive an incentive close to or the same as incentives available to BC Hydro industrial customers?

Response:

Please see the response to Celgar IR2 Q8.5.

12.0 Reference

"The calculation appears to be correct, but FortisBC is not certain how it can confirm that this calculation is from BC Hydro." (emphasis added) (Exhibit B-5, Celgar IR1, 11.2)

http://www.bchydro.com/etc/medialib/internet/documents/psbusiness/pdf/a10_604_project_incentives_transmission.Par.0001.File.a10_604_project_incentives_transmission.pdf

12.1 Please follow the link, and then confirm that the calculation is from BC Hydro? Please file the BC Hydro "Project Incentives: Transmission" brochure.

Response:

Confirmed.

12.2 Please assume that the factors identified in Exhibit B-5, Celgar IR1 6.20 and Exhibit B-5 Celgar IR 1 6.14 do not apply, and then comment on whether or not the base rate of 30.9 cents/kWh noted in the BC Hydro brochure is comparable to the 10 cents/kWh that has been identified by FortisBC as its nominal incentive rate for industrial customers?

Response:

For reasons outlined in the response to Celgar IR2 Q5.5 the incentive offers are different.

12.3 Please comment on whether FortisBC has any reason to believe that BC Hydro has ever calculated an incentive to an industrial customer at less than the base rate of 30.9 cents/kWh?

Response:

Yes, FortisBC believes that BC Hydro has calculated an incentive at less than the base rate since the BC Hydro industrial incentives are capped by project costs:

- Projects costing $1 million or less are eligible for incentives up to 100 per cent;
- Those costing more than $1 million are eligible for incentives up to 75 per cent.

13.0 Reference

"Earnings Sharing Incentives, positive or negative, up to a 2 percent collar around the approved ROE will be shared equally between customers and FortisBC." (Exhibit B-1, Tab 4, p. 140, lines 9-11)

13.1 Is FortisBC applying to discontinue the ROE sharing mechanism for the test period?

Response:

The ROE sharing mechanism, as a feature of the Performance-Based Regulation (PBR) Plan, expires at the end of 2011. FortisBC is not proposing a PBR plan for the test period of its 2012 – 2013 Revenue Requirements, which is a cost-of-service based application. Therefore no ROE sharing mechanism is proposed for the test period. The Company may propose a PBR plan, including some form of earning sharing, in a future Revenue Requirements application.

14.0 Reference

"At the time of the decision, the Commission also determined that the AAM that was used to determine the ROE on an annual basis will no longer apply, and the ROE as determined in the decision will apply until changed by the BCUC."

Exhibit B-5, BCOAPO IR1, 101.1

14.1 Please file any letter, order or decision of the Commission that considered the report "A Review of Automatic Adjustment Mechanisms" of Concentric Energy Advisers dated November 29, 2010 and filed as an attachment to BCOAPO IR1, 101.1?

Response:

No formal letter, order or decision of the Commission was received by Terasen Utilities with respect to Concentric Energy Advisors' report, "A Review of Automatic Adjustment Mechanisms for Cost of Capital". No application was made to the Commission in respect of the Concentric report.

14.2 Does FortisBC acknowledge that the ROE is subject to revision and that the fair return standard must be met on an ongoing basis, and that the onus is on the utility to provide evidence that the rates are fair and reasonable?

Response:

As indicated in the preamble, the ROE applicable to the Company is subject to revision by the BCUC. The fair return standard requires that the ROE should, for ongoing utility operations, be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement), enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement), and permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement).

FortisBC's Return on Equity was determined by way of Orders G-52-05 concerning the Company's risk premium and capital structure and G-162-09 setting the benchmark utility ROE, and FortisBC believes that its ROE continues to meet the standard of providing a fair return. The Company believes that the fundamentals determining the Company's ROE and capital structure have not changed since those decisions and therefore is not seeking a change to components of the Cost of Equity.

14.3 Does FortisBC acknowledge that in the absence of the AAM and under a cost of service application the applicant has an onus to seek approval for all costs, including the cost of equity? If not, why does FortisBC make an exception for the cost of equity?

Response:

In a cost of service application, with or without an AAM, the applicant must seek approval for the total revenue requirement, including the cost of equity. In the 2012-13 RRA, FortisBC is seeking approval of Revenue Requirements in the amount of $294.484 million in 2012 and $319.109 million in 2013, which includes $43.352 million and $48.002 million in Cost of Equity in 2012 and 2013 respectively. The requested Cost of Equity is determined by the previously approved ROE (comprised of the benchmark ROE approved in Order G-162-09 and the Company's risk premium approved in Order G-58-06), times the mid-year Rate Base as detailed in the Application.

14.4 Please prepare a table that identifies and compares: 1) all approved deferral accounts as of December 2009 with 2) all approved deferral accounts and all deferral accounts that FortisBC is now seeking approval for and with 3) the approved deferral accounts the last time FortisBC was under cost of service regulation?

Response:

Table Celgar IR2 14.4 below provides deferral account information for the years 2005 (last cost of service filing), 2009, 2012 and 2013 as requested. While 2005 and 2009 are approved values, the 2012 and 2013 data represents the amounts that FortisBC is presently seeking approval for.

For further details on the Deferral Accounts please also refer to the following sections of the 2012-13 RRA:

1. Exhibit B-1, Tab-7, Tables 1-B, pages 12 to 15.
2. Exhibit B-1, Tab-5, Tables 5.4.2 & 5.4.3 page 11.
3. Exhibit B-1, Tab-5, Section 5.4, pages 10 to 37 for detailed write-ups on the Deferral Accounts 2012-13 outlining existing approval status and future approval requests.

Table Celgar IR2 14.4

Deferral Parameters	Approved 2005					Approved 2009					2012 (Approval Pending)					2013 (Approval Pending)				
	Previous Year Balance	Additions & Transfers	Amortized / Transfers to other Accounts	Amortization	Year End Balance	Previous Year Balance	Additions & Transfers	Amortized / Transfers to other Accounts	Amortization	Year End Balance	Previous Year Balance	Additions & Transfers	Amortized / Transfers to other Accounts	Amortization	Year End Balance	Previous Year Balance	Additions & Transfers	Amortized / Transfers to other Accounts	Amortization	Year End Balance
Energy Management	4,826	1,201	-	(1,023)	5,004	6,595	2,568	-	(934)	8,229	12,463	5,798	-	(1,771)	16,490	16,490	5,909	-	(2,179)	20,220
Deferred Regulatory Expense	(940)	(366)	1,790	(60)	424	(950)	1,840	1,443	(188)	2,145	(906)	-	5,416	(1,453)	3,057	3,057	150	-	(1,121)	2,086
Preliminary and Investigative Charges	1,286	762	(700)	-	1,348	1,153	2,763	(765)	-	3,151	3,811	1,937	(2,514)	-	3,234	3,234	775	(975)	-	3,034
Other Deferred Charges and Credits	6,717	29	23	(501)	6,270	6,896	(279)	(44)	(1,064)	5,509	243	1,145	(892)	(880)	(384)	(384)	1,365	(107)	(729)	145
Deferred Debt Issue Costs	2,883	164	-	(316)	2,732	3,644	1,315	-	(382)	4,577	3,797	(98)	-	(364)	3,335	3,335	1,410	-	(330)	4,414
Others	-	(98)	-	-	(98)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Deferred (Rate Base)	**14,773**	**1,692**	**1,113**	**(1,900)**	**15,679**	**17,337**	**8,207**	**635**	**(2,569)**	**23,611**	**19,408**	**8,782**	**2,010**	**(4,468)**	**25,731**	**25,731**	**9,608**	**(1,082)**	**(4,358)**	**29,899**
Deferred Charges (Non Rate Base)	-	-	-	-	-	28	-	-	-	28	1,801	11	(1,812)	-	-	-	-	-	-	-
Grand Total Deferred Charges	**14,773**	**1,692**	**1,113**	**(1,900)**	**15,679**	**17,365**	**8,207**	**635**	**(2,569)**	**23,639**	**21,209**	**8,793**	**198**	**(4,468)**	**25,731**	**25,731**	**9,608**	**(1,082)**	**(4,358)**	**29,899**

14.5 Please identify and calculate the percent of revenue requirement that is the subject of a deferral account for the comparisons noted in the previous question, including the percentage the aggregate deferral accounts represent of the total forecast revenue requirement for the applicable period?

Response:

Table Celgar IR2 14.5 below identifies and calculates the revenue that would be required as a result of the deferral accounts that are indicated in Table Celgar IR2 14.4 provided in response to Celgar IR2 Q14.4 above. It also provides the percentage the aggregate deferral accounts represent (Item 5 below) of the total forecast revenue requirements (Item 4 below) for the applicable periods (2005, 2009, 2012 and 2013).

Table Celgar IR2 14.5

REVENUE REQUIREMENT SPECIFIC TO DEFERRED ACCOUNTS
CELGAR IR2 14.5

			2005	2009	2012	2013
1	**Rate Base Calculation:**					
	Year End Deferred Charge Balance (Refer Table in IR2 Celgar 14.4)	A	15,679	23,611	25,731	29,899
	Mid Year Utility Rate Base (Deferral Related)	B = A/2	**7,840**	**11,806**	**12,866**	**14,950**
2	**Income Tax Calculation:**					
	Electricity Sales Revenue	N	3,850	5,099	7,231	7,373
	Deduct: Interest Expense	F	306	453	464	537
	Taxable Income	C=N-F	3,544	4,647	6,767	6,836
	Tax Rate	D	35.62%	30.00%	25.00%	25.00%
	Taxes Payable	E1=C*D	1,262	1,394	1,692	1,709
	Deferred Debt Issue Cost Tax Impact Adjustment	E2	86	265	98	177
	Regulatory Tax Provision	E = E1+E2	**1,348**	**1,659**	**1,790**	**1,886**
3	**Revenue Requirement Calculation:**					
	FINANCING COST					
	Debt Ratio	a	60.0%	60.0%	60.0%	60.0%
	Equity Ratio	b	40.0%	40.0%	40.0%	40.0%
	Average Debt Rate	c	6.5%	6.4%	6.0%	6.0%
	ROE	d	9.43%	8.87%	9.90%	9.90%
	Cost of Debt	F = B*a*c	306	453	464	537
	Cost of Equity	G=B*b*d	296	419	509	592
	Depreciation and Amortization (Refer Table in IR2 Celgar 14.4)	H	1,900	2,569	4,468	4,358
		L=F+G+H	2,501	3,440	5,442	5,487
	INCOME TAX	E	1,348	1,659	1,790	1,886
4	**Revenue Requirement for Deferral Accounts**	N=L+E	**3,850**	**5,099**	**7,231**	**7,373**
	Total Revenue Requirement for the year	P	**178,821**	**234,763**	**294,484**	**319,109**
5	**Revenue Requirement for Deferral Accounts As a percentage of Total Revenue**	% (N/P)	**2.2%**	**2.2%**	**2.5%**	**2.3%**

14.6 Please provide a link or electronically file a copy of the most recent Commission decision that approved a cost of service application by FortisBC (West Kootenay Power) prior to the approval of the AAM, and the Commission decision dated June 17, 1994 that approved the 1994/1995 revenue requirements for FortisBC?

Response:

Commission Decision G-41-93, in the West Kootenay Power Ltd. 1992/1993 General Rate Application is attached as Celgar IR2 Appendix 14.6.

14.7 Please comment on whether or not deferral accounts such as the Power Purchase Expense Deferral Account weaken the link between rates and costs so that returns are less sensitive to performance?

Response:

The Company has elaborated on the link between deferral accounts and ROE in the response to BCUC IR2 Q28.4.

14.8 Please comment on whether or not "deferral account" regulation reduces the need for regulatory review of costs?

Response:

The use of deferral accounts does not reduce the need for regulatory review of costs as they are still required to be prudently incurred pursuant to the Utilities Commission Act. Costs that are deferred are still subject to review and approval as part of the revenue requirements application processes.

14.9 Please comment on whether or not deferral accounts 1) obviate the need for the utility to manage costs and revenues and 2) reduce the incentive on the utility to be efficient and to innovate and in the long-term reduce costs?

Response:

Deferral accounts do not preclude the Company from effectively managing costs and revenues. The Company endeavours to ensure that all costs and revenues are prudently incurred, regardless of whether they are included as operating expenses, capital expenditures or deferral accounts. Costs or revenues accumulated in deferral accounts are subject to regular scrutiny through the Company's own internal review process and the rate setting processes that involve the Commission and interveners.

Please also see the response to BCUC IR2 Q28.2.

14.10 Please comment on whether or not the elimination of the link between performance standards and an incentive will change the utilities accountability for performance against the performance standards?

Response:

The measurement of non-financial performance against a specific set of Performance Standards has been a feature of the Company's PBR Plan, which expires at the end of 2011. In this application, FortisBC is not proposing a set of Performance Standards against which to measure non-financial performance. The Company may propose a PBR plan, including non-financial Performance Standards, in a future Revenue Requirements application.

The absence of a set of Performance Standards tied to a financial incentive in no way changes the Company's focus on the delivery of safe and reliable energy to its customers at the lowest reasonable cost.

Performance metrics in a PBR context have traditionally been applied as a safeguard to ensure a utility does not compromise service delivery to enhance returns rather than as an incentive to improve performance.

15.0 Reference

"To the extent that Power Purchase Expense variance resulting from a difference in sales load between forecast and actual are adjusted, it is necessary to match this treatment by means of a deferral account to flow through variances in sales revenue, the majority of which are attributable to weather related load variances, customer usage rate variances and customer load variances." (Exhibit B-1, Tab 4, p. 24)

15.1 Please comment on whether or not FortisBC believes that the Power Purchase Expense Variance Deferral Account is necessary if a Revenue Variance Deferral Account was approved?

<u>Response:</u>

Yes. FortisBC believes that it is necessary to link the revenue and expense variances in any deferral account treatment.

Approval of either a revenue or expense variance true-up mechanism alone could potentially result in either the Company or its customers overpaying or underpaying for the cost of purchased power.

The Company proposed the Power Purchase Expense Variance Account after considering the 2011 NSA provision regarding existing deferral mechanisms for BC Hydro. It concluded that a corresponding Revenue Variance Account is needed for consistent treatment of load variances, and noted (Exhibit B-1, Tab 4, page 24) that the BC Hydro energy cost deferral accounts also include load related revenue variances.

FortisBC does not believe that a Revenue Variance Deferral Account should be approved unless the related Power Purchase Expense Variance Deferral Account is also approved.

15.2 If not, please comment on whether or not FortisBC would seek approval for the Revenue Variance Deferral Account if the Power Purchase Expense Variance Deferral Account was denied? If so, please explain why?

<u>Response:</u>

No. For the reasons stated in the response to Celgar IR2 Q15.1 above, FortisBC believes that it is necessary to link the revenue and expense variances in any deferral account treatment.

15.3 Please comment on whether or not there are opportunities to reduce power purchase expense by the prudent management of those expenses?

Response:

The Company actively monitors power purchase expense to ensure that all expenses incurred are prudent and is continually looking for ways to reduce power purchase expense while maintaining reliable supply. This includes managing the variance in expenses resulting from a difference in sales load between forecast and actual.

However, as the Company must plan well in advance to meet potential load requirements, there will inevitably be variances between the Company's resources and the load requirement. While the Company prudently manages these variances, they will occur and may increase or decrease power purchase expense. In addition, the Company currently is reliant on market purchases to meet existing energy and capacity gaps where system requirements exceed contracted and owned resources, and in addition attempts to capture market opportunities to further mitigate power supply costs through displacement of other resources. Actual costs and savings associated with these activities are not only dependant on differences in forecast and actual loads but also on market conditions at the time. Therefore, the Company believes it is reasonable to establish the Power Purchase Expense Variance Deferral Account as proposed.

16.0 Reference

"Because community investment is required by the successful operation of the utility for the benefit of customers, these costs have, and should continue to be, borne by customers." (Exhibit B -1, BCUC IR1, 52.4)

16.1 Please compare the cost of "donations and sponsorships" as a percentage of revenues with other utilities, including FortisAlberta and Atco Gas.

Response:

FortisBC was unable to find publicly available information to make this comparison.

16.2 Please comment on whether or not the Commission should establish a benchmark for donations and sponsorships that is a based on a percentage of revenues?

Response:

Based on feedback from customers, FortisBC believes that the current community investment funding and program is appropriate and sufficient. If a new benchmark were to be established based on revenues, the amount would have to be consistent with the current budget to be effective, provide appropriate value, and allow for strategic planning.

16.3 Please provide the operating costs, capitalized costs and capital expenditures incurred by year from 1993 to 2012 for:

16.3.1 Charitable Donations,

Response:

Through the strategic development and deployment of the corporate community investment program, FortisBC provides donations and sponsorship support to the communities, including First Nations within its service area. This program helps FortisBC connect its customers and employees through a variety of local initiatives and contribute to the economic and social fabric of the communities the Company serves, while maintaining its corporate reputation.

Current community investment funding levels include charitable donations and have been effective, provide appropriate value, and allow for strategic planning.

Table Celgar IR2 16.3.1 Charitable Donations

	2007	2008	2009	2010	2011	2012
	($000s)					
Operating	87	130	119	182	116	134
Capitalized	11	0	26	37	12*	n/a

**To September 30, 2011*

16.3.2 Donations and Sponsorships

Response:

Through the strategic development and deployment of the corporate community investment program, FortisBC provides donations and sponsorship support to the communities, including First Nations within its service area. This program helps FortisBC connect its customers and employees through a variety of local initiatives and contribute to the economic and social fabric of the communities the Company serves, while maintaining its corporate reputation.

Current community investment funding levels have been effective, provide appropriate value, and allow for strategic planning.

Table Celgar IR2 16.3.2 Other Donations and Sponsorships

	2007	2008	2009	2010	2011	2012
	($000s)					
Operating	136	116	87	80	137	150
Capitalized	44	72	56	125	88*	n/a

** To September 30, 2011*

16.3.3 Corporate Communications & Public Relations,

Response:

There is significant public interest in corporate initiatives, operational activities and infrastructure improvement projects. There is also a need for targeted and strategic communications around safety and energy efficiency.

The table below provides the operating costs for Corporate Communications & Public Relations.

Table Celgar IR2 16.3.3 Corporation Communications and Public Relations Operating Costs

2007	2008	2009	2010	2011	2012
($000s)					
860	893	997	1,067	903	923

16.3.4 Advertising & Promotion:

16.3.4.1 Power Sense,

Response:

The table below provides the Advertising & Promotion for Power Sense.

Table Celgar IR2 16.3.4.1 PowerSense Advertising and Promotions

	2007	2008	2009	2010	2011F	2012
	($000s)					
Operating	-	7	1	-	-	-
Capitalized	106	145	307	314	312	n/a

16.3.4.2 FortisBC,

Response:

As noted in the response to Celgar IR2 Q16.3.3 there is significant public interest in corporate initiatives, operational activities and infrastructure improvement projects. There is also a need for targeted and strategic communications around safety and energy efficiency.

The table below provides the Advertising & Promotion for FortisBC, excluding PowerSense.

Table Celgar IR2 16.3.4.2 FortisBC (excluding PowerSense) Advertising and Promotions

	2007	2008	2009	2010	2011	2012
	($000s)					
Operating	248	148	207	145	266	267
Capitalized	55	76	62	23	12*	n/a

** To September 30, 2011*

16.3.5 Aboriginal Relations & Negotiations.

Response:

The Company's Aboriginal Relations program focuses on initiating, developing, and maintaining sustainable business relationships with the First Nations in FortisBC's service area.

FortisBC's success in developing and maintaining its First Nation relationships enables the Company to move projects and programs forward in a timely manner. FortisBC has worked to establish open and consultative relationships with First Nations and Aboriginal communities. This is fundamental to making decisions that appropriately reflect and incorporate First Nation interests and interests of the Company and its customers.

The Community and Aboriginal Affairs department budget increases over the past few years reflect the increased costs of meeting consultation requirements for First Nations due to the increasing complexity of these relationships.

Aboriginal Relations and Negotiations is part of the Community and Aboriginal Affairs department which includes aboriginal affairs, municipal relations, public consultation and community investment.

The table below provides the Community and Aboriginal Affairs operating costs.

Table Celgar IR2 16.3.5 Aboriginal Relations and Negotiations Operating Costs

2007	2008	2009	2010	2011	2012
($000s)					
143	186	153	571	594	674

17.0 Reference

"The increase in additions to CIAC in 2012F is a result of the changes to Schedule 74 as part of the 2009 Cost of Service and Rate Design Application and the Company contribution level for customers." (Exhibit B-1, BCUC IR1, 96.1)

17.1 Please compare the revised Schedule 74 with the immediately preceding Schedule 74 and comment on whether or not the Company contribution level for customers would be expected to be higher under the revised Schedule 74?

Response:

Under the preceding Schedule 74, the Company's contribution for new customers consisted of the costs to provide and install a transformer, drop service, and metering. The Customer was responsible for the remainder of the new extension costs.

The Company contribution under the revised Schedule 74 is based on the net book value of the Company's investment for new connects (Company investment made into new extensions under less accumulated depreciation). As such, the level of investment provided by the

Company for new customers under the revised Schedule 74 is less than the amount previously provided by the Company for customers under the preceding extension policies.

18.0 Revision

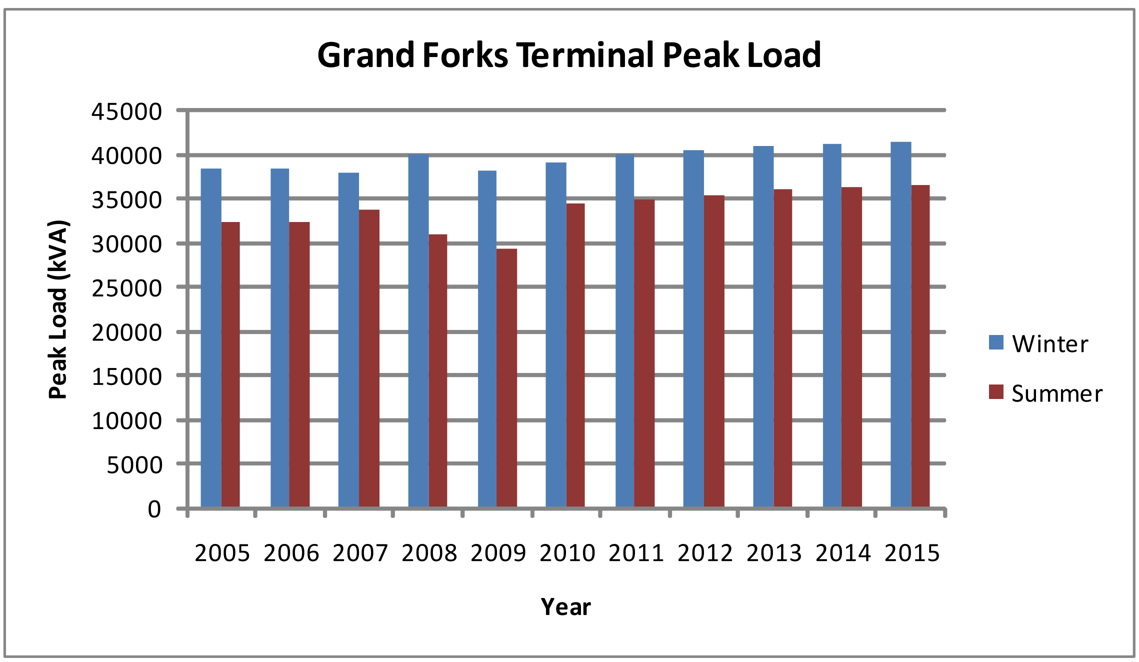
"The Grand Forks Terminal is a major substation which provides the normal transmission supply for Grand Forks, Christina Lake and surrounding areas." (Exhibit B-1, Tab 6, p. 30, lines 4-5)

18.1 Please provide actual and forecast load growth at the Grand Forks Terminal from 2005 to 2015?

Response:

The following figure shows the actual and forecast loads supplied from the Grand Forks Terminal for the requested interval.

Figure Celgar IR2 18.1



18.2 Please comment on whether or not load growth, in part or in whole, justifies the need for this project?

Response:

No – load growth in the Grand Forks area is not a driver for this project.

18.3 Please provide customer satisfaction survey results for customers serviced by the Grand Forks Terminal for the period 2005-2011?

Response:

FortisBC surveys customer satisfaction for the entire residential and commercial customer base, but does not have customer satisfaction survey results by geographic area. This is due to the increased sample size (and increased costs) that would be required.

19.0 Reference

"The recent acquisition of surplus capacity from the Waneta Expansion ("WAX") will satisfy FortisBC's capacity deficit after the project is commissioned in 2015." (Exhibit B-1-2, 2012 Long Term Resource Plan, Midgard Report, p. 4)

"The FortisBC system is a relatively small power system with a very large unit-contingent resource in the form of the WAX Capacity Purchase Agreement ("WAX CAPA") accounting for a significant proportion of its resource portfolio. Given that an outage to a single WAX generating unit has a material impact on the overall resource stack,…" (Exhibit B-1-2, 2012 Long Term Resource Plan, Midgard Report, p. 4)

"FortisBC's demand forecasts used in this Resource Plan are inclusive of the required PRM as set out in this section." (Exhibit B-1-2, 2012 Long Term Resource Plan, p.58, lines 2-3)

"The Waneta Expansion Project constitutes approximately 7.0 percent of the total 11.4 percent customer rate increase in the year 2015." (Exhibit B-5, BCUC IR1, 169.1)

19.1 Did FortisBC disclose to the Commission either in the application or during the review of the application for approval of the WAX CAPA the rate increase of 7.0 percent in the year 2015 for the WAX CAPA?

Response:

Yes, the expected rate increase due to the WAX CAPA contract was disclosed to the Commission as part of the application.

19.2 Please provide a detailed breakdown of the WAX CAPA costs that result in the rate increase of 7.0 percent in the year 2015?

Response:

The Company is not requesting approval of the 2015 rate increase and this question is therefore beyond the scope of issues in this application. The indication of likely rate increases through 2016 was provided for informational purposes only. The Company will also be considering the need for any form of rate impact smoothing. However, for informational purposes, the breakdown of expected WAX CAPA costs and offsets for 2015 is presented in the following table.

Table Celgar IR2 Q19.2

WAX CAPA 2015	($000s)
Annual Payment	$37,795
Forecast Offsets	$12,040
Net Impact	$25,755

19.3 Did FortisBC identify PRM requirements in its application or during the review of the application for approval of the WAX CAPA?

Response:

FortisBC did discuss PRM requirements in its application for approval of the WAX CAPA, however the justification for entering into the WAX CAPA was based on addressing growing capacity gap requirements before any consideration of planning reserve margin. Although the Company identified that the WAX CAPA could be used to help the Company to meet planning reserve requirements, it was not part of the principal justification for entering into the agreement.

19.4 If so, did FortisBC justify the need for and the costs of PRM driven by the WAX CAPA?

Response:

No. Please refer to the response to Celgar IR2 Q19.3 above.

19.5 If so, please provide full details of the PRM costs and approximate rate increases that were disclosed to the Commission during the WAX CAPA review?

Response:

Please refer to the response to Celgar IR2 Q19.3. As PRM requirements were not part of the justification for entering into the WAX CAPA, an analysis of PRM costs and related rate increases were not part of the application.

19.6 Please prepare a table comparing the PRM costs assuming the resource stack includes purchases of capacity from Powerex under the current agreement with the PRM costs assuming the resource stack includes capacity purchases under the WAX CAPA?

Response:

This question is beyond the scope of issues in this application. The WAX CAPA is expected to be in service beginning in January 2015 and regardless of the PRM will be included in FortisBC's resource stack. The Powerex agreement will be terminated at that time. There will not be an option to choose between the WAX CAPA and the Powerex agreement to meet the Company's resource requirements, with or without a PRM.

19.7 Assuming no PRM requirement, please compare the forecast of the power purchase expense and the forecast rate increase in 2015 under the current Powerex agreement with the WAX CAPA?

Response:

Please refer to the response to Celgar IR2 Q19.6.

19.8 Please provide in both tabular and graph format the monthly capacity load/resource balance in 2016 and 2020 with no PRM capacity requirement and with and without the capacity purchases under the WAX CAPA?

Response:

Please find the requested table and chart for 2016 and 2020 with no PRM capacity requirement. Please also refer to Celgar IR2 Q19.6 as to why it is not correct to remove WAX CAPA as a resource.

Figure Celgar IR2 19.8a 2016 Monthly Capacity Load/Resource Balance with WAX and No PRM

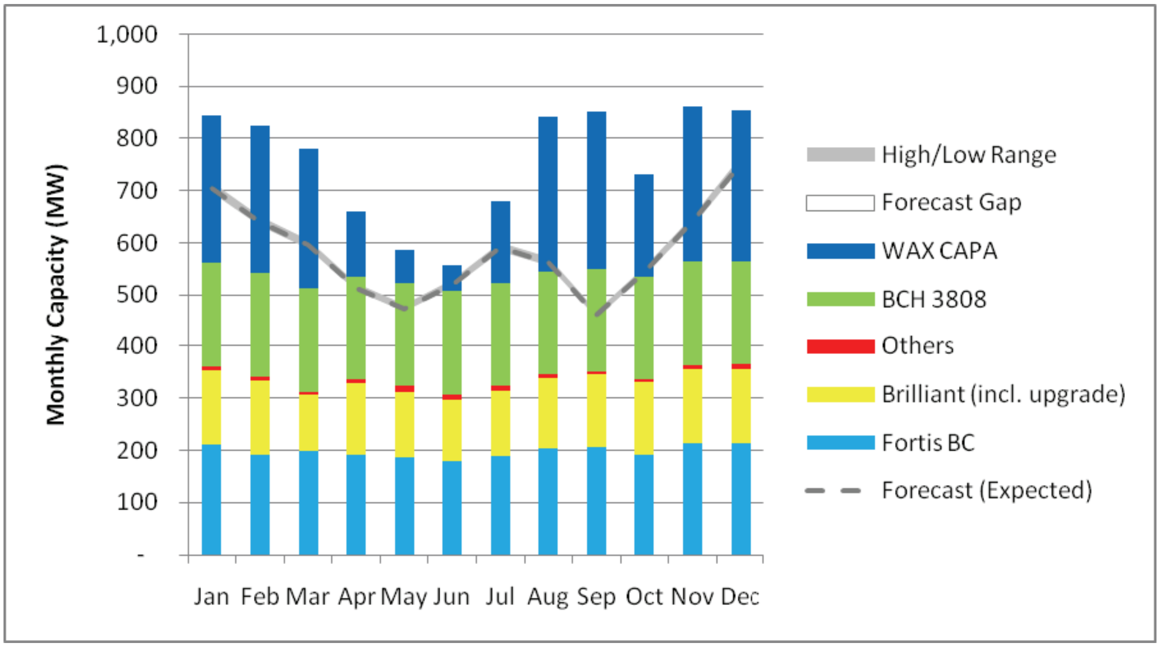


Table Celgar IR2 19.8a 2016 Monthly Capacity Load/Resource Balance with WAX and No PRM

2016 with WAX	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Capacity Gaps (MW)												
Expected	0	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0	0	0
Low	0	0	0	0	0	0	0	0	0	0	0	0
Peak Demand (MW)												
Expected	703	639	595	514	474	521	590	563	462	545	639	751
High	715	650	606	523	482	530	600	572	470	554	650	764
Low	695	632	589	508	469	515	583	556	457	538	632	743
Resources (MW)												
Fortis BC	210	192	200	192	187	178	188	203	206	191	214	213
Brilliant (incl. upgrade)	142	143	107	137	126	119	126	135	139	139	143	143
Others	9	7	5	7	10	10	10	8	5	5	8	9
BCH 3808	200	200	200	200	200	200	200	200	200	200	200	200
WAX CAPA	283	282	269	124	65	50	157	296	301	197	298	290
	844	824	780	659	587	558	681	842	851	732	862	855

Figure Celgar IR2 19.8b 2020 Monthly Capacity Load/Resource Balance with WAX and No PRM

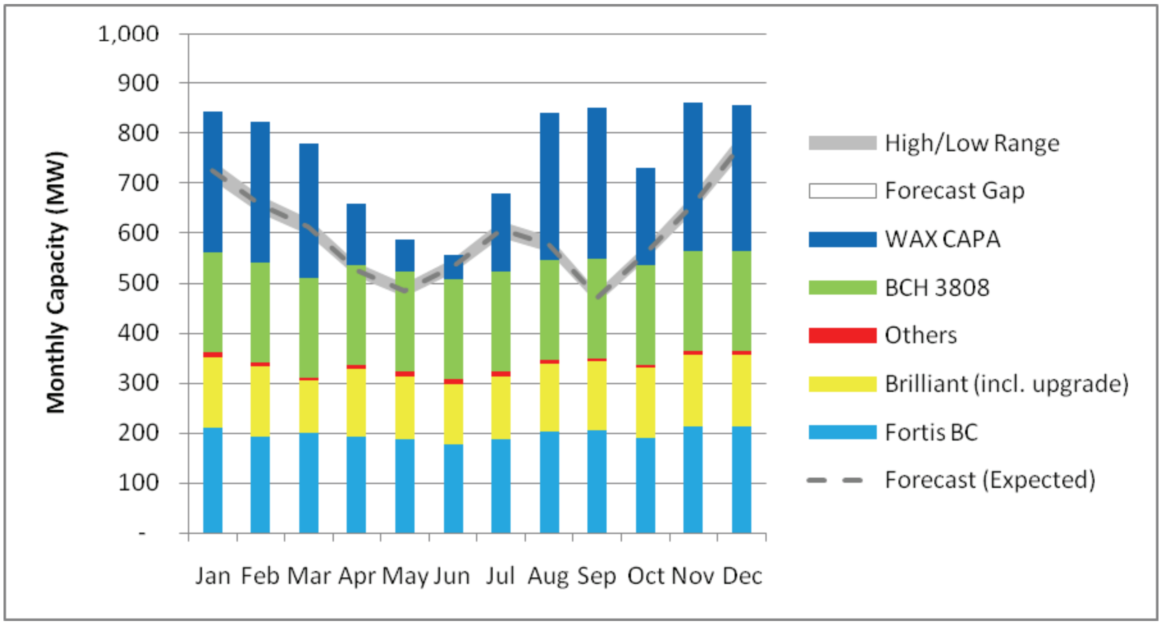


Table Celgar IR2 19.8b 2020 Monthly Capacity Load/Resource Balance with WAX and No PRM

2020 with WAX	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Capacity Gaps (MW)												
Expected	0	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0	0	0
Low	0	0	0	0	0	0	0	0	0	0	0	0
Peak Demand (MW)												
Expected	725	657	613	526	486	534	607	578	472	559	659	778
High	746	676	630	542	500	549	624	594	485	576	678	800
Low	707	640	597	513	473	520	592	563	460	545	642	758
Resources (MW)												
Fortis BC	210	192	200	192	187	178	188	203	206	191	214	213
Brilliant (incl. upgrade)	142	143	107	137	126	119	126	135	139	139	143	143
Others	9	7	5	7	10	10	10	8	5	5	8	9
BCH 3808	200	200	200	200	200	200	200	200	200	200	200	200
WAX CAPA	283	282	269	124	65	50	157	296	301	197	298	290
	844	824	780	659	587	558	681	842	851	732	862	855

19.9 Please justify the WAX CAPA capacity purchase assuming the Commission in this proceeding concludes that FortisBC does not have a PRM requirement?

Response:

Please refer to the response to Celgar IR2 Q19.3.

20.0 Reference

Exhibit B-1, Tab 5, Section 5.4.2, p. 12-14

Exhibit B-5, BCUC IR1, 99.1

20.1 Please explain why preliminary and investigative charges should not be approved before being booked as a deferred charge for later disposition?

Response:

The Company has requested deferral of preliminary and investigative charges in the Application. The calculation of forecast rate base includes an estimate of Deferred and Preliminary charges including preliminary and investigative charges. Please refer to Tab 5, Page 12, Section 5.4.2 of the 2012-13 RRA.

20.2 Please explain why FortisBC continues to investigate PSH as a potential resource?

Response:

As summarized in Table 6.1.2-A in the 2012 Long Term Resource Plan, pumped storage hydro (PSH) was highly ranked in an evaluation of potential new capacity resources. In Table 6.1.3-A, it is further identified as one of FortisBC's Preferred Build Strategy Resource Options for addressing capacity requirements. Section 6.1.3 gives a more detailed description of some of the attributes of PSH.

FortisBC believes there are site specific PSH opportunities in its service territory which warrant further investigation. Therefore FortisBC will continue to retain PSH as a potential capacity resource option.

20.3 Please comment on whether or not BC Hydro has discontinued investigation of PSH as a potential resource?

Response:

BC Hydro continues to investigate pumped storage hydro as a potential resource option:

- Knight Piesold recently completed a study for BC Hydro, "Evaluation of Pumped Storage Hydrologic Potential Screening Assessment", dated November 30, 2010;
- Hatch Ltd. finished a study for BC Hydro entitled "Preliminary Cost Assessment of Pumped Storage at the Mica Generating Station", dated December 2010;
- PSH has been discussed in BC Hydro's Technical Advisory Committee meetings related to its IRP earlier in 2011; and
- Randy Reimann, Director of Resource Planning at BC Hydro presented an overview of BC Hydro's pumped storage investigations entitled "Pumped Storage - Future Need and Benefits" at Clean Energy BC's "Generate 2011" conference on September 26, 2011.

21.0 Reference

"The Commission Panel approves BC Hydro's proposal that annually the average balance in each deferral account attract an interest charge or credit equivalent to BC Hydro's weighted cost of debt during the same period." (Decision: BC Hydro 2004/05 to 2005/06 Revenue Requirements Application and BCTC Application for Deferral Accounts, dated October 29, 2004, p. 45, Order G-96-04)

"all deferred expenditures or credits (with the exception of the non-cash items identified in Schedule 1A) should be included in Rate Base and financed at the Weighted Average Cost of Capital ("WACC")." (Exhibit B-5, BCUC IR1, 98.2)

21.1 Please explain why BC Hydro deferral accounts should be financed at the cost of debt and FortisBC deferral accounts should be financed at the WACC?

Response:

The Company takes no position on how BC Hydro deferral accounts should be financed but it is important to point out there are significant differences in the determination of capital structure and allowed return on equity for BC Hydro and for FortisBC.

In BC Hydro's case, the allowed ROE is determined by direction of the provincial government and is not determined by the BCUC. The directed ROE is applied to a non-standard definition of Equity which in BC Hydro's case includes Retained Earnings, Deferred Revenue, Contributions arising from the Columbia River Treaty, and Contributions in Aid of Construction. It is important to note that BC Hydro Equity does not include deferral accounts.

The Company understands that BC Hydro deferral accounts are financed at the Weighted Average Cost of Debt (WACD) because deferral accounts are not considered in the calculation of its Equity return. In other words, BC Hydro is approved to raise debt and incur interest in order to finance its deferral accounts rather than through traditional utility financing practices.

In FortisBC's case, rate base is financed in accordance with the approved deemed capital structure (40% equity) resulting in a financing cost consistent with the weighted average cost of capital. Rate Base includes Net Property, Plant and Equipment, Deferral Accounts, Contributions in Aid of Construction (as a credit to rate base), and an Allowance for Working Capital. The cost of debt is determined by multiplying a weighted average cost of debt (WACD) by the deemed debt component (60%) in the approved Capital Structure and added to the cost of equity to come up with a WACC. FortisBC's Rate Base, which includes deferral accounts, incurs both a debt and equity cost.

Since FortisBC's Rate Base, including deferral accounts, is deemed to be financed 60% through debt and 40% through equity, the financing rate applied to Rate Base uses the same ratio of 60% debt and 40% equity. As such, WACC, which includes the debt and equity ratio of 60/40, is the appropriate and approved rate used to finance FortisBC's deferral accounts.

22.0 Reference

> "The cost to develop an asset management strategy will be captured in a deferred account." (Exhibit B-5, BCUC IR1, 108.1)
>
> "Expenditures of $785,000 in 2012 and 2013 are proposed to accommodate the development of a project team comprising internal and external resources." (Exhibit B-1-1, Long Term Capital Plan, p. 5)
>
> "FortisBC has not approached BC Hydro as a potential provider of Asset Management services at this time." (Exhibit B-5, BCUC IR 1, 188.4)

22.1 Please identify when FortisBC first implemented an asset management model?

<u>**Response:**</u>

The Company's asset management model historically has been time based which has been common utility practice for decades. The implementation of technology over a number of years has allowed the ability to transition from managing the assets from a time-based to condition based criteria and practices. The next step in this transition is the proposed project which is to develop a formal asset management solution and an implementation strategy leveraging off of today's technology.

22.2 Is the asset management approach being developed with the expenditures of $785,000 intended to replace an existing asset management strategy?

Response:

Review of existing processes, procedures and tools will be part of the scope of this project and used to provide a foundation of the asset management strategy. It is FortisBC's intent not to replace existing asset management strategy but rather move to developing a higher level of sophistication for determining maintenance and capital expenditures.

22.3 If so, what are the costs of the existing asset management strategy and are those costs included in the O&M budget?

Response:

FortisBC does not have a specific asset management group and the effort is spread across various parts of the organization. The costs of the existing asset management processes are included in both O&M and Capital expenditures. Although some costs (i.e. line condition assessment) can be directly linked to the current asset strategy, other costs are embedded in various budgets throughout the organization and cannot be broken out into any granularity.

22.4 Is FortisBC willing to seek Commission approval for the Asset Management option and implementation plan that it believes is the most cost-effective solution?

Response:

Yes. As stated in Exhibit B-4, BCUC IR1 Q108.1, p. 217, FortisBC will identify the implementation strategy and costs associated with it. Treatment of the costs in the deferred account as well as the identified implementation cost will be submitted for approval in a future application.

SCHEDULE 90 - DEMAND-SIDE MANAGEMENT SERVICES

APPLICABLE: To all Customers in all areas served by the Company and its municipal wholesale Customers.

OBJECTIVE: The purpose of the Company's Demand-Side Management (DSM) Services is to promote the efficient use of Electricity, in terms of consumption (Conservation) and/or timing (Demand Response).

PROGRAMS: DSM programs, compliant with applicable regulations, address electrical end-uses, through approved Measure(s), which may consist of an energy-efficient product, device, piece of equipment, system, building or process design and/or operational practice which exceeds applicable codes and/or current practice.

The Company will maintain an updated DSM program listing on its website, available in print format, detailing current program offerings and rules.

FINANCIAL DETAILS: DSM programs will consist of monetary incentives provided by the Company in the form of custom option or product option offerings to promote the purchase and installation of approved Measures. Incentives are targeted to Customers but may also be provided to trade allies who provide or install the Measures.

Monetary incentives are based on the annual kWh savings, or the on-peak kW reduction, attained through the Measure as determined on a prescriptive or custom calculation basis.

Monetary incentives are capped to the lesser of:

i. the Company's long-term avoided power purchase costs,
ii. 50% of installed Measure cost for existing construction,
iii. 100% of incremental cost for new construction, or
iv. The amount sufficient for the Customer to achieve a two-year payback.

Monetary incentives may alternately consist of low-cost financing O.A.C. for residential Customers only.

DSM Services may also consist of non-monetary offerings in the form of: public information, educational programs, or training; audits of Customer Premises or processes or Measures and reports thereof; product samples; pilot projects to test new Measures; and market transformation activities undertaken in conjunction with other utilities and/or governments.

SCHEDULE 90 – DEMAND-SIDE MANAGEMENT SERVICES (Cont'd)

TERMS AND CONDITIONS

The following terms and conditions are an integral part of the Demand-Side Management Services listed under Schedule 90:

FINANCIAL INCENTIVES

1. In order to be eligible for financial incentives, a Customer must receive the Company's approval prior to initiation of work on the approved Measure.

2. Only those audit or upgrade costs which are pertinent to DSM considerations will be eligible for financial incentives. An estimate of costs related to such issues as obsolescence, depreciation, maintenance, plant betterment and environmental concerns will be made to isolate that portion of the cost strictly related to energy.

3. Where incentives are in excess of $10,000, payment of one half of the rebate will be deferred for up to one year. Upon confirmation of project savings, the remaining portion of the rebate will be paid pro rata to the energy savings. No interest will be paid on the withheld portion. Irrespective of actual savings, the final rebate will not exceed the original estimated rebate.

4. For those Customers in receipt of an incentive in excess of $20,000, the unamortized balance of financial incentives paid to or on behalf of the Customer, under Rate Schedule 90 shall be remitted to the Company within 30 days of billing, if:

   (a) the incented equipment or facilities are disabled or removed;

   (b) the Customer's electrical load is reduced by more than 50% for a continuous period of twelve months or longer; or

   (c) over 50% of the Electricity previously provided by the Company is replaced by another source including self-generation or another supplier.

   In regards to (c) above, the repayment shall be prorated based on the amount of energy replaced compared to the amount of energy supplied by the Company in the year immediately preceding the Electricity replacement.

5. Any consulting or study subsidy offered under the Demand-Side Management tariff is contingent upon available budget and resources. When the Company pays more than $1,500 for these Services on behalf of a Customer, any incentive amount that is eventually payable to that Customer will be reduced by the amount of the consulting or study contribution.

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-41-93

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AN ORDER IN THE MATTER OF the Utilities Commission Act, S.B.C. 1980, c. 60, as amended

and

An Application by West Kootenay Power Ltd.
Commission Orders No. G-120-91 and G-6-92

BEFORE: M.K. Jaccard, Chairperson;	)	
L.R. Barr, Deputy Chairperson; and	)	June 9, 1993
K.L. Hall, Commissioner	)	

WHEREAS:

A. On March 8, 1993 a public hearing commenced at Penticton, B.C. into the West Kootenay Power Ltd., ("WKP") November 28, 1991 general Rate Application as amended; and

B. Commission Order No. G-6-92 granted WKP an interim, refundable rate increase of 8.7 percent effective January 1, 1992 and Order No. G-123-92 granted an interim, refundable rate increase of 4.8 percent effective January 1, 1993; and

C. The Commission has considered the Application and the evidence adduced thereon, all as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission, for reasons stated in the Decision, orders WKP as follows:

1. The Rate Base and Revenue Requirements for the test years ending December 31, 1992 and December 31, 1993 are as set out in the Schedules contained in the Decision.

2. A general revenue requirement increase of 8.05 percent for 1992 and 3.70 percent for 1993 to all customer classes is approved as firm, except for that portion relating to the April 1, 1993 British Columbia Hydro and Power Authority ("B.C. Hydro") interim increase. That portion will remain subject to refund pending the outcome of the September 13, 1993 public hearing into B.C. Hydro's 1993 Revenue Requirement Application and subsequent Commission Decision.

3. The proposal for flattening of residential rates is approved effective October 1, 1993, however, the basic charge for both schedules is to remain at its current level.

4. The proposed changes to Rate Schedule 90 up to December 31, 1993 are accepted.

5. The proposed changes to the General Service Rate Schedules 20 and 21 are approved effective October 1, 1993.

6. The amendments proposed by WKP for Rate Schedule 73 - Extensions are approved effective October 1, 1993 with the exception of the Environmental Aesthetics application.

7. The application for a new connection fee for Rate Schedule 82 is approved effective October 1, 1993.

8. The Commission will accept, subject to timely filing by WKP, amended Electric Tariff Rate Schedules which conform to the terms of the Commission's Decision.

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-41-93

9. WKP will comply with all directions contained in the Decision accompanying this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 9th day of June, 1993.

BY ORDER

Dr. Mark K. Jaccard
Chairperson

BCUC/Order/WKPIncr&Decision

WEST KOOTENAY POWER LTD. RATES JUNE 9, 1993
CAARS

1.0 INTRODUCTION

The West Kootenay Power Ltd. ("the Applicant", "WKP", "the Company") system serves some 116,000 customers. Approximately 40 percent are served indirectly through the sale of power to municipal distribution utilities in Grand Forks, Nelson, Kelowna, Penticton, Summerland and through Princeton Light and Power Company, Limited ("PLP"), a private company serving Princeton and vicinity.

Power is supplied from WKP's own four plants on the Kootenay River, purchases from Cominco Ltd. ("Cominco") and purchases from the British Columbia Hydro and Power Authority ("B.C. Hydro"). WKP is a wholly-owned subsidiary of UtiliCorp British Columbia Ltd. ("UtiliCorp B.C."), which in turn is a subsidiary of UtiliCorp Inc. ("UtiliCorp") of Kansas City, Missouri.

1.1 Power Supply

In 1992 WKP had a peak load of approximately 600 MW. The four WKP plants on the Kootenay River, with a total installed capacity of 190 MW, supplied only 32 percent of WKP's capacity requirements. Purchases from Cominco supplied a further 42 percent and purchases from B.C. Hydro 26 percent (WKP 1992 Annual Report).

Energy sales of 2,480 gigawatt hours ("GW.h") were supplied 55 percent from WKP's own generation facilities. Thirty-five percent was purchased from Cominco, and the remaining 10 percent from B.C. Hydro.

WKP purchases power from Cominco under two power supply agreements. The Long-Term Firm Power Supply Agreement provides for the purchase by WKP of 75 annual average megawatts ("aaMW") on a take-or-pay basis, until September 30, 2005. The 1999 Firm Power Supply Agreement, provides for the purchase by WKP of a further 38 aaMW, on a firm take-or-pay basis, until December 31, 1999. WKP is entitled to utilize, on an hourly basis, any unused Cominco capacity at no cost.

Purchases of power by WKP from B.C. Hydro have been largely for seasonal peaking purposes and vary from maximum levels in the winter to at or near zero in the summer. The power purchases have been made according to the Power Purchase Agreement ("PPA") which provides for energy and capacity under B.C. Hydro Rate Schedule 3807 ("Rate 3807"). In accordance

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with a British Columbia Utilities Commission ("the Commission") Decision, and Order No. G-27-93 issued April 22, 1993, Rate 3807 will terminate on October 1, 1993. It will be replaced on that same date by Rate Schedule 3808 ("Rate 3808") and an amended PPA.

The area served by WKP is expected to have an increasing need for electricity due mostly to the growing population. The major growth area is centred in the Okanagan. Increasingly, electricity to serve this area must be moved long distances from the generating sources on the Kootenay River, or be purchased from B.C. Hydro.

1.2 The Application

WKP applied on November 28, 1991, for an interim refundable increase of 4.2 percent to be effective January 1, 1992, and a further increase of 5.8 percent effective January 1, 1993. The Applicant stated that the increases were necessary to provide adequate revenue to generate a fair return on the increased investment in plant and equipment, and to offset higher forecast costs for power purchases and wheeling. The interim increase for 1992 was approved, subject to refund with interest, by Commission Order No. G-120-91, dated December 20, 1991.

Commission Order No. G-6-92 dated January 6, 1992, increased the interim rate increase, effective January 1, 1992, to 8.7 percent to include the additional cost of power purchased under the two new Power Supply Agreements with Cominco authorized by the Commission Decision of December 18, 1991.

On May 29, 1992, WKP requested approval of the Aesthetic Environment Projects section of its Application for amendments to Rate Schedule 73 - Extensions.

On November 30, 1992, WKP filed an Application to amend the 5.8 percent increase for which it had previously applied to 4.8 percent effective January 1, 1993. In addition, the Company also applied to increase its standard charges applicable to distribution line extensions and to flatten the residential and general service rate structures.

The Application and its amendments, pursuant to Commission Order No. G-123-92, dated December 23, 1992, were set down for hearing on March 8, 1993, in Penticton, B.C.

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On March 5, 1993, WKP filed an Application to further amend the Application filed on November 28, 1991 with respect to the January 1, 1993 rate increase. Specifically, WKP applied to amend the previously applied for increase of 4.8 percent to 5.3 percent effective January 1, 1993. The Applicant stated that this amendment was required to comply with the Commission letter of February 26, 1993, regarding the Decision on WKP power purchase costs from B.C. Hydro.

A portion of the interim rates have been outstanding since January 1, 1992. This is a much longer time than normal and represents an unusual situation and one that the Commission seeks to avoid. However, the extensive and significant changes with regard to WKP's cost of purchased power which entailed lengthy and involved negotiations between WKP and B.C. Hydro necessitated the delay. A revenue requirements hearing during the early part of 1992 would have been neither effective nor efficient when the largest single cost component remained unresolved. The hearing would have incurred unjustified costs to WKP's customers.

The hearing in Penticton commenced on March 8 and was completed with final argument on March 17, 1993.

An intervenor, Mr. Herchak, made a submission (Exhibit 15) wherein he referred to a May 29, 1992 petition to the Commission containing some 1,100 signatures, demanding that "*the British Columbia Utilities Commission request the Government of British Columbia to legislate changes to the B.C. Utilities Act that no interim rate increase be allowed until after a public hearing, or limit rate increase applications to one every three years...*"

The Policy of the Commission, as stated in its May 6, 1993 letter on this subject is:

> "*A request for interim rate relief should respond to the legislation by identifying the 'special circumstance' that leads to the public interest being served by the issuance of an Interim Order. The Commission will consider cost increases and expected sales changes as matters eligible for interim relief, but the Commission will not accept proposed policy changes or other changes to rates or terms and conditions of service that do not have a special circumstance requiring interim relief.*"

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Many legitimate factors can delay a hearing or the issuance of a Decision after a hearing. If interim rate increases (or decreases) were not granted, the utility's retroactive attempts to recover revenue from customers may lead to some misallocation of costs. Also, the amount to be recovered may be large, depending on delays, and this could cause undue budgetary hardships on some customers. In any event, when interim rate increases are denied in the subsequent Decision, the overpayment is returned to the customer with interest.

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2.0 INTEGRATED RESOURCE PLANNING

2.1 Past Resource Planning Uncertainty

In recent years, WKP has faced significant uncertainty with respect to resource planning, due primarily to questions regarding its relationship to B.C. Hydro. Although the Commission had urged the utility to take responsibility for prudent resource planning to meet its customers' long-term energy needs (see Decision of December 20, 1990), purchases from B.C. Hydro under Rate 3807 remained the lowest cost incremental supply-side resource for WKP. Growing reliance on B.C. Hydro was thus a legitimate outcome of prudent resource planning.

The major effort by WKP to develop its own resources, a proposed gas turbine, failed to receive government approval after a contentious regulatory review. In the opinion of WKP management, a gas turbine installation may still be a viable option.

Alberta utilities, Bonneville Power Authority ("BPA") and Independent Power Producers ("IPP's") are all potential non-B.C. Hydro suppliers for WKP. However, without a finalized provincial wheeling policy, WKP was hindered from pursuing contracts with these suppliers.

The replacement of Rate 3807 with Rate 3808, as determined in the April 22, 1993 Commission Decision, provides WKP with long-run information on the price and conditions under which it may purchase electricity from B.C. Hydro. The cost of any purchases from B.C. Hydro in excess of the Customer Demand Limit specified in Rate 3808 will be negotiated by the two parties, with the Commission ensuring that the outcome reflects fair arrangements. It is expected that the price at which electricity in excess of the Customer Demand Limit will be offered by B.C. Hydro will reflect B.C. Hydro's opportunity costs, notably the incremental value of energy and capacity. WKP will be able to use these as one indicator of its own avoided cost.

In addition, the Commission is committed to ensuring wheeling access for WKP on B.C. Hydro's transmission system. This will provide WKP with access to competitive alternatives to B.C. Hydro supply, another indicator of WKP's avoided cost.

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2.2 WKP's Integrated Resource Plan ("IRP") Efforts

WKP presented an interim IRP in the course of the B.C. Hydro Rate 3808 hearing. After the Commission's letter of February 26, 1993, which provided the key elements of the Commission's decision on B.C. Hydro's Rate 3808 Application, WKP prepared a revised IRP for the public hearing (Exhibit 11). The revised interim IRP relies on a load following, combustion gas turbine as the avoided cost, against which all other resource options are compared. WKP identifies the cost of this resource as $103/kW per year for capacity and 2.62 cents/kW.h for energy.
In February, the Commission issued IRP Guidelines (Exhibit 21). While the Guidelines are not detailed, and thereby confer broad discretion upon utility management, they nonetheless decrease WKP's regulatory uncertainty by outlining the Commission's general methodological preferences with respect to IRP.

WKP has recently devoted considerable effort to IRP. In the rate hearing, company witnesses recognized that this effort must be even greater in the future (T. 893), and the Commission is in agreement. The Commission will withhold its assessment of WKP's IRP efforts until the utility has had the opportunity to prepare a detailed IRP that responds to the recent dramatic changes in its resource planning environment. That IRP, which is expected later this year, is required to set the planning context for evaluating and approving WKP resource initiatives, be they on the supply or demand side. However, although it is not possible at this time to fully evaluate WKP's IRP efforts, it is possible to provide preliminary feedback by comparing the general approach of WKP's interim IRP with the Commission's IRP Guidelines. This feedback is presented below.
Guideline #2 emphasizes the importance of demand forecasting methods that allow the utility to distinguish those elements of demand that can be influenced by demand-side management ("DSM") actions. Generally, this implies end-use detail in demand forecasts, since DSM programs usually correspond to specific end-uses. WKP has been moving toward this type of end-use forecasting (T. 883, 1001).

Guidelines #3, #4 and #5 call for identification and measurement of all feasible supply and demand resources, and their combination into resource portfolios. WKP has made progress in characterizing its demand and supply resource options, as witnessed by its interim IRP. However,

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the Commission is looking for further progress in the development of a transparent method for characterizing the financial characteristics of each resource option. The exact methodology used in preparing the interim IRP, or in evaluating DSM program options (Exhibit 87), was not readily apparent from the documentation that was provided.

Of particular interest, given the Commission's Decision on Rate 3808, will be the means by which WKP is able to evaluate alternative demand and supply (including purchase) options for meeting its winter peak demand. Intervenors and the Commission have pointed out that the particular situation facing WKP may favour resource options that are relatively unique. These options, some of which require little or no investment, need to be examined in greater detail. On the supply-side, the utility should assess in depth its prospective B.C. Hydro and non-B.C. Hydro energy and capacity purchase options. These may prove to be less costly than development of WKP supply resources. One unique supply resource might be an agreement by Cominco to interrupt its own demand in order to contribute to WKP's winter peak capacity requirement. On the demand-side, the utility should thoroughly explore all feasible means of reducing its winter peak. Some options are technological mechanisms for load shifting; for example, the utility is advancing a water heater control that would shift water heating to off-peak periods. Other options attempt to change behaviour, for example, by increasing public awareness of the cost of peak electricity use or by charging time-of-use prices. Some options focus on demand that is potentially interruptible, whether by technological or behavioural actions. For example, there may be residential customers who use electricity for space heating yet also have adequate alternate heat sources. In industry, there may be various opportunities for firms to benefit from interruptible contracts that charge a lower price of electricity provided that the utility has the right of interruption for a certain amount of time during peak demand periods. In summary, each DSM program should be evaluated and credited for its ability to contribute to reduction of the peak demand. Guidelines #6 and #7 refer to the production of resource portfolios and an action plan. While WKP's interim IRP is understandably short on details, it nonetheless provides an informative summary of the major resource options as seen by WKP's management. Greater detail is anticipated in the future.

Guideline #8 calls for extensive public involvement in the analysis and selection of resource portfolios, preferably through a process that involves major stakeholders. In recent years, WKP management has established customer advisory panels to provide feedback on various management decisions. But WKP witnesses recognized that the advisory panels are insufficient to provide the

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extent of public involvement envisioned by the IRP Guidelines and noted in the hearing their intention to extend the public involvement process (T. 1045).

2.3 Demand-Side Management ("DSM") Programs

Under its *Rate Schedule 90 - Energy Management Service*, WKP applied for the updating of its existing slate of five DSM programs and an expansion into six new programs. Mr. Ash, Senior Vice-President and Chief Operating Officer of WKP, explained WKP's DSM initiatives in his opening remarks.

> *"We have the people and the desire and the urgent need to implement demand-side management. And I would simply add that given the price of power paid to B.C. Hydro compared with the revenue which results from selling that power, there is an almost unique built-in incentive to achieve DSM savings." (T. 60)*

New programs are forecast to account for 30 percent of the total DSM expenditure in 1993 (Exhibit 6). Four of the new programs are modified versions of B.C. Hydro programs while the fifth is a unique residential program fostering limited applications of ground source heat pumps.

WKP's DSM programs, categorized on a generic basis, are as follows:

Existing DSM Programs:

(i) Home guard
(ii) Energy Efficient Refrigerators (to February 28, 1993)
(iii) Lighting
(iv Efficient Motors
(v) WKP Internal

New DSM Programs:

(i) R2000 Construction (replaces Quality Plus Homes)
(ii) Second Source Heat Pump
(iii) New Building and Process Design
(iv) Building and Process Improvements
(v) Efficient Pumps and Fans
(vi) Efficient Compressors

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In Exhibits 6, 38 and 87 WKP provided total resource unit costs of each program along with benefit/cost ratios relative to purchases from B.C. Hydro under Rate 3807. This analysis suggests that each program is economically justifiable, even without an effort at full social cost accounting, which tends to favour DSM over supply options.

As noted in the previous section in the discussion of IRP, the Commission is not yet satisfied with the information and analysis provided in support of WKP's DSM programs. First, the Commission expects WKP to provide a more complete explanation of the method it follows in estimating and evaluating DSM program costs and penetration rates. Use of a single technology as the sole indicator of avoided cost is but one mechanism for comparing supply and demand resources, and it is not necessarily the most useful in a dynamic resource planning context. Second, the Commission expects WKP to provide a more complete hindsight evaluation of the results of its DSM programs. This includes the important step of designing programs so that their operation provides feedback information to check against initial estimates of costs and penetration rates. Third, this information should be more effectively integrated into the resource planning framework, so that the Commission and the interested public can better assess the contribution of each resource to the capacity and energy needs of WKP.

Although the Commission will require additional information in the future to justify WKP's DSM programs, the Commission is satisfied that the currently proposed programs are all economically justifiable. The Commission approves the changes to Rate Schedule 90 up to December 31, 1993, as applied for by WKP.

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3.0 UTILITY EXPENSES

3.1 Power Purchases

WKP states in its application that the driving force behind the continuing need for rate increases is the requirement for greater quantities of purchased power to meet growing loads (Exhibit 5, Tab 1).

In his summary, Mr. McIntosh (Counsel for WKP) said:

> "*power purchase costs...reflect 60 percent of the increase in revenue requirements in both years.*" (T. 1456)

The Application shows actual power purchase costs of $27.8 million in 1992 and forecasted expenditures of $32.4 million in 1993. These amounts contrast with actual 1991 expenses of $20.4 million. In 1992, 42 percent of the power purchase costs were paid to B.C. Hydro and in 1993 it is forecast that proportion will increase to 48.2 percent. Purchases from Cominco made up the bulk of the remaining power acquisitions.

The final calculations of the cost of B.C. Hydro power are based upon Rate 3807 until September 30, 1993 and Rate 3808 from October 1, 1993, in accordance with the Commission determination contained in its letter of February 26, 1993 concerning the B.C. Hydro Rate 3808 hearing. The Application also took into account the interim increase of 3.9 percent in B.C. Hydro rates as of April 1, 1993 approved by the Commission.

The costs of Cominco power are governed by two new power purchase agreements which became effective on January 1, 1992. The contracts were approved by the Commission after a public hearing in 1991 and provide for a firm source of power until at least December 31, 1999, with the longer of the two agreements expiring September 30, 2005.

The previous Commission Rate Decision of December 20, 1990 pointed out that WKP had not aggressively investigated possible out of province power sources or storage opportunities and this was raised during the hearing. When questioned on this point Mr. Ash stated that WKP has purchased power from the BPA and will investigate possible storage with B.C.Hydro in the future (T. 106).

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Mr. Ash and later Mr. Siddall (Manager, Resources and Systems Operations for WKP) went on to explain that the BPA rates were not competitive with B.C. Hydro's Rate 3807, but that during peak winter months the power was available at a lower cost from the U.S. source.

WKP testified that they had also pursued purchases from Alberta utilities but that there were difficulties in wheeling the power into their service territory. In light of the recent B.C. Hydro Rate 3808 hearing and the Commission's stated desire that B.C. Hydro provide wheeling service to WKP, Mr. Ash anticipated that the company:

> "*would therefore be in discussions with the utilities in Alberta as another option in terms of the alternatives we look to...*" (T. 108)

Several intervenors raised the issue of power purchase costs driving the rate increases and whether or not this was fair to the ratepayers in those parts of WKP's service areas which are not responsible for the large growth in power requirements. As discussed in Section 8.0, the Commission declined to examine this issue in this hearing.

The relationship of the forecasted 1993 power purchase expenses and the budgeted savings through DSM was raised in argument by Mr. Weafer, counsel for the Consumers Association of Canada (B.C. Branch) et al ("CAC et al"). They were concerned that the utility may have a low estimate of DSM potential and this would lead to an over estimation of power purchase costs. The Commission is aware of this concern and will review the results and forecasts in future hearings to ensure that WKP is prudent in their analysis.

3.1.1 Power Purchase Billing Disputes

On September 4, 1992 WKP applied to the Commission for relief from the take-or-pay provisions of the 1986 PPA for the 1991/92 test year. The disputed amount of $3 million relating to energy billed by B.C. Hydro has not been recorded by the Company. On October 14, 1992, WKP made an application pursuant to Section 97 of the Act for the Commission to conduct an inquiry to determine the demand charges applicable to WKP for 1992. The Company has recorded the disputed amount of $2.4 million as a Deferred Charge in 1992 and assumes recovery in 1993 (Exhibit 3, Tab 3, p. 13). By Commission Order No. G-119-92, both matters were referred to the B.C. Hydro Rate 3808 hearing.

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In its April 22, 1993 Decision, the Commission determined that it did not have jurisdiction to decide what contractual terms were in place at the time of the disputes.

In response to questions of the CAC et al's counsel, WKP's counsel noted that WKP was seeking legal advice as to its next step and suggested that any inquiry into the Company's liability was premature (T. 71).

Mr. Bursey, counsel for the Wholesale Customers, said that his clients would like an opportunity to comment on the disposition of the costs if they show up in rates and that it is inappropriate that the matter be deferred indefinitely and at cost to the customers (T. 1523).

The Commission accepts that the amount of $2.424 million paid in the demand billing dispute should stay in a deferred account outside of rate base at this time. Disposition of this account will be determined by the Commission at such time as both billing disputes with B.C. Hydro are resolved through negotiation or as the result of a court decision.

3.2 Operation and Maintenance

In the three-year period from 1990 to forecast 1993, total Operation and Maintenance ("O&M") costs have risen significantly. By far the largest contributor to this escalation has been an increase in labour costs. During this same period material costs have remained substantially unchanged (Exhibit 3, Tab 9, p. 1).

The labour wage rates for both management and union employees were reviewed and the evidence was that utility wage rates were higher than typical wages in the communities being served (T. 318) but lower than B.C. Hydro (T. 56) and some industry norms (T. 611, 1463, Exhibit 77).
There was testimony that maintenance projects suspended during the strike included activities which were cancelled and projects which were deferred, which would be caught up over a period of time with no need for extraordinary expenditures (Exhibit 71). However, there was also testimony which indicated that some programs which were already backlogged could be vulnerable to breakdowns and would require a more aggressive program to catch up, perhaps at the expense of other routine maintenance work (T. 543, 545).

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The Wholesale Customers expressed concern about the increase of 20 percent in total O&M costs in just a two-year period (T. 115). Other intervenors questioned labour costs, the expenditures incurred in supervisor bonuses during the 1992 strike and the executive incentive bonus package. The Electrical Contractors Association of B.C. questioned the efficiency of using in-house personnel and equipment for virtually all field work, including the majority of capital projects.

The Commission is alarmed about the rapid escalation in O&M costs. There is a pressing need for management to constrain controllable costs in these difficult economic times. WKP management needs to re-examine more carefully those areas in which reductions in controllable expenses might be achieved. The Commission expects the utility to present sufficient evidence in its next revenue requirement hearing to justify O & M expenses, and any application will only be considered on this basis.

3.3 Property Taxes

Property taxes paid in 1992 increased by 18.7 percent over 1991 primarily due to the addition of substation equipment to the tax base. This has been partially offset by the creation in 1991 of a deferral account for this purpose, approved in the last Commission Decision. The offset will also apply to 1993 property taxes but, even so, they are forecast to increase by 8.8 percent due to plant additions and estimated mill rate increases.

WKP has expressed its concern to the government and the B.C. Assessment Authority that property tax levels are excessive. However, WKP expects that its revised assessments will include additional generating plant and substation equipment in the Company's 1993 tax base. Unless the mill rate is adjusted downwards to compensate, the impact could be a $2-3 million increase in expenses (Exhibit 5, Tab 1, p. 6). The Company has assumed a 26.5 percent decrease over the 1992 mill rate in order not to reflect this impact in the Rate Application numbers (Exhibit 6, BCUC Information Request, Question 48, p. 117). The Company proposes that any property tax increase would be the subject of a separate pass-through Application. More current assessments from the B.C. Assessment Authority show the impact could increase rates later in 1993 by 4 percent (T. 136).

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Late in the hearing, Mr. Isherwood (Rates and Regulations Manager for WKP) suggested that such increases could be deferred and amortized to avoid any rate impact in 1993 (T. 656).

The Commission is aware that actual numbers for the anticipated increase in property taxes for 1993 are not yet available. For this reason, WKP has assumed a reduction in mill rate to offset increased assessments to produce a zero impact on 1993 expenses. When the actual property tax numbers are available, any Application by WKP for a pass-through of increased tax expense will be given consideration. A decision on whether the full amount of any property tax increase will be charged to 1993 expenses or amortized over a longer period will be made following that consideration.

3.4 Hearing Costs

WKP included an estimate of $300,000 for its cost on the B.C. Hydro Rate 3808 hearing, to be amortized over five years, and $210,000 for the current WKP rate hearing, amortized in 1992 and 1993. Actual costs incurred were $178,000 and $204,000 respectively.

WKP anticipated that a Rate Design hearing would take place in late 1992 or early 1993 and included an amount of $382,000 in 1993 Deferred Charges, to be amortized over three years (Exhibit 3, Tab 3, p. 12). This hearing is not now likely to take place until late 1993 or 1994. During questioning by Mr. Bursey, counsel for the Wholesale Customers, Mr. Ash acknowledged that those costs are more appropriate for 1994 rather than 1993 (T. 155).

The Commission directs that the costs incurred by WKP in the B.C. Hydro Rate 3808 hearing be amortized over five years commencing in 1993. The costs for the WKP 1992/93 Rate hearing are to be recovered in the 1992 and 1993 fiscal years. The Commission agrees that recovery of costs incurred in the upcoming Rate Design hearing be deferred for consideration in 1994 revenue requirements.

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4.0 RATE BASE

4.1 Capital Programs

4.1.1 System Expansion and Upgrading

In its 1989 Rate Decision, the Commission expressed concern for WKP's apparent lack of planning and directed WKP to file a ten-year system development plan with annual updates to that plan. In the 1990 WKP Rate hearing, WKP produced a "*1990 Transmission System Plan*" Volume 1, Subtransmission System, and Volume 2, Bulk Transmission System. These documents identified the expected system upgrading requirements and formed the basis for the development of WKP's capital plans and future development studies such as the South Okanagan Substation ("SOK"). WKP also produced a ten-year capital plan and five-year financial plan. These plans were updated in the 1993 rate hearing.

The Commission has not received updates to WKP's Transmission System planning reports of 1990 or yearly updates of WKP's ten-year capital plans. It is the Commission's impression that WKP's planning and capital improvement programs are suffering from a lack of consistent planning and documented justification. An example of confusion arising out of this lack of documentation is the so-called rebuild of line 43. This line had not been included in any capital plan until the 1992 plan (Exhibit 6, p. 85) but was discussed in the 1990 System Plan and the rebuild was rejected at that time. Testimony of Mr. Dube indicated that this line was still planned for upgrading to 138 kV (T. 695) and that parts had already been completed and had been undergoing various rebuilds to 138 kV standards since 1983 (T. 684). Mr. Loo indicated that WKP had no actual plans to energize this line at 138 kV but planned to review this project (T. 990). Further examples of confusion with respect to WKP's capital projects evolves from the vague use of the term "general upgrading" and "phases 1, 2 and 3" with no supporting documentation of what work is actually being done.

Generation programs such as the Dam Stabilization program appear to be well documented with respect to the overall requirements (i.e. Dam Safety Evaluation Reports by Monenco Engineering and Exhibit 6, p. 85); however, the proposed turbine upgrade projects (Exhibit 6, p. 85) lack justification documentation.

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WKP juggles its personnel between capital and maintenance projects to maintain a stable work force (T. 543, 561, 1462). The submission of the Electrical Contractors Association was that WKP is incurring inefficiencies by this practice when it could be taking advantage of lower costs through a competitive bidding process (T. 380). WKP responded by suggesting their collective agreement was a limiting factor in the "contracting out" of work by the Company (T. 510).

In the Commission's view, the planning and execution functions of WKP's long-range capital programs need substantial improvement. A revised and improved IRP, based on realizable objectives, would be of considerable assistance in directing the Annual Capital Budget programs.

4.1.2 Quality of Service and Reliability

WKP measures distribution customer reliability according to Canadian Electrical Association ("CEA") formats for numbers of outages experienced per customer and duration of outages per customer. WKP's statistics compare favourably with CEA statistics (Exhibit 25, T.502) as compiled for Canadian utilities. Generation forced outages and generation maintenance outages also compare very favourably with statistics generated by the CEA and the National Electric Reliability Council (of which WKP is a member) (Exhibit 23, 24, T. 500). It is also apparent that WKP is collecting sufficient data to adequately assess its system reliability and is performing sufficient analysis to determine what corrective action would be appropriate if needed.

Having noted the above, the Commission also recognizes the evidence in respect of outages and power quality affecting line #43 and complaints from Princeton Light and Power Company, Limited and Apex Alpine Ski Lodge regarding the quality of service and supply from this line. Although WKP appears to have investigated complaints with this line, there does not seem to be adequate follow-up to resolve problems (T. 688). The present situation with PLP being supplied through B.C. Hydro line 1L251 and #43 open at Princeton appears to be a satisfactory temporary solution.

The Commission directs WKP to review the line #43 upgrade program and advise the Commission on the measures taken to ensure a more reliable supply before WKP restores service to PLP through this line.

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4.1.3 Head Office

WKP is completing construction of a new head office in downtown Trail at a cost of approximately $6 million. The Commission was first made aware of the new building in the summer of 1991 when the utility requested and received confirmation that a Certificate of Public Convenience and Necessity ("CPCN") would not be necessary. WKP was advised that the costs incurred in the construction (estimated at that time to be approximately $4.5 million) would be examined at the next revenue requirements hearing.

The Company maintained that the new headquarters were necessary as the existing facilities were no longer adequate. As stated by Mr. Ash:

> *"We looked to alternatives, and the first alternative was to consider expanding where we are. It is a shopping mall. We're on the top floor, but we approached the owners of the shopping mall to see if the space could be expanded. They came back with some very high capital cost to added (sic) very small amounts of space. So we were in the order of $1.5 million just to add, I think it was 3,000 square feet."* (T. 249)

The new facilities will increase office working space by 6,100 square feet. The $6 million cost will not be reflected in the rate base, as WKP plans to sell the building and lease it back. The lease costs will be charged to operations at a levelized rate over a 20 year period. The Company calculates that the new lease will not affect customers rates in 1993, but will increase rates by approximately 0.25 percent in 1994, by 0.16 percent in 1995, and will reduce the impact each year after that.

By charging the lease to operations at a levelized amount, WKP is following Generally Accepted Accounting Principles ("GAAP"). A special accounting order from the Commission would be required in order to charge only the actual amounts of the lease paid in each year. As pointed out by the Company, however, accounting for the lease in this way would result in larger charges to operations to be recovered in rates in future years, rather than having the recovery take place at an even pace over the period of the lease.

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One of the main concerns of those intervenors who questioned the project was the likelihood of finding a purchaser for the building and the effect on customer rates if WKP had to finance the construction itself. The Company is confident that this is not a scenario that would develop. The investment firm of Burns Fry has been engaged to complete the sale/leaseback transaction and a letter was provided by them providing support for WKP's position (Exhibit 69).

The Commission accepts the position taken by WKP and their method of recognizing the lease payments. In the event that the building is not sold and leased back, the costs involved in the project would be reviewed.

4.1.4 Deferred Short-Term Loan Interest

Pursuant to previous Commission Decisions, WKP forecasts its interest rate on short-term loans for regulatory purposes and any difference from actual is deferred and amortized over future years. In 1992, WKP forecast a short-term bank rate of 10.5 percent (Exhibit 3, Tab 2, p. 8). Actual short-term rates were lower, creating a credit of $103,000 to the Deferred Charges Account. This was partially offset by a previous debit of $75,000 and left a balance of $36,000 available to reduce 1993 expenses (Exhibit 8, Wholesale Customers Information Request, p. 2). Counsel for the Wholesale Customers argued that, since the actual costs for 1992 are now known, the credit should be adjusted in the year it occurred (T. 1502). Short-term interest rates are not as volitile as they were when the deferred account was first set up. However, at the present time, a change in treatment would not benefit the customers.

The Commission concurs with WKP that it should continue the practice of forecasting its short-term interest rate and deferring any differences from actual rates for amortization over future years.

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4.1.5 Demand-Side Energy Management Costs

The Commission's December 20, 1990 Decision directed WKP to amortize certain DSM costs over a 20 year period commencing in 1991, which it has done in this Application (Exhibit 3, Tab 3, p. 12). In light of the new mix of programs, WKP proposes that the amortization period be reduced to ten years, effective January 1, 1994.

For 1992 and 1993, the period shall remain at 20 years. The Commission is not prepared to accept at this time that the amortization of all DSM programs should be reduced to ten years. WKP is directed to group projects with similar life expectancies so that consideration can be given, in the future, to more than one amortization period. This will be reviewed at the next revenue requirements hearing.

4.1.5 Working Capital

Working capital is the amount of money required to cover deposits, inventory on hand and accounts receivable, less funds on hand such as employee withholdings. The final allowance for working capital presented by WKP increased from $5.4 million in 1991 to $8.2 million in 1992 and $6.8 million in 1993 (Exhibit 53).

The Applicant, in response to an information request (Exhibit 8, p. 12), indicated that the forecast increase in the working capital was due to the result of a larger lead/lag study which justified a larger allowance, increased power purchase expenses, increased inventory levels and a reduction in reserves (since WKP is no longer self insuring for Workers' Compensation claims).

One large component of the working capital allowance is inventory. Average inventory levels of $5.4 million were thought by one intervenor to be unduly high in comparison to the normal withdrawals from supply of approximately $650,000 in each year. The Company maintained that there was a requirement to keep on hand expensive components, such as transformers, which in an emergency would be required immediately (T. 593).

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The lead/lag study is another major item making up the working capital allowance. One intervenor was concerned that WKP had not completed a review of new billing procedures which would impact the lag study, as directed by the Commission in the 1990 Decision. The Company indicated that the review was now underway, delayed as a result of staff turnover and the 1992 strike.

Commission staff scrutinized the calculation of the allowance and noted that some of the values used had not been updated. The amount representing withholdings from employees was unchanged from the 1990 hearing (Exhibit 53), although employee wages have increased. Also, the "*GST working capital impact*" had not been updated to 1992 or 1993.

In response to an information request WKP stated that the average Goods and Services Tax remittance for 1992 was $317,000 (Exhibit 6, p. 63), while the calculation of the allowance was based on an amount of $280,000. If this reduction of $37,000 in the 1993 calculation of the updated amount is used, there would be a reduction of $100,000 in the total working capital, after rounding.

The Commission is concerned that the two issues raised regarding the working capital allowance may indicate that WKP should devote more care to ensuring that the amounts used in calculating the allowance reflect current conditions. The Commission directs that the 1993 working capital allowance be reduced by $100,000 to a rounded amount of $6.7 million.

4.2 Major Projects

4.2.1 <u>South Okanagan Substation</u>

The SOK was proposed in the mid 1980's as a solution to the bulk supply for the Okanagan Valley. In 1986, B.C. Hydro committed to a joint study with WKP to determine economic and technical feasibility of the project. At that time, terms of a Power Purchase Agreement between the two companies were unresolved, as were interconnection and operating agreements (including cost sharing arrangements). In 1988 WKP purchased the land for the substation. The Commission allowed WKP to put these costs in construction work in progress ("CWIP") collecting AFUDC.

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Volume 2 of the WKP 1990 Transmission System plan examined the technical justification and, to some extent, the economic justification for the substation.

In April, 1992, B.C. Hydro and WKP completed the Joint Technical Study "*Long-Term Supply to the Okanagan Valley*" which explored the technical and economic feasibility of a number of supply options based on power purchases. This study concluded that the SOK was the best choice from an economic standpoint. Subsequently, negotiations for a revised PPA failed and pursuant to an Application from B.C. Hydro in December, 1992, the Commission issued its Decision on April 22, 1993 which defined the costs for WKP's power purchases from B.C. Hydro. About the same time WKP made an application to the Ministry of Energy, Mines and Petroleum Resources ("MEMPR") for an Energy Project Certificate for this project.

B.C. Hydro's response to an information request by Mrs. Slack suggested that the Authority no longer endorses the conclusions of the Joint Study, citing among other problems: unknowns introduced by the breakdown of negotiations of the revised PPA, the unknown extent to which WKP would rely on B.C. Hydro for its resource acquisitions, and the unresolved operating agreements which would justify system loss savings.

In this Application, WKP has projected substantial costs for Engineering and Design work and material acquisition for 1992 and 1993 for the SOK project (Exhibit 3, Tab 3, p. 7 and Exhibit 6, p. 86).

The Commission notes that the construction of this substation may not be supported by B.C. Hydro at this time, that there are still some public issues outstanding and that no approval has yet been received from the MEMPR. Purchase of the land was placed in the Construction Work In Progress account with approval of the Commission. The Commission now directs that future expenditures are to be placed in a deferral account, outside of rate base, pending a decision on the Energy Project Certificate Application.

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4.2.2 Gas Turbine

Following the 1987 decision of the Provincial Government with respect to the Company's application for an Energy Project Certificate for its proposed gas turbine, WKP carried out further studies to locate a suitable site. Commission Order No. G-4-90 had previously approved that the initial Energy Removal Certificate Application and hearing costs of $1,516,000, including AFUDC, be allowed in Rate Base, awaiting final disposition of the project. WKP placed the additional study costs of $502,000, incurred in 1991, into the deferral account pending review at this hearing (Exhibit 3, Tab 3, p. 12). WKP suggested amortization of the account over five years.

As the original costs had only been approved after WKP provided the Commission with a detailed justification of their prudency, Commission counsel suggested WKP provide similar details of the additional costs (T. 400). WKP responded by filing Exhibit 37 and further detailed support.

Counsel for the Wholesale Customers, and Mr. and Mrs. Slack argued for denial of the additional costs (T. 1521, 1635), although Mr. Slack suggested the original costs be amortized over five or ten years (T. 1644). Mr. Scarlett, representing the Electric Consumers Association ("ECA"), proposed that all turbine costs, including investment costs already paid by the rate payers, go into a deferred account. He further suggested that these costs not be recovered from customers but accumulated, and that the disposition of those monies be determined at the time of an Energy Project Certificate hearing into a gas turbine project. At that time all component costs would be subject to disallowance from rate base.

Commission Order No. G-4-90 accepted the original costs of the gas turbine application and hearing in the amount of $1,516,000 for inclusion in rate base. The Commission now directs that this amount be amortized over five years commencing in 1992. The additional costs of $502,000 incurred subsequent to that hearing are to be retained in a deferral account, outside of rate base, until the relevance of a gas turbine project in the South Okanagan has been determined in a revised IRP which has yet to be filed and accepted by the Commission.

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5.0 CAPITAL STRUCTURE

5.1 Introduction

WKP has applied for a 11.32 percent rate of return on rate base for 1992 and a 10.915 percent rate of return on rate base for 1993. These returns reflect the actual capital structure, including equity components of 47.41 percent and 47.31 percent for 1992 and 1993 respectively, and the actual costs of debt and preferred share capital for each of the two years, as well as an estimated cost of common equity capital. Specifically, WKP, supported by the evidence of Dr. R. Evans, has applied for the following:

Capital Structure and Cost of Capital - WKP Application

	1992		1993	
	Proportion	Cost	Proportion	Cost
Long-Term Debt	36.78	12.67	36.81	11.85
Bank Loans	2.25	10.50	3.69	7.00
Deferred Taxes	6.21	0.00	5.84	0.00
Preferred Shares	7.34	7.87	6.35	7.87
Common Equity	47.41	12.33	47.31	12.25
Total	100.00	11.32	100.00	10.915

(Exhibit 3, Tab 2, p. 8 as updated by Exhibit 53, Tab 2, p. 8)

In contrast, Dr. W.R. Waters, appearing for the Wholesale Customers, put forward evidence suggesting that WKP's actual capital structure contained an excessive equity component. As a result, he suggested that the Commission allow a 35 percent common equity component in WKP's capital structure and treat the remaining actual common equity as if it were preferred share equity. This results in a capital structure and cost of capital for WKP as follows:

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Capital Structure and Cost of Capital - Position of Wholesale Customers

	1992		1993	
	Proportion	Cost	Proportion	Cost
Long-Term Debt	36.78	12.67	36.81	11.85
Bank Loans	2.25	10.50	3.69	7.00
Deferred Taxes	6.21	0.00	5.84	0.00
Preferred Shares	7.34	7.87	6.35	7.87
Deemed Pref. Sh.	12.41	7.50	12.31	7.50
Common Equity	35.00	11.25	35.00	11.25
Total	100.00	10.56	100.00	9.98

(Exhibit 59, p. 1, 2, and 3)

5.2 Position of Applicant

Dr. Evans, appearing on behalf of the Applicant, testified that the appropriate common share equity component for WKP's capital structure was 40 to 45 percent for both 1992 and 1993. This assessment was based on a comparison of WKP's business, financial and investment risks with those of other companies with which the utility competes for capital.

Dr. Evans defined business risk as "*all of the physical, economic, political, competitive and regulatory risks to which the income-earning potential of the business assets are exposed*" (Exhibit 4, p. 5). Sources of business risk identified for the Company included risks associated with power supply, the customer base, construction and financing plans, competition, general economic circumstances in the Company's service area and regulatory risk (Exhibit 4, p. 7). In particular, Dr. Evans testified that approximately 65 percent of revenues from industrial sales are forecast to come from companies in the traditionally cyclical lumber and pulp businesses. He stated that another principal industry in the service area, mineral processing, which is expected to contribute approximately 19 percent of WKP's industrial sales in 1992/93, was also cyclical. Dr. Evans stated that the current level of the Canadian dollar and the persistent recession in the U.S. do not auger well for these industries (Exhibit 4, p. 10).

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Dr. Evans stated that financial risk is associated with the way in which the assets of a corporation are financed. The greater the proportion of debt to total capital and the lesser the proportion of common equity, the greater are the financial risks. To assess WKP's financial risk, Dr. Evans compared its capital structure to that of four other Canadian electrical utilities; namely, TransAlta Utilities ("TransAlta"), Canadian Utilities ("CU"), Maritime Electric and Fortis. His examination of WKP's capital structure showed that the Company's prospective common equity ratios exceeded those of the other electric utilities, indicating lesser financial risk on the part of WKP. Dr. Evans testified that the capital structure of each of the other utilities contained a higher proportion of preferred shares and a lower proportion of debt than did WKP's capital structure. Dr. Evans indicated that these two factors suggested the comparison utilities enjoyed lesser financial risk than did WKP, so that, on balance, WKP's financial risk was not substantially different from that of the comparison utilities.

Dr. Evans also examined alternative measures of financial risk, such as pre-tax interest and fixed charge coverage ratios for WKP and for each of the comparison utilities. On the basis of interest coverage ratios, WKP was seen to be of lower risk than three of the other four electrical utilities even though the high proportion of preferred shares in the capital structure of the other utilities improved interest coverage ratios (T. 1092). The fixed charge coverage ratio, which measures the ability of the utility to meet all of its fixed obligations including preferred share dividends, indicated WKP was of lesser risk than all four comparison utilities (Exhibit 4, p. 13).

Dr. Evans defined investment risk as the combination of business and financial risk which is appraised by investors in securities markets (Exhibit 4, p. 6). An evaluation of WKP's bond ratings indicated that it is a lesser rated utility than three of the four comparison utilities. However, Dr. Evans stated that given the size of WKP and the size of its bond issues that it was not realistic to assume that it would be able to improve its bond rating, even if its interest coverages were substantially improved (T. 1268). Similarly, Dr. Evans stated that he could "*conceive of no circumstances*" under which the shares of WKP would achieve the same ratings as those of Canadian Utilities or TransAlta because of the size of the utility (Exhibit 6, p. 155, T. 1278).

On the basis of his analysis, Dr. Evans found that the appropriate common equity component for WKP is 40 to 45 percent although the actual equity component for each of the two years is

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approximately 47 percent. To compensate for the excess equity, Dr. Evans testified that he adjusted the otherwise appropriate rate of return on equity downward by 25 basis points.

Dr. Evans argued against suggestions that the Commission disallow the extra equity and deem a capital structure. He stated that it was very rare for a Commission to deem a capital structure when the operation of the utility is the company's only business (T. 1098, 1099). If the Commission found that WKP had excess equity, Dr. Evans suggested it should allow the actual capital structure to stand but reduce the rate of return on equity which it would otherwise allow, as he had done (T. 1056). However, Dr. Evans stated that if the Commission were to deem a common equity component which was different from the actual equity component, then the Company should be allowed to recapitalize itself to reflect the deemed capital structure (T. 1057, 1058).

In addition, Dr. Evans stated that he was not concerned about an overly thick equity component since WKP was considering the construction of additional generating facilities and such a construction program would lead to a reduction in the Company's common equity ratio (Exhibit 4, p. 3). This was borne out by the Applicant's Five Year Financial and Capital Plans which indicated that the Company anticipated spending approximately $26 million on construction in 1993, $38 million in 1994 and $91 million over the course of the following three years. As a result, the common equity component of the capital structure was expected to decline to 45.6 percent by year-end 1993, 41.8 percent by year-end 1994 and 39.0 percent by year-end 1997 (Exhibit 54). He suggested that, given the possibility of a substantial construction program, deeming a capital structure for WKP should be approached with some caution (T. 1058).

Dr. Evans stated that he was confident that UtiliCorp would take seriously the commitment it had made when acquiring WKP to provide required equity funds on three months notice but that "*the future is uncertain*" (T. 1059). Dr. Evans testified that deeming a lower common equity component:

> "*would increase the uncertainty associated with the availability of common equity in the future, an uncertainty which this Commission actively sought to avoid when West Kootenay was originally acquired by UtiliCorp.*" (T. 1059)

In response to the suggestion that WKP's common equity component be reduced to 35 percent of its capital structure and the excess equity be treated as preferred share equity, Dr. Evans suggested

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that such a reduction could cause coverage ratios to decline and if this were to occur WKP's bond rating would likely decline from A(low) to BBB. Were that to happen, Dr. Evans indicated that WKP's access to debt markets would be considerably lessened since many institutional investors have rules against holding paper which is rated below A(low) (T. 1068).

5.3 Position of Intervenors

Dr. Waters, testifying on behalf of the Wholesale Customers, also examined the business and financial risks facing WKP to determine the appropriate common equity component for the Company's capital structure. Dr. Waters concluded that the appropriate common equity component for WKP was 35 percent for both 1992 and 1993. He recommended that the excess common equity, approximately 12 percent of the capital structure, be treated as preferred share equity, a treatment which "*recognizes the fact that the excess of common equity over the optimal level does, in fact, represent equity financing*" and also provides for a reasonable after-tax return to shareholders on the extra equity (Exhibit 59, p. 2).

Dr. Waters identified three categories into which the business risks faced by WKP can be assigned.

(i) The risk that the rates will not be set at a level sufficient to provide a fair rate of return on total capital invested.

(ii) The risk that a particular period's operating and/or financing costs will exceed those utilized in setting the rates, or that the revenues will fall short of those projected.

(iii) The risk that at some point, WKP will be unable to set rates which are sufficiently high to enable it to recover fully its fixed costs, including those related to financing. The result would be impairment of WKP's ability to service its debt, repay its debt, or both (Exhibit 59, p. 20).

With respect to the first risk, Dr. Waters testified that investors anticipate that the Commission will continue to treat the utilities under its jurisdiction fairly and with respect to the third risk, he stated that there were no developments indicating that WKP faces substantial uncertainties regarding its

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ability to achieve its allowed rate of return (Exhibit 59, p. 21). Further, Dr. Waters stated that WKP's exposure to the second category of risk was minimal, since:

> "*given the nature of the product, the absence of competition from other suppliers of the product, and the limitations on the substitution of other types of energy for electricity, the demand forecasting task facing WKP is at the low end of the spectrum of difficulty and potential for error for individual corporations. Similarly, the fact that the preponderance of WKP's costs are fixed in advance or subject to only small quantity variations place it at the low end of the range of potential error.*" *(Exhibit 59, p. 21)*

In addition, Dr. Waters indicated that WKP has some discretion with respect to what expenses it incurs in any given period. However, he agreed that there were some circumstances such as weather and general economic conditions which the utility could not control (T. 1355). In support of his view that WKP faced minimal business risk, Dr. Waters stated that WKP has consistently demonstrated an ability to achieve a net income close to its allowed rate of return with little year-to-year variability (Exhibit 59, p. 22).

Dr. Waters agreed that the possibility of erosion of WKP's service area had become recently more apparent (T. 1327). Further, he agreed that he had not considered the effect of the Commission's February 26, 1993 determination with respect to B.C. Hydro's Rate 3808 application on WKP's business risk when preparing his evidence (T. 1328), nor had he considered the impact of the determination on WKP's construction plans (T. 1347). However, Dr. Waters rejected the notion that these issues would necessarily be seen by investors as increasing the business risk of WKP (T. 1330, 1333, 1358).

With respect to WKP's construction plans, Dr. Waters stated that he did not expect the Company's external financing requirements to be either so large or so time critical as to warrant the additional cost of financing flexibility inherent in an overly thick capital structure (Exhibit 59, p. 22).

With respect to the financial implications of his proposal, Dr. Waters testified that his recommendation would result in WKP enjoying a 2.9 times before tax interest coverage ratio and a 1.9 times before tax fixed charge coverage ratio (Exhibit 59, p. 24). This interest coverage ratio fell within the range of interest coverage ratios for utilities rated A by the Dominion Bond Rating

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Service for the period 1982 to 1991 and well above the identified range for utilities rated BBB (Exhibit 59, Table 12B).

Dr. Waters agreed that one of the reasons for the current high equity component in WKP's capital structure was the restriction that was placed on the utility as a result of the 1987 UtiliCorp hearing, namely that the dividend payout rate not exceed 44 percent (T. 1343). However, he indicated that the restriction had ended in September of 1992 and, assuming no tax implications, he foresaw no difficulties in UtiliCorp replacing the excess equity with debt capital (T. 1344, 1345, 1346). Dr. Waters stated that his recommendation to treat the excess common equity as preferred equity allowed UtiliCorp time to respond to the deemed structure (T. 1349).

The position of the Wholesale Customers with respect to WKP's capital structure was supported by the CAC et al (T. 1535).

The ECA disputed the idea that Utilicorp B.C. might be unable to provide equity capital at some time in the future, stating that "*Utilicorp B.C. has some $20 million earmarked, we're told, for utility investment, sitting in investments here in Canada.*" (T. 1612).

5.4 Commission Determinations

On the basis of the evidence presented to it during the course of this hearing, the Commission continues to hold the opinion expressed in the 1990 Decision, namely that the recommended common equity component of 40 to 45 percent is not justified by the risks faced by WKP. Indeed, given the risks identified, the Commission agrees with Dr. Waters that the appropriate maximum common equity component is in the order of 35 percent.

Nonetheless, the Commission believes it would be inappropriate to deem a 35 percent capital structure for WKP for the 1992 and 1993 test years for the following reasons. First, the Commission recognizes that the current thick equity structure enjoyed by WKP reflects the 1987 Commission Decision with respect to the purchase of WKP by UtiliCorp United Inc. As part of the conditions for approval of the purchase, UtiliCorp agreed to the following terms:

> "*4. UtiliCorp United and UtiliCorp B.C. will provide WKPL with whatever form of financial support is necessary to allow WKPL to obtain the full*

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> *benefit of UtiliCorp B.C. and UtiliCorp United's financing ability, including without limitation, guaranteeing the indebtedness of WKPL and providing the full faith and credit of UtiliCorp and UtiliCorp B.C.*
>
> *6.* *WKPL will reduce its dividend payouts to 44 percent of its earnings for the next five years.*
>
> *8.* *UtiliCorp United and UtiliCorp B.C. will cause WKPL to maintain an efficient capital structure satisfactory to the Commission and UtiliCorp United or UtiliCorp B.C. will contribute equity within three months of any request by the Commission to achieve or maintain the required capital structure. If UtiliCorp United or UtiliCorp B.C. are unable or unwilling to contribute the required equity themselves, they will, without delay, cause WKPL, and WKPL will use its best efforts, to make an offering of and to issue, equity securities to Canadian investors.*" (Commission Order No. G-31-87)

Although the restriction on dividend payout rates ceased to have effect in September 1992, the Commission believes that it is unrealistic to expect the Company to have restructured its capital to achieve a 35 percent common equity ratio for 1992. The Commission agrees with Dr. Evans that the utility should be allowed to recapitalize to reflect any deemed capital structure (T. 1057, 1058) and believes that such an adjustment should not be required retroactively. Therefore, the Commission accepts the actual equity component of 47.41 percent for test year 1992. The reduction in risk enjoyed by the utility as a result of the thick equity component will be reflected in the allowed rate of return on equity.

In contrast to 1992, the Commission believes that there is sufficient time for the utility to re-organize its 1993 capital structure to reflect a more efficient level of common equity. Further, the Commission does not believe that the evidence presented at the hearing allows it to accept the argument that the Company's future construction activity will cause the utility's common equity component to decrease to prudent levels of its own accord. The Commission is firmly of the mind that all utility resource acquisitions must be justified within the context of the Company's IRP. Although WKP presented an interim IRP as part of its evidence in this hearing (Exhibit 11), the Commission believes that the issue of Commission Order No. G-27-93, which sets out the major terms under which WKP may purchase power from B.C. Hydro up to the 200 MW Customer Demand Limit, means that a new IRP is required before any resource additions can be approved.

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Therefore, the Commission finds that WKP should move to reduce, over time, the common equity component of its capital structure to approximately 35 percent from the current level of approximately 47 percent. In order to ensure that such a reduction takes place, the Commission deems a common equity component of 44.20 percent for the 1993 test year. This level reflects an assumed common equity component of 40 percent by year end. Further, the Commission directs WKP to undertake the necessary steps to achieve a common equity component of approximately 38 percent by year-end 1994 and approximately 35 percent by year-end 1995. For the purposes of establishing rates for the 1993 test year, the excess equity of 3.11 percentage points will be treated as debt and assigned a cost of 9.5 percent as a proxy for the cost of long-term debt. In making this determination as to the treatment of the excess equity, the Commission notes that WKP is acting to eliminate the preferred equity in its capital structure. As done for the 1992 test year, the reduction in risk enjoyed by the utility as a result of the thick equity component will be reflected in a lower rate of return on equity than the Commission would otherwise award. However, as the equity component has decreased over the two years, the gap in the allowed rate of return between the two years is not as large as it would otherwise be.

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6.0 RETURN ON EQUITY

6.1 Position of Applicant

Dr. Evans used three different methods to determine the appropriate rate of return on common equity for WKP. These were:

- The Comparable Earnings test, which estimates the investors required rate of return by measuring the return on book equity achieved by a group of unregulated industrial companies, with the same risk characteristics as the subject utility, over a selected time period;

- Discounted Cash Flow ("DCF") tests which estimate the prospective rate of return on market valued common equity for similar risk companies using a dividend yield plus growth model; and

- Risk Premium tests which estimate the necessary premium over and above the risk free interest rate, as measured by long-term government bonds, that must be paid by the utility to attract investors.

The first two methods calculate the Return on Equity ("ROE") by reference to a selected group of non-regulated companies of similar risk to the utility or for whom the difference in risk from the utility can be estimated, while the third relies on a direct comparison of utility risk to that of the equity market as a whole.

Using data reported by the Financial Post Investment Databank, Dr. Evans selected 54 companies which met specific data criteria and ranked them from lowest to highest risk based on five selected risk measures, three of which related to statistical measures of risk and two to stock rankings. The first 14 non-regulated companies comprised his primary reference group. In addition, Dr. Evans estimated the cost of capital for an alternate reference group comprised of the first 11 non-regulated companies, excluding resource companies.

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Using the comparable earnings test, Dr. Evans found that the indicated rate of return on book value for the highest quality, lowest risk unregulated companies, as represented by his sample, was 12.75 to 13.25 percent. Applying the DCF test to the same group of companies, Dr. Evans found that the investor's required rate of return was 12.0 to 12.25 percent based on market value. However, as utilities are regulated on book value, Dr. Evans stated that it was necessary to adjust this "bare-bones" return upwards to allow the utility to maintain a market to book ratio of 110 to 120 percent. Without such an adjustment, new common equity financing could not be undertaken without the risk of dilution of existing book value. This would normally result in an investors' required rate of return of 12.75 to 13.75 percent; however, as WKP is allowed to recover its out-of-pocket financing costs through its costs of service, Dr. Evans reduced the DCF estimates by 40 basis points to 12.35 to 13.35 percent.

To the results of both the comparable earnings and DCF tests, Dr. Evans made two offsetting adjustments: a 25 basis point increase to reflect the extra risk associated with WKP versus the group of reference companies and a 25 basis point decrease to reflect the reduction in risk associated with the excess equity in WKP's capital structure. However, in response to questioning as to WKP's relative risk ranking vis a vis the group of 54 companies from which he drew his reference group, Dr. Evans indicated that WKP would rank between the tenth and the eleventh company on this list, measured from least risky to most risky, based on the three statistical measures of risk used to rank the companies (T. 1194). Stock ratings are not available for WKP.

Dr. Evans also estimated the investors' required rate of return using the risk premium test. To estimate the amount of premium the equity market requires above the yield of long-term government bonds, Dr. Evans examined three studies:

(i) The Task Force on Retirement Income Policy study which suggested a market risk premium in the 3.25 to 3.75 percent range;

(ii) A Scotia McLeod study which suggested a risk premium of 1.25 to 2.5 percent above the yield on long corporate bonds which themselves incorporate a risk premium of 25 to 75 basis points above long term Government of Canada bonds; and

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(iii) A study by Professors Hatch and White which suggested a risk premium of 5.0 to 5.75 percent.

On the basis of these three studies and after adjusting for factors such as changes in taxation policy over time, Dr. Evans concluded that the appropriate risk premium for low risk, high quality utilities is 3.5 to 4.0 percent. Assuming a Government of Canada long-term bond rate of 8.0 to 8.5 percent for 1993, and the mid-point of his risk premium range, the investors required rate of return is approximately 12.0 percent. However, as this value reflects the return on market value as opposed to book value, Dr. Evans adjusted this result upwards to permit new common share financing, as explained with reference to the DCF test. This result was further adjusted to reflect the difference in risk between high quality utilities (which were assumed to be of the same risk as the sample group of non-regulated companies) and WKP, the impact of the excess equity, and the recovery of out-of-pocket financing costs through the cost of service. As a result, Dr. Evans estimated the cost of new common equity for WKP as indicated by the risk premium test to be 12.35 to 13.1 percent.

Dr. Evans agreed that the risk premium he estimated for high quality low risk utilities of 3.5 to 4.0 percent was higher than the risk premium for the market as a whole as estimated by two of the studies to which he referred and that, generally, utilities were considered less risky than the market as a whole (T. 1287). However, Dr. Evans stated that he did not accept the two lower estimates of the market risk premium as reasonable because of factors such as changes in taxation rules (T. 1287).

Dr. Evans rejected suggestions that the wholly owned subsidiary status of WKP by UtiliCorp negated the need to set the ROE at a level sufficient to attract capital in the market (T. 1207, 1208). Instead, he stated that the utility and its capital needs should be assessed on a stand-alone basis. He suggested that :

> "*... once you start down the path of looking upstream to who owns the company, you are then led into the position of saying that the fair return depends on the happenstance of ownership rather than the underlying risks of the assets providing the service, and that concept I reject, because that would be to say that if West Kootenay were owned by O&Y that this Commission should award a higher rate of return to West Kootenay and its customers should pay more simply because the shares happen to be owned by Olympia and York, which is very risk, as opposed to the shares being owned by say Bell Canada, which is less risky.*" (T. 1101)

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Based on the above three studies, Dr. Evans concluded that the appropriate rate of return on common equity for the 1993 test year was 12.5 to 13.0 percent. Given that the yield on long-term Government of Canada bonds is expected to be approximately 50 basis points higher than the assumed bond yield for 1993, Dr. Evans concluded that the appropriate rate of return for 1992 would also be greater than for 1993. He recommended 12.75 to 13.25 percent.

Both of these recommendations exceed the rates of return on equity applied for by the Company, namely 12.33 percent for 1992 and 12.25 percent for 1993.

6.2 Position of Intervenors

Dr. Waters, appearing for the Wholesale Customers, estimated the appropriate rate of return on common equity for WKP using the DCF test and the Risk Premium test. Dr. Waters rejected the comparable earnings test, stating that:

> "*(i) the concept of comparable earnings does not necessarily have any relationship with the concept of a fair return:*
>
> *(ii) the measurement of comparable earnings (based on accounting data) provides results which are difficult to compare meaningfully across companies and across time.*" (Exhibit 59, p. 61)

As indicated in the previous section, the DCF test is applied to samples of low risk Canadian non-utilities. Using data contained in the Financial Post's computer data base, Dr. Waters selected 208 companies which met specific data criteria and ranked them from lowest to highest risk based on five selected risk measures. His primary sample consisted of the 20 non-utility corporations which, on the basis of five risk measures, were determined to be in the lowest risk septile. Two supplementary samples were also examined, consisting of the 20 largest corporations, inclusive of financial institutions, in the lowest and next to lowest risk septiles, and the 20 largest corporations, exclusive of financial institutions, in the lowest and next to lowest risk septiles.

Dr. Waters testified that the DCF test indicated that the investors' required rate of return for low risk non-utilities was no higher than 11.0 percent. However, based on information developed as part of the risk premium test, Dr. Waters stated that the low risk non-utilities were riskier than the

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lowest risk utilities and required an investors' required rate of return some 70 basis points greater than utilities. Therefore, he deducted this difference from the 11 percent value determined above and found that the investors required rate of return for lowest risk utilities was approximately 10.25 percent (Exhibit 59, p. 59). However, due to unsettled conditions in the financial markets, Dr. Waters concluded that the risk premium test should be given greater weight in determining the cost of equity capital.

To undertake the risk premium test, Dr. Waters estimated the required risk premium for the Canadian equity market as a whole, for his sample of low risk non-utilities and for lowest risk utilities. Using historical data from five different sources, he concluded that the equity market risk premium was in the range of 4.0 to 4.5 percent. Based on three measures of share price volatility and two measures of per share earnings volatility, Dr. Waters determined that his sample of low risk non-utilities had approximately two-thirds of the risk of the equity market as a whole (Exhibit 59, p. 50) while low risk high grade utilities were only one-half as risky as the market. (Exhibit 59, p. 52) giving rise to premiums of 3.0 and 2.3 percentage points respectively.

Assuming a long-term Government of Canada bond yield of 8.0 to 8.5 percent for 1993, Dr. Waters determined the investor's required rate of return for lowest risk utilities by adding to it the premium determined above. This gives rise to an estimate of 10.25 to 10.75 percent. To this number he added 25 basis points to account for the difference in risk between WKP and the lowest risk utilities and a further 50 basis points as a margin of safety or allowance for "*flotation costs*". Dr. Waters stated that this second adjustment was intended to cover costs associated with the issue of new common equity and minimize the possibility of diluting shareholder equity if issues of new equity needed to be made into unfavourable markets (Exhibit 59, p. 4). Thus, the risk premium test indicated that the appropriate rate of return on common equity for WKP in 1993 was 11.0 to 11.5 percent.

Based on the above, Dr. Waters concluded that WKP's financial integrity would be maintained if its return on common equity were set in the range of 11.0 to 11.5 percent for the 1993 test year. The same range was recommended for 1992.

The position of the Wholesale Customers was supported by the CAC et al.

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The Regional Districts of Central Kootenay and Kootenay Boundary argued that the evidence of both Dr. Evans and Dr. Waters focused on the economic health and security of the utility and its investors and did not take into account the ability of the utility's customers to pay or the specific economic circumstances of the region (T. 1564). Characterizing such an approach as unacceptable to the public in the current "*tough*" economic environment, they called upon the Commission to administer to WKP "*a dose of reality*" (T. 1565) and allow the Company a rate of return on equity of 10 percent. They argued that such a rate met all the legal and economic criteria that must be met in setting the fair rate of return and protected the public interest.

In support of this suggestion, the Regional Districts noted that the blended or merged rate of return on common and preferred equity which flowed from Dr. Waters capital structure proposal was 10.1 percent (T. 1566, Exhibit 51, Question No. 2).

The ECA argued that it was inappropriate to award WKP the same rate of return that it would merit if it were a publicly traded company since the 100 percent ownership of WKP by UtiliCorp B.C. lessened the risk borne by the investor in the utility. As an example of the lessened risk, the ECA noted that WKP could issue additional shares to UtiliCorp B.C. without risk of diluting the value of the existing shares (T. 1610).

As a result, the ECA argued that the appropriate rate of return on common equity was no more than 10 percent.

6.3 Commission Determinations

As indicated in Section 5.4, the Commission believes that the current level of common equity contained in WKP's capital structure substantially exceeds that which is appropriate. Although Dr. Evans accounted for the excess equity by recommending a rate of return on common equity 25 basis points less than he would otherwise have recommended, the Commission believes this adjustment to his findings does not adequately reflect the costs imposed on customers by the excessive equity component.

Further, the Commission is not convinced that the cost of common equity capital estimated by Dr. Evans through the comparable earnings, DCF and Risk Premium tests reflects the costs faced

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by WKP. In particular, the Commission notes, that on the basis of three of the five measures used by Dr. Evans to rank companies by risk, WKP ranks between the tenth and eleventh company of the 54 companies from which Dr. Evans drew his sample, when ranking is done from least to greatest risk. In addition, the Commission is not convinced that the equity risk premium for low risk high grade utilities is appropriately estimated at a value which exceeds two of the studies on which Dr. Evans relied to estimate the market as a whole. The Commission also recognizes the discrepancies between the risk premiums estimated by Dr. Evans and Dr. Waters.

The Commission does not accept the argument that the appropriate rate of return on equity should be set with regard to the ability of customers to pay. While sympathetic to the concerns of the Regional Districts, the Commission agrees with Dr. Evans that returns to invested capital should be based on the best alternative use of that capital (its opportunity cost) and that this principle of regulation offers the greatest long run benefits to consumers.

The Commission determines that the appropriate rate of return on common equity for 1992 is 11.75 percent and for 1993 is 11.5 percent.

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7.0 RATE DESIGN CHANGES

7.1 Residential Rate Flattening

In Commission Decision and Order No. G-109-90 dated December 20, 1990, the Commission directed WKP as follows:

> *"Thus, the Commission directs the Company to study specific load changes, by rate classes, in order to better understand the effect of load curtailment and growth at the margin. The purpose of such a study is to identify the sources of negative contribution margin and to target changes in rate design or DSM that will alleviate this anomaly."*

and,

> *"In addition to the amended connection charge directed on Page 18 of this decision, which is intended to recover the full cost and other related charges, new tariff rates should be developed by July 1, 1991. The process should include effective public consultation with interested parties, and should have the objective of removing the negative margin referred to above."*

In June 1991 the Company responded to these directions by filing a proposal to flatten its residential rate structure. After examining the proposal, the Commission directed WKP to seek customer input. WKP reviewed the proposal with its Customer Advisory Panels and with other interested groups throughout its service area.

Currently, WKP's residential customers are served under one of three rate schedules. Schedule 1 applies to all residential customers in the Trail/Rossland area, while Schedule 3 and Schedule 4 apply to non-electric heat and electric heat customers, respectively, elsewhere in the service area. At present, all three of the Schedules consist of three blocks: a fixed bimonthly charge for the first 40 kW.h of energy, which must be paid whether or not the energy is taken, and a per kW.h charge for each of the remaining two blocks. The per unit cost declines with each successive block.

The proposed rate structure consists of a basic bimonthly charge, which must be paid whether or not any energy is taken but to which no energy attaches, and a single per kW.h charge which applies to all units of energy taken. A comparison of the existing and proposed changes is given in the following table.

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Existing Rate Schedule 1	Proposed Rate Schedule 1
For a Two Month Period	For a Two Month Period
First 40 kW.h or less $14.98 Next 360 kW.h at 5.176¢/kW.h All over 400 kW.h at 3.847¢/kW.h	Basic Charge $14.91 All Energy 4.044¢/kW.h
Minimum $14.98 Discount 10 percent	Net Basic $13.42 Discount 10 percent
Existing Rate Schedule 3 and 4	**Proposed Rate Schedule 3 and 4**
For a Two Month Period	For a Two Month Period
First 40 kW.h or less $14.98 Next 360 kW.h at 6.633¢/kW.h All over 400 kW.h at 3.847¢/kW.h	Basic Charge $18.91 All Energy 4.044¢/kW.h
Minimum $14.98 Discount 10 percent	Net Basic $17.02 Discount 10 percent

(Exhibit 6, pp. 140 and 141, T. 1014)

As shown in the table, under the current rate schedules, the fixed bi-monthly charge is the same for all rate schedules but the energy charge for the second block is lower for Schedule 1 than for Schedules 3 and 4. Under the proposed schedules, the energy charge is the same for all three schedules but the basic charge is lower under Schedule 1 than under Schedules 3 and 4. WKP stated that there was no "*necessary rationale*" for the differential in fixed charges between Schedule 1 and Schedules 3 and 4, although it maintained the differential that is present in the existing rate schedules. WKP proposes to phase out the differential over time. However, the Company stated that to do so immediately would result in a transfer of costs from the customers of one rate schedule to the other and, in addition, would result in rate impacts which the Company wished to avoid (Exhibit 6, p. 136, T. 1017). The Company showed that the financial impacts from the proposed rate changes ranged from declines of $15 per annum (-5.4 percent) for customers consuming 4500 kW.h per annum to increases of $46 per annum (3.1 percent) for customers consuming 40,000 kW.h per annum. Customers using less than 500 kW.h per annum, identified primarily as seasonally used cottages, vacant houses, garages etc. (T. 785), faced increases of approximately $21 per annum (21 percent) as a result of the increase to the basic charge.

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WKP stated that it had not updated its cost of service study since its 1983 Rate Design Application but believed the residential rate flattening proposal was non-controversial and provided a platform to progress to:

> ". . . *a rate structure with either seasonal or inverted characteristics or higher energy and/or demand in basic charges. . .*" (Exhibit 6, p. 136)

In support of its non-controversial nature, WKP testified that the proposal had received "*unanimous support ... from all parties contacted*" (Exhibit 3, Tab 17, p. 1). In addition, WKP stated that the proposed rates: were easier to understand, established a distinction between the costs of administering an account and the cost of energy, moved closer to a structure which recognizes the company's increasing marginal costs, and encouraged energy savings (Exhibit 3, Tab 17, p. 4).

WKP indicated it plans to file a complete rate design application by the end of 1993 (T. 1023).

As a general principle, the Commission does not favour piecemeal rate design changes, and would have preferred to see WKP file a complete rate design package, including a cost of service study, for the Commission's consideration. However, in this case, the Commission believes the Company has provided sufficient justification for regulatory consideration of the residential rate flattening proposal.

Based on the evidence which showed that the declining block rate structure currently embedded in the residential rate schedules is inconsistent with the increasing marginal cost structure faced by the utility, the Commission finds that it is appropriate for the utility to move to a flat residential rate structure. The Commission notes that this structure has received substantial approval from the customers most directly affected. In addition, the Commission approves the change from a minimum charge which includes an energy component to a basic charge which does not.

However, the Commission is concerned about the proposal to increase the level of the basic charge for customers served under Schedules 3 and 4 from the current minimum charge level while maintaining approximately the same level of charge for customers served under Schedule 1. The Company has testified that the difference in the basic charges for the various rate schedules does not reflect differences in the costs of serving the customers under the different rate schedules, but has been instituted to reflect a historical differential between the rates to prevent the transfer of revenue responsibility from customers served under one rate schedule to another, and to prevent

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undue rate impacts on high use customers which would occur if more of the revenue requirement is collected through the energy charge.

Without evidence from a cost of service study to support the level of the basic charge, the Commission does not accept that the basic charge for Schedules 3 and 4 should be increased from the level of the minimum charge currently being collected. In making this determination, the Commission recognizes that there will be some shifting of the revenue requirement between Schedule 1 and Schedules 3 and 4; however, as the Company has presented no evidence to indicate that the costs imposed by the customers of one schedule are different from the costs imposed by the other customers, such a shift is acceptable.

Therefore the Commission orders that WKP proceed with its proposal to flatten residential rates effective October 1, 1993 but requires the Company to keep the basic charge for both schedules at the current minimum charge level of $14.98 per two month period.

7.2 General Service Rate Restructuring

By Order No. G-109-90, the Commission directed WKP:

> "*...to file tariffs which confirm the interim of 5.5 percent for 1990, to file tariffs for 1991 incorporating an increase of 5 percent to all customer classes and to apply the 1991 commercial rate allocation to reduce the rate in the second energy block of Rate Schedule 20, Small General Service and Rate Schedule 21, General Service effective January 1, 1991.*"

WKP has complied with this Order and now seeks permission to further reduce the revenues derived from the second block of Rate Schedules 20 and 21 by an amount of $700,000. The Company stated that such a reduction would have the impact of bringing the second and third blocks closer together as a step towards the eventual flattening of the rate, and would provide for a more equitable cost recovery from this class.

As indicated above, WKP has not produced a cost of service study since 1983 and therefore has no direct evidence in support of its assertion that reducing the amount of revenue collected from the general service customers will result in a more equitable cost recovery. However, the Company provided charts indicating that WKP's general service rates as a percentage of residential rates was

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substantially greater than the ratio for several other Canadian electrical utilities. In addition, WKP showed that its small commercial rate significantly exceeded that of B.C. Hydro while all of its other rates fell below B.C. Hydro's rates (Exhibit 3, Tab 17, pp. 9-11).

The Commission accepts the evidence put forward by WKP in support of the General Service rate restructuring and orders the utility to make the proposed changes effective October 1, 1993.

7.3 Rate Schedule 73 - Distribution Line Extension Policy

This is an Application to increase the costs charged to customers for extending distribution service (Exhibit 3, Tab 16).

The Application increases the pole-in-place costs used to calculate the customer contribution to construction by approximately 24 percent and the monthly extension charge to new customers by 100 percent.

WKP estimates that the revised charges would increase customer contribution in aid of construction by $110,000 annually. The resultant reduction in rate base would decrease revenue requirements by $18,000 per year.

The Commission accepts the revision in charges and directs that an amended Rate Schedule be filed for approval. The Commission points out that, in similar cases, it would be desirable to amend such charges more frequently to avoid subsidization by other customers.

7.4 Rate Schedule 73 - Environmental Aesthetics

On April 2, 1992, WKP applied to the Commission to amend Rate Schedule 73 - Extensions to add a provision to enable WKP to participate in municipal projects to meet environmental and visual aesthetic objectives. Under the policy WKP would contribute one-third of the costs of placing electric service underground for environmental impact, aesthetic reasons, and/or in response to community/public redevelopment projects. It was anticipated that one-third of the costs would be paid by the Province but the WKP share was not dependent upon this participation. The initial budget was set at $100,000 annually. Requests exceeding the allocation would be

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resubmitted the following year and would receive priority. On June 11, 1992 the Commission advised WKP the request was denied and informed the Company that the Application would be considered at the next Rate Hearing.

The Company re-submitted the Tariff in this hearing (Exhibit 48) with a proposed effective date of January 1, 1994. The proposal is modelled after that of B.C. Hydro, except that the B.C. Hydro policy is not filed as a Tariff (T. 772). Commission Counsel's cross-examination noted some problems with the proposal, namely that the program would not be available immediately to wholesale municipal customers and that it was in conflict with the current WKP policy on above-ground service (T. 926). WKP viewed the undergrounding of lines in urban centres as being of benefit to its customers over the long-term.

The Commission is concerned about the potential discriminatory effects of this proposed Rate Schedule and the potential for subsidization of some projects by the ratepayers in general. While the Commission supports the purpose and intent of this schedule, it is of the view that the policy requires further investigation and better refinement. The Commission encourages WKP to return at the rate design hearing with a proposal that more completely reflects the assignment of costs to those who benefit. This amendment application is rejected.

7.5 Rate Schedule 82 - New/Upgraded Service Connection Fee

In its December 20, 1990 Decision the Commission, at page 18, directed WKP to apply for a revised connection fee "*so that new installations of residential space heating will pay the full cost of the connection and other related costs.*" On January 21, 1991, WKP applied to change the connection fee for residential service to add a size of service component of $10 per amp. above 100 amps for single-phase service and $20 per amp. for three-phase service. The Application also requested approval to add a size of service component of $40 for each kW over 20 kW to the connection fee for general service and industrial space heating. WKP also suggested an increase from $27 to $200 in the basic service connection fee. The Commission directed on June 14, 1991 "*that WKP undertake public consultative information sessions.*"

On January 8, 1993 WKP amended its Application to modify Rate Schedule 82 to change the connection fees for new or upgraded service for residential and general service customers (Exhibit 5, Tab 3). The proposed fee structure is designed to move towards a more complete

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recovery of the costs of providing the service. For both classes of service there would be an increase in the basic connection fee from $27 to $200. For residential service only, WKP has proposed an additional variable component of $2 per amp. for single phase service above 100 amps. and $4 per amp. for three-phase service above zero amps. Examples of the fees for new or increased residential service, based on normal voltages, would be:

(i)	For a 100 amp. single-phase service:	$200 fee.
(ii)	For a 200 amp. single-phase service: $200 basic fee plus $2 per amp over 100 amps.	$400 fee.
(iii)	For a 200 amp. three-phase service: $200 basic fee plus $4 per amp over zero amps.	$1,000 fee.

The Application provides the cost basis for the fees. In the above examples, the fees for single-phase service represent about one half of the additional distribution plant cost and the fee for three-phase service represents about one quarter of this additional cost (Exhibit 5, Tab 3, p. 3).

The evidence shows that WKP obtained public input on the proposals primarily through its customer advisory panels. WKP testified that some survey results of residential customers indicated that a single-phase service fee greater than $2 per amp. would be supported by the residential class (T. 455). The customer advisory panel at Castlegar, on the other hand, felt that a $10 per amp. fee was excessive (Exhibit 6, p. 237).

WKP testified that the new fees do not have an impact on revenue requirements because the fees are customer contributions in aid of construction (T. 1030).

The Commission approves the application for a new connection fee to take effect on October 1, 1993. This will provide WKP time to give sufficient notice to customers who may wish to modify their construction plans. WKP is also directed to apply in its next rate application, for a further revision to its connection fee for general service customers so as to add a "size of service" component.

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One benefit of the increased connection fee for large amperage services is to encourage customers to minimize the size of their connection requirements by implementing maximum energy efficiency. Further changes to service connection policies could encourage efficient installation for all customers where this can be demonstrated to be in the interests of the customers and the utility. WKP is directed to continue to explore how its connection fee policy may be used in support of broad utility objectives including cost recovery, efficient electricity use and Integrated Resource Planning.

WKP is to report its finding and any recommendations as part of its next rate application.

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8.0 REGIONAL DISTRICT PROPOSALS

The Regional District of Central Kootenay and the Regional District of Kootenay Boundary ("Regional Districts") appeared as intervenors at the hearing. The Regional Districts are made up of 14 municipalities and 16 electoral areas with an estimated population of 85,000 persons (Exhibit 85).

They took the position that, for various reasons, the Application by WKP should be denied and a differential rate be designed for the Kootenays and the Okanagan areas (T. 1552).

The Regional Districts stated that the territories under their jurisdiction had been disadvantaged as a result of the loss of productive land through flooding by dams and reservoirs used for the generation of power to serve primarily other areas of British Columbia (Exhibit 85). Mr. McDannold, counsel for the Regional Districts, argued that, because the Districts forego taxation on most B.C. Hydro properties, local tax-payers are required to pay 40 percent more on their individual municipal and property taxes (T. 1553). The Regional Districts also felt that there was an additional inequity in that the municipal utilities in the Okanagan are able to resell the power purchased from WKP and use the profits to lower their own general tax rates (Exhibit 85).

Another concern of the Regional Districts was the accumulative impact of successive rate increases which, together, resulted in what they considered to be undue rate shock. Rate increases were being caused by increases in power purchase costs, water rental fees, taxation and operating costs. Counsel for the Regional Districts pointed out that the 1992/93 increases applied for, together with other increases forecast by WKP within the next few years, would result in rate increases of over 50 percent in just six years (T. 1553).

The Regional Districts argued that the Okanagan area was the most costly area for WKP to serve. The rapid growth in electricity sales in the area required more costly power purchases by WKP from B.C. Hydro. Transmitting power to the Okanagan over long distances on old power lines resulted in high line losses and added cost. In addition, the high capital cost of replacing and upgrading these lines placed an unreasonable and discriminatory burden on customers in the Central Kootenay and the Kootenay Boundary Regional Districts. Their counsel maintained that it was unreasonable and unduly discriminatory for power consumers in these Regional Districts to continue to pay for the ever-increasing high costs of supplying power to the Okanagan (T. 1552).

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Based on these arguments, the Regional Districts requested the design of differential rates for the Kootenay and Okanagan areas. They also suggested that the Okanagan portion of the WKP service area ought to be transferred from WKP to B.C. Hydro. In presenting final argument, Mr. McDannold stated at T. 1555:

> "*Until the Commission at the next WKP rate design hearing has the opportunity to deal with both of these issues of differential rates and adjustment of the WKP service area, they submit that WKP ought not to be granted the massive rate increases which it is currently seeking, nor should they be granted the automatic flow-through costs, nor should they get the automatic rate increases and increases in the rates of return which they are now seeking.*"

Several issues have been raised. The proximity of a region to generation facilities, the negative impact of dams and reservoirs on a region and the consideration for economically disadvantaged areas are among these. In fairness, these issues cannot be examined in only one region of the province. They have far-reaching implications for the rate-making principles that the Commission applies to the entire province. As well, they have implications for public policy initiatives undertaken by government.

The argument for differential rates or service area re-allocation are not without merit. However, there are counter-arguments and challenges which were not examined in detail at this rate hearing. In particular, the postage-stamp rate making principles have served the whole service territory well for many years. The Commission must also consider the long-term implications of a move to differential rates within the context of a more competitive electricity policy in British Columbia.

At the commencement of this rate hearing, the Commission ruled that the proposition that a preliminary discussion of the evidence of the two Regional Districts at this hearing would be of benefit to participants in a future rate design hearing (T. 35). At this time the Commission is of the view that it is unable to accept the proposals for a differential rate between the Kootenays and the Okanagan or severance of the Okanagan area from the WKP service area.

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DATED at the City of Vancouver, in the Province of British Columbia this day of June, 1993.

Dr. M.K. Jaccard
Chairperson

L.R. Barr
Deputy Chairperson

K.L. Hall
Commissioner

APPEARANCES

M. MOSELEY	Commission Counsel
G. MACINTOSH, Q.C. R. HOBBS	West Kootenay Power Ltd.
C. WEAFER	Consumers' Association of Canada (B.C. Branch), B.C. Old Age Pensions' Organization, Counsel of Senior Citizens' Organizations of B.C., Federated Anti-Poverty Groups of B.C., West End Seniors' Network
D. AVREN	British Columbia Hydro and Power Authority
D. BURSEY	City of Kelowna, District of Summerland, City of Grand Forks, City of Penticton, City of Nelson
G . McDANNOLD	Regional Districts of Central Kootenay and Kootenay Boundary
W. MENNELL	Fairview Heights Irrigation District
E. BEALLE	Keremeos Irrigation District
J. HALL	Princeton Light & Power Company, Limited
R. MORTON D. BETTS	Apex Alpine Recreations Ltd.
D. SCARLETT	Kootenay-Okanagan Electric Consumers Association
J. and B. SLACK	Themselves
D. GEORGE	Himself
M. HERCHAK	Himself
C. PILKEY	Electrical Contractors Association of B.C.

LIST OF EXHIBITS

	Exhibit No.
West Kootenay Power Ltd. Rate Application dated November 28, 1991, Volume 1	1
West Kootenay Power Ltd. Rate Application dated November 28, 1991, Volume 2	2
West Kootenay Power Ltd. Rate Application dated November 30, 1992, Volume 3	3
West Kootenay Power Ltd. Rate Application dated January 8, 1993, Volume 4	4
Update to West Kootenay Power Ltd. Rate Application Volume 4	4A
West Kootenay Power Ltd. Rate Application dated January 8, 1993, Volume 5	5
West Kootenay Power Ltd. Rate Application dated February 11, 1993, Volume 6	6
West Kootenay Power Ltd. Rate Application dated February 25, 1993, Volume 7	7
West Kootenay Power Ltd. Rate Application dated March 5, 1993, Volume	8
Affidavit of Publication of Robert Hobbs	9
Errata Sheet for Exhibits 1 to 8	10
Interim Report on Resource Planning at West Kootenay Power Ltd.	11
Letter from West Kootenay Power Ltd to Commission dated March 5, 1993	12
February 26, 1993 Letter of Decision of Commission Regarding B.C. Hydro Rate Schedule 3808 Application	13
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EXECUTIVE SUMMARY

The Commission has made the following determinations:

1. The appropriate rate of return on common equity for 1992 is 11.75 percent and for 1993 is 11.50 percent.

2. The Commission accepts the actual equity component of 47.41 percent for 1992 and deems a common equity component of 44.20 percent for 1993.

3. WKP is directed to undertake the necessary steps to achieve a common equity component of approximately 38 percent by year-end 1994 and approximately 35 percent by year-end 1995.

4. WKP is to proceed with its proposal to flatten residential rates effective October 1, 1993 but is required to keep the basic charge level of $14.98 per two month period.

5. The proposed changes to Rate Schedule 90 up to December 31, 1993 are accepted.

6. The amortization of energy management programs will continue over a 20 year period.

7. The proposed changes to the General Service rate are accepted as of October 1, 1993.

8. Requested changes to Rate Schedule 73 are also approved with the exception of the provision to meet environmental and visual aesthetics objectives.

9. A new connection fee is approved to take effect on October 1, 1993 for Rate Schedule 82.

10. Future expenditures on the South Okanagan Substation, other than land acquisition, are to be placed in a deferral account outside of rate base, pending a decision on the Energy Project Certificate Application.

11. The Gas Turbine costs of $1,516,000 are directed to be amortized over a five year period commencing in 1992. Additional costs of $502,000 incurred in 1991 are to be retained in a deferral account outside of rate base.

12. The method of recognizing the lease payments for the new head office is accepted.

13. WKP costs for the B.C. Hydro Rate 3808 hearing are to be amortized over a period of five years commencing in 1993. The costs for the WKP 1992/93 Revenue Requirements Hearing are to be recovered in the 1992 and 1993 periods.

14. The amount of $2.424 million paid in the demand billing dispute should stay in a deferred account at this time.

15. The proposals for a differential rate between the Kootenays and the Okanagan and for severance of the Okanagan areas from the WKP service area are not accepted.

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1. How many projects and expenditures that have been approved by BCUC have not been started? Also, how many have been started but not completed? Describe the projects and the associated amounts of unspent, approved monies.

Response:

All but one of the projects approved by the BCUC in the 2011 Capital Plan have been started. None of the projects approved are complete to date but are either in the execution or close-out stage and are expected to be substantially complete by year end.

The HR Payroll Upgrade project included in the 2011 capital plan, budgeted at $0.446 million, was not executed. This project was to replace the existing payroll provider, ADP, with a new provider, Ceridian, to meet payroll processing requirements that ADP could no longer deliver. When the project was developed ADP was unable to commit to providing the software changes within two years that would enable them to continue to provide payroll services for FortisBC. However, after the 2011 Capital Plan had been submitted and approved, ADP advised that they were able to provide the necessary updates to their software to meet FortisBC's payroll requirements. Thus, the Ceridian conversion was no longer required. The upgrade to ADP is estimated to cost $20,000.

2. State Fortis BC's total revenue in each of the last 5 years.

Response:

FortisBC's total actual electricity sales revenue in each of the last five years (2006-2010) has been provided below:

Table Gabana IR1 2

	2006	2007	2008	2009	2010
			($000s)		
FortisBC Electricity Sales Revenue (Actual):	203,362	209,651	220,909	238,572	246,791

3. State individually the amounts of dividends, capital, interest and principal paid from Fortis BC to all related parties in each of the last five years and what percentage of total revenue it represented.

Response:

Please see Table Gabana IR1 3 below.

Table Gabana IR1 3 - Amounts Paid To Related Parties

	2010	2009	2008 ($000s)	2007	2006
Dividends	15,000	14,500	13,400	11,800	10,200
Capital	-	-	-	-	-
Interest	-	-	-	480	104
Principal (Borrowed and Repaid)	-	-	-	31,000	10,000
Total Paid	15,000	14,500	13,400	43,280	20,304
Total Electricity Revenue	246,791	238,572	220,909	209,651	203,362
% of Total Electricity Revenue	6.1%	6.1%	6.1%	20.6%	10.0%

4. Fortis BC is permitted a guaranteed 9.5% return on investment. Provide a continuity schedule of this base investment value for each of the last 5 years showing opening balance, additions, deletions, adjustments and closing balance. Also provide listing of major projects and expenditures for the additions.

Response:

FortisBC's approved Return on Equity (ROE) for each of the last five years has been as follows:

2006: 9.20%

2007: 8.77%

2008: 9.02%

2009: 8.87%

2010: 9.90%

2011: 9.90%

The 2012 and 2013 RRA reflects an ROE of 9.90%.

The approved ROE for a utility is not a guarantee of return on the utility's investment. It is the basis upon which equity returns are calculated for rate setting purposes. The Company has the ongoing obligation to prudently manage costs and is exposed to many cost variances which can affect the actual level of return.

The Tables below provide the continuity schedule of the Utility Rate Base along with listing of major projects and their costs for the last five years.

UTILITY RATE BASE
CONTINUITY SCHEDULE
AS AT DECEMBER 31

		Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010
				($000s)		
1	Plant in Service, January 1	820,437	943,920	1,062,070	1,165,457	1,273,476
2	Net Additions	107,875	118,150	103,387	108,019	130,141
3	Plant in Service, December 31	928,312	1,062,070	1,165,457	1,273,476	1,403,617
4						
5	**Add:**					
6	CWIP not subject to AFUDC	33,208	13,112	7,214	5,913	7,213
7	Plant Acquisition Adjustment	11,912	11,912	11,912	11,912	11,912
8	Deferred and Preliminary Charges	18,311	14,473	16,227	15,508	16,698
9						
10		991,743	1,101,567	1,200,810	1,306,809	1,439,440
11	**Less:**					
12	Accumulated Depreciation					
13	and Amortization	219,975	250,323	275,128	301,384	323,203
14	Contributions in Aid of Construction	66,132	78,351	86,783	90,267	93,763
15		286,107	328,674	361,911	391,651	416,967
16						
17	Depreciated Rate Base	705,636	772,893	838,899	915,158	1,022,473
18						
19	Prior Year Depreciated Utility Rate Base	631,231	712,911	772,893	838,899	915,158
20						
21	Mean Depreciated Utility Rate Base	668,434	742,902	805,896	877,029	968,815
22						
23	**Add:**					
24	Allowance for Working Capital	7,511	6,519	8,261	7,231	5,756
25	Adjustment for Capital Additions	(4,806)	(2,878)	(11,591)	(16,577)	(28,934)
26						
27	Mid-Year Utility Rate Base	671,138	746,543	802,566	867,683	945,637

Note: Minor differences due to rounding

MAJOR PROJECTS PLANT ADDITION SCHEDULE

		2006	2007	2008	2009	2010	Total
1	**PLANT ADDITIONS - MAJOR PROJECTS**			($000s)			
2	**Generation Projects:**						
3	P1U1 Upgrade & Life Extensions	12,737	118	-	-	-	**12,855**
4	P1U3 Upgrade & Life Extension	-	14,175	453	-	-	**14,628**
5	P3U1 Life Extention	-	221	-	-	15,342	**15,564**
6	P3U3 Life Extention	-	1	-	12,827	-	**12,827**
		12,737	**14,515**	**453**	**12,827**	**15,342**	**55,874**
7	**Transmission Projects:**						
8	Kelowna Area Upgrade	14,036	844	-	-	-	**14,880**
9	Okanagan Transmission Reinforcement	-	-	-	4,302	47,427	**51,730**
10	Big White 138 KV Line & Substation	-	6,740	13,648	110		**20,498**
11	Ellison Distribution Source	1,443	(1,446)	-	17,109	102	**17,208**
12	Black Mountain Distribution Source	24	(29)	-	14,720	(6)	**14,708**
13	New East Osoyoos Source (Nk'Mip Sub)	-	19,729	144	-	-	**19,873**
14	Kettle Valley Project	-	5,668	18,940	1,874	-	**26,482**
15	Benvoulin Distribution Source	-	-	-	-	15,544	**15,544**
		15,503	**31,507**	**32,731**	**38,115**	**63,068**	**180,923**
16	**Distributiion Projects:**						
17	Customer New Connects	18,586	21,918	24,434	15,833	15,927	**96,698**
18	CIAC	(9,729)	(13,075)	(11,737)	(7,141)	(7,368)	**(49,050)**
		8,857	**8,843**	**12,697**	**8,692**	**8,559**	**47,648**
19	**Net Plant Additions - Major Projects**	**37,097**	**54,865**	**45,882**	**59,633**	**86,969**	**284,445**

5. Provide summary compensation tables for the 5 most highly compensated Fortis BC employees for each of the last 5 years showing salaries, bonuses, other incentives, total direct compensation, pension value, other compensation and total compensation.

Response:

The following table sets out the regulated compensation information for each person who served as the Chief Executive Officer (CEO) or Chief Financial Officer (CFO), and for the three other most highly compensated executive officers of FortisBC. Non-Regulated bonuses and stock options have not been included in the table below as they are charged to a non-regulated affiliate and do not form part of customer rates.

Table Gabana IR1 5

		Annual Compensation		
Name and Principal Position	**Year**	**Salary**	**Bonus**	**All Other Compensation**
John C. Walker	2010	$453,192	$225,000	$94,442
President and CEO	2009	$385,000	$231,000	$63,831
	2008	$360,000	$205,000	$31,271
	2007	$339,519	$210,000	$425,208
	2006	$314,519	$180,000	$5,811
Michele I. Leeners	2010	$230,000	$85,000	$9,531
VP Finance and CFO	2009	$230,000	$105,000	$11,091
	2008	$215,000	$95,000	$12,227
	2007	$204,423	$80,000	$10,829
	2006	$174,615	$60,000	$20,230
Don L. Debienne	2007	$209,808	$95,000	$10,154
VP Generation	2006	$199,837	$95,000	$17,600
Michael A. Mulcahy	2010	$252,846	$131,000	$43,366
VP Customer and Corporate	2009	$230,000	$105,000	$62,461
Services	2008	$215,000	$90,000	$76,705
	2007	$204,808	$93,000	$57,473
	2006	$194,846	$90,000	$42,751
David C. Bennett	2010	$225,000	$88,000	$18,581
VP Regulatory Affairs, General	2009	$225,000	$105,000	$34,675
Counsel and Corporate Secretary	2008	$215,000	$90,000	$17,054
Doyle Sam	2010	$230,000	$100,000	$4,398
VP Engineering and Operations	2009	$230,000	$105,000	$13,605
	2008	$202,000	$100,000	$56,769
	2007	$204,423	$97,000	$12,625
	2006	$174,615	$80,000	$11,256

6. Describe Fortis's views of a utility and its roll.

Response:

FortisBC's primary objective and responsibility, subject to supervision by the B.C. Utilities Commission pursuant to the *Utilities Commission Act*, is to deliver electricity to its customers, safely and reliably, at the lowest reasonable cost. The Company also plays a role in helping the

Province to meet its energy and environmental goals as defined in the BC Energy Plan, the *Clean Energy Act* and the *DSM Regulation*.

7. Provide yearly revenues from each contract or operating agreement that Fortis has that does not involve only the sale of electricity.

Response:

FortisBC has a number of individual contracts that comprise the Electric Apparatus Rental component of Other Income as described in Exhibit B-1, Tab 4.5.1, Page 104, Line 2. Contractual obligations regarding confidentiality limit the amount of financial detail that may be published. A summary of these contracts by category and the 2011 forecast annual revenue is provided in the following table.

Table Gabana IR1 7

Contract Category	Number of Contracts	2011 Forecast Revenue ($000s)
Cable TV and Telephone Service Providers	4	2,701
Municipal Distribution Underbuild	4	5
Fibre Optic Cable Attachments and Leasing	4	319
Total (Exhibit-B1, Tab-4, Pg 104, Table 4.5, Line-2)	**12**	**3,070**

Revenues from contracts for the operation and management of generation and distribution facilities for third parties are individually detailed in Exhibit B-1, Table 4.5, Page 104, lines 5 – 12.

8. Show revenue derived from the rental or leasing of Fortis BC's equipment from the above question.

Response:

The revenue derived from the rental or leasing of FortisBC equipment in 2011 is $3.070 million as shown in the response to Gabana IR2 Q7.

Rental and lease revenue information is also found at Line 3 of Table 4.5, page 104, Tab 4, Exhibit B-1.

9. Fortis BC's parent company now owns B.C. Gas. What is the current best estimate of potential savings from jointly reading the gas and electricity meter readings?

Response:

FortisBC has estimated that the potential net annual operating savings from joint manual meter reading with FortisBC Energy Inc. would be approximately $1.4 million as compared to the status quo (exclusive of any capital costs). Although this option will be considered in the AMI CPCN application, the overall benefits derived from AMI are expected to exceed joint manual meter reading benefits.

10. Fortis BC paid residents of Castlegar to attend their workshop. Provide a copy of the Fortis BC policy that authorizes Fortis BC to make these payments.

Response:

FortisBC undertakes a number of consultation activities including open houses, one-on-one meetings, presentations to customer groups and local governments, online feedback mechanisms, and research. In part this consultation is required to meet BCUC filing guidelines for significant projects and/or applications.

To ensure adequate feedback and input from a representative sample of FortisBC customer groups, one of the activities undertaken for some processes is a type of focus group, called a Super Group. This activity was undertaken as part of Integrated System Plan (ISP) consultation process. It is a common practise for participants in focus groups to be paid a fee for their time. The participants in the ISP super focus groups were paid an honorarium to attend.

One of the two Super Group sessions was held in Castlegar. Fifty nine customers participated from throughout the Kootenay region. Forty-three of those were residential customers, and the remainder were general service, industrial, primary/transmission, lighting and irrigation customers.

11. How many meetings did Fortis BC pay non-employees to attend in the last 2 years? What were the total payments made to non employees?

Response:

FortisBC conducted four Super Group research sessions, to support consultation processes over the past two years – two for ISP and two for COSA/Rate Design consultation.

It is a common practise for participants in focus groups to be paid a fee for their time. The participants in the ISP super focus groups were paid an honorarium to attend. The honorarium for participants in the each session was:

- COSA/Rate Design : $75. for individuals living within an hour and a half drive to the location of the Super Group session or $100 for individuals who drove over an hour and a half.
- ISP : $75. for individuals living within an hour drive to the location of the Super Group session or $100 for individuals who drove over an hour. The driving time differential was shortened in this case because the sessions were held in the winter and driving conditions were more difficult.

The payments made to the 229 participants totalled $17,850.

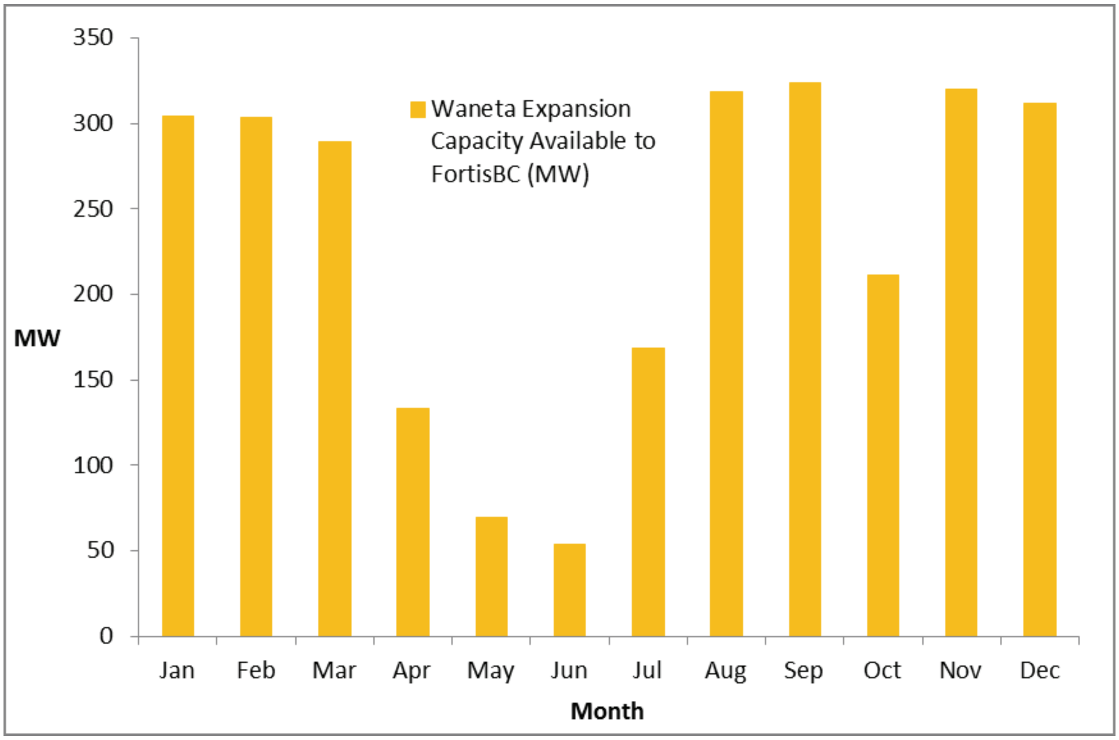
12. Referring to page 12 of the materials distributed for the July 22, 2011 workshop in Kelowna. The graph show power available from the Waneta Expansion in yellow.

    a. is this power available for 12 months in each year.

Response:

No, the graph on page 12 of the workshop materials only shows the capacity available from the Waneta Expansion in December. The figure below shows the amount of Waneta Expansion capacity that is anticipated to be available to FortisBC on a monthly basis.

Figure Gabana IR1 12a



b. how will the rate per MW to purchase this yellow block of power compare to the rate per MW to purchase the dark blue block from Powerex and the average rate per MW purchased from other sources.

<u>Response:</u>

The response to Celgar IR2 Q19.2 presents an overview of the expected 2015 WAX CAPA costs. For 2015, the net power supply cost associated with the WAX CAPA is expected to be about $26 million.

With the WAX CAPA agreement, the Company gains greatly increased certainty over the long term of supply throughout the year to meet current and projected capacity needs.

13. How much money has been spent on the upgrades to the generators on the Kootenay River since Fortis BC purchased the company. Provide the response by year, by generator, by project.

Response:

All upgrade work completed on the Generators has been completed as part of a ULE project. The following is the list of ULE projects completed, with the cost relating to the Generators only.

Table Gabana IR1 13a

		2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Forecast	Total
1		($000s)							
2	Upper Bonnington Unit 5 Upgrade Life Extension	97	(1)	-	-	-	-	-	96
3	Upper Bonnington Unit 6 Life Extension	22	-	-	-	-	-	-	22
4	Lower Bonnington Unit 1 Upgrade Life Extension	1,514	2,531	(48)	-	-	-	-	3,997
5	Lower Bonnington Unit 3 Life Extension	238	908	1,960	-	-	-	-	3,106
6	South Slocan Unit 1 Upgrade Life Extension	-	-	1,206	107	1,970	121	-	3,403
7	South Slocan Unit 3 Life Extension	-	-	1,176	2,226	408	-	-	3,810
8	Corra Linn Unit 1 Upgrade Life Extension	-	-	-	-	290	3,272	374	3,936
9	Corra Linn Unit 2 Upgrade Life Extension	-	-	-	-	-	286	4,317	4,603
10	**Total**	**1,872**	**3,438**	**4,293**	**2,332**	**2,668**	**3,679**	**4,691**	**22,974**

Note: Cost of Removal is not included.

The following table shows the total project costs.

Table Gabana IR1 13b

		2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Forecast	Total
1		($000s)							
2	Upper Bonnington Unit 5 Upgrade Life Extension	459	7	-	-	-	-	-	466
3	Upper Bonnington Unit 6 Life Extension	826	1	-	-	-	-	-	827
4	Lower Bonnington Unit 1 Upgrade Life Extension	7,552	4,825	118	-	-	-	-	12,495
5	Lower Bonnington Unit 3 Life Extension	511	5,707	7,980	430	-	-	-	14,628
6	South Slocan Unit 1 Upgrade Life Extension	-	244	3,160	2,433	8,135	1,591	79	15,642
7	South Slocan Unit 3 Life Extension	-	-	3,164	7,714	1,949	-	-	12,827
8	Corra Linn Unit 1 Upgrade Life Extension	-	-	102	650	2,611	9,647	3,055	16,065
9	Corra Linn Unit 2 Upgrade Life Extension	-	-	-	-	33	3,505	12,748	16,286
10	**Total**	**9,348**	**10,784**	**14,524**	**11,227**	**12,728**	**14,743**	**15,882**	**89,236**

Note: Cost of Removal is not included.

14. Show the power gain and return on investment as a result of each project for each generator.

Response:

Table Gabana IR1 14 below shows the capacity increase for each of the eight units which have been completed and Canal Plant Agreement increases negotiated for. Three units (South Slocan Unit 1, Corra Linn Unit 1 and Corra Linn Unit 2) have not completed efficiency testing and as such have not been increased under the terms of the Canal Plant Agreement.

Table Gabana IR1 14

Plant	Unit #	Original Capacity (MW)	Upgraded Capacity (MW)	Increase
Lower Bonnington	1	13.8	16.3	**2.5 MW**
Lower Bonnington	2	13.8	16.3	**2.5 MW**
Lower Bonnington	3	13.8	14.2	**0.4 MW**
Upper Bonnington	5	18.4	22.6	**4.2 MW**
Upper Bonnington	6	18.4	18.7	**0.3 MW**
South Slocan	2	18.2	19.2	**1.0 MW**
South Slocan	3	18.2	18.6	**0.4 MW**
Corra Linn	3	17.1	17.4	**0.3 MW**

Since the start of the Upgrade Life Extension (ULE) program the Company has invested approximately $150 million to upgrade and life extend 11 of its 15 generating units. At the conclusion of the program, the Company has not only preserved the existing 202 MW of capacity and 1,541 GWh of annual entitlement energy well into the future, but expects to increase it to 227 MW and 1,612 GWh per year respectively. As noted in the 2012 Long Term Capital Plan, pp. 36 the increase in capacity and energy entitlements as a result of the ULE program will result in approximately $3 million dollars of avoided power purchase costs in 2012 alone.

It is difficult to show a specific return on investment for projects implemented to extend the life of an asset as the assumption is predicated on the assessment that the units will fail in the near future. This was the basis of the Company's ULE program. Simplistically, the market cost to replace a unit (based on the average entitlement of the FortisBC units) would exceed $4.5 million annually. Considering a simple average cost of $13.5 million per unit, the average payback period is three years.

15. Show which units encountered problems that caused significant lost power generation for 7 consecutive days in the last 20 years. Please provide estimated financial losses from this downtime.

Response:

According to FortisBC records, the following is a list of outages greater than 7 days (84 hrs) in duration for the past 10 years. Prior to 2002, records are not as reliable and therefore information is only provided for the previous 10 year period.

Table Gabana IR1 15

Plant	Year	Unit	Reason for Outage	Number of Hours Out of Service	Estimated Financial Loss ($000s)	Comments
Upper Bonnington	2002	Unit #3	Lower turbine bearing housing detached from foundation	978.19	$144	
Upper Bonnington	2002	Unit #4	Governor Issues	128	$18	
Lower Bonnington	2006	Unit #2	Transformer imminent winding failure discovered	3278.2	$334	Insurable loss, Company exposed to financial loss for first 30 days of outage
Corra Linn	2006	Unit #1	Generator deluged by failure of fire suppression valve	1087.15	$334	Insurable loss, Company exposed to financial loss for first 30 days of outage
Upper Bonnington	2009	Unit #3	Unit #3 Transformer internal cooling failure	624.47	$110	

Detailed determination of exact financial losses due to forced outage events are difficult to determine as the cost to replace energy and capacity during a forced outage can vary greatly depending on the time of year and the market price of power at the time of the outage. In order to provide a representative cost for a forced outage event, the Company has assumed that a forced outage event would require purchase of replacement energy at the next lowest firm cost of energy, the BC Hydro 3808 contract. It is also assumed that the Company had sufficient capacity at the time of the outage and therefore was not required to purchase additional capacity at the time of the outage as well.

16. Does Fortis BC hold any contingency funds? If so, what are they for and how much are they.

Response:

The Company maintains certain reserves, such as allowance for doubtful accounts (AFDA), inventory obsolescence and an insurance self reserve (SIR), all of which could possibly be interpreted as contingency funds.

AFDA is a common reserve account used by most entities that have customer sales and is a contra account to accounts receivable that represents an estimate of the portion of outstanding receivables whose collection is expected to be doubtful. As at the end of 2010, the AFDA balance was approximately $1.0 million.

Inventory obsolescence is a common reserve account used by most entities that have inventory and is a contra account to the inventories account that represents an estimate of the portion of the inventories whose value is expected to be impaired. At the end of 2010, the inventory obsolescence balance was approximately $0.1 million.

Through to 2011, the Company maintained a Self Insurance Reserve as described in Section 4.3.4.18 on page 94 of Tab 4 of the 2012-2013 RRA as follows:

> "(iv) Self Insurance Reserve
>
> FortisBC's insurance expense has also included an annual Self Insurance Reserve (SIR) expense to build up a provision. The SIR provision is then reduced by the actual costs incurred relating to smaller first and third party claims, which include theft and damages. The SIR expense has been used to mitigate the risks associated with the ownership and operation of the transmission and distribution segment of the business which is not insurable. Over the last several years, the SIR provision balance has exceeded the actual first and third party claims and grown to approximately $0.4 million. FortisBC is proposing to return the reserve balance of $0.4 million to customers in 2012."

As part of the 2012-2013 RRA, the $0.4 million insurance reserve balance forecast for the end of 2011 is being refunded back to customers as reduction to rates in 2012.

17. Show a continuity schedule of power sources and uses including line loss for each of the last 5 years. Include how much power Fortis BC produces and purchases per year? How much Fortis BC sells to residential, commercial/industrial, wholesales, BC Hydro and others.

Response:

The table below shows power FortisBC produced, purchased and sold over the period of 2006 to 2010.

Table Gabana IR1 17

Gross Load (GWh)	2006	2007	2008	2009	2010
FortisBC Resources	1,509	1,498	1,610	1,586	1,530
Brilliant	919	914	921	923	922
BC Hydro	929	959	826	836	600
Market and IPP	75	53	74	159	327
Other	9	20	18	13	(6)
Surplus Sales	(37)	(35)	(48)	(38)	(49)
Total Gross Load	**3,405**	**3,410**	**3,400**	**3,478**	**3,324**

Net Billable Load (GWh)	2006	2007	2008	2009	2010
Residential	1,049	1,162	1,224	1,273	1,216
General Service	616	650	661	675	660
Wholesale	972	877	924	931	881
Industrial	348	314	218	216	234
Lighting	13	13	13	13	14
Irrigation	43	48	46	49	40
Total Sales (GWh)	**3,041**	**3,064**	**3,087**	**3,157**	**3,044**

Losses (GWh)	2006	2007	2008	2009	2010
Losses in the transmission and distribution system	312	310	272	258	227
Company Use	12	13	11	12	12
Losses due to wheeling through the BC Hydro System	40	23	30	51	41
Total Sales (GWh)	**364**	**346**	**313**	**321**	**280**

18. What are the top three projects that would reduce power loss on the Fortis BC's grid. Fortis has previously stated there is about 8% to 10% loss.

Response:

While the reduction of transmission and distribution losses is not the primary driver for any projects currently in the Long Term Capital Plan, loss reduction is an additional consequential benefit of several projects. For example, the recently completed Okanagan Transmission Reinforcement (OTR) project had, in addition to system reliability benefits, significant benefits resulting from a reduction of power losses. The latter are documented in the response to BCUC

IR1 Q1.3 (Exhibit B-7). The following are some future projects that are expected to result in lower losses:

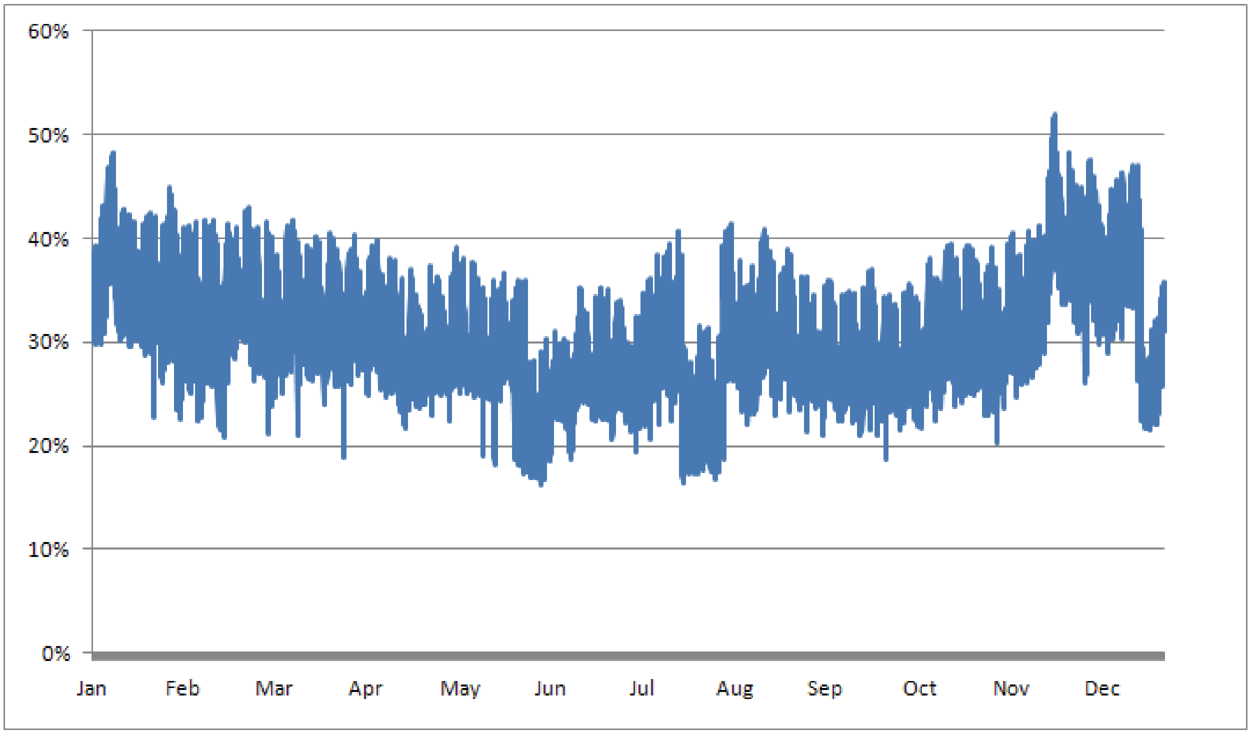
1. The Advanced Metering Infrastructure (AMI) project, in its capacity to identify the causes of system losses as well as by supporting conservation and efficiency objectives, such as the Conservation Voltage Reduction (CVR) program, has the potential of reducing distribution losses.
2. Distribution Voltage Conversion, described in 2012 Long Term Capital Plan, pp. 157-158. The upgrade of distribution feeders to 25kV can result in significant reduction of distribution losses. For example, doubling the voltage on a distribution feeder will reduce the losses on that feeder by 75%.
3. The Kelowna Bulk Transformer Capacity Addition (KBTCA) project will reduce transmission losses by approximately 1100 MWh annually in the Kelowna area.

19. Regarding the Grand Forks transformer referenced on page 38 of the work shop document: provide a graph of its operating load as a function of its capacity.

Response:

A graph of the transformer load as percent of transformer capacity rating is provided below. The graph is derived from hourly kVA readings from January 1, 2010 to December 31, 2010.

Figure Gabana IR1 19



20. If this transformer failed tomorrow, what is Fortis BC's currently documented contingency plan, what other options were considered and what cost assumptions were made to reach the respective conclusions?

Response:

A failure of the Grand Forks Terminal T1 transformer would result in a power outage for approximately 4,200 customers in Grand Forks, Christina Lake and the surrounding areas. The duration of the outage would be from the time of failure to the time of manually reconfiguring the system to use the backup 63 kV supply source from Trail. Depending on the switching required, restoring the load from the Trail supply could take from approximately ½ hour to 2 hours.

This contingency plan requires that at least one of the two 63kV lines between Trail and Warfield must be in a good condition and available for service. For this reason, FortisBC currently incurs both capital and operating costs to maintain these lines. As described in the response to BCUC IR1 Q127.17, the planned and emergency costs to maintain these lines was approximately $710,000 for the years 2007 to 2010.

Other than using the 63-kV transmission lines to provide a backup supply from Trail, there is no other option available to provide a supply for customers in the Grand Forks area following a failure of the existing Grand Forks T1 transformer.

21. What is the probability of the failure Fortis BC assumed in reaching its conclusion in its current contingency plan? What are the industry statistics for these transformers?

Response:

There are broad ranges in both the lifespan and probability of failure for large power transformers as reported in various industry sources. Typical mid-life failure rates for a population of power transformers (which are normally operated below maximum nameplate capacity) are approximately 0.5 to 1% per year.

FortisBC has historically experienced a failure of a power transformer approximately once every 2 to 3 years. Given the population of power transformers in the FortisBC system (approximately 120 units) this empirical evidence is consistent with the previously cited results.

22. What is Fortis estimated cost to change its customer meters to AMI

Response:

At this time, the AMI Project is expected to cost approximately $45 million.

23. Who would pay? How much would they pay? Over what time period would they pay?

Response:

As with all approved capital projects, FortisBC ratepayers pay all costs associated with the project as the capital asset is being used for the provision of utility service.

In the case of the AMI project, the financial benefits are expected to be larger than the costs over time, and therefore rates will be lower than they would have been if AMI weren't implemented. The various components of the AMI project are expected to be depreciated over different time frames, the longest being 20 years.

24. What is Fortis BC's projected return on investment and return on capital for AMI?

Response:

The forecast return on investment for capital projects, including the AMI project is equal to the Commission approved, currently allowed return on equity of 9.9 percent. The return on capital for capital projects, including AMI, is forecast to be approximately 7.6 percent in 2016.

25. Fortis occupies office space in downtown Trail. During Fortis BC's tenure, there have been a number of financial transactions involving this occupancy. Please describe the changes over time and how this has affected Fortis BC's costs and return on investment.

Response:

There are two types of financial transactions relating to the FortisBC leased office in downtown Trail:

1. In 1993, the building was constructed by FortisBC and then sold and leased back from an another arms-length company. The sale-leaseback arrangement was meant to mitigate the impact of the cost of the new building on customers by designing the lease payments on a step increase basis. Lease payments were lower in the early years and as revenue requirements increased, so did the lease payments; and
2. FortisBC has been sub-leasing space in the building to other tenants thereby offsetting a portion of the FortisBC lease costs and reducing overall costs to customers.

Both measures have served to reduce costs to customers by reducing operating costs and to the extent the transactions have reduced working capital requirement they have also reduced financing costs.

26. Fortis BC and Columbia Basin Trust and its subsidiaries (CBT) have numerous interlocking agreements. I would like to understand how this affects our power rates. As a starting point, please provide a summary of all payments to CBT for the past 5 years.

Response:

FortisBC does not make direct payments to the Columbia Basin Trust (CBT). CBT and the Columbia Power Corporation (CPC) have entered into a number of arrangements in order to share in the ownership and income streams of various electric generating and transmission assets.

FortisBC has two power purchase agreements with CBT/CPC for electricity generated at the Brilliant hydroelectric plant. FortisBC has also entered into an agreement for interconnection with CBT/CPC at the Brilliant Terminal Station and pays for the interconnection as a capital lease. A summary of those payments is presented below.

Table Gabana IR1 26 - Payments regarding the Brilliant Plant, Brilliant Expansion and Brilliant Terminal Station

	2006	2007	2008	2009	2010
			($000s)		
Brilliant Plant Power Purchases	29,258	29,924	30,195	30,931	33,053
Brilliant Expansion Power Purchases	-	131	287	350	371
Brilliant Terminal Station Interconnection	2,457	3,222	3,206	3,054	3,069
	31,715	33,278	33,688	34,335	36,493

With respect to the impact of these agreements on customer's power rates, using 2010 as an example, the $36.5 million payment represented approximately 14.0% of the 2010 revenue requirement of $259.3 million.

27. BC Hydro was recently filed with BCUC a 10% cut to its capital plan. Has Fortis BC begun a similar initiative? What are the effects on Fortis BC's operations and the consumers power rates under this scenario?

Response:

FortisBC would like to clarify that BC Hydro has not, in fact, "recently filed with BCUC a 10% cut to its capital plan". On March 21, 2011, BC Hydro filed a Revenue Requirements Application for fiscal years 2012 through 2014 which requested a cumulative rate increase over those three years of 32 percent. The proposed total value of capital additions for the same period was $5.493 billion (Reference: BC Hydro F12-F14 RRA, Schedule 13.0 Line 36). In an attempt to mitigate this rate increase, the provincial government directed an independent business review to be conducted on BC Hydro in order to examine opportunities to reduce capital expenditures and operating costs. The review, which was filed with the BC government in June 2011, identified a number of areas of opportunity and contained recommendations to reduce the cumulative rate impact to approximately half of the requested 32 percent. In response to this government-ordered review, on September 27, 2011 BC Hydro filed an RRA update letter with the Commission which identified reductions in a number of operating and capital cost areas. In particular, BC Hydro has identified a reduction in capital additions of $75 to $100 million over the three year period. This represents a 1.4 to 1.8 percent reduction in capital additions (not 10 percent). At this point, BC Hydro has not determined which specific capital projects will be impacted.

With respect to FortisBC's 2012-13 Capital Plan, all of the identified projects have been proposed on the basis that they are prudent and required to continue to provide safe and reliable service to customers. FortisBC has not specifically undertaken a similar initiative to that directed for BC Hydro by the BC government. However, in order to mitigate rate increases, as a matter of policy FortisBC looks to minimize expenditures through methods such as scope optimization, competitive tendering, blanket purchasing using corporate purchasing power and partnering arrangements.

An analysis was conducted in order to determine the potential impact on rates from a theoretical 10% reduction in capital expenditures. The following assumptions were made in this analysis:

1. Capital expenditures are reduced by 10% in both the years 2012 and 2013;
2. Reduced capital is Transmission in nature;
3. There is no change to Customer New Connects and Contributions in Aid of Construction (CIAC) as these are customer driven and FortisBC has an obligation to serve;
4. There is no change to Cost of Removals (COR); and
5. The reduction in capital expenditures is equivalent to the reduction in Plant Additions in the same year.

Given these assumptions, the impact on the proposed 2012 and 2013 rate increases would be a reduction by 0.1% in 2012 and a reduction by 0.4% in 2013.