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October 21, 2011

Via Email
Original via mail

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 British Columbia Utilities Commission Information Request No. 2

Please find attached FortisBC's responses to Information Request No.2 from the British Columbia Utilities Commission (BCUC or the Commission).

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

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

POWER PURCHASES

1.0 Reference: Power Purchases

Exhibit B-4, BCUC 1.7.1; Exhibit B-5 BCMEU 1.10;

Exhibit B-6 Summary of Pending Adjustments

Revision to Power Purchase Expense

In the above references, FortisBC indicates that it will further revise its forecast Power Purchase Expenses for 2012 and 2013 once BC Hydro updates its RRA or prior to the setting of FortisBC rates.

1.1 Please confirm that FortisBC will provide a revised Power Purchase Expense forecast in the same format as Table BCUC IR1 7.1 in Exhibit B-4 to be filed 3 weeks prior to the commencement of the oral public hearing or alternative dispute resolution process for FortisBC's 2012-13 RRA. That forecast would update each expense item based on FortisBC's best estimates at that time and should include explanations of the changes to the forecasts from Table BCUC IR1 7.1.

Response:

Confirmed. FortisBC believes it would be helpful to the Commission and Interveners to file an Evidentiary Update to the 2012-13 RRA and will endeavour to file this Evidentiary Update no later than November 2, 2011.

Table BCUC IR2 1.1 lists the changes to be included in the Evidentiary Update. These changes include the updated Power Purchase Expense related to the BC Hydro F2012 – F2014 Revenue Requirements referenced in this question, other items identified in the Company's letter of September 16, 2011 (Exhibit B-6), changes identified in Round 2 of the Information Requests, as well as updates to the 2011 flow-through and ROE sharing adjustments based on current estimates of 2011 financial results.

Table BCUC IR2 1.1

Cost Account	Component	Application Reference
Power Purchase Expense	BC Hydro Increases	Exhibit B-6
	Market Rates	BCUC IR2 Q 2.1
	System Losses	BCUC IR2(L) Q1.4
O&M Expense	Enterprise Rd. Lease Expiry	BCOAPO IR1 Q39.1 and Exhibit B-6
Interest Expense	Long Term Interest Rates	BCUC IR1 Q33.1.1
	Short Term Interest Rates	BCUC IR2 Q35.1.1
Depreciation Expense	Street Lighting	BCUC IR2 Q36.4
Capital Expenditures	Enterprise Rd. Lease Expiry	BCOAPO IR1 Q39.1 and Exhibit B-6
	Station Urgent Repairs	BCOAPO IR1 Q32.1 and Exhibit B-6
	Transmission Line Urgent Repairs	BCUC IR2 Q51.1
	19 Line Rehabilitation Adjustment	BCUC IR2 Q56.1
2011 Flow-through Adjustment	2011 Interest Expense	BCUC IR1 Q81.4 and Exhibit B-6
2011 ROE Sharing Adjustment	Power Purchase Expense update	BCUC IR1 Q7.1 and Current information
	2010 Income Tax Under-Provision	BCOAPO IR 2.5.1
	Other Updates to 2011 Financial forecast	Current information

2.0 Reference: Power Purchases

Exhibit B-4, BCUC 1.15.1

Forecast Market Prices

In response to BCUC 1.15.1, FortisBC reduced its forecast of market energy and capacity costs for 2012 and 2013 and states that "the Company is proposing that any variance in power purchase expenses from forecast, including market price variances will flow through to the ratepayer."

2.1 What is the dollar impact of the revised forecasts on overall power purchase expenses (PPE) in 2012 and 2013?

<u>Response:</u>

Table BCUC IR2 2.1 below updates Table 4.1-1 from the 2012-13 RRA (Exhibit B-1) with the market price forecast update provided in BCUC IR1 Q15.1. The updated market price forecast results in a decrease to power purchase expense of $0.019 million in 2012 and $0.068 million in 2013.

Table BCUC IR2 2.1

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
		($000s)			
1	Brilliant	33,216	32,267	35,601	36,785
2	BC Hydro	29,544	36,874	52,519	57,965
3	Independent Power Producers	914	153	155	158
4	Capacity Block Purchases	2,080	2,291	2,475	2,808
5	Market Purchases	8,222	4,211	196	478
6	Surplus Revenues	(1,000)	(259)	(284)	(267)
7	Capital Projects	(398)	(467)	-	-
8	Special and Accounting Adjustments	421	385	(750)	(750)
9	Balancing Pool	(1,036)	501	(156)	-
10	Planning Reserve Margin	-	-	-	311
11	Department Budget	-	-	1,211	1,266
12	**TOTAL**	71,964	75,956	90,965	98,753

2.2 Assuming approval of the PPE variance deferral account, would FortisBC agree that the final approved forecast should be as unbiased as possible so as to minimize the expected price variance impact on both test years and following years? ("unbiased" is intended to mean that the actual outcomes would be equally likely to be either above or below forecast) If not, why not?

Response:

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

3.0 Reference: Power Purchases

Exhibit B-5, BCMEU 1.4 and 1.12

Forecast Market Prices

Table BCMEU IR1 4 shows that actual PPE from 2008 through 2010 have been over $9 million less than approved for the three years. In BCMEU 1.12, FortisBC acknowledges that "Current market conditions are such that additional savings may be possible, however, actual savings will depend on market condition at the time, which in turn depend on a number of factors such as loads, weather, water levels, gas costs, economic conditions, etc."

3.1 Given FortisBC experiences over the last four years, including 2011, and current expectations of low natural gas prices, high BC Hydro reservoir levels and soft economic conditions, wouldn't it be more appropriate to anticipate market purchase savings of at least $3 million per year rather than the $750 thousand included by FortisBC, especially if any variance in PPE is to be trued up in later years? Please explain the Company's view.

Response:

It is the Company's position that the forecast of Power Purchase Expense should be on the basis of the firm resources that it holds to meet its firm load requirements. The Company's base energy portfolio covers practically all of the Company's energy needs in 2012 and 2013 and is reasonable and moderately priced. Therefore, it is appropriate to rely on this existing portfolio of moderately priced resources in determining forecast Power Purchase Expense costs.

FortisBC does depend on the market to purchase incremental energy and capacity requirements that exceed firm owned and contracted resources and to a smaller degree to sell eligible surplus resources. The net cost of these activities have been forecast based on current market information and load forecasts, however actual costs could be markedly different than forecast due to a number of factors that are beyond the Company's control including those listed. FortisBC also strives to generate savings for customers over forecast by managing its contractual obligations and making purchases when market opportunities arise to displace energy and capacity that on a forecast basis are expected to be sourced under the BC Hydro PPA. In 2010 and expected in 2011, these activities have created significant value for customers due largely to a 'perfect storm' of circumstances which have all served to put downward pressure on market prices and could not have been forecast or "locked-in" in the previous period. Nor can it be expected that this set of circumstances will be repeated. For example, it is not appropriate to presume that certain weather patterns or water conditions will hold in the test years just because they have been experienced in a recent year. In fact, the laws of probability suggest that on average they will return to more normal conditions. (The Company's practice, which is consistent with previous Commission directives and normal utility practice, is to base its forecast of requirements on average or "normalized" weather.) Natural gas prices are expected to continue to be relatively low, however there continues to be significant volatility and in fact while natural gas has served to act as a 'cap' on North American power prices as a whole, in the Pacific Northwest (PNW) region it is principally hydrological conditions that have caused power prices to collapse in recent months. This is evidenced by a much lower level of natural gas fired generation dispatch in the PNW in 2011.

It also should be noted that a significant portion of the savings are due to the flexibility afforded to FortisBC under the current terms of the BC Hydro PPA which expires in October 2013. Although FortisBC expects to renew the agreement, it is not certain that it will have the same level of flexibility which could reduce future mitigation opportunities.

The Company does accept that any power supply arrangements that are entered into before rates are set for the test period could be considered in the forecast of Power Purchase expenses provided they represent firm resources. For example, if the Company is able to lock in savings by executing forward market deals to secure lower prices these could be incorporated in the forecast for the period. While this allows savings to be locked in, it does limit the ability to capture value that may be available in the future. For example, it may be desirable to wait until relatively close to the time power is desired to purchase rather than to execute up to 2 years in advance as would be required for the later part of the test period. The market is relatively illiquid and a premium must be paid if attempting to do deals too far in advance, if the deal can be done at all.

If higher expected savings need to be accounted for at the beginning of the test period rather than reconciled at the end of the test period, then it will be required for the Company to operate in a more conservative manner and potentially forego additional savings. Therefore, the Company strongly believes that a continuation of the current practice of forecasting power purchase expense based on firm resources to meet firm load is necessary and prudent. Nevertheless, for rate making purposes, the Company has proposed to continue to assume the savings of $0.750 million that has been agreed to for 2011.

4.0 Reference: Power Purchases

Exhibit B-4, BCUC 1.9.1

CPA Exchange Accounts

Response to BCUC 1.9.1 does not seem to adequately explain the reason for the expected use of 17 GWh of storage energy from the balancing pool in 2011 and the storage of 4 GWh in 2012.

4.1 Please provide a more comprehensive explanation of the forecast use of the balancing pool.

Response:

The balancing pool is the Company's ability to store energy in the storage accounts under the Canal Plant Agreement and as such represents the Company's energy reserves. The forecast use of the balancing pool is based on the starting position of the balancing pool, and a general strategy to use the balancing pool to store energy for the winter, since that is when the Company forecasts its peak loads. The use of 17 GWh of balancing pool energy in 2011 is a result of the amount of energy in the balancing pool at the end of 2010.

In 2010, FortisBC experienced a cold snap in late November, followed by an unexpectedly mild December. This allowed the Company to replenish energy reserves (balancing pool) in December 2010 for potential need later in the winter. For 2011 and 2012, the forecast use of the balancing pool is similar. The Company forecasts filling the balancing pool by the end of November, and drafting the balancing pool over the winter. Since the 2011 balancing pool starting position is higher than the forecast starting position for 2012, the forecast use of the balancing pool is more in 2011.

Financially, for planning purposes in 2012 and 2013, balancing pool usage is not relevant since any forecast storage or draft is matched by a corresponding increase or decrease in the Power Purchase Agreement (PPA) with BC Hydro purchases. Since the financial value associated with balancing pool activity is the PPA purchase rate, there is no net effect on forecast 2012 and 2013 power purchase expense.

4.2 What led to the $1.036 million saving in the balancing pool expense in 2010 shown in Table BCUC IR1 7.1 line 9?

Response:

The $1.036 million in savings in the balancing pool expense in 2010 was a result of storing 37 GWh in the account throughout the year. FortisBC began 2010 with -17 GWh in the balancing pool account due to cold weather in December of 2009, and ended 2010 with 21 GWh in the balancing pool (slight difference due to rounding).

Please refer to the response to BCUC IR2 Q4.1 for further details around balancing pool operations.

5.0 Reference: Purchase Power

Exhibit B-4, BCUC 1.7.1; Exhibit B-1, Tab 4, p.3

Purchased Power Deferral Account

FortisBC indicates that the approved power purchase cost in 2011 is $81.2 million while the current forecast is $74.6 million, a variance of $6.5 million.

FortisBC also indicates that the cumulative power purchase variance between 2007 and 2011 (latest forecast) is approximately $20 million.

5.1 During the PBR period, an ROE Sharing Mechanism Adjustment provides for equal sharing of variances within a 2 percent band above or below the approved return on equity. With the true-up mechanism contained in the proposed purchased power deferral account, it is still expected that FortisBC continue to provide the best estimate and effectively mitigate power purchase costs in a prudent manner. Please discuss what incentives are in place/could be in place that will encourage effective cost management in this area.

Response:

Mitigation of costs, including Power Purchase Expense, is a key focus of the Company, whether or not operating in a PBR environment. As discussed in the Application, the Company's ability to mitigate power purchase costs is largely dependent on its ability to capture market opportunities as they arise which in turn depend on a number of factors such as loads, weather, water levels, gas costs, and economic conditions. In order to encourage continued and enhanced capability to respond to dynamic market conditions and capture mitigation opportunities, an incentive type mechanism that would align the interests of the customers and Company that is based on savings achieved through market activities could be explored in a future proceeding.

6.0 Reference: Planning Reserve Margin (PRM)

Exhibit B-4, BCUC 17.3 and BCUC 258.1

6.1 The response to BCUC 1.17.3 refers to BCUC 1.258.1 for a detailed discussion of Planning Reserve Margin (PRM) costs, while BCUC 1.258.1 refers back to BCUC 1.17.3. Please provide a detailed reconciliation, on a month-by-month basis, of how PRM costs are calculated.

Response:

A detailed discussion of how PRM costs are calculated was attached to the response to BCUC IR1 Q258.1. Specifically, please refer to BCUC IR1 Appendix 258.1, a Memorandum from Midgard Consulting dated February 7, 2011 entitled "Costs to Procure Planning Reserve Margin Shortages 2011 to 2020".

This four page report proposes a methodology and the estimated cost to FortisBC of procuring market-based capacity, broken down by month. It also assumes the WAX CAPA is available to address PRM capacity gaps. Table 1 in BCUC IR1 Appendix 258.1 is the source of the estimated costs provided in BCUC IR1 Q17.3, and provides an annual estimate of PRM cost to procure. Tables 2 and 3 provide the PRM capacity gaps and the projected PRM capacity purchases, both on a monthly basis. Table 4 provides the BC Hydro Super-Peak time of delivery factors used to calculate monthly cost, and Table 5 summarizes Midgard's estimated cost of capacity per month in 2010 dollars.

As discussed in the response to BCUC IR1 Q258.1, this is a preliminary estimate and the Company will seek to minimize the cost of procuring resources to meet its system requirements, including PRM, by optimizing its own portfolio and other contracted or owned resources on an on-going basis.

6.2 FortisBC states that the PRM costs shown in "Table BCUC IR1 17.3 PRM Cost to Procure: 2014 to 2018" are based on a percentage of a simple cycle gas turbine UCC cost. Please explain whether PRM can be provided by excess WAX CAPA capacity, and if so, please prepare a similar cost table.

Response:

Yes, PRM could be provided by excess WAX capacity in some months. In fact, the table in BCUC IR1 Q17.3 assumes that excess WAX capacity had already been utilized for PRM before these additional resources are acquired. Therefore there is no excess WAX capacity available to meet the PRM gap assumed by the table.

Please also see the responses to BCUC IR2 Q6.1 and Q6.3.

6.3 Is FortisBC considering using excess WAX CAPA capacity to supply PRM, or otherwise using WAX CAPA in a capacity swap with a third party to provide PRM?

Response:

The Company will seek to minimize the cost of procuring resources to meet its system requirements, including PRM, by optimizing its own portfolio and other contracted or owned resources on an on-going basis. Utilizing excess WAX CAPA capacity or using WAX CAPA in a capacity swap with a third party to provide PRM will be among options to be considered and evaluated.

7.0 Reference: Power Purchase Expenses

Exhibit B-4, BCUC 23.2

Planning Reserve Margin

"FortisBC is in different circumstances than NorthWestern Energy and as a result FortisBC must carry a prudent level of PRM."

7.1 As an alternative to carrying PRM in the form of physical capacity, please discuss the alternative strategy of purchasing market capacity in the event of a unit failure.

Response:

Failure to carry a planning reserve margin would force FortisBC to rely on market purchases to meet any future capacity shortfalls. In Section 5.3 of Exhibit B-1-2 Appendix D, Midgard describes the factors that will make depending on the market in this way increasingly risky. These include: increasing installed intermittent generation, decreasing regional capacity margins, the re-introduction of industrial load accompanying an economic recovery, the saturation of demand side management initiatives, variable hydrology, and transmission congestion.

FortisBC does not believe relying on the real-time market to be a viable long term solution for meeting system requirements in response to a unit failure. However, FortisBC will consider contracting for firm resources from the market, provided firm transmission is available to the FortisBC system, as one of the options to meeting future PRM requirements.

7.1.1 In the event of a WAX unit failure, provide the 2013 NPV cost for market-sourced capacity purchases occurring in the entire month for January 2016, January 2018, and January 2020. Please also show the sensitivity to market prices by providing the analysis for 75 percent, 100 percent, and 150 percent of market forecast prices.

Response:

The January capacity under the WAX CAPA is 304 MW. Taking into account reserves, the total capacity available is 283 MW. One unit would be allocated half of that, or 142 MW.

The Midgard Wholesale Market Price curve was utilized to determine annual market prices in 2016, 2018 and 2020. This was broken down into monthly prices using a 2x12 table developed from the current Mid-C forward curve. January costs in 2016, 2018 and 2020 were calculated using these values and the number of HLH and LLH in January, and converted back into 2013 dollars assuming 2% inflation in Table 7.1.1-A. A 2013 NPV was also calculated utilizing an 8% nominal discount rate, and is presented in Table 7.1.1-B.

Table BCUC IR2 7.1.1a

Replacement Cost of 1 Unit at Waneta Expansion (Nominal Dollars)			
Market Price Forecast Percent	**75%**	**100%**	**150%**
January 2016	$ 6,120,528	$ 8,160,703	$ 9,180,791
January 2018	$ 6,835,908	$ 9,114,545	$ 10,253,863
January 2020	$ 7,410,567	$ 9,880,756	$ 11,115,850

Table BCUC IR2 7.1.1b

NPV(8%) Replacement Cost of 1 Unit at Waneta Expansion in January (2013 Dollars)			
Market Price Forecast Percent	**75%**	**100%**	**150%**
2016	$ 4,858,672	$ 6,478,229	$ 7,288,008
2018	$ 4,652,404	$ 6,203,206	$ 6,978,607
2020	$ 4,323,995	$ 5,765,326	$ 6,485,992

Note that this analysis is based on the Midgard Wholesale Market energy curve, which is a price forecast. It can only provide an estimate to the cost of market sourced capacity purchases in those years. FortisBC cannot sign a contract based on these prices today.

7.2 Please identify any regulatory or industry mandates which require FortisBC to carry a PRM. Describe the consequences to FortisBC's ratepayers for failure to abide by any such mandates.

Response:

Explicit mandates to carry PRM are not in force for any utility in the Western Electricity Coordinating Council ("WECC"). However, WECC states in its 2010 Power Supply Assessment that:

> *"WECC does not currently have a planning reserve margin requirement. However, the "Power Supply Assessment Policy" (see Attachment 4) defines a requirement to "project whether enough physical resources exist, at any price, to meet load and possible reserves while considering the transmission transfer capabilities of major paths." …reserve margin developed by [the Loads and Resources Subcommittee] and approved by [the Planning Coordination Committee] is a means to meet that requirement.*

In Attachment 6 of the same document, WECC states that:

> *"any given [Load Serving Entity] may use different Building Blocks or different values for the Building Blocks, or even an entirely different method to set its target reserve margin, than what is used in the [Power Supply Assessment]."*

Thus, WECC, while not *mandating* acceptable planning reserve margins solutions explicitly, believes that carrying reserves in excess of day-to-day operating reserves is a part of prudent utility practice. As shown in Table 5.2.1.1-C of the Resource Plan, most neighboring utilities, with the exception of Northwestern Energy, carry planning reserve margin. BC Hydro also plans its resource requirement based on carrying planning reserve margin to meet uncertain load requirements, provide operating flexibility and to manage resource delivery uncertainty.

Failure to carry a planning reserve margin would force FortisBC to rely on market purchases to meet any future energy or capacity shortfalls. In Section 5.3 of Exhibit B-1-2 Appendix D, Midgard describes the factors that will make depending on the market in this way increasingly risky. These include: increasing installed intermittent generation, decreasing regional capacity margins, the re-introduction of industrial load accompanying an economic recovery, the saturation of demand side management initiatives, variable hydrology, and transmission congestion.

Taking into consideration all of the above factors, FortisBC believes that not carrying a planning reserve margin (i.e. relying on an increasingly volatile market in the event of future shortfalls in supply) would expose its ratepayers to an unacceptable level of risk.

8.0 Reference: Purchased Power Management Expense (PPME)

Exhibit B-4, BCUC 1.25.1-1.25.5

"The increase to 7 FTEs in 2012 from 6 FTEs in 2011 will add an additional FTE to concentrate on managing power purchase costs." (BCUC 1.25.1)

8.1 Please provide a history of actual market power purchase volumes since 2007, and a forecast of market power purchase volumes to 2016, excluding any purchases made under contracts of greater than one year duration. Please separately identify any purchases made from Celgar if they are included in the foregoing volumes.

<u>Response:</u>

The table below shows the history of actual market power purchases since 2007, and a forecast of market power purchases to 2016, excluding any purchases made under contracts of greater than one year duration. This table does not include purchases from Celgar.

Actual and estimated power purchases from 2007 to 2011 include those made to meet energy and capacity requirements that exceed firm owned and contracted resources, and those made to displace energy that would otherwise be purchased under the BC Hydro PPA in response to market opportunities that allow for savings. The forecast market purchases for 2012 to 2016 are based on meeting the forecast energy and capacity requirements that are in excess of firm owned and contracted resources including the BC Hydro PPA, and do not include any forecast of purchases made to displace PPA energy, as this will depend on the ability of the Company to respond to actual market conditions as they arise.

Table BCUC IR2 8.1a

Year	Actual/ Estimate/ Forecast	FortisBC Total Market Purchases (GWh)
2007	Actual	34.6
2008	Actual	43.8
2009	Actual	120.7
2010	Actual	291.6
2011	Estimate	395.0
2012	Forecast	4.0
2013	Forecast	9.0
2014	Forecast	14.0
2015	Forecast	13.0
2016	Forecast	14.0

The table below shows the actual and forecast purchases made from Celgar from 2007 to 2016.

Table BCUC IR2 8.1b

Year	Actual/ Estimate/ Forecast	Purchases from Celgar (GWh)
2007	Actual	13.5
2008	Actual	19.8
2009	Actual	33.2
2010	Actual	28.9
2011	Estimate	0.3
2012	Forecast	0.0
2013	Forecast	0.0
2014	Forecast	0.0
2015	Forecast	0.0
2016	Forecast	0.0

"FEI will also provide enhanced capabilities to the electric power supply group through activities like contract administration, regulatory and policy compliance, business planning and load forecasting." (BCUC 1.25.1)

"These FEI services will provide an opportunity to enhance current work practices through the provision of cost effective services in support and administrative areas…" (BCUC 1.25.1)

8.2 FortisBC describes the increases in FEI charges and its related efficiencies above. Please explain why these efficiencies do not offset the requirement for the additional FTE in 2012.

Response:

The reference to "cost effective" in BCUC IR1.25.1, and that has been characterized as "efficiencies" in the above question, refers simply to the fact that FEI can provide these services for a lower cost than if FortisBC were to undertake to put in place additional resources to provide these services itself. In other words, if FEI did not provide these services, FortisBC would likely require the addition of more than one FTE in 2012 in order to be able to appropriately respond to increased levels of activity.

The Company believes that additional resources are required in order to continue to cost effectively manage the power supply portfolio and to ensure the Company is properly resourced to respond to new and unavoidable work activities that impact the power supply planning and operations. The Company is of the view that in part this requirement can be most efficiently met by sharing resources and expertise between FEI and FortisBC, with the services provided by FEI being primarily administrative and process support in nature. These services will be provided by a number of different FEI employees, and the requested funding is equivalent to less than one-half of an FTE. The provision of these services by FEI will help to permit FBC management resources to focus more effort on demands driven by the increasingly complex environment the Company faces. These demands have increased considerably in the past, cannot be avoided, and cannot continue to be successfully managed with the level of resources currently available.

Importantly, the need to support additional requirements is the primary driver for the requirement for an additional FTE in 2012 and is the minimum needed at this time.

Examples of some of new requirements that the Company foresees driving increased and unavoidable work activities include:

1. The need for more in-depth analysis of power supply options. The market is expected to undergo fundamental change in response to a number of regional initiatives and additional opportunities may be created to obtain lower cost power. It is necessary to increase the understanding of how power markets will now function in order to more fully take advantage of these opportunities, and to better manage overall opportunities related to our existing base resources;

2. The need to participate more fully in the regional organizations as the region grapples with the integration of renewable generation onto the regional grid. This need must be managed at the same time that overall levels of capacity margins are shrinking. At this time, many of the underlying procedures of the regional power system are under review to better accommodate renewable generation integration onto the grid. The move to 30 minute scheduling is one example of how this will be managed. By participating as a full member of organizations, such as the NorthWest Power Pool and the Western Electricity Coordinating Council, the Company has the opportunity to ensure the needs of smaller utilities such as FortisBC are not overlooked by the major regional utilities. Areas of particular concern are the rules governing scheduling practices and timelines, and operating reserves and how these potential changes may relate to the Company's relationship with BC Hydro under the Canal Plant Agreement;

3. The need for an additional resource at the System Control Centre with business continuity expertise. The specialized knowledge required to effectively oversee the Company's System Control Center power supply operations cannot be acquired without considerable work experience that is gained primarily over a long period of time. Particularly as the operating environment undergoes the current pace of change, it is critical that multiple individuals be able to supervise System Control Centre power supply operations to ensure business continuity is maintained;

4. The need for more active management with the dispatchers monitoring the real-time load resource balance. As the Company's PPA contract with BC Hydro is renegotiated and as loads continue to grow and the operating environment becomes more complex, the need for the training and supervision of the Company's hourly load resource balance increases. Actively managing load resource balancing is critical in order to ensure contractual obligations are met and that the security of supply to customers is maintained; and

5. The need to plan, implement and manage 30 minute schedules. In order to maximize efficiency, and be in a position to be able to better take advantage of regional short term market opportunities, the Company may be required to move to what is becoming the new scheduling standard of 30 minutes rather than 60 minutes. This will require revisions or replacements of the systems currently used to track the Company's real-time operations. New algorithms will be needed to predict short-term loads as all historical load information is for 60, not 30, minute periods. This change will result in a doubling of the scheduling work load to oversee and manage as there would be 48 scheduling periods in the day rather than 24.

It is quite possible, that given the additional complexity that is described in part in the above examples, that in the future that one additional FTE will insufficient and that more are required. If this need is substantiated, it will be addressed in future RRAs.

Please also refer to the response to BCOAPO IR2.3.1.

8.3 What is the additional work that is required to managing power purchase costs in 2012 when FortisBC appeared to have done successfully with the 3 FTEs (and subsequently, up to 6 FTEs) during the PBR?

Response:

This question attributes an incorrect number of FTEs to solely the management of power purchase costs. Please refer to page 47 of BCUC IR1.28.2 for a detailed discussion of the history and responsibilities of the Power Purchase Management group (also referred to as the "Resource Planning Department"). This department currently has 6 FTEs as a result of increases in the scope of activities for which the team is responsible, including power supply, load forecasting, and resource planning.

As described in BCUC IR1 Q25.1 there is currently only one, not three, FTEs dedicated to the day-to-day management and optimization of the power supply resources. BCUC IR1 Q25.4 details at some length the increases in complexity that must be managed to be able to continue to provide cost effective and reliable service to customers and be positioned to capture market opportunities to mitigate cost. As a result, the Company has identified the requirement to add an additional resource.

Please also refer to the responses to BCUC IR2 Q8.2 and BCOAPO IR2 Q3.1.

"Labour Expenses are required to cover costs associated with the Company's annual load forecast (1.5 FTEs)…" (BCUC 1.25.1)

8.4 Please explain why a permanent 1.5 FTE is required in the PPME when the load forecast is completed only annually? Could FortisBC allocate this employee to offset the need for the additional FTE in 2012? Explain why or why not.

Response:

The current and expected future requirements that need to be undertaken to complete annual load forecasts will not permit a reduction in the current level of effort. Completing a load forecast is a complex undertaking that requires a significant amount of time over the course of the typical year.

The preparation of the load forecast itself is a complex process that includes not only responsibility for the actual Load Forecast but also all the associated monthly reporting requirements plus the preparation of materials for the regulatory process. These additional tasks are estimated to require the equivalent of 0.5 FTE to complete.

Preparation of the load forecast itself includes many areas and is estimated to require 1.0 FTE:

1. Model development and maintenance which is done in-house to avoid costly 3rd party software contracts;
2. Ongoing research into a variety of load forecast methodologies such as DSM integration or an examination of various load drivers to ensure best practises are being maintained;
3. Customer contacts to explore load requirements that may not be properly reflected in the forecast models;
4. Ongoing research into new technologies such as electric vehicles to ensure forecast loads consider new loads that may be adding to system load in the future but are not reflected in historical data;
5. Data examination and validation to ensure system load data is correct and reasonable to use for forecasting purposes;
6. Analysis of data anomalies to resolve and understand what on the surface can appear to be inconsistent data or that needs to be reconciled to local economic conditions;
7. Preparation of the actual forecast taking all the above factors into account.

Finally, as part of the overall Resource Planning Department, the Load Forecast team provides direct support and updates to the Power Supply team through the analysis of longer term weather patterns that the Company must consider in planning for seasonal resource adequacy.

> "Of the 2.5 Resource Planning FTEs for 2012, only 1.5 FTE is being recovered through Resource Planning Departmental charges with the remaining FTE charged to the Resource Plan project." (BCUC 1.25.1)

8.5 Please explain the Resource Planning Department as this does not appear to be an O&M department. How is this portion of the PPME "charged out"?

Response:

The "Resource Planning Department" includes the three cross functional teams of Power Supply, Resource Planning and Load Forecasting that work on an integrated basis. In 2011, these costs were classified as the "Resource Planning Department" and included in O&M. For 2012 and 2013 these costs were reclassified as PPME and included in Purchased Expense instead of O&M. This treatment more closely aligns the costs to plan, procure, manage and optimise the power supply portfolio with the costs of the portfolio itself (See also the response to BCUC IR 1.26.1.)

Currently there are 6 positions included in the team, and the proposal is to include one more position beginning in 2013 in response to the increased level of activity and the need for more specialized resources to support the power supply activities (as discussed in BCUC IR2.8.2).

From a cost planning perspective, the Power Purchase Management Expense (also referred to as the “Resource Planning Department”) includes all costs incurred by this team, including all resource planning costs that are not charged to a project. The 2011 budget was based on certain staff members involved in the development of the Resource Plan charging a portion of their time to the Resource Plan project deferral account. This reduced the staffing costs included in the Resource Planning Department 2011 O&M costs by approximately the equivalent funding required for one FTE.

In other words although the group currently has 6 positions, the O&M budget included full funding for the equivalent of only 5 FTEs. In preparing the budget for the 2012 and 2013 PPME, it was assumed that these employees would continue to charge a portion of their time to other projects or departments as appropriate, and therefore this level of “charged-out’ costs has been continued in the 2012 and 2013 budgets. In other words, the funding request for the 7 positions in the group in 2012 and 2013 is approximately equivalent to 6 fully funded FTE positions.

8.6 For the 1.0 FTE charged to the Resource Plan project, where will this position be moved to after the completion of the Resource Plan?

Response:

Please refer to the response to BCUC IR2 Q8.5.

"The 30 percent increase in labour costs in 2012 compared to 2011 is mainly driven by the increase in 1 FTE at a forecast fully loaded cost of approximately $0.145 million. The remaining increase of approximately $0.055 million is due to salary increases for existing employees and changes to the charge out rate to the Resource Plan." (BCUC 1.25.3)

8.7 Please compare the labour cost of $0.145 million for the incremental FTE with the industry average for similar positions.

Response:

Based on the best information available to the Company, the industry average for this type of position is $82,000 per year before loadings. The Company loading rate is approximately 76% for a total cost of approximately $145,000.

8.8 How much of the $0.055 million is due to salary increases?

Response:

The salary increases for existing employees is $0.021 million.

OPERATION AND MAINTENANCE

9.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 1.28.1 – 1.28.3

O&M Increases in 2011

In response to BCUC 1.28.1, FortisBC provides explanations to the 15.1 percent cost per customer increase in 2011 over 2010.

9.1 Explanation (b) in the response refers to Order G-27-10 (a variance to Order G-123-09) which pertains to BC MRS. Has FortisBC obtained approval from the Commission for the deferral of or expenditure of the $1.0 million?

Response:

Yes. The BC MRS expenses were identified as a Z-factor in determining 2011 O&M Expense. Approval for the 2011 Revenue Requirements Application was granted through Commission Order G-184-10.

9.2 O&M increases as a result of Order G-195-10 regarding the Company's 2011 Capital Expenditure Plan accounts for approximately 8.4 percent of the total increases (explanation (a) in the response). However, the balance appears to be in the Health, Safety and Environment department (25 percent) and Transportation Services department (103 percent). Where does explanation (c) and (d) reconcile to in the table?

Response:

The table below provides an explanation and reconciliation of the O&M parameters (i.e., "a, b, c & d" from BCUC IR1 Q28.1 - 28.3) referred to above:

O&M Parameters	2010 Actual	2011 Forecast	% Increase	Remarks / Reconciliation
Year End Customer Count	112,250	113,977	1.5%	Refer BCUC IR1 28.1
O&M without PPME ($000s)	45,321	52,957	16.8%	Refer BCUC IR1 28.1
O&M without PPME / Actual Customer ($)	404	465	15.1%	Refer BCUC IR1 28.1
Increases in 2011 as a % of YE cost per customer :		($000s)		
Reclassification of Capital Expenditures in 2011	a	3,767	8.2%	Refer BCUC IR1 28.1
Mandatory Reliability Standards (MRS)	b	955	2.1%	Refer BCUC IR1 28.1
Corporate and Executive Management	c	400	0.9%	Out of the total departmental increase of $1,023k ($6,072k - $5,049k - Refer Table BCUC IR1 28.1) in 2011 over 2010, $400k of the departmental increase relates to recoveries for one-time non regulated work that occurred in 2010 and is not expected to recur in 2011 or beyond.
Pension and other post retirement benefits	d	1,000	2.2%	The $1,000k increase in pension and other post retirement benefits affects labour not only in any specific department (i.e., Health & Safety / Environment), but affects all departments of the company.
TOTAL:		**6,122**	**13.3%**	Refer BCUC IR1 28.1

Note: PPME – Power Purchase Management Expenses.

The response to BCUC 1.28.1 stated, that the above items account for 13.3 percent of the 15.1 percent increase in O&M per customer.

The following table expresses the increases of 25% and 103% in Health, Safety and Environment and Transportation Services on a cost per customer basis. The cost per customer increases for these two departments is as follows:

O&M Parameters	2010 Actual	2011 Forecast	% YE Cost / Customer Increase	% of Deptt O&M Increase
	($000s)			
Environment Health & Safety	727	907	0.4%	25%
Transportation Services	377	766	0.8%	103%
	1,104	**1,673**	**1.2%**	

Together these two tables account for 14.5% (i.e., 13.3% + 1.2%) of the 15.1% increase in cost per customer.

Please also note that:

- The Health, Safety and Environment department has increased one FTE (refer Exhibit B-1, Tab 4, page 78, Table 4.3.4.13). Additionally a decreased SAWCO (Salaries and Wages Charged Out) has resulted in increased O&M cost for the department.

- The Transportation Services department has experienced a sharp rise in gas and diesel prices as compared to 2010. In addition, the relative volume of vehicle charge outs to projects has reduced in 2011 compared to 2010 due to a reduction in capital projects. This has resulted in an increase to the department's O&M in 2011.

10.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 1.34.3

Executive Compensation

"As a general policy, FortisBC establishes base and incentive compensation targets so as to compensate executives at a median level of a broad reference group of Canadian commercial industrial companies." (Exhibit B-1, Tab 4, p. 44)

10.1 In response to BCUC 1.34.3, FortisBC provides a table reproduced from the reference group data on base salary and target bonus. In all executive positions listed in the table, FEU's base salary is higher than or equal to the median for the reference group. Is this statement true? Explain why or why not.

Response:

Yes, the FEU's base salary is higher for two positions and equal for two positions. As a general policy salary mid-points are targeted to be consistent with market median. Individual salary placements are generally to be within the established salary range for the position, the range is from 80% to 110% of the market rate for the position. Individual salary placement within the range is established giving due consideration to job performance and work experience.

10.2 Please explain the percentages shown in the table under Target bonuses.

Response:

The percentages shown in the table under target bonuses represent the target level of annual incentive for each position. Currently, the five incumbents have been assigned a target bonus of between 30% - 50% and the 2011 commercial industrial median is showing that the targets are between 31% - 54%.

11.0 Reference: Operation and Maintenance
Exhibit B-4, BCUC 1.34.8
Supplemental Executive Retirement Plan (SERP)

11.1 Please include a separate column for the table to BCUC 1.34.8 which shows the corresponding number of executives for each year.

<u>Response:</u>

Please refer to the below table.

Table BCUC IR2 11.1

Balance in SERP Account, Years Ended 2006-2010		
Year	**Balance ($)**	**# Members**
2006	302,490	7
2007	620,004	9
2008	827,892	9
2009	1,044,892	9
2010	1,293,258	8

**** Note: The number of members includes all who have SERP balances at year end each year, whether or not they remain actively employed with FortisBC at year end.*

**** Note: There are some employees covered under the SERP who are not at the executive level, due to individual employment terms and conditions. These employees are included in the total number above.*

11.2 The balance in the SERP account has grown over 400 percent over the last 5 years. Is this related to the increase in the number of executives or the compounding effect of the 13 percent annual base salary accrual into the SERP?

<u>Response:</u>

The increase in the balance from 2007 to 2010 is mainly due to the cumulative effect of the annual accrual into the SERP (13 percent of each Member's Earnings in excess of the Member's CRA Earnings Limit). There were no material changes in the number of executives under the SERP or to the contribution rate during this period of time.

The SERP began June 1, 2004. The increase in the cumulative SERP balance over the last five years is a relative increase (see table presented in the response to BCUC IR 2.11.1). Specifically, if the SERP had been in existence for a much longer time, such as twenty years, the increase from 2007 to 2010 would not be perceived as significant. The increase since inception is over a relatively short period of time (last five years) and therefore has the perception of a greater increase.

11.3 Please provide the percent of SERP accruals for comparable companies in BC and in Canada. Is 13 percent a reasonable figure?

Response:

FortisBC has not specifically compared the percent of SERP accruals for comparable companies in BC and in Canada. However the Hay Group provides independent advice to FortisBC regarding executive compensation issues. Hay Group confirms that FortisBC's Defined Contribution Supplemental Employee Retirement Plan ("DC SERP") value of 13% is a reasonable figure and is within the norm of other executive retirement programs in the Canadian marketplace. For clarification, the FortisBC's DC SERP provides for the accrual of 13% of base salary and annual incentive in excess of the Canada Revenue Agency limit (not the full amount of 13% of salary).

12.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 1.35.1; Exhibit B-1, Tab 4, p.45

Employee Turnover

Between 2008 and 2010, FortisBC recruited 181 new employees, for the most part, as a result of backfilling turnover. However, Table 4.3.4 in the Application indicates that total FTEs have actually reduced from 564 to 535 during that same period.

12.1 Please provide, in table format, the turnover rates by department for the years 2008 – 2011. Please add a column to include the most common reasons for department turnover and another column to include any incremental costs associated with the turnover by department (severance costs, other one-time expenses).

Response:

Please refer to the below table.

Table BCUC IR2 12.1

	Turnover Rate %				Av	Employee Turnover	
DEPT	2008	2009	2010	2011	%	Reason	Incremental Costs
Corporate Services	12%	3%	4%	13%	8%		
FTE	138	140	144	145			
				3		Intercompany Transfer	
	9	4	6	9		Resigned - Other employment/personal	
	6			3		Retirement	
	2			4		Terminated - Non disciplinary	$97,258
Engineering	11%	12%	7%	6%	9%		
FTE	53	57	55	62			
	2	1	1	2		Resigned - Other employment/personal	
	3	5	2	2		Retirement	
	1	1	1			Terminated - Non disciplinary	$107,219
Finance	16%	9%	10%	13%	12%		
FTE	70	68	69	60			
	10	4	6	6		Resigned - Other employment/personal	

	Turnover Rate %				Av	Employee Turnover	
DEPT	2008	2009	2010	2011	%	Reason	Incremental Costs
		2	1			Retirement	
	1			2		Terminated - Non disciplinary	$55,402
Generation	8%	1%	7%	5%	5%		
FTE	97	98	96	98			
	1					Deceased	
	1		2	1		Resigned - Other employment/personal	
	5	1	5	4		Retirement	
	1					Terminated - Non disciplinary	$36,850
Network Services	7%	6%	8%	7%	7%		
FTE	199	178	174	175			
				1		Deceased	
	6	4	10	7		Resigned - Other employment/personal	
	7	5	4	5		Retirement	
		1				Terminated - For cause	
	1	1				Terminated - Non disciplinary	$45,816
Grand Total	56	29	38	46			$342,546

12.2 High employee turnover may have the potential to reduce morale, indicate internal work/operational issues, and may put upwards pressure on costs in terms of training, re training, and loss of efficiencies. How can FortisBC get a better handle on employee turnover and to better manage the turnover rate in the future?

Response:

FortisBC recognizes the challenge of employee turnover and anticipates the level to continue as approximately 50% of the current workforce is eligible to retire in the next five years. In order to continue to manage this, FortisBC has programs and initiatives in place to attract employees to backfill key positions, as well as retain existing employees. Some of these programs and initiatives include:

- Ensuring that the Company's total benefit and compensation program aligns FortisBC with market competitors;
- Ensuring that the Company retains and motivates its workforce by recognizing and rewarding achievement and contribution;
- Promoting continuous learning and leadership development; and
- Focusing on succession planning and transfer of knowledge to mitigate the effect anticipated retirements may have on the workforce.

13.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 1.36.1

Generation

"FortisBC considers it likely that (the Umatilla dace) will be listed as threatened, triggering the prohibitions under SARA and thus increasing species management expectations for FortisBC."

"It is likely that (the short-headed sculpin) will be down-listed removing the prohibition triggers under SARA and thus reducing species management expectations for FortisBC."

13.1 Given the two statements above, wouldn't the operating costs balance out leaving little significant impact to costs? How does this reconcile to FortisBC's "estimates that operating costs may increase from $0.01 to $0.10 million per year"?

<u>Response:</u>

It is unknown at this time whether or not the operating costs would balance out if the short-headed sculpin were down-listed and the Umatilla dace were listed, as the work required to mitigate the threat to these species is not defined at this time.

As noted in the response to BCUC IR1 36.4 in Exhibit B-4, increases to operating costs could include activities such as participation in work groups and technical committees, increased observation and monitoring during routine maintenance outages and fish stranding inspections. It is anticipated that regardless of the number of species listed some or all of the above activities could be required.

13.2 Since FortisBC has made no specific allocation in 2012 or 2013 for these costs, is it assumed that these costs will be absorbed as it is incurred?

Response:

If the costs were a result of legislative changes (such as the listing of a new species under the Species at Risk Act) then, depending on the magnitude of the expenditure, FortisBC would apply to the Commission for recovery of the costs.

14.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 1.37.1 – 1.37.2

Generation

14.1 Given the correction of Table 4.3.4.1 of the Application in Errata 2, it appears that the labour expenses in the Generation department is increasing 11 percent in 2012 then another 12 percent in 2013. Please explain why, particularly when the number of FTE remains constant at 97.

Response:

FortisBC utilizes its FTE complement to complete operating tasks, capital work and work for third party clients. The percentage of work completed in each area varies by year. As discussed in the response to BCUC IR1 Q38.1 (Exhibit B-4), FortisBC has seen an increase in the overall amount of work required in its regulated operations, resulting in higher labour expenses as shown in Table 4.3.4.1.

"…the Company has also seen an increase in the total number of labour hours required to complete the revised scope of work described above primarily as a result of changes to legislation such as working alone and confined space…". Excerpt from response to Exhibit B-4, BCUC IR1 Q38.1.

By allocating some of its existing resources from capital work to this operating work, FortisBC has been able to complete the increased O&M workload without increasing its complement of FTEs.

15.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 39.1, BCUC 39.2, BCUC 44.1

Maintenance Management Systems

"The information gathered by the Maintenance Rationalization Project (MRP) was fed in to Generation's maintenance scheduling system (GenJO). The information translated to adjustments to a number of existing maintenance intervals within GenJO."

"CMMS and the Maintenance Rationalization Project (MRP) are not related. CMMS is a software system employed by the Utility Operations group to manage its maintenance work."

15.1 Please identify the differences and similarities of GenJO and CMMS and explain why FortisBC is using multiple systems for managing maintenance work.

Response:

GenJO and CMMS are similar in that they provide maintenance crews with a work management system. CMMS was adopted by Network Services to manage the equipment found in the substations and terminal stations in the Company in 2006. GenJO was developed by the Company in the mid 1990s to provide a work management tool specific to generating equipment. Over the years it has been modified and improved and now serves as both a work management system and data collection area for generation assets. It does not have the capability to provide maintenance triggers based on condition data entered into the program.

CMMS is similar to GenJO except that it does possess the capability to provide maintenance triggers based on condition data entered into the system. The potential to migrate the generation equipment over to the CMMS program was investigated in the mid-2000s however the option was not pursued at that time. It is anticipated that the option of combining all FortisBC assets under one system will be reviewed once again as the Asset Management Program is investigated over the next two years.

16.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 1.42.1 – 1.42.2

Utility Operations

"In 2007, FortisBC did have a large number of PLTs which were part of the overall succession plan to compensate for the ageing workforce and anticipated retirements."

16.1 Does the above statement suggest that there were a number of retirements of PLTs during 2007-2010?

Response:

Yes, there were retirements as well as resignations during 2007-2010.

FortisBC states that "The numbers in 2007 to 2010 represent actual FTEs on the roles, less vacancies, whereas 2011 to 2013 represents the forecast numbers, inclusive of vacancies, which have been budgeted for."

16.2 Please identify the number of vacancies in each of 2011 to 2013. Please reconcile the amount of work increases with the need to backfill vacancies during the test period (4 percent FTE increase in 2011, 5 percent FTE increase in 2012, and 1 percent FTE increase in 2013).

Response:

The FTE count is based on budgeted work required for operating and maintenance, internal capital and third party contracts. The budget is based on estimated labour hours which equates to FTE positions. Any vacancies during the year are offset by temporary or contracted manpower. Vacancies are variable in nature based on when employees actually leave and when they are replaced which could be days, weeks or months.

Utility Operations vacancies at the end of September 2011 were 12. These vacancies will be filled in 2012 and 2 FTEs will be added in 2013.

17.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 1.42.2

Utility Operations

In the 2009-2010 FortisBC's Capital Expenditure Plan (CEP), FortisBC included $0.75 million per year for 2009 and 2010 and estimated that expenditures of approximately $0.5 million per year would be required for the years 2011 to 2016 to cover the cost of the Hot Tap Connector Replacement program. (2011 CEP Decision, p. 63)

In response to BCUC 1.42.2, FortisBC states that the number of hot tap connectors replaced is 4,946 in 2010 and 1,670 in 2011. (Exhibit B-4, BCUC 1.42.2)

17.1 Given the references above, it appears that the average unit replacement cost is substantially higher in 2011 than in 2010. Please explain why and use calculations to illustrate.

Response:

The 4,946 units replaced in 2010 represent the work identified in the 2009/10 capital plan. The planned work for 2009 was carried over into 2010 and hence the work done in 2010 represents 2 years of replacements.

The 4,946 units were replaced for a total cost of $1.024 million representing a unit replacement cost of $207.20. It should be noted that 3,552 of the units were replaced in the Kelowna region. This is a more urban distribution system with the benefit of less travel and more on the tool time.

In 2011, it is estimated that 1,670 units will be replaced and this has been budgeted at $0.385 million, which represents an estimated unit replacement cost of $230.54. The remainder of 2011 will be used to assess the regions where replacements will take place in 2012.

17.2 Please discuss and show the estimated expenditures in 2012 and 2013 along with the number of hot tap connector replacements.

Response:

The estimated unit cost of replacement for 2012-13 is $300, based on the fact that the majority of this work will be conducted in rural areas.

The estimated expenditures and numbers for hot tap connector replacements for 2012 and 2013 are shown in the table below:

Table BCUC IR2 17.2

	2012	2013
Budget ($000s)	409	411
Estimated units	1,365	1,370

18.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 1.45.1(c), 1.45.2, 1.45.3 and 1.46.1

Mandatory Reliability Standards (MRS)

"FortisBC has estimated that 4.5 FTEs need to be dedicated to maintain compliance in addition to incremental costs to the various departments in the organization. The departments with incremental costs include Planning, Information Systems, Generation, Internal Audit, Human Resources, Vegetation Management, and Station Maintenance." (Exhibit B-4, BCUC 1.45.1(c), p. 77)

"The original budget for 2011 was $853,000 and is currently forecast at $955,000….In 2011, this increase has been mitigated by operating cost savings in other departments." (Exhibit B-4, BCUC 1.45.2, p. 81)

18.1 Given that FortisBC is able to mitigate incremental cost increases with savings in other departments during 2011, is it reasonable to assume that FortisBC can similarly maintain compliance with MRS using 4.5 FTEs during the test period without incurring incremental costs elsewhere? Please discuss.

Response:

As identified in the response to BCUC IR1 Q45.2, the increase in expenditures for 2011 is due to the requirement to become auditably compliant with field devices, the mitigation plans for which have been approved by the Commission. Ongoing reviews of the standards through processes such as annual self-certification or BCUC/WECC audits could result in a change in effort and associated costs. It is not reasonable to assume that the Company can maintain compliance with additional requirements without incurring incremental costs elsewhere.

FortisBC will continue to manage the costs associated with BC Mandatory Reliability Standards compliance to minimize impact on customer rates while maintaining compliance to the satisfaction of BCUC/WECC.

FortisBC also states that "2011 is a transition year, in which work is still ongoing to become compliant under mitigation plans. The change from 3.6 FTE to 4.5 FTE (as shown in the Table BCUC IR1 45.1b of the response to BCUC IR1 Q45.1) represents the transition to maintenance of the standards." (Exhibit B 4, BCUC 1.46.1)

In 2011, FortisBC focused on "transitioning from initial assessment and development of compliance plans to monitoring and maintenance of compliance with the standards." (Exhibit B-4, BCUC 1.45.2, p. 81)

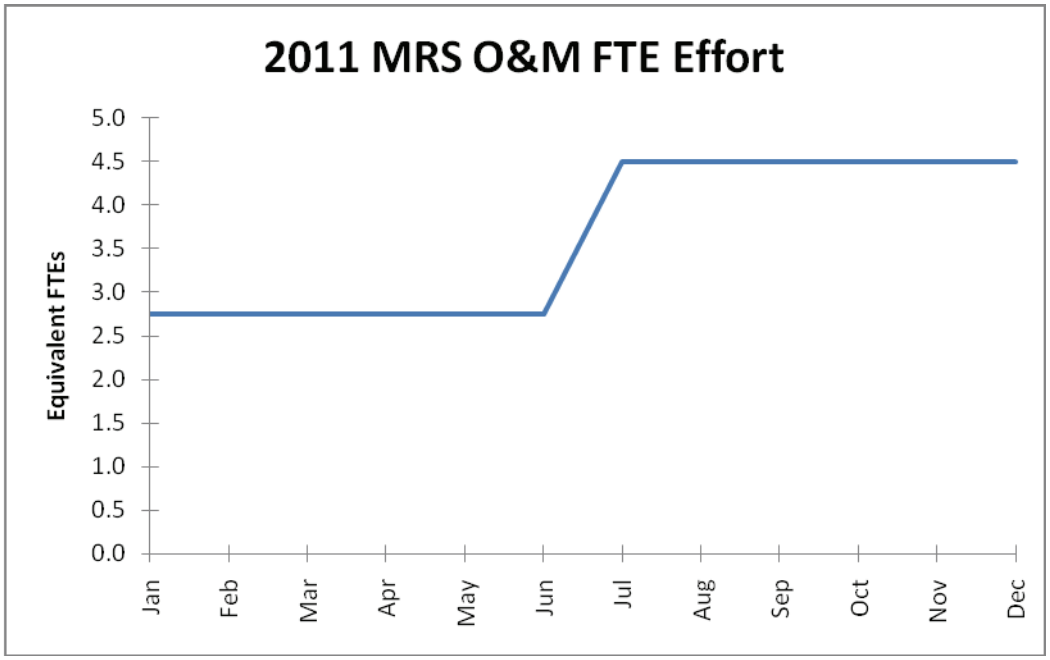
18.2 Given the substantial reduction in tasks involved in the test period (compared to 2011), please explain why an increase in FTEs from 3.6 to 4.5 is still required.

Response:

There is not a reduction of tasks involved but a transfer of effort which includes different tasks. The additional 3.6 FTEs is an average number for the year. As identified in the chart below, the initial additional estimated O&M FTE is 2.75 in January, increasing to 4.5 in December. The change from 2.75 (Q1, 2011) to 4.5 (Q4, 2011) represents the completion of mitigation plans and the change to focused effort in maintaining the standards. For example, the capital effort to install systems to limit access to specific authorized personnel is transitioned to the annual operating effort to maintain the processes, records, tools and software to support the systems implemented.

2011 is a transitional year where the full operating costs are identified in the last quarter of the year and is representative for future years. The first part of 2011 represents the deployment of resources to mitigation plans filed with the BCUC/WECC and are capital in nature. The additional resources were added as necessary to ensure the Company is compliant to the satisfaction of the BCUC/WECC. Adjustments to processes, efforts and costs may be required based on the results of annual self-certification or BCUC/WECC audits. FortisBC will continue to manage the costs associated with BC Mandatory Reliability Standards compliance to minimize impact on the customer rates while maintaining compliance to the satisfaction of BCUC/WECC.

Figure BCUC IR2 18.2



19.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 1.51.1

Customer Service

FortisBC provided a table breaking out FTEs in the Customer Service department.

19.1 In 2011, the number of FTEs in the Billing function increased 30 percent (from 13 to 17) although the growth in the number of customers is forecast to be 1.5 percent. Please explain why.

Response:

The number of employees in the Billing department was forecast to increase in 2011 to accommodate two temporary FTEs to handle anticipated payment processing errors related to gas payments, one permanent FTE to cover the reception area in the Kelowna office and one permanent additional billing analyst to handle anticipated increases in complex billing. FortisBC notes that the number of employees in Billing is forecast to decline to 14.3 by 2013.

19.2 The number of FTEs in the Energy Management function remained relatively constant from 2007-2010 then increased to 38 percent in 2011 to a total of 11 FTEs. What kind of work load changes would require such an increase? Please discuss.

Response:

The number of FTEs in the Energy Management function increased in 2011 in order to prudently manage the increased DSM expenditures approved. A Monitoring and Evaluation Analyst position was added in 2011 to ensure that the larger number of PowerSense programs continue to be cost-effective and that the associated energy savings are accurately accounted for. An engineering position was also added to provide additional technical support for the development of the new and enhanced programs. Finally, an additional part-time community ambassador position was added in 2011 to help promote DSM programs.

20.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 1.52.4

Community Investment

"Ownership of the corporate name and goodwill, similar to ownership of other assets, is not determinative as to who should pay for costs associated with benefits or values received from the asset."

20.1 Given that utility shareholders own the corporate name and Company assets, please clarify whether it is the ratepayers or the shareholders who own the goodwill of the Company.

Response:

A utility's goodwill is the intangible value of its ongoing business, associated with or resulting from its performance and reputation with its customers. Ownership of the corporate name and goodwill, similar to ownership of other assets, is not determinative as to who should pay for costs associated with benefits or values received from the asset. A public utility's corporate name and goodwill provide benefits to the ratepayers. Community investment enhances the relationship between the utility and the communities it serves, and in turn, it can affect the expenses associated with public consultation that are necessary as part of the utility's operation.

Community investment is expected of any significant business enterprises by the communities they serve and are thus part of the cost of doing business. As such, such costs should be recoverable in rates.

20.2 Please explain the US GAAP accounting treatment for goodwill as can be seen in FortisBC's financial reporting. In the event that the Company is dissolved, please explain how goodwill is distributed. Does goodwill accrue to ratepayers or shareholders upon dissolution of the company assets?

Response:

The goodwill referred to in the response to BCUC IR1 Q52.4 is not goodwill as reported in financial statements; rather it is more in the context of providing a positive relationship with the community.

Goodwill for accounting purposes arises as a result of the amount paid by an acquirer in excess of the cost or fair value of an acquired business entity that cannot be attributed to specific assets. In the event that the Company is dissolved, the distribution of any accounting goodwill and whether it accrues to the ratepayers or shareholders will depend on the circumstances that existed at the time of acquisition.

21.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 1.59.3

Finance and Accounting

"As a result of receiving the OSC exemption, the forecast 2012 and 2013 Finance and Accounting O&M expenses have appropriately excluded any expenses related to SOX 404 attestation expenses."

21.1 What is FortisBC's best estimate of annual expenses related to SOX 404 attestation after 2013?

Response:

The Company has an Ontario Securities Commission (OSC) exemption to prepare and file its financial statements under US GAAP until the end of 2014, therefore SOX 404 attestation costs are not required to be incurred during this time. However assuming that the OSC exemption is not continued and the Company continues to prepare its financial statements under US GAAP, then the SOX 404 attestation costs of approximately $60,000 would have to be incurred in 2015 and annually going forward. One time SOX 404 conversion costs would also have to be incurred prior to the attestation in 2014 at a cost of approximately $75,000.

22.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 1.55.1, 1.60.5; Exhibit B-1, Section 4.3.4.18, p. 91

Overhead Charge and Fully Loaded Wage

FortisBC states that "Currently, the cross charges to and from FEI include a fully loaded wage plus an overhead charge of 5.5 percent." (Exhibit B-1, p. 91)

22.1 Please discuss the expected changes to this overhead charge in 2012 and 2013, particularly if the rate is expected to change.

Response:

The Company is not expecting to change the rate in 2012 or 2013; however, as indicated in Lines 10 -14, Section 4.3.4.18, page 91 of the Application, the Company is proposing to eliminate the overhead charge of 5.5 percent on charges to FEI.

22.2 Provide the value of the overhead charges from FortisBC to FEI and from FEI to FortisBC in 2010 2011 and forecast for 2012-2013.

Response:

Overhead charges from FortisBC to FEI were approximately $29,000 in 2010 and are forecast to be approximately $80,000 in 2011.

Overhead charges from FEI to FortisBC were approximately $46,000 in 2010 and are forecast to be approximately $180,000 in 2011.

As noted in Exhibit B-1, Section 4.3.4.18, p. 91, Lines 10 – 14, the Company is requesting to not include an overhead charge in 2012 and 2013.

In response to BCUC 1.62.3, FortisBC explains and provides a calculation for the fully loaded wage charged to O&M, capital and third party work.

22.3 Please explain the base salary "net of time away." Please explain what this is referenced to. Idle time, office time, etc? Please provide an example of how "time away" is calculated. Similarly, how does FortisBC calculate billable hours to a work order or a capital project?

Response:

a) Base Salary "net of time away" is equal to total salary less paid time off. Paid time off is made up of:
   - Vacation
   - Sick time
   - Statutory holidays
   - Other paid time off

b) Time away is calculated by the time off (number of hours) times the base rate of pay per hour.

c) Employees charge billable hours to a cost centre, work order or capital project. Time away is charged to the fringe benefit loading pool and applied to regular billable hours as described in the response to BCUC Q1.62.3.

22.4 Please explain how vehicle charges are included in the fully loaded charge-out rates? Is this also "net of time away"? How does FortisBC determine vehicle usage billable hours? Provide an example with calculations (include considerations for fuel and vehicle maintenance costs).

Response:

Vehicle charges are not included in the loaded wage rates. Vehicles are charged in the payroll system to projects or third-party work by the vehicle operator based on the number of hours the vehicle was utilized.

Vehicle charge out rates are calculated and charged out separately from labour charge out rates. There are 12 separate charge out rates for different vehicle classes such as Passenger Vehicles, 1/2 Ton Trucks & Smaller, Service Vehicles (3/4 & 1 Ton), Single Axle Line Truck (Digger or Aerial) and Tandem Axle Line Truck (Digger or Aerial).

Vehicle charge out rates are determined by dividing the total estimated operating costs for a particular vehicle class by the estimated average billable hours per class. Operating costs include, Staff Labour and Expenses, Fuel & Oil, Tires, Parts and Supplies, Preventive Maintenance costs, Corrective Maintenance costs, Lease costs, Insurance, etc.

The average billable hours per class is based on historical billed hours for the vehicle class.

Example:

Total estimated operating costs for vehicle class:	$250,000
Estimated billable hours for vehicle class:	10,000
Vehicle charge out rate (per hour):	$25.00

22.5 Are there tracking or audit reports for area managers to confirm that the fully loaded charge-out rates (including vehicle?) are properly reported? What are the internal control mechanisms in place?

Response:

The fully loaded charge-out rate is calculated and updated annually in SAP. The actual loading charged is compared to forecast on a monthly basis at the corporate level to ensure that the recovery is appropriate. The loading charge is calculated by SAP cost allocation routines to department or project work orders. The Company has very tight change management controls with regard to changes to SAP. The controls are tested by the Company's external auditors annually.

Managers have a variety of SAP reports available to them in order to determine if costs are being properly reported. SAP reports can provide details of any costs including labour or vehicle charges to departments or projects.

Management is required to create zero base budgets annually and update the departmental forecasts monthly and provide variance explanations for any material differences. Capital expenditure plans are also reviewed monthly and updated forecasts with variance explanations are also provided monthly. Work orders are created for all projects utilizing a work breakdown structure in order to capture costs according to the various work being performed.

Management is also required to provide a quarterly certification that they have reviewed the operating and maintenance, capital and deferred charges spending reports in the quarter and that there are no material differences in the amounts that are under their management. Additional certification by Process Owners is also required quarterly attesting that the process narratives maintained by the Company do not need to be changed and accurately describe the process. Processes include but are not limited to Accounts Payable, accounting for Property Plant and Equipment, accounting for Deferred Charges, Financial Reporting, Taxation, Treasury, Payroll, etc.

The Company also has an Authorities Policy that specifies the Operating and Commitment Authority of every employee.

The Internal Audit department routinely performs audits of activities and processes undertaken by the Company. The results of Internal Audits are reviewed by Management, Executive and the Audit Committee of the Board of Directors.

22.6 How often does the fully loaded charged-out rates get reviewed an updated? Are they also reviewed by internal audit?

Response:

The fully loaded charge out rates are reviewed and updated annually.

Internal Audit reviews the effectiveness of internal controls of significant business processes that includes reconciliation of the payroll accounts, pension, budgeting, financial reporting and general accounting processes all of which contribute to the calculation of the charge-out rates.

These controls are tested annually by Internal Audit and were found to be operating effectively in the most recent Internal Controls testing for 2011.

23.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 1.60.2 and 1.60.3

Transportation Services

23.1 FortisBC submits that only 25 percent of the vehicle maintenance work is outsourced, compared to 70 percent at BC Hydro and 100 percent at FEI and PNG. Please discuss these large differences in outsourcing ratios.

Response:

The Company cannot comment on differences in the amount of vehicle maintenance work outsourced by BC Hydro versus FortisBC. The amount of outsourcing can vary from one company to another for a variety of reasons. FortisBC is an electric utility with a transmission and distribution system that is overhead construction. Therefore, the Company utilizes a number of heavy duty trucks that incorporate overhead booms, digger derricks and rubber trucks for working on energized lines. The Company is of the opinion that the knowledge, training and experience associated with servicing and maintaining overhead, specialized vehicles and equipment is best kept in-house and enables the Company to maintain a safe, reliable working fleet. Gas utilities do not utilize as much specialized equipment and are able to contract for vehicle maintenance services in the market. FortisBC is exploring opportunities for contracting out the light fleet vehicle maintenance.

23.2 Please explain the benefits and costs savings of outsourcing a larger volume of maintenance work. Could FortisBC outsource more maintenance work yet still be effective in providing safe and reliable vehicles? Explain why or why not, particularly given the comparison to other utilities in the previous question.

Response:

Some of the possible benefits of outsourcing a larger volume of maintenance work include discounts for parts and service. The Company is investigating the possibility of outsourcing more of the routine maintenance work on the light duty vehicles. The business case would have to demonstrate cost savings, and ensure the optimization of the existing fleet workforce without compromising safety and reliability of the heavy fleet.

23.3 Please provide in a table format the detailed breakout of the type of vehicles in the fleet for the period 2007-2013. Explain any changes to the vehicle count that is greater than the customer growth rates from year over year.

Response:

Please refer to the below table.

Table BCUC IR2 23.3

Category	2007	2008	2009	2010	2011	2012	2013
Heavy Vehicles (# units)	46	48	46	48	47	46	46
Service Vehicles (# units)	101	102	89	91	88	90	90
Light/Passenger Vehicles (# units)	97	106	107	114	118	119	119
Specialty/Off-Road/Trailers (# units)	85	95	100	95	97	95	97
Total vehicle count	329	351	342	348	350	350	352
Vehicle growth rate (%)		7%	-3%	2%	1%	0%	1%
Customer growth rate (%)		2%	1%	1%	2%	2%	2%

From 2007 to 2013F the overall number of units grew by 7%, while the customer growth rate grew by 10%. The number of vehicles is not directly related to the rate of customer growth. Customer growth is more granular in nature. The number of vehicles is related more to the nature and design of the sustaining electric system than to the customer growth rates.

23.4 Given that the bulk of capital work is near completion, shouldn't there be an expectation to have a reducing fleet count rather than increasing? Please explain.

Response:

The number of fleet units is not generally related to the amount of capital work since the Company determines the fleet size based on the level of sustaining capital and operating work, not only capital expenditures levels. Where capital work requires more resources than the Company is able resource, the work has been contracted out and the contractor would supply their own vehicles. The total fleet count is expected to remain mostly stable through 2013.

The Company disagrees with the statement that the bulk of the capital work is near completion. While certain of FortisBC's capital work is currently nearing completion, capital expenditures of $105.86 million are forecast in 2012 and $129.08 million are forecast in 2013, as described in the 2012 – 2013 Capital Expenditure Plan (Tab 6 of the 2012-13 RRA).

24.0 Reference: Operation and Maintenance

Exhibit B-4, BCUC 1.62.19, 1.62.20; Exhibit B-5, BCOAPO 1.96.1, 1.96.3

Fortis Inc. Corporate Services Charge

24.1 Please explain why the cost allocation method included a phased-in approach in 2008-2009.

Response:

A phased-in approach was adopted in order to smooth the impact of the transition to the new cost allocation methodology.

24.2 Has FortisBC considered any other cost allocation methods in the past such as based on the number of FTEs or number of transactions? Why or why not? If previous studies are available, please summarize the results.

Response:

There are a number of different models that can be used for cost allocation. These models most often allocate costs based one or a combination of such factors as:

- Assets;
- Revenue; and
- Payroll

Fortis Inc. allocates its recoverable costs based solely on asset levels at the utilities as it is most closely correlated with the net investment required of Fortis Inc. in the utilities, which is a key driver of the recoverable operating costs at Fortis Inc. The use of revenue as an allocation method could distort the allocation of the recoverable costs because utilities, such as FortisAlberta, that only charge customers for distribution services, would receive a disproportionately low allocation of the costs, while other utilities could receive a disproportionately high allocation of the costs in periods when customer rates and related revenue reflect the pass through to customers of rising gas and fuel prices. Likewise, payroll as an allocation method is not appropriate because the basis of cost recoveries is not on a shared-services model and is in no way related to relative payroll costs/number of employees at the utilities.

24.3 What is the value of the pole rental revenue offset that is no longer available in 2011?

Response:

The pole rental revenue that was available to offset Fortis Inc. recoverable costs in 2010 was $184,000. Please also refer to BCOAPO IR1.96.1.

FortisBC's response in BCOAPO 1.96.1 includes a table which separately breaks out the Corporate Services costs allocated to FortisBC by function. While the percentage of allocation remains relatively constant (from 12.74 percent to 13.16 percent), the total allocated cost has increased 70 percent from 2009 to the test years, largely attributed to the Executive function. FortisBC states that the Executive function at Fortis Inc. provides "strategic and corporate governance…and provide access to equity markets and a market return to shareholders." (Exhibit B-5, BCOAPO 1.96.3)

24.4 Does FortisBC consider the increased expenditures in the Executive function to be reasonable?

Response:

FortisBC considers the increased expenditures in the Executive function to be reasonable. The Executive costs in the test years should be compared to those in 2010 not 2009 since the full transition to the new allocation method was not complete until 2010. So the actual increase in the Executive function from 2010 to the test years is in the order of 18% or a geometric average increase of 5.7%.

The Executive costs were found to be reasonable as demonstrated by the KPMG report to FEI in 2009. A copy of the report was included in the Terasen Gas Inc. 2010 and 2011 Revenue Requirements and Delivery Rates Application and the Fortis Inc. costs were applied for and approved by the Commission for FEI in 2010-2011.

24.5 What is the value/benefit that is attributed to ratepayers from the large increase in executive costs?

Response:

Please refer to the response to BCUC IR2 Q24.4. The Company does not consider the increase in Executive function costs to be excessive. As evident from the KPMG report previously referenced in the response to BCUC IR2 Q24.4, the value/benefit of the Executive function is that ratepayers benefit from the efficiencies realized when Executive functions are shared by the various Fortis Inc. subsidiaries and by Fortis Inc. providing centralized access to capital.

CAPITALIZED OVERHEAD

25.0 Reference: Capitalized Overhead

Exhibit B-4, BCUC 1.63.2

"There is not an abundance of explicit or detailed guidance around the concept of "directly attributable" under IFRS and it is therefore subject to different interpretation."

25.1 Please discuss the definition and treatment for Capitalized Overhead under US GAAP.

Response:

There is no specific guidance, definition or discussion of the treatment of Capitalized Overhead under US GAAP. However, as outlined in Appendix M to the 2012-2013 RRA, there is US GAAP literature that provides guidance on asset accounting and accounting for rate-regulated activities.

ASC 360-10 defines the cost of property, plant and equipment as all costs necessary to bring it to the condition and location necessary for its intended use. ASC 360-10 also states the following:

"If an asset requires a period of time in which to carry out the activities necessary to bring it to that condition and location, the interest cost incurred during that period as a result of expenditures for the asset is a part of the historical cost of acquiring the asset. The term activities is to be construed broadly. It encompasses physical construction of the asset. In addition, it includes all the steps required to prepare the asset for its intended use. For example, it includes administrative and technical activities during the pre-construction stage, such as the development of plans or the process of obtaining permits from governmental authorities. It also includes activities undertaken after construction has begun in order to overcome unforeseen obstacles, such as technical problems, labour disputes, or litigation."

Generally, US GAAP allows a rate regulated entity to capitalize costs that normally would be expensed if the costs are "allowable costs" for rate making purposes. Allowable costs can be actual or estimated and there must be reasonable assurance that the regulator will permit recovery of the costs in rates.

Specifically, ASC 980-340 state the following:

"Actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:

a) It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes;

b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost."

As a result of the above, if an amount of capitalized overhead is included in the cost of an asset, is approved by a regulator and is expected to be recovered from customers in future rates, then that capitalized overhead amount forms part of the cost of that asset.

"Based on a high level preliminary analysis that was performed back in 2010 during the Company's planned transition to IFRS, an appropriate IFRS overhead rate was expected to be in the range of approximately 6% to 12%."

25.2 Please provide the existing capitalized overhead rates for other comparable utilities in BC. Understanding that different utilities may use different methods for calculating capitalized overhead rates, please generally discuss any major differences between the rate calculated by FortisBC and the other utilities.

Response:

The Capitalized Overhead for comparable utilities in BC is discussed below:

1. FortisBC Energy Inc. (FEI) – pursuant to Commission Order G-141-09 FEI applies a 14 percent capitalized overhead rate on Gross O&M. In its 2010-2011 Revenue Requirements Application, FEI had requested a reduction in its Capitalized Overhead rate from 16 percent to 8 percent. The reduction was meant in part to recognize that IFRS only allows costs to be capitalized if they were directly attributable to the asset. Order G-141-09 recognized the results of a negotiated settlement Capitalized Overhead rate of 14 percent that reflected the approximate actual FEI Capitalized Overhead rate for 2009.

2. BC Hydro – in its F12-F14 Revenue Requirements Application, BC Hydro has requested a Capitalized Overhead rate including a regulatory deferral for rate setting purposes of

25 percent, but is proposing to reduce the rate to 9 percent over a ten year period. The reduction is meant to meet the IFRS directly attributable guidelines.

3. Pacific Northern Gas Ltd. (PNG) – as per Commission Order G-92-11, PNG was directed to apply the Capitalized Overhead rate that was requested in PNG's 2011 Rate Application. The rate was established at 6.49 percent (PNG utilities overall rate) and is meant to recognize a transition from Canadian GAAP to IFRS.

FortisBC calculated its capitalized overhead rate based on activity based costing methodology that is meant to allocate costs based on cost drivers. One of the easier examples to relate is with respect to the cost of the Human Resources (HR) department, where the most logical cost driver for allocating HR costs would be based on the number of employees utilized in producing a particular product or service or in this case used to construct a capital asset. This is different than IFRS guidance that requires the costs to be directly attributable to the construction or acquisition of an asset. So generally speaking, administrative costs such as those associated with the HR department would not be directly attributable to the construction or acquisition of an asset.

Each entity has approached the calculation of Capitalized Overhead differently as there is no single regulatory statement or guideline that prescribes how or the type of costs that should be capitalized. Generally, for regulatory purposes, utilities rely on GAAP and regulators for guidance. FortisBC has relied on US GAAP for guidance in this Application.

Please also refer to BCUC IR2. 25.1.

25.2.1 Similarly, discuss the rate differences between FortisBC's proposed 20 percent versus the high level range of 6-12 percent from the study performed under IFRS. As a reasonability check, how can there be such a large difference?

Response:

Capitalized overhead rates under IFRS must meet the criterion of directly attributable, which has generally been interpreted as being more restrictive than US GAAP or CGAAP and therefore a lower rate or amounts capitalized is expected under IFRS. For example, certain administrative type costs may be interpreted as excluded from capitalization under IFRS, thereby excluded from the pool of costs to be capitalized.

In the development of the 20% capitalized overhead rate included in the 2012-13 RRA, FortisBC incorporated a broader pool of costs as there are many different departments and costs that contribute to the process of self-constructing an asset or putting plant into service which should be reflected in property, plant and equipment. The result is a capitalized overhead rate higher than might be expected under IFRS but would be permitted under US GAAP, provided that the rate or the capital expenditures inclusive of the overheads are approved by the regulator with the expectation of recovery from customers in future rates.

25.3 Please provide the rate impact for a capitalized overhead rate of 15 percent.

Response:

Changing the Capitalized Overhead rate to 15 percent would increase the 2012 rate increase by 1.2 percent from 4.0 percent to 5.2 percent and decrease the 2013 rate increase by 0.2 percent from 6.9 percent to 6.7 percent.

25.4 Please describe the difference between Capitalized Overhead and the loadings identified in BCUC 132.4.

Response:

The loadings described in BCUC IR1 Q132.4 include direct Transmission and Distribution (T&D) Overhead loading as well as indirect Capitalized Overhead. The T&D loading is meant to recover T&D supervisory and administrative costs that are not readily charged directly to projects. Capitalized Overhead is meant to recover corporate support overhead that is not easily charged directly to projects. The loadings identified in BCUC IR1 Q132.4 are a composite of the two overhead pools and are calculated as follows:

(Transmission and Distribution Overhead loading plus Capitalized Overhead applicable to T&D Projects)

Divided by

Total Unloaded T&D Project Costs

Example:

Transmission and Distribution Overhead = $6.0 million

Capitalized Overhead applicable to T&D Projects = $6.0 million

Total Unloaded T&D Project Costs = $75.0 million

\$6.0 + \$6.0 = \$12 / \$75.0 = 16 percent

The loading is then applied to each T&D project.

RATE BASE

26.0 Reference: Rate Base

Exhibit B-4, BCUC 99.2

Preliminary Investigative Charges

26.1 Please explain why the P1-P4 Sustainment Capital is a recurring entry in the preliminary and investigative charge deferral account. Why is this amount not more properly considered an annually-recurring O&M charge instead of deferred charges?

Response:

This amount is not considered an annually recurring O&M charge because the work completed under this category consists primarily of engineering studies and assessments to determine capital program requirements in subsequent years. Although the spending category appears yearly, the specific projects addressed within this category are not similar in nature and are primarily undertaken to ensure that the Company is prudently extending the life of an asset, improving efficiency or reducing operating costs.

26.2 Please explain why the investigation and development of the pumped storage hydro has progressed without Commission approval of the option FortisBC has selected.

Response:

The inclusion of the Pumped Storage Hydro costs in investigative (deferred) charges has been approved in previous revenue requirements applications. Pumped Storage Hydro is in the investigative stage, not the development stage. Investigative costs are necessary to determine whether a potential capital project will be viable and likely to proceed to the stage of filing a regulatory application.

27.0 Reference: Rate Base

Exhibit B-4, BCUC 1.99.4 and 1.100.2

AMI Investigative Funds

FortisBC states that $1.8 million of investigative funds related to the AMI project will be moved a Rate Base deferral account in 2012. Of this amount, $0.121 relates to AFUDC costs (Exhibit B-4, BCUC 1.100.2)

In response to BCUC 1.99.4, FortisBC states that AFUDC does not apply to the balances in the Preliminary Investigative deferral account until the projects are approved and placed into Construction Work in Progress. (Exhibit B-4, BCUC 1.99.4)

27.1 Please explain the AFUDC costs of $0.121 that is accrued to the AMI project.

Response:

The $0.121 million of AFUDC that is accrued to the AMI project costs is a specific circumstance that was agreed upon in the 2011 Revenue Requirements Application Negotiated Settlement Agreement pursuant to BCUC Order G-184-10 which states the following:

"However FortisBC agrees, for the purpose of this NSA, to record the AMI development costs in a non-rate base deferral account that will attract AFUDC for the 2011 Revenue Requirement, on a without prejudice basis." (page 3)

28.0 Reference: Rate Base

Exhibit B-4, BCUC 1.102

Non-Controllable Deferral Items

"The Company is proposing to introduce Non-Controllable Item Deferral Accounts to be used for expenditures which are either outside of the Company's control or where the Company has limited ability to influence costs which should appropriately be borne by customers." (Exhibit B-1, Tab 5, p. 14)

28.1 For the following table, please indicate the degree of controllability that FortisBC may have on influencing costs:

Deferral Account	Completely Non-Controllable/Somewhat Controllable/May be Controllable

Power Purchase Expense Variance Deferral Account	
Revenue Variance Deferral Account	
Income Tax Variance Deferral Account	
HST Removal or Reform Variance Deferral Account	
Property Tax Asset Variance Deferral Account	
Interest Expense Variance Deferral Account	
Pension and Other Post-Employment Benefits Expense Variance	
Insurance Expense Variance Deferral Account	

Response:

For additional clarity, the Company believes that certain of these variance accounts are "Primarily Non-controllable, as explained below.

Deferral Account	Completely Non-Controllable/Primarily Non-Controllable/Somewhat Controllable/May be Controllable
Power Purchase Expense Variance Deferral Account	Primarily Non-controllable (1)
Revenue Variance Deferral Account	Completely Non-controllable (2)
Income Tax Variance Deferral Account	Primarily Non-controllable (3)
HST Removal or Reform Variance Deferral Account	Primarily Non-Controllable (4)
Property Tax Asset Variance Deferral Account	Completely Non-controllable (5)
Interest Expense Variance Deferral Account	Somewhat controllable (6)
Pension and Other Post-Employment Benefits Expense Variance	Completely Non-controllable (7)
Insurance Expense Variance Deferral Account	Somewhat controllable (8)

1) **Power Purchase Expense Variance Deferral Account: "Primarily Non-controllable"** – this proposed deferral account would accumulate variances as a result of elements that are both in and out of the Company's control, as detailed in 4.1.5 Power Purchase Expense Variance Deferral Account on page 23 of Tab 4 of the 2012-13 RRA which states the following:

> "In this Application, FortisBC proposes a deferral account to capture variances between forecast and actual Power Purchase Expense….Variances in Power Purchase Expense during the test years may result from:
>
> 1 Load variances due to variances in customer growth, usage, or weather;

2 Unit price variances from forecast, including market prices compared to forecast and regulated price changes (BC Hydro rates) not known at the time of application:

3 The Company's ability to displace BC Hydro purchases with lower-cost market purchases;

4 True-up of BPPA costs; or

5 Factors related to the operation of the CPA affecting the Company's usage or timing of entitlements."

As noted above, this deferral account would include potential variances that result from elements that are clearly "completely non-controllable" by the Company, such as customer growth, customer usage, weather and market prices. Also noted above is the ability by the Company to displace BC Hydro purchases with market purchases, subject to favourable market conditions, suggesting that this is an element that can be influenced to some degree by the Company. Since this proposed deferral account would accumulate differences as a result of elements that are completely "non-controllable" and "somewhat controllable" by the Company, this deferral variance account has been designated as "primarily non-controllable".

2) **Revenue Variance Deferral Account: "Completely Uncontrollable"** – this proposed deferral account would accumulate variances that results from elements that are completely out of the Company's control, as detailed in 4.1.5.1 Revenue Variance Deferral Account on page 24 of Tab 4 of the 2012-13 RRA which states the following:

> "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 count load variances."

As noted above, this deferral account would include variances that result from the revenue variances derived from weather related load, customer usage and customer count loads, all of which are factors beyond the Company's control. Therefore, this proposed deferral account has been designated as "completely uncontrollable".

3) **Income Tax Variance Deferral Account: "Primarily Non-controllable"** – this proposed deferral account would accumulate variances that result from elements that are both in and out of the Company's control, as detailed in 4.6.2.4 Request For Income Tax Variance Deferral on page 114 of Tab 4 of the 2012-13 RRA which states the following:

> "At any time, the Company can face uncontrollable changes in tax laws or accepted assessing practices in respect of Federal income tax, Provincial income tax, Provincial sales taxes or any other tax that may be imposed. The Company is seeking an Income Tax Variance deferral account to capture and accumulate variances from forecast, as described in Section 4.6.2, resulting from the impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any tax year, and impacts on taxes of changes in accounting policies at Federal, Provincial or any other level of jurisdiction. The proposed Income Tax Variance deferral account would also accumulate any required compliance costs, including changes to information systems. During the last six years of FortisBC's PBR term, as approved under BCUC Order No. G-58-06, income tax variances qualified as a Z factor provision resulting from Acts of legislation or regulation of government and were treated in a similar manner for rate-setting purposes…"

As noted above, this deferral account would include primarily potential variances that result from elements that are clearly "completely uncontrollable" by the Company, such as changes in tax laws and changes in policies at the Federal or Provincial level. Should these completely uncontrollable changes occur, there is the potential for incremental compliance costs, such as changes to information systems, for which the Company may have a degree of control in managing costs. As this proposed deferral account would accumulate differences as a result of elements that are completely uncontrollable and could possibly include a minor element of compliance cost that potentially may be influenced by the Company, this deferral variance account has been designated as "primarily non-controllable".

4) **HST Removal or Reform Variance Deferral Account: "Primarily non-controllable"** - this proposed deferral account would accumulate variances as a result of elements that are both in and out of the Company's control, as detailed in 4.6.3.3 Request For HST Removal or Reform Deferral Account on page 117 of Tab 4 of the 2012-13 RRA which states the following:

> "This 2012-13 RRA has been prepared using assumptions based on the current HST legislation which permits the recovery of HST charged on goods and services by way of ITC, with the exception of certain restrictions

> previously noted. The HST referendum outcome and resulting decisions are out of the Company's control and we are not able to reasonably forecast the potential resulting effect, if any."

As noted above, this deferral account would include potential variances that result from elements that are clearly "completely uncontrollable" by the Company, which includes the outcome of the HST referendum and the resulting BC provincial government decisions and legislative changes. While the Company has absolutely no control over how the BC provincial government transitions back to a PST regime, if changes to information systems are required, the Company would have a degree of control in managing such costs. As this proposed deferral account would accumulate variances that result from elements that are completely uncontrollable and may include an element of compliance costs that could potentially be influenced by the Company, this deferral variance account has been designated as "primarily non-controllable".

5) **Property Tax Asset Variance Deferral Account: "Completely Non-controllable"** – this proposed deferral account would accumulate variances as a result of elements that are completely out of the Company's control, as detailed in 4.6.1.4 Property Tax Asset Variance Deferral on page 108 of Tab 4 of the 2012-13 RRA which states the following:

> "The BC Assessment Authority is undertaking a review of the valuation of certain electrical system rates for property tax purposes. This review could potentially impact FortisBC and result in a variance from the property tax amounts forecast in 2012 and 2013 in Table 4.6.1.3 above. The Company is seeking a property tax variance deferral account related to the BC Assessment Authority's review of asset valuation, in the event that a review is conducted, as it is largely out of the Company's control and any impact cannot be reasonably forecast at this time."

As noted above, this deferral account would include variances that result from the potential BC Assessment Authority review. The Company has no ability to control the BC Assessment Authority or its decisions; therefore this proposed deferral account has been designated as "completely non-controllable".

6) **Interest Expense Variance Deferral Account: "Somewhat Controllable"** - this proposed deferral account would accumulate variances as a result of elements that are both in and out of the Company's control, as detailed in 4.7.1 Request For Interest Expense Variance Deferral Account on page 125 of Tab 4 of the 2012-13 RRA which states the following:

> "To avoid potential gains or losses on forecasting interest expense, for the 2012 and 2013 forecast period FortisBC is proposing to accumulate variances from forecast within an Interest Expense Variance deferral account. This proposed rate base deferral account would capture all variances relating to long and short-term interest expense, including financing fees, as the cost of debt can be largely influenced by capital market conditions which are less predictable and largely outside of the Company's control. During the last six years of FortisBC's PBR term, as approved under BCUC Order no. G-58-06, the difference between actual and forecast interest expense was captured in a deferral account and treated in a similar requested manner for rate setting purposes."

As noted above, this deferral account would include potential variances that result from elements that are clearly "completely uncontrollable" by the Company, such as capital markets. On the other hand, the Company may have the ability to negotiate certain terms of its bank credit facilities which could influence any variances from forecast. However, the ability to negotiate is also largely influenced by market conditions that exist at the time of the bank credit facility renewals, as well consideration by the banking syndicate for recent regulatory decisions. As this proposed deferral account would accumulate variances as a result of elements that are completely uncontrollable and may include more minor elements that may also be influenced by the Company, this deferral variance account has been designated as "somewhat controllable".

7) **Pension and Other Post-Employment Benefits Expense Variance: "Completely Non-controllable"** - this proposed deferral account would accumulate variances as a result of elements that are outside of the Company's control, as detailed in 5.4.3 Non-Controllable Items Variances – Pension and Other Post-Employment Benefits Expense Variance on page 16 of Tab 5 of the 2012-13 RRA which states the following:

> "Changes in the accounting expense related to both Pension and Other Post Employment Benefit costs can result from various factors such as performance of pension plan investments, external factors affecting global financial markets, changes in plan membership, and changes in accounting requirements, all of which are substantially out of the Company's control."

As noted above, this deferral account would include potential variances that result from elements that are clearly "completely uncontrollable" by the Company, such as external factors affecting global financial markets, changes in plan membership and changes in accounting requirements. Additionally, this deferral account is necessary as there will be a variance between the estimate in the final approved 2012-13 rates and the actual 2012-13 pension and OPEB expenses.

Even though the 2012-13 RRA considers the best information at the time of forecasting, market conditions and changes to plan membership will have an impact on the final determination of pension and OPEB expenses. An actuarially determined measurement is required at December 31 of each year under US GAAP, which contemplates variables such as the discount rate at the time of measurement, to determine the actual pension and OPEB expense for the subsequent year. As this proposed deferral account would accumulate variances as a result of elements that are completely uncontrollable, this deferral variance account has been designated as "completely non-controllable".

8) **Insurance Expense Variance Deferral Account: "Somewhat Controllable"** - this proposed deferral account would accumulate variances as a result of elements that are both in and out of the Company's control, as detailed in 4.3.4.18 Insurance Expense Variance Deferral Account on page 94 of Tab 4 of the 2012-13 RRA which states the following:

> "Insurance expenses may differ from the levels forecast, primarily due to changes in economic factors outside of the Company's control as well as the rise in copper wire theft, for which the future impact is unpredictable. Global events can influence insurance expense and the impact of this type of event cannot be reasonably incorporated into insurance forecasts, therefore a deferral account to capture the difference between actual and forecast insurance expense, including first and third party liability, is requested."

As noted above, this deferral account would include potential variances that result from elements that are clearly "completely uncontrollable" by the Company, such as changes in economic factors and global events. On the other hand, the Company, as part of the Fortis Group of Companies insurance program, may have the ability to negotiate certain terms of its annual insurance premium renewals. However the ability to negotiate is also largely influenced by uncontrollable market conditions that exist at the time of renewal. As this proposed deferral account would accumulate variances as a result of elements that are completely uncontrollable and could include more minor elements that may also be influenced by the Company, this deferral variance account has been designated as "somewhat controllable".

28.2 During the PBR period, an ROE sharing mechanism was available to provide an incentive for the Company to manage costs effectively. Please discuss what incentives are available to the Company during the test period to effectively manage costs, particularly in light of the proposal of these deferral accounts.

Response:

The absence of an ROE sharing mechanism or the existence of deferral accounts will not change the manner in which the Company continues to effectively manage costs. It is important to note that the existence of deferral accounts will not deter the Company from continuing to effectively manage prudent costs and to continue to seek out efficiencies to mitigate customer future rate increases.

For example, during the PBR period, the Company proactively achieved savings in interest expense and certain income tax expense variances relating to cost of removal which were captured in deferral accounts and the variances were flowed 100% back to the customer as a reduction in rates. The Company is incented to seek out similar opportunities in all costs of service for which the result will mitigate customer rate increases.

The existence of deferral accounts does not reduce the Company's incentive to continue to seek out efficiencies and opportunities to reduce costs with an objective of keeping customers satisfied. No customer, no matter what product or service one purchases, wants to see the price of that commodity or service increase. Therefore the Company has the incentive to do everything required to operate a safe and reliable electric utility in a cost effective manner. One of the factors perceived by the Company's management for a successful operation of a utility is to mitigate the pressure on costs of service. Efficiencies and costs savings obtained, either through capital and operating cost savings, or lower deferral account balances will have an effect in maintaining customer satisfaction.

Additionally, the Company will be exposed to the 2012 and 2013 costs of service which are not captured by these proposed deferral accounts, such as O&M expense and will therefore be incented to continue managing effectively.

28.3 FortisBC's application incorporates an ROE of 9.90 percent, calculated as the BC low-risk utility benchmark ROE (9.50 percent) plus FortisBC's 40 basis points risk premium. Does FortisBC agree that the approved ROE serves to compensate a utility for the appropriate level of risk involved in utility operations?

Response:

By letter dated May 15, 2009 the Terasen Utilities filed with the BCUC pursuant to sections 59 and 60 of the Utilities Act, an application for Return on Equity and Capital Structure. The application requested that the return on equity allowed for Terasen Gas Inc. will be the Benchmark ROE, be set at 11% effective July 1, 2009.

FortisBC supported the application and the request of 11.0% for the Benchmark ROE. Incorporating FortisBC's 40 basis points risk premium would have resulted in an ROE of 11.4%

The BCUC in its decision dated December 16, 2009 ordered that the Benchmark ROE would be 9.5% and that this would serve as the Benchmark ROE for FortisBC. This resulted in an approved ROE of 9.9% for FortisBC.

In general, FortisBC agrees that the approved ROE is intended to compensate a utility for the level of risk it faces.

28.4 Please discuss how the use of multiple deferral accounts reduces the Company's overall business risk? Should the 40 basis points premium be reduced to be aligned with the lower risk profile?

Response:

Requesting to have deferral accounts in place over the short-to medium term does not suggest an automatic change in the overall business risk profile of a Company and the resulting risk premium determination. Rather the business risk profile and risk premium are based on a much longer term perspective and incorporate many other factors, certain of which are mentioned in the response to BCUC IR2 Q31.1. As such, the 40 basis points premium should not be reduced as the risks pertaining to the Company's business risk profile have not lessened.

29.0 Reference: Rate Base

Exhibit B-4, BCUC 1.105.1

Shaw Application for Transmission Facility Access

29.1 Please explain whether and in what way the FortisBC shareholders benefited from the Shaw dispute and explain why all the costs of the dispute should be borne by the ratepayers.

Response:

FortisBC shareholders did not receive any benefit from the resolution of the Shaw dispute. The benefit from the additional lease revenue accrued 100% to FortisBC customers through reduced revenue requirements and thus the resulting rate mitigation. Please refer to Table 4.8.1 in

Exhibit B-1 Tab 4, Page 141. The full cost of the dispute was borne by customers since customers received the full benefit.

30.0 Reference: Rate Base

Exhibit B-4, BCUC 1.108.1, 1.108.1, 1.108.3, 1.188.2

Other Deferred Charges and Credits – Asset Management

"The majority of the costs are required to support the engagement of external consultants and contractors."

30.1 Please explain why an asset management strategy is not simply a way of scheduling maintenance and should be appropriately charged as an operating expense.

Response:

FortisBC believes that scheduling of maintenance tasks is only one of the results of an asset management strategy. As discussed Section 1.1, page.1 in the 2012 Integrated System Plan, an Asset Management strategy assists in making optimal maintenance and capital investment decisions when measured against performance targets and financial constraints. The desired outcome is that all stakeholders should have full knowledge of what planned projects will deliver, the risk versus cost tradeoffs between available options, and the costs and risks of not meeting performance targets.

Some of the tangible benefits of a formal Asset Management strategy are:

- Provides regulatory and corporate confidence that capital and maintenance investment levels match the needs of the system without going further than necessary;
- Provides confidence that appropriate mechanisms are in place to manage assets and provide the best value to customers;
- Ensures that risk is being managed appropriately;
- Establishes a long-term view of infrastructure investment;
- Objectively establishes a view of asset health and identifies necessary investments;

- Ensures the organization consistently carries out work to a recognized standard and that there is consistency in approach; and
- Reduces the reliance on individual experts and instead builds overall corporate knowledge.

The proposed project will examine FortisBC's existing Asset Management processes and provide a comprehensive report and project cost estimate recommending changes and mapping out an implementation plan. The project will also investigate and evaluate available Asset Management software solutions.

The outcome of this project will be a fully-developed business case with a specific Asset Management implementation strategy. Included in the deliverables is the identification of a software solution capable of producing priority-ranked project listings developed from the objective analysis of equipment health and criticality indices.

The Asset Management strategy will result in the development of systematic processes and the implementation of a software solution that will provide benefits in subsequent years and therefore should be capitalized. This is analogous to the development of other systematic solutions such as the implementation of a Customer Service program and the implementation of a computerized Customer Information System (CIS) in order to enhance customer service or offer flexible customer billing. The Customer Service function or the Billing function are treated as operating expenses, but the development of the program and the implementation of the CIS would be considered capital in nature.

30.2 Please explain why it is necessary for FortisBC to "develop" an asset management strategy rather than adopting and applying existing strategies available from third parties to the FortisBC asset base.

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 utilities. It will examine FortisBC's existing Asset Management processes and provide a comprehensive report and project cost estimate recommending changes and mapping out an implementation plan. Any recommended solution will be cost effective for the Company and the ratepayer.

30.3 Please provide a description of all systems FortisBC currently uses to monitor or record equipment condition, and all systems used to schedule, track and record maintenance activities. Please also identify when these systems were implemented and at what cost.

Response:

FortisBC uses a variety of system, information and experience to review asset health. Some of the primary systems used are the following:

- GENJO – Used to schedule, track and record maintenance activities for all Generation major equipment assets. The system also contains work plans/procedure documents. This system was implemented in the mid 1990s and has been improved upon over time. Specific capital implementation costs are not readily available.
- CASCADE – Used to schedule, track and record maintenance activities for Transmission and Distribution substation assets. The system also contains work plans/procedure documents. This system was implemented through a capital project by Commission Order G-52-05. It was completed in 2008 at a cost of $1.46 million dollars.
- ArcFM – This is the Graphical Information System (GIS) for Transmission and Distribution line assets (overhead and underground). It tracks limited information on poles and wires assets such as distribution transformer PCB information and age of poles (where available). This system was implemented through a capital project by Commission Order C-20-06. The implementation was completed in November 2008 at a capital cost of $2.8 million dollars.

In addition, the Company uses a variety of smaller systems and tools such as eDNA (stores equipment real-time operational data in a long-term historical database), TOA4 (web accessible power transformer oil analysis database), DobleWeb (web accessible power transformer condition test database). These tools have been implemented over time and costs were not tracked specifically and thus are not readily available.

Finally, FortisBC also uses corporate software such as Microsoft Excel and Access to manage information and assist in decision making.

FINANCING AND ROE

31.0 Reference: Allowed Return on Equity

Exhibit B-4, BCUC 1.87.1, p. 182; Exhibit B-1, Appendix H, p. 2 of 6

Risk Premium

FortisBC states that "Assuming FEI's approved ROE remains the benchmark ROE, if it were to change, FortisBC's revised ROE would equal the new FEI approved ROE, plus the 40 basis points risk premium which was approved pursuant to Commission Order G-58-06."

Moody's credit opinion states that "The Baa1 senior unsecured rating of FBC reflects the low-risk nature of the utility where over 95% of its operations are regulated and the few unregulated operations it does have are viewed to be relatively low-risk. [...] Moody's considers FBC's business risk to be lower than that of other cost-of-service regulated vertically integrated utilities. [...] FBC's location in British Columbia, which, until recently, enjoyed a relatively strong provincial economy and continues to enjoy a supportive regulatory climate, contributes to our view of FBC as a lower risk utility."

DBRS credit opinion states that "On October 1, 2010, DBRS upgraded the ratings of FortisBC Inc.'s Secured and Unsecured Debentures to A (low) from at BBB (high)."

31.1 Does FortisBC agree that its risk premium of 40 basis points over the benchmark should be reduced in light of the upgrade in FortisBC's credit metrics? If so, please elaborate on what risk premium would appropriately reflect the Company's current risk profile. If not, please explain what risk factors are causing FortisBC's risk premium to remain unchanged since 2006.

<u>Response:</u>

No, FortisBC does not agree that its risk premium of 40 basis points over the benchmark should be reduced as a result of an upgrade in its credit ratings. FortisBC's business risk profile, which is based on a <u>long-term perspective</u>, continues to support a risk premium over the benchmark and therefore should not be reduced.

It is important to note that the ratings upgrades were largely driven as a result of the allowed ROE approved in December 2009 pursuant to Commission Order G-158-09, which increased the benchmark ROE from 8.47% to 9.50%. This Order effectively increased FortisBC's ROE from 8.87% to 9.90% effective January 2010. The increase in allowed ROE, improved the Company's forecast credit metrics, which in turn provided the Company with the ability to address certain challenges previously identified by the rating agencies, including increased liquidity by changing the terms of its bank credit facilities.

The increased allowed ROE, which provided for improved credit metrics and the ability to increase the liquidity on its bank credit facilities, was instrumental in the rating agencies' decisions to upgrade FortisBC Inc.'s ratings from BBB (high) to A (low) and from Baa2 to Baa1. In Moody's May 6, 2010 press release for upgrading FortisBC's rating to Baa1, stable outlook the following was stated:

> "The rating upgrade reflects an improvement in FBC's liquidity combined with the expectation that FBCs' financial profile will show modest improvement over the next few years. Historically FBC's relatively weak liquidity has been a constraining factor on the rating……the increase in the three-year tranche of FBC's credit agreement to $100 million from $50 million provides the company with significantly greater liquidity risk insurance and enables FBC to satisfy Moody's standard liquidity stress test." In addition, a slight improvement in FBC's key credit metrics is expected following the December 2009 decision of the British Columbia Utilities Commission (BCUC) to increase its benchmark ROE, which resulted in an increase in FBC's 2010 allowed ROE to 9.90% from 8.87% in 2009".

Any reduction in allowed ROE would again challenge the Company's credit metrics and available liquidity on its bank credit facilities, which in turn could result in a credit downgrade by the ratings agencies and an increase in the cost of debt. This was corroborated in Moody's September 6, 2011 credit opinion, included in the response to BCUC IR 2.31.2, they have indicated that FortisBC's

- "financial metrics remain weak compared to Baa1-rate peers"
- "a downgrade of FBC's rating would likely require a combination of a deterioration of FBC's….liquidity and financial profile or an inability to earn its allowed return. This might include sustained weakening of FBC's metrics such as CFO pre-W/C Interest coverage of below 2.7x and CFO pre-W/C to Debt below 10%."

In DBRS' October 6, 2011 credit opinion, included in the response to BCUC IR 2.31.2, the agency stated the following with respect to challenges:

- "FortisBC's ROE of 9.90% is a result of a positive 2009 decision that also determined that the automatic adjustment mechanism that was used to determine the ROE on an annual basis would no longer apply and the ROE as determined would apply until changed by the BCUC. The Company's deemed capital structure remains unchanged at 60% debt/40% equity. DBRS believes that while the ROE is favourable, uncertainty remains as to when and how ROE levels will be adjusted in the future."
- "Challenges related to the relatively large anticipated capital expenditures over the next 5 years will continue to contribute to large free cash flow deficits"
- "Challenges related to the execution of the anticipated capital expenditure program"

So while FortisBC has been able to address certain credit metrics and liquidity issues identified by the credit rating agencies, prior to its ratings upgrades in 2010, there are clearly still ratings challenges and risks that currently exist for the Company.

In addition to the credit ratings discussed above, many other risk factors exist that support not reducing FortisBC's risk premium established in 2006 including the following:

- FortisBC is a relatively small utility serving a generally rural service area;
- Major industries served by FortisBC include forestry/pulp and paper, agriculture and tourism;
- FortisBC has significant heating load (in competition with natural gas), with approximately one-third of direct residential (and likely wholesale) sales for heating purposes;
- FortisBC competes to some extent with alternative suppliers of electric power, such as BC Hydro, given the customer choice available to wholesale and large industrial customers;
- Technological change is expected to increasingly create competitive alternatives;
    - -FortisBC generates 45 percent of its supply from its own hydroelectric plants, obtaining the remainder of its supply through long-term contracts and market purchases;
    - -FortisBC's Power Purchase Agreement with BC Hydro expires in 2013, and there remains uncertainty around the terms of any eventual renewal of that agreement;
- FortisBC has relatively weak quantitative credit metrics; and
- FortisBC's interest coverage ratio limits its flexibility and liquidity.

To conclude, a credit ratings upgrade is not the sole determinant of a business' risk premium and is primarily an assessment of risk by debt providers of default, not equity providers. There are many other factors that influence an entity's long-term business risk profile, such as relative size of the utility, major industries served by the Company, population and economic growth, competition, technological changes and government policy, among other risks.

Collectively, these factors do not support a reduction to FortisBC's risk premium.

31.2 Moody's credit opinion is dated May 6, 2010 and DBRS credit opinion is dated October 26, 2010. Please advise whether these reports represent the latest information that FortisBC has from these two rating agencies? If more recent reports have been issued, please provide a copy. If not, please advise when FortisBC expects the next updates to be available?

Response:

The latest credit opinion reports are dated September 6, 2011 from Moody's and October 6, 2011 from DBRS. These reports are attached as BCUC IR2 Appendix 31.2.

32.0 Reference: Cost of Debt

Exhibit B-4, BCUC 1.81.4, p. 171

Interest Expense

FortisBC states that “In this circumstance, the forecast 2011 interest expense on the weighted average balance of short-term debt (draws on facility/deemed adjustment) should have been a positive balance of approximately (3% x $2.718 million) $0.082 million instead of a recovery of $0.110 million.”

32.1 Please show how FortisBC calculates the interest expense recovery of $0.110 million.

<u>Response:</u>

The response to BCUC IR1 Q81.4 stated that the $0.110 million interest expense recovery was an error. The correct calculation was 3% X $2.718 million to arrive at interest expense of $0.082. This stated adjustment will be included in the Evidentiary Update discussed in response to BCUC IR2 Q1.1.

33.0 Reference: Forecast of Long-Term Interest Rates for 2013 Debenture

Exhibit B-4, BCUC 1.83.0, p. 172; Exhibit B-1, Tab 4, Section 4.7.1.1, p. 122

Table 4.7.1.1 Long-Term Interest Rate Forecast

FortisBC states that “The Company used the most recent publications available at the time of forecasting for the 2012-13 RRA during late May 2011. FortisBC expects to issue its next long-term debenture in the second half of 2013, however the forecast publications from the Canadian Chartered Banks only provide forecasts until the end of 2012. Therefore the Company has used an average of the 30 year Government of Canada Bond rates forecast for the fourth quarter of 2012 as the closest approximation.” (Exhibit B-4, BCUC 1.83.1, p. 173)

In addition, Table BCUC IR1 83.1 shows that the banks’ forecasts used by FortisBC were published between March 16, 2011 and May 3, 2011.

Given the recent announcement by the Bank of Canada to hold its benchmark interest rate unchanged at 1 percent, the long-term interest rates forecasts used by FortisBC may need to be updated. In September 2011, RBC published updated forecasts of economic indicators, including interest rates. RBC now forecast the 30-year Government of Canada Bond rate at 4.00 percent for the fourth quarter of 2012, down from its May 2011 forecast of 4.55 percent.

33.1 If changed, please revise Table BCUC IR1 83.1 with updated forecasts for the 30-year Government of Canada Bond and resulting average forecast rate based on current market conditions.

Response:

Table BCUC IR2 33.1

Canadian Chartered Bank	Publication Date	Rate (3)
Toronto Dominion Quarterly Economic Forecast (1)	September 13, 2011	4.05%
Scotia Economics Global Forecast (2)	October 7, 2011	3.40%
CIBC World Markets Economic Insights (2)	September 28, 2011	3.15%
RBC Capital Market Forecasts (2)	October 7, 2011	3.45%
Average of GofC 30 year forecast rates (above)		3.51%
Rounded up to nearest 0.05%		0.04%
30 year Government of Canada Bond used in response to BCUC IR2 33.1.1		**3.55%**

The Company used the most recent publications available, at the time of responding to this IR, to update the rates in the table above.

1. The Toronto Dominion Bank has provided quarterly 2013 forecasted rates for 30 year Government of Canada Bonds, therefore the average of the third and fourth quarter rates of 2013 was used to estimate the rate to correspond with the forecasted timing of issuance.
2. The forecast publications from the remaining Canadian Chartered Banks have only provided quarterly forecast rates for 30 year Government of Canada Bonds to the end of 2012, therefore fourth quarter rates have been used to estimate the rate to be used for the 2013 long-term debt issuance.
3. The Company has used an average of the 30 year Government of Canada Bond rates forecast in the table above as the closest approximation for the rate of the 2013 long-term debt issuance.

The Canadian Chartered bank publications are attached as BCUC IR2 Appendix 33.1.

33.1.1 If changed, please update Table 4.7.1.1 on p. 122 and Table 4.7.1-2 on p. 120 of the Application and Table BCUC IR1 83.3 of Exhibit B-4, as well as all other references to a coupon rate of 5.90 percent in the Application and in Exhibits B-4 and B-5 based on current market conditions.

Response:

Please refer to the table below, based on Table 4.7.1.1 of the 2012-13 RRA and Table BCUC IR1 83.3, reflecting updated interest rate forecast for 2013.

Table BCUC IR 2 33.1.1 Long-Term Interest Rates

	2009A	2010A	2013F
Series	MTN Series 1	MTN Series 2	2013 Issuance
Date of Issuance	2-Jun-09	24-Nov-10	2013
Term (Years)	30	40	30
30-year Government of Canada Bond	4.15%	3.66%	3.55%
Long-term Debt Rate Spread	1.95%	1.35%	1.70%
All-in Borrowing Rate	**6.10%**	**5.01%**	**5.25%**

The 30-year Government of Canada Bond for 2013 of 3.55% was derived from the forecast and most recent supporting publications included in the response to BCUC IR 2 33.1.

The long-term debt spread of 1.70% was derived from the average of several October 2011 indicative credit spreads provided to FortisBC in confidence, therefore it is representative of the most recent available information.

The table below summarizes FortisBC's annual weighted debt balances forecast for 2012 and 2013, similar to Table 4.7.1-2, reflecting updated long-term interest rates.

Table BCUC IR 2 33.1.1 Weighted Average Cost of Debt (2012-2013)

Description of Debt	Maturity Dates	Rates	2012 Forecast Weighted Average Balance ($000s)	2012 Forecast Interest Expense ($000s)	2013 Forecast Weighted Average Balance ($000s)	2013 Forecast Interest Expense ($000s)
Long-Term Debt						
Series F	16-Oct-12	9.65%	12,483	1,205	-	-
Series G	28-Aug-23	8.80%	25,000	2,200	25,000	2,200
Series H	01-Feb-16	8.77%	25,000	2,193	25,000	2,193
Series I	01-Dec-21	7.81%	25,000	1,953	25,000	1,953
Series 1 - 04	28-Nov-14	5.48%	140,000	7,672	140,000	7,672
Series 1 - 05	09-Nov-35	5.60%	100,000	5,600	100,000	5,600
Series 1 - 07	04-Jul-47	5.90%	105,000	6,195	105,000	6,195
MTN Series 1 - 2009	02-Jun-39	6.10%	105,000	6,405	105,000	6,405
MTN Series 2 - 2010	24-Nov-50	5.00%	100,000	5,000	100,000	5,000
Series 2013	30 year est.	5.25%	-	-	25,151	1,321
Total Long-Term Debt			637,483	38,422	650,151	38,538
Weighted average rate on Long-Term Debt				6.03%		5.93%
Short-Term Debt						
Draws on facility/deemed adjustment			49,669	2,002	77,158	4,004
Financing Fees						
Total Standby Fees				367		301
Total Banking Agreement Charges				275		280
Other financing fees				180		190
Demand Line interest				74		77
Total Financing Fees				896		848
Total Short-Term Debt			49,669	2,898	77,158	4,852
Weighted average rate on Short-Term Debt				5.83%		6.29%
Total Long-Term and Short-Term Debt			**687,152**	**41,320**	**727,309**	**43,390**
Weighted average rate on Total Debt				**6.01%**		**5.97%**

The above table only reflects the change in the forecast 2013 long-term debt issuance rate from 5.90 percent to 5.25 percent, as derived in Table BCUC IR 2 33.1.1 Long-Term Interest Rates. The above table does not reflect any update to 2012 and 2013 short-term interest rate forecast as that has been requested in BCUC IR2 Q35.1.1.

33.1.2 If changed, please also recalculate FortisBC's weighted average rate on long-term debt and weighted average cost of debt based on current market conditions.

Response:

Please see the response to BCUC IR 2 33.1.1.

34.0 Reference: Short Term Debt Financing

Exhibit B-4, BCUC 1.84.0, p. 176

Operating Credit Facilities

FortisBC states that "In determining the **annual 2010 actual** and 2011-2013 forecast operating credit facility balances, the Company does not estimate draws on its operating credit facility on a monthly basis … Rather than calculate on a monthly basis, the weighted average balances for the operating credit facilities are deemed adjustments to make up the variance between the Company's actual and forecast long-term debt balances and the 60 percent component of deemed debt used to finance rate base as required under the Company's approved capital structure pursuant to Commission Order G-58-06." (Emphasis added)

34.1 Please provide the monthly balances of the two credit facilities for 2010, which is an actual year of use.

Response:

Please see the following table.

Table BCUC IR 2 34.1 2010 Actual Month-End Credit Facility Balances

	Jan 10	Feb 10	Mar 10	Apr 10	May 10	Jun 10	Jul 10	Aug 10	Sep 10	Oct 10	Nov 10	Dec 10	Weighted Average
	($000s)												
Facility A Balance	26,910	28,943	25,947	21,964	44,930	46,874	68,957	65,970	62,363	63,898	-	-	39,668
Facility B Balance	-	-	-	-	-	-	-	-	-	-	-	-	

	Jan 10	Feb 10	Mar 10	Apr 10	May 10	Jun 10	Jul 10	Aug 10	Sep 10	Oct 10	Nov 10	Dec 10	Weighted Average
	($000s)												
Facility A Balance	26,910	28,943	25,947	21,964	44,930	46,874	68,957	65,970	62,363	63,898	-	-	39,668
Facility B Balance	-	-	-	-	-	-	-	-	-	-	-	-	-

The credit facility balances in the table above are actual month-end balances of draws on Facilities A and B, including both Prime Rate Loans and Bankers' Acceptances.

The above actual balances drawn on the credit facilities are not necessarily indicative of the draws or the deeming adjustment for regulatory purposes to finance 60% of rate base.

34.1.1 Please also demonstrate how the use of these credit facilities helped FortisBC meet its cash flow requirements in 2010.

Response:

During 2010, the draws on the bank credit facilities described in the response to BCUC IR 2.34.1, along with equity contributions from the ultimate parent company and funds generated from operation activities were used to finance the Company's approved capital expenditure program and working capital requirements. When the draws on the bank credit facilities approach $100 million, the Company converts the bank credit facilities into longer term public debt. On November 24, 2010, FortisBC issued its MTN Debenture Series 2 with net proceeds of $99.3 million which were used to repay the actual balances drawn on its bank credit facilities, as well as finance the capital expenditure program and working capital requirements.

34.1.2 Please elaborate on how these credit facilities will be used in 2012 and 2013 and the appropriateness of the credit facility renewal.

Response:

Table BCUC IR2 34.1.2 Use of Credit Facilities in 2012 to 2013

	Forecast 2012	Forecast 2013
	($000s)	
Mid-Year Utility Rate Base	1,145,253	1,212,181
Approved Capitalization Structure	60%	60%
Total Required Debt Financing	687,152	727,309
Less: Long-term debt	637,483	650,151
Shortfall of 60% debt deemed to be financed through credit facilities	49,669	77,158

In 2012 and 2013, the draws on the credit facilities will be deemed as financing the 60% of rate base not financed by the long-term debt issuances. The renewal of these credit facilities is appropriate as it provides the Company with the ability to continue financing 60% of its rate base with flexible financing sources in between long-term debt issuances. FortisBC endeavours to maintain committed operating credit facilities with capacity sufficient to repay its financial liabilities when they became due. The Company regularly monitors the maturity dates, committed amounts and balances drawn on its operating credit facilities in order to reduce its liquidity risk to an appropriate level when considering upcoming financial liabilities. The appropriateness and importance of the credit facilities has been further emphasized by the credit rating agencies as follows.

- Moody's May 21, 2008 credit opinion on FortisBC stated that "liquidity arrangements are a relative weakness" and "Moody's anticipates that unless FBC raises term debt on a relatively frequent basis the company's liquidity will become strained by its ongoing capital program";
- As part of the Company's ratings upgrade by Moody's on May 6, 2010, they stated that one of the ratings drivers was "improved credit facilities result in a satisfactory liquidity position";
- Moody's September 6, 2011 Credit Opinion report, included in the response to BCUC IR2 31.2, stated that "with undrawn committed credit facilities of approximately $140 million at June 30, 2011, FBC is able to withstand our standard liquidity stress scenario, which assumes that an issuer loses access to new capital, other than credit available under its committed credit facilities, for a period of 12 months"; and
- DBRS Ratings Report on October 6, 2011, included in the response to BCUC IR2 31.2, stated that "despite the continuing free cash flow deficits over the near to medium term, DBRS expects the Company's financial profile and credit metrics to remain adequate for the rating. With its $160 million in bank credit facilities (including a $10 million demand overdraft facility), FortisBC's liquidity is considered sufficient to meet any short-term funding requirements".

In order to maintain liquidity, finance its capital expenditure programs, fund its working capital requirements and maintain its debt credit ratings, the credit facilities are not only appropriate, but are necessary for FortisBC for prudent cash management purposes.

35.0 Reference: Forecast of Short-Term Interest Rates for 2012-2013

Exhibit B-1, Tab 4, Section 4.7.1.2, p. 123; Table 4.7.1.2-1 Short-Term Interest Rate Forecast; Table 4.7.1.2-2 Short-Term Interest Expense Forecast; and

Exhibit B-4, BCUC 1.85.0, p. 177

FortisBC states that "Short-term interest rates are projected to increase in the coming months. Canadian chartered banks have forecast Bankers' Acceptances to remain on average at 1.37 percent for 2011 (using the Canadian 3 month Treasury bill rates), and then increase to an average of 3.90 percent for 2013." (Exhibit B-1, p. 124)

FortisBC also states that "Chartered banks expect the Prime Rate (Overnight Bank Rate plus 200 basis points) to remain on average at 3.63 percent for 2011 and increase to an average of 4.50 percent for 2012 and 5.25 percent for 2013." (Exhibit B-1, p. 124)

In September 2011, RBC revised its interest rates forecasts downward from its May 2011 forecasts. For instance, RBC's revised overnight rate forecasts for 2012 are 1.00 percent (Q1), 1.25 percent (Q2), 1.75 percent (Q3) and 2.00 percent (Q4), which are much lower from the May 2011 forecasts found in Table BCUC IR1 85.2a (Exhibit B-4, p. 178). Likewise, RBC's 3-month rate forecasts for 2012 are 1.15 percent (Q1), 1.30 percent (Q2), 1.85 percent (Q3) and 2.15 percent (Q4), which are significantly lower than the May 2011 forecasts presented in Table BCUC IR1 85.2a.

35.1 Please provide a new table combining Table BCUC IR1 85.1 (Exhibit B-4, p. 177) with Table 4.7.1.2-1 (Exhibit B-1, p. 124) with updated figures for the short-term interest rates forecasts.

Response:

The table below combines the data for the years 2009 (actual), 2010 (actual), 2011 (forecast), 2012 (forecast) and 2013 (forecast) reflecting updated short-term interest rates for 2012 and 2013, combining Table BCUC IR1 85.1 and Table 4.7.1.2-1 of the 2012-13 RRA.

Table BCUC IR2 35.1

Bankers' Acceptances	**2009A**	**2010A**	**2011F**	**2012 F**	**2013 F**
Bankers' Acceptance Rates (3 month T-bill)	0.78%	0.80%	1.50%	1.50%	2.30%
Acceptance Fee Rate	1.48%	2.25%	1.41%	1.25%	1.25%
Bankers' Acceptance Rate	2.26%	3.05%	2.91%	2.75%	3.55%
Prime Rate Loan	**2009A**	**2010A**	**2011F**	**2012 F**	**2013 F**
Prime Rate (Overnight Bank Rate plus 200bps)	2.25%	2.50%	3.38%	3.25%	4.00%
Prime Rate Margin	1.50%	1.13%	0.37%	0.25%	0.25%
Prime Interest Rate	3.75%	3.63%	3.75%	3.50%	4.25%
Weighted Average Short-term Debt Rate	2.30%	3.07%	3.00%	2.83%	3.62%

The determination of the 2012 and 2013 Bankers' Acceptance Rates (3 month T-bill) and Prime Rate (Overnight Bank Rate plus 200 basis points) in the above table have been updated consistent with the response to BCUC IR2 Q35.2, which also uses the most recent Canadian Chartered Bank publications included in the response to BCUC IR2 Q33.1.

35.1.1 Please update all the figures and references that are based on the old short-term interest rate forecasts, including but not necessarily limited to, Table 4.7, Table 4.7.1-1, Table 4.7.1-2 and 4.7.1.2-2 of the Application.

Response:

The following table summarizes the short-term interest expense forecast for 2012 and 2013, based on updated forecast rates that have been derived as per the response to BCUC IR2 Q35.1, which also uses the most recent Canadian Chartered Bank publications included in the response to BCUC IR2 Q33.1.

Table BCUC IR2 35.1.1a Short-Term Interest Expense Forecast

2012	Interest Rate	Average Principle ($000s)	Percentage of Principal of Financing	Interest ($000s)
Bankers' Acceptance	2.75%	44,702	90.00%	1,229
Prime Rate Loan	3.50%	4,967	10.00%	174
Average all-in cost	**2.83%**	49,669		**1,403**
2013	**Interest Rate**	**Average Principle ($000s)**	**Percentage of Principal of Financing**	**Interest ($000s)**
Bankers' Acceptance	3.55%	69,442	90.00%	2,465
Prime Rate Loan	4.25%	7,716	10.00%	328
Average all-in cost	**3.62%**	77,158		**2,793**

Table BCUC IR2 35.1.1b remains unchanged from Table 4.7.1-1 Weighted Average Cost of Debt (2010-2011) in the 2012-13 RRA, with the exception of the correction of the 2011 short-term interest expense as included in the response to BCUC IR1 Q81.4.

Table BCUC IR2 35.1.1b Weighted Average Cost of Debt (2010-2011)

Description of Debt	Maturity Dates	Rates	2010 Actual Weighted Average Balance ($000s)	2010 Actual Interest Expense ($000s)	2011 Approved Weighted Average Balance ($000s)	2011 Approved Interest Expense ($000s)	2011 Forecast Weighted Average Balance ($000s)	2011 Forecast Interest Expense ($000s)
Long-Term Debt								
Series F	16-Oct-12	9.65%	15,000	1,448	15,000	1,448	15,000	1,448
Series G	28-Aug-23	8.80%	25,000	2,200	25,000	2,200	25,000	2,200
Series H	01-Feb-16	8.77%	25,000	2,193	25,000	2,193	25,000	2,193
Series I	01-Dec-21	7.81%	25,000	1,953	25,000	1,953	25,000	1,953
Series 1 - 04	28-Nov-14	5.48%	140,000	7,672	140,000	7,672	140,000	7,672
Series 1 - 05	09-Nov-35	5.60%	100,000	5,602	100,000	5,601	100,000	5,601
Series 1 - 07	04-Jul-47	5.90%	105,000	6,195	105,000	6,195	105,000	6,195
MTN Series 1 - 2009	02-Jun-39	6.10%	105,000	6,405	105,000	6,405	105,000	6,405
MTN Series 2 - 2010	24-Nov-50	5.00%	12,603	507	110,000	5,609	100,000	5,000
Series 2013	30 year est.	5.90%	-	-	-	-	-	-
Total Long-Term Debt			552,603	34,174	650,000	39,275	640,000	38,666
Weighted average rate on Long-Term Debt				6.18%		6.04%		6.04%
Short-Term Debt								
Draws on facility/deemed adjustment			(3,686)	(184)	5,945	220	2,718	82
Financing Fees								
Total Standby Fees				560		511		458
Total Banking Agreement Charges				410		260		150
Other financing fees				143		170		165
Demand Line interest				35		70		36
Total Financing Fees				1,148		1,011		809
Total Short-Term Debt			(3,686)	964	5,945	1,231	2,718	891
Weighted average rate on Short-Term Debt				-26.15%		20.71%		32.78%
Total Long-Term and Short-Term Debt			**548,917**	**35,138**	**655,945**	**40,506**	**642,718**	**39,557**
Weighted average rate on Total Debt				**6.40%**		**6.18%**		**6.15%**

Table BCUC IR2 35.1.1c reflects updated short-term interest rates for 2012 and 2013, similar to Table 4.7.1-2 of the 2012-13 RRA, which are derived from the short-term interest expense amounts included in Table BCUC IR2 35.1.1a above. It does not reflect any update to the 2012 and 2013 long-term interest rate forecast as that has been requested in BCUC IR2 Q33.1.1.

Table BCUC IR2 35.1.1c Weighted Average Cost of Debt (2012-2013)

Description of Debt	Maturity Dates	Rates	2012 Forecast Weighted Average Balance ($000s)	2012 Forecast Interest Expense ($000s)	2013 Forecast Weighted Average Balance ($000s)	2013 Forecast Interest Expense ($000s)
Long-Term Debt						
Series F	16-Oct-12	9.65%	12,483	1,205	-	-
Series G	28-Aug-23	8.80%	25,000	2,200	25,000	2,200
Series H	01-Feb-16	8.77%	25,000	2,193	25,000	2,193
Series I	01-Dec-21	7.81%	25,000	1,953	25,000	1,953
Series 1 - 04	28-Nov-14	5.48%	140,000	7,672	140,000	7,672
Series 1 - 05	09-Nov-35	5.60%	100,000	5,600	100,000	5,600
Series 1 - 07	04-Jul-47	5.90%	105,000	6,195	105,000	6,195
MTN Series 1 - 2009	02-Jun-39	6.10%	105,000	6,405	105,000	6,405
MTN Series 2 - 2010	24-Nov-50	5.00%	100,000	5,000	100,000	5,000
Series 2013	30 year est.	5.90%	-	-	25,151	1,484
Total Long-Term Debt			637,483	38,422	650,151	38,701
Weighted average rate on Long-Term Debt				6.03%		5.95%
Short-Term Debt						
Draws on facility/deemed adjustment			49,669	1,403	77,158	2,793
Financing Fees						
Total Standby Fees				367		301
Total Banking Agreement Charges				275		280
Other financing fees				180		190
Demand Line interest				74		77
Total Financing Fees				896		848
Total Short-Term Debt			49,669	2,299	77,158	3,641
Weighted average rate on Short-Term Debt				4.63%		4.72%
Total Long-Term and Short-Term Debt			**687,152**	**40,721**	**727,309**	**42,342**
Weighted average rate on Total Debt				**5.93%**		**5.82%**

Table BCUC IR2 35.1.1d provides an overview of the deemed capital structure and the weighted average cost of capital for 2010 through to 2013 based on updated short-term interest rates for 2012 and 2013 provided in Table BCUC IR2 35.1.1a, in a format similar to Table 4.7 of the Application. The table also recognizes the correction of the 2011 short-term interest expense as included in the response to BCUC IR1 Q85.3 and provided earlier in the response to this IR.

It does not reflect any update to the 2012 and 2013 long-term interest rate forecast that has been requested in BCUC IR2 Q33.1.1.

Table BCUC IR2 35.1.1d Financing Costs

	Actual 2010	Approved 2011	Forecast 2011	Forecast 2012	Forecast 2013
			($000s)		
CAPITALIZATION					
Debt	548,917	655,945	642,718	687,152	727,309
Common Equity	396,927	437,296	428,479	458,101	484,872
	945,844	1,093,241	1,071,197	1,145,253	1,212,181
Equity as % of Total	42%	40%	40%	40%	40%
EARNED RETURN					
Interest Expense	35,138	40,506	39,557	40,721	42,342
Net Earnings	38,293	43,292	45,922	45,352	48,002
	73,431	83,798	85,479	86,073	90,344
RETURN ON CAPITAL					
Weighted Average Cost of Debt	6.40%	6.18%	6.15%	5.93%	5.82%
Return on Equity	9.65%	9.90%	10.72%	9.90%	9.90%
Weighted Average Cost of Capital	7.76%	7.67%	7.98%	7.52%	7.45%

35.2 Please update Table BCUC IR1 85.2a Bankers' Acceptance Rates on Term Bank Debt (3-month T bill), Table BCUC IR1 85.2a Prime Rate (Overnight Bank Rate plus 200 basis points) and Table BCUC IR1 85.3.

Response:

Please refer to the below tables.

Table BCUC IR 2 35.2a Bankers' Acceptance Rates on Term Bank Debt (3 month T-bill)

		2012					2013
Canadian Chartered Bank	Publication Date	**Q1**	**Q2**	**Q3**	**Q4**	**Average**	**Annual**
BMO Capital Markets Research	October 7, 2011	0.83%	0.83%	0.83%	0.83%	0.83%	N/A
Toronto Dominion Quarterly Economic Forecast	September 13, 2011	0.90%	0.90%	0.95%	1.00%	0.94%	1.95%
Scotia Economics Global Forecast	October 7, 2011	0.95%	1.10%	1.35%	1.95%	1.34%	N/A
CIBC World Markets Economic Insights	September 28, 2011	1.00%	1.20%	1.35%	1.40%	1.24%	N/A
RBC Capital Market Forecasts	October 7, 2011	1.15%	1.15%	1.30%	1.60%	1.30%	N/A
Average rate		***0.97%***	***1.04%***	***1.16%***	***1.36%***	***1.13%***	*1.95%*
Spread		0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
Sub total before Stamping Fee		1.27%	1.34%	1.46%	1.66%	1.43%	2.25%
Rounded up to nearest 0.10%		**1.30%**	**1.40%**	**1.50%**	**1.70%**	**1.50%**	**2.30%**

Table BCUC IR 2 35.2b Prime Rate (Overnight Bank Rate plus 200 basis points)

		2012					2013
Canadian Chartered Bank	Publication Date	**Q1**	**Q2**	**Q3**	**Q4**	**Average**	**Annual**
BMO Capital Markets Research	October 7, 2011	1.00%	1.00%	1.00%	1.00%	1.00%	N/A
Toronto Dominion Quarterly Economic Forecast	September 13, 2011	1.00%	1.00%	1.00%	1.00%	1.00%	1.88%
Scotia Economics Global Forecast	October 7, 2011	1.00%	1.00%	1.25%	1.75%	1.25%	N/A
CIBC World Markets Economic Insights	September 28, 2011	1.00%	1.00%	1.25%	1.50%	1.19%	N/A
RBC Capital Market Forecasts	October 7, 2011	1.00%	1.00%	1.25%	1.50%	1.19%	N/A
Average rate		***1.00%***	***1.00%***	***1.15%***	***1.35%***	***1.13%***	*1.88%*
Add 200 basis points		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Sub total before prime rate margin fee		3.00%	3.00%	3.15%	3.35%	3.13%	3.88%
Rounded up to nearest 0.25%		**3.00%**	**3.00%**	**3.25%**	**3.50%**	**3.25%**	**4.00%**

The above tables make reference to Canadian Chartered Bank publications which are included in the response to BCUC IR2 Q33.1 with one exception. BMO Capital Markets did not provide an estimate for 30 year debt and therefore was not included in the response to BCUC IR2 Q33.1. BMO Capital Markets do, however, provide forecast rates for Bankers' Acceptances and Prime Rates which have been used to forecast the above rates, therefore the publication is included in Figure BCUC IR2 35.2 below.

1 **Figure BCUC IR2 35.2**

ECONOMIC FORECAST SUMMARY FOR OCTOBER 7, 2011

BMO Capital Markets Economic Research

	2011				2012				ANNUAL		
CANADA	I	II	III	IV	I	II	III	IV	2010	2011	2012
Real GDP (q/q % chng : a.r.)	3.6	-0.4	2.0	1.5	1.8	2.1	2.3	2.5	3.2	2.2	1.8
Consumer Price Index (y/y % chng)	2.6	3.4	3.0	2.5	2.0	1.9	2.2	2.0	1.8	2.9	2.0
Unemployment Rate (%)	7.7	7.5	7.2	7.2 ↓	7.4 ↓	7.3 ↓	7.3 ↓	7.2 ↓	8.0	7.4 ↓	7.3 ↓
Housing Starts (000s : a.r.)	178	193	193	185	184	181	181	182	192	187	182
Current Account Balance ($blns : a.r.)	-40.3	-61.3	-61.7	-64.7	-61.8	-59.8	-59.6	-58.8	-50.9	-57.0	-60.0
Interest Rates (average for the quarter : %)											
Overnight Rate	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.60	1.00	1.00
3-month Treasury Bill	0.95	0.95	0.88	0.83	0.83	0.83	0.83	0.83	0.56	0.90	0.83
10-year Bond	3.31	3.16	2.53	2.13	2.05	2.05	2.12	2.22	3.24	2.78	2.11
Canada/U.S. Interest Rate Spreads (average for the quarter : bps)											
90-day	82	90	86	81	81	81	81	81	42	85	81
10-year	-15	-5	10	23	28	30	28	26	2	3	28
UNITED STATES											
Real GDP (q/q % chng : a.r.)	0.4	1.3	1.9	1.5	1.7	2.1	2.6	2.9	3.0	1.6	1.9
Consumer Price Index (y/y % chng)	2.2	3.3	3.7	3.6	3.0	2.7	2.5	2.3	1.6	3.2	2.6
Unemployment Rate (%)	8.9	9.1	9.1	9.2	9.2	9.1	9.0	8.9	9.6	9.1	9.1
Housing Starts (mlns : a.r.)	0.58	0.57	0.59	0.60	0.61	0.62	0.63	0.64	0.58	0.58	0.63
Current Account Balance ($blns : a.r.)	-478	-509	-478	-474	-462	-457	-453	-449	-471	-485	-455
Interest Rates (average for the quarter : %)											
Fed Funds Target Rate	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
3-month Treasury Bill	0.13	0.05	0.03	0.02	0.02	0.02	0.02	0.02	0.14	0.05	0.02
10-year Note	3.46	3.21	2.43	1.90	1.77	1.75	1.83	1.96	3.21	2.75	1.83
EXCHANGE RATES (average for the quarter)											
US¢/C$	101.4	103.4	102.1	95.4 ↓	93.0	93.0	95.2	98.8	97.1	100.6 ↓	95.0
C$/US$	0.986	0.967	0.979	1.048	1.075	1.075	1.050	1.012	1.030	0.995	1.053
¥/US$	82	82	78	76	76	76	77	79	88	79	77
US$/Euro	1.37	1.44	1.41	1.33	1.30	1.30	1.33	1.38	1.33	1.39	1.33
US$/£	1.60	1.63	1.61	1.53 ↓	1.50	1.50	1.53	1.58	1.55	1.59	1.53

Note: Blocked areas represent BMO Capital Markets forecasts
Up and down arrows indicate changes to the forecast ↑↓

BMO Capital Markets™

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There has been minimal change in the 2011 forecast short-term interest rates and related interest expense as shown in the response to BCUC IR1 Q85.3 and, as such, the table included in the response to BCUC IR1 Q85.3 has not been updated in this IR response

DEPRECIATION

36.0 Reference: Depreciation and Amortization

Exhibit B-4, BCUC 1.51.2, Table BCUC IR1 88.3, BCUC 1.89.1, 1.89.2, 1.89.3 -

Table BCUC IR1 89.3, 1.90.2, 1.90.2 – Attachment 90.2, and 1.90.4

Recommended Depreciation Rates

The depreciation study derives an average service life estimate based on a combination of actual data analysis of retirement history and professional judgment from such sources as peer industry experience, Gannett Fleming and FortisBC staff. The amount of professional judgment used to derive a recommended depreciation rate varies from asset account to asset account. For some asset classes, professional judgment used in deriving the recommended rate can be as high as 70 percent with historical retirements data analysis weighted at 30 percent.

In Attachment 1-90.2 of IR 90.2, FortisBC provided the approximate weighting of each factor in determining average service life estimates for all asset accounts. Selected asset accounts are presented below:

	ESTIMATION OF APPROXIMATE WEIGHTING APPLIED TO EACH FACTOR IN THE DETERMINATION OF EACH AVERAGE SERVICE LIFE ESTIMATE					
		Professional Judgment				
ACCOUNT	Actual Data Analysis of Retirement History	Peer Industry experience	Gannett Fleming Professional Judgment	Discussions with FortisBC Staff	TOTAL	AGGREGATE % OF FACTORS BASED ON PROFESSIONAL JUDGMENT
353.0 - Transmission - Station Equipment	30%	40%	20%	10%	100%	70%
390.1 - General Plant - Structures - Masonry	30%	40%	20%	10%	100%	70%
373.0 - Distribution - Street Lightning and Signal Systems	30%	40%	20%	10%	100%	70%

In addition, a large portion of the professional judgment component consists of peer industry experience. FortisBC obtained depreciation rates for selected asset accounts from relevant utilities with transmission and distribution services and provided these rates in Table BCUC IR1 88.3 and Table BCUC IR1 89.3. Selected asset account comparatives are presented below:

ACCOUNT	COMPARABLE DEPRECIATION RATES OF RELEVANT UTILITIES WITH TRANSMISSION AND DISTRIBUTION: Newfoundland Power	BC Hydro	SaskPower	Hydro Quebec	AVERAGE DEPRECIATION RATE OF RELEVANT UTILITIES
353.0 - Transmission - Station Equipment	2.60%	3.30%	2.50%	2.50%	2.73%
390.1 - General Plant - Structures - Masonry	2.30%	3.50%	2.30%	2.00%	2.53%
373.0 - Distribution - Street Lightning and Signal Systems	5.90%	2.40%	2.90%	2.90%	3.53%

The following table provides a summary of selected asset accounts, the degree of professional judgment involved in determining its rate, FortisBC's depreciation rate from the 2006 depreciation study, its current and recommended depreciation rate, its comparable average peer industry depreciation rate, and estimates of the impact on depreciation expense of different rates:

ACCOUNT	% OF PROFESSIONAL JUDGMENT USED TO DERIVE DEPRECIATION RATE	FORTISBC DEPRECIATION RATE FROM 2006 STUDY	FORTISBC CURRENT RATE	FORTISBC RECOMMENDED RATE	AVERAGE DEPRECIATION RATES OF RELEVANT UTILITIES	INCREASE (DECREASE) IN DEPRECIATION USING FORTISBC RECOMMENDED RATE IN RRA (in '000s)	ESTIMATED DECREASE IN DEPRECIATION USING AVERAGE DEPRECIATION RATE OF RELEVANT
353.0 - Transmission - Station Equipment	70%	3.26%	3%	3.40%	2.73%	$962.00	($1,623.38)
390.1 - General Plant - Structures - Masonry	70%	5.92%	3%	6.10%	2.53%	$796.00	($917.97)
373.0 - Distribution - Street Lightning and Signal Systems	70%	2.40%	2.40%	23.00%	3.53%	$2,353.00	($2,224.50)

36.1 For Transmission – Station Equipment (account 353), it appears that there is a significant degree of professional judgment (70 percent) used in deriving this recommended depreciation rate. When comparing the depreciation rates from the 2006 and 2011 depreciation study, these recommended rates at 3.26 percent (2006) and 3.4 percent (2011) are consistently higher than the average depreciation rate of its relevant utilities of 2.73 percent. In determining the recommended rate for this asset account, a significant degree of judgment, at 70 percent, was used with approximately 40 percent weighting placed on peer industry experience. If the average industry rate of 2.73 percent was used as the recommended depreciation rate, this would reduce depreciation expense in the RRA by an estimated $1.6 million.

36.1.1 Please explain what underlying factors would justify FortisBC adopting a higher rate than the average industry experience rate.

Response:

When comparing the recommended depreciation rate to comparable utilities, the depreciation rate is not the key comparable factor. Rather, the average service life estimate, depreciation rate calculation procedure, and the Accumulated Depreciation variance between the required Accumulated Depreciation balance and the actual booked Accumulated Depreciation variance used within the depreciation rate are the factors which must be considered.

The following table outlines the comparison of the relevant factors for this account to consider in the comparison to the peer utilities for which the comparable depreciation rates are provided. As Gannett Fleming was not involved in the depreciation rate calculations leading to the currently used depreciation of Hydro Quebec, Gannett Fleming is not aware of the details of the depreciation rate influences.

Table BCUC IR2 36.1.1

Utility	Net Salvage Percentage	Average Service Life estimate	Amount of Accumulated Depreciation Variance true-up as at Depreciation Study Date	Depreciation Calculation procedure
FortisBC Proposed	0%	50 years	$29,775,810	Average Service Life
Newfoundland Power	-10%	46 years	$194,493 (*)	Equal Life Group
BC Hydro	0%	30 years	$0 (*)	Average Service Life
SaskPower	0%	35 years	$0 (*)	Average Service Life
Hydro Quebec	Unknown	Unknown	Unknown	Unknown

(*) In the circumstances of SaskPower and BC Hydro there are no significant amounts of Accumulated Depreciation variances. As such, no variance true up amounts were included in the depreciation rate calculations. In the circumstance of Newfoundland Power the Accumulated Depreciation variance did not meet a minimum threshold for it to be included in the depreciation rate calculation.

As indicated in the above table, the average service life estimate recommended for FortisBC is significantly longer than the average service life estimates of the peer group. However, a large

Accumulated Depreciation variance has accumulated that requires recovery over the remaining life of this account. The recovery of the Accumulated Depreciation surplus provides an impact of 0.7% in the total depreciation rate of 3.40%.

36.1.2 Given the high degree of professional judgment used in deriving this rate, please explain why the average industry experience rate of 2.73 percent should not be used.

Response:

The application of and use of professional judgment occurs in the selection of the average service life estimates (including the retirement dispersion or Iowa curve shape). The development of the actual depreciation rate after the above depreciation parameters are selected does not include any application of professional judgment.

As indicated in response to BCUC IR2 Q36.1.1 the depreciation rate used by the peer companies are based on shorter average service life estimates, which are offset by the very significant amount of Accumulated Depreciation variances in the circumstances of FortisBC. Given that all of the peer companies have no Accumulated Depreciation variances to consider in the depreciation rate calculations, it would not be appropriate to use the depreciation rates from the peer group of companies.

36.2 For General Plant – Structures – Masonry (account 390.1), it appears that there is a significant degree of professional judgment (70 percent) used in deriving this recommended depreciation rate. When comparing the depreciation rates from the 2006 and 2011 depreciation study, these recommended rates at 5.92 percent (2006) and 6.10 percent (2011) are consistently and considerably higher than the average depreciation rate of its relevant utilities of 2.53 percent. In determining the recommended rate for this asset account, a significant degree of judgment, at 70 percent, was used with approximately 40 percent weighting placed on peer industry experience. If the average industry rate of 2.53 percent was to be used as the recommended depreciation rate, this would reduce depreciation expense in the RRA by an estimated $0.9 million.

36.2.1 Please explain what underlying factors would justify FortisBC adopting a higher rate than the average industry experience rate for General Plant – Structures – Masonry (account 390.1).

Response:

When comparing the recommended depreciation rate to comparable utilities, the depreciation rate is not the key comparable factor. Rather, the average service life estimate, depreciation rate calculation procedure, and the Accumulated Depreciation variance between the required Accumulated Depreciation balance and the actual booked Accumulated Depreciation variance used within the depreciation rate are the factors which must be considered.

The following table outlines the comparison of the relevant factors for this account to consider in the comparison to the peer utilities for which the comparable depreciation rates are provided. As Gannett Fleming was not involved in the depreciation rate calculations leading to the currently used depreciation of Hydro Quebec, Gannett Fleming is not aware of the details of the depreciation rate influences.

Table BCUC IR2 36.2.1

Utility	Net Salvage Percentage	Average Service Life estimate	Amount of Accumulated Depreciation Variance true-up as at Depreciation Study Date	Depreciation Calculation procedure
FortisBC Proposed	0%	35 years	$3,555,865	Average Service Life
Newfoundland Power	0%	70 Years (*)	$(672,702)	Equal Life Group
BC Hydro	0%	30 years	$0 (**)	Average Service Life
SaskPower	0%	40 to 50 years	$0 (**)	Average Service Life
Hydro Quebec	Unknown	Unknown	Unknown	Unknown

(*) The general plant buildings at Newfoundland Power have a specific life span date assigned to each building. The 70 year average service life estimate is used for the determination of interim retirement activity.

(**) In the circumstances of SaskPower and BC Hydro there are no significant amounts of Accumulated Depreciation variances. As such, no variance true up amounts were included in the depreciation rate calculations.

As indicated in the above table, the average service life estimate recommended for FortisBC is within a reasonable range of the average service life estimates of the peer group, after the use of the 70 year life estimate for Newfoundland Power is understood. Additionally, a large

Accumulated Depreciation variance has accumulated that requires recovery over the remaining life of this account. The recovery of the Accumulated Depreciation surplus provides an impact of 3.1% in the total depreciation rate of 6.10%. As indicated in the preamble to this question and in FortisBC's response to BCUC IR1 Q88.2, the depreciation rate from the 2006 depreciation study was reduced from a required 5.92% to 3.00%. This significant reduction in the depreciation rate over the period from 2007 through 2009 has, in large part, contributed to the much larger than per group comparable depreciation rates. None of the peer companies had a significant Accumulated Depreciation true up, such as that required by FortisBC.

36.2.2 Given the high degree of professional judgment used in deriving this rate, please explain why the average industry experience rate of 2.53 percent should not be used.

Response:

The application of and use of professional judgment occurs in the selection of the average service life estimates (including the retirement dispersion or Iowa curve shape). The development of the actual depreciation rate after the above depreciation parameters are selected does not include any application of professional judgment.

As indicated in response to 36.2.1 the depreciation rate used by the peer companies are based on comparable average service life estimates. However, the FortisBC depreciation rate has been influenced by the very significant amount of Accumulated Depreciation variances. Given that all of the peer companies have no or limited amounts of Accumulated Depreciation variances to consider in the depreciation rate calculations, it would not be appropriate to use the depreciation rates from the peer group of companies.

36.3 For Distribution – Street Lightning and Signal Systems (account 373), it appears that there is a significant degree of professional judgment (70 percent) used in deriving this recommended depreciation rate. When comparing the depreciation rates from the 2006 and 2011 depreciation study, these recommended rates at 2.4 percent (2006) and 23 percent (2011) are considerably different than the average depreciation rate of its relevant utilities of 3.53 percent. FortisBC is recommending a rate of 23 percent. In response to BCUC 1.89.1, FortisBC states that "…Over 70% of the investment in this account is in excess of 45 years of age with the depreciated value of the account currently less than 15% of its total balance. As such, a large amount of true-up through depreciation expense is required in order to provide for the recovery of the investment within the period prior to the anticipated retirement of the plant." However, in determining the recommended rate (and anticipated retirement period) for this asset account, a significant degree of judgment, at 70 percent, was involved with approximately 40 percent weighting placed on peer industry experience. The average depreciation rate of comparable utilities is 3.53 percent, substantially lower than the recommended rate of 23 percent. If the average industry rate of 3.53 percent was to be used as the recommended depreciation rate, this would reduce depreciation expense in the RRA by an estimated $2.2 million.

36.3.1 Given the high degree of professional judgment used in deriving this rate, please explain why the average industry experience rate of 2.53 percent should not be used.

Response:

Please see the response to BCUC IR2 Q36.3.4.

36.3.2 Please explain what factors have contributed to the significant retirements experienced in this asset account since the last depreciation study to warrant an accelerated depreciation rate over its average peer experience rate of 3.53 percent.

Response:

Please see the response to BCUC IR2 Q36.3.4.

36.3.3 Please comment on your maintenance program for this asset account and whether any significant changes were made.

Response:

FortisBC does not follow a specified maintenance program in servicing its street lights and signal systems. Instead, the Company performs reactive maintenance work where assets are repaired or replaced upon failure or on an as needed basis.

36.3.4 Please explain how this account came to be in such an under-depreciated state, and please provide a table showing the status of the account from 2007 to 2014, assuming the proposed depreciation rate is approved. Also show the remaining book value of the asset class in each year.

Response:

FortisBC has provided a table indicating the status of the account from 2007 through 2010 actual, as well as the 2011, 2012 and 2013 forecast periods.

Table BCUC IR2 36.3.4

	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
				($000s)			
Gross Value	5,691	7,318	7,272	10,275	11,485	11,438	11,391
Add: Reclass	-	-	1,744	-	-	-	-
Add: Additions	1,680	-	1,312	1,257	-	-	-
Less: Retirements	(53)	(46)	(53)	(47)	(47)	(47)	(47)
	7,318	7,272	10,275	11,485	11,438	11,391	11,344
Accumulated Depreciation	(1,415)	(1,471)	(1,601)	(3,383)	(3,464)	(3,693)	(6,274)
Add: Reclass	-	-	(1,744)	-	-	-	-
Add: Depreciation	(137)	(176)	(216)	(247)	(276)	(2,628)	(2,616)
Add: (Gain), Less: Loss	(25)	(3)	(13)	(12)	-	-	-
Less: Retirements	78	49	66	59	47	47	47
Less: Cost of Removal	28	-	125	119	-	-	-
	(1,471)	(1,601)	(3,383)	(3,464)	(3,693)	(6,274)	(8,843)
Net Book Value	5,847	5,671	6,892	8,021	7,745	5,117	2,501

The Accumulated Depreciation variance in this account is largely caused by a balance of over $7 million in the 1960 installation year based on the data as used in the depreciation study, as indicated on page VI-23 of the depreciation study filed in Appendix J of the 2012-2013 RRA. By attributing an older age to this balance, a higher depreciation rate has been assumed in the 2011 Depreciation Study resulting in a higher depreciation expense for 2012-13 depreciation expense.

However, both the Company and the depreciation consultant, Gannett Fleming, agree that approximately $7 million of these costs are better represented with a more recent aging. This suggests that the aging of street light data in the 2011 Depreciation Study should be amended, thus producing a revised higher composite remaining life analysis and lower depreciation accrual rate for this account. Both the Company and Gannett Fleming agree that a revised rate closer to the 2.4% currently used by FortisBC as determined in the depreciation study filed with the 2006 RRA is a more appropriate rate of depreciation than the 23.0% originally requested as part of the 2011 Depreciation Study used to determined depreciation expense in the 2012-13 RRA.

The Company is working with Gannett Fleming to determine a revised depreciation rate. Once a revised depreciation rate has been finalized, the Company proposes to recalculate depreciation expense on Distribution – Street Lighting and Signal Systems (Account 373.0) as part of the final determination of 2012-2013 revenue requirements.

However, to provide a high-level sense of amending the depreciation rate for Distribution – Street Lighting and Signal Systems (Account 373.0) from 23.00%, as recommended in the 2011 Depreciation Study, to a rate of 2.4%, as utilized in the last depreciation study for the 2006 RRA, the following was modeled:

		Impact to Revenue Requirement			
		($000s)		%	
Item	**Significant Assumptions Used**	**2012**	**2013**	**2012**	**2013**
Depreciation Rate of Street Lighting and Signal Systems	Depreciation rate for 2012 and 2013 was adjusted downwards to 2.4% from 23.0% to provide an approximate impact to FortisBC's revenue requirements for the test period.	-$3,000	-$2,800	-1.1%	+0.1%

The test period customer rate impact would be a decrease of approximately 1.1%, from 4.0% to 2.9%, for 2012 and an increase of approximately 0.1%, from 6.9% to 7.0%, for 2013.

36.4 Please calculate the test period rate impact of adopting the average industry peer depreciation rates for the 3 asset classes mentioned in the previous questions.

Response:

After adjusting the depreciation rates for Transmission-Station Equipment (Account 353.0) from 3.40% to 2.73%, General Plant-Structures-Masonry (Account 390.1) from 6.10% to 2.53%, and Distribution-Street Lighting and Signal Systems (Account 373.0) from 23.00% to 3.53%, the test period customer rate impact would decrease by approximately 2.2%, from 4.0% to 1.8%, for 2012, and increase by approximately 0.2%, from 6.9% to 7.1%, for 2013.

However, it is important to note that based on further review of the assets aging in the Distribution – Street Lighting and Signal Systems account, the Company and its depreciation consultant have agreed that a revision to the depreciation rate would be appropriate. The background, potential rate impacts and the timing of incorporating such an amendment in 2012-2013 rates are discussed in further detail in the response to BCUC IR2 Q36.3.4.

37.0 Reference: Depreciation and Amortization

Exhibit B-4, BCUC 1.51.2, 1.92.1, 1.92.2, 1.92.5, 1.97.2 – Table BCUC IR1 97.2;

Exhibit B-1, Tab 7, Appendix 7B

Charges Less Recoveries

In Table BCUC IR1 97.2, Fortis provided the forecasted asset retirement amounts under the Previous Year Method, 3 Year Rolling Average Method and 5 Year Rolling Average Method of Forecasting.

37.1 The asset retirement in 2010 has increased significantly from prior years. Are there anomalies in the 2010 that should be adjusted, similar to 2009, or if not, what factors were considered that would support this trend would continue in the future?

Response:

During 2010, there were no asset retirement anomalies similar to that which were adjusted in 2009.

The reason for the increase is due to retirements of certain transmission assets related to significant projects. As part of the Kettle Valley project, which was granted a CPCN pursuant to Order C-5-06, 9 Line and 10 Line were retired during 2010 with total gross costs of approximately $4,297,000 removed from Plant in Service. In addition, as part of the Okanagan Transmission Reinforcement (OTR) project, which was granted a CPCN pursuant to Order C-5-08, 40 Line was retired during 2010 with total gross costs of approximately $2,991,000 removed from Plant in Service. These two projects together comprise approximately $7,288,000 of the $12,256,000 in total gross cost of plant retired during 2010.

It should be reiterated that as noted in BCUC IR No. 1 Q92.2 and Q92.3, when forecasting for an item of plant to be retired, its cost is removed from plant in service and the charges less recoveries are removed from accumulated depreciation. Therefore, in the forecast 2012 and 2013 periods, the total retired cost recorded against plant in service will be equivalent to the total charges less recoveries recorded against accumulated depreciation. In other words, if the forecast 2012 and 2013 plant retirement dollar amounts are adjusted; there will be no net effect to forecast rate base for 2012 and 2013.

37.2 What method of forecasting has FortisBC historically used to forecast asset retirements?

Response:

As explained in BCUC IR1 Q23.2 from the 2010 RRA, BCUC IR1 Q21.1 from the 2011 RRA, and BCUC IR1 Q97.2 from the 2012-2013 RRA, FortisBC has historically used the "Previous Year Method", whereby the actual retirements from the preceding year are used as the forecast retirements in the current application.

37.3 Which method is commonly used in the utilities industry for forecasting asset retirements?

Response:

There are many forces of retirement that make forecasting difficult to predict. As far as FortisBC is aware, there is no generally accepted method used for forecasting retirements in the utilities industry. Of the methodologies outlined in BCUC IR No. 1 Q97.2, there is evidence of the use of both a prior year actual method as well as a rolling average method in the utilities industry.

37.4 How are the Costs of Removal forecasted in Appendix 7B of Tab 7 of the 2012-13 RRA derived? How is this amount impacted by the three methodologies discussed?

Response:

The individual project Costs of Removal were identified during the development of the project estimates. The Cost of Removal is an estimate component developed from knowledge of the project scope and experience from previously completed work. This estimate incorporates input and knowledge from groups such as Engineering, Project Management, Operations or other business areas where required. Please also see the response to BCUC IR2 Q69.3.

The Costs of Removal forecast amount is not impacted by the Retirement Forecasting Methodology.

38.0 Reference: Depreciation and Amortization

Exhibit B-4, BCUC 1.51.2 and 1.91.2

US GAAP accounting for depreciable assets

In response to BCUC 1.91.2, FortisBC identified five key areas where differences in accounting treatment for depreciable assets exist between FortisBC and FortisBC Energy Utilities: net negative salvage value, commencement of depreciation, gains and losses on disposal, investigative spending and capitalized overhead. FortisBC states that "in light of adverse customer rate impacts, FortisBC has proposed to maintain its current method of accounting…and will propose consistent accounting treatment at a time when there is less pressure on customer rates." (BCUC 1.91.2)

38.1 For each of these key areas, please quantify the dollar impact and rate impact in the test period if FortisBC was to adopt the same accounting treatment as FortisBC Energy Utilities.

Response:

The following dollar and rate impacts in the test period have been modeled at a high level and have used assumptions as documented in the table below. The impacts to revenue requirements in the table below are only approximations, but should provide a general sense of how revenue requirements would be affected given a change in accounting treatment. Furthermore, each of the suggested accounting treatments were modeled independently from each other and due to the intricacies of modeling such impacts, if two or more new accounting treatments were considered together, the resulting outcome would not be the sum of the change for each.

		Impact to Revenue Requirement			
		($000s)		%	
Item	Significant Assumptions Used	2012	2013	2012	2013
Net Negative Salvage Value [1]	Salvage rates used were obtained directly from the 2011 Depreciation Study as filed (see Appendix J to 2012-2013 RRA).	+$14,700	+$14,600	+5.1%	-0.5%
Commencement of Depreciation [2]	Used a high level average to determine when plant would be placed in service.	+$1,600	+$3,200	+0.5%	+0.5%
Gains and Losses on Retirement of PP&E [3]	FortisBC does not forecast gains and losses on disposal.	N/A	N/A	N/A	N/A
Investigative Spending [4]	Removed only the additions to investigative spending for 2012 and 2013.	+$100	+$500	0.0%	+0.1%
Capitalized Overhead [5]	6% (low range of estimate per BCUC IR No. 1 Q63.2)	+$9,900	+$9,200	+3.4%	-0.5%
	14% (consistent with FEU's current approved rate)	+$4,200	+$3,900	+1.4%	-0.2%

Key Assumptions:

[1] This scenario was modeled with the assumption the provision for estimated negative salvage is included in depreciation expense on a prospective basis, beginning in 2012. The determination of negative salvage included in depreciation expense used the negative salvage rates from Table 4.7.3.7 in the 2012-13 RRA, which was consistent with the negative salvage rates from page 45 of the 2011 Depreciation Study prepared by Gannett Fleming included as Appendix J to the 2012-13 RRA. As such, the composite rate (depreciation life plus negative salvage) was used to determine depreciation expense and the accumulated depreciation charge to rate base. In practice, this negative salvage provision would accumulate outside of accumulated depreciation as a separate credit to rate base. This scenario has not considered any costs that may be required to implement this accounting policy change to the capital asset accounting information systems (SAP).

[2] This scenario was modeled with the assumption that the commencement of depreciating assets when placed into service during 2012 would occur on a prospective basis. It has assumed a simple average of capital spending forecasts, as included in Table 1-F – *Adjustment for Capital Expenditures* in Tab 7 of the Application, to calculate the weighted average additions to plant in service throughout the year. Depreciation was calculated on these additions and was included in depreciation expense and the accumulated depreciation charge to rate base. This scenario has not considered any costs that may be required to implement this accounting policy change to the capital asset accounting information systems (SAP).

[3] This scenario was modeled with the assumption that gains and losses would be recognized in their own deferral account on a prospective basis, rather than recognized to accumulated depreciation. Since the Company does not forecast gains and losses on disposal as part of its revenue requirements there is no forecast impact. It is assumed that adding gains and losses to a deferral account instead of embedding in accumulated depreciation would result in no difference to rates in the year the change is made. Going forward, electricity rates would increase in the year amortization begins to be calculated on the actual deferred balance, with a nominal decrease in the year after. This scenario has not considered any costs that may be required to implement this accounting policy change to the capital asset accounting information systems (SAP).

[4] This scenario was modeled with the assumption that only investigative spending incurred in 2012 and 2013, on a prospective basis, would be recognized in operating and maintenance expenses. Therefore the scenario has not considered the expensing of investigative spending costs that were previously, or are expected to be, approved for inclusion in rate base at the end of 2011. As such, the investigative spending costs related to the AMI project, the majority of which have been forecast to occur prior to

2012 as outlined in Tab 7, Table 1-B of the 2012-2013 RRA, have not been expensed to operating and maintenance expense in this scenario.

[5] This scenario was modeled assuming a range of potential capitalized overhead rates, including an estimated 6% rate for IFRS purposes and a 14% rate to be consistent with the FortisBC Energy Utilities (FEU). The 6% capitalized overhead rate was used as a lower range scenario as a result of the response to BCUC IR 1.63.2, which stated that "based on a high level preliminary analysis that was performed back in 2010 during the Company's planned transition to IFRS, an appropriate IFRS overhead rate was expected to be in the range of approximately 6% to 12%. This range would have to be qualified in that a more thorough and detailed review would have to be undertaken prior to quantifying a supportable rate." The 14% capitalized overhead rate was used as an upper range scenario as a result of the capitalized overhead rate used by the FEU which is likely not appropriate to apply to FortisBC as a result of certain differences, including the relative size of the entities, the commodity being delivered and the nature and type of assets being constructed. The capitalized overhead rates were adjusted, thus affecting operating and maintenance expense for 2012 and 2013 as well as additions to plant in service for 2012 and 2013. Depreciation expense on the revised plant in service balance for 2012 was recalculated in 2013.

38.2 By deferring consistent accounting treatment to a future period, how will these accounting treatment differences impact rates in the next revenue requirement application period?

Response:

Future rate impacts would depend on the accounting treatment change. Not adopting those accounting policies related to negative salvage, commencement of depreciation and capitalized overhead essentially defer the rate impacts of recovering capital investment activity under the concept of paying now, or paying later for the costs. Adopting an amortization period for gains/losses that differs from the requested composite depreciation rate would put upward pressure on rates. Investigative spending is not expected to be significant in the future, hence the low impact in the test period, but could have more significant rate impacts in periods where investigative charges are high.

It is not known how the next revenue requirements will be impacted since it will depend on a number of variables, including forecast customer and load growth, rate base, BC Hydro power purchase flowthroughs, variances accumulated in deferral accounts, other changes in accounting policy and regulatory decisions that impact the relative revenue requirements. At that time, all of these accounting treatment differences will be considered for implementation however, similar to the 2012-13 RRA, the Company will take into consideration the impact that changes in accounting policy choices would have on customer rate increases.

38.3 Please confirm that FortisBC's current method of accounting will comply with US GAAP, despite the accounting differences with FortisBC Energy Utilities.

Response:

The guidance for these depreciation and capitalization related topics is acceptable under US GAAP since US GAAP guidance permits the accounting for the effects of rate-regulation. Therefore, if a regulator approves a certain accounting treatment for the purposes of setting rates with the expectation of recovery or refund in customers' future rates, then it is permitted under US GAAP.

CAPITAL EXPENDITURE PLAN

39.0 Reference: Risk Assessments on Capital Expenditure Plan projects

Exhibits B-1 and B-1-1, Various IRs

Various IRs requesting Risk Assessments

39.1 Various IRs in BCUC IR No. 1 requested risk assessments for projects contains in the Capital Expenditure Plan. Using the table below, please provide a summary by project which evaluates the likelihood of the event occurring in years, the risk using a scale of 1 through 5 (with 5 being the highest risk), the impact or consequence using a scale of 1 through 5 (with 5 being the highest impact) and risk score being the product of the impact times the likelihood. Also include a brief explanation for the values chosen for the risk, likelihood and impact.

PROJECT	IR 1 REFERENCE	RISK	LIKELIHOOD	IMPACT	RISK SCORE	EXPLANATIONS

<u>Response:</u>

In this evaluation, FortisBC believes that ranking the "risk" of a project and the "likelihood" of an adverse event are the same. The "risk" column therefore contains a description of the possible adverse event. The likelihood of an event occurring has been scored on a scale from 1 to 5 with 5 representing a high probability of an event. Impact has also been scored from 1 to 5, with 5 representing a high financial loss, significant environmental damage or an injury to workers or the public. Any projects which are required as a legislated change (i.e. WorkSafeBC requirements) or required as a result of an engineering analysis which demonstrated upgrades to meet current day standards have been rated as a 5 for both likelihood and impact.

Project	IR1 Ref	Risk	Likelihood	Impact	Score	Explanations
P1 - LBO - Rock Trap Cleanout Refurbish Leaking Pipe	114.2	There are two potential injury risks to workers; the first is the risk of injury operating the rock trap cleanout adjacent the leaking pipe. The second is the risk of injury is present during the repair operation should the pipe be left to fail.	4	3	12	Since the pipe is currently leaking and the condition is likely to worsen, the likelihood of an event is high. The impact has a moderate rating due to the concerns associated with repairing the rock trap cleanout under flow.
P2 - UBO - Replace Damaged Bracing On Head Gate Towers	114.2	There is a potential risk of injury should these damaged braces be left unrepaired. Under certain load conditions (i.e. head gate jammed) the compression bracing may fail leading to tower collapse.	2	5	10	The likelihood of a tower collapse due to failure of the compression bracing is low but since the gates are generally operated from push button located on the tower, it is reasonable to anticipate a serious injury would arise.
P3 - SLC - Resurface Stair Nosings	114.2	The stairs accessing the switch yard area at South Slocan have deteriorated and currently require rehabilitation to reduce the risk of tripping and fall hazards in a high voltage area.	4	3	12	During the winter months workers shovel snow from this area on a frequent basis. The stairs are currently in bad condition and workers could easily slip and fall down the stairs. Moderate injury or worse is anticipated.
P4 - COR - Install Kick Plate On Walkway	114.2	Sections of the existing handrail at Corra Linn do not meet the WorkSafe BC requirements for handrail; these	5	5	25	There is a potential of an object falling from the overhead walkway and hitting a worker below. Although the injury associated with

Project	IR1 Ref	Risk	Likelihood	Impact	Score	Explanations
		sections require the installation of kick plate to reduce the risk of falling objects.				falling objects varies widely, serious injury can arise. <u>These sections of handrail currently fail to meet WorkSafe BC requirements.</u>
P4 - COR - Refurbish Damaged Stairs	114.2	The stairs accessing the Forebay area at Corra Linn have deteriorated and currently require rehabilitation to reduce the risk of trip and fall hazards.	4	3	12	During the winter months workers shovel snow from this area on a frequent basis. The stairs are currently in bad condition and workers could easily slip and fall down the stairs. Moderate injury or worse is anticipated.
P4 - COR - Replace Damaged Bracing On Head Gate Towers	114.2	There is a potential risk of injury should these damaged braces be left unrepaired. Under certain load conditions (i.e. head gate jammed) the compression bracing may fail leading to tower collapse.	2	5	10	The likelihood of a tower collapse due to failure of the compression bracing is low but since the gates are generally operated from push button located on the tower, it is reasonable to anticipate a serious injury would arise.
P1 - LBO - Upgrade Hoist Frame To Tower Connections	114.2	An engineering analysis of the head gate superstructure has noted that the connections between the hoist frames and the steel towers at Lower Bonnington are undersized and in some locations show signs of failure.	5	5	25	The hoist frame supports the winch for raising and lowering the head gates. This frame is cantilevered out over top of the head gates. A failure of this support frame would result in the hoist mechanism falling to forebay deck level and could result in serious injury and equipment

Project	IR1 Ref	Risk	Likelihood	Impact	Score	Explanations
						damage. This issue is typical among all the river plant head gate support structures.
P3 - SLC - Stairway To Head Gates - Replace Rotten Roof	114.2	The roof above the stairs leading to the head gates at South Slocan is wood construction exposed to the elements. Over time the supports and joists in the roof have deteriorated and could fail under heavy snow loads.	4	4	16	Due to the deterioration of the roof support system, a heavy snow load is likely to cause a failure of the roof. If the failure were to occur while the stairs are occupied, a serious injury is highly likely.
P4 - COR - Re-grout Head Gate Superstructure Base Plates	114.2	A number of grout pads beneath the steel tower bases which support the superstructure for both the spillway gates and the head gates have deteriorated over the years. These grout pads are a direct path for the load transfer between steel and concrete.	5	5	25	Grout pads are an integral part of the structure. If the superstructure is loaded to full design load it is likely there will be some damage to the superstructure and the gates it supports.
P2 - UBO - Upgrade Hoist Frame To Tower Connections	114.2	An engineering analysis of the head gate superstructure has noted that the connections between the hoist frames and the steel towers at Upper Bonnington are undersized and in some locations show	5	5	25	The hoist frame supports the winch for raising and lowering the head gates. This frame is cantilevered out over top of the head gates. A failure of this support frame would result in the hoist mechanism falling to forebay deck level and could

Project	IR1 Ref	Risk	Likelihood	Impact	Score	Explanations
		signs of failure. This project involves the upgrading of these connections to ensure the head gates remain operable.				result in serious injury and equipment damage. This issue is typical among all the river plant head gate support structures.
P1 - LBO - Refurbish Tailrace Gantry Lower Sills	114.2	The tail race gantry crane at Lower Bonnington is supported by a crane rail partially embedded in a concrete beam. These concrete beams supporting the crane have significant deterioration which impacts the safety and rating of the crane. The project involves removing deteriorated concrete and restoring the support beams to original design standards.	3	5	15	The tailrace gantry crane at Lower Bonnington rides on crane rails which are supported by concrete beams beneath. The upstream concrete beam has signs of serious deterioration which could result in a crane collapse during operation. This would result in significant equipment damage and quite likely worker injury.
P4 - COR - Upgrade Spillway Gantry Lifelines To Current Standards	114.2	The lifelines on the spillway gate gantry crane do not meet current WorkSafe BC standards and require upgrades to ensure worker safety during maintenance activities.	5	5	25	The likelihood of an injury is low due to the use of temporary lifelines but if an injury were to occur it would be quite serious. The justification for this project is minimizing the inefficiencies of installing and removing temporary lifelines each time a gate requires operation.

Project	IR1 Ref	Risk	Likelihood	Impact	Score	Explanations
P4 - COR - Upgrade Hoist Frame To Tower Connections	114.2	An engineering analysis of the head gate superstructure has noted that the connections between the hoist frames and the steel towers at Corra Linn are undersized and in some locations show signs of failure. This project involves the upgrading of these connections to ensure the head gates remain operable.	5	5	25	The hoist frame supports the winch for raising and lowering the head gates. This frame is cantilevered out over top of the head gates. A failure of this support frame would result in the hoist mechanism falling to forebay deck level and could result in serious injury and equipment damage. This issue is typical among all the river plant head gate support structures.
P3 - SLC - Upgrade Hoist Frame To Tower Connections	114.2	An engineering analysis of the head gate superstructure has noted that the connections between the hoist frames and the steel towers at South Slocan are undersized and in some locations show signs of failure. This project involves the upgrading of these connections to ensure the head gates remain operable.	5	5	25	The hoist frame supports the winch for raising and lowering the head gates. This frame is cantilevered out over top of the head gates. A failure of this support frame would result in the hoist mechanism falling to forebay deck level and could result in serious injury and equipment damage. This issue is typical among all the river plant head gate support structures.
P4 - COR - Work Platforms On Crane Bridge	114.2	The gantry crane for lifting spillway gates at Corra Linn has a number of grating panels that are currently lifting due to deteriorated and	3	4	12	The grating along the walkway access to the spillway gantry at Corra Linn is loose and missing fasteners. If a panel were to dislodge a worker would fall

Project	IR1 Ref	Risk	Likelihood	Impact	Score	Explanations
		missing fasteners. This project involves refastening or replacement of the grating panels to ensure worker safety.				from the gantry onto the spillway gate. A serious injury would result.
P4 - COR - Upgrade Gate Access Lifelines To Current Standards	114.2	The existing spillway gate lifelines do not meet the current WorkSafe BC standards and require replacement. The current practice involves the use of temporary lifelines each time a spillway gate requires operation. This project will replace the existing lifelines and remove the requirement to install and remove the temporary system each time a gate is operated.	5	5	25	The likelihood of an injury is low due to the use of temporary lifelines but if an injury were to occur it would be quite serious. The justification for this project is minimizing the inefficiencies of installing and removing temporary lifelines each time a gate requires operation.
P1 - LBO - Refurbish Core Holes In Forebay Walkway	114.2	There are a number of cored holes along the dam crest area at Lower Bonnington. These holes were presumably cored in the past to investigate concrete quality but are no longer required. The existence of these holes poses a tripping hazard to	4	3	12	These core holes are both tripping hazards and provide pockets to collect water. When the water freezes in the winter they damage the concrete and provide a slipping hazard. The incident caused by these holes is likely to be a slip, trip or fall.

Project	IR1 Ref	Risk	Likelihood	Impact	Score	Explanations
		workers and allows for the water to collect - accelerating freeze thaw deterioration in the winter months.				
P1 - LBO - Resurface Forebay Deck Area	114.2	The forebay deck area at Lower Bonnington is deteriorating and has lead to the development of high and low areas which allow for water to pond. This project will resurface those areas where ponding occurs to reduce freeze thaw deterioration and slipping hazards for workers in the winter months.	3	3	9	These high and low pockets in the forebay deck provide pockets to collect water. When the water freezes in the winter they damage the concrete and provide a slipping hazard. The incident caused by these pockets is likely to be a slip, trip or fall.
Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows	115.2	Potential for window panes or panels to fall or misoperate due to deterioration.	3	4	12	There is a moderate likelihood that another window could become dislodged and fall from the frame during operation. Since workers operate the window from directly below it is reasonable to expect a serious injury.
Corra Linn Unit 3 Completion - Transformer Oil Containment	116.2	A transformer failure and associated oil leak	2	5	10	The likelihood of a major transformer failure is very low but the consequence of a failure is extremely high due to the proximity of the

Project	IR1 Ref	Risk	Likelihood	Impact	Score	Explanations
						transformer to the water.
Corra Linn Unit 3 Completion - Spare Generator Coils	117.4	Failure of a generator coil	2	5	10	The likelihood of a coil failure is low but the consequence of a failure is high due to high anticipated outage costs.
Upper Bonnington Old Plant Various Unit Upgrades	118.1	One of the old 3 phase transformers can fail, resulting in the loss of generation from one of the old units.	4	4	20	Due to the recent transformer failure at UBO, the likelihood of reoccurrence due to the age of the transformers is high. The forced outage that will follow a failure is considered a high impact.
21 - 23 Line Rebuild - Replacement vs. Repair	136.3	The current condition of the line creates a public/employee safety risk and financial risk associated with the potential to start a forest fire. Depending on the nature of the outage, the current condition also has an impact on reliability for customers.	5	4	20	In 2011 there have been 3 pole fires; 2 on 22L and 1 on 23L so the likelihood of a pole failure within 5 years is high. These are redundant lines though so the impact is fairly low for most of the year. During freshet all lines are required to evacuate the generation and a line failure would have a higher financial impact. A forest fire resulting from a pole fire has the potential to create a high financial and public safety impact.

Project	IR1 Ref	Risk	Likelihood	Impact	Score	Explanations
24 Line Rebuild - Replacement vs. Repair	136.4	The current condition of the line creates a public/employee safety risk and financial risk associated with the potential to start a forest fire. Depending on the nature of the outage, the current condition also has an impact on reliability for customers.	5	4	20	In 2011 there have been 3 pole fires; 2 on 22L and 1 on 23L so the likelihood of a pole failure within 5 years is high. These are redundant lines though so the impact is fairly low for most of the year. During freshet all lines are required to evacuate the generation and a line failure would have a higher financial impact. A forest fire resulting from a pole fire has the potential to create a high financial and public safety impact.
Add Arc Flash Detection To Legacy Metal-Clad Switchgear	143.2	Arc Flash incident occurring while staff is working in the room, with the equipment energized and not wearing protective suits.	2	5	10	The likelihood of an arc flash incident occurring is relatively low, but the impact to unprotected employees would be extremely high due to the energy release involved

40.0 Reference: All Plants Concrete and Structural Rehabilitation

Exhibit B-4, BCUC 1.114.2

Remaining Life of Concrete Structures

"A number of projects involving the mitigation of potential risk to public and worker safety have been included in the "All Plants Concrete and Structural Rehabilitation" category. A risk assessment for the do-nothing option was not completed as these projects were included within the program based on engineering judgment and the potential to create hazards for employees for the public at FortisBC facilities.

Of the 22 total projects put forward between 2012 and 2013, 18 of them involve some degree of risk to public or worker safety. These projects represent a cost of $0.671 million out of the $1.2 18 million proposed in these years."

40.1 Please provide a risk assessment for the do-nothing option for the remaining four projects in 2012 and 2013.

Response:

Project	Risk	Likelihood	Impact	Risk Score	Explanation
P1 - LBO - SERVICE TUNNEL CRACK - MONITOR AT THIS TIME	TBD	100%	TBD	TBD	A substantial crack in the service tunnel has appeared, this project is to install a crack monitor. The crack monitor will be used to assess movement within the tunnel and determine risk.
P4 - COR - RESURFACE TAILRACE WALL	4	100%	4	16	The tail race wall at Corra Linn has deteriorated. If the wall were to remain unaddressed there is a high likely hood the wall could fail leading to structural stability issues. The downstream sections of the wall have already collapsed.
P2 - UBO - REFURBISH CRACK IN POWER HOUSE WALL	4	100%	1	4	This is a small project for repairing a crack in the power house wall. This project was placed in this year to take advantage of the access required for the power house window refurbishment thereby lowering the overall cost. Due to the location of the crack, additional load is currently being transferred through the windows.
P1 - LBO - RESURFACE FOREBAY WALL AND NORTH PIERS	4	100%	4	16	The intake area of the Lower Bonnington Dam has deteriorated to the point where spalled concrete has fallen into the water and likely went through the units. These structures are continuing to deteriorate and pose risk to intake stability and equipment

					damage. As a result of these risks, the intake area requires immediate attention.
A LIKELIHOOD OF 100% INDICATES EVENTS THAT HAVE ALREADY OCCURRED OR ARE CURRENTLY OCCURING.					

41.0 Reference: All Plants Concrete and Structural Rehabilitation

Exhibit B-4, BCUC 1.114.7

Remaining Life of Concrete Structures

41.1 For the "P4 - COR - Upgrade Spillway Gantry Lifelines To Current Standards" project, and the "P4 - COR - Upgrade Gate Access Lifelines To Current Standards" project, please explain how they differ, and why the use of temporary lifelines is insufficient or otherwise not allowed by WorkSafeBC standards.

Response:

The Corra Linn Dam has fourteen spillway gates that are operated with two spillway gantry cranes. These gantry cranes travel back and forth between the gates. Each time a gate is to be operated a worker must climb down onto the gate and manually attach the screw jacks to the spillway gate prior to lifting. Once the gate is fully opened, the gate is locked in the open position and the screw jacks are disconnected thus allowing the gantry to move to another gate.

The first project, "P4 – COR – Upgrade Spillway Gantry Lifelines to Current Standards", addresses the access required for a worker to disconnect the screw jacks when the gate is locked in the fully opened position and for maintenance of the locking mechanism. Currently there are permanent lifelines installed which are attached to the traveling gantry crane and are located approximately 40 feet above the pier caps. The exact installation date of these permanent lifelines is not known, however they do not meet current WorkSafeBC standards. As such, FortisBC employees use temporary lifelines when disconnecting the screw jacks to comply with WorkSafeBC legislation.

The second project, "P4 – COR – Upgrade Gate Access Lifelines to Current Standards", addresses the access required for a worker to connect the screw jacks to the gate when the gates are in the closed position prior to opening. As with the spillgate gantry lifelines, there are permanent lifelines which are attached between spillway hoist towers and are located approximately 2 feet below the pier caps. The existing permanent lifelines installed for the purposes of connecting the screw jacks also do not meet WorkSafeBC standards, so FortisBC employees use temporary lifelines for this work as well.

While permitted by WorkSafeBC, the use of temporary lifelines is not the preferred option for these repetitive tasks at the Corra Linn plant. The installation of the temporary lifelines requires two people, the lifelines need to be located, inspected, transported to the gates and installed prior to use. Following their use, the lifelines need to be removed and transported back to storage. The frequency of installation and removal can lead to complacency related safety concerns; improper storage and handling along with additional wear on the safety equipment.

For these reasons, FortisBC has proposed the above projects to upgrade the existing permanent lifeline installations to current WorkSafeBC standards and remove the requirement for the use of temporary lifelines for this work.

41.2 For the “P4 - COR - Refurbish Tower To Bridge Connections” project, please explain why the “further investigation” is considered a capital expenditure.

Response:

The “further investigation” does not refer to the investigation to determine if the project is required, rather it refers to the engineering analysis and design required for the connection upgrades.

42.0 Reference: Corra Linn Unit 3 Completion

Exhibit B-4, BCUC 1.117.3

Spare Generator Coils

42.1 Please explain why spare coils were not procured at the time of the original project, and whether that is a prudent step to take when rewinding a generator.

Response:

FortisBC is unable to confirm why spare coils were not procured at the time of the Corra Linn Unit 3 Life Extension project. Subsequent to this project spare coils became part of the contract responsibilities for future Upgrade Life Extension projects.

FortisBC believes that having spare coils available is prudent as it considerably limits the length of outage time in the event of a coil failure.

42.2 Please identify which, if any, of the ULE's have had spare generator coils supplied under the ULE project.

Response:

All of the ULEs, except Corra Linn Unit 3, have had spare generator coils supplied under the ULE project.

43.0 Reference: Upper Bonnington Old Plant Various Unit Upgrades

Exhibit B-4, BCUC 1.118.1

Scope

43.1 Please provide the complete scope for the proposed work with the unit transformers. Two of the four transformers are identified as being over 95 years old; what is the age of the remaining transformers?

Response:

The Unit 2 transformer is 40 years old and the Unit 4 transformer is 46 years old.

The complete scope for the proposed work with the Unit transformers is outlined in BCUC IR2 Appendix 43.1.

44.0 Reference: Generation Capital Expenditures

Exhibit B-4, BCUC 1.120.1, 1.196.1

Upper Bonnington, Lower Bonnington and Corra Linn Fire Panels

44.1 Please confirm that the November 2010 Risk Control Report does not contain any recommendations requiring the additional fire safety systems FortisBC is proposing at the generating stations.

Response:

It is confirmed that the November 2010 Risk Control Report does not contain any recommendations requiring [personnel] fire safety systems other than what FortisBC is currently proposing.

45.0 Reference: Generation Capital Expenditures

Exhibit B-4, BCUC 1.123.1, 1.123.4, 1.123.5

Lower Bonnington and Upper Bonnington Upgrade 4 Spillway Gate Control Phase 2 (2012 and 2013)

45.1 Please describe the time frames involved in the onset of water flood levels that would require the use of the spillway gates at Upper and Lower Bonnington, and explain why lower cost methods of gate opening could not be employed in the case of a control system failure.

Response:

An examination of the Probable Maximum Flood (PMF) completed by Acres International in 1999 indicated that the outflow of Kootenay Lake (approximately the inflow to Upper and Lower Bonnington) would rise by 585m^3/s (20,700 cfs) per day from a flow rate of 2800m^3/s (98,900 cfs) to the peak flow of 7700m^3/s (271,900 cfs).

Based on the above analysis the time frame for gate operation under PMF conditions would be:

UBO Spill Gates = 40,000cfs / 20,700cfs = 1.93 days

LBO Spill Gates = 73,000cfs / 20,700cfs = 3.53 days

During a control system failure, a crew would be dispatched to manually operate the gate. As a onetime event, this would be a lower cost alternative. However, annually during freshet the gates are operated to optimize water levels as well. For instance, in 2011 the spill gates at LBO were operated throughout freshet by FortisBC System Control Center. During this time, the gates were often raised or lowered one or two times per day. It is estimated that the manual operation of these gates during this time period (3 months) would have cost approximately $30,000.

45.2 Please identify the maximum discharge this year that made it necessary to operate the Lower Bonnington spillway gates.

Response:

The Lower Bonnington spillway gates are operated at a total flow in excess of 27,000cfs. During 2011 we exceeded 27,000cfs from May 23 until July 13. The peak flow during the period was 67,686cfs on June 23.

45.3 Please identify the discharge capability of both Upper Bonnington and Lower Bonnington including the spillway gate capacity and compare this discharge capability to the Probably Maximum Flood.

Response:

The discharge capability of the Lower Bonnington Plant is as follows:

1. Overflow Spillway - 137,000cfs
2. Gated Spillway - 73,000cfs

Total:210,000cfs

Although the Company does not have records of the Lower Bonnington Unit 4 Head Works spill capability, they could also be utilized if emergency spill capacity were required. The head works has two 17ft wide by 30ft high openings and are currently isolated with concrete stop logs.

The discharge capability of the Upper Bonnington Plant is as follows:

1. Overflow Spillway - 200,000cfs
2. Gated Spillway - 40,000cfs

Total: 240,000cfs

The probable maximum flood for these two plants is 275,000cfs.

46.0 Reference: Transmission and Station Growth Projects

Exhibit B-4, BCUC 1.127.1, 1.127.2, 1.127.4

Grand Forks Terminal Transformer Addition and High Capacity Communications Project

46.1 Please explain why Option 2 is not the preferred option since it has the lowest Net Present Value.

Response:

Although it has the lowest Net Present Value, Option 2 is not the FortisBC preferred option because other solutions presented address other FortisBC system priorities (the need for communications between the Okanagan and Kootenay fibre optic systems) with only a minimal incremental rate impact.

Currently, there is no FortisBC-owned link between the Okanagan and Kootenay fibre optic systems and this has negative impacts on FortisBC operations. The Net Present Value is strictly a financial calculation, and does not take into account the non-financial impacts of the various options. These additional benefits can be difficult to quantify, but qualitatively would result in improved service to FortisBC customers.

Following is a discussion of some of these benefits:

- The offer to lease a significant portion of the fibre to be installed to a third-party is time-limited and is subject to the project being approved by December 31, 2012 and the fibre installed and ready for use prior to September 15, 2014. The significant additional revenue from this leased fibre goes directly to reducing FortisBC customer rates and this opportunity will be forgone if the fibre build is deferred.
- There is currently a reliance on third-party communications for critical SCADA traffic between the majority of the load in the Okanagan and the System Control Centre in the Kootenays. The third-party provider will not prioritize FortisBC needs in the event of a major communications failure, natural disaster or other emergency. The proposed fibre route would allow FortisBC to have control over its communications facilities, and therefore the electric system, if one of these events were to occur.
- As the BC Mandatory Reliability Standards continue to evolve (primarily due to increasingly stringent standard development in the United States), FortisBC expects that emphasis will be placed on the ability of an electric utility to maintain reliable communications networks to support the operation of the Company's Bulk Electric System. Currently FortisBC has very robust communications to a portion of its BES infrastructure, but in the case of the Okanagan system has a relatively low speed communications circuit provided by a third party and this is the only link to bring the data

back to the control centre. Completion of the “missing link” between the Kootenay and Okanagan fibre-optic systems is required to ensure FortisBC has the robust communications facilities to reliably operate the entire Bulk Electric System.

- The available bandwidth of the existing leased Okanagan to Kootenay circuits is insufficient for short-term growth and is barely adequate for current substation SCADA requirements. New applications such as Distribution Automation, Synchrophasors and Automated Metering Infrastructure as well as a general trend to improved substation automation will increase the amount of operational data being brought back to the System Control Centre, and cannot be supported within the currently available bandwidth. The cost of leasing additional bandwidth for these future applications is expected to decrease the NPV gap between the preferred Option 1 and the lowest NPV Option 2. Therefore, if future needs are fully considered, the proposed option would likely have a lower NPV than Option 2.

- FortisBC-owned fibre can be leveraged by other business area for purposes such as voice communications and corporate data. This will reduce third party communications costs to support these functions.

As discussed, new application data requirements, the need for more bandwidth, anticipated changes to the Mandatory Reliability Standards, and the need for the System Control Centre to be able to have certainty in their ability to respond to power system events will drive the need to upgrade the facilities between the Kootenay and Okanagan regions in the near future. In light of these drivers, FortisBC has proposed the Grand Forks Terminal Transformer Addition and High Capacity Communications projects as the option that will put in place the infrastructure that will be needed in the near future while taking advantage of the limited-time offer of additional revenue which will help to mitigate rate increases. Thus, Option 2 has a lower NPV, but does not provide the additional non-financial benefits of the preferred option.

46.2 Please provide the SIADI, SAIFI and CAIDI statistics for the customers served through GFT T1 since 2006 and provide a comparison with the overall FortisBC statistics.

Response:

FortisBC has interpreted this question to be referring to outages affecting customers caused by transmission and station problems related to the GFT T1 transformer. These statistics do not include outages to customers caused by faults on the distribution system (which generally occur with greater frequency than transmission outages). In addition, because SAIDI, SAIFI and CAIDI statistics are meant to indicate the average system-wide duration and frequency of outages, they cannot be meaningfully used to compare the performance of a specific transformer to the overall system.

The numbers reported here are the average duration and frequency of outages affecting customers served from GFT T1, due to transmission and station faults and forced outages only.

Table BCUC IR2 46.2a

	2010	2009	2008	2007	2006
SAIDI	0.000	0.000	2.627	0.000	1.265
SAIFI	0.000	0.000	1.000	0.000	3.000
CAIDI	N/A	N/A	2.627	N/A	0.422

For comparison, following are the corresponding system wide averages for transmission and stations.

Table BCUC IR2 46.2b

	2010	2009	2008	2007	2006
SAIDI	1.272	1.798	1.353	0.854	1.954
SAIFI	2.187	2.145	2.629	1.861	4.546
CAIDI	0.582	0.838	0.515	0.459	0.430

46.3 Please provide the anticipated improvement in the SIADI, SAIFI and CAIDI statistics for Options 1, 2 and 3, for the same customers as the previous question.

<u>Response:</u>

FortisBC does not anticipate significant differences in the SAIDI, SAIFI or CAIDI statistics for the Grand Forks area between the various proposed options. The need for the proposed second transformer at the Grand Forks Terminal station is not driven by a need to improve reliability, but rather to maintain existing reliability levels while at the same time salvaging approximately 64 km of legacy transmission line infrastructure. The removal of these lines will reduce ongoing operating and capital investments which are currently necessary to ensure that the lines are available at all times to provide an alternate source for the Grand Forks area load in the event that the Grand Forks Terminal T1 transformer fails or is otherwise unavailable.

46.4 Please provide the cost for the option of installing GFT T2 as a "standby" transformer, with disconnect switches to allow GFT T1 to be disconnected and GFT T2 to be put in the circuit in place of GFT T1. Please confirm that in this configuration, the fibre communications upgrade is not required. If it is required, please explain why.

Response:

FortisBC has developed an estimate to install the Grand Forks Terminal (GFT) T2 transformer as a cold-standby unit. The substation expenditures are forecast to be within 10 percent of the cost of the preferred option of installing and operating T2 in parallel with the existing transformer (T1). However, this configuration would not provide customers in the area with full N-1 reliability, as time would be needed to put the transformer into service in the event of a GFT T1 fault. FortisBC did not propose the cold-standby option because the nominal additional substation capital cost (less than 10 percent) of running the transformer in parallel with GFT T1 was not considered significant when compared to the benefit of full N-1 reliability.

The relatively small cost difference between the cold-standby option and the preferred option is a function of the following factors:

- Civil work such as transformer foundation pad and oil containment is the same and required for both options;
- Work required to prepare the transformer for service is the same and required for both options;
- The FortisBC proposed option utilizes an existing spare 63-kV breaker remaining from the recent removal of the 9W and 10W Lines, so there was negligible savings on the installation of the low side bus and equipment;
- The FortisBC proposed option did not require the addition of a new high side circuit breaker;
- Protection sensors (current transformers) for the T1 transformer are embedded in the transformer bushings, and cannot be re-used to protect the T2 transformer; thus, dedicated relaying for T2 is required in both cases.

The cost difference is mostly attributed to the decrease in the amount of work required on the high side bus when implementing the cold-standby option. The proposed option requires some work to be completed on the high side bus to move the connection points for the circuit breakers that would not be needed for the cold-standby option. There are also some savings from the elimination of some voltage transformers and disconnects.

FortisBC confirms that the fibre-optic communications would not be required specifically for transformer protection if the cold-standby option were implemented; however, this does not mean that fibre-optic communications is not required in general. FortisBC has already identified the need for reliable, high-bandwidth communications between the Okanagan and Kootenay systems and approached the solution holistically by combining the transformer addition at Grand Forks with the fibre-optic upgrades. Considering the projects together minimizes the overall ratepayer impact: the fibre-optic communications simplifies the GFT T2 design and decreases total costs; and the GFT T2 project supports installation of the fibre on a timeline that takes advantage of a long-term commitment to lease portions of this fibre.

FortisBC maintains that both the GFT T2 addition and fibre optic communications between the Okanagan and Kootenay systems are important for operating the system efficiently and reliably and that the proposed solution allows for both at significant savings to the ratepayer versus considering them independently. For example, the estimated cost of the proposed option (building the communications link in 2012-2013 and installing GFT T2 with a simplified bus arrangement in 2014-2015) is $9,586k[1] with a one-time rate impact of approximately 0.19%. If considered separately, the cost of the GFT T2 installation with a full ring bus option is $9,051k and the cost of building the fibre after deferring until 2015-2016 is $5,424k for a total of $14,475k (one-time rate impact of 0.28%). Installing the fibre communications prior to GFT T2, and early enough to execute on the offer to lease the excess fibre, saves the ratepayer approximately $2.5 million dollars resulting from the ongoing lease revenue and approximately $3 million in GFT T2 installation costs due to simplification of the design.

46.5 The total cost of the fibre installation appears to be $6.199 million. Has FortisBC discussed any proposal with any third-party to build the fibre and lease back dark fibres to FortisBC? If so, please provide details of those proposals, and if not, why not?

Response:

The potential addition of third-party-owned fibre cable onto FortisBC transmission structures would first need to address a number of concerns:

1. The fibre cable would be an encumbrance on FortisBC's transmission infrastructure due to the additional structure loading and clearance requirements. These impacts would

[1] All costs shown in this response are the Net Present Value (NPV) of the Revenue Requirements; therefore a lower number is more beneficial to ratepayers.

affect the ability of FortisBC to operate, maintain and upgrade its infrastructure (for example by preventing the future installation of FortisBC-owned fibre).

2. FortisBC owns the rights-of-way for the transmission line infrastructure and therefore any party seeking to attach to the transmission poles would need to negotiate appropriate land rights.
3. The fibre design and installation would need to be conducted by FortisBC or its contractors to ensure that the reliability of the line is not negatively impacted.

These issues would need to be addressed and compensated for appropriately to ensure that FortisBC customers are not harmed, either by a reduction in the transmission line reliability or by increased future capital or operating costs.

Given the concerns above, and as discussed in the response to BCUC IR1 Q127.13, no third-party has indicated a desire to locate its own fibre on FortisBC infrastructure in this area. Instead, FortisBC has entered into a binding agreement with a third-party communications provider who is willing to commit to a firm, long-term lease of excess fibre capacity. This lease revenue stream will result in a firm $2.5 million NPV financial contribution to the benefit of FortisBC customers without the associated unknown risks and negative cost impacts if the third-party were to own the fibre cable and lease back to FortisBC.

46.6 Has any party approached FortisBC with a request to install fiber on this route? If so, please provide details.

Response:

Please refer to the response to BCUC IR2 Q46.5.

47.0 Reference: Transmission and Station Growth Projects

Exhibit B-4, BCUC 1.127.3, 1.127.5, 1.127.8

Grand Forks Terminal Transformer Addition and High Capacity Communications Project

47.1 Please describe whether the three to four week replacement period is on a "best efforts" basis. For instance, please describe why a work plan could not be developed in advance if the spare transformer was stored at GFT.

Response:

The three to four week replacement estimate assumes normal crew work schedules and that no customers are experiencing a consequential outage due to the failure of the transformer. However, even in an emergency situation resulting in customer outages it would be difficult to reduce the outage duration to less than approximately one week without incurring significant safety and equipment risks – even if the transformer is stored onsite. Removal and replacement of a large power transformer is a complex process involving the use of both internal and external labour resources and equipment. A work plan laying out the steps necessary to remove a failed transformer and replace it with a spare unit is only one part of this process. Following are some of the steps that would need to take place once the failure actually occurred:

1. Safely isolate the failed transformer from the high-voltage system.
2. Locate and engage the necessary internal crews and/or external contractors, tools and equipment to:
   a. Disconnect the high-voltage bus-work and low-voltage control cabling from the failed transformer.
   b. De-oil and remove any necessary ancillary equipment from the failed transformer.
3. Perform any required environmental clean-up if the transformer failure was major (i.e. resulted in an oil spill or fire).
4. Engage an external civil contractor to:
   a. Physically remove the failed transformer from its foundation pad.
   b. Physically relocate the spare transformer from its storage location to the transformer foundation pad.
5. Refill or top-up the transformer with oil as necessary.
6. Reconnect the high-voltage bus-work (along with any necessary modifications to accommodate different equipment dimensions).

7. Reconnect the low-voltage control cabling to the transformer and tapchanger.
8. Commission the transformer / tapchanger assembly (Doble test, turns-ratio, etc.).
9. Re-commission the transformer protection and control systems.
10. Energize the transformer with no load and take oil samples to confirm the health of the unit.
11. Transfer load to the transformer.

As discussed above, safely completing the above steps would take many days, even in an emergency scenario. FortisBC considers it is unacceptable to have 4200 customers exposed to a multiple-day outage due to a credible single-contingency event (the failure of a power transformer). On that basis, relying on the transformer as a “non-connected cold spare” would be imprudent and hence some other form of transmission backup must be provided.

47.2 Please confirm that the intent of Mandatory Reliability Standards is to document compliance with standards rather than change the way the system is operated, configured, or built, and as such the standards do not define communications requirements, but define how they should be documented.

<u>Response:</u>

Not confirmed. Although the compliance aspect of the BC Mandatory Reliability Standards emphasizes documentation to demonstrate compliance, both the standards and their supporting interpretation documents have specific requirements that can result in substantive changes to the system.

For example, the MRS reliability standard COM-001-1.1 – Telecommunications (refer to BCUC IR2 Appendix 47.2 for the complete standard), lists the following as a requirement:

R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:

R1.1. Internally.

R1.2. Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.

R1.3. With other Reliability Coordinators, Transmission Operators, and Balancing

Authorities as necessary to maintain reliability.

R1.4. Where applicable, these facilities shall be redundant and diversely routed.

Currently, no industry-wide standards exist that mandate or define “adequate and reliable” telecommunications facilities. There are however two WECC guidance documents entitled “Guidelines for the Design of Critical Communications Circuits” and “Communications Systems Performance Guide for Protective Relaying Applications” that outline utility industry best practices for telecommunications system design (refer to BCMEU IR1 Appendix 22a and 22b for copies of these documents). These documents define industry accepted “adequate and reliable telecommunications facilities”, and thus the MRS requirements cited above implicitly require that the recommendations in these documents be followed.

48.0 Reference: Transmission and Station Growth Projects
Exhibit B-4, BCUC 1.127.16, 1.127.17
Grand Forks Terminal Transformer Addition and
High Capacity Communications Project

48.1 Please confirm that the rehabilitation of 9L and 10L can be performed while either line is de energized, and can be performed in favourable seasons.

Response:

Yes, rehabilitation work could be conducted on a de-energized 9 Line or 10 Line as long as the other line remains in service during the outage and most of the construction work can be scheduled during favourable seasons.

48.2 Please provide a structure count for both 9L and 10L, identifying the number of tangent, H frame and other structures in each line. Please also reconcile the structure count against the estimate of 40 percent of each line that requires rehabilitation to arrive at an average cost of replacement per structure for each structure type.

Response:

It is important to note that the estimated cost to rebuild these lines was not developed on a “per structure” basis, but rather on a “per kilometer” basis. The cost per kilometer used by FortisBC in this estimate is a blended cost that has been developed using actual values from previously completed projects. It is an “all-in” estimate which includes all of the costs associated with a line rebuild including design, procurement, construction, salvage, environmental mitigation, vehicle usage, corporate loadings/overheads, etc. It is not simply the reconstruction costs of the line infrastructure itself and for high-level estimating purposes FortisBC considers this method of calculation more accurate than a “per pole” calculation.

The following is an approximate breakdown of structures in the section of 9L and 10L between Christina Lake and Cascade substations:

9 Line

Total Structures:	352
Tangent Structures:	321
Angle Structures:	4
Double Dead End Structures:	11
H Frame Structures:	16

10 Line

Total Structures:	497
Tangent Structures:	476
Angle Structures:	5
Dead End Structures:	16
H Frame Structures:	0

Given the age, condition and historical reliability of the lines, FortisBC expects that approximately 40% of the lines will require rebuilding in the near future. As outlined above there are 849 structures in this section of line and therefore 40% of the line would equate to approximately 340 structures. A simple calculation of $12 million divided by 340 structures equates to approximately $35,000/structure. As discussed above, this cost implicitly includes all of the embedded ancillary costs related to the line reconstruction.

49.0 Reference: Transmission Sustainment Programs and Projects

Exhibit B-4, BCUC 1.129.1

Table BCUC IR129.1 Transmission Sustainment Projects

49.1 Please explain why the Total Transmission Sustainment projects have been below forecast for each year from 2007 to 2010. Please provide 2011 data to demonstrate why FortisBC expects 2011 expenditures to be above forecast.

Response:

In 2007 and 2008, the total Transmission Sustainment projects were below forecast because of construction resource constraints for the Transmission Rehabilitation program. Not all rehabilitation projects scheduled to take place in those years were able to be completed. In 2009 and 2010 the Pine Beetle Hazard Allocation program was originally estimated to have a much larger impact on the Transmission system than the Distribution system. The field assessment identified that the Distribution system was impacted more by the pine beetle than originally expected and the Transmission system less. Therefore to manage the pine beetle damage on the system, the Transmission Pine Beetle Hazard Allocation program was under spent in both years and the Distribution Pine Beetle Hazard Allocation program was over spent. The total dollars spent in both programs was consistent with the total approved dollars in the 2009/2010 Capital Expenditure Plan.

The second reason the 2010 actual expenditures were below forecast was because the 30 Line Lake Crossing project was cancelled, accounting for $0.350 million under spent. The original scope of the project was to replace some marker balls on the lake crossing, but in the early stages of the project, it was discovered that there were some deficiencies with the structures supporting the lake crossing as well that needed to be addressed as part of the project. Also, the tendered cost to replace the marker balls was greater than originally planned. The company then decided to cancel the project and re-apply for the increased scope of work to rehabilitate the lake crossing in a future application (as discussed in the 2012 Integrated System Plan, Volume 1, Appendix F).

The 2011 Transmission Sustainment projects are expected to exceed forecast primarily because of the Transmission Rehabilitation work. The forecast shown in 129.1 of BCUC IR1 is the BCUC approved amount and excludes the Cost of Removal (COR) as it was not approved by the BCUC in the 2011 Capital plan submission. The current estimated amount shown in the table includes COR consistent with the actual costs shown in historical years. The estimated 2011 spend for Transmission Rehabilitation COR is $0.355 million which is being sought in this application. The capital spend excluding COR for 2011 is $1.249 million ($1.604 million minus $0.355 million) which is only slightly over forecast. The Transmission Rehabilitation work for 2011 has been reduced to what is considered to be a minimum acceptable level by FortisBC.

50.0 Reference: Transmission Line Rehabilitation

Exhibit B-4, BCUC 1.131.3

Rehabilitation Volume

50.1 Please explain why FortisBC is proposing to rehabilitate 25 percent of the transmission pole population in a 2 year period. Has there been some change in assessment procedure, or has past maintenance failed to keep up with pole condition, or some other factor to create this volume of work?

Response:

FortisBC's Transmission Condition Assessment program is based on an eight year cycle meaning all transmission facilities will be condition assessed every eight years. This means that 25 percent of the transmission pole population has to be rehabilitated during 2012 and 2013 in order to stay on cycle. There has been no change to the assessment procedure. However pole counts for rehabilitation do vary slightly from year to year because of the number of poles on each transmission line.

51.0 Reference: Transmission Line Urgent Repairs

Exhibit B-4, BCUC 1.132.4

Cost of Removal

51.1 Please explain why the 20 percent Cost of Removal allowance is added to the 2012 and 2013 budget values, and why this is not already included in the 2008 through 2010 actual amounts.

Response:

The 20 percent Cost of Removal (COR) allowance is already included in the 2008 through 2010 actual amounts. In the 2012/2013 submission COR was added to the historic three year rolling average values which already included COR as shown in the response to BCUC IR1 Q132.4. This resulted in effectively a double counting of the COR. FortisBC has corrected the Transmission Urgent Repair budget (see Errata 3) and will update its 2012/2013 Revenue Requirement during the calculation of final rates to reflect this change. The corrected forecast values are shown in the table below:

Table BCUC IR2 51.1: Transmission Urgent Repairs (revised)

2012	2013
$000s	
508	558

51.2 Please explain the increase in loadings from 15 percent in 2008 to 21 percent in 2010 to 27 percent in 2012.

Response:

The loading percentages for Transmission Urgent Repair / Transmission & Distribution (T&D) Sustaining Projects are a function of four parameters:

1. Capitalized Overhead;
2. Direct Overhead;
3. Other adjustments; and
4. The Company's annual capital expenditure plan (unloaded).

The loading rate is calculated by dividing the Overhead amounts to be recovered by the total unloaded Capital Expenditures. Since the Capital Expenditure is the denominator of the loading calculation and it is forecast to decrease over the 2008 to 2012 period, and the numerator is the Overhead amounts and is increasing over the same period, both contribute to the increase in the loading percentage.

Additionally, during 2008-2010 periods, the Okanagan Transmission Reinforcement (OTR) project had a specific Capitalized Overhead percentage applied to it in recognition that the project was an Engineer/Procure/Construction Manage (EPCM) project that should not attract the full Capitalized Overhead rate or Direct Overheads. This in turn had an impact on the overhead loading percentage of the remaining projects.

The Table below provides a high level calculation of the loading percentage applicable to T&D Sustaining projects after normalizing for the OTR project.

Please note that the loading percentage in 2010 has been restated as 18% from 21% referenced in this IR based on actual year end results and not the forecast values that were used previously. The minor difference in the loading percentages in Table BCUC IR2 51.2 below is due to the use of certain estimated numbers.

Table BCUC IR2 51.2

		2008 Actual	2010 Actual	2012 Forecast
Unloaded Capital Expenditure Excluding OTR	A	93,883	77,339	74,369
Capitalized OH Excluding OTR	B	8,691	5,604	11,512
Capitalized OH (Excluding OTR) Percentage	C=B/A	**9%**	**7%**	**15%**
Unloaded T&D Capital Expenditure Excluding OTR	D	67,268	47,004	46,695
Direct OH	E	4,720	5,157	5,000
Direct OH (Excluding OTR) Percentage	F=E/D	**7%**	**11%**	**11%**
Total Loadings Applicable to T&D Sustaining Projects	G=C+F	**16%**	**18%**	**26%**

52.0 Reference: 6 Line/26 Line River Crossing Reconfiguration
Exhibit B-4, BCUC 1.134.1
Cost of Removal

52.1 Please describe the risk to fish in the Kootenay River arising from the transmission line crossing, and describe any past incidents involving the lines and harm to fish.

Response:

The risk of failure of one of the conductors or structures on the 6 Line/26 Line river crossings is considered high given the equipment age and condition. Failure of either of these pieces of equipment on any of the four river crossings could result in an energized conductor falling into the river, posing a safety hazard to fish and any personnel that may be in the area.

A failure near this location did occur about three years ago on a distribution feeder crossing causing an energized conductor to fall in the river. The line protection detected the phase to ground fault when the conductor came in contact with the ground and water and correctly de-energized the line. This event was considered a high-risk incident and was investigated both internally and by the Ministry of Environment to ensure no fish, particularly the endangered sturgeon which are common in this area, were harmed.

FortisBC's line protection relays operate as quickly as practical following the detection of a fault; however, an energized conductor contacting the water for even a short duration presents a hazard to aquatic species in the immediate area. The only way to eliminate the risk is to remove the crossings. The proposed project would salvage two of the four river crossings and thus the risk of a failure at those two crossings would be eliminated. Two crossings are still required to provide service to customers in the area; however, these would be rebuilt which would minimize the risk of failure at those locations going forward.

53.0 Reference: 6 Line/26 Line River Crossing Reconfiguration

Exhibit B-4, BCUC 1.134.2

Cost Savings

53.1 Please confirm the reduction in capital and operating expenditures described in the referenced response are reflected in the 2012 and 2013 forecast.

Response:

The project has no impact on other forecast capital expenditures in 2012 and 2013 and thus no changes are required. Going forward, if this project is approved then the pole counts will be reduced for this line resulting in a reduced spend in Condition Assessment and Rehabilitation during the next cycle. As discussed in the response to BCUC IR1 Q134.2 there will be an avoided capital expenditure in not having to rehabilitate the sections of line being salvaged.

The reduction in operating costs is not reflected in 2012 operating expenditures as the project is not expected to be complete until the end of 2012. The incremental reduction in 2013 operating expenditures (approximately $1,250) has been reflected in the 2013 O&M forecast.

54.0 Reference: 27 Line Rebuild (63 kV Circuit)

Exhibit B-4, BCUC 1.135.1, 1.138.2

Costs and Safety Concerns

54.1 Please confirm the number of transmission to distribution contacts on 27 Line since 2007.

Response:

To FortisBC's knowledge, there have been three transmission to distribution contacts on 27 Line since 2007.

54.2 Please provide the customers' safety concerns.

Response:

FortisBC has experienced some instances where trees falling into the line from outside of the right of way or snow unloading events have caused the transmission conductors to come into contact with underbuilt distribution conductors (refer also to the response to BCUC IR2 Q54.1). This type of inter-circuit contact can result in a condition sometimes referred to as an "extreme temporary overvoltage" on the distribution conductors which then also results in an overvoltage on the service entrances to individual customers in the area. These overvoltage events have resulted in damage to customer equipment such as failed surge suppressors (i.e. computer power bars or whole-house surge suppressors), electronic equipment and hardwired smoke detectors.

55.0 Reference: 21 - 24 Line Rebuild

Exhibit B-4, BCUC 1.136.8, Table BCUC IR1 136.8

Replacement vs. Repair

55.1 Please explain the absence of any urgent repairs to lines 21L to 24L in 2007 and 2009.

Response:

There were no expenditures under Urgent Repairs on 21 to 24 Lines in 2007 or 2009 because no equipment had failed in either of those two years requiring an urgent repair. These lines, although in similar condition to some of the other original vintage lines such as 20 Line and 27

Line, have fewer failures due to the fact that the lines only range from 2km to 5km long. The shorter line lengths result in a lower probability of failure.

55.2 Please provide the project justification supplied to the Commission for the expenditures in excess of $15 million in 2010.

Response:

The legend for Table BCUC IR1 136.8 shows values in dollars, not thousands of dollars; thus, the expenditures on 21-24 Lines in 2010 were only in excess of $15,000, not $15 million. The expenditures were required to repair failed equipment on the lines and are consistent with the scope of work intended under the Transmission Urgent Repair program and were included in that budget.

56.0 Reference: 19 Line/29 Line Reconfiguration

Exhibit B-4, BCUC 1.137.3

Cost Savings

56.1 Please confirm the reduction in capital and operating expenditures described in the referenced response are reflected in the 2013 forecast.

Response:

The project only has impact on the Transmission Condition Assessment budget for 2012 and the Transmission Rehabilitation budget in 2013 because 19 Line is scheduled to be condition assessed in 2012. No changes were previously made to the 2012/2013 submission with respect to this pole reduction. FortisBC has corrected the pole counts, with respect to the section of 19 Line being salvaged, and will update its 2012-13 Revenue Requirement during the calculation of final rates to reflect the change. The corrected amount for Transmission Condition Assessment (2012) and Rehabilitation (2013) budgets are shown below. The reduction in operating costs is not reflected in 2012/2013 operating expenditures as the project is not expected to be complete until the end of 2013. Please refer to Errata No. 3.

Table BCUC IR2 56.1a: Transmission Condition Assessment 2012 (revised)

2012
($000s)
491

Table BCUC IR2 56.1b: Transmission Rehabilitation 2013 (revised)

2013
($000s)
2,463

57.0 Reference: 20 Line Rebuild (63 kV)

Exhibit B-4, BCUC 1.138.2

Costs and Safety Concerns

57.1 Please confirm the number of transmission to distribution contacts on 27 Line since 2007.

Response:

To FortisBC's knowledge, there have been no transmission to distribution contacts on 27 Line since 2007.

58.0 Reference: Environmental Compliance (PCB Mitigation)

Exhibit B-4, BCUC 1.140.5

Appendix BCUC IR1 Electronic Attachment 140.5

58.1 Please describe whether FortisBC intends to replace all the equipment identified on Attachment 140.5, or whether the equipment will be retained if found not to contain PCB.

Response:

The Company will not necessarily replace all equipment. Each piece of equipment is being considered on a case by case basis. Equipment that can be sampled to provide proof it is not contaminated will remain in service. In the event equipment must be removed from service in order to obtain a test sample, replacement equipment will be installed. PCB-free test results from removed equipment will allow the equipment to be reused by the PCB program where possible to minimize costs to customers.

58.2 Please explain whether FortisBC will attempt to sample equipment which was not sampled previously because attempts to sample the equipment were not practical due to safety concerns, or attempts to sample the equipment were not successful and time constraints required the equipment to be returned to service, or access to the equipment would require significant outages. If not, why not, and why is it feasible to take an outage to replace the equipment, but not to sample it?

Response:

Yes, an attempt will be made to obtain samples when an opportunity exists. If a previous attempt failed another attempt will be made if appropriate preparations can be made.

For bushings that are sealed, the labour cost of removing the bushing to take a sample is 2 to 4 times the cost of the equipment. The most cost effective strategy in many of these cases will be to replace the bushing and test to determine disposal requirements. In the case of sealed bushings this test is likely to compromise the bushing integrity rendering it unusable.

If an outage is required that affects a large number of customers, or the company has limited resources (i.e. insufficient mobile transformers to manage the program), then it may be advantageous to customers for the company to take one outage to replace the equipment and not take an outage to first sample the equipment and then possibly expose the customers to a second outage to replace the PCB contaminated equipment along with the increased costs. This decision will be influenced based on PCB concentration sampling results as the program progresses.

59.0 Reference: Arc Flash Detection

Exhibit B-4, BCUC 1.143.2

59.1 Please provide an explanation of the rules of approach to electrical equipment used in the CSA arc flash standards.

Response:

CSA-Z462-08, the Canadian Standards Association publication on Workplace Electrical Safety, specifies the requirements for safe working procedures where workers are exposed to electrical hazards. The standard defines Qualified persons (Section 4.1.6.4.1) and the approach distances and related voltage levels (Table 1 of the standard). As well, Table 4 of the standard provides a hazard/risk category and protective equipment requirements for switchgear rated 1 – 38kV. The rules of approach are based on the minimum distance required for air insulation to flashover and cause an arc flash incident. The CSA standard sets the limits of approach based on the amount of incident energy impressed on a surface during an arc flash event. This incident energy decreases with distance. The arc flash protection boundary is set at the point where a second degree burn (incident energy of 1.2 calories/cm^2) would occur to a person standing at that point, or at 1.5 calories/cm^2 at locations where fault clearing time is 0.1 seconds or less.

59.2 Please provide a similar table but with staff wearing protective suits or outside the limits of approach.

Response:

The table remains the same as in BCUC IR1 Q143.2, but the addition of staff wearing protective suits or outside of the limits of approach would remove the Catastrophic and Critical columns in the 'Severity of Arc Flash Incident' portion of the table, as these protective barriers (protective suits and limiting approach) would reduce the incident energy delivered to staff.

Figure BCUC IR2 59.2

RISK (+ to –)	Exposure to Arc Flash Incident	Severity of Arc Flash Incident: Marginal	Severity of Arc Flash Incident: Negligible
+	Frequent	Unacceptable	Tolerable with mitigation
R	Probable	Tolerable with mitigation	Tolerable with mitigation
I S	Occasional	Tolerable with mitigation	Tolerable
K	Remote	Tolerable with mitigation	Tolerable
–	Improbable	Tolerable with mitigation	Tolerable

\+ RISK –

60.0 Reference: Huth Low Voltage Breaker Replacement (2 Units)

Exhibit B-4, BCUC 1.144.3

Costs

60.1 Please describe whether the existing foundations could be retrofitted to accommodate the proposed new equipment, or whether the scope of bus re-alignment and other improvements could be reduced to avoid unnecessary immediate costs. Please discuss whether ratepayers would receive better value for money from adoption of a lower level of standard and avoid paying the "gold standard" of utility installations.

Response:

The existing foundations, bus, associated ground grid, and control wiring will be re-used where possible and practical. Detailed engineering and construction planning, to be completed in 2013, will determine whether existing infrastructure can be used for the proposed new equipment. According to the Provincial Government's "Review of BC Hydro" report (June 2011), the "gold standard" is defined as a corporate culture focused toward the goal "to be the best". Replacing a circuit breaker that has failed in service, along with the related equipment required to complete the installation is maintaining the power system in the reliable state that ratepayers have paid for and received in the past.

61.0 Reference: Distribution Growth Project

Exhibit B-4, BCUC 1.150.1

Glenmerry Feeder 2 to Glenmerry Feeder 1 Tie Line

61.1 Please provide the timing of the customer load additions of 1.0 MVA and 1.5 MVA relative to the feeder loading at the time of addition and describe whether either of these additions met the criteria of customer Contributions in Aid of Construction. If so, in what amount, and if not, why not?

Response:

The 1 MVA load was connected to Beaver Park Feeder 2 (BEP2) on March 8th, 2011. The total project cost was $50,270 and the Customer Contribution in Aid of Construction (CIAC) was $18,082. The remainder of the project was funded by FortisBC as per Schedule 74 of the tariff. This customer also paid a Service Installation Charge (SIC) of $17,360.

The 1.5MVA load was temporarily connected to BEP2 on August 18th, 2010 and then permanently on January 6, 2011. The total project cost was $83,446 and the Customer

Contribution in Aid of Construction (CIAC) was $47,173. The remainder of the project was funded by FortisBC in accordance with Schedule 74 of the Electric Tariff. This customer did not pay a Service Installation Charge (SIC) as they are primary metered.

The 2010 winter peak load level on the feeder supplying these customers was 4.49MVA and prior to these customers being connected the 2011 forecast winter peak was approximately 5.5MVA. The increase from 4.49MVA to 5.5MVA is due to annual load growth and a load transfer from the neighboring Fruitvale feeder.

62.0 Reference: Ellison Feeder 2 to Sexsmith Feeder 1 Tie

Exhibit B-4, BCUC 1.151.2

Sexsmith T1 Transformer

"The expected life reduction of a transformer due to operation at temperatures higher than rated is a function of how high the over temperature is and how long the over temperature is sustained. FortisBC does not overload substation transformers under normal operating conditions."

62.1 Please provide the annual duration that the Sexsmith T1 transformer is expected to be overloaded in 2015 and each of the next 5 years, absent the proposed project?

Response:

The summer load forecast for the Sexsmith T1 transformer without the load transfer from Sexsmith onto Ellison is shown below in table BCUC IR2 62.1a.

Table BCUC IR2 62.1a

		2015 (kVA)	**2016 (kVA)**	**2017 (kVA)**	**2018 (kVA)**	**2019 (kVA)**	**2020 (kVA)**
Sexsmith T1	**Summer**	32,711	33,749	34,685	35,848	36,891	38,124

The table shows that, under peak conditions, the Sexsmith T1 transformer is expected to be overloaded by 0.7 MVA in 2015 and 6.1 MVA in 2020.

Using load data from the 2011 summer season, the following Table BCUC IR2 62.1b shows the approximate annual duration (in hours) that the Sexsmith T1 transformer could be expected to be overloaded if no mitigating action is taken first.

Table BCUC IR2 62.1.b

		2015 (hours)	2016 (hours)	2017 (hours)	2018 (hours)	2019 (hours)	2020 (hours)
Sexsmith T1	**Summer**	1	3	19	56	125	205

62.2 Please discuss whether a transformer is capable of serving short duration overloads. What is FortisBC's policy for accepting or not accepting any overload of transformers and why?

Response:

Yes, a transformer is capable of serving short duration overloads. FortisBC will, in a contingency situation, consider overloading a transformer depending on the amount and duration of the expected overload, the ambient temperature and any other relevant factors. The choice of whether to overload equipment in response to system contingencies is a real-time, operational decision. Consistent with past practice, FortisBC does not consider the planned overloading of transformers to be an appropriate application of planning criteria.

FortisBC does not plan to overload distribution transformers in normal (no-contingency) operations. Therefore, as soon as the load is forecast to exceed the capacity of a transformer with all elements in service, a capital project is identified to either offload the transformer or add transformation capacity ahead of time in order to avoid planned overloading which is consistent with Good Utility Practice.

62.3 Please explain why FortisBC has not examined potentially more cost-effective solutions such as additional transformer cooling.

Response:

It is possible that additional transformer cooling could be implemented thereby increasing the capacity of the Sexsmith T1 transformer. However, the other driver for a second Sexsmith transformer is the contingency planning criteria in the event that the Sexsmith T1 transformer fails. Under FortisBC's planning criteria, eighty percent of the peak load must be able to be picked up from neighbouring stations which may not be the case if the existing Sexsmith T1 capacity is increased. This issue will be investigated in more detail nearer to the time the Sexsmith T1 capacity becomes insufficient.

63.0 Reference: Kelowna 138 kV Loop Fibre Installation

Exhibit B-4, BCUC 1.156.5

Options E and F and Table 5.1.1

63.1 Please describe the extent of the informal third party discussions with the third party communications provider. Provide details of any assessments (including costs and rate impacts) that FortisBC may have performed to determine whether ratepayers would be better served by a FortisBC capital expenditure rather than a third party operating expense.

<u>Response:</u>

The referenced discussions with the third party were general and brief with respect to their building new fibre along FortisBC transmission corridors and to then lease back to FortisBC. As discussed in the response to BCUC IR1 Q156.5, the third party does not have a need for new fibre in the areas of the proposed builds, except to service FortisBC, and is not interested in constructing these links. For this reason, no additional assessments of costs or rate impacts were completed for this scenario prior to this IR.

FortisBC has conducted an analysis to determine the rate impact of leasing vs. building the loop fibre in the Kelowna area. In the analysis, FortisBC assumed that two buffer tubes would be needed for full redundancy and the lease rate of $375 per fibre per kilometer was used (based on average quoted rates obtained during a recent solicitation). Based on this analysis, the build option had a rate impact of 0.028% vs. 0.032% for leasing.

Finally, FortisBC does not believe any other private party could build this fibre infrastructure and expect to recoup their investment with suitable return as FortisBC is the only identified customer and would be leasing a relatively small portion of the fibre cable. In fact, in a situation where FortisBC is the only customer, there are only three scenarios that produce a valid business case for a private party to build the fibre:

1. FortisBC agrees to pay above market rates for the fibre, or to lease more fibre than it requires (thus increasing the monthly lease amount).

   As evidenced by the rate impact analysis discussed above, at market rates and the number of fibres FortisBC would lease, it is in the ratepayers benefit for FortisBC to build the infrastructure themselves. Increasing the per-fibre rate or the number of fibres leased would only increase the negative rate impact of a leasing scenario.

2. The third party can install fibre for significantly less than FortisBC.

   This is not likely to occur because the infrastructure would still need to be designed and installed to FortisBC specifications as it would be built on FortisBC infrastructure. If FortisBC chooses to tender the work for design or construction it would expect to receive the same pricing responses as the third party.

3. The third party has access to less expensive capital than FortisBC.

FortisBC's cost of capital is relatively low compared to other private corporations, and organizations with lower cost of capital are typically government and non-profits. FortisBC is unaware of these types of companies engaged in the telecommunications business in the Kelowna area.

Since none of these options are plausible, it is unlikely FortisBC could find another third party willing to build this infrastructure. Even if a willing third party were located, the customer rate impact resulting from FortisBC building and operating the infrastructure is still more desirable than a leasing option.

64.0 Reference: SCADA System Sustainment Costs

Exhibit B-4, BCUC 1.158.2

64.1 Please provide a detailed breakdown of the SCADA System Sustainment Costs for 2012 and 2013.

Response:

The following table provides a detailed breakdown of the estimated expenditures for the SCADA System Sustainment project.

Table BCUC IR2 64.1

Description	2012	2013
	($000s)	
SCADA System Sustainment Internal Labour	120	124
SCADA System Sustainment Contracted Labour	85	86
SCADA System Sustainment Hardware Cost	130	130
SCADA System Sustainment Software Cost	115	120
Subtotal SCADA System Sustainment	**450**	**460**
MRS System Sustainment Internal Labour	80	83
MRS System Sustainment Contracted Labour	40	45
MRS System Sustainment Hardware Cost	95	100
MRS System Sustainment Software Cost	42	45
Subtotal MRS System Sustainment	**257**	**273**
Total	**707**	**733**

65.0 Reference: General Plant

Exhibit B-4, BCUC 1.162.1

Used & Useful

65.1 Please explain why the “used and useful” concept was not an option.

Response:

The concept of “used and useful” was the basis for the accelerated write-off of the existing meters. In accordance with US GAAP, as the meters are removed from service over the 2013 to 2015 period they would be deemed to be no longer used and useful and would require accelerated depreciation. Option 1 recognized that the meters are no longer used and useful and would be written off over the 2014 to 2016 period. Options 2 and 3 also recognize that the meters are no longer used and useful but seek to reduce the rate impact by extending the write-down over longer periods of time.

66.0 Reference: Rate Forecasts

Exhibit B-4, BCUC 1.169.1

Waneta Expansion Project rate Impact

66.1 Please provide a forecast of the rate impact of the Waneta Expansion Project for each year to 2020.

Response:

As presented previously in BCUC IR1 Q169.1, the rate impact of the Waneta Expansion Project for 2015 is currently estimated to be 7%. The estimated impact for 2016 is 1.5%. Beyond 2016 there will be a minimal impact of approximately 0.1 to 0.2% per year. If necessary, the Company will explore the use of a rate smoothing mechanism in the early years of the contract.

67.0 Reference: Status of Past Directives and Negotiated Settlement Provisions

Exhibit B-4, BCUC 1.170.1, 1.170.2

Worst Performing Feeders

67.1 Please provide a working spreadsheet model which demonstrates how the weighting was calculated to identify the 10 worst performing feeders in 2009 and 2010.

Response:

A working spreadsheet model is attached as BCUC IR2 Electronic Attachment 67.1.

The weighting was calculated based on SAIDI (customer hours) and the number of times that the feeder was in the top ten using the following as an example:

PRI4 feeder was identified three times in the top ten for the period 2007 to 2009.

As described in the response to BCUC IR1 Q170.2 a comparison between the 2009 and 2010 performance metrics of the ten worst performing feeders in 2009 was conducted.

Results of the ten worst performing feeders for 2010 were not submitted, but the same weighting was used to calculate them.

67.2 Were worst performing feeders identified on a "per feeder" basis or "per kilometer" basis?

Response:

The worst performing feeders were identified on a "per feeder" basis.

CAPITALIZATION POLICY

68.0 Reference: Capitalization Policy

Exhibit B-4, BCUC 1.174.5

Condition Assessments

The original question attempts to understand the accounting treatment of the costs relating to condition assessment activities. FortisBC's responses provided in BCUC 1.174.5 deals with major inspections, which may be capitalized.

68.1 Please describe whether FortisBC considers Major Inspections to be distinguishingly different than Condition Assessments. If so, what is the difference in criteria between the two activities?

Response:

No, the Company does not believe that Major Inspections to be distinguishingly different than Condition Assessments. Both activities are undertaken to assess whether assets or equipment require capital improvement and therefore are capitalized.

FortisBC states that the transmission and distribution condition assessment program "consists of a test and treat component and an above ground visual condition inspection." (Exhibit B-1, Appendix M, pp. 7 and 9)

"Currently, FortisBC Energy considers two main types of inspections to be major inspections which are in-line inspections and marine crossing inspections. All other inspections are expensed." (Exhibit B-4, BCUC 1.174.5)

In FortisBC Energy's current Revenue Requirement Application (Section 5, page 163), it states that "Operations and Maintenance includes schedules and unscheduled operating and maintenance activities dedicated to mitigating operating risks and ensuring the safety and reliability of the distributions system. Activities include system inspection, leak survey, preventative and corrective maintenance of equipment, valves, stations and meter sets. The level of activity required is influenced by code and standard equipment requirements…" [emphasis added]

68.2 Based on the definition and quote above, it appears that FortisBC may consider pole and line condition assessments to be more like major inspections rather than routine system inspections. Please confirm and discuss the rationale for this.

Response:

Confirmed. The Company performs two types of inspections on the transmission and distribution system:

1. Routine annual line inspections - the cost of which is expensed, and

2. Transmission & Distribution Condition Assessments that are each based on an eight-year cycle. The Condition Assessments program consist of a test and treat component and an above ground visual inspection. The test and treat component is considered a betterment that extends the life of the asset. The inspection component is a managed scheduled program that provides the preliminary planning information necessary for the development of scope and engineering necessary for subsequent capital plans and are considered major inspections.

68.3 Please explain whether FortisBC considers the pole and line condition assessments to be a form of preventative and corrective maintenance of the system. Please discuss.

Response:

No, the Company does not consider the assessments to be a form of preventative and corrective maintenance. FortisBC considers the Transmission and Distribution Condition Assessments to be similar to the preliminary and investigative spending necessary to develop capital expenditure plans for subsequent periods. The assessment program allows for the scoping and budgeting for capital work carried out as capital Transmission Rehabilitation or Urgent Repair projects. The assessments thereby provide benefits for a period of more than one year.

68.4 Please provide the cost estimates according to the different activities for the program:

Transmission and Distribution Condition Assessment Program:	2012	2013
Test and Treat Component	$	
above ground visual condition inspection	$	
Total		

Response:

The 2012 estimates shown below reflect the reduction to the Transmission Condition Assessment program identified in the response to BCUC IR2 Q56.1. Please refer to Errata 3.

Table BCUC IR2 68.4

Transmission and Distribution Condition Assessment Program	**2012**	**2013**
	($000s)	
Test and Treat Component	771	764
Above ground visual condition inspection	1,129	1,118
Total	1,901	1,882

Note: Differences due to rounding.

68.4.1 What is the rate impact of reclassifying these sustaining capital programs to operating expense for 2012 and 2013?

Response:

Reclassification of sustaining capital projects of $1.90 million in 2012 and $1.88 million in 2013 to O&M as indicated in the table below (Refer response to BCUC IR2 68.4) would result in the following rate impacts:

1. Rate Impact 2012: 4.4% - An increase of 0.4% over the “Base Case Rate Impact” of 4.00%
2. Rate Impact 2013: 6.8% - A decrease of 0.1% over the “Base Case Rate Impact” of 6.9%

Table BCUC IR2 68.4.1

Transmission and Distribution Condition Assessment Program Reclassification:	2012	2013
	($000s)	
Test and Treat Component	771	764
Above ground visual condition inspection	1,129	1,118
Total	**1,901**	**1,883**
Incremental Rate Impact for Project reclassification to O&M	**0.4%**	**-0.1%**

It may be noted here that, the additional O&M allocation due to reclassification of the sustaining capital programs as above, will result in an increment of capitalized overhead (by 20% of the incremental O&M) which will be reallocated to the remaining capital projects during 2012 and 2013.

69.0 Reference: Capitalization Policy

Exhibit B-4, BCUC 1.192.6; Exhibit B-5, BCOAPO 1.7.1 and 1.27.1

Cost of Removal

"The work to install the new structure as well as a portion of the alteration to stand-off existing facilities to safely place the new structure is considered "new construction." The remainder of the alteration costs as well as the removal of the old facility is considered "cost of removal" (COR)." (Exhibit B-4, BCUC 1.192.6)

69.1 Please explain whether there is engineering charges for both the removal of the existing pole and the installation of the new pole to the capital activity? Please explain why a further 30 percent charge for future engineering costs of removal is not "double counting" this activity.

Response:

Replacing an existing pole incurs engineering requirements for both the installation of the new pole and the removal of the old pole. Typical engineering charges for new construction would include design, material specification, anchoring and guying calculations, engineering reviews and drawing production. Typical engineering charges for the removal component would include safe work planning for the removal, updating records for pole height and class, updating asset tag records, updating or transferring joint use information, updating or transferring transformer or switch information and updating of the condition assessment records. During the course of the project, the total engineering effort is captured under a single order. Once the project is complete, a percentage of the engineering charges are transferred to cost of removal in accordance with the project salvage plan. A typical salvage rate for engineering effort on line rebuilds and rehabilitations is 30 percent.

69.2 Please explain how employees are trained to distinguish and properly record the capital portion versus cost of removal portion of the total work order. What are the checks that are in place to verify that work orders are properly recorded (area manager or audit department)?

Response:

The Company recognizes that it can be difficult for employees to distinguish and properly record capital tasks from cost of removal tasks. For this reason the salvage costs are recorded in accordance with the salvage plan as described in the response to BCUC IR2 69.3 below.

69.3 Please explain the 30 percent and 50 percent factor applied to engineering, labour, vehicles, supervision, and third party costs to determine cost of removal. Is this an estimate based on historical actual costs? Weighted average or rolling average?

<u>Response:</u>

The estimated 30 percent Cost of Removal on Transmission and Distribution Rehabilitation and rebuild projects is based on historical information and personnel experienced amassed from completing many projects of similar scope. As salvage and installation work is often completed concurrently in the field, it is difficult to reconcile the actual daily costs to each component of new construction or salvage. For this reason, salvage plans will be developed for any relevant projects or programs in the 2012-2013 Capital Expenditure Plan prior to the start of any salvage work. Project costs are then transferred to salvage as determined in the salvage plan. Although salvage costs for engineering, labour, vehicles, supervision and third party costs are estimated at 30 percent, the actual amounts transferred to salvage may vary.

The estimated 50 percent Cost of Removal on Transmission and Distribution Urgent Repairs is also based on historical information amassed from completing many repairs of similar scope. These repairs are urgent in nature and often completed in short timeframes where the duration to install the new plant is often equal to the duration to safely remove the old plant. For urgent projects of larger complexity, a salvage plan is created for the specific project and costs are transferred in accordance with the plan.

69.3.1 Has there been an independent study done to determine these percentages? If so, when? How does one determine the accuracy of these percentages to be representative of the costs?

<u>Response:</u>

There has not been an independent study completed on estimating salvage costs. Please see Response to BCUC IR2 69.3 above for accuracy of salvage percentages.

69.3.2 How often do these ratios change/updated? Has there been an internal or external audit on the validity of these ratios?

Response:

The actual salvage ratios are based on the project specific salvage plan as described in response to BCUC IR2 Q69.3 above. There has not been an internal or external audit completed to validate these ratios.

69.4 Is COR recorded net of salvage/resale value?

Response:

Yes.

69.5 In BCOAPO 1.27.1, FortisBC explains that the salvage/resale value of the existing transformer (in the Summerland Substation Transformer Upgrade project) is not currently reflected in the $6.58 million project cost. Please explain FortisBC's treatment of the salvage value obtained from old assets removed.

Response:

Salvage proceeds from old assets are netted against costs of removal, which are charged to accumulated depreciation when incurred.

INTEGRATED SYSTEM PLAN & LONG TERM CAPITAL PLAN

70.0 Reference: Security of Assets, Prevention and Mitigation Programs

Exhibit B-4, BCUC 1.182.1

Safety Incident

70.1 Please confirm whether the described safety incident was recorded in FortisBC's safety statistics, and please confirm the PLT was following FortisBC Safety Practices for removing objects from energized lines when the shock occurred.

<u>Response:</u>

Yes, the incident was recorded and is reflected in FortisBC safety statistics that are reported to the BCUC and the CEA. The PLT in question was not following FortisBC Safety Practices. FortisBC completed the incident investigation in conjunction with WorkSafeBC and it was determined that several safety practices were not followed. WorkSafeBC is satisfied with the investigation and did not issue any orders. The employee in question has since chosen to leave FortisBC.

71.0 Reference: Upper Bonnington Unit 1 to Unit 4 (The Old Plant)

Exhibit B-4, BCUC 1.193.1, Upper Bonnington Unit 1 to Unit 4 (The Old Plant)

Value of Generated Electricity

71.1 Please provide a similar table showing the time weighted (on-peak and off-peak) Mid-C market value of the electricity produced by each unit by month for 2006-2011, using the historical Mid-C market prices as required.

<u>Response:</u>

Table BCUC 71.1a shows the average monthly market price based on actual historical hourly Mid-C market prices, compiled from the Dow Jones Mid-C Hourly Index.

Table BCUC 71.1a Average Actual Mid-C Hourly Market Prices, based on Dow Jones Hourly Index ($/MWh)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2006	$ 47.73	$ 48.47	$ 43.71	$ 18.30	$ 26.05	$ 23.86	$ 55.89	$ 53.45	$ 43.46	$ 49.28	$ 52.51	$ 54.56
2007	$ 50.07	$ 54.28	$ 31.78	$ 39.70	$ 44.82	$ 46.88	$ 45.26	$ 53.71	$ 48.07	$ 57.32	$ 56.72	$ 57.72
2008	$ 71.18	$ 65.62	$ 70.18	$ 83.74	$ 48.07	$ 15.41	$ 54.05	$ 63.10	$ 53.66	$ 47.72	$ 44.46	$ 52.77
2009	$ 37.09	$ 36.12	$ 28.39	$ 17.66	$ 21.29	$ 16.10	$ 28.32	$ 32.60	$ 32.66	$ 39.78	$ 32.36	$ 48.83
2010	$ 44.28	$ 42.81	$ 37.14	$ 33.79	$ 28.25	$ 11.26	$ 26.94	$ 32.12	$ 31.74	$ 30.19	$ 32.03	$ 32.03
2011	$ 25.84	$ 20.62	$ 15.97	$ 17.75	$ 16.99	$ 14.02	$ 19.67	$ 25.23	$ 28.38			

Table BCUC 71.1b shows the market value of the Upper Bonnington (UBO) Unit 1 to Unit 4 (The Old Plant) generation from 2006 to 2010, based on the actual Mid-C market prices shown in Table BCUC 71.1a.

Table BCUC 71.1b UBO Generation Market Value ($)

2006	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Unit 1	-	-	-	-	53,453	103,125	183,820	-	-	-	-	-	**340,398**
Unit 2	-	-	-	-	21,701	54,573	71,383	-	-	38,165	-	-	**185,821**
Unit 3	-	-	-	-	41,775	79,963	143,521	-	-	-	-	-	**265,259**
Unit 4	-	-	-	-	48,771	96,908	145,404	(32)	-	-	-	33	**291,084**
2006 Total	-	-	-	-	165,700	334,568	544,128	(32)	-	38,165	-	33	**1,082,562**
2007	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Unit 1	-	-	1,627	21,515	201,513	196,677	25,717	-	-	-	3,403	-	**450,452**
Unit 2	-	-	1,405	17,274	162,331	164,359	136,403	-	-	-	-	-	**481,771**
Unit 3	-	-	-	16,746	161,331	163,955	141,368	-	-	-	-	-	**483,401**
Unit 4	-	(33)	-	20,161	189,142	172,492	24,106	-	-	-	-	-	**405,868**
2007 Total	-	(33)	3,032	75,696	714,316	697,483	327,594	-	-	-	3,403	-	**1,821,492**
2008	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Unit 1	-	-	(4,197)	-	86,958	66,090	113,927	-	-	-	-	-	**262,778**
Unit 2	-	-	-	25	70,498	52,569	92,615	-	-	-	-	-	**215,707**
Unit 3	-	-	-	17	71,277	53,061	85,021	-	6	-	-	-	**209,382**
Unit 4	-	-	-	17	77,565	65,032	95,998	-	-	-	-	-	**238,612**
2008 Total	-	-	(4,197)	59	306,297	236,753	387,561	-	6	-	-	-	**926,479**
2009	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Unit 1	4,276	6,842	53,529	-	13,994	68,174	-	-	-	-	-	-	**146,814**
Unit 2	-	2,904	44,732	7,177	11,098	55,556	8	-	-	-	-	-	**121,477**
Unit 3	-	29	44,593	-	-	23,987	-	2,171	27,403	-	-	-	**98,183**
Unit 4	-	25	-	-	14,394	66,417	-	-	-	-	-	-	**80,836**
2009 Total	4,276	9,800	142,854	7,177	39,486	214,134	8	2,171	27,403	-	-	-	**447,310**
2010	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Unit 1	-	-	-	24	-	44,124	32,637	3	-	-	-	-	**76,788**
Unit 2	-	-	-	17	701	38,037	12,033	-	-	6,424	-	-	**57,212**
Unit 3	-	-	-	-	14	34,816	23,263	-	-	-	-	-	**58,093**
Unit 4	-	-	-	30	-	41,169	29,183	-	-	-	-	-	**70,383**
2010 Total	-	-	-	71	715	158,146	97,117	3	-	6,424	-	-	**262,476**

72.0 Reference: Long Term Capital Plan

Exhibit B-4, BCUC 1.195.1, 1.195.2

Corra Linn Spillgate and Spillway Concrete Rehabilitation

72.1 Please discuss FortisBC's approach to the approval for this project. Is an application for a CPCN anticipated, and if so when? What costs are anticipated to be incurred on this project prior to Commission approval to proceed?

Response:

FortisBC has engaged an engineering consultant to assess the structural stability of the spillway gates. In addition, as part of the legislative requirements a Dam Safety Review is underway at the Corra Linn Dam. These two reports will provide scope clarification for the project.

Once the full scope of the project is defined, a review of construction methodology will be completed along with a compilation of estimated costs. Should the project require a CPCN application, (based on the guidelines for CPCN applications identified at Tab 6, pages 5-6 of the 2012-13 RRA (Exhibit B-1)), the application would likely be filed during the third quarter of 2012. If a CPCN application is not required, the Company will request approval for the project in its next Capital Expenditure Plan application.

The anticipated investigative cost of the project is estimated to be $150,000 which will be incurred defining the project scope, construction methodology, construction schedule and estimated cost.

73.0 Reference: South Okanagan Area Upgrade

Exhibit B-4, BCUC 1.202.1

Similkameen Supply

73.1 Please confirm that the supply to all load fed from Line 43 L is radial, and thus can be shed for single contingencies.

Response:

The load served by 43 Line can be supplied from two possible sources: the FortisBC Bentley Terminal Station, or BC Hydro's Nicola substation (via 56 Line and BC Hydro line 1L251). The two sources are not run in parallel (except for short durations to accommodate load transfers). In the shoulder seasons the line is typically supplied from the FortisBC system in order to limit energy purchases from BC Hydro, while at the peak seasons the line is supplied from BC Hydro.

FortisBC's interpretation of the BC Mandatory Reliability Standards is that these loads can be disconnected as a consequence of faults along 43 Line itself (until they are transferred to the alternate supply) but cannot be shed for single contingencies originating outside of 43 Line.

73.2 Please identify any projects in the Long Term Capital Plan which would change the supply to any load from "radial" to "meshed". Please confirm that FortisBC's description of the MRS requirements as they apply to mesh-supplied loads suggest a higher (and more costly) obligation of service to mesh-supplied loads as compared to radial-supplied loads.

Response:

The following proposed projects will change the supply to loads from "radial" to "meshed":

1. **42L Meshed Operation (Huth and Oliver)**.
   Loads served by the 63 kV 42 Line are not (and will not be) subject to MRS requirements, as lines less than 100 kV are not considered part of the "Bulk Electric System".

2. **Meshing Kelowna Loop**.
   All Kelowna-area 138 kV substation loads will be normally supplied from more than one source following the completion of this project. Thus, MRS requirements would normally apply to these loads. However, NERC is currently in the final stage of Project 2010-17, which will revise the definition of the "Bulk Electric System" (BES). The revised definition excludes Local Networks (LN) from compliance with NERC standards. A Local Network is defined as a group of contiguous transmission elements operated at or above 100 kV but less than 300 kV that distribute power to load rather than transfer bulk power across the interconnected system. LNs emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer load and not to accommodate bulk power transfer across the interconnected system. One of the characteristics of the LN is that power flows only into the LN. The meshed Kelowna system would fall into this "to be excluded from NERC compliance" category. Project 2010-17 was mandated by FERC and will be filed for FERC approval in January 2012. On this basis, FortisBC does not expect any MRS requirements to apply to this project when it is implemented in 2014-16.

74.0 Reference: Meshing Kelowna Loop

Exhibit B-4, BCUC 1.205.1; Exhibit B-5, BCOAPO 26.1

Meshed Operation

74.1 Please confirm the project to increase the reliability of the Kelowna loop communications would eliminate the need for the meshed operation through better certainty of being able to open and close the connection points around the loop.

Response:

Not confirmed. Yes, the increased reliability of the Kelowna loop communications will provide greater certainty that the system can be reconfigured to restore power following a transmission system outage. This increased communications reliability will reduce the duration of the customer outage to just the time interval that it takes the System Control Centre dispatchers to remotely reconfigure the transmission network using the FortisBC SCADA system. However, a customer outage will still occur, and it will typically last for 5 to 20 minutes (the approximate length of time it takes the dispatchers to determine the cause of the outage, to develop a corrective switching procedure and then to safely implement it). If any switching equipment fails to remotely operate as expected, then the outage could be extended by 1 to 2 hours. In an urban area like Kelowna, a wide-area transmission outage – even lasting only 5 to 20 minutes – can be highly disruptive to businesses and society in general depending on the time of day that the outage occurs. The future Kelowna meshing project would close all of the current "normally open" transmission points, and provide full N-1 transmission reliability to all of the Kelowna distribution substations. This would prevent a single transmission line fault from causing any customer outages.

Thus, the communications upgrade project will not prevent outages due to transmission line failures, but it will serve to minimize the length of the outage. The future Kelowna meshing project will prevent the transmission line failure from resulting in an outage in the first place. As discussed in the application, FortisBC is not currently seeking approval to mesh the Kelowna transmission system. Tools such as reliability and outage cost analysis will be used in a future Capital Plan application to show the customer benefits that will result from meshing of the transmission system and thus demonstrate that the project is in the public interest.

75.0 Reference: DG Bell 138 kV Breaker Addition

Exhibit B-4, BCUC 1.211.1, 1.211.2, 1. 211.3

Project Benefits

The existing system has had no nodes outages since 2007 although FortisBC states that the impact on system reliability statistics is not representative of the benefits provided by this project.

75.1 Please describe the need for this project and the benefits accruing to ratepayers from pursuing this project. Could this be a FortisBC example of the "gold standard" that is described in the Provincial Government's "Review of BC Hydro" report (June 2011)?

Response:

FortisBC is concerned that the introductory statement above is concluding that since the station "has had no node outages since 2007" that no issues are present. Further, in 2006/07 the node experienced seven outages (as discussed in the response to BCUC IR1 Q211.2). Although the D.G. Bell terminal station has not experienced any node forced outages since 2007, there is no certainty that this performance will continue into the future. FortisBC strives to minimize bus faults and node outages through ongoing maintenance programs; however, outages due to other causes such as random equipment failures, animal contacts or lightning strikes can still occur. It is generally incorrect to draw a statistical conclusion by extrapolating a sample size as small as a single substation for a short period of time in order to determine the long-term average performance of the system. Instead, like most utilities, FortisBC relies on long-term averages from large sample populations provided by relevant utility information sources to determine the expected performance of substation equipment.

The addition of the 138 kV circuit breaker at the D.G. Bell Terminal station will upgrade the station into a typical four-breaker "ring bus" arrangement. The ring bus is an economical bus arrangement used commonly in North America at higher voltage levels (138 kV and above)[2]. For maximum reliability and operational flexibility, each bus section (node) should supply only one circuit[3]. Currently at D.G.Bell, three circuits (two transformers and one capacitor bank) are connected to a single node.

Since the first installation at the F.A. Lee Terminal in 1996, FortisBC has standardized on the use of ring-bus arrangements for all major transmission substations. As a result, ring bus

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[2] Blackburn, J. Lewis (1987). *Protective Relaying Principles and Applications.* New York: Marcel Dekker, Inc., p. 344.

[3] US Department of Agriculture (2001), Rural Utilities Services. *Bulletin 1724E-300 - Design Guide for Rural Substations.*, p. 136.

designs have been implemented at eight previously-approved FortisBC transmission substations including the Warfield Terminal Station, the Black Mountain substation, and most recently, the Bentley Terminal Station. In all cases (excepting the D.G. Bell Terminal), the bus arrangements at these stations conform to the principle cited above that each bus section should have only one connected circuit. In 2005 when the T2 transformer was added to the D.G. Bell substation, the Company chose not to add the fourth breaker in the ring. At the time it was felt that the cost savings outweighed the potential reduction in reliability and flexibility and that these negative impacts could be accepted for some period. FortisBC customers have benefitted financially from that cost savings.

Given the addition of the 138 kV capacitor bank in 2011, there are now three elements connected to the same node. With this number of elements sharing the same node, and based on long-term equipment performance statistics, it is expected that negative reliability impacts will occur in the future. As this station is expected to remain in service for decades, FortisBC is proposing to mitigate the reliability and operational flexibility impacts by adding the fourth circuit breaker in 2014/15.

According to the Provincial Government's "Review of BC Hydro" report (June 2011), the "gold standard" is defined as a corporate culture that is focused toward a goal "to be the best" without regard for the associated cost. FortisBC has no such goal. Rather, the completion of this project will bring the D.G. Bell substation to the up to the same standard employed at other FortisBC transmission substation projects previously approved by the Commission.

76.0 Reference: Osoyoos Substation 63 kV Breaker Additions

Exhibit B-4, BCUC 1.212.1, 1.212.2, 1.212.3

Project Benefits

The existing system has been in place since the 1980's and has not been performing inadequately although FortisBC states that the impact on system reliability statistics is not representative of the benefits provided by this project.

76.1 Please describe the need for this project and the benefits accruing to ratepayers from pursuing this project. Could this be a FortisBC example of the "gold standard" that is described in the Provincial Government's "Review of BC Hydro" report (June 2011)?

Response:

The primary benefit of the breaker additions at the Osoyoos substation will be to improve the reliability for the 6400 customers connected to 44 Line. These customers are currently served by four distribution transformers (two at Pine Street and two at Osoyoos). Presently, a bus or transformer fault occurring on either of the Osoyoos transformers will result in an outage not only to the customers served by the faulted transformer, but to all customers served by the 44 Line. This is because a fault at the Osoyoos substation will be detected by relays at the Oliver substation, where 44 Line originates, and will operate the circuit breaker at Oliver before the protective fuses at Osoyoos melt, thus unnecessarily de-energizing the line and causing an outage to both the Pine Street and Osoyoos substations. Consequently, the number of customers that will experience an outage is approximately 300% greater than necessary. Adding circuit breakers and protection relays to each transformer will allow the transformer protection to coordinate with the 44 Line protection relaying. After the upgrade, a fault on one of the Osoyoos transformers will result in an outage to only the customers served by that transformer.

Rather than increasing reliability to a “gold standard”, this project will instead bring the Osoyoos and Pine Street substation reliability in line with the level experienced by customers served from the Creston Substation. A similar project at the Creston substation location installed circuit switchers and protection relays on the two transformers there in place of high-voltage protective fuses. The Creston Substation Protection Upgrade project was identified in the FortisBC 2009/10 Capital Expenditure Plan. The proposed project was found to be in the public interest and approved by the Commission in Order G-11-09.

LONG TERM RESOURCE PLAN

77.0 Reference: Energy and Capacity Supply / Demand Gaps

Exhibit B-4, BCUC 1.231.1, p. 402

Customer Information Portal Savings

FortisBC states that “The savings were based on the following assumptions: 1) 15% of customers will regularly use the CIP, 2) those customers that regularly use the CIP will reduce their energy consumption by 2%.”

77.1 Which 15 percent of FortisBC’s customers are forecast to use regularly the CIP (e.g., low-usage customers, high-usage customers, etc.)?

Response:

FortisBC assumed that the mean consumption of the 15% group was the same as the mean consumption of the residential customer population as a whole. No further assumptions were made regarding the composition of the group.

77.1.1 For those 15 percent of customers, please provide the customer breakdown by their annual energy use along with the number of customers in each usage category (and their percentage share of total number of customers), their total annual energy use and the anticipated savings by completing the table below.

Annual energy use category(kWh)	Number of customers forecast to regularly use the CIP (and %)	Total annual energy use by the customers in each annual energy usage category	Anticipated savings from the CIP program kWh (%)
e.g., 0 – 5,000			
e.g., 5,000 – 10,000			
…			
e.g., > 25,000			
TOTAL	Total Number of Customers (15%)		

Response:

FortisBC did not assume any particular composition of the 15% of customers that would use the CIP when calculating the savings. Please also see the response to BCUC IR2 Q77.1.

78.0 Reference: Energy and Capacity Supply/Demand Gaps

Exhibit B-4, BCUC 1.231.3, p. 403

Residential Inclining Block Savings

FortisBC states that "So while elasticity savings are shown by year in the RIB Application, as requested, they reflect the savings that will occur over time associated with the change in rates for each year. FortisBC, as previously stated, is not able to estimate how much of the savings will occur in any given year.

The RIB energy savings in 2012-13 RRA match the estimated conservation from the minimum elasticity assumption for the preferred RIB rate option as shown in the "Conservation Impact" column of Table 7-2 in FortisBC's RIB Application.

RIB savings were assumed to reduce residential load by a total of 1.9 percent, starting at 0.22 percent in 2012 and increasing incrementally until the full 1.9 percent is realized in 2017 as the 1.9 percent savings resulting from 2011 rates would likely not all be achieved until 2017. After 2017, no incremental savings from RIB are assumed." [Emphasis added]

However, in Appendix B of Exhibit B-11 (Additional Evidence) submitted in the FortisBC Residential Inclining Block (RIB) Rate Application (RIB Application), the RIB savings for the Company's preferred option 8 are estimated as followed, using the minimum elasticity assumption: a total of 2.4 percent, starting at 1.9 percent in 2011, and increasing incrementally to 2.0 percent in 2012, 2.1 percent in 2013, 2.2 percent in 2014 until the full 2.4 percent is realized in 2015.

78.1 Please reconcile the two series of estimates above.

Response:

There is no discrepancy between the two statements above.

Table 7-2 in FortisBC's RIB Application shows conservation impacts, for the preferred option, ranging on the conservative end from 1.9% to the aggressive end of 5.5%. These percentages are intended to represent the total conservation that would be achieved over a ramp up period of 6 years relating to the implementation of the preferred RIB rate if the conservation impact of future rate increase was ignored.

Appendix B of Exhibit B-11 shows conservation impacts for the preferred option incorporating the conservation impacts of future rate increases. These conservation impacts would still be achieved over a similar 6 year ramp up period. The 2.4 percent shown in 2015 for Option 8.1 (the preferred option), for example, is not the amount of savings expected to be achieved in 2015, but is the amount of savings expected to be achieved over the 6 year ramp up period beginning in 2015 and ending in 2021. These conservation impacts are cumulative, as opposed to additive, to the conservation impacts from the RIB Table 7-2 impacts that achieve the 1.9%.

The following table illustrates the conservation effect of the preferred RIB rate option when factoring in rate increases.

Table BCUC IR2 78.1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
			Conservation Effect Year										
	Attributable Year	**Rate Increase including Rebalancing**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
(1)	2011		0.2%	0.5%	0.8%	1.1%	1.3%	1.6%	1.9%				
(2)	2012	6.5%		0.5%	0.8%	1.1%	1.3%	1.6%	1.9%	2.0%			
(3)	2013	9.2%			0.8%	1.1%	1.3%	1.6%	1.9%	2.0%	2.1%		
(4)	2014	5.8%				1.1%	1.3%	1.6%	1.9%	2.0%	2.1%	2.2%	
(5)	2015	11.4%					1.3%	1.6%	1.9%	2.1%	2.2%	2.3%	2.4%
(6)	**Total Conservation Effect**		**0.2%**	**0.5%**	**0.8%**	**1.1%**	**1.3%**	**1.6%**	**1.9%**	**2.1%**	**2.2%**	**2.3%**	**2.4%**

Column (a) is the year of the rate change;

Column (b) is the size of the rate increase (including any rebalancing increases);

Columns (c) through (m) are years in which the conservation impacts will occur;

Rows (1) through (5) show the year of the rate increases, the magnitude of the increase and the conservation achieved through the 6 year ramp up period;

Row (6) is the total conservation achieved by year which ranges from 0.2% in 2011 to 2.4% in 2021. The 2.4% in 2021 is the combined effect of the implementation of the preferred RIB rate option and the cumulative rate increases between 2011 and 2015.

Therefore, the Company believes the current estimate of conservation savings is reasonable and does not require a change.

In response to BCUC 1.19.2 in the RIB Application, Table BCUC IR1 19.2 shows, for the preferred RIB rate option 8, that <u>1.9 percent of total energy savings</u> corresponds to estimated savings of <u>23,591 MWh or 23.591 GWh</u> under the minimum elasticity assumption.

However, Table C.1-2 Residential Energy Savings Before Losses – GWh in Appendix 3C of TAB 3 Load and Customer Forecast in the 2012-2013 RRA shows RIB savings of <u>3 GWh</u> in 2012 and <u>8 GWh</u> in 2013.

78.2 Please explain the marked difference between expected savings of 23.591 GWh in 2011 (as shown in Appendix B of Exhibit B-11 in the RIB Application) versus 3 GWh in 2012 and 8 GWh in 2013 in the 2012-13 RRA.

<u>Response:</u>

The 3 GWh in 2012 and 8 GWh in 2013 are the savings expected in those years as customers begin to respond to the RIB rate assumed to be implemented in 2012.

The 23.591 GWh figure is the total savings expected (over 5 years) from the implementation of the RIB rate in the long-term. Please also see the response to BCUC IR2 Q78.1.

79.0 Reference: Supply and Demand

Exhibit B-1-2, Section 3.1, p. 30; Exhibit B-4, BCUC 1.237.3, p. 414

Filing of Long-Term Resource Plans

In response to BCUC 1.237.3, FortisBC states that it "plans to file a Long-Term Resource Plan approximately every five years. If there is a significant event that would prompt a material revision in the Long-Term Resource Plan, FortisBC may file an earlier update to the Resource Plan."

Before the implementation of the *Clean Energy Act* (CEA), which directs BC Hydro to file an Integrated Resource Plan once every five years after the submission of the first one, BC Hydro's Long-Term Acquisition Plan (LTAP) were filed more frequently than once every five years. For example, BC Hydro filed its 2004 Integrated Electricity Plan (IEP) on March 31, 2004, its 2006 IEP/LTAP on March 29, 2006 and its 2008 LTAP on June 12, 2008.

In the case of Pacific Northern Gas-West (PNG), PNG filed a Long-Term Resource Plan on January 30, 2009 and a subsequent one on July 6, 2011.

79.1 Please confirm that FortisBC would be amenable to filing its next Long-Term Resource Plan approximately two years after a Commission decision on its 2012 Long-Term Resource Plan to be consistent with other utilities in BC. If not, please explain why not.

Response:

Currently, the Company expects to file a Resource Plan approximately every five years and believes this interval would be appropriate in order to achieve full transparency and regulatory efficiency. However, the Company is amendable to making a filing at an earlier stage depending on circumstances, and will regularly assess the timing of future plans. An earlier filing may be triggered by material changes to the Company's resource strategy, material changes to market conditions or changes to forecasts load that materially impact the timing of resource acquisitions. Provincial policy or legislative changes that affected the Company's resource strategy may also trigger a Resource Plan update.

80.0 Reference: FortisBC's Own Resources

Exhibit B-1-2, Section 5.1.1, p. 46; Exhibit B-4, BCUC 1.250.2, p. 438

Upper Bonnington Plant

FortisBC states that "The remaining four generating units, all of which are installed at the Upper Bonnington Plant, provide the remaining 10 percent of the capacity entitlement of the FortisBC Plants under the Canal Plant Agreement. These units are now due for refurbishment or replacement. FortisBC is currently studying the optimal method of ensuring that the Upper Bonnington plant continues to contribute to the Company's existing generation resources." (Exhibit B-1-2, p. 46)

In response to BCUC 1.250.2, FortisBC states that "The assessment confirmed that the units are operating satisfactorily and as such this project is not required at this time."

80.1 Please confirm that the study on the Upper Bonnington Plant concluded that the four generating units are currently not due for refurbishment or replacement during the test period.

Response:

FortisBC confirms that the generating units are operating satisfactorily at this time. The Upper Bonnington Old Units Repowering Project is not scheduled during the test period.

81.0 Reference: Key Attributes of FortisBC's Preferred Build Strategy Resource

Exhibit B-4, BCUC 1.265.3, p. 470

Single Cycle Gas Turbine

FortisBC states that "it has not factored in its failed effort in 1988 to obtain approval for a single cycle turbine in Oliver into its assessment of this option".

81.1 What factors have caused the project of a single cycle gas turbine in Oliver to fail in 1988?

Response:

The project did not proceed for a number of reasons, including local environmental concerns and questions about its necessity and economics on a provincial basis.

In its decision, Commission recommended that the project proceed if it met specific conditions: The following excerpts from Section 7 of the February 24, 1989 Commission Decision illustrate this point:

"On the basis of the evidence presented, the Commission concludes that the most appropriate independent resource would be the gas turbines proposed by the Applicant provided that a long-term gas supply contract with prices generally at or below levels escalated as described in the 1986 MEMPR "B.C. Energy Supply and Requirements Forecast" (as amended in 1987 for the years 1987 to 1992) is negotiated." (p.73)

"There are four primary sources of environmental concern : (1) noise generated by the turbine; (2) emissions of sulphur dioxide and nitrogen oxides and, to a lesser extent, particulates and hydrocarbons; (3) potential site instability because of the floodplain location of the proposed facility; and (4) spills of fuel oil from storage tanks or during transport of oil to the site. Air emissions and noise were the main focus of the Commission's review and public concerns expressed during the hearing." (p.74)

"For the above reasons it is the view of the Commission that if the gas turbine project is to proceed an alternative site is required. Accordingly the Commission recommends that, subject to the long-term gas fuel contract described in paragraph 7.1, and subject to the environment-related conditions described below, the Application be approved for construction at a site more suitable than that currently proposed in the Village of Oliver." (p.76-77)

"If the Applicant is able to secure, in 1989, both a long- term, appropriately priced gas supply contract and a more suitable site , the project should proceed on the basis put forward by the Applicant, as amended to incorporate water injection and subject to compliance with the conditions listed in paragraph 7.5.1. In the alternative, if construction on the proposed Oliver site is approved, the additional conditions listed in paragraph 7.5.2 should also be applied.

"In summary, it is clear that the gas turbine proposal, subject to compliance with the aforementioned conditions, provides the highest probability of minimizing rate impact on WKP's customers. It is possible that, once the plant is constructed, it may run only infrequently if additional interruptible power can be purchased at attractive rates. Hence it will have served its purpose by reducing the cost of new purchased resources below what they might have been without the gas turbine. From a broader provincial perspective, it could be argued that B.C. Hydro would benefit from the gas turbine by virtue of reduced demand on its resources and deferral of capital projects which in themselves are likely to impact the environment in some way.

'In the alternative, if the above-described conditions cannot be met in a reasonable time period (e.g. by December 31, 1989), the preferred resource for

WKP would be continued purchases from B.C. Hydro pursuant to the Terms and Conditions of the 1986 Dispute Decision." (p.79)

The specific approval conditions in 7.5.1 referred to above are summarized as:

- Turbines must meet a guaranteed maximum noise level and must not produce discrete tones
- Project should have an Emergency Response Plan
- Project must meet emission standards and air quality objectives
- Monitoring program to ensure compliance with source emissions and ambient air quality; and
- Fuel containing greater than 0.02% should not be used in the turbines during the growing season.

There were also special conditions in 7.5.2 related specifically to the proposed Oliver site.

81.2 Why did FortisBC choose not to factor in its previous failed effort regarding a single cycle gas turbine? Would the ranking be different had it factored in that failed attempt?

Response:

No, the project ranking would not have been different if the Company had factored in the previous attempt to proceed with the Oliver project. FortisBC understands that there will be specific stakeholder concerns with any type of project it may seek to proceed with in the future. Early stakeholder consultation and education on cost and benefits of different project options will be an important step toward realizing support for future project proposals.

82.0 Reference: Preferred Resource Strategy

Exhibit B-1-2, Section 6.4, p. 84; Exhibit B-4, BCUC 1.273.1, p. 483

Correlation between Market Purchases and Wholesale Market Price Spikes

FortisBC states that "Consequently, if FortisBC finds that in practice its market purchases are correlated with Wholesale market price spikes, it may be prudent to shorten its timelines for building new generation assets." (Exhibit B-1-2, p. 84)

In response to BCUC 1.273.1, FortisBC states that "FortisBC has does not have the historic data in a suitable format to perform this requested analysis. However, based on past buying practices, the Company believes that historically there would be a high correlation between market purchases used to meet peak demand and wholesale market price spikes. Typically the Company's peak demand periods are the same peak demand periods for neighbouring utilities, which creates upward pressure on wholesale market prices."

82.1 Given the response to BCUC 1.273.1, does FortisBC plan to track this data in a format suitable to perform such analysis in the future as the Company intends to assess whether to shorten its timelines for building new generation assets?

Response:

Yes, FortisBC will monitor and track market information and system requirements that would help to do such analysis in the future and which would help to assess the business case for building new generation resources.

83.0 Reference: Long Term Resource Plan

Exhibit B-4, BCUC 1.238.2

Excess Capacity Charges

83.1 Please confirm that when an excess capacity charge is triggered under the BC Hydro PPA, FortisBC can call on up to 75 percent of the excess capacity amount for the next 11 months without incurring additional capacity charges.

Response:

That is not correct.

Capacity payments for any month are based on the higher of (i) peak demand in that month, (ii) 75% of the peak demand over the last 11 months, and (iii) 50% of the annual nomination.

There is no separate billing process for excess and regular capacity purchases. What happens is that the excess capacity raises the eleven-month trailing ratchet calculations for regular capacity purchases. Potentially, a single one-time purchase of 10 MW of excess capacity in any hour could incrementally cost as much as $0.5 million or even more when all the bills over the entire twelve-month period have come in.

Excess capacity (i.e. the amount by which capacity taken exceeds the maximum annual nominated capacity of 200 MW) is calculated as 1.2 times the total actual excess amount. In other words, if 10 MW of excess capacity is actually taken, it will be treated as 12 MW for billing purposes for that month and eleven-month trailing ratchet calculations.

For example, if FortisBC takes 10 MW of excess capacity in January, the Company is required to pay for 212 MW in January and (200 * 0.75) + (10 * 1.2 * 0.75) = 159 MW of excess capacity over the next eleven months, which would be until December. Any take over the February to December period that exceeds 159 MW will incur additional capacity charges and if the take is high enough could even set a new ratchet.

Therefore, the 10 MW excess capacity purchase raised the minimum purchase for the next eleven months by 9 MW. While it is true the Company can now make beneficial use of that 9 MW up to the extent that it is needed to meet loads without being <u>double billed</u> for it, it is not free.

The Company cannot use excess capacity in these months without charge since the actual monthly take would then exceed 200 MW and so the Company would be billed based on the monthly purchase rather than ratchet provisions.

Finally, it should be understood that excess capacity is intended to be a supply of last resort to FortisBC and BC Hydro does not have a firm contractual obligation to provide it.

84.0 Reference: Long Term Resource Plan

Exhibit B-4, BCUC 1.239.3

Transmission Availability and Constraints

84.1 Please explain what is meant by the statement "FortisBC has indefinite rights to use Teck's 71 Line".

<u>Response:</u>

FortisBC's right to use Teck's 71L to import power is second only to Teck's right to import power over 71L to meet smelter load in the event of a Waneta outage. Therefore, as long as Teck is not requiring the use of 71L, 370 MW of import capability is available. If Teck does require the use of 71L, then approximately 150 MW of import capability is available.

85.0 Reference: Long Term Resource Plan

Exhibit B-4, BCUC 1.240.1, 1.240.2

Transmission Availability and Constraints

85.1 Please confirm that in the presence of significant transmission constraints between BC and Alberta, FortisBC is unlikely to be competing with Alberta for access to firm capacity suppliers in BC or the US Pacific Northwest.

Response:

Although there are significant transmission constraints between BC and Alberta, certain marketers including Powerex, TransCanada and Northpoint Energy Solutions have acquired significant long-term firm and conditional firm transmission positions on this border intertie. Those who have these firm transmission rights can deliver firm capacity to Alberta, and FortisBC will likely be competing with them, and therefore Alberta, for access to firm capacity suppliers in BC or the Pacific Northwest.

86.0 Reference: Long Term Resource Plan

Exhibit B-4, BCUC 1.242.1, Table BCUC IR1 242.1 Long Run Marginal Cost

FortisBC's Long Run Marginal Cost

86.1 Please provide the numerical calculation used to arrive at FortisBC's Long Run Marginal Cost of $111.96/MWh.

Response:

Please see Table BCUC IR2 86.1 below.

1 **Table BCUC IR2 86.1**

Levelized LRMC		
Assumed inflation	2.0%	
Number of	30	
Discount Rate	8%	
NPV	$1,260.47	$1,260.47
Levelized LRMC	**$111.96**	

Year	BC New Resources Cost Curve (Nominal $)	Levelized (Nominal $)
2011	$101.39	$111.96
2012	$102.45	$111.96
2013	$103.53	$111.96
2014	$104.61	$111.96
2015	$105.71	$111.96
2016	$106.82	$111.96
2017	$107.94	$111.96
2018	$109.08	$111.96
2019	$110.22	$111.96
2020	$111.38	$111.96
2021	$112.55	$111.96
2022	$113.73	$111.96
2023	$114.92	$111.96
2024	$116.13	$111.96
2025	$117.35	$111.96
2026	$118.58	$111.96
2027	$119.83	$111.96
2028	$121.09	$111.96
2029	$122.36	$111.96
2030	$123.64	$111.96
2031	$124.94	$111.96
2032	$126.25	$111.96
2033	$127.58	$111.96
2034	$128.92	$111.96
2035	$130.27	$111.96
2036	$131.64	$111.96
2037	$133.02	$111.96
2038	$134.42	$111.96
2039	$135.83	$111.96
2040	$137.26	$111.96

87.0 Reference: Long Term Resource Plan

Exhibit B-4, BCUC 1.243.1

Assessment of Potential Risks

87.1 FortisBC states that market prices are far more likely to increase by 50 percent than they are to decrease by 50 percent. Please discuss whether the probability of an increase or decrease is symmetrically distributed without regard to the magnitude of the increase or decrease.

Response:

The Company believes that the probability of market prices being higher is greater than the probability of prices being lower. So therefore it believes the probability of increases or decreases is not symmetric.

88.0 Reference: Load Forecast

Exhibit B-4, BCUC 1.246.1, Figure BCUC IR1 246.1a, Figure BCUC IR1 246.1b

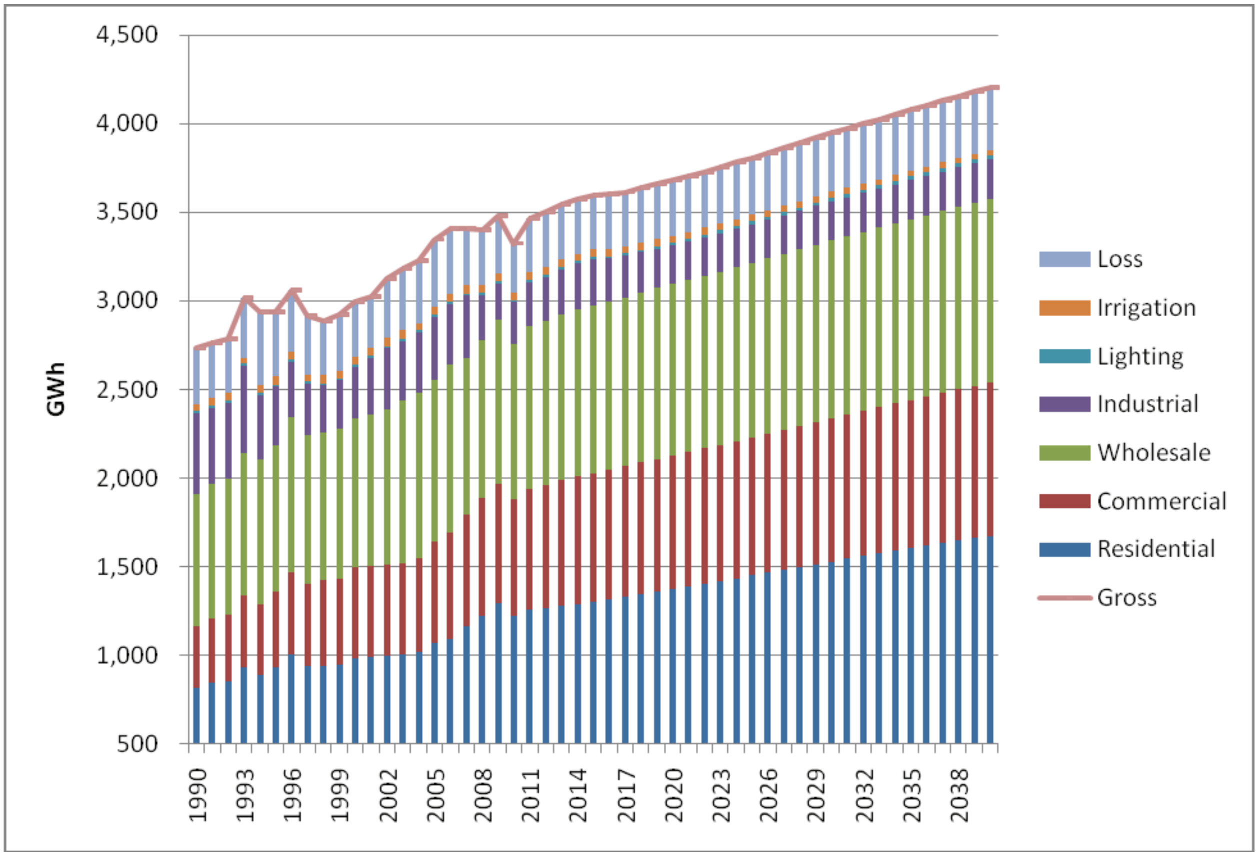
Energy Requirement (GWh) and Annual System Peak (MW)

88.1 The referenced IR requests date back to 1990, but the response only provides data to 2000. Please provide the data originally requested.

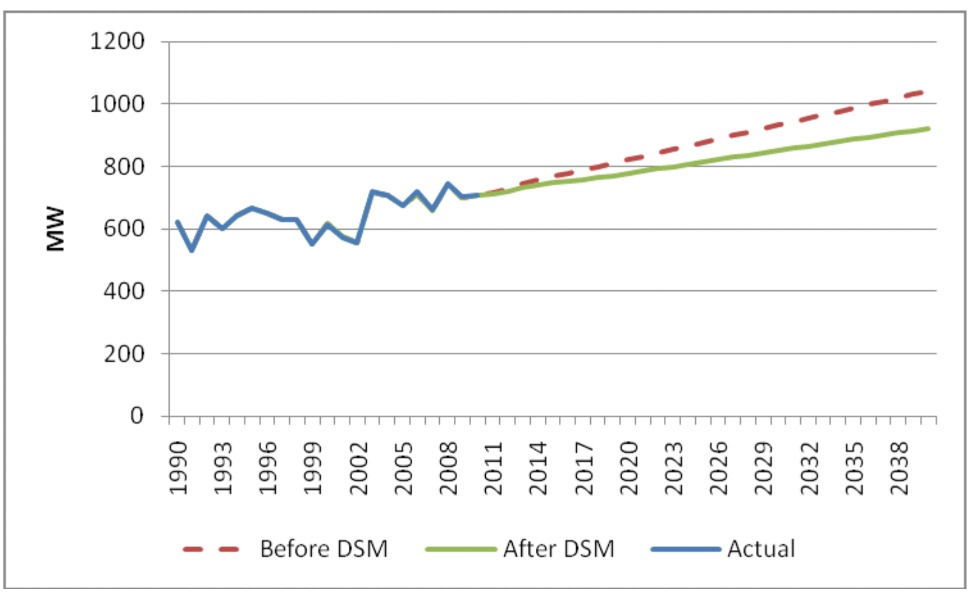
Response:

At the time of the IR, FortisBC was unable to obtain the data to do the analysis prior to 2000. The Company now has the data to complete the response. The figures and the associated data have also been attached to these responses as BCUC IR2 Electronic Attachment 88.1

1 **Figure BCUC IR2 88.1a**

2 

3 **Figure BCUC IRR2 88.1b**

4 

89.0 Reference: Long and Medium Term Contractual Resources

Exhibit B-4, BCUC 1.254.4

Waneta Expansion Capacity Purchase

89.1 Please confirm that when the WAX capacity is being utilized, the energy associated with this capacity is actually derived by virtue of the other facilities in the Canal Plant Agreement.

<u>Response:</u>

This is correct. The Canal Plant Agreement contractually creates a common storage account from which any unit under the Canal Plant Agreement can draw from regardless of which unit was originally responsible for the storage.

90.0 Reference: Application of Planning Reserve Margin (PRM)

Exhibit B-4, BCUC 1.258.4

FortisBC Inc. Planning Reserve Margin Study

90.1 Please describe FortisBC's utilization of the WAX CAPA capacity if FortisBC is denied the establishment of a planning reserve margin. In other words, if the WAX CAPA capacity is not being used for planning reserve margin, how will FortisBC use the excess capacity?

<u>Response:</u>

FortisBC plans to sell any excess WAX CAPA capacity not being used to meet load. As FortisBC's load grows, this excess capacity amount will be reduced.

90.2 Please confirm that if smaller-sized units than the WAX generators were used to fulfill FortisBC's capacity requirements, that the planning reserve margin requirements would also be lower.

<u>Response:</u>

Yes, if smaller sized units than the WAX generators were used to fulfill FortisBC's capacity requirements, the PRM requirements under the current formula would be lower. As described in Section 5.2.1.1 of the 2012 Long Term Resource Plan, PRM requirements are affected by the single largest utilized contingency, and in the case of the WAX CAPA, that calculation is based on notionally splitting the utilized WAX CAPA entitlement between the two WAX units.

However, in order to properly consider this one would also have to look at the full impact of using smaller size units, including the impact on capacity cost.

90.3 When comparing the costs of the WAX CAPA capacity contract with other resources, please discuss whether the incremental costs required for the greater amount of planning reserve margin associated with the WAX CAPA capacity contract as compared to smaller-sized resources were considered.

Response:

Incremental PRM requirement related to the inclusion of the WAX CAPA was considered at the time of the 2010 Section 71 Filing on the WAX CAPA agreement, and the Company believed at that time that there would not be an impact.

Subsequent to that, the Midgard Planning Reserve Margin Report (Appendix D of the 2012 Long-Term Resource Plan) recommended that the single largest utilized contingency should be considered, which would be the WAX CAPA once it was available. FortisBC modified the Midgard recommendation to reduce the impact by notionally splitting the utilized WAX CAPA entitlement between the two WAX units.

Please also see the response to BCUC IR2 Q6.1.

91.0 Reference: Application of Planning Reserve Margin (PRM) Key Attributes of FortisBC's Preferred Build Strategy Resource Options

Exhibit B-4, BCUC 1.267.2

Pumped Storage Hydro

"It is worth noting that for one site, on Nicola Lake near Merritt, BC, the Company did commence the procedure to obtain a water license. Since the original application, given further investigation, the Company has determined that the Nicola site is no longer suitable and has terminated the application process."

91.1 Please describe how the costs associated with the Nicola Lake water license application were reconciled. Were the costs assigned to operating or capital budgets, or are they being held in a deferral account?

Response:

The costs associated with the Nicola Lake water license are currently part of the pumped storage hydro (PSH) account, under the "Preliminary & Investigative Charges" deferral account. The investigative costs for pumped storage hydro are being considered collectively as there are a number of pumped storage hydro sites being investigated. Additionally, PSH facilities involve long lead times for siting, permitting and construction due to the requirement for water storage sites and therefore development activities must be pursued prudently long in advance of actual project commissioning.

DEMAND SIDE MANAGEMENT

92.0 Reference: Demand Side Management

Exhibit B-4, BCUC 1.281.3.1

DSM Savings Forecasts

FortisBC states "The annual DSM targets were then converted to acquired DSM savings i.e. DSM forecast, for load forecasting purposes."

92.1 Please explain the steps taken to convert the DSM targets to the acquired DSM savings.

Response:

The steps are explained, and formulae shown in the Company's response to BCUC IR1 280.5.1

92.2 Please specify any assumptions that were made in any of the steps.

Response:

The following assumptions were made in including the Achievable Energy Savings in the after DSM load forecasts:

- The annual profile of energy savings for each measure in the programs; and
- The program measures are implemented evenly through the year. i.e. 1/12th of the programs are implemented in each month.

93.0 Reference: Demand Side Management

Exhibit B-4, BCUC 1.284.1

2011 Year to Date Spending

93.1 Please re-file Electronic Attachment 1 and provide the 2011 Spending to Date figures.

Response:

Please refer to BCUC IR2 Electronic Attachment 93.1.

93.2 Please explain all instances where spending is less than 60% of the planned annual budget for Programs and Supporting Initiatives.

Response:

The following table highlights those programs and initiatives where YTD expenditures (to end of September) are below 60% of the approved annual budget.

Table BCUC IR2 93.2 Approved DSM Program Budgets versus Actual YTD Expenditures

		Approved 2011	To Sept 30, 2011	% of Plan
		($000s)		
1	**Residential**			
2	Home Improvements			
3	Building Envelope*	1,379	98	7%
4	Heat Pumps	694	647	93%
5	Residential Lighting	438	129	29%
6	New Home Program	54	128	237%
7	Appliances*	245	79	32%
8	Electronics*	49	20	40%
9	Water Heating*	162	0	0%
10	Low Income*	305	56	18%
11	Behavioural*	310	78	25%
12	Residential Subtotal	**3,636**	**1,234**	**34%**
13	**Commercial**			
14	Lighting	1,080	1,120	104%
15	Building and Process Improvements	572	438	77%
16	Computers	34	0	0%
17	Municipal **	392	32	8%
18	Irrigation	40	0	0%
19	Commercial Subtotal	**2,118**	**1,590**	**75%**
20	**Industrial**			
21	EMIS	10	26	260%
22	Industrial Efficiencies	603	83	14%
23	Industrial Sub-total	**613**	**109**	**18%**
24	**Program Subtotal**	**6,367**	**2,932**	**46%**
	Supporting Initiatives	725	289	40%
	Total	**7,092**	**3,221**	**45%**

Note: Programs with spending below 60 percent of Plan are highlighted in grey

* These programs were included in Home Improvements program in prior years.
** Includes Irrigation and Municipal water treatment and wastewater handling.

In the Residential Sector, spending in each of the the Building Envelope, Residential Lighting, Appliances, Electronics, Water Heating, Low Income and Behavioural programs is under 60 percent of the planned annual budget for the following reasons:

- Home retrofit programs, including Building Envelope, depend primarily on the LiveSmart collaborative program, which was stalled for six months until the anticipated federal ecoEnergy program was launched in mid-July;
- Appliances – the YTD spend reflects the mid-year launch of this program;
- Electronics – about 75 percent of annual TV sales occur in the last quarter leading up to Christmas; and
- Behavioural – the fall heating awareness campaign was cancelled due to a vacancy, and PowerSense month expenditures have not yet been recorded;
- Lighting – an instant rebate program with large box retailers will begin this fall; and
- Low Income – a direct install lighting pilot project is underway this fall, in conjunction with BC non-profit housing association (BCNPHA) members.

In the Commercial sector the Computer, Municipal infrastructure and Irrigation programs are below the 60% spending threshold for the following reasons:

- Computer – there have been no new data server “farms” in the FortisBC service area;
- Irrigation – an irrigation pilot program is planned to begin after the fall harvest is complete, please also see the response to BCUC IR2 96.2;
- Industrial Efficiency is underspent due to a proposed large DSM project by Celgar for which FortisBC has received no formal application to date;
- Supporting Initiatives are underspent largely because FortisBC has not had the capacity to set up the necessary arrangements (e.g. training subsidies to fully utilize this expanded category); and
- Municipal – a large Wastewater Treatment plant project will be booked in November.

94.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-6, Section 1, p. 1 and Table 3.2.3, Updated p. 15; Exhibit B-4, BCUC 1.292.2.3

DSM Savings Targets

FortisBC states "The first five years of the 2012 DSM Plan (2012-2016) are an extension of the approved [by Order G-195-10] 2011 DSM Plan, thereafter a constant savings target is used as a placeholder for future DSM activities." (p. 1)

FortisBC also states "the 2012 Long-Term DSM Plan timeline spans 2012-2031."

Table 3.2.3 – Savings Targets

Year	Residential	Commercial	Industrial	Proxy '17-31
	GWh			
2011	16.2	13.5	2.5	-
2012	16.1	13.4	2.5	-
2013	14.2	13.4	2.5	-
2014	15.8	14.9	2.8	-
2015	16.7	15.8	2.9	-
2016	17.6	16.6	3.1	-
2017-30	-	-	-	28

94.1 Given that the 2012 Long Term DSM Plan models savings targets and compares the targets to the 2007 BC Energy Plan target from 2011-2016, and thereafter uses a constant savings as a placeholder, is it more accurate to term the plan a five year DSM plan?

Response:

Please see the response to BCUC IR2 Q94.1.1.

94.1.1 Why has Fortis only modeled the next five years for its DSM savings targets and DSM programming?

Response:

The DSM Planning cycle referred to in section 3.3.1 of the 2012 Long Term DSM Plan provides detailed planning data that is valid for approximately five years (due to the rapidly changing nature of DSM technology and costs). In a DSM detailed planning context, five years is "long term".

Thereafter, a proxy is used to represent future DSM targets, which will likely be comprised of a mix of ongoing and new DSM programs.

The DSM plan inputs (end-use surveys and conservation potential reports) need to be refreshed to inform the next DSM Plan, which will in turn provide detail for the next planning period.

94.2 The Long Term DSM Plan projects fairly flat DSM savings targets for 2011-2012. Does FortisBC not foresee a need to increase DSM programming over the next five years? If not, why not?

Response:

FortisBC has increased DSM expenditures per customer by almost 500% since 2000 (please see Slide 28 of Exhibit B-2). DSM savings per customer have nearly doubled over the same period, and now meet the 2007 BC Energy Plan policy action of 50% of load offset through conservation,

FortisBC proposes to maintain DSM programming over the 2011-2016 period as illustrated in Figure 3.2.4. Thereafter a 28 GW.h proxy is deployed which ensures the 50% offset is achieved over the entire 2011-31 planning period.

94.3 In Updated Table 3.2.3 the Industrial Savings Targets were increased from the range 1.1 1.9 GWh to the range of 2.5-3.1 GWh. Please explain these changes.

Response:

This Table was corrected in Errata 2 since the original figures were taken from the wrong source spreadsheet.

94.3.1 If these changes are attributable to specific projects please list the projects and the measures that will be installed.

Response:

Please see the response to BCUC IR1 Q94.3.

95.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-2, Section 3.3.1, p. 17

DSM Planning Cycle

FortisBC states "The major steps of the DSM planning cycle are anticipated to be repeated at approximately five year intervals, unless circumstances change. The major steps, which are detailed in Section 2.2, include end use studies, and a Conservation Demand Potential Review resulting in an updated Long Term DSM Plan."

95.1 Please file any best practices or DSM guidelines that suggest the best time interval for a utility to undertake end use studies, a conservation demand potential review and create a long term DSM plan.

Response:

BC Hydro is required under the *Clean Energy Act* to prepare an Integrated Resource Plan every five years, which includes DSM Plan Options. It does not have a defined period for new CPRs, but agree that five years is a good rule of thumb. End-use and/or market studies are done periodically to inform yearly DSM Plan updates, program business cases and long term DSM Plans.

FortisBC Energy Utilities do not have a formal policy, but also intends to do a CPR approximately every five years.

The Ontario Energy Board (OEB) has established 4-year conservation targets for its distributors.

The Northwest Power and Conservation Council produces a regional power plan including detailed DSM potential estimates every five years, with an update at the midpoint (2.5 years) of this cycle.

The State of Washington requires utilities to develop a 10-year assessment of their potential and set targets to achieve this potential. This 10-year plan must be updated every 2 years.

The State of California requires a biennial Integrated Energy Policy Report (odd years).

95.2 Please provide information on how often other relevant utilities undergo a DSM Planning Cycle as described above.

Response:

Please see the response to BCUC IR2 Q95.1 above.

96.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-2, Section 1, pp. 18-29; Exhibit B-4, BCUC 1.286.1

New Programs

FortisBC states "There are a considerable number of new or enhanced programs proposed for 2011-13, based on the 2010 CDPR." (BCUC 1.286.1)

96.1 Please confirm that this is the complete and correct list of new programs or program elements planned for 2011-2013. If not, please revise and add all new programs to the table.

Sector	Program	Continuing	New Programs 2011	New Program 2012-2013
Residential	Home Improvement Program	Home Improvement Program		
	Heating and Cooling Program	Heat Pumps	Programmable Thermostats	Heat Pump Maintenance Duct Sealing Pilot Program for Homes with Electric Heat
	Residential Lighting	Rebates CFL + LED bulbs		
	Energy Star Appliances and Electronics		Rebate programs for clothes washers, Refrigerators, freezers, dishwashers, bathroom fans and televisions Fridge and Freezer pick-up	
	Water Heating		Rebates for installation of solar hot water systems Heat pump water heaters pilot program Distribution of low flow showerheads	
	New Home Program		Incentives to achieve EnerGuide 84 or 90	

			Funding for engineering studies and other assessments	

Response:

The following table is the list of new programs or measures (elements) planned at this time. The Company may add (or delete) measures or programs as the market evolves.

Sector	Program	Continuing	New Measures 2011	New Measures 2012-13
Residential	Home Improvement Program	Building Envelope	Programmable Thermostats	Financing pilot project
	Heating and Cooling Program	Heat Pumps	Maintenance (tune-up) pilot	Heat Pump Maintenance Duct Sealing Pilot
	Residential Lighting	CFL Specialty rebates	LED rebates	
	Appliances and Electronics		EnergyStar clothes washers, refrigerators, freezers, dishwashers, bathroom fans and televisions Fridge pick-up	
	Water Heating		Heat pump water heater pilot low flow showerheads	Delete SHW offer
	New Home Program	Funding for engineering studies	Performance based EnerGuide 80, 84 or 90	Modify to suit revised EnerGuide scale
	Residential Behavioural	Clotheslines	Education materials	In home displays Social norm pilot

Commercial	Lighting	Lighting incentives	Street lighting incentives	LED incentives for municipalities and parking lots
	Building Improvements Program	50% of cost of approved energy study Rebates on efficiency measures		Enhanced product option rebates
	Computers		Incentives and tools for data centres and servers	
	Lighting Direct Installation		direct lighting installation for small businesses (FLIP)	
	Municipal Programs	Rebates and training support		
	Building Optimization Program		Pilot project	Move from pilot to full implementation
	Irrigation Programs	Custom Option rebate		Product option rebates Irrigation audit pilot project
	Commercial kitchen			Product rebates for commercial dish washers, refrigeration, exhaust fans, etc.
Industrial	Energy Management Information Systems (EMIS)	Financial incentives and operational assistance	Pilot EMIS	Add ISO 50,001
	Industrial Efficiency	Customized assistance and financial incentives		

Other	Residential Low-Income Households Program		Energy Savings Kit (ESK) Direct install lighting for common areas	ECAP - Direct install – weatherization partnership
	Rental Accommoda tion Programs – Single and Multi family	ESK		financial incentive offers to landlords, property managers, rental agencies – collaborate with other public utilities; Multi family, same as single family but add social marketing tactic
	First Nations Residential Households	Incorporate in appropriate programs (New Home, Heat pump, low income & rental)		ECAP for First Nations
Supporting Initiatives	Public Awareness	Okanagan Conservation Ambassadors	Add Kootenay Ambassador	
	Education			Curriculum-based (intermediate) education package Curriculum development for Sustainability program with Okanagan College
	Community Energy Planning		Rossland Energy Diet	
	Codes and Standards			

96.2 Have any programs planned for 2011 been unable to commence? If so, please explain why.

Response:

FortisBC started a rental behavioural pilot project in 2010 that it expected to expand in 2011. Barriers identified in the pilot project and other circumstances delayed full implementation. This program roll-out is now planned for 2012.

FortisBC had expected to introduce an enhanced Product Incentive Program (fixed rebate program) in mid-2011 efforts to reach and assist small and medium sized commercial enterprises. It will extend beyond lighting products to include commercial refrigeration and kitchen appliances, and small fans and motors. The launch of that program was delayed due to a number of other initiatives that occupied available resources, and will now commence in January 2012.

An irrigation rebate pilot project was planned but the irrigation customer survey won't be issued until after the fall harvest is completed. A modified program that focuses on irrigation audits and pumping, and complementary to the BC Ministry of Agriculture's Environmental Farm Plan, will be launched in Spring 2012.

96.3 Please provide the results of any evaluations done on the Building Optimization Program to support its transition from pilot program to full implementation. If no evaluation has been done, please justify the full program implementation.

Response:

This program addresses an opportunity for energy savings in existing buildings through a commissioning process. The energy savings with retro-commissioning and the building audit portion of the building optimization program was studied in the Mills report[4] from 2009. It assesses the savings opportunity for commissioning new and retrofitted buildings. The study looked at 561 existing buildings across the US. The energy savings for a retro-commissioned building range from 9-31% with an average of 16% for the whole building. The electrical savings averaged 9%. The report also states that only 0.03 % of the existing building stock have been commissioned for energy savings

[4] Mills, Evan. 2009. *Building Commissioning: A Golden Opportunity for Reducing Energy Costs and Greenhouse-gas Emissions.* Lawrence Berkeley National Library. 2009.

The Evaluation Study[5] on the retro-commissioning program in California by SBW consulting indicates a relatively short persistence of savings (3-5 year) with retro-commissioning. The report confirms the existence of savings and indicates a minimal free-ridership of the program. FortisBC has modeled BoP on the BCH Continuous Optimization program, which addresses the persistence issue with the inclusion of an Energy Management Information System (EMIS) i.e. software installation and tracking requirements.

Quarterly M&T (Monitoring and Tracking) reports from the EMIS vendor will provide ongoing indications of energy savings. The building optimization program evaluation will be included in the next monitoring and evaluation plan (2015 and beyond).

97.0 Reference: Demand Side Management

Exhibit B-4, BCUC 1.286.1

New Programs

Program Name	heat pump maintenance (tune-up)
Energy Savings per Installation (kWh):	360 kWh/yr
	1. N/A 2.North West Energy Council, Bonneville Power Authority and the Energy Trust of Oregon. Savings from a 2005 study by the Energy Trust of Oregon: Baylon, David, et al. Analysis of Heat Pump Installation Practices and Performance. For the Heat Pump Working Group. Oregon. 2005

97.1 Please file the two data sources listed from the North West Energy Council and Baylon et al.

<u>Response:</u>

There is only one report. The heat pump tune-up measure is rolled up into a program known as "Performance Tested Comfort Systems" which includes controls, duct testing, and Heat Pumps (installation and tune-ups).

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[5] SBW Consulting Inc. *Final Report 2006-08 Retro-Commissioning Impact Evaluation*. California Public Utilities Commission. Energy Division. 2010.

The Baylon report from the Northwest Energy Council includes analysis of results from the "CheckMe" tune-up program operated by the Eugene Water and Electric Board. The result was 360 kWH/yr average savings compared to a statistically significant control group.

The Executive Summary, with the key findings of the report is filed as BCUC IR2 Appendix 97.1.

98.0 Reference: 2012 Long Term Demand Side Management Plan

Exhibit B-1-2, Appendix D, pp. 4, 7, 9-11; Exhibit B-4, BCUC 1.298.2

Monitoring and Evaluation

FortisBC states "FortisBC plans to conduct two full scale M&E studies annually in addition to three Mini Reviews. A full scale review would normally consist of a process, market and an impact study. The Mini Review consists of a Process study and some measurement and verification activities using a sample of projects." (p. 4)

FortisBC states "Pilot studies are generally conducted during and immediately after a pilot project, while process studies are generally conducted six to eighteen months following program launch and often include a preliminary market assessment to determine the progress of the changes in the market. Market and impact studies are generally conducted anywhere from twenty-four to thirty-six months after program launch, when sufficient information is available, and then periodically at an interval of 2 to 3 years." (p. 7)

"This means that some programs will never undergo a full scale review, or will only undergo one infrequently. However such programs would still be subject to a Mini-Review, which ensures a smaller scale program review is undertaken for smaller programs." (BCUC 1.298.2)

98.1 Please confirm that the following compilation of the information from the Monitoring and Evaluation plan, pages 9-11 is a complete listing of the evaluations by program completed and planned for 2011-2014. If not, please complete the table.

		Evaluations				
Sect-or	Program	Completed 2009-2011	Planned for Completion 2011	Planned for 2012	Planned for 2013	Planned for 2014
Residential	Home Improvement Program			✗ - Mini Review		
	Heating and Cooling	✓ -			✓ -	

	Program	Comprehensive - Heat Pumps			Comprehensive - Heat Pumps	
	Residential Lighting		✓ - Comprehensive		× - Mini Review	
	Energy Star Appliances and Electronics					
	Water Heating					
	New Home Program			× - Mini Review		✓
	Residential Behavioural		× - Baseline Study		× -Survey and mini-review	× - Evaluation
Commercial	Lighting	✓		✓ - Comprehensive		× - Mini Review
	Building Improvements Program	✓ - New	✓ - Retrofit		✓ - (New Projects)	✓ - Retrofit
	Computers					
	Lighting Direct Installation					
	Municipal Programs			× - Mini Review		
	Building Optimization Program					
	Irrigation Programs					
Industrial	Energy Management Systems (Previously Integrated Programs & Integrated Building Optimization)					
	Industrial Efficiency			✓ - Comprehensive		× - Mini Review
Other	Residential Low-Income Households Program				× - Mini Review	
	Rental					

	Accommodation Programs – Single and Multi family					
	First Nations Residential Households					
Supporting Initiatives	Public Awareness					
	Education					
	Community Energy Planning					
	Codes and Standards					

Response:

The revised table, with program names changed in some cases to match the 2012-13 Capital Plan filing, is as follows:

		Evaluations				
Sector	Program	Completed 2009-2011	Planned for 2011	Planned for 2012	Planned for 2013	Planned for 2014
Residential	Building Envelope			✗ - Mini Review		
	Heat Pumps	✓ - Comprehensive			✓ - Comprehensive	
	Residential Lighting		✗ - Mini Review		✗ - Mini Review	
	Appliances and Electronics					
	Water Heating					
	New Home			✗ - Mini Review		✓ - Comprehensive
	Residential Behavioural			✗ - Baseline Study	✗ -Survey and mini-	✗ - Mini Review

					review	
Commercial	Lighting, including Direct Installation	✓- Comprehensive		✓ - Comprehensive		× - Mini Review
	Building Improvements	✓ - New	✓ - Retrofit		✓ - (New Projects)	✓ - Retrofit
	Computers					
	Municipal Programs			× - Mini Review		
	Building Optimization Program					
	Irrigation Programs					
Industrial	Energy Management Information Systems					
	Industrial Efficiency			✓ - Comprehensive		× - Mini Review
Other	Residential Low-Income & Rental Households Program				× - Mini Review	
Supporting Initiatives	Public Awareness					
	Education					
	Community Energy Planning					
	Codes and Standards					

FortisBC indicates that Process Studies are generally conducted six to eighteen months following program launch while Market and Impact studies are generally conducted anywhere from twenty-four to thirty-six months after program launch. FortisBC also indicates that a Mini-Review is a process study and some measurement and verification activities using a sample of projects while a Comprehensive Review (full scale review) usually entails a process, market and impact study.

98.2 Please explain why FortisBC is planning Comprehensive Reviews of the Commercial Lighting and Industrial Efficiency programs in 2012 and Mini Reviews in 2014? If the Comprehensive Review includes a Process, Market and Impact study, shouldn't the Comprehensive Review span multiple years and cover the content of the Mini Review?

<u>Response:</u>

FortisBC is planning Comprehensive Reviews of Lighting and Industrial Efficiency programs in 2012 and Mini Reviews again in 2014 primarily because these programs generate significant savings and have been enhanced in 2011; and the Mini Reviews are to ensure that the objectives of these enhancements are being met. Since these Reviews are looking at past projects that have been completed with at least one full year of operation after installation of the measures, the 2012 Reviews will not cover any of the 2011 projects, hence the need for the Mini Reviews in 2014.

The Comprehensive Reviews will cover the issues covered in the Mini Reviews plus the impacts of the programs, but they will cover different time periods. In both cases the Comprehensive Reviews in 2012 will cover projects installed up to and including the end of 2010, while the Mini Reviews will cover projects installed in 2011 and 2012. The purpose of the Mini Reviews is to ensure that the market changes over the intervening years are factored into planning future changes of the programs.

98.3 Please provide any Best Practices or guidelines from other jurisdictions that support FortisBC's 10 GWh/year savings threshold for a Comprehensive Review. Please describe what threshold other jurisdictions use.

<u>Response:</u>

FortisBC has not undertaken any benchmarking of other jurisdictions but it was noted that BC Hydro in its 2008 LTAP - DSM Plan Sub Appendix I indicated that impact reporting of savings of 10 GWh/year would trigger an evaluation review. This savings threshold appears reasonable and has been adopted by FortisBC.

98.4 Why has FortisBC not considered program spending when creating its threshold for a Comprehensive Review?

Response:

FortisBC has not explicitly considered program spending when creating its threshold for a Comprehensive Review. However, as energy savings are linked to spending, the 10 GW.h saving threshold also results in programs with higher spending getting a higher priority for Review.

98.4.1 What would be an appropriate spending threshold to trigger a Comprehensive Review?

Response:

FortisBC considers a spending trigger at an accumulated amount of $1 Million appropriate for a Comprehensive Review if the 10 GWh energy saving threshold had not already been reached. The Company would also consider a $500,000 per year expenditure as a threshold for conducting Comprehensive Reviews, at three year intervals, to be appropriate. These levels of spending and energy savings would be sufficient to justify the costs for these types of Reviews.

98.5 Please justify why some programs never undergo a Comprehensive Review?

Response:

For programs with accumulative expenditures and energy savings that are not expected to reach energy savings or expenditure thresholds, because of market realities (the willingness of customers to participate) the cost of a Comprehensive Review could be considered excessive.

For such programs, other approaches to estimating savings would be used. Assumptions used to generate the energy savings estimates (based on the experience of other jurisdictions), with corrections for local conditions if need be, would be factored into the engineering estimate of savings and used for reporting purposes. Participant surveys are an alternate tool the Company uses to verify behavioural and deemed savings measures that wouldn't warrant a comprehensive review.

98.6 Please justify why, according to the table above, some programs do not undergo evaluation at all before 2015.

Response:

The primary reason why some programs do not undergo evaluation before 2015 is that the spending and savings are too small to justify the high relative cost to undertake these studies. For example in the Residential sector, Appliances, Water heating and Electronics were delayed, and the other new initiatives Street Lighting and Industrial Building Optimization have been combined with the larger initiatives Commercial Lighting and Industrial Efficiency. Please also see the response to BCUC IR2 Q98.5.

98.7 Please propose another Evaluation Schedule, using the same budget, where new programs undergo a Process Evaluation six to eighteen months following program launch and Market and Impact studies are conducted twenty-four to thirty-six months after program launch. Please ignore the 10 GWh/yr threshold. If this is not possible under the current planned budget, please create the schedule and estimate its cost.

Response:

The Table below lays out a revised schedule of M&E Studies as requested. New programs undergo a Process Evaluation six to eighteen months following program launch and Market and Impact Studies occur twenty-four to thirty-six months after launch. An enhanced budget is required as it is not possible to abide by these guidelines within the same budget. The three year budget is estimated to cost $1.465 Million, with the first year estimated at $0.470 million, the second year $0.550 million and the third year $0.445 million.

The current M&E plan budget is $0.385 million per annum for the 2012 and 2013 test period, (see BCUC IR1 Q298.4.2). The revised schedule would increase M&E costs by an estimated $0.310 million over the full 3 year M&E Plan timeframe.

1 **Table BCUC IR2 98.7**

		Evaluations				
Sector	**Program**	**Completed 2009-2011**	**Planned for Completion 2011**	**Planned for 2012**	**Planned for 2013**	**Planned for 2014**
Residential	Home Improvement (Building Envelope)			× - Mini Review	✓ - Comprehensive	
	Heating and Cooling (Heat Pumps)	✓ - Comprehensive -			✓ - Comprehensive	
	Residential Lighting		✓ - Mini Review	✓ - Comprehensive		
	Energy Star Appliances and Electronics			× - Mini Review	✓ - Comprehensive	
	Water Heating				× - Mini Review	
	New Home			× - Mini Review		✓ - Comprehensive
	Residential Behavioural			× - Baseline Study	× -Survey and mini-review	× - Survey and Mini Review
Commercial and Industrial	Lighting	✓- Comprehensive			✓- Comprehensive	
	Building Improvements	✓ - New Comprehensive	✓ - Retrofit Comprehensive		✓ - New Comprehensive	✓ - Retrofit Comprehensive

	Computers			× - Mini Review		✓ - Comprehensive
	Municipal (Wastewater and Irrigation)			× - Mini Review		✓ - Comprehensive
	Industrial Efficiency (and EMIS)			✓ - Comprehensive		
Other	Low Income (Includes Rental Accommodation and First Nations)			× - Mini Review		✓ - Comprehensive

OTHER TOPICS

99.0 Reference: Sales Revenue

Exhibit B-1, Tab 7, p. 26

Revenue Forecast

In FortisBC's last Rate Design and COSA Application, a Green Power Rider was proposed and approved as RS 85. This rider allows customers the option of paying 1.5 cents per kWh above the published tariff rate or the contribution of some monetary amount towards the purchase of electricity from environmentally desirable technologies.

99.1 Please provide the data in tabular format showing the number of customers, revenues derived, and volume of uptake for Option 1 and Option 2 of RS 85 for each rate class.

Response:

The Company has not forecast any customers or revenue for RS85 in 2012 and 2013. Please also refer to BCUC IR2 Q99.3.

99.2 Please indicate where the forecast revenues from RS 85 can be identified. Is it included in the sales forecast for each customer rate class ("Revenues under approved rates")? Is it included in Other Income and treated as a revenue offset? Provide references to schedules.

Response:

The Company has not forecast any customers or revenue for RS85 in 2012 and 2013. Please also refer to BCUC IR2 Q99.3.

99.3 Please discuss how FortisBC has promoted this rate rider during the year and comment on the success/uptake of the rate rider.

Response:

Green power rates have been available to FortisBC customers since 1998, and were split out as a separate rate rider in 2011 for simplicity. FortisBC has not changed its activities related to green rates since the change was only structural within the tariff and did not impact customers. FortisBC currently has no customers billed with the green power rider (although there has been at least two in the past). FortisBC currently has no marketing efforts planned or budgeted for green rates.

99.4 Please discuss whether the revenues derived from RS 85 are used to purchase Renewable Energy Credits (RECs)? If so, provide details on the reconciliation of RECs purchases during 2011. Are these used to offset GHGs produced from the Company's own generation or is it sold as an environmental attribute to rate payers? Please discuss and provide an illustrative example.

Response:

A total of $307.33 has been collected since program inception and these funds remain unspent.

The Company is currently looking into acquiring physical power that is eco-logo certified and expects to purchase up to 50 MWh.

100.0 Reference: Clean Energy Act

Exhibit B-5, BCOAPO 1.1.1

"The 50 percent target proposed in the 2007 BC Energy Plan was directed toward BC Hydro, but FortisBC has voluntarily committed to the target."

100.1 Please identify any incremental costs FortisBC has incurred by voluntarily committing to this target. Has FortisBC identified and sought approval from the Commission for any such incremental costs?

Response:

It is not possible to identify any such incremental costs. Past regulatory filings that proposed DSM programs to achieve this target included the 2009/10 DSM Plan and the 2011 DSM Plan, both of which were tested and subsequently approved by the BCUC.

101.0 Reference: Radial Loads

Exhibit B-5, BCOAPO 1.21.1, Table BCOAPO IR1 21.1 – Radially Supplied Substations and Associated Peak-Load

101.1 Please explain why FortisBC does not consider the loads served by line 43 L to be radial loads.

Response:

Each of the substations along 43 Line has two possible transmission sources:

1. From the Bentley Terminal station (via 43 Line); or
2. From the BC Hydro interconnection at Princeton (via 56 Line and 43 Line).

In normal operations, a normally open point exists between these two sources (the two sources are not run in parallel or meshed). Refer to Appendix D-2 of the 2012 Long Term Capital Plan for a single-line diagram showing the transmission system in this area.

As described in the response to BCOAPO IR1 Q21.1, the Table BCOAPO IR1 21.1 only contains substations that currently have only one possible transmission source (i.e. they are served by a single transmission line). Since the 43 Line loads have two possible sources of supply, they were not included in the table.

MOODY'S
INVESTORS SERVICE

Credit Opinion: FortisBC Inc

Global Credit Research - 06 Sep 2011

British Columbia, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Unsecured -Dom Curr	Baa1

Contacts

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Key Indicators

[1]**FortisBC Inc**

	[2]LTM	2010	2009	2008	2007
(CFO Pre-W/C + Interest) / Interest Expense	3.2x	3.0x	2.9x	2.8x	2.7x
(CFO Pre-W/C) / Debt	12.9%	11.6%	11.9%	11.2%	10.9%
(CFO Pre-W/C - Dividends) / Debt	10.7%	9.5%	9.6%	8.9%	8.8%
Debt / Book Capitalization	59.7%	60.0%	59.4%	63.8%	64.4%

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments. [2] LTM = last twelve months to June 30, 2011

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Low-risk vertically integrated hydro-electric utility

Supportive regulatory environment

Relatively weak financial metrics

Free cash flow deficits have moderated due to rate base and cash flow growth

Sufficient liquidity

Corporate Profile

Headquartered in Kelowna, British Columbia, FortisBC Inc. (FBC) is a vertically integrated regulated hydro-electric utility that operates primarily under a cost-of-service regulatory regime. FBC is an indirect, wholly-owned subsidiary of Fortis Inc. (FTS, not rated), a diversified electric and gas utility holding company based in St. John's, Newfoundland.

SUMMARY RATING RATIONALE

The Baa1 senior unsecured rating of FBC reflects the low-risk nature of the utility where over 95% of its operations are regulated and the few unregulated operations it does have are relatively low-risk. The rating also considers FBC's location in a supportive regulatory environment and the limited performance based regulatory regime under which FBC has operated that has allowed it to earn more than its allowed return on equity (ROE) in most years since 2003. These strengths are offset by financial metrics that remain weak relative to those of Baa1-rated peers notwithstanding that FBC's financial metrics have improved modestly in recent years. Over the past five years, FBC's total assets grew by more than 75% driven by utility capital investment. Cash flow from operations before working capital changes (CFO pre-WC) was almost $83 million in 2010 (roughly double the 2005 level) primarily due to rate base growth although a higher allowed ROE of 9.9% in 2010 also contributed. We expect FBC will have smaller free cash flow deficits going forward and less need for parental equity injections. FBC's liquidity resources are sufficient.

DETAILED RATING CONSIDERATIONS

REGULATED HYDRO-ELECTRIC UTILITY WITH LIMITED HYDROLOGY RISK

FBC's rating reflects the company's low business risk profile where over 95% of its operations are regulated and its unregulated operations are low-risk in nature. Moody's considers FBC's business risk to be lower than that of other cost-of-service regulated vertically integrated utilities. While vertically integrated utilities are often exposed to commodity price and volume risks in their generation segments (fuel purchase and electricity sales), a hydro-electric utility's greatest risk is hydrology. Actual water flows can vary significantly from those forecast with significant cash flow repercussions. However, FBC's hydrology risk is substantially mitigated by the Canal Plant Agreement (CPA), which runs until at least 2035. Under the CPA, FBC and others cede scheduling control of their generation facilities to British Columbia Hydro and Power Authority (BCH, Aaa) in exchange for power from BCH based on 50-year historical hydrology regardless of the actual hydrological conditions in any contract year. FBC's hydro-electric generation facilities provide about 45% of its annual energy requirement. FBC has power purchase agreements (PPAs) with BCH and Brilliant Power Corporation (BPC, A1, stable) which provide the bulk of the balance of FBC's requirements, representing approximately 18% and 27%, respectively, of its 2010 energy requirements. With the exception of BCH, FBC is the only integrated, regulated electric utility operating in the province of British Columbia.

FBC's largest unregulated asset is the Walden Power Plant, a 16 MW run-of-river hydro-electric project that sells power to BCH under a PPA expiring in 2013. FBC also generates a small amount of revenue by providing operations and management services to embedded utilities and hydro-electric generators.

SUPPORTIVE REGULATORY ENVIRONMENT

FBC's location in British Columbia which enjoys a relatively strong provincial economy (2010 GDP growth of ~4%) and continues to enjoy a supportive regulatory climate, contributes to our view of FBC as a lower risk utility. We consider Canada to have supportive regulatory and business environments relative to other jurisdictions globally. Furthermore, we consider the regulatory environment in British Columbia to be one of the more supportive in Canada reflecting the fact that regulatory proceedings tend to be less adversarial and decisions tend to be balanced with minimal regulatory lag.

FBC is regulated primarily on a cost-of-service basis although there have been limited performance based rate-making (PBR) provisions in place relative to operating and maintenance (O&M) expenses. To a degree, the regulatory regime mitigates FBC's exposure to forecast risk by allowing the company to forecast costs other than O&M in its annual revenue requirement application and then recover or refund variations between certain forecast and actual revenues and expenses. Under PBR, FBC has been able to achieve actual ROEs in excess of its allowed ROEs in every year except 2010 since 2003. In 2010, FBC fell just short of achieving its allowed ROE due primarily to unfavourable weather conditions in the first half of the year. FBC's revenue requirement application for 2012 and 2013, filed in June 2011, does not contemplate a continuation of the limited PBR arrangement.

FBC's largest expense item is purchased power; however, certainty of recovery of these costs is high because the majority of FBC's power purchases occur pursuant to the BPC and BCH PPAs, both of which have been approved by the BCUC. The costs incurred by FBC under these agreements are therefore, effectively a flow-through to ratepayers.

On a periodic basis, FBC submits a capital plan to the BCUC for review and approval. The capital plan's rate impacts are also reviewed during FBC's annual revenue requirement application process. This process of obtaining regulatory pre-approval of capital spending reduces the risk of being unable to fully recover capital investments that have already been incurred.

FINANCIAL METRICS REMAIN WEAK COMPARED TO Baa1-RATED PEERS

FBC's financial metrics have demonstrated modest improvement since the company was acquired by FTS in 2004. We expect FBC's financial metrics to remain relatively stable over the next few years with CFO pre-W/C to Debt in the range of 12% to 13% and Interest Coverage of approximately 3x. Achievement of these metrics is dependent upon, among other things, execution of BCUC-approved capital spending on budget and effective management of forecast risk.

Despite the modest improvement in FBC's metrics, the company's ratios remain weak relative to Baa1-rated peers. However, we believe that FBC's relatively weak financial profile is offset by the company's relatively low business risk and location in an above average supportive regulatory environment.

FBC's ratios are generally consistent with those of Baa3 electric utilities, and remain weaker than its Baa1-rated sister companies, FortisAlberta Inc. (FAB, a distribution utility) and Newfoundland Power Inc. (NPI, predominantly a T&D utility). For example, FAB and NPI have reported CFO pre-W/C to Debt of approximately 15%-20% while FBC's range has been in the low teens. The marked improvement in FBC's adjusted Debt / Book Capitalization to 59.4% at December 31, 2009 compared to 63.8% at December 31, 2008 reflects the change in Canadian accounting standards, effective January 2009, requiring regulated utilities to recognize future income tax assets and liabilities as well as related regulatory liabilities and assets. This has a ratio impact because deferred taxes are a component in the calculation of capitalization. Moody's notes that the improvement is due to a non-cash accounting change that does not alter FBC's fundamental credit profile although it does enhance the comparability of debt/capitalization metrics between Canadian and US-based peers. Given the relatively small 7.5% weighting of the debt to capitalization metric in the rating methodology, the accounting change does not materially impact the methodology-indicated rating.

CAPITAL EXPENDITURES MORE MANAGEABLE

To date, FBC has successfully managed a large capital expenditure program, and regular equity contributions from FTS have enabled it to maintain its capital structure close to its deemed 60/40 capital structure. FBC's capital program is driven by growth in portions of its service territory as well as the continued need to reinforce its system following a period of under-investment by the previous owner. Between 2005 and 2007, FBC's capex typically represented around 2x its CFO pre-W/C, resulting in relatively large free cash flow deficits. We expect capital investment to be in the range of $100 million to $125 million for the next few years but we expect the ratio of capital investment to CFO pre-WC to fall to roughly 1.1x to 1.2x. We expect that FBC will continue to generate negative free cash flow in the medium-term, but from 2011 onward we expect these deficits to be smaller than those of past years with the result that the need for parental equity injections could be eliminated as early as 2012.

As has been the case since FTS acquired FBC, we expect FBC's capital investments to require rate increases at levels above the rate of inflation. While it has not done so to date, this could eventually lead to ratepayer fatigue. That said, we believe that the risk of ratepayer fatigue is significantly mitigated by the BCUC's review and approval of FBC's periodic capital plans as well as its review of the rate impact of company's spending plans as part of the annual revenue requirement application process. Once the capital spending plans are approved by the BCUC, we believe that it is relatively unlikely that the BCUC would then fail to approve rate increases sufficient to support those capital expenditures. We also note that the increase in FBC's rates is consistent with trends across the Province. In fact, FBC's requested rate increases of 4% for 2012 and 6.9% for 2013 are lower than the 9.73% increase requested by BCH for its service territory in each of its fiscal years ending March 31, 2012, 2013 and 2014. Accordingly, we believe that the greatest risk related to FBC's capital expenditure plans is the company's ability to prudently manage its projects to avoid excessive cost overruns, the full recovery of which might not be permitted by the regulator.

Liquidity Profile

FBC's liquidity arrangements are satisfactory. We estimate that FBC will have negative free cash flow of approximately $40 million for the twelve month period ending June 30, 2012. The company does not have any material debt maturities during this period so it's funding requirement will be similarly sized. With undrawn committed credit facilities of approximately $140 million at June 30, 2011, FBC is able to withstand our standard liquidity stress scenario, which assumes that an issuer loses access to new capital, other than credit available under its committed credit facilities, for a period of 12 months. On this basis, FBC has an estimated buffer of approximately $100 million, not including projected equity contributions from FTS.

FBC maintains a committed syndicated credit agreement which comprises two separate facilities. Facility A is a $100 million three-year revolving facility with a May 7, 2014 maturity. Facility B is a $50 million 364-day revolving facility with a May 3, 2012 maturity. The three-year tranche will continue to be extendible annually for further one-year periods, subject to the agreement of the banks, while the 364-day tranche will continue to have an automatic 6-month term-out in the event that it is not extended. The credit facilities do not include features like a material adverse change clause that would limit access to funds during a period of financial stress. They are, however, subject to a covenant that requires FBC's debt to capitalization ratio not to exceed 75%. At June 30, 2011, FBC was in compliance with this covenant with debt to capitalization of roughly 60%.

Rating Outlook

The rating outlook is stable based on our expectation that FBC will continue to achieve rate increases necessary to support its capital spending program or, in the absence of such rate increases, that FBC will restrict the scope and scale of its capital program to ensure that its financial metrics are not materially weakened.

What Could Change the Rating - Up

FBC's rating could be positively impacted if FBC were to be able to demonstrate a sustainable improvement in financial ratios, such as CFO pre-W/C Interest Coverage of approximately of 4.0 times and CFO pre-W/C to Debt above 16%.

What Could Change the Rating - Down

A downgrade of FBC's rating would likely require a combination of a deterioration of FBC's regulatory framework or liquidity and financial profile, or an inability to earn its allowed return. This might include sustained weakening of FBC's metrics such as CFO pre-W/C Interest coverage of below 2.7x and CFO pre-W/C to Debt below 10%.

Rating Factors

FortisBC Inc

Regulated Electric and Gas Utilities Industry [1]	[2]**Current**		[3]**Moody's 12-18 month Forward View As of 08/30/2011**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		A		A
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position (10%)		Baa		Baa
b) Generation and Fuel Diversity (0%)		Aa		Aa
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	2.9x	Baa3	3.0x	Baa3
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	11.6%	Ba1	12%-13%	Ba1
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	9.4%	Baa3	9%-10%	Baa3
e) Debt/Capitalization (3 Year Avg) (7.5%)	60.9%	Ba2	58%-60%	Ba2
Rating:				
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		Baa1		

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments [2] Financial ratios reflect three year averages for 2008, 2009 and 2010, Source: Moody's Financial Metrics [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures

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Rating Report
Report Date:
October 6, 2011

Report Date:
October 26, 2010

Insight beyond the rating.

FortisBC Inc.

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The Company
FortisBC Inc. (FortisBC) is a vertically integrated utility company operating in south-central British Columbia (B.C.). Its generation assets include four hydroelectric generating plants (totalling 223 megawatts) on the Kootenay River in south-central B.C. and FortisBC provides electricity services to approximately 161,000 customers. FortisBC is ultimately a wholly owned subsidiary of Fortis Inc., a diversified, international utility holding company having investments in distribution, transmission and generation utilities, as well as in commercial real estate and hotel operations.

Recent Actions
November 19, 2010
Rates $100 million New Issue

Rating

Debt	Rating	Rating Action	Trend
Secured Debentures	A (low)	Confirmed	Stable
Unsecured Debentures	A (low)	Confirmed	Stable

Rating Rationale

DBRS has confirmed the ratings of FortisBC Inc.'s (FortisBC's or the Company's) Secured Debentures and Unsecured Debentures at A (low), with Stable trends. The rating confirmation reflects FortisBC's low business risk, stemming from the regulated nature of its operations and supportive regulatory environment; its integrated operations, which include a secure low-cost hydro-based power supply portfolio; its diversified customer base; its demonstrated ability to execute as planned; its stable credit metrics over the years despite the continued capital expenditure-driven free cash flow deficits; and its strong parental support from Fortis Inc. (Fortis, rated A (low), with a Stable trend); see separate DBRS rating report).

The regulatory environment remains stable and supportive, providing a strong cost-of-service/rate-of-return rate-setting methodology, with some performance-based rate (PBR)-setting attributes. The cost-of-service methodology allows for recovery of all forecast and prudently incurred power purchase costs, operating expenses and capital expenditures within a reasonable time frame.

In December 2010, FortisBC received approval by the British Columbia Utilities Commission (BCUC) for a 6.6% rate increase, effective January 1, 2011. The rate increase is inclusive of the 2011 Revenue Requirements negotiated settlement agreement and the 2011 Capital Expenditure Plan (CEP), as well as the 2011 allowed return on equity (ROE) of 9.90%. In addition, the BCUC also approved a refundable interim rate increase of 1.4% effective June 1, 2011, arising from an increase in 2011 power purchase expenses as a result of a refundable interim increase approved for British Columbia Hydro & Power Authority (BC Hydro, rated AA (high), with a Stable trend; see separate DBRS rating report dated June 6, 2011). (Continued on page 2.)

Rating Considerations

Strengths
(1) Supportive regulatory environment
(2) Low-cost, competitive hydroelectric generation base
(3) Secure, reasonably priced electricity supply contracts
(4) Diversified customer base

Challenges
(1) Large capital expenditure program
(2) Free cash flow deficits over the medium term
(3) Earnings and cash flow affected by lower ROEs

Financial Information

($ millions)	12 mos. Ending June 30, 2011	For the 12-month period ended Dec. 2010	Dec. 2009	Dec. 2008	Dec. 2007	Dec. 2006
EBIT	89.9	78.4	73.0	67.3	62.7	57.2
EBIT interest coverage	2.31	2.10	2.04	2.05	2.04	2.11
EBITDA interest coverage	3.41	3.21	3.06	3.09	3.04	3.09
% total debt in the capital structure	60.2%	60.7%	60.4%	60.4%	61.1%	60.9%
Cash flow/total debt	13.8%	12.3%	12.2%	11.4%	11.4%	11.2%
Cash flow/capital expenditures (times)	0.80	0.59	0.69	0.62	0.45	0.53
Free cash flow	(56.5)	(72.3)	(55.3)	(45.6)	(73.3)	(67.4)
Approved ROE	9.90%	9.90%	8.87%	9.02%	8.77%	9.20%

Rating Rationale (Continued from page 1.)

FortisBC filed its 2012–2013 Revenue Requirements Application, along with the Company's Integrated System Plan (ISP), with the BCUC in June 2011, which resulted in a request for an interim 4.0% rate increase for electricity customers effective January 1, 2012, and a 6.9% increase effective January 1, 2013. The two-year Revenue Requirements is based on a cost-of-service/rate-of-return rate-setting methodology. The filing included the 2012–2013 CEP, which outlines capital expenditures necessary to provide reliable service, ensure public and employee safety and deliver Demand-Side Management (DSM) programs to the Company's growing customer base.

The 2012–2013 CEP includes capital expenditures of $100.1 million and $123.2 million (net of customer contributions) and DSM expenditures of $5.8 million and $5.9 million for 2012 and 2013, respectively. The ISP includes the Company's Resource Plan, Long-Term Capital Plan and Long-Term DSM Plan.

FortisBC's ROE of 9.90% is a result of a positive 2009 decision that also determined that the automatic-adjustment mechanism that was used to determine the ROE on an annual basis would no longer apply and the ROE as determined would apply until changed by the BCUC. The Company's deemed capital structure remains unchanged at 60% debt/40% equity. DBRS believes that while the ROE is favourable, uncertainty remains as to when and how ROE levels will be adjusted in the future.

FortisBC continues to invest in its significant capital program, which will be the greatest challenge for the Company over the medium term. The Company's elevated capital expenditure program, which has been ongoing for several years and is expected to be between $450 million and $500 million over the next five years, is projected to cause continuing free cash flow deficits over the medium term. The primary focus of this large capital program is to provide reliable service to a growing customer base and to ensure public and employee safety. The resulting free cash flow deficits will continue to be funded with a combination of incremental debt financing and equity support from the parent, Fortis, to maintain its current credit profile and capital structure at the regulatory-approved levels. Fortis is a large, integrated utility holding company that has the financial wherewithal to provide equity support as required in this context.

DBRS expects the key credit ratios to remain stable over the next few years before showing modest improvement as capital expenditures level off. Despite the continuing free cash flow deficits over the near to medium term, DBRS expects the Company's financial profile and credit metrics to remain adequate for the rating. With its $160 million in bank credit facilities (including a $10 million demand overdraft facility), FortisBC's liquidity is considered sufficient to meet any short-term funding requirements.

Rating Considerations Details

Strengths

(1) FortisBC operates in a stable, supportive regulatory environment that allows it to recover its cost of service and earn a return on its investments. The Company has operated under a PBR mechanism, in one capacity or another, since 1996, providing it with incentives for achieving productivity improvements. FortisBC's 2012–2013 Revenue Requirements application, filed in June 2011, is based on a cost-of-service/rate-of-return rate-setting methodology and does not include a continuation of the PBR mechanism.

(2) FortisBC owns and operates four low-cost hydroelectric generating plants on the Kootenay River system, with a total generating capacity of 223 megawatts (MW), which provide about 45% of FortisBC's energy needs and 30% of its capacity needs. The Company is insulated from hydrology risk as a result of the Canal Plant Agreement (CPA) among BC Hydro, FortisBC and other parties, in which BC Hydro takes all of the power actually generated by the plants and is contractually obligated to deliver a fixed amount of power to the Company, which is currently based on 50-year historical water flows. This provides stability to a significant portion of the Company's earnings and cash flows, removing from this portfolio the water-flow risk that is experienced by other hydro-based utilities. Furthermore, FortisBC retains its right to the original water licences and flows in perpetuity.

(3) FortisBC also benefits from having secure, reasonably priced electricity supply contracts, including (a) a long-term take-or-pay contract with Brilliant Power Corporation (Brilliant, rated A (high), with a Stable trend; see separate DBRS rating report dated November 9, 2010). The contract runs until 2056 and supplies on average since 2007 low-cost power representing 27% of the Company's energy needs, and (b) a power purchase contract with BC Hydro. This contract has flexible volumes (based on rolling five-year nominations of capacity requirements) and expires in 2013. The parties are currently in the process of negotiating a renewal of the contract. On average since 2007, approximately 95% of FortisBC's energy requirements were met through the combination of owned generation and these supply sources. The balance of supply was met through small power purchase contracts and spot market purchases.

Prudently forecast and incurred costs related to these small power purchase contracts and spot market purchases (averaging approximately 5% of the Company's energy load requirements since 2007) are passed on to customers as well. The Company has made various types of advance purchases, including capacity purchases and fixed-price energy purchases, to help mitigate the risks of market volatility and availability on its spot market purchases.

(4) The Company has a diverse customer base in a growth-oriented franchise area, which provides a degree of stability to revenues and earnings. For 2010, electricity sales to stable residential customers accounted for about 40% of total sales volume, while 23% of sales were to commercial customers and 29% to wholesale customers (which, in turn, sell primarily to residential and commercial customers). Only 8% of sales were to low-margin, economically sensitive industrial customers. FortisBC's level of diversification and low reliance on economically sensitive customers helps mitigate the potential negative impact of an economic downturn.

Challenges

(1) FortisBC's financial profile continues to be affected by free cash flow deficits from its ongoing large capital expenditure program; however, credit metrics remain acceptable for the current rating. The Company's capital expenditure program has been ongoing for several years and is expected to be approximately $450 million to $500 million (net of customer contributions) over the next five years. Internal cash flow generation (net of dividends) will continue to fund the majority of capital expenditures for the next few years. The remainder will be financed with a combination of incremental debt and equity support from Fortis, with the target of maintaining a capital structure at the regulatory-approved 60% debt/40% equity level. The Company will need to seek some external debt financing during this stage of capital growth, which will likely keep key coverage ratios restrained during this period. Fortis is expected to provide equity support in order to maintain the Company's regulatory-approved capital structure.

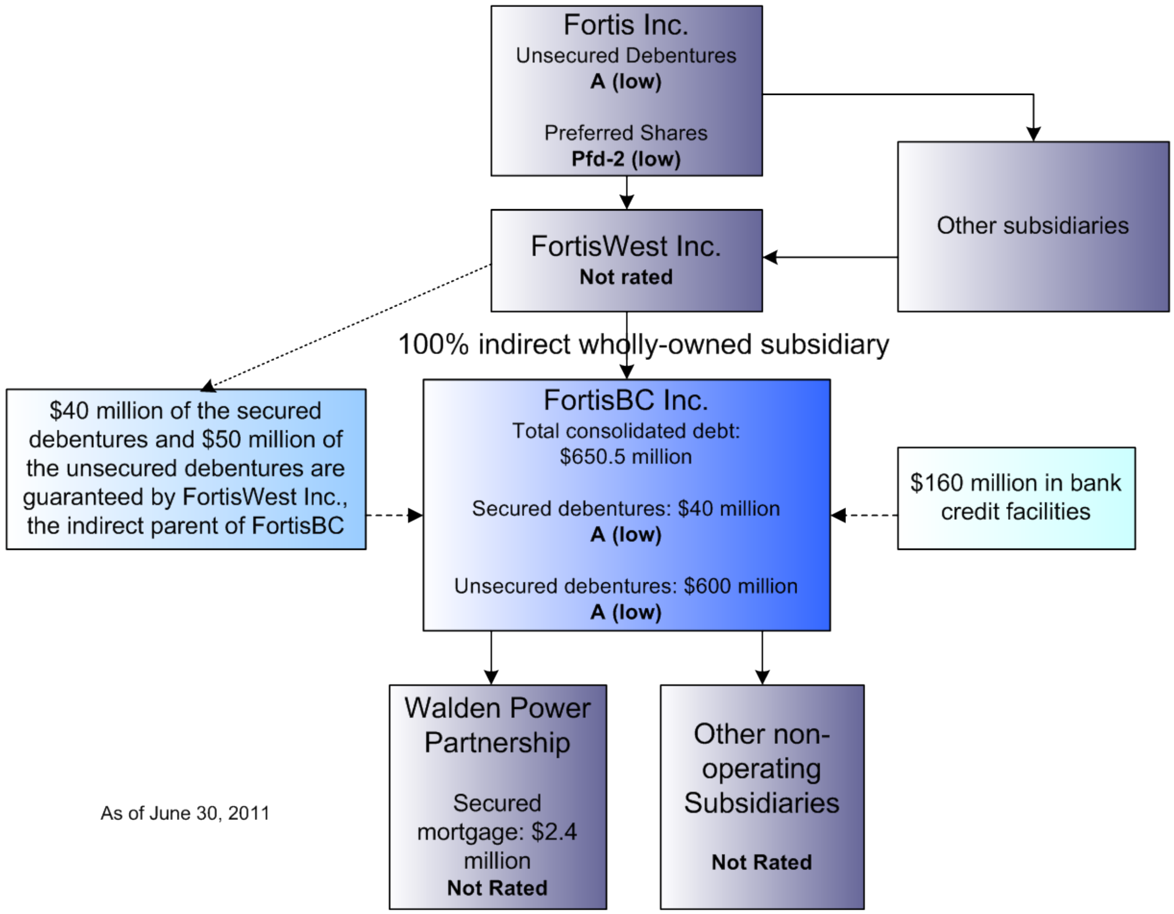
(2) The Company faces execution risk with respect to its large capital expenditure program over the next five years. The focus of the capital program will be on providing reliable service to a growing customer base, ensuring public and employee safety and completing projects on budget.

(3) The BCUC terminated the automatic-adjustment ROE formula and set FortisBC's approved level at 9.90% (effective January 1, 2010), after having been in the low 9% range and below since 2007. While FortisBC's ROE is now set at a benchmark level plus 40 basis points (bps), the absolute increase in the benchmark level (i.e., FortisBC Energy Inc.'s (FEI's) ROE, which rose to 9.50%) drove the increase in FortisBC's ROE to the 9.90% level. With the use of the automatic-adjustment formula having been terminated, there is uncertainty as to how ROE levels will be determined in the medium and longer term.

FortisBC Inc.

Report Date:
October 6, 2011

Simplified Ownership/Debt Chart



FortisBC Inc.

Report Date:
October 6, 2011

Earnings and Outlook

($ millions)	12 mos. Ending June 30, 2011	For the 12-month period ended Dec. 2010	Dec. 2009	Dec. 2008	Dec. 2007
Revenues	272.4	256.9	244.1	229.2	219.7
EBITDA	133.3	120.1	110.1	101.5	93.8
EBIT	89.9	78.4	73.0	67.3	62.7
Gross interest expense	38.4	36.8	35.4	32.4	30.4
Core net income	47.7	41.8	36.2	32.7	30.1
Net income (reported)	47.7	41.8	36.2	32.7	30.1
Return on average common equity	10.8%	10.5%	9.5%	9.4%	9.6%
Approved Rate Base	1,093.2	975.1	908.0	822.8	747.2
Growth in Rate Base	12.1%	7.4%	10.4%	10.1%	10.5%
Deemed common equity	40.0%	40.0%	40.0%	40.0%	40.0%
Approved ROE	9.90%	9.90%	8.87%	9.02%	8.77%

Summary

FortisBC has witnessed a continual improvement in EBITDA and EBIT, which can be primarily attributed to the Company's increasing rate base, higher ROEs and the terms of the PBR agreement.

More than 95% of FortisBC's operations are regulated, providing strong stability to earnings and cash flow. Earnings stability is further bolstered by the favourable customer mix, with residential and commercial customers providing the bulk of the Company's revenues. Electricity revenues increased for the 12 months ending June 30, 2011, as a direct result of rate increases approved by the BCUC, driven primarily by ongoing investment in infrastructure and higher cost of capital.

The increase in interest expense for the 12 months ending June 30, 2011, and year ending 2010 is primarily due to increased borrowings sourced to finance the capital expenditure program. Nevertheless, coverage ratios remain fairly stable as a result of the earnings growth.

The impact of power price volatility on earnings is limited as power procurement-related costs are passed on to customers. Costs stemming from owned generation and the long-term power purchase agreements (PPAs) that supply, on average since 2007, approximately 95% of FortisBC's power load requirements are automatically passed on to customers. The remaining 5% has been procured through spot market purchases and small independent power purchase contracts. Prudently forecast and incurred costs related to these spot market purchases are passed on to customers as well. The Company has made various types of advance market purchases, including capacity purchases and fixed-price energy purchases, to help mitigate the risks of market volatility and availability on its spot market purchases.

Outlook

Going forward, FortisBC should benefit from a recovery of economic activity and overall consumption. DBRS continues to believe that the current 9.90% ROE and the growth in rate base related to the ongoing capital projects will have a positive impact on earnings going forward. The investment in capital assets is necessary to provide reliable service to a growing customer base and to ensure public and employee safety.

DBRS expects EBIT and net income to continue to grow over the medium term due to growth in rate base and the continuation of the 9.90% ROE.

FortisBC Inc.

Report Date:
October 6, 2011

Financial Profile

($ millions)	12 mos. Ending	For the 12-month period ended			
Cash Flow Statement	June 30, 2011	Dec. 2010	Dec. 2009	Dec. 2008	Dec. 2007
Core net income	47.7	41.8	36.2	32.7	30.1
Depreciation and amortization	43.8	42.0	37.5	34.2	31.1
Other non-cash adjustments	5.5	0.7	2.0	(1.8)	(0.1)
Cash Flow From Operations	97.0	84.5	75.7	65.1	61.0
Common dividends	(16.0)	(15.0)	(14.5)	(13.4)	(11.8)
Capital expenditures	(120.5)	(142.8)	(110.2)	(105.3)	(134.2)
Free Cash Flow Before W/C Changes	(39.5)	(73.3)	(49.0)	(53.6)	(85.0)
Net changes in working capital	(17.0)	1.1	(6.3)	8.1	11.7
Net Free Cash Flow	(56.5)	(72.3)	(55.3)	(45.6)	(73.3)
Other investing activities	(6.9)	(4.9)	(2.8)	(2.2)	(0.1)
Other adjustments	(5.6)	6.0	(0.6)	0.3	(0.6)
Amount to be Financed	(68.9)	(71.2)	(58.7)	(47.4)	(74.0)
Net debt financing	59.5	62.1	49.7	32.5	60.2
Net equity financing	10.0	10.0	10.0	15.0	15.0
Other financing	(0.9)	(0.9)	(1.0)	(0.0)	(1.2)
Net Change in Cash	(0.3)	(0.0)	(0.0)	0.0	(0.0)
% debt in capital structure	60.2%	60.7%	60.4%	60.4%	61.1%
EBIT interest coverage (times)	2.31	2.10	2.04	2.05	2.04
Cash flow/total debt	13.8%	12.3%	12.2%	11.4%	11.4%
Total debt to EBITDA (times)	5.27	5.71	5.64	5.60	5.69
Dividend payout ratio	33.5%	35.9%	40.0%	41.0%	39.3%

Summary

Cash flow from operations has witnessed an increase over time as a result of higher net income, which can be attributed to increased revenues as the Company added capital assets to its rate base. Depreciation and amortization rates have increased over the years and particularly during 2010, largely the result of changes to a growing depreciable asset base as capital assets were added to rate base.

DBRS notes that although FortisBC maintains strong and increasing cash flow from operations, elevated capital expenditure levels continue to cause free cash flow deficits, which are financed with a combination of incremental debt and equity support from Fortis, with the target of maintaining capital structure at the regulatory-approved 60% debt/40% equity.

FortisBC has witnessed an overall improvement in credit metrics in 2010 and during the last 12 months (LTM) ending June 30, 2011. DBRS believes that the Company will continue to maintain a reasonable financial profile, reflecting an improving balance sheet and credit metrics for the rating.

Outlook

Free cash flow deficits are expected to persist as a result of the ongoing capital expenditure program. However, improving revenues and net income as a result of these capital expenditures increasing the rate base should continue to lead to an increase in cash flow, which will cause a modest decline in cash flow deficits. Annual capital expenditures are expected to remain high, with approximately $450 million to $500 million in projects planned over the next five years. DBRS expects cash flow deficits will be financed with incremental debt and equity support from Fortis. DBRS expects cash flow from operations to be largely adequate to fund future capital expenditures. Therefore, despite the free cash flow deficits, DBRS expects the Company's financial profile and credit metrics to remain adequate for the rating. Key credit ratios are expected to be flat to modestly improving during this elevated capital program period as increased debt levels are offset by higher earnings on a growing rate base.

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Long-Term Debt Maturities and Liquidity

Debt Chart ($millions)

		June 30/11
Secured Debentures		
Guaranteed by FortisWest Inc.		
Oct. '12	9.65%	15.0
Aug. '23	8.80%	25.0
WPP Mortgage		
Oct. '13	9.44%	2.4
		42.4
Unsecured Debentures		
Guaranteed by FortisWest Inc.		
Feb. '16	8.77%	25.0
Dec. '21	7.81%	25.0
No Guarantee		
Nov. '14	5.48%	140.0
Nov. '35	5.60%	100.0
July '47	5.90%	105.0
MTN June '39	6.10%	105.0
MTN Nov '50	5.00%	100.0
		600.0
Bank Credit Facilities		
Operating credit facilties		7.0
Overdraft facility		1.1
		8.1
Total Debt		650.5
Less current portion		2.1
Long-Term Debt		648.4

as at June 30, 2011

Maturity Schedule ($MM)	2011	2012	2013	2014	2015	Thereafter	Total
Debt maturities	2.1	15.9	7.5	140.0	0.0	485.0	650.5

FortisBC had $650.5 million of total consolidated debt outstanding at June 30, 2011, including $600 million of unsecured debentures, $42.4 million of secured debt (including the Walden Power Partnership (WPP) mortgage) and $8.1 million of bank credit facilities (including the $1.1 million in overdrafts).

The secured debt is expected to continue to account for a decreasing percentage of overall debt as the Company funds itself with unsecured debentures. The secured debentures (Series F and Series G), totaling $40 million, and the unsecured debentures (Series H and Series I), totaling $50 million, are guaranteed by FortisWest Inc. (FW). FW is a direct wholly owned subsidiary of Fortis, whose assets consist of shares in FortisBC and FortisAlberta Inc. This debt was outstanding when Fortis purchased the Company.

The debt profile as of June 30, 2011, is as follows:

- $40 million in secured debentures, Series F and Series G, guaranteed by FW and collateralized by a fixed and floating first charge on the assets of the Company. These debentures mature in 2012 and 2023, respectively

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- $50 million in unsecured debentures, Series H and Series I, also guaranteed by FW and maturing in 2016 and 2021, respectively.
- An additional $345 million of unsecured debentures, issued in three series that mature from 2014 to 2047.
- $205 million in unsecured medium-term note debentures, Series 1 and Series 2, that mature in June 2039 and November 2050, respectively.
- A $2.4 million mortgage on the Walden power plant in British Columbia, owned and operated by WPP, which is secured by a pledge by FortisBC of its interest in WPP. The mortgage matures October 31, 2013, and bears interest at 9.44%.

FortisBC's bank credit facilities amended in April 2011 and consist of the following:
- A $100 million three-year revolving unsecured operating credit facility, maturing May 7, 2014.
- An additional $50 million 364-day revolving unsecured operating credit facility, maturing on May 3, 2012. This facility may be extended for another 364 days or, if not extended, termed out for a six-month period.
- A $10 million demand overdraft facility.

As of June 30, 2011, $7.0 million was utilized against the $150 million operating credit facilities (December 31, 2010 – zero) and $1.1 million was drawn on the overdraft facility.

Certain of the Company's debt covenants contain restrictions on the payment of dividends if consolidated debt exceeds 70% of consolidated capitalization, if the dividends are not in the ordinary course of business or if the cumulative dividends paid since the date that certain debt instruments were issued exceed thresholds based on the cumulative net earnings of the Company.

Outlook
FortisBC's $160 million in bank credit facilities (including $10 million in demand overdraft facilities) should provide sufficient liquidity to meet any short-term funding requirements. As at June 30, 2011, $151.9 million was available under the bank credit facilities. The debt repayment schedule is modest; however, the Company has $140 million due in 2014. DBRS expects FortisBC to refinance its maturing debt given its stable credit profile and cash flows generated from its low-risk operations. Furthermore, DBRS expects additional debt issuance over the medium term to fund the Company's ongoing capital expenditure program.

Description of Operations

FortisBC is a vertically integrated utility operating in south-central British Columbia. The Company serves approximately 161,000 direct and indirect customers, including wholesale customers such as the cities of Kelowna and Nelson.

Approximately 63% of its power is sold to relatively stable residential and commercial customers, 8% to industrial customers and 29% to wholesale customers, which resell the power to their own residential and commercial customers. FortisBC meets its customers' power requirements through the following sources:
- Four owned hydroelectric plants, with 223 MW of capacity, representing approximately 45% of its energy needs. Electricity production from these plants is insulated from hydrology risk as a result of the CPA among BC Hydro, FortisBC and other parties, originally signed in August 1972 and amended in July 2005. Pursuant to the CPA, BC Hydro takes all of the power actually generated by the Company's four plants and delivers a fixed amount of power, currently based on 50-year historical water flows. Since 1998, the Company's hydroelectric facilities have been subject to a life extension and upgrade program, which is expected to conclude in 2012.
- The power purchase contract with the Brilliant hydroelectric plant, which expires in 2056, supplies on average since 2007, approximately 27% of the Company's energy needs. The contract includes a market-related price adjustment in 2026. In addition to purchasing the power, FortisBC operates and maintains the plant on behalf of Brilliant.
- The long-term, firm power purchase contract with BC Hydro, expiring in 2013, which provided, on average since 2007, 23% of the Company's energy needs.

- A number of small purchase power contracts with independent power producers collectively provide approximately 1% of the Company's energy requirements.
- Any electricity requirements not met by the above sources are satisfied through the spot market.

FortisBC also has a limited amount of non-regulated operations, principally made up of WPP, the owner of an independent power producer. The plant is a 16 MW hydroelectric station that sells all of its output to BC Hydro pursuant to a PPA that expires in 2013. The debt of the Partnership is non-recourse to FortisBC.

Regulation

FortisBC is regulated by the BCUC, which is authorized to set electricity rates, the deemed capital structure and the allowed rate of return on deemed common equity, as well as approve and oversee the construction of new projects. For the period of 2006 through 2011, rates were based on a cost-of-service/rate-of-return methodology, with some PBR-setting attributes as described below. FortisBC's 2012–2013 Revenue Requirements application, filed in June 2011, is based on a cost-of-service/rate-of-return rate-setting methodology and does not include a continuation of the PBR mechanism.

The significant terms of the PBR agreement negotiated in 2006 are as follows:
- Annual gross operating and maintenance expenses before capitalized overhead will be set by a formula incorporating customer growth and inflation (i.e., the consumer price index (CPI) for British Columbia) minus a productivity improvement factor (PIF) of 2% in 2007, 2% in 2008 and if applicable, 3% in 2009.
- Annual capitalized overhead will be set at 20% of the BCUC-approved gross operating and maintenance expense.
- Other components of revenue requirements will be forecast annually.
- A 2% collar has been set around the allowed ROE whereby variances (adjusted for certain revenue and cost variances that flow through to customers) as a result of actual financial performance, positive or negative, will be shared equally among customers and shareholders. If the variance exceeds the 2% collar, the excess will be placed in a deferral account for review and disposition during the next rate-setting process. The Company's portion of the incentive is subject to the Company meeting certain performance standards and BCUC approval.

The ROE for FortisBC was set at 9.90% in 2010 and remains unchanged in 2011.

As part of the approval of 2009 Revenue Requirements in December 2008, the PBR agreement was extended for 2009 to 2011. The terms of the settlement are consistent with the May 2006 PBR agreement except that annual gross operating and maintenance expenses before capitalized overhead will be set by formulae incorporating customer growth and inflation (i.e., CPI for British Columbia) minus a PIF of 3% in 2009, 1.5% in 2010 and 1.5% in 2011. Should inflation be in excess of 3%, the excess is added to the PIF, which effectively caps the CPI at 3%.

In December 2010, FortisBC received approval by the BCUC for a 6.6% rate increase effective January 1, 2011. The rate increase is inclusive of the 2011 Revenue Requirements negotiated settlement agreement and 2011 CEP, as well as the 2011 allowed ROE of 9.90%. In addition, the BCUC also approved a refundable interim rate increase of 1.4%, effective June 1, 2011, arising from an increase in 2011 power purchase expense following a refundable interim increase approved for BC Hydro.

FortisBC filed its 2012–2013 Revenue Requirements application, along with the Company's ISP, with the BCUC in June 2011, which resulted in a request for an interim 4.0% rate increase for electricity customers effective January 1, 2012, and a 6.9% increase effective January 1, 2013. The two-year Revenue Requirements is based on a cost-of-service/rate-of-return rate-setting methodology. The filing included the 2012–2013 CEP, which outlines capital expenditures necessary to provide reliable service, ensure public and employee safety and deliver DSM programs to the Company's growing customer base.

The 2012–2013 CEP includes capital expenditures of $100.1 million and $123.2 million (net of customer contributions) and DSM expenditures of $5.8 million and $5.9 million for 2012 and 2013, respectively. The ISP includes the Company's Resource Plan, Long-Term Capital Plan and Long-Term DSM Plan.

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FortisBC's ROE of 9.90% is the result of a positive 2009 decision that also determined that the automatic-adjustment mechanism that was used to determine the ROE on an annual basis would no longer apply and the ROE as determined would apply until changed by the BCUC. The Company's deemed capital structure remains unchanged at 60% debt/40% equity. DBRS believes that while the ROE is favourable, uncertainty remains as to when and how ROE levels will be adjusted in the future.

As at December 31, 2010, FortisBC had total assets of $1,271.4 million and approved rate-base assets of $975.1 million. Approved rate-base assets in the 2011 Revenue Requirements application are $1,093.2 million.

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Balance Sheet ($ millions)	12 mos. Ending June 30, 2011	As at Dec. 2010	Dec. 2009
Assets			
Cash + equivalents	0.0	0.0	0.0
Accounts receivable/unbilled revenue	37.4	45.8	41.1
Inventories	0.6	0.5	0.5
Other	10.8	3.0	3.5
Current Assets	48.9	49.3	45.1
Net fixed assets	1073.8	1049.0	944.7
Deferred charges/Goodwill	175.7	173.2	157.4
Total	1298.4	1271.4	1147.2

Liabilities & Equity	12 mos. Ending June 30, 2011	As at Dec. 2010	Dec. 2009
Short-term debt	0.0	0.0	0.0
Debt due one yr.	11.8	2.0	3.7
A/P + accr'ds	46.6	60.5	49.3
Current Liabilities	58.4	62.5	53.0
Long-term debt	600.2	593.0	528.6
Secured debt	42.4	42.9	43.7
Capital lease obligations	32.2	31.9	28.9
Other l.t. liabilities	112.1	107.5	96.0
Shareholders' equity	453.1	433.7	396.9
Total	1298.4	1271.4	1147.2

Ratio Analysis	12 mos. Ending	For the 12-month period ended			
Liquidity Ratios	June 30, 2011	Dec. 2010	Dec. 2009	Dec. 2008	Dec. 2007
Current ratio	0.84	0.79	0.85	0.35	0.84
Accumulated depreciation/gross fixed assets	20.6%	20.6%	21.4%	22.1%	22.0%
Cash flow/adjusted debt (1)	13.8%	12.3%	12.2%	11.4%	11.4%
Cash flow/capital expenditures	0.80	0.59	0.69	0.62	0.45
Cash flow-dividends/capital expenditures	0.67	0.49	0.56	0.49	0.37
% debt in capital structure	60.2%	60.7%	60.4%	60.4%	61.1%
% adjusted debt in capital structure (1)	60.8%	61.2%	61.0%	60.9%	61.7%
Deemed common equity	40.0%	40.0%	40.0%	40.0%	40.0%
Coverage Ratios (1)					
EBIT interest coverage	2.31	2.10	2.04	2.05	2.04
EBITDA interest coverage	3.41	3.21	3.06	3.09	3.04
Fixed-charges coverage	2.31	2.10	2.04	2.05	2.04
Adjusted debt/EBITDA	5.27	5.71	5.64	5.60	5.69
Earnings Quality/Operating Efficiency					
Power purchases/revenues	26.9%	28.4%	29.3%	29.7%	31.0%
EBIT margin	33.0%	30.5%	29.9%	29.4%	28.5%
Net margin (before extras)	17.5%	16.3%	14.8%	14.2%	13.7%
Return on avg. common equity (before extras)	10.8%	10.5%	9.5%	9.4%	9.6%
Allowed ROE – mid-point	9.90%	9.90%	8.87%	9.02%	8.77%
Direct customers/employee	211	210	205	201	202
Growth of customer base	0.8%	1.3%	1.1%	2.3%	1.2%
Rate base ($ millions)	1,093.2	975.1	908.0	822.8	747.2
Growth in rate base	12.1%	7.4%	10.4%	10.1%	10.5%

(1) Adjusted for operating leases.

SUMMARY OF OPERATING STATISTICS

	12 mos. Ending	For the 12-mo For the 12-month period ended				
Generation	June 30, 2011	Dec. 2010	Dec. 2009	Dec. 2008	Dec. 2007	Dec. 2006
Hydro capacity (MW)	223	223	222	223	223	235
Gross energy generated (GWh)	1,544	1,530	1,586	1,610	1,498	1,509
Plus: purchases	1,880	1,796	1,893	1,790	1,912	1,896
Energy generated + purchased	3,424	3,326	3,479	3,400	3,410	3,405
Less: transmission losses + internal use	281	280	322	313	320	365
Total GWh sold	3,143	3,046	3,157	3,087	3,090	3,040

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Rating

Debt	Rating	Rating Action	Trend
Secured Debentures	A (low)	Confirmed	Stable
Unsecured Debentures	A (low)	Confirmed	Stable

Rating History

	Current	2010	2009	2008	2007	2006
Secured Debentures	A (low)	A (low)	BBB (high)	BBB (high)	BBB (high)	BBB (high)
Unsecured Debentures	A (low)	A (low)	BBB (high)	BBB (high)	BBB (high)	BBB (high)

Related Research

- DBRS Rates FortisBC Issue of $100 Million 5.00% Medium-Term Notes, Series 2, at A (low), November 19, 2010.

Note:
All figures are in Canadian dollars unless otherwise noted.

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MARKET CALL

- Markets are half way to pricing in a North American recession, but whether we have one or not is in the hands of governments in Europe and the US. At this point, we are giving both the benefit of the doubt, expecting Europe to keep Greece afloat and/or provide a capital cushion to banks, and looking for the US to approve at least the tax components of Obama's stimulus bill. If so, bond yields will drift higher over the forecast horizon as the recession threat recedes.

- Two weeks ago, in our *Monthly FX Outlook*, we pushed back the timing for even a token rate hike by the Bank of Canada by two quarters, and trimmed both Canadian and US interest rate targets. We are now further nudging our forecast for yields in the longer end of the Treasuries curve a bit lower. While we had anticipated an "operation twist" announcement, the scale of the term extension effort was larger than expected.

- The C$ hit and went through our December end target for a sell-off on softer commodity prices, and could again explore weaker levels in the weeks ahead while the fate of the global economy is still up in the air. In the absence of a global recession, it should ultimately turn stronger, but our call on the loonie, like the rest of the forecast, is subject to political risks to global growth.

INTEREST & FOREIGN EXCHANGE RATES

		2011		2012			
END OF PERIOD:		**27-Sep**	**Dec**	**Mar**	**Jun**	**Sep**	**Dec**
CDA	Overnight target rate	1.00	1.00	1.00	1.00	1.25	1.50
	98-Day Treasury Bills	0.86	0.95	1.00	1.20	1.35	1.40
	2-Year Gov't Bond	0.94	0.95	1.05	1.40	1.80	1.90
	10-Year Gov't Bond	2.19	2.30	2.35	2.60	2.80	2.95
	30-Year Gov't Bond	2.83	2.90	3.00	3.05	3.10	3.15
U.S.	Federal Funds Rate	0.08	0.10	0.10	0.10	0.10	0.10
	91-Day Treasury Bills	0.01	0.05	0.10	0.10	0.10	0.20
	2-Year Gov't Note	0.24	0.30	0.40	0.40	0.40	0.40
	10-Year Gov't Note	1.97	2.05	2.10	2.25	2.45	2.60
	30-Year Gov't Bond	3.07	3.10	3.20	3.25	3.35	3.40
Canada - US T-Bill Spread		0.85	0.90	0.90	1.10	1.25	1.20
Canada - US 10-Year Bond Spread		0.22	0.25	0.25	0.35	0.35	0.35
Canada Yield Curve (30-Year — 2-Year)		1.89	1.95	1.95	1.65	1.30	1.25
US Yield Curve (30-Year — 2-Year)		2.84	2.80	2.80	2.85	2.95	3.00
EXCHANGE RATES	CADUSD	0.98	0.98	1.01	1.05	1.06	1.04
	USDCAD	1.02	1.02	0.99	0.95	0.94	0.96
	USDJPY	77	78	77	77	75	74
	EURUSD	1.36	1.35	1.34	1.35	1.36	1.38
	GBPUSD	1.56	1.56	1.57	1.59	1.61	1.64
	AUDUSD	0.99	0.97	0.96	1.01	1.02	1.01
	USDCHF	0.90	0.89	0.90	0.90	0.91	0.91
	USDBRL	1.81	1.82	1.75	1.70	1.65	1.60
	USDMXN	13.37	13.50	13.40	13.00	12.70	12.50

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FINANCIAL MARKET FORECASTS

October 2011

Interest rates (%, end of quarter)

	10Q3	10Q4	11Q1	11Q2	11Q3	Forecast 11Q4	Forecast 12Q1	Forecast 12Q2	Forecast 12Q3	Forecast 12Q4	2009	2010	Forecast 2011	Forecast 2012
Canada														
Overnight	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.50	0.25	1.00	1.00	1.50
Three-month	0.88	0.97	1.10	0.90	0.80	1.10	1.15	1.15	1.30	1.60	0.19	0.97	1.10	1.60
Two-year	1.40	1.71	1.85	1.42	0.88	1.00	1.20	1.25	1.50	1.75	1.47	1.71	1.00	1.75
Five-year	2.04	2.46	2.65	2.06	1.39	1.50	1.90	2.10	2.30	2.50	2.77	2.46	1.50	2.50
10-year	2.75	3.16	3.25	2.91	2.15	2.30	2.60	2.65	2.75	2.90	3.61	3.16	2.30	2.90
30-year	3.34	3.55	3.80	3.42	2.77	3.10	3.35	3.40	3.35	3.45	4.07	3.55	3.10	3.45
Yield curve (10s-2s)	135	145	140	149	127	130	140	140	125	115	214	145	130	115
United States														
Fed funds	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0.13	0.13	0.13	0.13	0.13	0 to 0.25	0 to 0.25	0.13	0.13
Three-month	0.16	0.12	0.15	0.03	0.02	0.05	0.10	0.10	0.10	0.10	0.06	0.12	0.05	0.10
Two-year	0.44	0.61	0.70	0.41	0.25	0.30	0.30	0.35	0.50	0.60	1.14	0.61	0.30	0.60
Five-year	1.27	2.01	2.10	1.45	0.96	1.10	1.30	1.60	1.75	1.80	2.69	2.01	1.10	1.80
10-year	2.48	3.30	3.45	2.92	1.92	2.15	2.25	2.40	2.50	2.85	3.85	3.30	2.15	2.85
30-year	3.67	4.34	4.50	4.27	2.92	3.20	3.45	3.50	3.55	3.75	4.63	4.34	3.20	3.75
Yield curve (10s-2s)	204	269	275	251	167	185	195	205	200	225	271	269	185	225
Yield spreads														
Three-month T-bills	0.72	0.85	0.95	0.87	0.78	1.05	1.05	1.05	1.20	1.50	0.13	0.85	1.05	1.50
Two-year	0.96	1.10	1.15	1.01	0.63	0.70	0.90	0.90	1.00	1.15	0.33	1.10	0.70	1.15
Five-year	0.77	0.45	0.55	0.61	0.43	0.40	0.60	0.50	0.55	0.70	0.08	0.45	0.40	0.70
10-year	0.27	-0.14	-0.20	-0.01	0.23	0.15	0.35	0.25	0.25	0.05	-0.24	-0.14	0.15	0.05
30-year	-0.33	-0.79	-0.70	-0.85	-0.15	-0.10	-0.10	-0.10	-0.20	-0.30	-0.56	-0.79	-0.10	-0.30

Exchange rates (%, end of quarter)

	10Q3	10Q4	11Q1	11Q2	11Q3	Forecast 11Q4	Forecast 12Q1	Forecast 12Q2	Forecast 12Q3	Forecast 12Q4	2009	2010	Forecast 2011	Forecast 2012
Australian dollar	0.97	1.02	1.03	1.07	0.97	1.00	1.03	1.03	1.02	1.01	0.69	1.02	1.00	1.01
Brazilian real	1.69	1.66	1.63	1.56	1.88	1.80	1.80	1.83	1.85	1.85	2.32	1.66	1.80	1.85
Canadian dollar	1.03	1.00	0.97	0.96	1.05	1.04	1.03	1.02	1.01	1.00	1.26	1.00	1.04	1.00
Renmibi	6.69	6.59	6.55	6.46	6.38	6.25	6.15	6.05	5.95	5.85	6.83	6.59	6.25	5.85
Euro	1.36	1.34	1.42	1.45	1.34	1.31	1.30	1.29	1.28	1.27	1.33	1.34	1.31	1.27
Yen	84	81	83	81	77	74	73	70	73	75	99	81	74	75
Mexican peso	12.59	12.36	11.91	11.71	13.90	13.00	12.75	12.50	12.50	12.50	14.17	12.36	13.00	12.50
New Zealand dollar	0.73	0.78	0.76	0.83	0.76	0.78	0.78	0.79	0.77	0.77	0.56	0.78	0.78	0.77
Swiss franc	0.98	0.93	0.92	0.84	0.91	0.93	0.94	0.95	0.97	0.98	1.14	0.93	0.93	0.98
U.K. pound sterling	1.57	1.56	1.60	1.61	1.56	1.54	1.55	1.55	1.56	1.59	1.43	1.56	1.54	1.59

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Global Forecast Update

Financial Markets	10Q4	11Q1	11Q2	11Q3f	11Q4f	12Q1f	12Q2f	12Q3f	12Q4f
					(%, end of period)				
Canada									
BoC Overnight Target Rate	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.75
3-month T-bill	1.05	0.96	0.90	0.82	0.85	0.95	1.10	1.35	1.95
2-year Canada	1.68	1.83	1.59	0.89	1.00	1.10	1.30	1.80	2.15
5-year Canada	2.42	2.78	2.33	1.40	1.50	1.70	1.85	2.30	2.60
10-year Canada	3.12	3.35	3.11	2.16	2.10	2.20	2.45	2.65	2.90
30-year Canada	3.53	3.76	3.55	2.77	2.70	2.75	3.00	3.20	3.40
Real GDP (q/q, ann. % change)	3.1	3.6	-0.4	1.4	1.4	1.6	2.0	2.4	2.4
Real GDP (y/y, % change)	3.3	2.9	2.2	1.9	1.5	1.0	1.6	1.9	2.1
Consumer Prices (y/y, % change)	2.3	2.6	3.4	2.9	2.6	2.2	1.8	1.9	2.1
Core CPI (y/y % change)	1.6	1.3	1.6	1.8	1.8	1.8	1.8	1.8	1.8
United States									
Fed Funds Target Rate	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
3-month T-bill	0.12	0.09	0.01	0.02	0.00	0.05	0.05	0.10	0.15
2-year Treasury	0.59	0.82	0.46	0.24	0.30	0.40	0.70	0.90	1.10
5-year Treasury	2.00	2.28	1.76	0.95	1.00	1.20	1.35	1.55	1.70
10-year Treasury	3.29	3.47	3.16	1.92	1.80	1.90	2.20	2.60	3.00
30-year Treasury	4.33	4.51	4.37	2.91	2.80	2.85	3.15	3.60	4.00
Real GDP (q/q, ann. % change)	2.3	0.4	1.3	2.5	1.5	1.2	1.4	1.7	2.0
Real GDP (y/y, % change)	3.1	2.2	1.6	1.6	1.4	1.6	1.6	1.4	1.6
Consumer Prices (y/y, % change)	1.3	2.3	3.5	3.2	2.8	2.0	1.6	2.0	2.1
Core CPI (y/y % change)	0.6	1.1	1.5	1.6	1.6	1.7	1.7	1.7	1.8
Spreads									
Target Rate	0.75	0.75	0.75	0.75	0.75	0.75	0.75	1.00	1.50
3-month T-bill	0.93	0.87	0.89	0.80	0.85	0.90	1.05	1.25	1.80
2-year	1.09	1.01	1.13	0.65	0.70	0.70	0.60	0.90	1.05
5-year	0.42	0.50	0.57	0.45	0.50	0.50	0.50	0.75	0.90
10-year	-0.17	-0.12	-0.05	0.24	0.30	0.30	0.25	0.05	-0.10
30-year	-0.80	-0.75	-0.82	-0.14	-0.10	-0.10	-0.15	-0.40	-0.60
Central Bank Rates									
European Central Bank	1.00	1.00	1.25	1.50	1.50	1.50	1.50	1.50	1.50
Bank of England	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Swiss National Bank	0.25	0.25	0.25	0.00	0.00	0.00	0.00	0.25	0.25
Bank of Japan	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Reserve Bank of Australia	4.75	4.75	4.75	4.75	4.75	4.75	5.00	5.00	5.00
Exchange Rates									
Canadian Dollar (USDCAD)	1.00	0.97	0.96	1.05	1.02	1.00	0.99	0.98	0.98
Canadian Dollar (CADUSD)	1.00	1.03	1.04	0.95	0.99	1.00	1.01	1.02	1.02
Euro (EURUSD)	1.34	1.42	1.45	1.34	1.40	1.42	1.42	1.40	1.40
Euro (EURGBP)	0.86	0.88	0.90	0.86	0.88	0.88	0.88	0.86	0.85
Sterling (GBPUSD)	1.56	1.60	1.61	1.56	1.60	1.61	1.62	1.63	1.64
Yen (USDJPY)	81	83	81	77	80	82	83	84	85
Australian Dollar (AUDUSD)	1.02	1.03	1.07	0.97	1.00	1.02	1.04	1.06	1.08
Chinese Yuan (USDCNY)	6.6	6.5	6.5	6.4	6.3	6.2	6.1	6.0	5.9
Mexican Peso (USDMXN)	12.3	11.9	11.7	13.9	12.9	12.9	12.7	12.7	12.7
Brazilian Real (USDBRL)	1.66	1.63	1.56	1.88	1.80	1.79	1.77	1.76	1.75

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FINANCIAL INDICATOR OUTLOOK *end-of-period level*													
	Spot Rate	2011				2012				2013			
	12/09/2011	Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
CANADIAN FIXED INCOME													
Overnight Target Rate (%)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.75	2.00	2.50
3-mth T-Bill Rate (%)	0.92	0.96	0.90	0.90	0.90	0.90	0.90	0.95	1.00	1.30	1.80	2.10	2.60
2-yr Govt. Bond Yield (%)	0.89	1.83	1.59	0.80	0.80	0.85	0.90	1.00	1.40	1.90	2.30	2.70	3.10
5-yr Govt. Bond Yield (%)	1.41	2.77	2.33	1.30	1.40	1.50	1.75	2.05	2.20	2.40	2.70	3.10	3.40
10-yr Govt. Bond Yield (%)	2.21	3.35	3.11	2.15	2.05	2.30	2.65	3.05	3.30	3.50	3.60	3.70	3.90
30-yr Govt. Bond Yield (%)	2.89	3.76	3.55	2.65	2.60	2.80	3.30	3.55	3.75	3.83	3.85	4.00	4.10
10-yr-2-yr Govt. Spread (%)	1.33	1.52	1.52	1.35	1.25	1.45	1.75	2.05	1.90	1.60	1.30	1.00	0.80
GLOBAL CURRENCIES													
USD per CAD	1.00	1.03	1.04	0.99	0.96	1.00	1.03	1.05	1.05	1.04	1.04	1.03	1.03
USD per EUR	1.37	1.42	1.45	1.41	1.40	1.40	1.40	1.45	1.45	1.42	1.42	1.38	1.38
JPY per USD	77.1	83.1	80.5	76.0	76.0	78.0	78.0	83.0	85.0	88.0	88.0	90.0	90.0

F: Forecast by TD Economics as at September 2011

Source: Statistics Canada, Bank of Canada, Bloomberg

Planning Process #:
4.5 & 6.14.4

PROJECT SCOPE DOCUMENT

FORTISBC

DATE: October 13, 2010

PROJECT NAME: P2 Old Plant Spare Transformer Acquisition

PLANNING No: PLN11-3052 **FILE CODE No:** 250-20

FortisBC OWNER: Ian Finke **BUDGET:** Capital

PROJECT MANAGER: Lane Hutton

PROJECT SCOPE DESCRIPTION:

1) **OBJECTIVE:**
   - To procure FortisBC Construction and Maintenance division's old 6.5 MVA mobile substation and remove the transformer to use as a spare step-up transformer for Units 1, 2, 3 and 4 at the Upper Bonnington generating station.

2) **SCOPE:**
   - Transportation of the mobile substation to South Slocan.
   - Build a temporary oil containment to enclose the mobile sub.
   - Remove the transformer from the trailer including:
     a) Remove the HV bus and HV switch sections
     b) Remove the side paneling
     c) Remove the LV bushing cabinet and LV breaker cabinet
     d) Remove the existing control and metering equipment
     e) Remove the existing station service transformer
     f) Modify the mounting platform on the tractor trailer to allow for a bolted connection of the transformer for future removal
   - Repair or replace oil pump and cooling fans.
   - Repair or replace oil temperature and level sensors, pressure relief vent and flow switch.
   - Install new cabinet for controls and starters for fans and pumps.
   - Installation of new 600-120/240 3-phase transformer for pumps and fans.
   - Re-condition transformer oil.
   - Replacement of silica gel.
   - Re-gasketing of bushing flanges, ports, inspection covers.
   - Dry out transformer and purge with nitrogen.
   - Vacuum fill the transformer with reconditioned oil.
   - Perform acceptance tests of transformer.

Date ______________________ Date ______________________

FortisBC Owner Sign Off ______________ Project Mgr Sign Off ______________

3) JUSTIFICATION:

- The generating voltage of units 1, 2, 3 and 4 at Upper Bonnington is 2300 volts which is unique to the rest of the FortisBC river plants. The new spare step-up transformer currently on site could not be utilized should one of these four transformer banks fail.
- Two of the four transformer banks are made up of three single phase transformers which are cooled by a closed water loop circulating inside the transformers. Due to excessive age and corrosion, one of these transformers banks has already experienced a damaged cooling water line which flooded the inside of the transformer with water and rendered the unit inoperable for an extended period.
- The life expectancy of two of the transformer banks has already been passed and a low-cost alternative to provide backup generation is required.
- The mobile substation from the Construction and Maintenance department is still operational and with some modifications can be made to serve as a reliable backup in case of a major transformer failure at the P2 plant.
- The spare transformer is rated at 6.5 MVA, which with the existing units being rated at 6, 5.6, 5.6 and 6 MVA collectively would allow for normal generated output.

4) CRITICALITY:

- Possible loss of generation due to an inoperable step-up transformer bank.
- Loss of generating revenue due to loss of entitlement in accordance with the Canal Plant Agreement.

Risks:

- Loss of generation
- Loss of entitlement

Preceding Jobs:
N/A
Succeeding Jobs:
N/A

5) LOCATION: P2 Upper Bonnington

6) SCHEDULE: 2012

Date ______________________ Date ______________________

FortisBC Owner Sign Off ______________________ Project Mgr Sign Off ______________________

7) **IS AN OUTAGE REQUIRED:** No

8) **OUTAGE DURATION:** N/A

9) **IS AN ASSET BEING REMOVED FROM "PLANT-IN-SERVICE":** No

10) **ASSET REMOVAL DESCRIPTION:** N/A

11) **PERFORMED BY:** FortisBC

ADDITIONAL INFORMATION:

- Testing to be performed on the transformer including but not limited to:

  a) Insulation resistance core and windings
  b) Ratio test on all tap positions
  c) Power factor test on windings, bushings and oil
  d) Sweep frequency response analysis
  e) DC resistance tests on all tap positions
  f) Oil quality sample
  g) Function tests on oil pumps, fans, gas relay
  h) Test operation of oil temperature, level sensors and flow switch
  i) Internal inspection
  j) Paper sample for polymerization analysis
  k) Vacuum fill transformer
  l) Re-conditioning of transformer oil

Date ______________________ Date ______________________

FortisBC Owner Sign Off ______________________ Project Mgr Sign Off ______________________

FINAL REPORT

Analysis of Heat Pump Installation Practices and Performance

Prepared for the

Heat Pump Working Group

ECOTOPE
CONSULTING
RESEARCH
DESIGN

Stellar Processes

David Baylon
Shelly Strand
Bob Davis
David Robison
Erin Kruse

December, 2005

Executive Summary

In 2004, a consortium of entities active in the conservation of energy in the Pacific Northwest, including the Bonneville Power Administration (BPA), the Northwest Energy Efficiency Alliance (Alliance), the Energy Trust of Oregon (Trust), the Northwest Power and Conservation Council (NPCC), Idaho Power and other regional utilities funded an in-depth study of heat pump performance in the Pacific Northwest. Heat pumps have enjoyed a significant increase in popularity in recent years, both with the public and with utility program designers. This study used a variety of analytical methods to assess the overall performance of heat pumps in Northwest climates and to identify the factors that have the most impact on the efficiency achieved. The study design was intended to address a number of project goals:

1. Assess the energy use and savings from heat pumps installed under the Conservation and Renewables Discount (C&RD) and Conservation Augmentation (ConAug) programs, and under the CheckMe!® program operated by the Eugene Water and Electric Board (EWEB).

2. Assess base case installation practices.

3. Assess heat pump performance under laboratory conditions to determine the performance impacts of variations from manufacturer-recommended refrigerant charge and air flow on system capacity and efficiency.

4. Assess the general approach of installers to control, sizing and performance issues; and of manufacturers to new technologies, etc.

To accomplish these goals, Ecotope conducted the following research steps:

1. ***Billing Analysis***: A large-scale billing analysis was conducted in targeted geographic areas across the region. These areas were chosen to represent a range of regional climate zones and building characteristics. A control group was selected to match each of the participant regions and also subjected to a billing analysis so that weather impacts could be removed from the savings calculations. A smaller analysis of about 400 customers of the Eugene Water and Electric Board (EWEB) was conducted to determine if savings could be attributed to use of a refrigerant charge and airflow field procedure used in the EWEB service territory and in other areas of the Pacific Northwest.

2. ***Field Review***: An extensive field review was conducted to examine the heat pump as installed, its set up and control strategy, and the characteristics of the ducts and house. This review included complete Duct Blaster® and blower door tests, as well as a check of the refrigerant charge. A separate billing analysis was conducted for this subset of the sample, which provided more detailed information for factors such as duct efficiency, Heating Seasonal Performance Factor (HSPF) and system sizing.

3. ***Laboratory Testing***: Ecotope developed a matrix of testing requirements to determine the impact of charge and airflow on overall heat pump efficiency under a variety of loads, and contracted with Purdue University to conduct these tests under strict laboratory conditions. These tests were conducted in heating mode and were meant to augment the data previously collected on cooling mode performance, primarily for the California climate.

4. ***Distributor & Installer Interviews***: Ecotope interviewed installers, distributors, manufacturer's representatives and other stakeholders to elicit data on equipment selection, sizing strategies, installation techniques and other issues that impact heat pump performance.

This effort has resulted in a much deeper understanding of the performance of heat pumps as installed under the C&RD and ConAug programs to date, as well as important information about what factors have the greatest impact on that performance.

Overall Findings and Conclusions

The various avenues of inquiry converged on some clear results regarding heat pump performance.

- From the billing analysis, it is clear that heat pumps are performing at or near what might be considered the expected level, at least for the C&RD/ConAug program participants. Savings averaged approximately 4,149 kWh/yr., representing about 15% of total electricity use. The overall realization rate was about 70% of savings anticipated when original Regional Technical Forum (RTF) estimates were prepared. The RTF had revised its original savings estimates downward as more data became available. When compared to the newer estimates, the realized savings were about 85% of expected.

- The EWEB billing analysis indicate average savings of about 360 kWh/yr. compared with a control group that did not receive the CheckMe!® service. Savings could not be attributed to the performance of the CheckMe!® procedure itself but since about 85% of the savings seen in the EWEB billing analysis came from the top 15% of heating energy consumers, it appears the correction of severe problems in a limited number of cases was more important than adjusting refrigerant charge and/or airflow.

- The Purdue laboratory data, the EWEB billing data, and the field review all indicate that running the system with non-optimal refrigerant charge does not have a significant impact on heat pump performance in heating mode. The system had to be run at 20% or more undercharge before any reduction in efficiency was noted. In fact, the data points to a slightly undercharged system as the optimal condition in heating mode. This was an unexpected finding, since previous research focused exclusively on the cooling mode did find significant efficiency impacts from over- or under-charged compressors.

- The field study of base case installations found a number of important findings. First, only about 10% of systems were found with undercharged compressors. Only a few systems out of the approximately 140 evaluated were seriously undercharged, and these systems were overdue for service. Low airflow across the indoor coil was noted in about 25% of cases. Airflow is an important determinant of field performance and remains a central part of ongoing field verification efforts in the Northwest. Control of auxiliary electric resistance heat in non-C&RD heat pumps is not carefully done and is assumed to be handled by adaptive recovery thermostats even though it can be easily circumvented by the system operator.

- There is a fairly high level of education about efficiency issues amongst regional installers, according to both our field audit results and contractor interviews. Installers generally understand the trade-offs inherent with heat pumps (more comfort compromises efficiency) and usually come down on the side of more comfort. This should be of concern to regional policymakers and utilities that expect rated efficiency from new heat pumps.

- Heat pump systems tend to be sized to about 70% of the required heating load according to the field research and interviews. Contractor interviews indicate that this is due primarily to first-cost considerations. Larger systems (more "tons") mean most or all of heating season requirements can be met by the refrigerant cycle rather than by auxiliary heat, but it is cheaper at the initial point of installation to install a smaller compressor and a larger resistance element combination. There is ongoing debate in the region on the best way to size a heat pump. The expected increasing use of multiple-capacity compressors will complicate this issue but may result in more heating energy coming from the refrigeration cycle and less from auxiliary heat, which will enhance the effectiveness of the heat pump in delivering conservation.

- Despite the continued positive development of regional installation standards, there is still a need for field verification of system performance. This field verification cannot be limited to evaluation of charge and airflow, as it has been in the past, but must be extended to system controls. Field verification cannot be limited to the installer's report but must include an additional layer of quality assurance. This is both to ensure the performance of the system and to maintain currency with the more advanced systems that will be installed in 2006 and later.